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FUTURE POLICY DIRECTIONS FOR AUSTRALIAN ELECTRICITY SUPPLY

A Submission to the Draft 2022 Integrated System Plan for the National Electricity Market of the Australian Energy Market Operator (AEMO)

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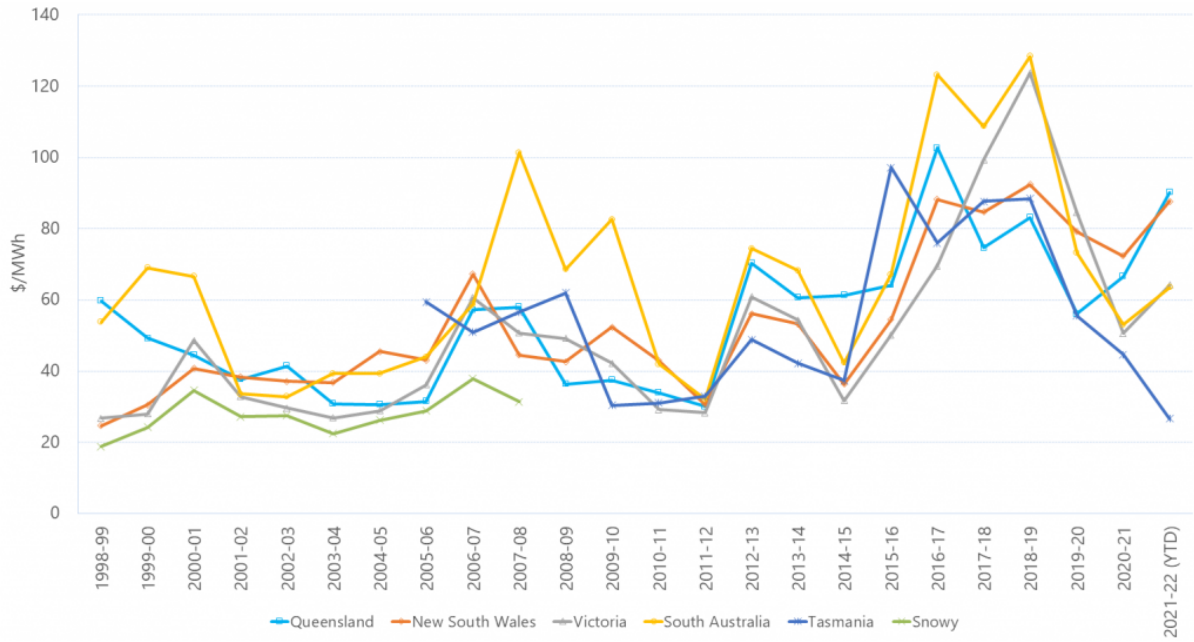
The undermining of Australia's formerly low cost, efficient electricity market

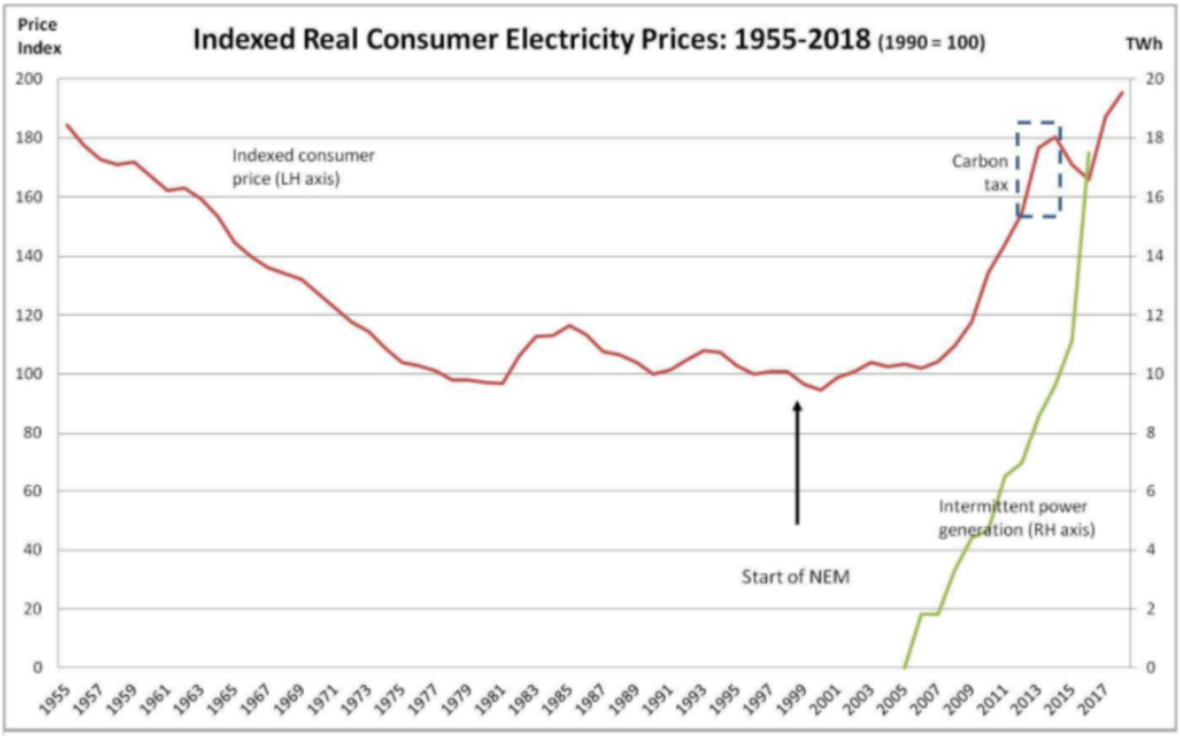
Wholesale price developments

Australian electricity prices have shown a jagged-toothed upward progression. Spot prices illustrate this.



source: AER

Another telling graph, as follows, shows real prices increasing rapidly with the increase in the (subsidised) renewables. Doubtless, the protagonist of renewable subsidies will call this pure coincidence and attribute the increases to the ageing fossil fuel plant.



Sources
Prices 1955 - 1980: *Electricity in Australia*, prepared for CIGRE by Frank Brady AM (former CEO, Electricity Commission of NSW), 1996
1980 - 2016: ABS 6401.0 Consumer Price Index
2017 - 2018: Adjustment (15% nominal increase) to take account of price increases announced by major elect distributors in June 2017
Intermittent power generation (Terra Watt hours, TWh) from Figure 4.2 in *Independent Review into the Future of the National Electricity Market*

The subsidies, without which the growth of wind/solar would be impossible, amount to some $7 billion a year, effectively doubling the revenue that wind/solar receive. The renewable energy industry's lobby group, the Clean Energy Council, recognises that even subsidies that amount to half of wind/solar revenues are inadequate to allow those electricity supply sources to expand. Among further support, the Clean Energy Council is calling for an additional, "$20 billion fund to leverage private sector investment in grid infrastructure". Snowy Hydro says its pumped hydro scheme also needs transmission subsidies without which there will be blackouts.

