'Zero Carbon Australia – Stationary Energy Plan'
- Critique

By

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1 Summary

This document provides a critique of the 'Zero Carbon Australia - Stationary Energy Plan'[1] (referred to as the Plan in this document) prepared by Beyond Zero Emissions (BZE). We looked at the total electricity demand required, the total electricity generating capacity needed to meet that demand and the total capital cost of installing that generating capacity. We did not review the suitability of the technologies proposed. We briefly considered the timeline for installing the capacity by 2020 but have not critiqued this part of the Plan in detail.

In reviewing the total energy demand, we referred to the assumptions made in the Plan and compared them to the Australian Bureau of Agricultural and Resource Economics (ABARE) report on Australian energy projections to 2029-30[2]. The key Plan assumptions we questioned were the use of 2008 energy data as the benchmark for 2020, the transfer of close to half the current road transport to electrified rail and transfer of *all* domestic air travel and shipping to rail which could have a devastating impact on the economy. In the Plan, total energy demand was reduced by 63% below ABARE's assessment. We recalculated the energy demand for 2020 without these particular assumptions. Our recalculation increased electricity demand by 38% above the demand proposed in the Plan.

We next turned our minds to the amount of generator capacity needed to meet our recalculated electricity demand. We assumed that the existing electricity network customers would require the same level of network reliability as now. At best the solar thermal plants would have the same reliability and availability of the existing coal fleet so the network operators would at least require a similar proportion of reserve margin capacity as in the existing networks. We kept the same proportion of wind energy as in the Plan (40%) and recalculated the total capacity needed to maintain the reserve margin. The total installed capacity needed increased by 65% above the proposed capacity in the Plan.

The Plan misleadingly states that it relies only on existing, proven, commercially available and costed technologies. The proposed products to be used in the Plan fail these tests. So to assess the total capital cost of installing the generating capacity needed, we reviewed some current costs for both wind farms and solar thermal plants. We also reviewed ABARE's expectation on future cost reductions. We considered that current costs were the most likely to apply to early installed plants and that ABARE's future cost reductions were more likely to apply than the reductions used in the Plan. Applying these costs to the increased installed

capacity increased the total capital cost almost 5 fold and increases the wholesale cost of electricity by at least five times and probably 10 times. This will have a significant impact on consumer electricity prices.

We consider the Plan's Implementation Timeline as unrealistic. We doubt any solar thermal plants, of the size and availability proposed in the plan, will be on line before 2020. We expect only demonstration plants will be built until there is confidence that they can become economically viable. Also, it is common for such long term projections to have high failure rates.

2 2020 Electricity Demand

BZE make a number of assumptions in assessing the electricity demand used to calculate the generating capacity needed by 2020. In summary these are:

1. 2008 is used as the benchmark year for the analysis. BZE defend this by saying "*ZCA2020 intends to decouple energy use from GDP growth. Energy use per capita is used as a reference, taking into account medium-range population growth.*".
2. Various industrial energy demands in 2020 are reduced including gas used in the export of LNG, energy used in coal mining, parasitic electricity losses, off-grid electricity and coal for smelting.
3. Nearly all transport is electrified and a substantial proportion of the travel kms are moved from road to electrified rail including 50% of urban passenger and truck kms and all bus kms. All domestic air and shipping is also moved to electric rail.
4. All fossil fuels energy, both domestic and industrial, is replaced with electricity.
5. Demand is reduced through energy efficiency and the use of onsite solar energy.

The net effect of these assumptions is to reduce the 2020 total energy by 58% below the 2008 benchmark and 63% below the ABARE estimate for 2020. The total electricity required in 2020 to service demand and achieve these reductions is 325 TWh. This is the equivalent of an average generating capacity of 37 GW over the year.

All of these assumptions are challenging and some are probably unrealistic or politically unacceptable. To address these concerns, we have adjusted the assumptions and recalculated the energy estimates shown in Table A1.3 of the Plan.

