Market design for valley-filling demand response

An AER Demand Response Participation submission forming a companion to a proposal submitted to AEMC AER AEMO in advance of AEW 2021

v 210415a

How can demand-side market participation be designed to: 1) maximise Australia's clean power and certified fuel production, 2) benefit all market participants: powerfuel producers, generators, consumers, and transmission network providers, and 3) ensure that market rules are technology-agnostic ?

Key premise from NEM design perspective:

There is no doubt that minimum-demand concurrent with high residential rooftop solar production is a real and near-term system security risk to the NEM. SA is on track to encounter this risk by 2023. Hence demand valley filling can and likely should be empowered by the same demand-side market participation rules as those envisioned for "peak shaving": the only difference being bottom up in lieu of top down market price impact. Powerfuel production is the most obvious application of valley filling demand response, but new rules can obviously apply to any valley filling energy consuming technology.

Key assertion from response perspective:

Increasing participation of VRE in the NEM is supported in part by technologies that time-shift energy delivery for later consumption (e.g. batteries, pumped hydro, thermal storage). But these technologies unnecessarily constrain market growth. In contrast, scalable production-excess consumption technologies can consume excess production and permanently remove it from the market. With sufficient demand-side participation of this type, total system energy delivery need not be capped, and production and consumption capacities can grow concurrently. Powerfuel production is a prime candidate for this role. For example, certified hydrogen can produced from excess VRE and exported to Asia and/or delivered to the domestic gas market, displacing current retail natural gas consumption.

Key assertion from powerfuels economics perspective:

Grid-connected certified powerfuels can compete with off-grid powerfuels: 1) if they can be certified as "clean"; 2) if revenue from grid-connected powerfuel is shared between fuel sales and grid services (e.g. FCAS); and 3) if the capital cost recovery of VRE infrastructure is shared with other-than-powerfuel consumers. Certification of powerfuels as "clean" requires evidence of the CO_2-e inheritance from electricity consumption. Once a NEM Region reaches zero fossil fuel power production, all powerfuel produced in that Region will be certifiable. In the interim, electricity consumption costs and hence CO_2-e inheritance decides the degree of utilization and hence electrolyser capital cost amortisation. Currently, the SA and TAS Regions are on track to reach near zero fossil fuel production ahead of other regions. The SA Region already has a sufficiently high proportion of VRE to have generated data sufficient to assess the impact of demand-side powerfuels participation in the market.

Key assertion from Operator (AMEO) and Regulator (AER) perspectives:

Supply and demand market design is required by legislation to be agnostic towards technologies and industry sectors. Despite the emphasis here on powerfuel technology as a prime candidate for demand-side market participation, other unforeseen candidates with similar techno-economic characteristics may emerge. The following short "paper" presents the economic opportunities that would arise from demand-side participation in the NEM.

Market design for grid-connected certified powerfuels

Background to a proposed stakeholder outreach /consultation

In proposing the application of two-sided markets, (Appendix C), Australia's Energy Security Board (ESB) has focused on 'demand response' and 'demand peak shaving' as a means to stabilise energy prices at times of peak demand [1,2].

Demand valleys[3] (times of very low demand) also affect system security and network load factors. In South Australia, demand valleys are now almost deep enough to trigger system failure. Can two-sided market design incorporate both 'demand peak shaving' and 'demand valley filling'? Can development of a growing powerfuel market[4,5] provide techno-economically efficient responses to demand valleys?

When operational demand is low and renewable production is high, prices fall to and sometimes below zero. With increasing proportions of renewables, these effects occur increasingly frequently. Expansion of roof-top solar further increases the risk of approaching the minimum demand required for system security. Accordingly, curtailment of wind power production by the Australian Energy Market Operator (AEMO) has increased over the last several years, and AEMO is now considering curtailment of roof-top solar. While this may be technically sufficient to maintain system security, it will become grossly economically inefficient, due to lost opportunities to sell otherwise valuable renewable energy (See Figs 1,2).

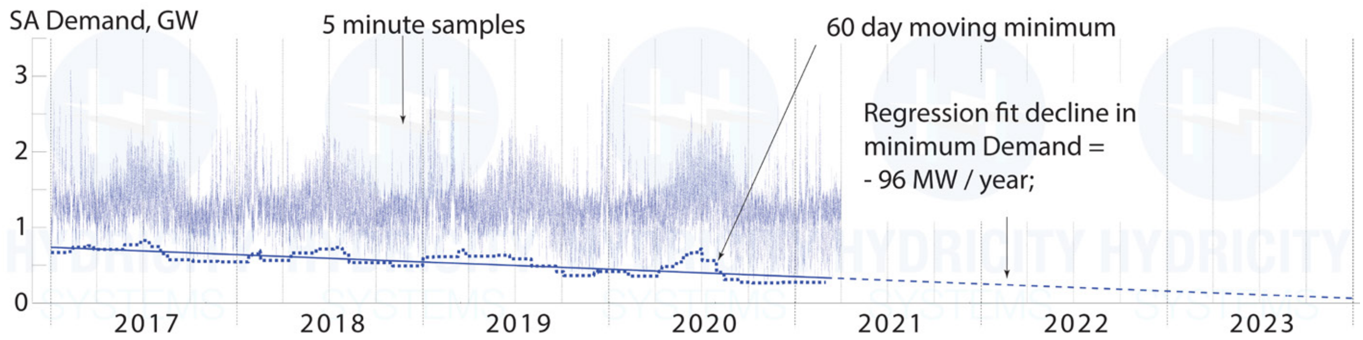

Fig 1: Actual SA Demand 2017 - 2021 with extrapolation of minimum trend to 2023

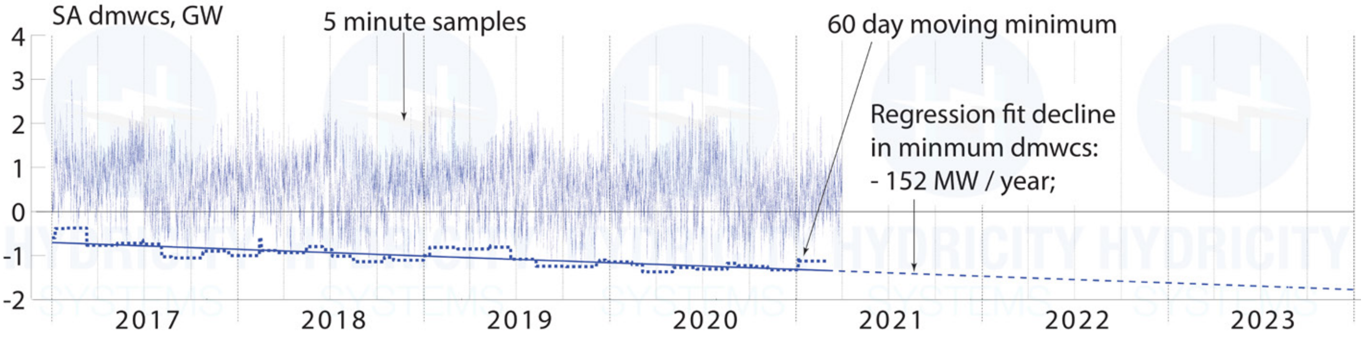

Fig 2: Actual SA Demand minus VRE and curtailment 2017 - 2020 with extrapolation of minimum trend to 2023

Robust (price-influencing) demand-side participation in the electricity market offers a techno-economically efficient solution. Consider the observed history and projected evolution of the South Australia region of the NEM, starting with price as a simple function of operational demand:

1998-2010 $RRP_{SA} = f\ (\ OpDemand\ )$

2010-2025 $RRP_{SA} = f\ (\ OpDemand - VRE\ production - VRE\ curtailment\ )$

2025-2050 $RRP_{SA} = f\ (\ OpDemand - VRE\ production - VRE\ curtailment + DemandMarket\ )$

Powerfuel production is a prime candidate for demand-side market participation to fill demand valleys. Among the mechanisms listed above, powerfuel production adds new demand, permanently removing excess VRE production from the NEM. In contrast, storage merely time-shifts demand across periods constrained by storage capacity.

As presented in the following table, scheduled loads and informal two sided markets without price auctions do not remove excess VRE and have limited influence on regional prices. In contrast, as presented in the third row of the table and the Figures below, a willingness to buy electricity expressed in terms of a purchase bid stack has clear potential to robustly influence price.

	Market Mechanism	**Current examples in SA**	**Price influence**	**Removes excess VRE**
1998-2025	Scheduled Market Loads	Load side of SA's 3 batteries	Barely observable due to FCAS business model (see Appendix E and pages 180-191 of IEA Hydrogen's T38 report[4]	No
2025-2030	Two-sided markets applied to demand response without price auctions	See Appendix C	To be determined	No
2025-2050	Robust demand-side participation	n/a to date	See graphics below	Yes

In robust demand-side participation, powerfuel produced during periods of otherwise excess renewable power production will result in marginal price increases. Modelling[6] shows that these increases are directly related to the maximum price at which powerfuel production systems are willing to buy power (Fig. 3) and the total regional powerfuel production capacity.

Further, with a robust demand side market design, expectations that powerfuel production will indefinitely rely on exploiting very low, zero, and below zero prices (Fig. 4) become obsolete. Instead, the competition to purchase valley-shaving power can marginally increase total power costs, in a way that scales according to 1) regional powerfuel production capacity, 2) maximum buy-bid price, and 3) renewables production scale (Fig. 5).

In contrast to arbitrage, which does not substantially affect load-duration curves (the dotted curve in Fig. 6) demand-side market-driven powerfuel production initially lifts load duration curves, lowering the risk of system failure due to unacceptably deep demand valleys. As powerfuel production capacity grows, the transmission network (peak operational demand + power consumption by powerfuel production systems) is affected only if the willingness to buy (max_buy_price) threshold is high. The top-most curve in Fig. 6 shows that even with the 500% increase in renewables by 2050 that is currently proposed by the SA government, the impact on network capacity is easily managed by clipping a small proportion of powerfuel production.

The notion that market-based valley filling removes any ongoing need to curtail roof-top solar to artificially 'generate' residential demand is presented in Fig 7. The minimum total demand becomes the current capacity of powerfuel production.

For powerfuel certification, the ability to compute acceptable CO_2-e inheritance regardless of purchase contract terms 'comes for free' in a demand side market (Fig. 8).

The need for storage depends on the downstream fuel consumer technologies and their tolerance of fuel consumption intermittency. The range of this tolerance is from accepting periods of zero consumption, up to some fixed consumption rate 24/7 365 days per year. Examples of the transformation of intermittency required to accommodate fixed off-take are presented in Fig 9.

Fig. 10 presents the intermittency of production from demand market based power purchases.

In conclusion, the primary objective of the proposed panel session is to discuss new demand-side market designs for valley filling. Such approaches could either extend or complement 'demand response'. As presented here, such designs can be expected to lead to the deployment of grid-connected powerfuel production in techno-economically efficient ways that benefit all players: producers and consumers of both hydrogen and electricity, and transmission and distribution network providers.

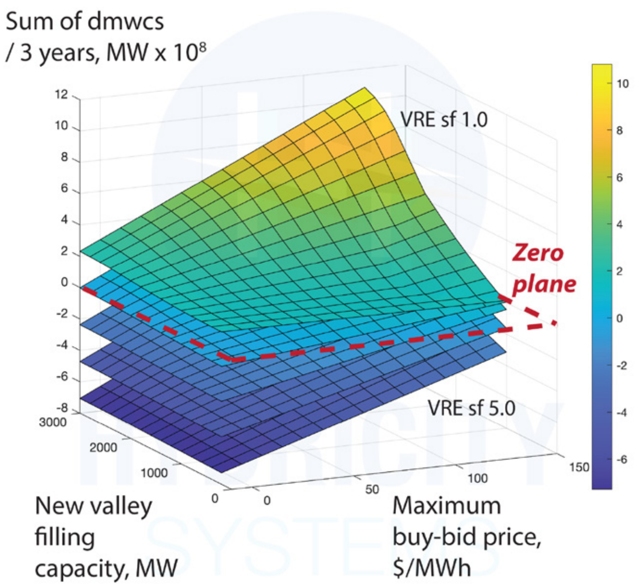

Fig 3: The total operational demand plus powerfuel demand minus VRE production over 3 years across the SA Region, increases with respect to each of the maximum powerfuel bid price, the regional powerfuel power consumption capacity and the scale of renewable energy capacity relative to 2020.