According to ASX forward data, 2025 prices average about $60 per MWh.

Following the privatisations and competition policy reforms 20-30 years ago prices hovered around $30-40 per MWh. They increased in the drought years of the mid noughties when hydroelectricity was in exceptionally short supply but then declined again, albeit not to the previous lows.

The spot market performs a real service in terms of setting a price that all suppliers receive, but very little product is actually traded on the spot market – it is largely a market for "unders and overs". The retailer is obliged to supply customers, usually at a fixed price, at any time. The retailer is however very vulnerable in this regard to a volatile five minutes price which, in Australia's case, can go as high as $15,000 per megawatt hour for a product which the retailer is essentially selling for, say, $100 per megawatt hour. For its part, the generator also seeks some certainty on price since this can go to below zero as well as to stratospheric heights.

Hence, like almost all other markets, electricity is largely bought and sold on contract. Electricity retailers, like any other retailer, performs a service in terms of discovering and meeting consumer needs and contracting the product by which these needs are served from third parties, in this case generators.

Contracting for prices and volumes avoids the price risks which both retailers and generators are keen to avoid. Retailers, like consumers, could not accept any supply simply on the basis of it being available only at the behest of the seller. In all markets retailers need certainty as do generators, hence insurance - hedge contracts - have always been a feature of electricity markets. They are all the more essential for intermittent supply, which is far more variable and uncertain than supply from nuclear, hydrocarbons or hydroelectricity. Whether taken out by the intermittent supplier or the retailer, the hedge contract "firms up" the supply and adds to its cost.

In this sense, although all electricity receives the same spot price, the real price varies between different sorts of plant. Hydro-power, which in almost all networks is supply constrained but able to switch on and off at very short notice, will command the premium price since it will be made available only at high price periods and is an ideal means of firming up all contracts. That latter feature makes it even more valuable when there is a considerable increase in variable, fluctuating capacity. While not as valuable as fast-start hydro, reliable, continuously operating coal plant will be valued more highly than wind/solar plant, the availability of which depends on the vagaries of weather.

Without government intercession this model in the post 1995 National Electricity Market delivered low priced, reliable electricity with new plant coming on line in a timely manner in response to market opportunities. Distortions were in place as a result of spot price caps (including a cumulative price cap), retail price caps and requirements to supply unwanted customers at prices that did not take into account their full costs. In addition, the market excluded payments for spinning reserve and other features that were taken for granted under a coal dominated system but which are not provided by wind and solar. Nonetheless, these distortions were not too serious to prevent efficient markets to operate.

This pattern was broken by subsidies to renewables.

Undermining the competitive market for electricity

Ten years ago, subsidised wind and solar were already having an impact; even though they comprised only three per cent of total supply by 2010, they were forcing up costs on the "baseload" coal suppliers, which were less able to run for the extended periods for which they were designed. Pinnacle price increases took place after the announced closures of two major facilities (the Northern and Hazelwood) in 2015.

The government moved to prevent future "surprise" early closures from the increased levels of subsidised intermittent supplies but the pressures on what are now termed "legacy" plant remain. COVID and its effect on demand brought price reductions but price increases are now once again being seen. The closure of a major facility (Eraring, Yallourn) will bring a new upward plateauing of spot prices. And although generators will seek to abide by government requirements to avoid abrupt closures, it is illegal for them or any other business to operate while insolvent; hence, deferring closures will require government subsidies (already in place with Yallourn). Ironically, the facilities that are being driven out of business by government subsidies to their competitors are now being given their own subsidies to remain operational!

At first, renewable energy subsidies had limited distortional effect – Australia's initial federal-wide objective from 2002 required retailers to incorporate a growing level of renewables into their supply, up to a notional 2 per cent. Failure to meet the annual total brought a penalty that could be *de facto* as high as $92 per MWh. Hence renewables (initially only wind) could negotiate a subsidy from consumers, via retailers that sometimes approached the $92 ceiling but was more often around $40-$50 per MWh, (on top of which, like all supplies, renewables received the spot price that averaged around $40 per MWh). The subsidy reflected the higher cost of the designated renewable energy.

As the renewables requirements were lifted, their higher market share impacted on the production pattern of more traditional supplies. This was compounded by subsidies to roof top supplies which, with now over 3 million installations, have created a "duck curve" demand, forcing considerable daily afternoon shutdowns or turndowns of coal generation. Coal generators also faced higher government charges (spuriously called coal royalties) and more onerous requirements for tapping into new coal reserves. These developments led to closures of the more marginal coal generators followed by sharp price increases.

The discriminatory support for renewables has been amplified by direct subsidies from government agencies and by regulations requiring new transmission to be built at the expense of consumers to facilitate delivery of renewables that are inherently more locationally dispersed. The transmission lines serving renewable supplies are also less intensively utilised – and hence more costly on a per MWh basis - than those supplying co-located hydrocarbon plant.

Capacity markets are often suggested as being an ideal antidote to excessive zeal for renewables which cannot be ramped up when there is no sun and no wind. Capacity markets reward controllable generators that can replace wind and solar during low production periods. But there are considerable costs to this approach compared to an energy-only market.

First, regulators have asymmetrical incentives. They gain little by saving costs and not directing more resources to be available but incur considerable opprobrium should shortages eventuate.