The revised assumptions are as follows:

1. Comparing Australia's energy use per capita with Northern Europe ignores the significant differences in population density and climate between the two regions. To address this, we have used ABARE's forecast for 2020 as the benchmark year for our analysis. The ABARE forecast assumes energy efficiency improvement of 0.5 per cent a year in non energy-intensive end use sectors and 0.2 per cent a year in energy intensive industries.
2. The export of LNG will continue. Much of the world may not wish to, or be able to, emulate this plan and the demand for gas as an energy source will continue for several decades. The other demand reductions shown in BZE assumption 2 above are included.
3. A substantial modal shift in transport to rail is unlikely to be politically acceptable, particularly domestic aviation and bus travel. Domestic aviation and shipping will continue to use fossil fuels or bio-equivalents. In our analysis, nearly all road transport is electrified but without a reduction in distance travelled. Though this transport electrification is unlikely to be achieved by 2020, it is a realistic long term goal so has been included in the revised calculations. ABARE energy data are for final energy consumption so a tank/battery to wheel efficiency comparison should be made. This is considered to be a 3:1 energy reduction[3] not 5:1 as identified in the Plan.
4. All fossil fuels energy is replaced with electricity as per the Plan.

5. Demand is reduced through energy efficiency and the use of onsite solar energy as per the Plan but discounted by the energy efficiency already included in the ABARE data identified in 1 above.

These assumptions and recalculations are based on information provided in Appendix 1 of the Plan. Each SET column shown in Table 1 below are defined in Appendix 1. Recalculations are based on data provided in Appendix 1. ABARE provided data for 2008 and 2030 only so 2020 is our estimate based on the ABARE figures.

The net effect of these revised assumptions is shown in
Table 1 which is a rework of Table A1.3 in Appendix 1 of the Plan. The total electricity required in 2020 to service the revised demand and achieve the energy reductions is 449 TWh or 38% more than the ZCA2020 Plan estimate of 325 TWh.

Table 1 – Calculation detail for 2020 Energy Revised Estimates

ABARE 2029-2030 PJ/yr ZCA2020 Table A1.3	2007-2008 SET 2 ABARE	2029-2030 ABARE	2019-2020 SET 2 New Base for 2020 using ABARE	2020 SET 3 Adjusted as per ZCA2020 ex gas for LNG	2020 SET 4 Transport using 3:1 efficiency road only	2020 SET 5 Other Fuel Switch as per ZCA2020	2020 SET 6 Effic. and Onsite Solar	
Transport Total	1465	1908	1707	1707	805	805	805	
Petroleum*	1455	1895	1695	1695	280	280	280	Air, ship and rail
Electricity*	8	10	9	9	472	472	472	
Bioliquids*	2	3	2	2	53	53	53	
Commercial and Residential Total	692	1048	886	886	886	779	639	
Petroleum*	206	312	264	264	264	0	0	
Electricity*	418	633	535	535	535	692	531	
Other*	68	103	87	87	87	87	108	
Industry Total	1576	2064	1842	1347	1347	1178	1026	
Petroleum*	1036	1524	1302	792	792	83	83	Gas for LNG export
Electricity*	396	396	396	339	339	833	614	
Other*	144	144	144	216	216	262	329	
Electricity Total	822	1039	941	884	1346	1996	1616	**449 TWh**
Energy Total PJ/yr	3733	5020	4435	3940	3039	2762	2470	
Accumulated Reduction				11%	31%	38%	44%	

* Sector data taken from ZCA2020 Fig A1.3

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3 Total Capacity Needed

A number of assumptions have been made by BZE in assessing the generating capacity needed to supply the electricity demand in 2020. These can be summaries as follows:

1. The Plan relies on 50 GW of wind and 42.5 GW of concentrating solar thermal (CST) alone to meet 98% of the projected electricity demand of 325 TWh/yr. In addition, the combination of hydro and biomass generation as backup at the CST sites is expected to meet the remaining 2% of total demand, covering the few occasions where periods of low wind and extended low sun coincide.
2. In the Plan system design the extra generating capacity needed to meet peak demand is reduced relative to current requirements. The electrification of heating, along with an active load management system, is assumed to defer heating and cooling load to smooth out peaks in demand resulting in a significant reduction in the overall installed capacity required to meet peak demand.
3. In the Plan, negawatts are achieved through energy efficiency programs which lower both overall energy demand and peak electricity demand as well as by time-shifting loads using active load management. Negawatts can be conceptually understood as real decreases in necessary installed generating capacity, due to real reductions in overall peak electricity demand.
4. The current annual energy demand in the Plan is considered to be 213 TWh which can be converted to an average power figure of 24 GW. BZE assumes that the current installed capacity to meet maximum demand is 45 GW. The difference (21 GW) is then considered power for meeting the demand for intermediate and peak loads only. The peak load in 2020 is assumed to be equal to the average of 37 GW plus the 21 GW for intermediate and peak loads. This is then reduced by a 3 GW allowance for ‘Negawatt’ to give an overall maximum demand of 55 GW.
5. In the worst case scenario modelled in the Plan of low wind and low sun, there is a minimum of 55 GW of reliable capacity. This is based on a projected 15%, or 7.5 GW, of wind power always being available and the 42.5 GW of solar thermal turbine capacity also always being available with up to 15 GW of this turbine capacity backed up by biomass heaters. The 5 GW of existing hydro capacity is also always available.

The key issues in these assumptions are that the maximum (peak) demand is 55GW and that the proposed installed capacity can deliver a minimum of 55GW at any time. We will deal with each of these issues separately.

3.1 Recalculation of peak demand

The ZCA2020 Plan proposes a single National Grid comprising the existing NEM, SWIS and NWIS grids. The current installed capacity and loads in the three regions are shown in Table 2. An accurate assessment of peak demand – not average demand – is critical for assessing the total installed capacity needed.

Reliability in each network is maintained by additional available capacity over and above the expected peak demand. This is to cover for planned or unexpected loss of generating capacity either through planned maintenance or unplanned breakdown. This additional capacity is often referred to as the ‘reserve margin’.

The current reserve margin in each network is approximately 33% higher than the actual peak load. Note also that the actual total installed capacity is 53 GW and average power is 26 GW across the three networks. These are both higher than suggested by BZE in assumption 4 above.

Table 2 – Current installed capacity across the total network

Installed capacity	NEM		SWIS		NWIS		Total	
	GW	TWh	GW	TWh	GW	TWh	GW	TWh
Total capacity	47.4		5.1		0.4		52.9	
Winter max	32.1		2.7		0.3		35.1	
Summer max	35.6		3.8		0.3		39.7	
Total energy	23.7	208	1.9	17	0.2	2	25.9	227
Reserve Margin	11.8		1.3		0.1		13.2	
Reserve Margin %	33%		34%		33%		33%	
Sources:								
NEM	AER							
SWIS	WA IMO							
NWIS	NT Utilicom							

The anticipated electricity demand in 2020 from
Table 1 is 449 TWh. Assuming no change in current peak demand we can expect the pro rata peak in 2020 would be 78.7 GW (39.7 x 449/227). If we apply the 3 GW negawatt reduction discussed in assumption 4, peak demand will become 75.7 GW as shown in Table 3.

3.2 Recalculation of required capacity to reliably meet demand

The Plan insists that the combination of wind power and solar thermal with storage can deliver continuous supply (baseload). The only way to accurately assess this and the capacity required to meed the performance demands on the network is to do a full loss of load probability (LOLP) analysis. This does not appear to have been done in the ZCA2020 Plan, or at least it was not discussed as such in the report.

It is also beyond the scope of this critique to perform an LOLP analysis. A reasonable proxy is to apply the reserve margin requirements currently in the network. To maintain reliability, all three network regions have a reserve margin of 33% above the anticipated peak demand.

The size of the reserve margin is, among other things, related to the reliability of the generators in the network. In the current networks the predominant generators are conventional fossil fuel plants supplying over 90% of the energy.

In the Plan, the predominant plants are solar thermal with biomass backup supplying just under 60% of the energy. The Plan states that "*The solar thermal power towers specified in the Plan will be able to operate at 70-75% annual capacity factor, similar to conventional fossil fuel plants*." The remainder of the energy mostly comes from wind powered generators.