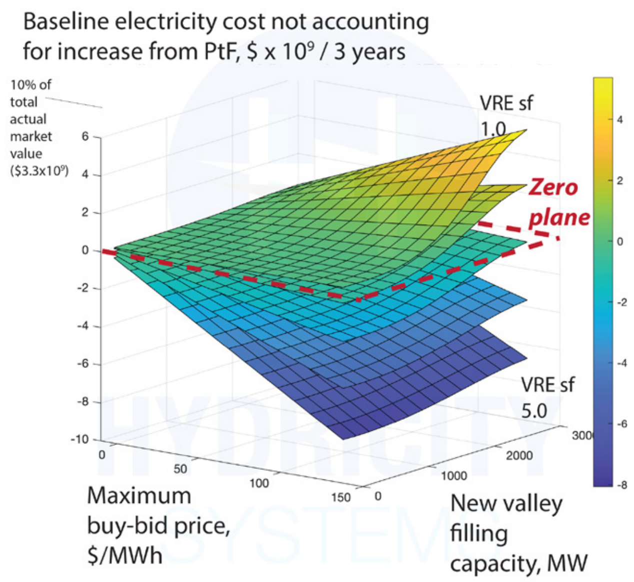

Fig 4: If the economics of the impact of powerfuel demand is not accounted for, the notion of "negative prices" persists which is clearly not sustainable.

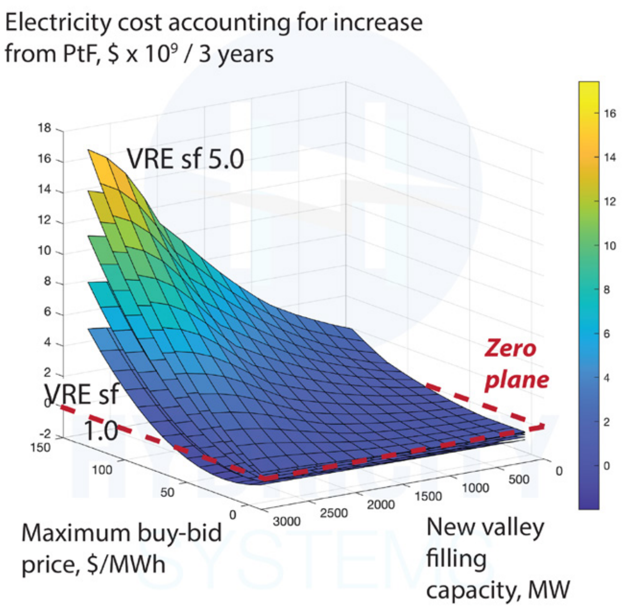

Fig 5: In contrast to Figure 2, when the impact of powerfuel demand is robustly accounted for in two-sided market in which powerfuel operators bid to buy electricity, everyone wins and the system is sustainable well into the coming decades of the 21st Century.

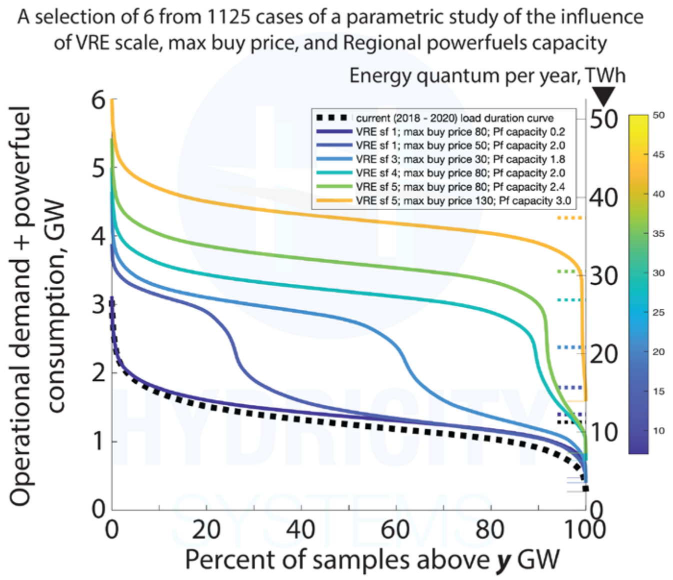

Fig 6: Whereas arbitrage has no effect on the load duration curve, demand market driven powerfuels lift the load curve in a natural (economics sense) way starting from right and ending and an easily capped (if required) peak on the left. The y-axis labels on the right show the corresponding evolution of energy per year delivered as "molecules" vs "electrons".

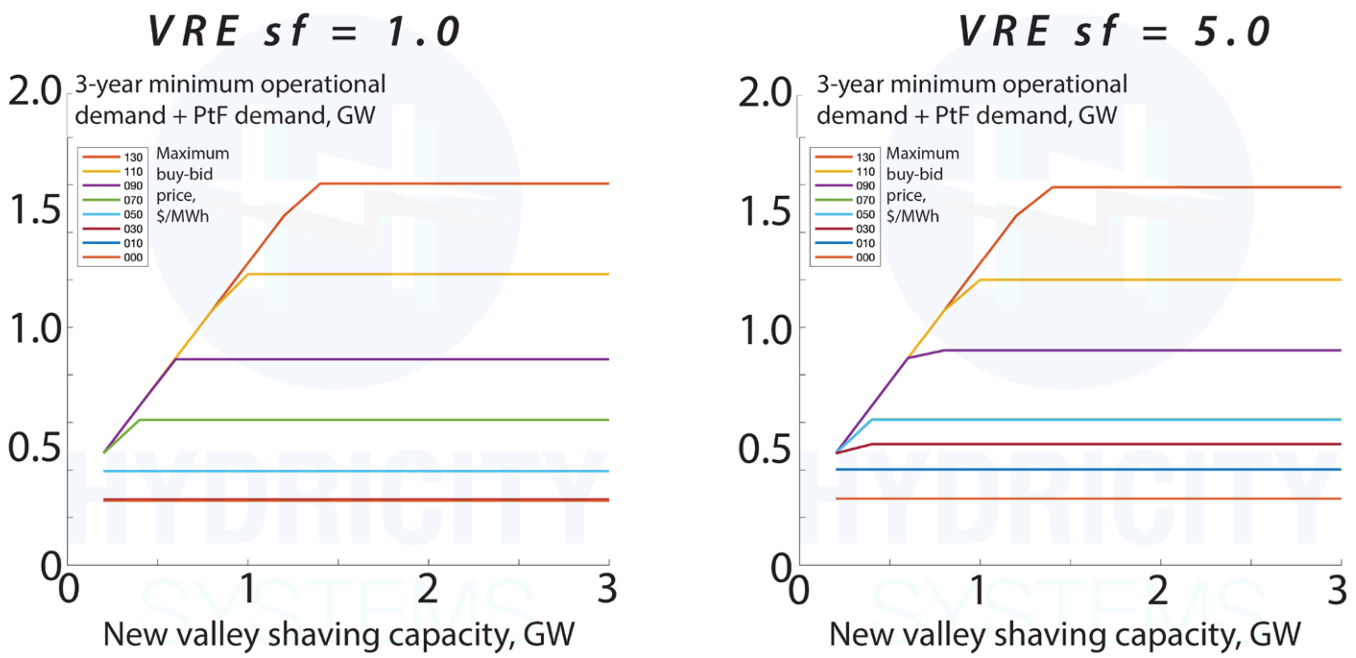

Fig 7: Regardless of the VRE scale, the 3+ year minimum operational demand plus powerfuel demand increases in a natural way (market economics sense) according to the willingness-to-buy-price.

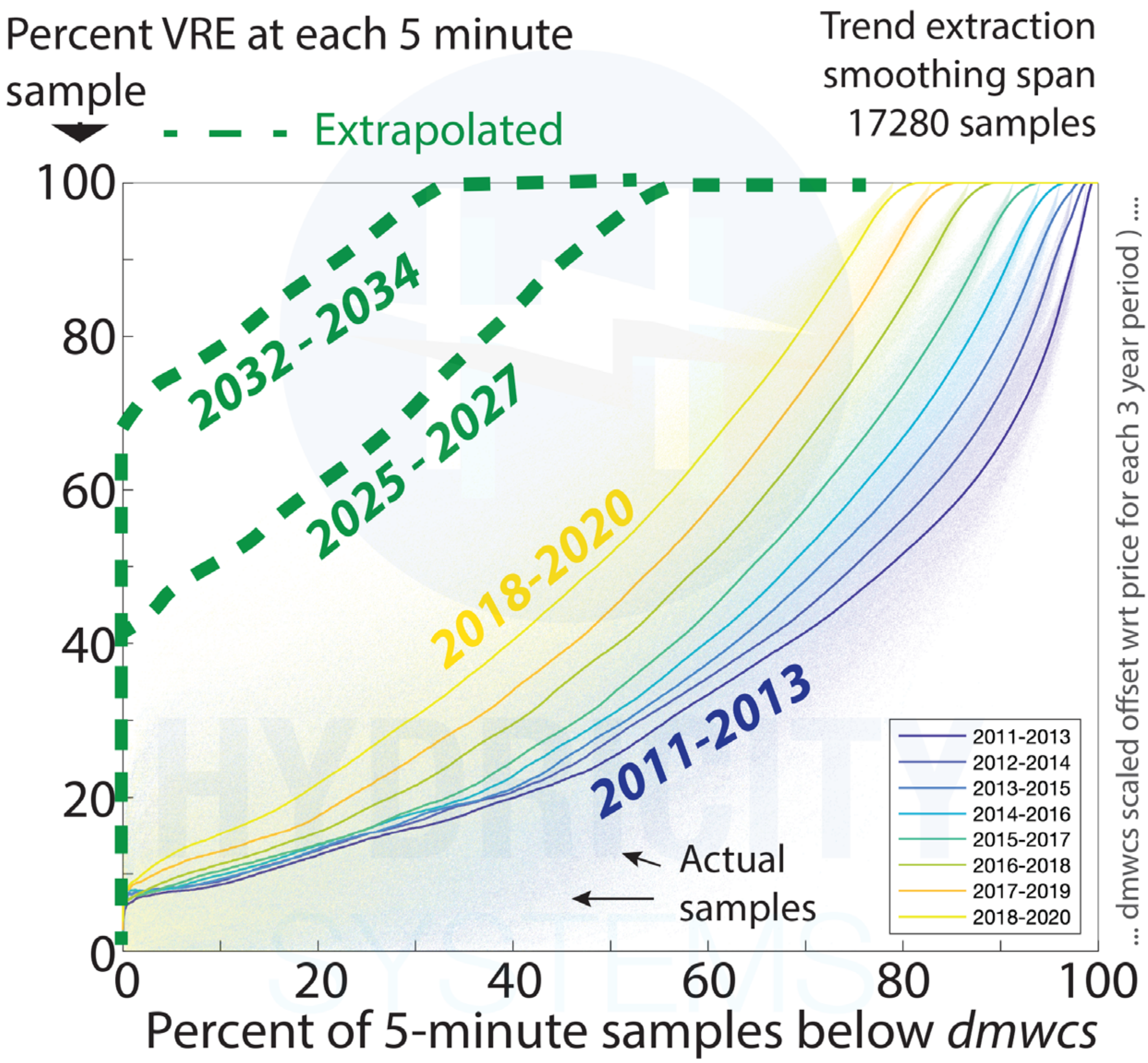

Fig 8: This graph shows that there is a clear statistically robust relationship between dmwcs, price, and VRE proportion. In turn, this provides clear unambiguous basis for computing CO_2-e inheritance in powerfuels regardless of wholesale or retail contract arrangements: all that is needed is a trustworthy accountable record of a powerfuel plant's consumption with respect to time.

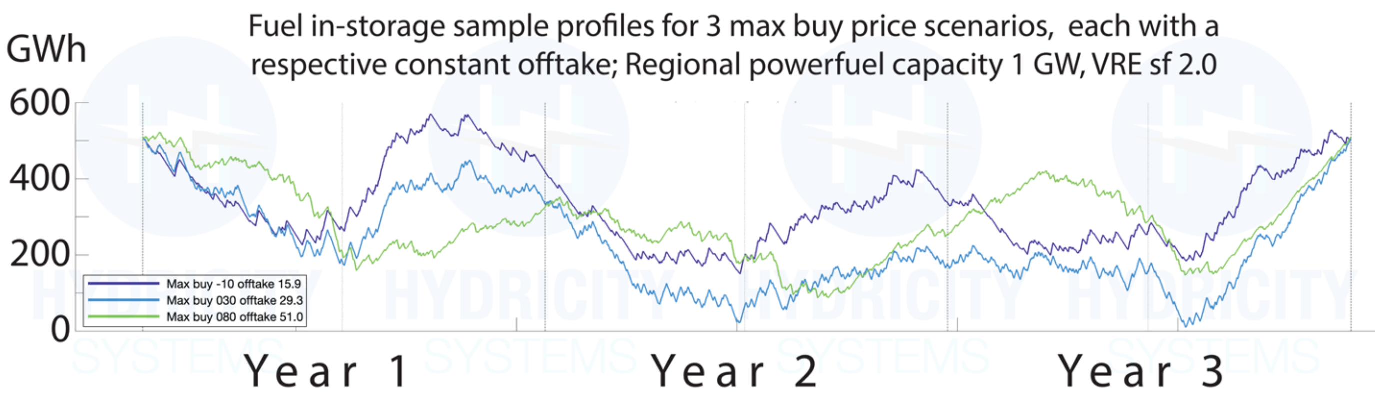

Fig 9: This graph shows the same three configurations as the VRE sf 2.0 case in Fig 7. These are the "worst case scenarios" regarding storage requirements, for a given inter-seasonal storage capacity and production capacity. The maximum off-take rate relates directly to the maximum buy-price: the higher the buy-price, the higher the uptime, and in turn, the higher maximum off-take rate.