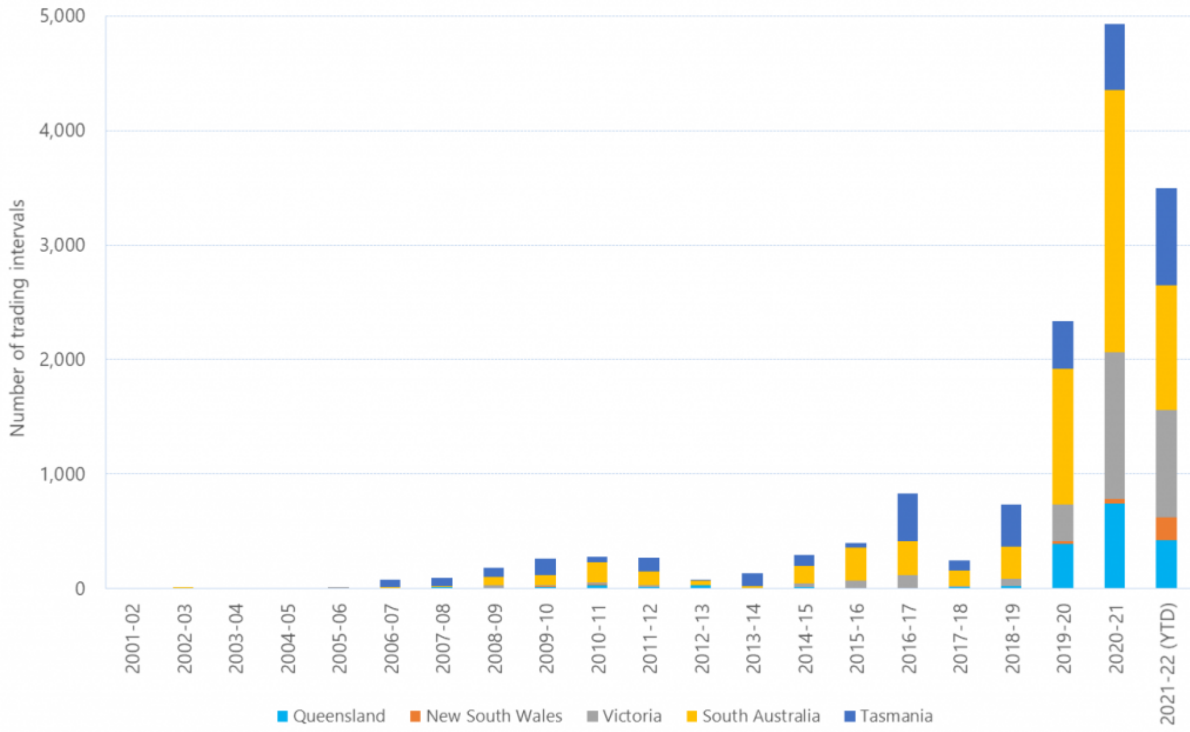
Secondly, unless there are strong penalties, suppliers in offering capacity are likely to exaggerate the degree of their available capacity and the speed that it can be brought online.

In fact, through the aforementioned firming contracts, an energy-only market creates its own capacity market. But there is no remedy to the distortion created by subsidised renewables.

The market malaise resulting from government interventions

Having formerly shown itself capable of efficiently augmenting supply when it was needed and without political direction, there is now no generation (or transmission) facility that has been or can be built without government assistance. Government intervention has destroyed the efficient, market responsive low-cost electricity market created as a result of the competition reforms and privatisations introduced in the decade and a half from 1985.

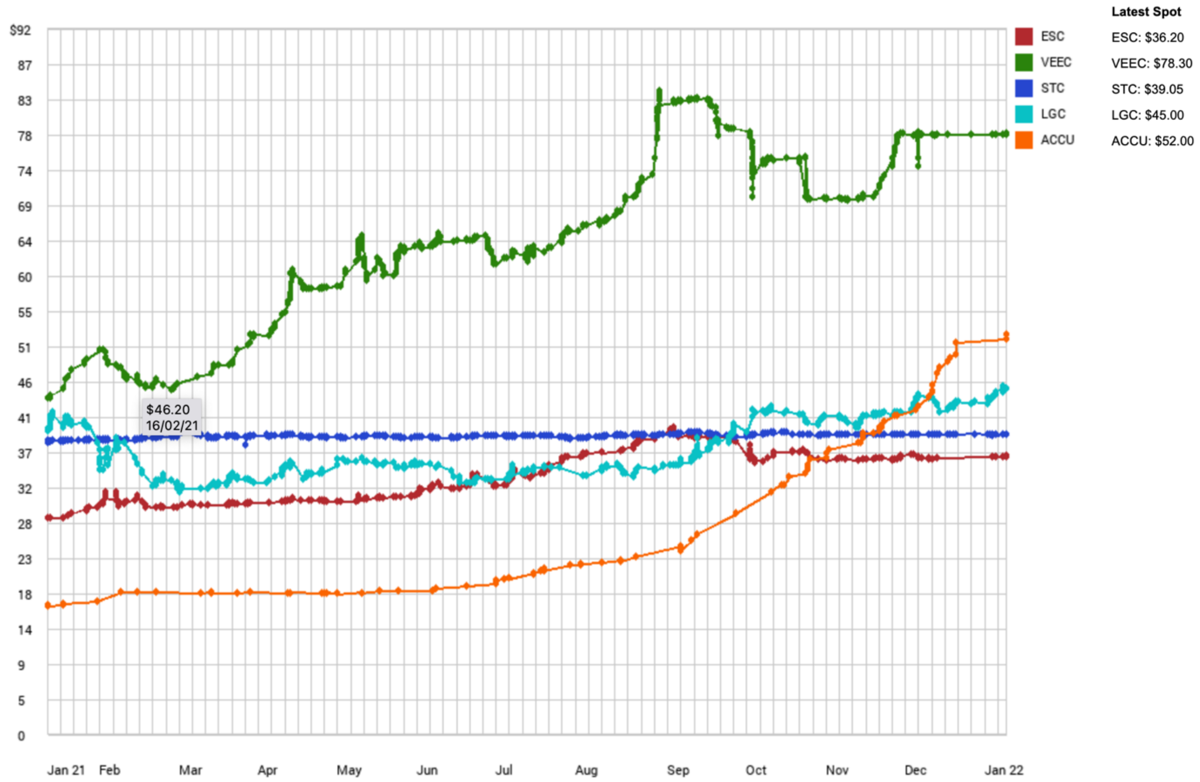
One illustration and manifestation of the present market malaise is the increase in periods where prices are below zero.



Source: AER

Zero prices are unsustainable except for those suppliers (wind and solar) which are subsidised and thereby able to cover (usually by contracting in advance) their low or negative market payments. Over the past decade, it was frequently maintained that such subsidies would trend down to zero as the renewable requirements are met and as technology brought wind/solar to became cheaper than hydrocarbon supplies. Indeed, the “infant industry” notion was always the justification for the wind/solar subsidies. This has proven to be a pipe-dream fuelled by vested interests and green zeal.