It would therefore seem likely that the network operators would continue, at a minimum, to require a 33% reserve margin to maintain the current levels of network reliability. The reserve margin may well be higher given the proportion of wind power and the use of relatively new solar thermal/biomass hybrid plants.

Table 3 shows the anticipated peak demand and total capacity needed to meet the 2020 demand calculated in section 2.

Table 3 – Calculation of the required capacity to reliably meet 2020 energy demand

Required capacity to meet 2020 energy demand		
Total energy	449	TWh
Pro-rata peak	78.7	GW
Negawatts	-3.0	GW
Reduced peak	75.7	GW
Reserve margin (33%)	25.2	GW
Total capacity	100.8	GW

3.3 Estimate of the required wind and solar capacity

As close as possible we have kept the percentage of energy coming from wind and solar the same as in the Plan. This means that roughly 40% of the energy will come from wind and 60% will come from solar thermal plants with sufficient biomass capacity and sufficient fuel supply system to back-up for when there is insufficient energy in storage.

40% of the 449 TWh demand required by 2020 shown in section 2 will require 68 GW of wind. This is 36% higher than the 50 GW of wind used in the Plan.

The Plan assumed that 15% of wind power would always be available (assumption 5 above). This is the capacity credit allocated when assessing network reliability. Dispatchable generators like fossil fuel plants typically have a capacity credit of 99%.[4]

For the purpose of this estimate, we have assumed that the solar plants will have sufficient biomass capacity and reliability to be given a capacity credit of 99%. This may require a higher availability of biomass at the solar sites than has been included in the Plan. Without an LOLP we are not able to make that assessment.

Table 4 shows the amount of wind and solar needed to satisfy the network requirement for a total capacity of 101 GW calculated in 3.2 and shown in Table 3. The solar supply and biomass backup will need to be more than doubled from the present 42.5 GW to 87 GW.

Table 4 – Estimate of the required wind and solar capacity to reliably meet 2020 demand

Required wind and solar generators to reliably meet 2020 demand			
Source	**Installed GW**	**Capacity Credit**	**Capacity Allocation**
Wind	68.3	15%	10.3
Solar plus biomass	87.0	99%	86.1
Hydro	5.0	99%	5.0
Total capacity	160.3		101.3

4 Capital Costs

The Plan makes an estimate of the capital costs for the generators and the transmission lines. The Plan states that it "*relies only on existing, proven, commercially available and costed technologies*". This is misleading. Although it is true that wind and solar thermal generators have been used commercially for a number of years, the particular products and product size suggested in the Plan are not yet available and caution is needed when estimating future costs for these products. Further, the Plan also assumes that baseload solar thermal is available today when the International Energy Agency does not expecting competitive baseload CSP before 2025.[5]

In this analysis we have compared the costs proposed in the Plan with known costs for solar and wind plants, together with ABARE's suggested likely cost reductions over time.

4.1 Wind costs

According to ABARE[6 7], current costs for wind farms in Australia are around $2.9 million/MW. In 2009 the costs were $2.3 million/MW – see Table 5.

Table 5 – ABARE's list of major electricity generation projects (Wind)

Wind Project	Expected Startup	New Capacity	Capital Expend	$Million/MW
April 2009				
Capital Wind Farm	mid 2009	140	$220	1.6
Clements Gap	late 2009	57	$135	2.4
Cullerin Range Wind Farm	mid 2009	30	$90	3.0
Hallett 2	late 2009	71	$159	2.2
Hallett 4 (North Brown Hill)	2011	132	$341	2.6
Musselroe	2011	129	$350	2.7
Total		**559**	**$1,295**	**2.3**
April 2010				
Collgar Wind Farm	2012	206	$750	3.6
Crookwell 2	2011	92	$238	2.6
Gunning	na	47	$140	3.0
Hallett 4 (North Brown Hill)	2011	132	$341	2.6
Hallett 5 (The Bluff)	2011	52	$140	2.7
Musselroe	2012	168	$425	2.5
Oaklands Wind Farm	2011	67	$200	3.0
Waterloo stage 1	2010	111	$300	2.7
Total		**875**	**$2,534**	**2.9**