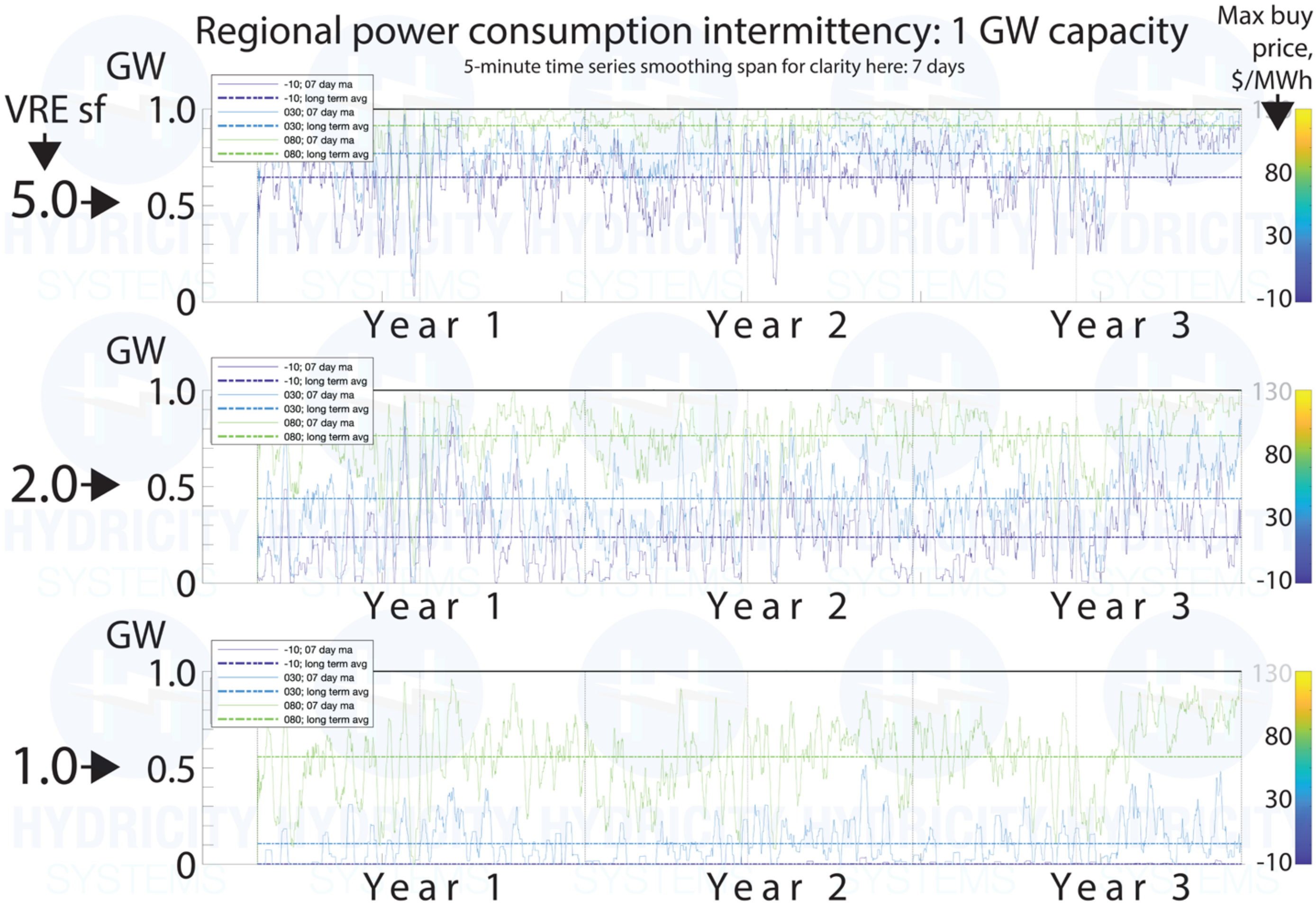

Fig 10 This graph shows how demand market based power purchases drive intermittency and in turn production per year. In all three graphs, the same Regional powerfuels capacity slice of the multidimensional scenario study is presented: 1 GW. From bottom to top (current SA VRE capacity to 500% current capacity by 2050 as suggested by currently proposed SA energy policy:

- At current SA VRE capacity, such an infrastructure network would need to be willing to pay at least 80 $/MWh to produce sufficient powerfuel to justify the 1 GW capacity.
- At 500% of current SA VRE capacity, the maximum buy price for productive effective uptime is reduced to at or near zero before adjusting for the impact of demand markets on marginally increasing otherwise-demand-trough prices.
- At any given VRE-capacity slice through the scenario study, it is easy to identify potential future trade-offs related to reductions in electrolyser capital costs, power consumption costs, and uptime per year.

Acknowledgments:

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End notes:

1 Energy Security Board. December 2020, The Health of the National Electricity Market
2 “Towards a two-sided market, the role for demand response in tomorrow’s grid”, Ecogeneration, Dec 2020
3 The currently observed demand minima in SA are short duration “troughs”. We use the term valley with a view to the intermediate and long terms when troughs widen to become valleys expanding the role for demand markets.
4 IEA Hydrogen, January 2021, Final Report of Task 38 Power to Hydrogen - Hydrogen to X
5 Global Alliance Powerfuels, Dena, https://www.powerfuels.org/home/
6 See summary graphic in Appendix B

Appendicies

Appendix A

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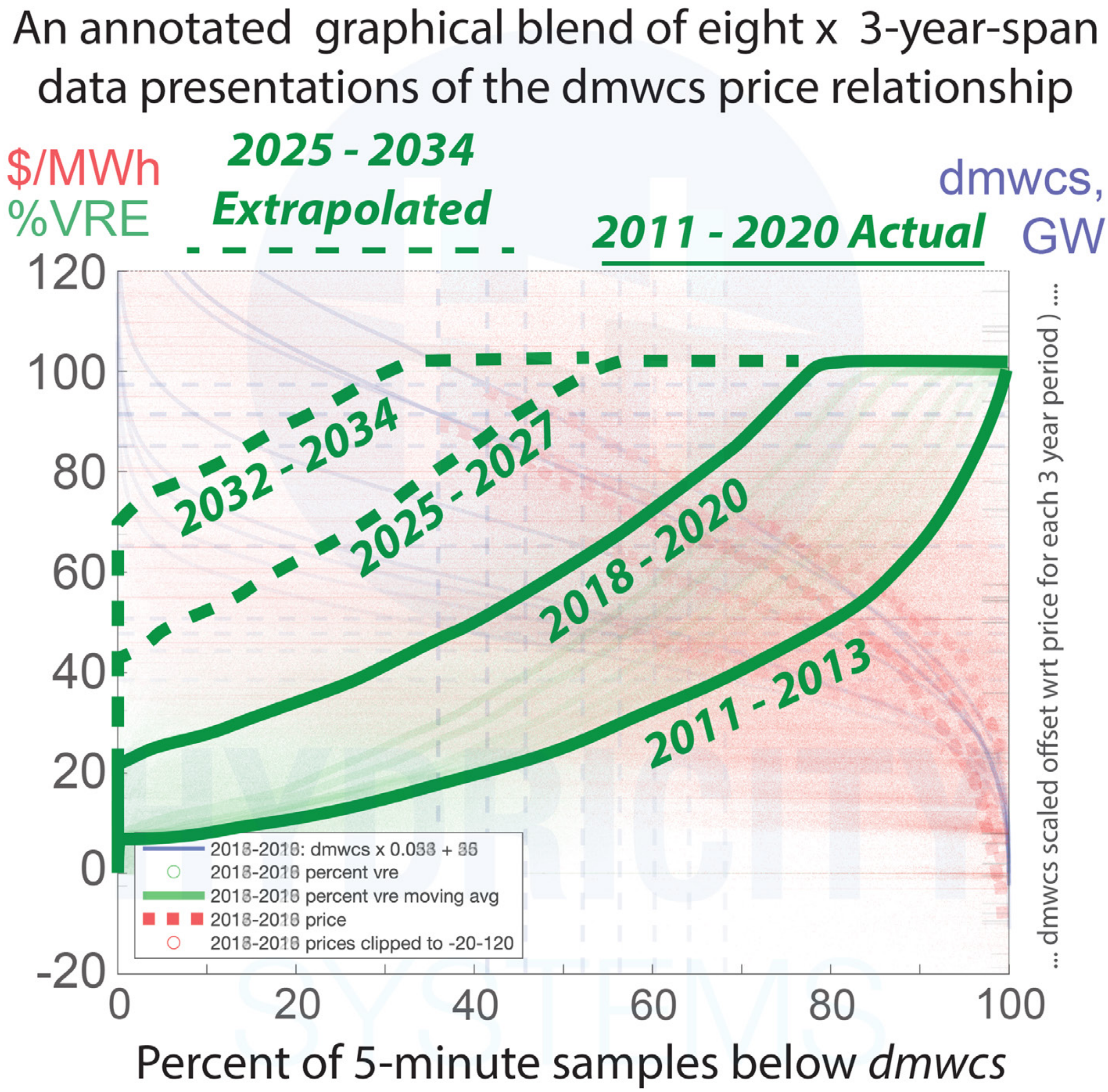
Appendix B

A "compressed" visualization of the price =
f (operational demand, powerfuel demand, wind power production, wind power curtailment, and large scale solar production ***)***



Appendix C

References to ‘two-sided markets’ in Energy Security Board documents

Energy Security Board
Post-2025 Market Design Directions Paper
January 2021

Of 50 or so references to ‘two-sided markets’ in the Post-2025 Market Design Directions Paper, only one refers to minimum demand.

Page 8:

> **Demand side participation**
>
> Customers should be rewarded for this flexibility where it is efficient to do so. To support this, the ESB is pursuing an integrated set of reforms, that incorporates market integration of DER, establishing a ***two-sided*** market and associated scheduling, technical, regulatory, consumer protection reforms.

Page 10:

> Setting a clear pathway for future changes to market design, and the accompanying roles and responsibilities to support an effective future ***two-sided*** market, is an important outcome of the Post-2025 program. ...
>
> ... This plan is intended to provide a pathway to jointly consider and determine future roles and responsibilities needed to support an effective ***two-sided*** market. ...
>
> Customer groups have had an active interest in the development of the ***two-sided*** market policy and customer advocates are keen to work with ESB and the market bodies to develop a customer protections framework that is more fit for purpose.

Page 36:

> Other Market Design Initiatives that affect resource adequacy and the ESB’s direction are: ... ***two-sided*** market, flexible demand and DER integration.

Page 37:

> A future where government underwrites new capacity sufficient to dampen spot prices in the wholesale market has a few ramifications for a ***two-sided*** market and the value of flexible demand and DER.

Page 57:

> While supportive of the concept of a ***two-sided*** market, many stakeholders agreed further work is needed to understand the barriers to participation, to reduce complexity and develop a clearer understanding of the potential value and flexibility of flexible demand.

Page 58:

> Setting a clear pathway for future changes to market design, and the accompanying roles and responsibilities to support an effective future two-sided market, is an important outcome of the Post-2025 program. ...
> Customer groups have had an active interest in the development of proposals for a ***two-sided*** market.
>
> **5.1.1 The case for a *two-sided* market**
>
> Stakeholders provided feedback in response to questions asked in the September Consultation and on related matters. Insights have also been gathered via the DER Integration engagement processes.
>
> While a majority of stakeholders welcomed a move to a more fully developed ***two-sided*** market, some questioned whether the case had really been made. Some stakeholders were concerned about the pace of reform and suggested that current initiatives (such as the wholesale demand response mechanism) should be implemented and evaluated before moving to additional measures.
>
> Stakeholders suggested the ESB carry out a more detailed assessment of the benefits and analyse the potential for the demand side to actively participate. This was linked to concerns about the feasibility of a large numbers of consumers engaging in a ***two-sided*** market. The barriers may be difficult and costly to address – these include the lack of cost-reflective price signals for small retail customers and perceived low levels of consumer engagement, understanding and trust.

Some stakeholders are concerned that the move to a ***two-sided*** market may not deliver equitable outcomes, suggesting the majority of benefits would be delivered to those customers who could afford to invest in rooftop solar, and DER more generally, partially at the expense of other customers.