Current subsidies are as follows

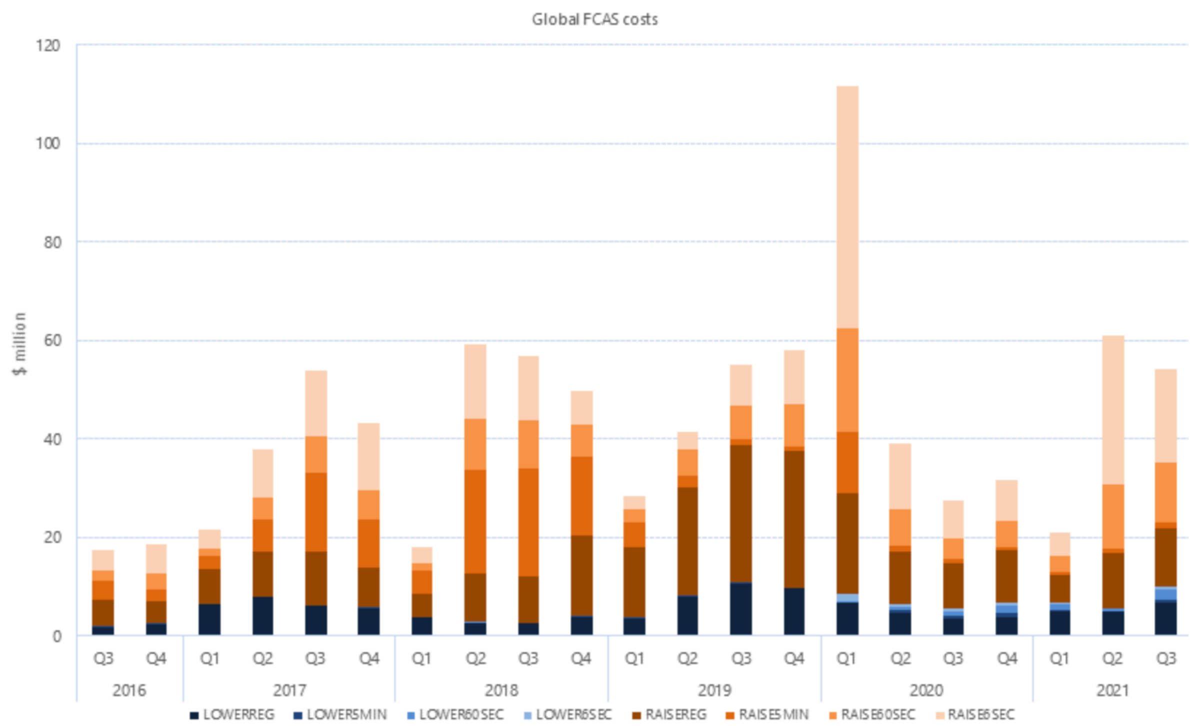


Source: Demand Manager

The main Large Generation Certificate (LGC) subsidy for commercial solar and wind is over $40 per MWh (similar to the full market price of electricity prior to the interventions). The solar rooftop subsidy, Small Scale Technology Certificates (STC), are paid up-front for their estimated lifetime to defray the cost of rooftop installations. This payment has remained near its $40 per MWh ceiling.

A more recent subsidy program, the Australian Carbon Credit Units (ACCU), are ostensibly designed to support farmers to carbon-enrich soils but by arbitraging different schemes, this has become important as a support for renewables.

The Australian Energy Council (AEC) drew attention to other measures that paper over the cracks of the market malaise. One feature of this is the increased Frequency Control payments being made to businesses being forced on-line to forestall supply deficiencies. Having originally been very rare, these are now frequent with annual costs running at $250 million. The AEC's advice (written by respected electricity supply analyst, Ben Skinner) calls "this practice entirely inconsistent with the intent of (AEMO's directions) power, and if allowed to continue, will undermine the market".



source: AER

The Draft Integrated System Plan (ISP)
Important matters AEMO says the ISP takes into account include:
• consumer-led DER investments, storage and generation investments, and demand side responses,
• the capital and fuel costs of generation, storage, transmission, distribution and DER,
• State and Commonwealth energy and environmental policies, including "net zero by 2050", state-based renewable energy targets and Renewable Energy Zones.

The ISP fuses these three criteria, wrongly supposing that they are compatible and interactively supportive.

In fact, the ISP is founded upon two principal pillars. First, global warming requires decisions by Australian governments to promote increased use of fuels with minimal emissions of carbon dioxide and other greenhouse gases. Secondly, that wind and solar are, in any event, the cheapest form of electricity and will prevail over hydrocarbons supply.

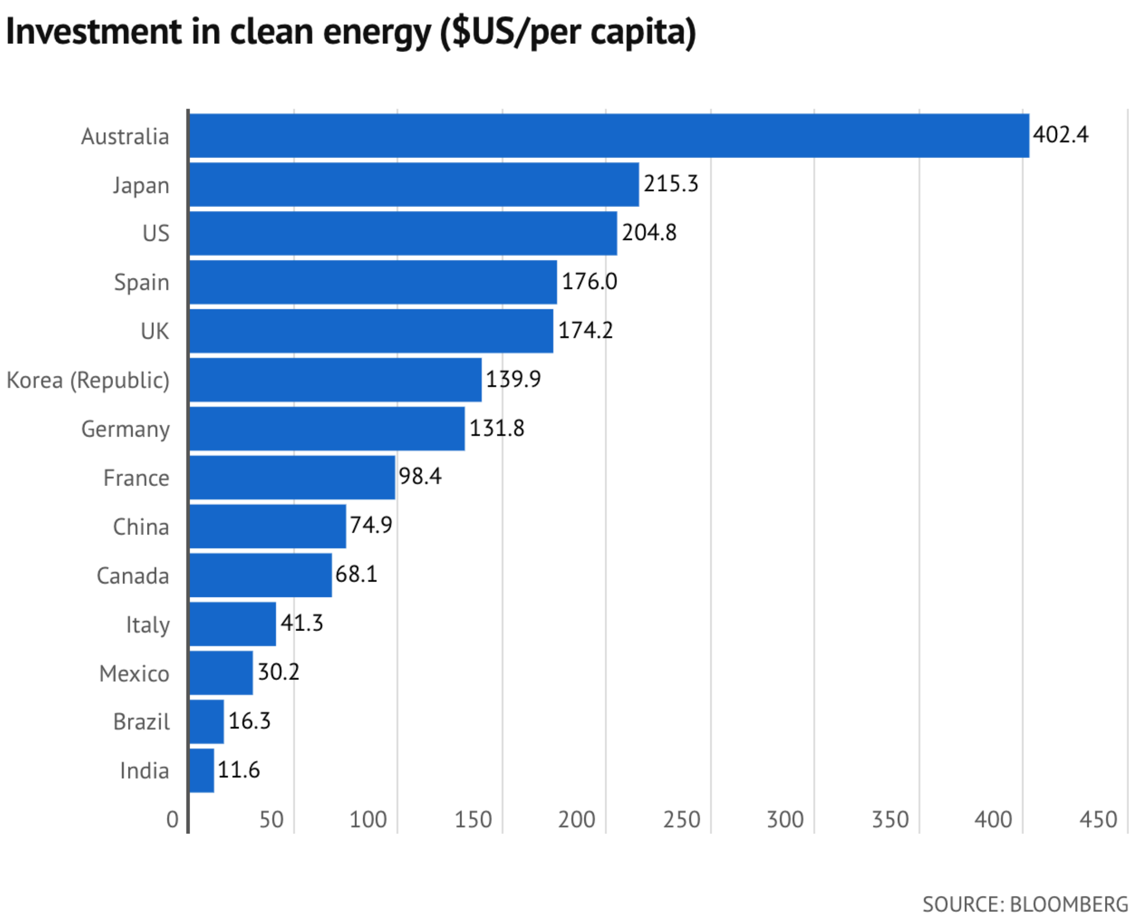
In addition, the ISP considers it likely that hydrogen-based fuels – green hydrogen derived from water – will supplant other fuel sources during the course of the next three decades. There is no evidence that hydrogen will become competitive as a power source and, as explained by Plimer and Montford, every likelihood that it will not. Minister Taylor disagrees and has already put $464 million of taxpayers' money to develop Clean Hydrogen Industrial Hubs in regional Australia. Attachment 1 provides estimates by Michael Bowden and Craig Brooking of the Economics of Operating a Gas Turbine Fuelled with Hydrogen Produced by Electrolysis and Renewable Energy. Even on highly conservative assumptions, the cost of hydrogen for energy is at least five times the cost of gas.