The following assumptions have been made by BZE in estimating the cost of wind farms:

1. The Plan involves a large scale roll out of wind turbines, that will require a ramp up in production rate, which will help to reduce wind farm capital costs and bring Australian costs into line with the world (European) markets.
2. The 2010 forecast capital cost of onshore wind is approximately €1,200/kW (2006 prices) or $2,200/kW (current prices). By 2015 the European capital cost of onshore wind is estimated to be around €900/kW (2006 prices) (or $1,650 in current prices).
3. It is expected that Australian wind turbine costs in 2011 will reduce to the current European costs of $2.2 million/MW. For the first 5 years of the Plan, the capital costs of wind turbines are expected to transition from the current European costs to the forecast 2015 European amount — $1.65 million/MW.
4. In the final five years the capital costs are expected to drop to approximately $1.25 million/MW in Australia.

Wind turbines are not new technology and this would not normally suggest such significant falls in future costs. The 7.5 MW Enercon E126 turbine proposed is significantly larger than any currently installed on-shore commercial turbine and is still being developed. No firm costs for such a turbine are yet available. It seems very optimistic to suggest that the cost of these turbines will almost halve over the next decade. That projection is not supported by ABARE, which forecasts[2] a reduction in the cost of wind power of 21% from 2015 to 2030. This is a simple average reduction of 1.5% per year.

Given the current cost of turbines in Australia ($2.9 million/MW) and accepting some economy of scale both in turbine size and volume purchased it might seem more prudent to assume the cost will fall from the current cost of $2.9 million/MW to $2.5 million/MW over the decade in line with ABARE's forecast.

4.2 Solar costs

The solar plant proposed by the ZCA2020 Plan is a solar thermal tower with 17 hours molten salt energy storage. The proposed 220 MW plant is 13 times larger than any existing solar tower system. As with the wind proposal, no firm costs for such a large sized plant are yet available.

We have prepared an analysis of two solar thermal tower projects of varying sizes and using molten salt with varying energy storage sizes. These are plants where the capital cost could be identified and shown in Table 6. All costs are converted to 2010 A$.

Part of the variation in cost per MW is related to the hours of storage. The size of the solar field has to be increased to support more hours of storage as does the size of the storage tanks. According to the Plan (p140), 80% of the cost of a solar tower system using molten salt storage comes from the solar field and the storage system. Scaling up the storage will increase the cost per MW. These costs have been adjusted in Table 6 to 17 hours storage as proposed in the Plan.

Table 6 – Solar Thermal Tower Plants

Project	Country	Base Cost Year	Capacity MW	Storage Hours	Capital Cost A$m 2010	Cost per MW A$m	Cost scaling storage to 17 hrs
Gemasolar	Spain	2009	17	15	$395	$23.2	$25.7
Tonopah	Nevada	2009	100	10	$1,050	$10.5	$16.4

The Plan (p61) has applied the following pricing which falls as more solar plants are installed:

1. The first 1,000 MW is priced at a similar price to SolarReserve's Tonopah project at $10.5 million/MW.
2. The next 1,600 MW is priced slightly cheaper at $9.0 million/MW.
3. The next 2,400 MW is priced at Sargent & Lundy' conservative mid-term estimate for the Solar 100 module which is $6.5 million/MW.
4. The next 3,700 MW is priced at Sargent & Lundy Solar 200 module price of $5.3 million/MW.
5. The remaining 33,800 MW is priced at $115 billion or $3.4 million/MW.

The Tonopah project is treated as a First-Of-A-Kind (FOAK) plant. Unfortunately the Tonopah plant has only 10 hours of storage[8] not 17 hours as required by the Plan. Grossing up the $10.5 million/MW from 10 hours to 17 hours based on the additional materials needed makes the cost $16.4 million/MW. For comparison, the Gemasolar plant shown in Table 6 has a scaled up cost of $25.7 million/MW.