Page 59:

Stakeholders noted that the DER Integration and ***Two-Sided*** Markets workstreams should work closely to remove barriers to aggregators providing services to customers.

Page 60:

Most NSPs are supportive of a two-sided market but are generally opposed to integrating the ***two-sided*** and DER workstreams due to the limited solar PV (and other forms of DER) capable of active management.

Page 62:

Of the limited number of stakeholders who did not support the move to a ***two-sided*** market, the main concern raised was that the two-sided market was too complex (including responses from Snowy Hydro and Dr M Gill) and that it would result in more complexity for consumers (Energy Queensland).

....

The growing uptake of DER means it is increasingly important to improve how the NEM integrates both supply and demand resources. Stakeholder feedback highlighted a number of challenges in making the shift to a ***two-sided*** market.

Page 63:

The ESB intends to progressively introduce reforms and controls which support a move to a ***two-sided*** market that addresses these challenges and unlocks value for all customers. While a ***two-sided*** market already exists for some large customers, a range of technical and process specifications limit the potential for many large loads to bid directly into the wholesale market, and smaller customers are further restricted from participating at all under the current framework.

Page 69:

The ESB considers that, while it is appropriate to keep the scheduling and central dispatch framework voluntary, the transition to a more active ***two-sided*** market should continue to be monitored.

Page 71

The key entities and elements in the trader-services model are set out in the earlier ***Two-sided*** market consultation paper.

Page 73

Energeia recommended that addressing these issues would provide a clearer path for customers to undertake the works required to engage with multiple financially responsible market participants and achieve a ***two-sided*** market. The ESB is developing an indicative cost benefit analysis method to assess new participation models on the path to a full ***two-sided*** market trader model.

Page 75

The use of such measures (by governments and/or other bodies) could assist in increasing the numbers of customers wishing to participate in a ***two-sided*** market, thereby increasing the availability of potentially flexible demand. This would increase the reliability, security and affordability benefits delivered to all customers. The ESB is working with the ECA and consumer groups to help identify how different segments of consumers would engage in a ***two-sided*** market.

Page 76

For the more strategic design of the ***two-sided*** market, there are a number of issues that must be considered as part of assessing the roles networks should play; e.g. should we expect tariffs to line up with wholesale price signals, should we rely on their impacts to address security issues such as minimum demand, and are they nimble enough to deal with the pace of change? ...

Page 79

The Post-2025 program will set out a pathway for development of a future ***two-sided*** market as part of a progressive phased approach to provide greater clarity to the market, stakeholders and customers. ... There is a need to address uncertainty regarding future roles and responsibilities in a ***two-sided*** market – the ongoing lack of clarity is leading to further uncertainty, uncoordinated and inefficient investment decisions. ...

Establishing a clear architecture, and accompanying roles and responsibilities to support the new two-sided market will be a major step forward in reducing this uncertainty, building consumer trust and providing long term clarity of direction for the DER community.

Page 80

The essential architecture of the future ***two-sided*** market can be explained as a platform that is capable of integrating customer owned energy technology systems and applications.
Roles and responsibilities in the ***two-sided*** *market*

The process for identifying roles and responsibilities for the new capabilities is an important component to supporting development of an effective ***two-sided*** market. Previous processes, such as the Network Transformation Roadmap and the Open Energy process, have outlined high level design concepts such as the hybrid model but stopped short of moving into sufficient functional detail needed to make meaningful decisions on detailed responsibilities. Decisions on these questions will be important to support the effective integration of DER into future ***two-sided*** market arrangements.

To support a fully effective two-sided market design, decisions will need to be made on these issues. ...

Page 81

Where DER penetrations increase sufficiently, consider how the future ***two-sided*** market may see a tighter coupling between the distribution network and transmission level energy, capacity and security services, and in the need for an expanded approach to co-optimisation.

... The rationale for moving to a Maturity Plan is to put a clear structure in place for governance, decision making and delegation. Specifically, this would cover system-wide architecture and design, roles and responsibilities, and technical progression and implementation of capabilities for the ***two-sided*** market. The plan would include scope of all aspects of long-term deep integration of DER across the system, including technical standards, regulatory issues, network access and market participation and articulate a clear transition path to the future state ***two-sided*** market.

Page 82

As the first step, the future vision of the ***two-sided*** market must be articulated and communicated with all stakeholders.

Page 83

In a ***two-sided*** market, the role of the consumer (end-user) changes. While an end-user will not need to participate in a ***two-sided*** market any more than they would today, the ability for a trader (such as a retailer or an aggregator) to shift a customer's load or import or export their energy will become a fundamental part of the market.

The new opportunities that will come from a ***two-sided*** market bring potential new risks for consumers. Given this, and the low base of consumer trust, a strong consumer protection framework is an integral part of the move to a ***two-sided*** market as well as a focus on reducing or removing complexity where possible.

However, the model originally contemplated by the NECF is no longer the only one available for consumers to access energy. This is testing the boundaries of application of the NECF. A ***two-sided*** market with ***two-way*** flows and digitalisation may blur the lines between the NECF and ACL. An example of this would be a bundled electric vehicle and charging service where the scope of what is covered by the ACL and the NECF may not be immediately clear. The ESB will need to address these challenges in developing a fit-for-purpose consumer protection framework for a ***two-sided*** market.

Page 84

As is the case today, not all aspects of the ***two-sided*** market will need to be governed by the NECF, and complementary consumer protections for energy products and services will be required.
...
Services that will be prominent in a more developed ***two-sided*** market exist today. Understanding the possible harms and risks associated with existing services will help to identify what consumer protection changes may be needed in the short term. Not only is this important for protecting existing customers but it also helps to deter activities that could reduce the community's trust in those services that will play an important role in a future ***two-sided*** market.

The Health of the National Electricity Market 2020
Energy Security Board
Volume 1: The ESB Health of the NEM Report

Page 7:

> The importance of distributed energy resources to the overall supply mix will continue to grow in the future and the post 2025 Market Design work on distributed energy resources and ***two-sided*** markets should offer further opportunities for customers to capture value.

Page 12

> The Post 2025 Market Design work through the Valuing DER and ***two-sided*** markets workstreams is working to ensure the market arrangements and regulatory frameworks support the use of these new technologies

Page 60

> The AEMC considers that the growing diversity in the market is likely to require more diversity in the regulatory approaches that are used, to strike the right balance between facilitating innovation and consumer protection and will continue to look for opportunities to move to these different regulatory approaches to suit the current and emerging market conditions, which in part is being considered through the ***two-sided*** markets work in the Post 2025 Market Design Work Program.

The Health of the National Electricity Market 2020
Energy Security Board
Volume 2: Major Report Summaries for 2020

Page 15

> **35. Wholesale demand response mechanism rule change**
>
> Rules were made in June 2020 to facilitate wholesale demand response in the NEM, allowing consumers to sell demand response in the wholesale market either directly or through specialist aggregators. The mechanism introduced will unlock under-utilised demand response and promote greater demand-side transparency as well as price and reliability-related benefits. This is an important step in the move towards a ***two-sided*** market which will assist the NEM in effectively evolving and transitioning to the future power sector.

Moving to a Two-Sided Market
Energy Security Board
April 2020

Page ii - iii

> **What is a two-sided market?**
>
> In simple terms, a two-sided market has all its participants responding to price based on their cost and value preferences. The parties who participate in the market are exposed to its outcomes, with buyers only supplied to the extent that they buy through the market and sellers only supplying to the extent they sell through the market.
>
> For the NEM, a two-sided wholesale market would be informed by quantity and price inputs from both consumers and producers of electricity and would enable more efficient participation in the market by even small consumers like homes and small businesses.
>
> Technological advances and digitalisation mean that consumers will not need to monitor electricity prices and decide how or when to participate. These decisions would be set up to happen autonomously or in an agreed way via their retailer or aggregator.
>
> **Benefits of a two-sided market**
>
> The energy market should be dynamic, and consumers rewarded for buying and selling energy, demand management and other services to the parties who value them the most, in a way that benefits all consumers.
>
> There are significant benefits from a two-sided wholesale market where customers with or without distributed energy resources (DER) are actively engaged in the demand for, and supply of, electricity, and technology can actively control the way in which they can reveal their intentions in the market.
>
> The high and growing penetration of variable and/or non-synchronous generation is changing the nature of the dispatch problem, while new technologies provide a much greater potential for demand-side response and engagement with the

market. As the growth of variable and non-synchronous generation creates new challenges for system reliability and security, increasing participation by customers, large or small, with DER or not, can contribute to the prevention and management of these issues while also improving market efficiency.

The ability to respond when prices are high and supply is scarce, creates incentives to change behaviour and conserve electricity or to shift the timing of consumption. Conversely, when supply is abundant and low cost there are strong drivers to change behaviours to make use of that supply. Full participation in a two-sided market can support higher levels of flexible capacity from both consumers and DER and facilitate greater innovation in services for customers.

Greater flexibility through exposure to price for all participants can enhance the efficiency and robustness of the market. A two-sided market could help address key system issues related to the integration of DER. Over time, this creates significant opportunities to reduce system costs and therefore, consumer prices.

Key features of a two-sided market
There are several considerations to be made when designing a two-sided market. In summary, a two-sided NEM would:

- Maximise participation by requiring that all entities trading energy in the wholesale market submit bids and be scheduled.
- Allow consumers to choose if and how they participate in the market or whether they operate through someone who does (for example through a retailer or aggregator). Technological advances and digitalisation mean that consumers will not need to monitor electricity prices, or actively participate if they choose not to.
- Require that the party best placed to provide forecasts of quantity and price to do so.
- Place obligations on functions and activities, rather than participant categories or technologies.

There is a spectrum of options that will move the market closer to the above objective and the benefits, costs and trade-offs of how this will work need to be carefully considered.
The move to a two-sided market is a significant shift for the market and any market design will include a transitional approach to maximise benefit while also minimising adverse impacts on consumers and market participants. A transitional approach to support the move to a two-sided market could include exploring different approaches to scheduling demand side participants through the Wholesale demand response mechanism rule change and AEMO’s Virtual Power Plant (VPP) trials.

Appendix D

References to ‘two-sided markets’ in AEMO documents

AEMO
Draft 2021 Inputs, Assumptions and Scenarios Report
December 2020
Draft report for consultation
For use in Forecasting and Planning studies and analysis

Page 23:

> **Sustainable growth scenario**
>
> In this scenario: Energy consumers are more engaged with the energy market, with reforms in ***two-sided*** markets resulting in higher levels of price-responsive DSP.

References to ‘hydrogen’ in AEMO documents

AEMO
Draft 2021 Inputs, Assumptions and Scenarios Report
December 2020
Draft report for consultation
For use in Forecasting and Planning studies and analysis

Page 3:

> These included ... the consideration of greater electrification and potential ***hydrogen*** production within the scenario collection (as means of achieving strong decarbonisation across sectors).

Page 4:

> The other scenarios are proposed to examine a plausible range of variations in the pace of the transition, as follows:
> ....
> Export Superpower – reflecting a possible future world that encompasses very high levels of global electrification, Australian ***hydrogen*** export opportunities, and domestic ***hydrogen*** usage that supports low-emission manufacturing, fuelled by strong policy to support growth and strong decarbonisation.

Page 5:

> Inputs and assumptions
> This Draft 2021 IASR describes in detail the current inputs and assumptions in relation to:
> ....
> Assumptions related to the modelling of ***hydrogen*** production and demand.

Page 12:

> Many uncertainties face the energy sector: ... opportunities for ***hydrogen*** production in Australia could have a transformative impact on the domestic energy sector if the Federal Government’s vision for Australia to become a world leader in ***hydrogen*** production and export is realised.

Page 13:

> Table 1 Stakeholder engagement to date
> Hydrogen in the 2021 GSOO Workshop 18 September 2020 Consultation/discussion

Page 17:

> The proposed scenarios in this Draft 2021 IASR have regard to the guidance provided in the Cost Benefit Assessment (CBA) Guidelines... Major sectoral uncertainties have been identified through insights developed in the 2020 ISP and recent stakeholder engagement; these include: The extent of electrification and location of this demand, as other sectors decarbonise and new industries such as ***hydrogen*** production emerge

Page 18:

> In addition, early insights on the treatment of an emerging ***hydrogen*** industry were gathered from stakeholders in a distinct, targeted workshop

Workshop 1 – ***Hydrogen*** in the 2021 GSOO

On 18 September 2020, AEMO held a workshop to examine the incorporation of ***hydrogen*** production in the 2021 GSOO. This workshop captured stakeholder perspectives on the potential scale, timeline and location of ***hydrogen*** development and consumption in Australia, with a focus on the impact of high ***hydrogen*** deployment on Australia's energy infrastructure.

Page 21:

2.3 Scenario narratives and descriptions
Export Superpower – reflecting a possible future world that encompasses very high levels of global electrification, Australian ***hydrogen*** export opportunities, and domestic ***hydrogen*** usage that supports low-emission manufacturing, fuelled by strong policy to support growth and strong decarbonisation.