The ISP's conclusions discuss a "once-in-a-century transformation in the way society considers and consumes energy … replacing legacy assets with low-cost renewables, adding batteries and other new forms of firming capacity, and reconfiguring the grid to support two-way energy flow to new power sources in new locations. It is doing so at world-leading pace, while continuing to provide reliable, secure and affordable electricity to consumers." In fact, these developments, unlike previous historic transitions are being driven not by the market adopting of new technologies but by government subsidies forcing replacement of the "legacy" technologies by others that are, manifestly, higher cost than those they supersede. Were this not the case, the need for subsidies would disappear.

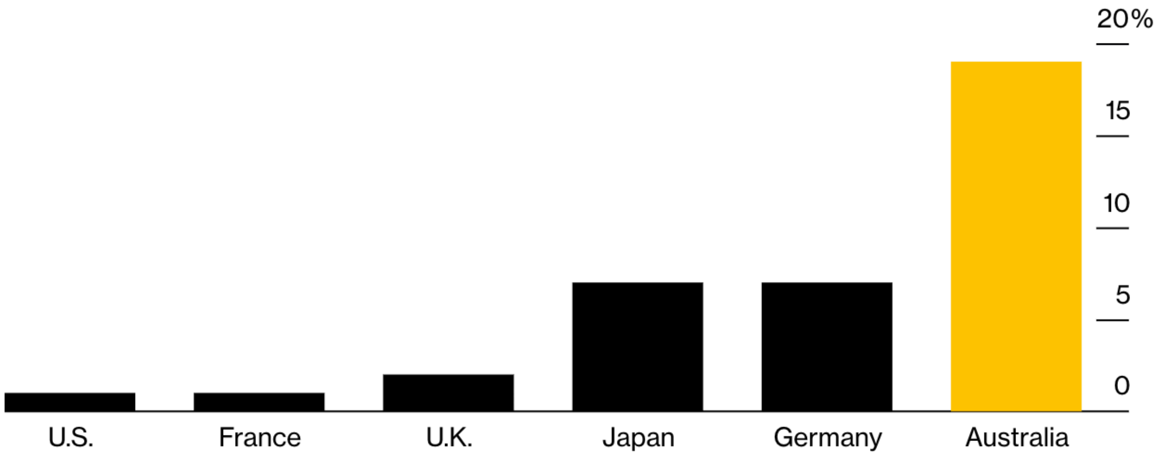
This is not the place to examine the basis of government actions in arresting a supposed trend to harmful human-induced climate change. Suffice it to say that over the last fifty years numerous warnings of future climate catastrophes have been made with the time for their occurrences always having passed without any of the predictions materialising. These projected catastrophes have included higher temperatures, (which have risen far less than forecast and without adverse effect); more hurricanes (fewer have taken place); rising oceanic levels (the increase has been no more than the trend estimated over the past three hundred years); increased wildfires (the evidence for these is absent); and the disappearance of the Great Barrier Reef (all the evidence points to its stability). Bjorn Lomborg itemises many of these falsified claims of doom.

In response to the climate hysteria governments, at least of developed nations, have moved to penalise and facilitate the replacement of hydrocarbon energy sources.

Australia has harmed itself far more than any other nation in forcing a substitution of renewables for low cost, reliable coal. This is demonstrated by the following two charts.



Share of solar rooftop installations in total dwellings



BNEF, OECD
Note: 2018 data

Determining clean energy expenditures to be a form of investment is mistaken. The expenditures rely on subsidies which enable them to displace investments that were put in place commercially. As such they are "malinvestments" and their damage is compounded to the degree to which public funding through agencies like the "Green Bank", the Clean Energy Finance Corporation, in the words of its CEO "crowd in" private capital attracted by the institution's government support. Each dollar of CEFC finance committed in 2018-19 was matched by more than $3 from the private sector.

To facilitate further such developments, the ISP envisages an increased participation and direction of the market by AEMO and other government agencies. Crucial to supporting these developments is a rapid increase in transmission lines to facilitate flows of energy between regions thereby ironing out different availabilities of wind and solar as well as facilitating transfers of variable power resources to firm-up the availability of the increasingly dominant intermittent sources.

The irony entailed in present policies is illustrated by the decision of the ALP to join the Morrison Government in a policy to build a $600 million gas-fired peaking plant in the Hunter Valley to firm the burgeoning renewable energy sector. Hence, as part of their policy "to transition the economy towards clean energy", mainstream political parties first subsidised renewables then added further subsidies to build plant that allows the renewables to work!

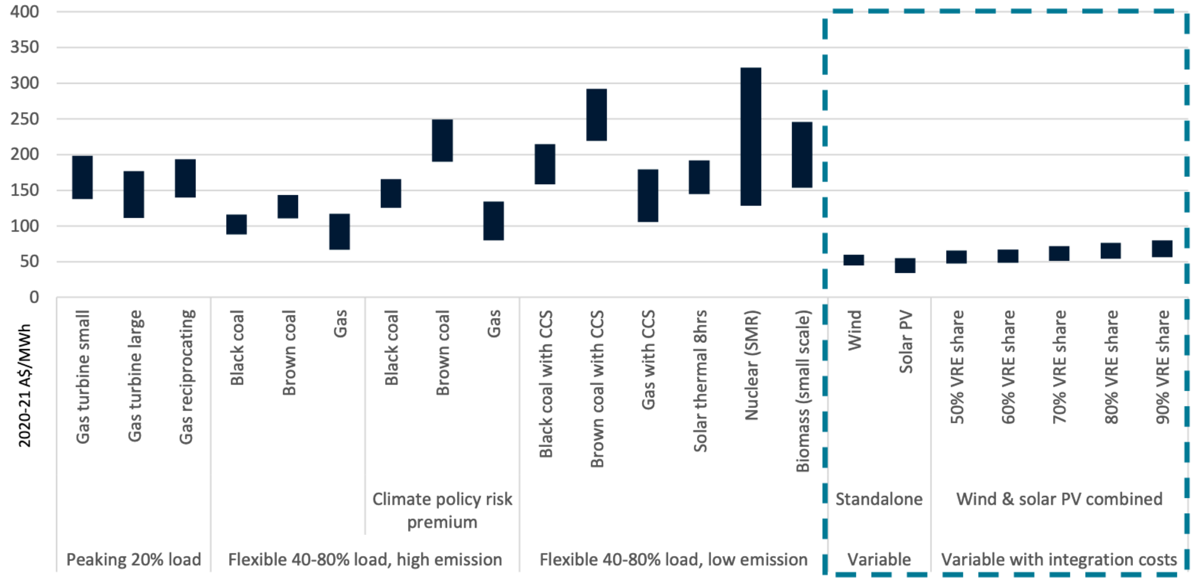
The ISP is based upon its positing of higher levels of efficiency from renewable resources and lower cost of these energy sources than hydrocarbons, but it fails to acknowledge the fact that wind/solar inroads into the aggregate supply levels have been founded upon subsidy regimes. The ISP appears to consider that such regimes are no longer needed as wind/solar is cheaper than coal/gas but it is silent on whether the subsidies should be withdrawn.

Informing this, the basis of its strategic plan, AEMO draws heavily upon the research of CSIRO which has produced a detailed body of work which purports to prove that wind/solar have lower costs than coal and gas.

CSIRO's conclusions are highly disputable. if they were true, we would not see the increased development of coal and gas plant in third world countries were wind and solar benefit less from favourable treatment. By their actions, the key rapidly growing countries including China, India, Indonesia and Vietnam are rejecting measures that would force the substitution of coal and gas by wind/solar. In adopting such market-based energy policies, these countries are becoming more competitive than those in the "first world". Energy intensive industries are therefore migrating to them.

Nor, if wind/solar were competitive, would we see the need and continued existence of Australian subsidies to renewables – if renewables were cheaper than their alternatives, the subsidies would be bid down to zero.

CSIRO's price estimates are as below:



Far more accurate are those developed by Solstice, illustrated below.

LRMC Dissection (2017 pricing)	UoM	CAPEX	Fuel	Fixed O&M	Variable O&M	CO_{2e} T&S	CO_{2e} Permits	Tax	Total
		$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
650MW Black coal HELE USC	Low	17	11	6	2	-	-	4	40
(87-90% Capacity Factor, $0/tCO2e)	High	22	35	11	4	-	-	6	78
650MW Black coal HELE USC+CCS	Low	26	13	7	5	10	-	8	69
(86-89% Capacity Factor, $0/tCO2e)	High	54	48	21	9	19	-	14	165
650MW Black coal HELE USC+CCS	Low	26	13	7	5	10	3	8	72
(86-89% Capacity Factor, $25/tCO2e)	High	54	48	21	9	19	3	14	168
650MW NG CCGT	Low	9	55	1	2	-	-	2	69
(82-84% Capacity Factor, $0/tCO2e)	High	14	86	5	7	-	-	3	115
650MW NG CCGT+CCS	Low	20	63	2	5	4	-	6	100
(81-84% Capacity Factor, $0/tCO2e)	High	28	103	9	12	7	-	7	167
650MW NG CCGT +CCS	Low	20	63	2	5	4	2	6	102
(81-84% Capacity Factor, $25/tCO2e)	High	28	103	9	12	7	2	7	169
650MW Variable Solar PV FFP	Low	62	-	12	-	-	-	16	90
(17-23% Capacity Factor)	High	127	-	17	2	-	-	26	171
650MW Variable Wind	Low	42	-	12	-	-	-	10	64
(34-39% Capacity Factor)	High	68	-	18	15	-	-	14	115
650MW OCGT	Low	49	106	5	7	-	-	12	179
(5-10% Capacity Factor)	High	148	204	30	12	-	-	36	430
650MW Solar+Battery	Low	263	-	17	5	-	-	44	328
(96% Capacity Factor)	High	782	-	22	7	-	-	102	913
650MW Wind + Battery	Low	156	-	16	4	-	-	36	211
(96% Capacity Factor)	High	577	-	23	20	-	-	73	693
650MW Solar plus HELE USC	Low	47	9	9	1	-	-	8	74
(87-90% Capacity Factor $0/t CO2e)	High	58	29	15	4	-	-	10	116
650MW Solar plus HELE USC+CCS	Low	47	10	10	4	7	-	11	89
(86-89% Capacity Factor $0/t CO2e)	High	91	40	24	8	16	-	19	197
650MW Solar plus HELE USC+CCS	Low	47	10	10	4	7	2	11	91
(86-89% Capacity Factor $25/t CO2e)	High	91	40	24	8	16	2	19	199
650MW Wind plus HELE USC	Low	48	7	11	1	-	-	8	75
(87-90% Capacity Factor $0/t CO2e)	High	61	23	19	8	-	-	10	121
650MW Wind plus USC+CCS	Low	48	8	12	3	6	-	11	88
(86-89% Capacity Factor $0/t CO2e)	High	94	31	28	11	12	-	19	196
650MW Wind plus USC+CCS	Low	48	8	12	3	6	2	11	90
(86-89% Capacity Factor $25/t CO2e)	High	94	31	28	11	12	2	19	198
650MW Solar plus CCGT	Low	40	55	5	1	-	-	6	107
(82-84% Capacity Factor $0/t CO2e)	High	52	115	8	6	-	-	8	189
650MW Solar plus CCGT+CCS	Low	46	63	6	3	3	-	9	130
(81-84% Capacity Factor $0/t CO2e)	High	67	137	12	10	6	-	12	245
650MW Solar plus CCGT+CCS	Low	46	63	6	3	3	2	9	132
(81-84% Capacity Factor $25/t CO2e)	High	67	137	12	10	6	2	12	246
650MW Wind plus CCGT	Low	41	44	7	1	-	-	6	99
(82-84% Capacity Factor $0/t CO2e)	High	55	91	13	10	-	-	8	176
650MW Wind plus CCGT+CCS	Low	47	50	8	3	2	-	9	119
(81-84% Capacity Factor $0/t CO2e)	High	70	108	17	13	5	-	12	225
650MW Wind plus CCGT+CCS	Low	47	50	8	3	2	1	9	120
(81-84% Capacity Factor $25/t CO2e)	High	70	108	17	13	5	1	12	226

These numbers are based on the ex-generator costs, which understate the true price disadvantage of wind/solar. This is because large scale solar and wind also carry higher transmission costs. Their intrinsically lower density power and irregularity means they need some threefold the transmission capacity that coal requires.