Page 23:

2.3.2 Sustainable Growth
In this scenario:
High levels of growth and decarbonisation do not lead to material electricity consumption on the NEM, with electrical loads associated with ***hydrogen*** production not being NEM-connected. Manufacturing industries that decarbonise to contribute to the net-zero objectives may gain access to low-emissions fuels, such as ***hydrogen*** or biofuels, although to a lesser extent than if production was NEM-integrated. As such, while some amount of ***hydrogen*** availability is expected, it is not envisaged to materially impact the NEM in this scenario. AEMO explores an alternative future with greater grid-integrated ***hydrogen*** production in the Export Superpower scenario, described in Section 2.3.5.

Page 29:

2.3.5 Export Superpower

Narrative summary
This proposed scenario represents a world with very high levels of electrification and ***hydrogen*** production, fuelled by strong decarbonisation targets and leading to strong economic growth.
Key differences to the Central scenario include:
...
- Continued improvements in the economics of ***hydrogen*** production technologies that enable the development of a significant renewable ***hydrogen*** production industry in Australia for both export and domestic consumption.
- Higher levels of electrification across many sectors, though with limited growth in EVs after 2030 due to competition from ***hydrogen*** fuel-cell vehicles.

Purpose
- To understand the implications and needs of the power system under conditions that result in the development of a renewable generation export economy which significantly increases grid consumption and necessitates developments in significant regional renewable energy generation.
- To assess the impact, and potential benefits, of ***large amounts of flexible electrolyser load***.

Similarity to 2020 ISP scenario narratives
- This scenario reflects a much stronger decarbonisation objective and the rise of a ***hydrogen*** economy. It is a new scenario that was not considered in the 2020 ISP.

In this scenario:
- Capitalising on significant renewable resource advantages, Australia establishes strong ***hydrogen*** export partnerships to meet international demand for clean energy. Achieving this requires significant government investment in early years to stimulate the ***hydrogen*** economy, including initial domestic applications.
- Both domestic and export ***hydrogen*** demand is fuelled, at least in part, by NEM-connected electrolysis powered by additional VRE development.
- ...
- ***Hydrogen*** production via electrolysers powered by low-cost VRE may impact the demand for other traditional energy sources such as coal and gas, both domestically and internationally.
- Fuel switching to electricity and ***hydrogen*** takes place across all sectors of the economy.
- The energy transition in Australia is embraced by consumers, as they seek clean energy and energy efficient homes and vehicles. Consumers also take advantage of ***hydrogen*** to access the benefits of combustion-based heating and cooking appliances, while still achieving a low carbon footprint.

Page 30:

Stakeholders have been encouraging AEMO to explore the impact of potential development of large-scale ***hydrogen*** production opportunities in future ISPs, and to consider scenarios that go beyond the ambitions previously applied in the Step Change scenario.

When presented with this scenario, stakeholders indicated that it is useful in exploring the needs of the power system and in understanding the risks of under- or over-investment. AEMO has engaged broadly with stakeholders on this scenario, including an additional targeted ***hydrogen*** stakeholder workshop in September 2020 to explore the most likely means by which large-scale hydrogen production would impact the NEM.

It is recognised that grid-scale, grid-connected electrolysis is one way ***hydrogen*** could be produced at scale in Australia.

The proposed scenario narrative is considered over other competing potential scenarios that include large scale ***hydrogen*** production, because:

- Investment signals are showing a preference for "green ***hydrogen***", sourced from electrolysis and fuelled by renewable energy.
- A large number of grid-connected electrolysers would have a significant impact on the NEM, and this impact needs to be understood. In contrast, the Sustainable Growth scenario considers a future whereby any ***hydrogen*** production, if produced in Australia, is off-grid.
- Exploring ***hydrogen*** export represents the most direct interpretation of this scenario. If the ***hydrogen*** was used as a feedstock for production of green steel or other high-value commodities the characteristics of the scenario would be more complicated

Stakeholders raised several issues which have been reflected in some of the settings, including:

- There were also mixed views on the uptake of EVs. AEMO will continue to engage on this topic as part of the updated forecast of EVs in early 2021; this will include consideration of the role of ***hydrogen*** fuel-cell vehicles.
- There was concern about the scale of ***hydrogen*** production resulting in significant transmission line or pipeline expansion and unduly influencing any justification for network investment based on power system need. The scenario is expected to locate VRE and ***hydrogen*** production facilities in complementary locations while minimising system costs.

Page 31:

Matters for consultation:

- Do you think the uptake of EVs (based on batteries) is likely to be affected significantly by competition with ***hydrogen***-powered vehicles?

Page 39:

Table 6 Status and update process for key inputs and assumptions

Input:	Hydrogen assumption (demand, supply and infrastructure needs)
Current status:	Draft
Forward plan for updating inputs and assumptions :	Any further updates will be based on feedback on this Draft 2021 IASR.

Page 43:

Victoria funding support is also provided to enable energy innovation, such as to support ***hydrogen*** projects and off-shore wind generation in Victoria.

Page 65:

Battery electric vehicle and fuel-cell vehicle uptake

Key factors for battery EV (BEV) adoption (including battery and plug-in hybrid EVs) include:

- Substitutes and alternatives to BEVs (such as public transport, rideshare services, and ***hydrogen*** fuel-cell vehicles).
- Competing developments – vehicle availability, technology improvement and infrastructure deployment – of ***hydrogen*** fuel-cell vehicles (FCVs).

Page 67:

AEMO will be updating the EV forecasts, both BEV and FCV, which will be consulted on through the February, March and April 2021 FRG meetings..... In the proposed Export Superpower scenario, the uptake of BEVs is initially strong but then plateaus due to the uptake of ***hydrogen*** fuel-cell vehicles.

Matters for consultation

- Is the assumption that BEV uptake will plateau in the proposed Export superpower scenario, with an increased relative share of ***hydrogen*** fuel-cell vehicles, appropriate?

Page 108:

Proposed changes since the 2020 ISP
Based on AEMO analysis and recent feedback from existing and intending TNSPs, the following changes to the 2020 ISP REZ zones have been proposed:

- A new candidate zone in the vicinity of the Gladstone area to be added to assess the potential benefits of new zones near to a potential ***hydrogen*** port.

Page 111:

Implications on REZ definitions for the Export Superpower scenario
Significant generation investment will be required under a ***hydrogen*** export scenario to meet the projected increase in electricity demand.

In this scenario, there will be a need to supply power from REZs to new loads for the production of ***hydrogen***. The proposed approach to connecting REZs with potential ***hydrogen*** ports is outlined in Section 4.14.

Page 116:

REZ expansion costs under the Export Superpower scenario
To allow optimal determination of REZ expansion to power ***hydrogen*** facilities, REZ expansion options will be determined for each zone based on the distance from the zone to each nearby port.

Page 137

South Queensland to Central and North Queensland (SQ–CNQ)
In the longer term, the development of large loads for ***hydrogen*** production (for example, the Export Superpower scenario) or the connection to the NEM of Mt Isa ...could materially change the energy needs in Central and North Queensland.

Page 171

As part of the ISP Methodology, AEMO uses an integrated gas and electricity model to project developments considering gas, ***hydrogen*** and electricity systems simultaneously.

Page 171 - 181

4.14 Hydrogen modelling : ***This section is quoted in its entirety in the following pages***

References to 'hydrogen' in AEMO documents - continued

AEMO
Draft 2021 Inputs, Assumptions and Scenarios Report
December 2020
Draft report for consultation
For use in Forecasting and Planning studies and analysis

Continued: pages 172-180 in its entirety

4.14 Hydrogen modelling

Input vintage	New content
Source	AEMO engaged with stakeholders in a Hydrogen Workshop in September 2020 to assist in defining the assumptions for the Export Superpower scenario.
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR and may be further updated through the ISP Methodology consultation process.
Get involved	Draft 2021 IASR consultation and ISP Methodology

[166] GSOO gas demand forecasting and gas supply adequacy methodologies, at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo. AEMO's 2020 Market Modelling Methodologies, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.

 | Draft 2021 Inputs, Assumptions and Scenarios Report 172

It is assumed that adequate water would be available either using treated local freshwater sources or desalination of seawater at the port. If desalination is required, the cost of desalination is assumed to be $0.05 per kilogram of hydrogen produced, in line with Australia's National Hydrogen Strategy[176].

Matters for consultation

- Grid-connected hydrogen is proposed to only be modelled in the Export Superpower scenario; in other scenarios any hydrogen is expected to either be insignificant or produced off-grid. Does this give sufficient coverage?
- In the Export Superpower scenario, decarbonisation ambitions lead to transitioning gas distribution networks to 100% hydrogen by 2045. Do you have any feedback on this approach?
- In the Export Superpower scenario, domestic hydrogen consumption is approximately equal to export until 2040, at which point domestic demand is largely saturated and export becomes the dominant cause of growth in demand. Do you have any feedback on the suitability of this trajectory?
- Do you have feedback on the penetration of battery and fuel-cell electric vehicles in the scenario collection?
- AEMO has selected PEM electrolysers as the preferred technology in this scenario, due to decarbonisation targets (preferencing green hydrogen), higher levels of flexibility in the operation of the assets, and notable investment activity in the market. Do you have any information that may indicate this assumption should be changed?
- Do you have any feedback on the cost of electrolysers, the efficiency of electrolysers, or the rate of cost reductions projected into the future?
- The electrolysers are assumed to have a fixed minimum baseload of 4.5% of their total capacity, even when they are not producing hydrogen. Do you have information that may indicate this assumption should be changed?
- Nine ports are proposed as candidates for the 2022 ISP expansion to produce export hydrogen. Do you have feedback on these candidates and their suitability over other options for hydrogen hubs?
- Water availability near the candidate export ports has been screened. Do you have any feedback on the assumed classification of fresh water being likely to be available or unavailable or desalination being required? Information that could help resolve the water availability at ports would be highly appreciated.
- The cost of desalination is assumed to be $0.05 per kilogram of hydrogen based on Australia's National Hydrogen Strategy. This is a small contribution to overall cost, and it is proposed that the electricity demand would likely be immaterial in the scale of the Export Superpower scenario (when compared with electrolyser demand). Do you think this is an acceptable simplification?
- It is assumed that only a small amount of hydrogen storage will be required at the ports for operational uses, and as such, the cost associated with this storage is immaterial. Do you agree with this approach?

[176] At https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy.

Hydrogen production was discussed qualitatively in the 2020 ISP, and feedback was received from stakeholders that it should be incorporated in more detail for the 2022 ISP.

Including hydrogen production as a driver within the scenario collection reflects the significant increase in interest and activity from industry and direct funding support from governments in Australia and internationally. As described in the scenario narratives presented in Section 2.3, NEM-connected hydrogen will only be modelled in the Export Superpower scenario. Other scenarios assume negligible impact from grid-connected electrolysers on the NEM. Accordingly, the assumptions and inputs discussed in this section are only applicable to the Export Superpower scenario.

To manage the modelling scale and complexity, a range of hydrogen variables are assumed as inputs to the model. The initial estimates and assumptions are outlined below, and AEMO invites feedback on these items as part of the Draft 2021 IASR consultation.

4.14.1 Hydrogen demand

Hydrogen demand assumed in the Export Superpower scenario includes both domestic applications and hydrogen exports, with a strong, emerging export economy assumed to start from 2030. Australia's Technology Investment Roadmap[167] has identified that energy export is of strategic importance to Australia and hydrogen is one of the priority low emissions technologies. Australia's National Hydrogen Strategy[168] recognises that a strong domestic sector will be required to successfully compete internationally. Consequently, this scenario assumes early domestic uptake facilitates export growth, allowing for a large and rapid development of hydrogen for export as the international market develops.

Multiple domestic applications for hydrogen are assumed:

- Hydrogen is used for fuel switching from natural gas to hydrogen by both residential and industrial consumers, with domestic use of natural gas phased out by 2045. Distribution blending of hydrogen into the gas grid enables domestic consumption. It is possible to blend up to 10% hydrogen (by volume) into the existing distribution gas network without any changes in gas rules or appliances. Over time the distribution network may be segmented into physically separated sections of network with different gas compositions. In the event of this segmentation, the distribution pipeline network would be able to incrementally transition to 100% hydrogen.
- Hydrogen is expected to have a strong role in replacing diesel-fuelled heavy vehicles, and this scenario increases the competitiveness of hydrogen fuel-cell vehicles to compete with BEVs.
- Increased availability of hydrogen may enable its use in power generation as an alternative to peaking gas and non-transport diesel.

This section outlines the assumptions and inputs proposed for hydrogen demand.