Attachment 2 comprises recent estimates by Michael Bowden and Craig Brooking which similarly find coal more competitive. Their estimates use a coal plant life of 50 years, rather than Solstice's highly conservative 30 years, and they use a capacity factor for wind of 33 per cent (Solstice used 34-39 per cent and the current average capacity factor is 29 per cent).

For coal with fuel costs at $3.50 per Gj ($12.6/MWh) operating at 85 per cent capacity, Bowden and Brooking estimate the cost at $53.1 per MWh; with 95 per cent capacity and a fuel cost at $2.80/Gj their estimate of the cost is $44.72 per MWh. For wind they estimate the costs at $48.87 per MWh but to firm that up using combined cycle gas plant is a further $72.27 placing the aggregate cost of firmed wind at $121.15 per MWh.

To reach their most competitive levels, coal generators need to operate at over 90 per cent of their capacity. This is pre-empted if other sources are subsidised to the degree that they are able to crowd-out coal generation, forcing it to operate sub-economically. Such an outcome would not be possible without subsidies.

Even though coal and gas generation is cheaper than wind/solar, the injection of those subsidised "must run" supplies damages the economics of coal plant which is designed to be baseload. With its heavy capital intensity, lengthy start up and impairment if operated under a frequent stop-start regime, it is uneconomic if obliged to operate as a backfill for intermittent supplies. New coal plant would struggle to adapt to the "duck curve" demand resulting from the growth of subsidised roof top renewables flattening afternoon prices and forcing coal plant into unprofitable operations that result in closures when significant new maintenance expenditures are required.

While welcome to solar/wind interests, this is dismal news for the economy as a whole. Schellenberger[1] describes the rising costs of a system where the share of intermittent wind and solar is increasing:

"Various studies have shown that the cost of integrating unreliable wind energy is high and rises as more wind is added to the system. For example, in Germany, when wind is 20 percent of electricity, its cost to the grid rises 60 percent. And when wind is 40 percent, its cost rises 100 percent. This is because of all the power plants, often natural gas, that must be standing by and ready to fire up the moment wind dies down, the extra power lines that have to be built to remote renewable energy locations, and all of the other extra equipment and personnel required to support fundamentally unreliable and often unpredictable forms of energy."

Schellenberger adds
"taking into account continent-wide weather and seasonal variation, for the United States to be powered by solar and wind, while using batteries to ensure reliable power, the battery storage required would raise the cost to more than $23 trillion. That number is $1 trillion higher than U.S. gross domestic product was in 2019."

Furthermore, he estimates that
"To back up all the homes, businesses, and factories on the U.S. electrical grid for four hours, would … cost of $894 billion."

Collateral damage is caused by the costs to the environment of the shift to renewables. Mark Mills[2] puts this as follows

> "The energy transition, as it's being conceived today, will create a need for tens of gigatons of materials for solar and wind generation, grid storage, and car batteries. The IEA terms this a "shift from a fuel-intensive to a material-intensive energy system." The agency estimates that an energy plan more ambitious than implied by the 2015 Paris Agreement, but one that remains far short of eliminating the use of fossil fuels, would increase demand for minerals such as lithium, graphite, nickel, and cobalt rare earths by 4,200%, 2,500%, 1,900% and 700%, respectively, by 2040."

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[1] *Apocalypse Never: Why Environmental Alarmism Hurts Us All*)
[2] https://issues.org/environmental-economic-costs-minerals-solar-wind-batteries-mills/#.YfcYTtq-mBE.link

Mills asks, “Can the world meet the minerals and mining demands of these collective goals?”

Not only is the cost of wind/solar generated electricity in excess of that of coal and gas in a well-managed system, but the replacement of coal and gas in developed world economies will not have as marked an effect on aggregate emission levels as western governments hope. Paradoxically, on the assumption intrinsic to Australian government’s energy policies, that the developed world countries will not see lower living standards from their penalising commercially provided energy sources, a diminution of the developed world’s energy-intensive industries will have little effect on net global emissions. This is because it would amount to a *relocation* of production and emissions rather than a *reduction*. Australia, unlike most other developed economies, is a net exporter of products incorporating energy-producing greenhouse gas emissions.

Australia’s closure of energy-intensive industries like smelting would reduce energy usage by some 25 per cent and greenhouse gas emissions by rather more. This would go a considerable distance to meeting a national “net zero” goal but it would not significantly reduce global emissions.

It is incumbent on AEMO to properly advise the public and governments of the cost entailed in the modelling it is presenting and to offer alternative approaches, including a business-as-usual approach that excludes the speculative cost reductions estimated for wind and solar (and hydrogen).

Planning the future

We cannot undo the damage that subsidised renewables have brought to the electricity supply system by eliminating the facilities that have been built reliant upon subsidies to become major elements of Australian electricity supply. But we can embark upon a program of reform to bring about a gradual restoration of low-cost efficient electricity market supply.

- Eliminate all subsidies to new facilities, including from regulations and from budgetary sources, and accelerate the phase down of subsidies to existing facilities.
- Restore discipline in AEMO market interventions so that they are strictly limited and subject to review
- Require all new generators to supply their own transmission, eliminating the tortuous central planning RiT-T process whereby consumers pick up the costs
- On the basis of constitutional provisions that require freedom of trade and national agreements that outlaw state preferences, penalise state governments that engage in subsidies to renewable energy including requirements that customers finance the build-out of Renewable Energy Zones
- Inform financial institutions that the government opposes discriminatory lending policies
- Require remediation bonds from all plant including wind generators and commercial and rooftop solar.

Vaclav Smil[3], of whom Bill Gates who has read all of Smil's 36 books said "I wait for new Smil books the way some people wait for the next Star Wars movie," calls out hubris, asking
“Why is it that some scientists keep on charting .. arbitrarily bending and plunging curves leading to near-instant decarbonization? And why are others promising the early arrival of technical super-fixes that will support high standards of living for all humanity? And why are these wishful offerings taken so often for reliable previsions and are readily believed by people who would never try to question their assumptions?"