Total demand (including export)

Through stakeholder collaboration, AEMO defined the assumed scale of annual NEM-connected electrolyser production in the NEM regions of approximately 8 megatonnes (Mt) by 2040, growing to over 20 Mt by 2050[169] (excluding hydrogen produced in Western Australia, the Northern Territory, and off-grid in NEM regions), shown in Figure 47. Production is assumed to start in 2023, supported by various state government policies and hydrogen ambitions.

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[167] See https://www.industry.gov.au/sites/default/files/September%202020/document/first-low-emissions-technology-statement-2020.pdf.

[168] See https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf.

[169] The export growth rate targets were based on combining and averaging the estimates for hydrogen scenarios from IRENA, Hydrogen Council, ACIL Allen and Deloitte. The numbers were taken from the summary in Deloitte's report and direct reference to the ACIL Allen report for more scenario information. Australia was assumed to supply a percentage of global demand in line with stakeholder feedback in the workshops. Deloitte: https://www2.deloitte.com/content/dam/Deloitte/au/Documents/future-of-cities/deloitte-au-australian-global-hydrogen-demand-growth-scenario-analysis-091219.pdf. ACIL Allen: https://www.acilallen.com.au/uploads/files/projects/227/ACILAllen_OpportunitiesHydrogenExports_2018pdf-1534907204.pdf.

Figure 47 NEM-connected hydrogen production (Mt)

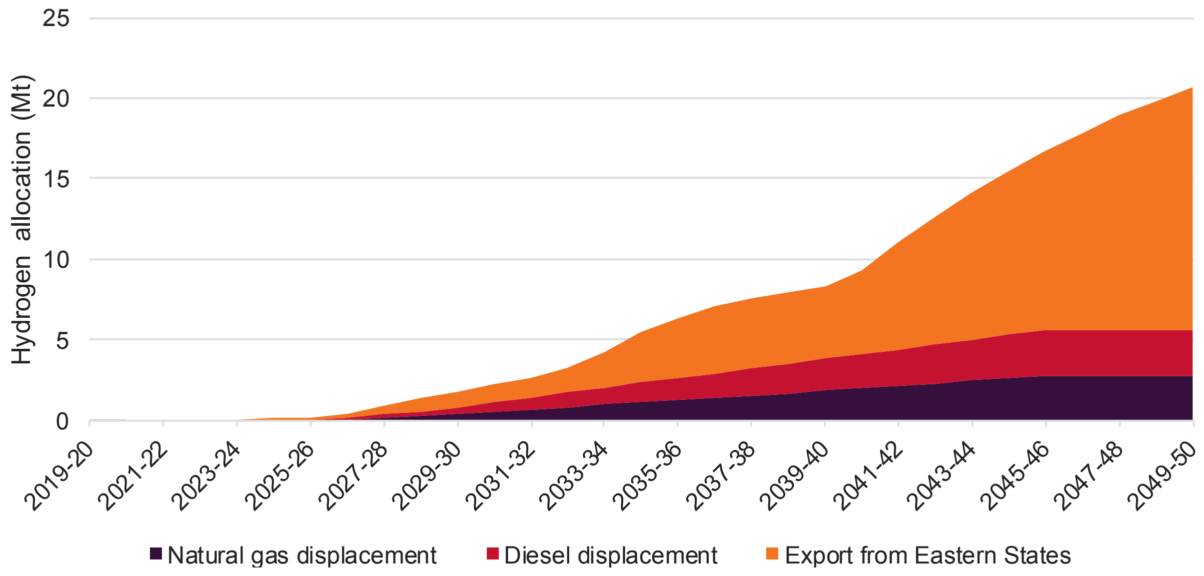
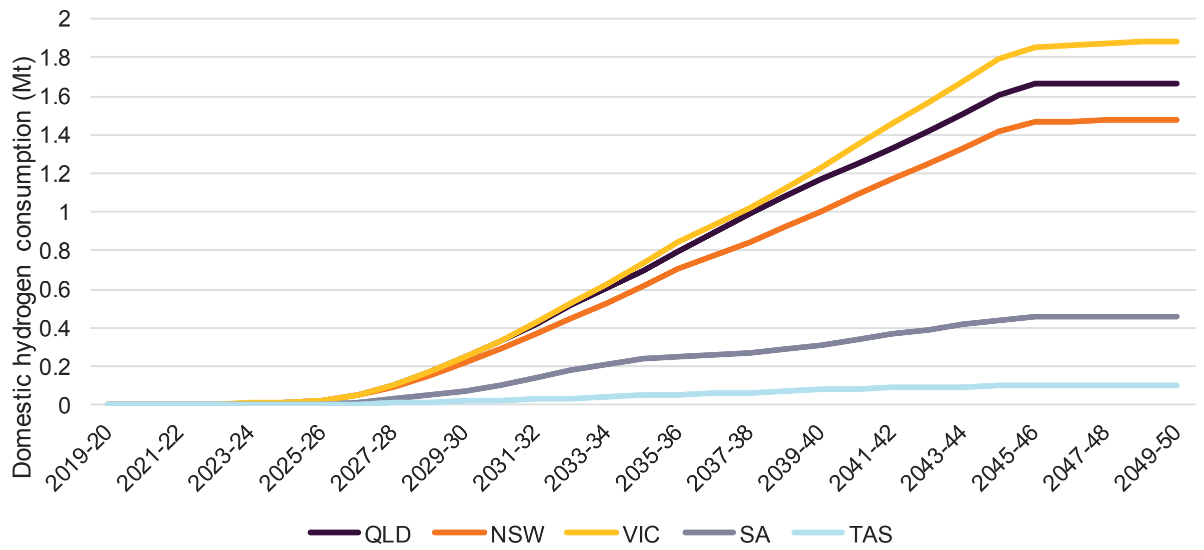


Figure 48 shows an indicative representation of projected hydrogen consumption based on gradual displacement of diesel and natural gas consumption of each region, coupled with export opportunities. These interim assumptions will be updated as part of AEMO's forecasting of distributed energy resources, particularly understanding the future projection of both battery electric and fuel cell electric vehicles.

Figure 48 Indicative domestic hydrogen consumption (Mt, based on diesel and gas displacement)



Residential and commercial demand

AEMO assumes existing gas distribution networks can accept up to 10% hydrogen blending (by volume) without any pipeline changes and without exceeding energy content standards for existing appliances. It is assumed that by segmenting the gas distribution grid (as described at the start of this section) the total amount of gas blending within the distribution grid can increase.

Large industrial demand

Currently large industry uses approximately 180 petajoules (PJ) a year of natural gas in Australia's eastern and south-eastern gas markets. Consistent with Australia's National Hydrogen Strategy, it is assumed that industrial hydrogen hubs are established in the Export Superpower scenario, allowing industrial customers to switch from natural gas to hydrogen, and supporting potential new industrial customers. At this stage a net increase in industrial load is not assumed, although some industries may be replaced with new ones.

Transportation demand

In the Export Superpower scenario, on-grid hydrogen is assumed to gradually replace diesel for long distance heavy transport (trucking and trains)[170]. Passenger vehicles are assumed to be mainly BEVs initially, although FCVs become available and grow over time. The balance of battery and hydrogen vehicle growth is requiring update for this scenario, and will be consulted through the February, March and April FRG meetings, as appropriate.

The Sustainable Growth scenario also is expected to feature relatively strong uptake of BEV and FCV fleets, although this scenario would not feature material transmission connected hydrogen production facilities. This reduces the relative ease for FCV adoption in this scenario.

4.14.2 Hydrogen supply

Hydrogen production technologies

There are three primary technology options to produce hydrogen:

- **Electrolysis** – uses electricity to split water molecules into hydrogen and oxygen. If this electricity is sourced from renewable electricity it can create "green hydrogen".
- **Steam methane reformation (SMR)** – reacts methane (natural gas) with steam under pressure to produce hydrogen and carbon dioxide.
- **Coal gasification** – reacts pulverised coal with oxygen and steam to produce hydrogen and carbon dioxide. Different quality coal can result in different processes and chemical compositions.

In the Export Superpower scenario, hydrogen production via electrolysis of water powered by VRE is assumed to be the primary hydrogen production technology, given the decarbonisation ambition of the scenario.

There are three electrolyser technology options:

- Alkaline – presently more mature technology and lower cost, but limited flexibility.
- Proton Exchange Membrane (PEM) – newer technology, which is substantially more flexible to variable loads and more suitable for modular large applications, but less mature than alkaline. At present, most hydrogen projects that are being developed are employing PEM electrolysis.
- Solid Oxide Electrolysis Cell (SOEC) – newest technology that can operate at high temperature and shows substantial promise; however, it is still early in its development and not yet being produced, or ready to be produced, in mass quantities.

AEMO proposes the use of PEM electrolysis to be the primary hydrogen production technology, reflecting the current technology development trends.

PEM characteristics

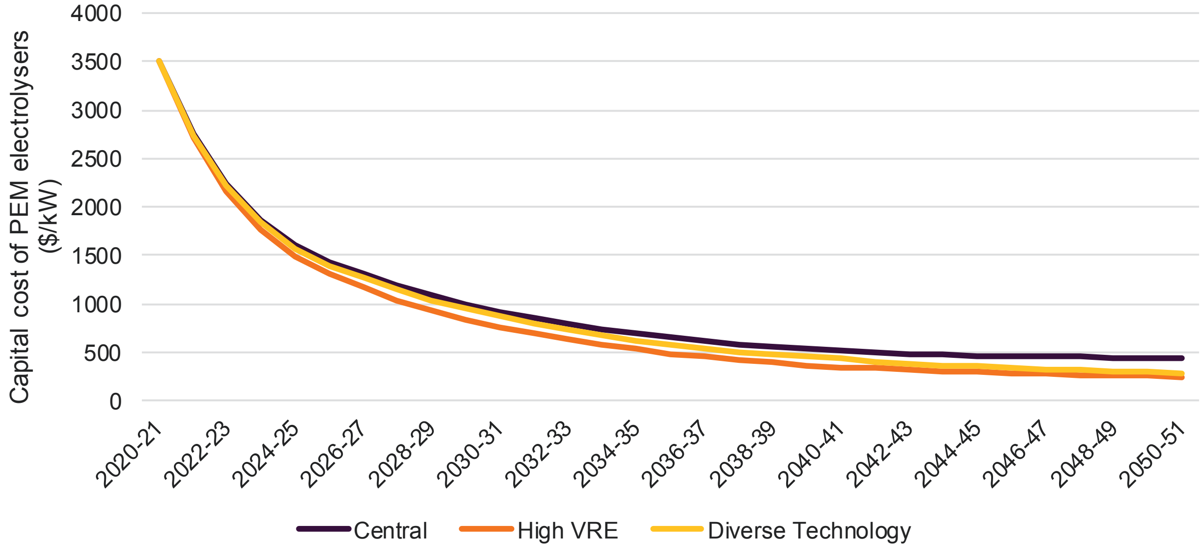
Assumptions around key PEM characteristics are outlined in the following section.

Capital costs

The GenCost report released with this Draft 2021 IASR contains estimates for the current capital cost of a PEM electrolyser, at $3,510/kW, with equipment and construction costs accounting for 70% and 30% of total capex respectively. By 2030 the cost of PEM electrolysers is projected to be less than $1000/kW in all scenarios. The cost trajectory projected in GenCost 2021 is shown in Figure 49.

[170] The details of this transition are being sourced through consultants.

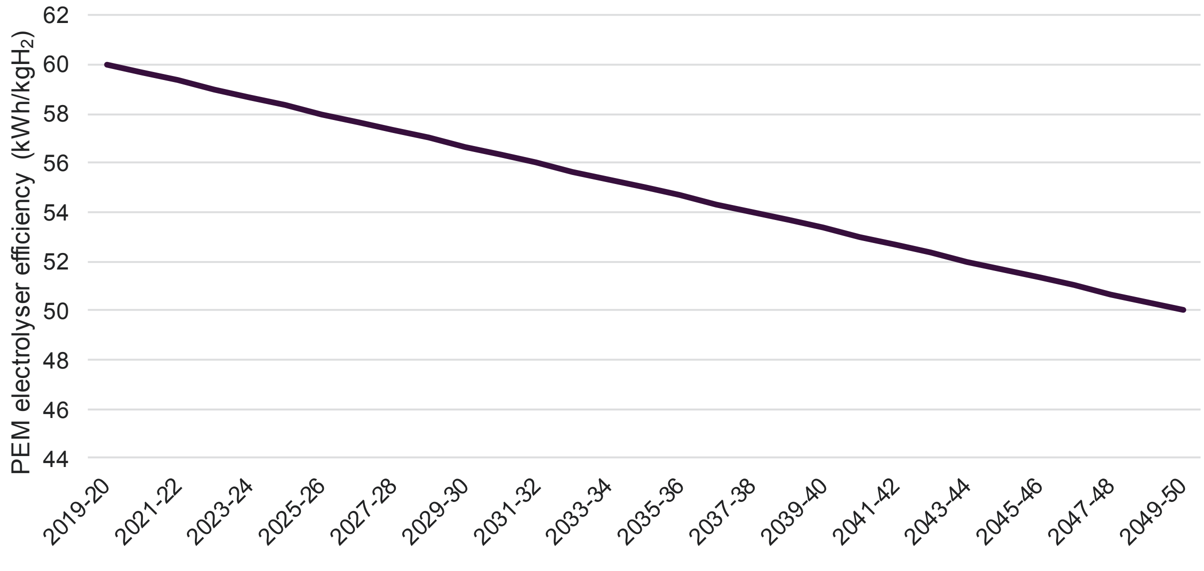
Figure 49 CSIRO GenCost 2021 capital cost projections for PEM electrolysers



Flexibility

The actual electrolyser itself can be ramped up and down rapidly, potentially even providing fast frequency response similar to electrochemical batteries. AEMO proposes to model PEM electrolysers as fully flexible, although there is an associated baseload component (as described below). The degree of actual flexibility offered in the market will depend strongly on the commercial arrangements in relation to the plant and its contracts for supply of hydrogen, relative to the effectiveness of the markets in the NEM and the opportunities to efficiently arbitrage between contract arrangements and the NEM. The efficiency of the electrolyser is projected to improve over time, as shown in Figure 50[171].