Smil further asks
"Was there a single climate modeler who predicted in 1980 the most important anthropogenic factor driving global warming over the past 30 years: the economic rise of China?"

[3] "How the World Really Works: A Scientist’s Guide to Our Past, Present and Future" by Vaclav Smil)

Estimates of the selling price of hydrogen needed to break even

Michael Bowden and Craig Brooking

Energy Conversion Factor	MJ/Kwh	3.60
Natural Gas Data		
Price	$/GJ	5.80
Hydrogen Data		
HHV	MJ/Kg	141.83
LHV	MJ/Kg	120.00
Density	Kg/m3	0.08
Price	$/GJ	
GE 9F04 CCGT Generation Data		
Net Output	MW	443.00
Heat Rate (LHV) for NG	kJ/kWh	5,978.00
Fuel (NG) consumption per annum	GJ	4,036,525.44
NG Fuel Cost per annum	$	23,411,847.54
CCGT Efficiency	%	60.20%
IEM Electrolyser Production Data		
Electrolyser Hydrogen Output	kg/day	4,050.00
Electrolyser Demand	MW	10.07
Tap water required to produce 1 kg of hydrogen	Lt	9.00
Operational Availability	%	95.89%
Life of Plant	Yrs	20
Hydrogen Fuel Requirements for generation		
Max Production Day	MWh	8,691.58
Max Production Day in MJ	MJ	31,289,700.00
Hydrogen consumed per max production day	kg	433,135.38
Maximum Average Production Day	MWh	4,514.84
Maximum Average Production Day in MJ	MJ	16,253,420.00
Hydrogen consumed per max average production day	kg	224,991.97
Annual Energy Production	MWh	675,230.08
Annual energy production in GJ by CCGT	GJ	2,430,828.30
Annual energy Consumed in GJ By CCGT	GJ	4,037,920.76
Annual H2 consumption	kg	33,649,339.70
Daily Production required to meet annual H2 Consumption	kg	96,140.97
Electrolysers Required to met daily H2 consumption	No	23.74
Electrolysers Required		
Assume H2 is stored in a Pipeline grid as for NG. This will allow the minimum no of electrolysers to meet the overall annual demand	No	24.00

Capital cost of Electrolysers

Capital cost of IEM Electrolysers	$/MW	920,000.00
Capital Cost of 24 Electrolysers	$	222,345,600.00

Storage required for hydrogen

Not required as the gas grid will act as storage. H2 will require compression and plant will need to be connected to the gas grid by pipeline

Calculation of water Consumption and Storage

Assume water is purchased from Sydney Water and water storage is not required.

Water Consumed	Lt/kg	9.90
Annual Water Consumption	kl	333,128.46

Initial Capital costs

Electrolyser capital cost	$	222,345,600.00
Land cost. Based on plant being constructed within existing Power Station Site (See Google Maps)	$	22,234,560.00
Electrical Grid Connection Cost	$	5,000,000.00
Compression and Pipeline Grid Connection Cost (1km)	$	2,500,000.00
Total Initial Capital Costs		252,080,160.00

End of Life Demolition and Restoration Costs	$	44,469,120.00
Land Sale at End of life		22,234,560.00

Operation and Maintenance costs

Cost of electricity sourced from wind farms	$/MWh	48.00
Annual electricity costs to power electrolysers	$	97,445,376.00
Assume water is purchsed from Sydney Water	$/kL	2.38
Sydney water service charge 100 mm connection	$/qtr	308.83
Cost of water per annum	$	794,081.06
O&M costs for 26 electrolysers per annum	$/MW	6,670,368.00

Net Present Value Calculations over 20 years

Hydrogen Selling Price	**$/GJ**	**34.51**
Discount rate	%	8%
Cost Inflation rate	%	3%
Revenue Inflation Rate	%	2%

Estimates of efficient costs of new coal, wind and gas.

Michael Bowden and Craig Brooking

Generation Type	Unit	Coal - Black HELE USC	Wind - NSW	Gas- Open Cycle	Gas - Combined Cycle
Plant Details					
Plant Name		Datteln - 4	4 No Sappire	2 no	2 no
Life of Plant - Technical	Years	50	25	25	25
No of Generating Units	No	1	75	6	6
Name Plate Rating	MW	1,050	1,080	1,098	1038
Average Seasonal Net Rating				1,059	994
Gross Maximum Energy Production per annum	MWh	9,198,000	9,460,800	9,618,480	9,092,880
Auxiliary Load % of Name Plate Production Output	%	4.00%	3.00%	1.53%	2.50%
Auxiliary Load with seasonal losses per annum	MWh	367,920	283,824	147,163	227,322
Plant Efficiency (Average Heat Rate)	GJ/MWh	9.50		24.63	10.47
Net Maximum Energy Production	MWh	8,830,080	9,176,976	9,471,317	8,865,558
Capacity Factor	%	85.00%	33.00%	47.27%	50.51%
Maximum Energy Sent Out per annum	MWh	7,505,568	3,028,402	4,477,092	4,477,993
AEMO Marginal Loss Factor		0.9711	0.9553	0.9553	0.9553
Maximum Energy Sold	MWh	7,288,657	2,893,033	4,276,966	4,277,827
Capital Costs of Generation Plant (50 Year Time frame)	$M	2,500.00	4,720.00	1,801.68	2,433.96
Operating Costs Per Annum					
Fuel	$/GJ	3.50		5.80	5.80
Fuel Costs	$M	249.56	-	639.44	271.80
O & M Fixed	$M	55.86	38.90	4.61	10.90
O & M Variable	$M	31.60	8.09	47.14	33.00
Total Operating Cost per Annum	**$M**	**337.02**	**46.99**	**691.20**	**315.70**
Total Operating Cost (50 Year Time frame)	**$M**	**16,850.93**	**2,349.37**	**34,559.80**	**15,785.13**
Total Cost	**$M**	19,350.93	7,069.37	36,361.48	18,219.08
Cost Of Energy Sold	**$/MWh**	**53.10**	**48.87**	**170.03**	**85.18**
Cost of Firming Energy (GAS)	$/MWh	-	72.27	-	-
Total Cost Of Energy	**$/MWh**	**53.10**	**121.15**	**170.03**	**85.18**
Total Cost Of Energy 95% CF; $2.80/GJ FUEL	**$/MWh**	**44.72**			
Rate of inflation	2.50%				
Discount rate	7.00%				