Figure 50 Efficiency projections for PEM electrolysers



[171] Based on Aurecon, 2020-21 AEMO Costs and Technical Parameter Review for the initial cost and CSIRO, National Hydrogen Roadmap (2018), for projected improvement rate.

Modularity

Much like PV and batteries, hydrogen electrolysers are highly modular and can be scaled up linearly. The modules are assumed to be available in 1 MW increments.

Baseload/auxiliary load of the electrolyser

While the electrolyser stack is fully flexible, an electrolysis plant has a range of components which respond at different rates. Such components include dryers, compressors/pumps and cooling. Discussion with various industry experts have placed the baseload demand consumed by the electrolyser at somewhere up to 10% of the total demand, even when the electrolyser is not producing hydrogen.

The best available information that could be sourced from an operating unit comes from Energiepark Mainz[172] and shows the operating characteristics of a 4 MW electrolyser plant comprised of three modular electrolysers. The baseload reported is 175 kW (~4.5%).

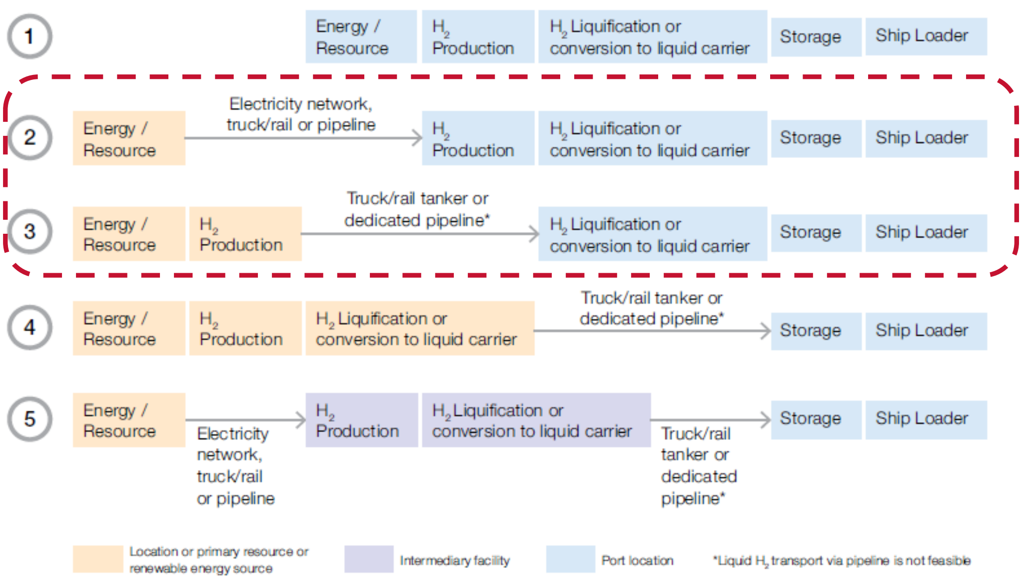
At this stage it is difficult to be sure how this will scale up with increase in capacity of electrolysers, yet discussions with equipment suppliers and international research organisations indicate that this is approximately the right magnitude and would likely scale fairly linearly. There is also opinion that the whole plant should be able to be shut down quickly. In the absence of better information, AEMO proposes to assume a baseload of 4.5%.

As noted previously, the actual operation of electrolyser plants will depend strongly on commercial arrangements in place for supply of hydrogen, relative to opportunities in the NEM.

4.14.3 Hydrogen infrastructure needs

ARUP's Australian Hydrogen Hubs report to the COAG Energy Council identified the potential hydrogen export pathways[173] in Figure 51. A hydrogen export pathway describes the supply chain from the energy source to the export location, and includes the method and form of energy transport; the location of the electrolysers; and the location of the hydrogen liquefaction or conversion facilities.

Figure 51 Hydrogen export pathways, highlighting those proposed to apply in AEMO's current and future forecasting and planning



Source: Arup, 2019, Australian Hydrogen Hubs Study

[172] Kopp, M., Coleman, D., Stiller, C., Scheffer, K., Aichinger, J., Scheppat, B. et al. (2017), "Energiepark Mainz: Technical and economic analysis of the worldwide largest Power-to-Gas plant with PEM electrolysis", International Journal of Hydrogen Energy, Vol. 42, Issue 52.

[173] At http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf.

In the 2022 ISP, AEMO proposes to consider transmission developments that are designed around the principles of pathway 2, which transports the energy for hydrogen production via electrical transmission lines. Pathway 3, which transports the energy via hydrogen transmission pipelines, may be considered as an alternative in future ISPs.

Electrolyser location

The export-focused electrolysers are proposed to be associated with nearby REZs. The selection of combined port/REZ candidates will be optimised to minimise the cost to produce the hydrogen. This will be constrained by the available resources (such as VRE and water), considering the deliverability of VRE in REZs to hydrogen hubs at regional ports (accounting for transmission augmentations as described in Section 4.9.3).

The proposed export ports were selected from 30 hydrogen hubs identified in ARUP's Australian Hydrogen Hubs report to the COAG Energy Council[174]. The following table outlines 10 proposed candidate hydrogen export ports (shown geographically in Figure 52) that provides a geographic spread with access to REZ and port infrastructure.

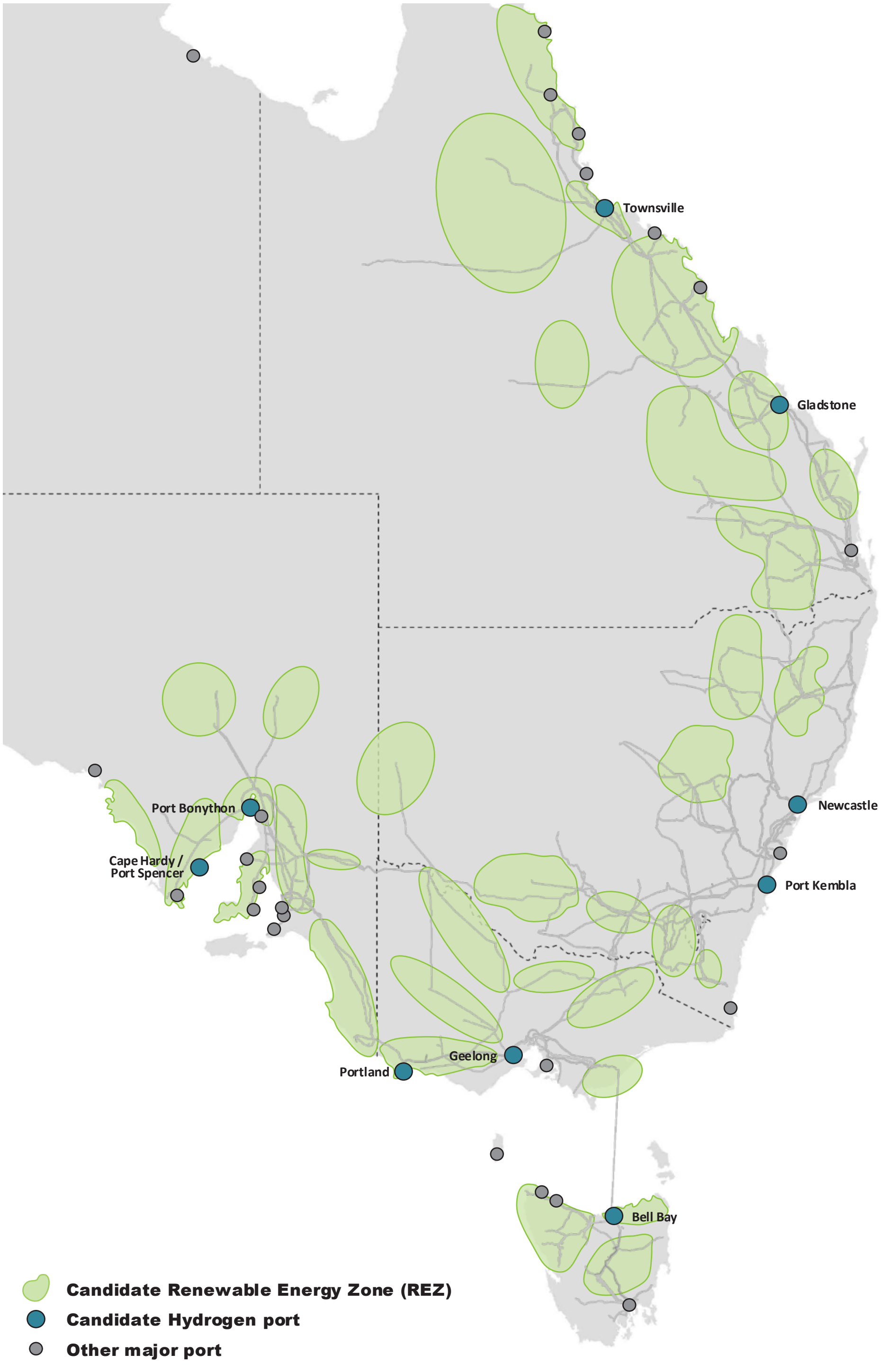
Table 71 Candidate hydrogen export ports

NEM Region	Potential port location
New South Wales	Newcastle, Port Kembla
Queensland	Gladstone, Townsville
South Australia	Port Bonython, Cape Hardy/Port Spencer
Tasmania	Bell Bay
Victoria	Geelong, Portland

There is also notable domestic consumption of hydrogen proposed in the Export Superpower scenario. The demand for each region's domestic load is assumed to be delivered from centralised electrolysis plants located near the regional load centre. Where possible, each state's domestic hydrogen will be produced in that state with electrolysers placed at the edge of the industrial zones near to the regional reference node.

[174] At http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf.

Figure 52 Candidate hydrogen export ports



Storage

For export purposes, pathway 2 has limited inherent storage, since the hydrogen is generated close to the port, with minimal pipeline needed. In this situation it will be assumed that storage is included in the hydrogen production facilities near the ports. Pathway 3 has an inherent advantage of large amounts of line pack in the new hydrogen transmission pipelines, which would provide firm hydrogen supply to the liquefaction or processing facilities; this pathway may be explored in future ISPs. Given the simplified modelling approach, the cost of hydrogen storage is implicit in the assumed price of hydrogen; it is assumed that hydrogen will be readily available in this scenario. Any hydrogen consumed for electricity generation purposes will need to be replaced, at cost, in the model.

For domestic hydrogen use, as stated above, the distribution pipelines will provide inherent storage through line pack. For power generation, hydrogen GPG may be useful for peaking gas and potentially seasonal storage. Information from Aurecon's 2020-21 Cost and Technical Parameter Review showed no capital cost difference between hydrogen combustion peaking plant and gas combustion peaking plant; this was based on interviews with manufacturers.

Water supply

Hydrogen production from electrolysis, coal gasification or steam methane reforming of natural gas all require water as a main feedstock. Electrolysis requires at least 9 litres/kg of hydrogen, possibly more depending on the quality and the pre-treatment required.

It is estimated that production of 8 Mt/year of hydrogen would require approximately 72 gigalitres (GL) of water per year, which is around 1 % of the 7,200 GL of water that was applied to crops and pastures in Australia in 2018-19[175]. It is important that careful consideration is given to siting of hydrogen production facilities, to ensure demand for water does not impact other local uses such as town water supplies or agriculture. Relying on alternative sources of water, such as desalinated seawater, would marginally increase the cost and complexity of producing hydrogen.

For the 2022 ISP, water availability is not proposed to be a significant limitation to siting options. Initial screening of water sources near the major ports indicates the potential water availability shown in Table 72. Detailed information and proposals for the approach to incorporation of water limitations will be part of AEMO's engagements on the ISP Methodology. AEMO welcomes stakeholder feedback on the appropriateness of the ports proposed for hydrogen production and export, as discussed above.

Table 72 Potential water availability at export ports – screening level only

Port	Potential water availability
Townsville	
Gladstone	
Newcastle	
Port Kembla	
Geelong	
Portland	
Bell Bay	
Port Bonython	
Cape Hardy / Port Spencer	

Legend:

	Fresh water likely to be available
	Desalination required
	Uncertain fresh water availability - further review required to determine if desalination will be required

[175] ABS, https://www.abs.gov.au/statistics/industry/agriculture/water-use-australian-farms/latest-release, accessed 25 November 2020.

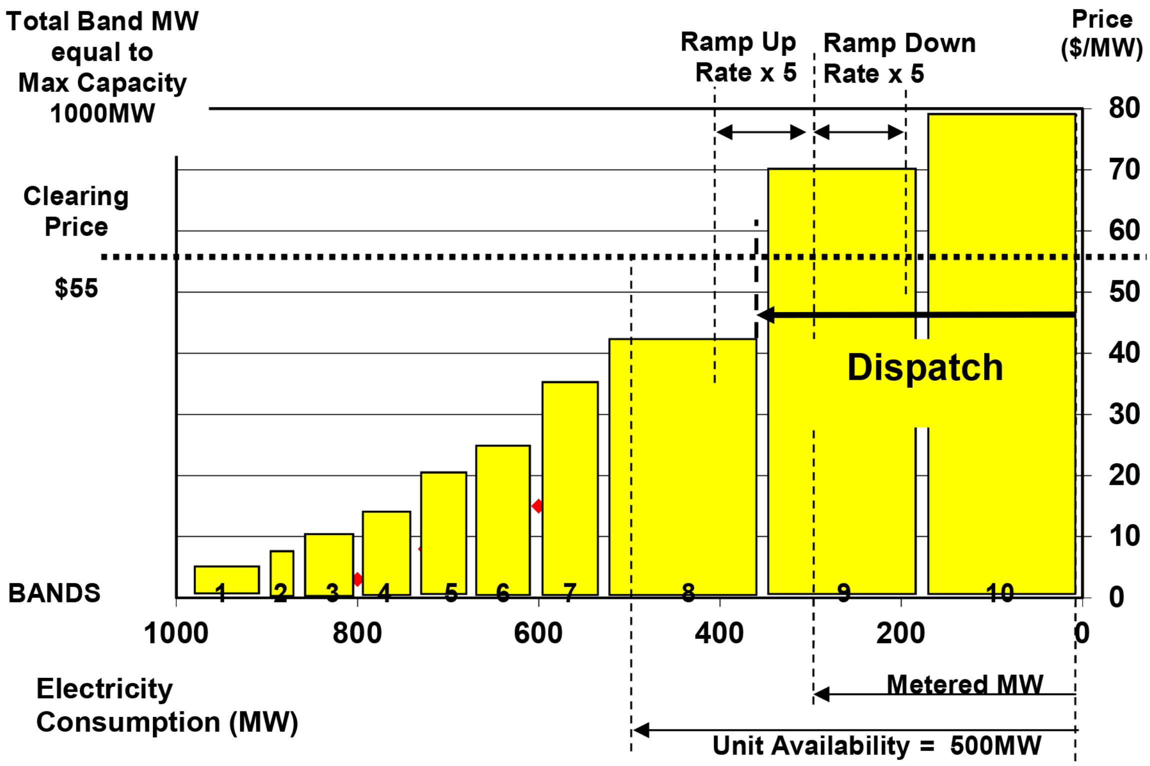
References to demand side market participation in AEMO documents

AEMO Guide to Scheduled Loads in 5 minute settlement

July 2021

(Change from 6 x 5 minute periods with 30 minute settlement)

Fig 1 A typical Dispatch Bid for scheduled load

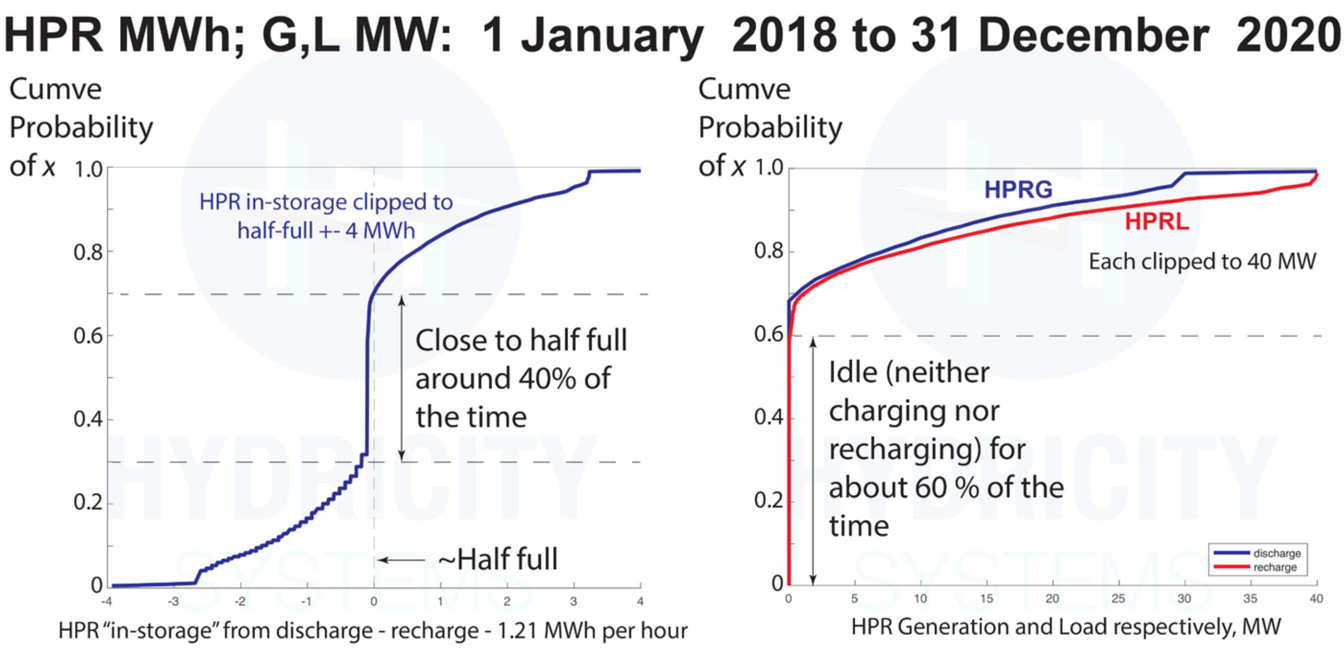


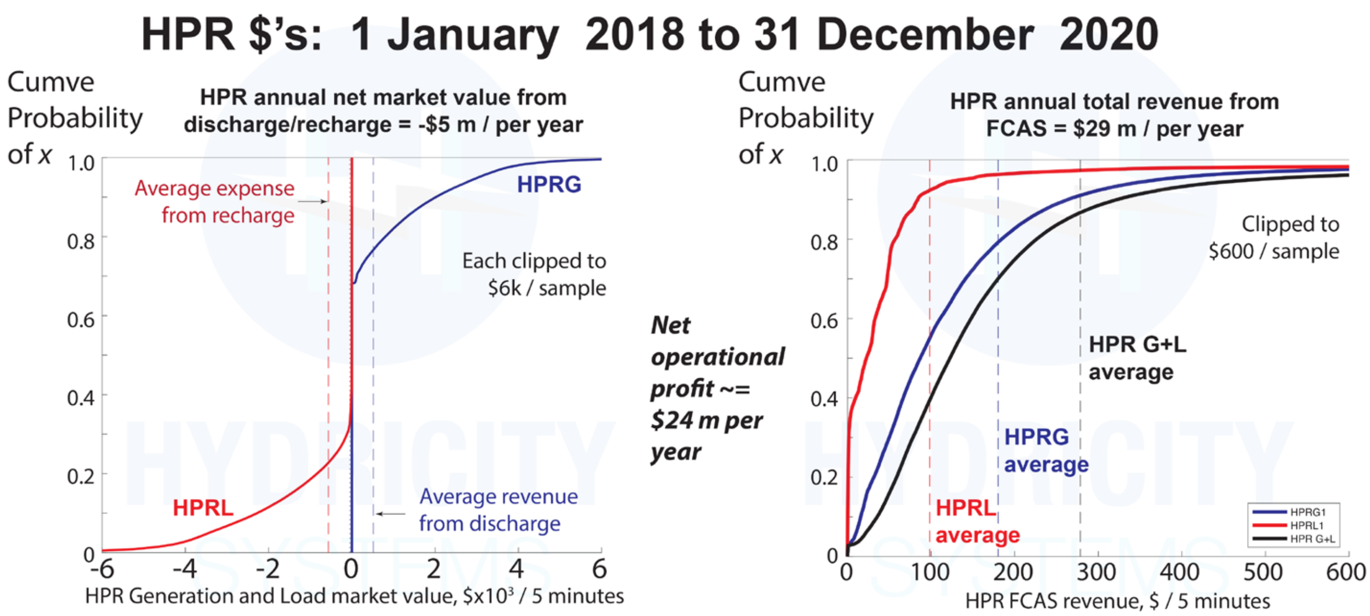
Appendix E

Powerfuels do not merely time shift electricity delivery within the NEM (Powerfuels is not arbitrage)

The economics of the Hornsdale Power Reserve in South Australia has evolved towards a system where arbitrage from scheduled market loads and generation is insignificant. The primary technical requirement for an financial return is to always have sufficient charge (battery energy stored), to consume or generate over the short duration periods of the frequency control ancillary services market (FCAS). This state of system design is unlikely to change even as system capacities increase.

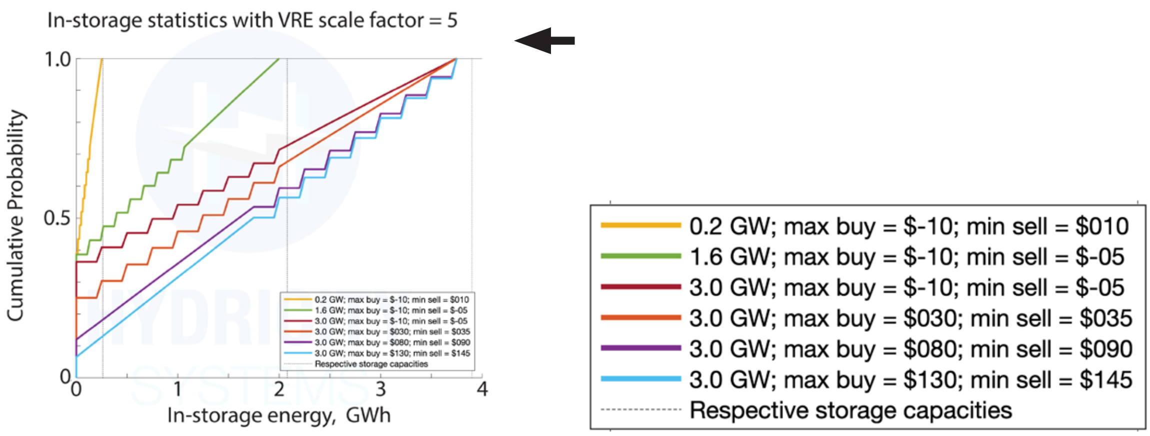
The graphics below presents summary statistic of how this has worked for the three years from January 2018 through December 2020.





The graphic below presents a selection from an arbitrage parametric study of 1200 cases, the outcome of which is, as expected. Regardless of economics (e.g. the max_buy_price and the span between max_buy_ price and min_sell_price):

- Merely time shifting power delivery does not change the total energy consumed over the long term,
- The opportunity for extracting value from arbitrage is a function of the time span between buys and sells, which in turn is a function of storage capacity, which in turn is a function of capital cost.



In contrast, powerfuels productively extract excess renewable energy production at the time of the excess, thereby adding value to the entire supply chain (generation fleet) without the cost of storage and concerns about time spans between buys and sells, and without competing in the generation market at some future time.   Instead the powerfuel is either exported outside Australia, or consumed domestically in the numerous other-than-electricity energy consuming services that can contribute to reducing national GHG emissions.

Appendix F

Scale of SA powerfuel production potential

The following graphic presents three views of the same SA powerfuel production potential family, each with respect to the willingness to buy electricity price, the capacity of powerfuel infrastructure across the Region, and VRE scale relative to 2020. For scale comparison, each graphs is annotated with of the approximate current capacity of the Moomba to Adelaide Pipeline system (MAPS) operated by Epic Energy (about 108 TJ per day). These numerics are based on an assumption that the electrical power to fuel energy production efficiency is 80%.