ABARE[2] forecasts a reduction in the cost of solar thermal with storage of 34% from 2015 to 2030. This is a simple average reduction of 2% per year. It might seem more prudent to assume the price will fall in line with ABARE's assessment which will lower the price from $16.4 million/MW to $13.7 million/MW over the decade.

4.3 Assessment of generator capital costs based on revised capacity

In 3.3 we estimated the needed capacity to meet reliability standards in the electricity networks. From Table 4 the wind capacity needed was 68 GW and solar thermal plant capacity was 87 GW.

In this section we take the construction timelines suggested in the Plan (p57, p67) and gross them up to meet the capacity figures above. We then apply the prices calculated in 4.1 and 4.2 to calculate the revised total capital cost.

Table 7 and Table 8 apply a construction schedule as close as possible to the schedules provided in Table 3.7 and Table 3.14 of the Plan. The price each year is assumed to fall uniformly over the 10 years. We recognise this is not what would happen in practice but the end result would not vary greatly.

Table 7 – Revised capital cost of wind

Projected capital cost of wind			
Year	**$m/MW**	**Installed MW**	**Cost ($m)**
2011	2.9	1,750	5,075
2012	2.9	4,500	12,854
2013	2.8	7,500	21,102
2014	2.8	8,500	23,557
2015	2.7	8,500	23,204
2016	2.7	8,500	22,856
2017	2.6	8,500	22,513
2018	2.6	8,500	22,175
2019	2.6	8,500	21,843
2020	2.5	2,500	6,328
2021		67,250	
		Total Capital Cost	**181,508**

The Plan's projected capital cost of wind = $72 billion.

Table 8 – Revised capital cost of solar thermal

Projected capital cost of CST (solar)			
Year	**$m/MW**	**Installed MW**	**Cost ($m)**
2011	16.4	2,000	32,800
2012	16.1	3,500	56,252
2013	15.8	3,500	55,127
2014	15.4	3,500	54,024
2015	15.1	7,500	113,451
2016	14.8	14,000	207,540
2017	14.5	16,000	232,445
2018	14.2	16,000	227,796
2019	14.0	15,000	209,288
2020	13.7	6,000	82,041
2021		87,000	
		Total Capital Cost	**1,270,765**

The Plan's projected capital cost of CST = $175 billion.
Because the required capacity for wind is 36% higher in this analysis than in the Plan and the capacity for solar is 105% higher, there is significant increase in capital cost over the Plan.

This is particularly so for the solar component as the average cost per MW over the 10 years has increased from the BZE assessment of $4.1 million to $14.6 million. This a 3.6 times increase in average capital cost.

4.4 Assessment of the revised total investment cost

As the total installed capacity has increased then both the transmission system and biomass supply will also need to be increased. For the purpose of this assessment, the biomass is assumed to increase pro rata with the increase in solar thermal capacity. The transmission is assumed to increase pro rata with the total installed capacity. The actual increases could only be properly assessed with a full LOLP analysis.

The Plan assumes that the biomass fuel will be transported from the biomass pelletising plants, which are located in the wheat growing areas, to the solar thermal power plants by electrified railway lines. It seems the Plan does not include the cost of these. We have made an allowance of $54 billion for the capital cost of the electrified rail system for the biomass fuel handling logistics. This assumes 300km average rail line distance per solar power site, for 12 sites at $15 million/km of electrified rail line. This is included in our revised total investment cost shown in Table 9.

Table 9 – Revised total investment cost

Component	ZCA2020		Revised		Uncertainty ($b)	
	Install GW	Cost $b	Install GW	Cost $b	Low	High
Solar	42	175	87	1271	635	3304
Biomass Backup		14		29	15	58
Biomass Rail		0		54	27	108
Wind	48	72	66	182	91	363
Transmission		92		157	78	313
Off-grid		17		17	9	44
Total	90	370	153	1709	855	4191

4.5 Uncertainty in the capital cost estimates

Capital costs for this Plan are highly uncertain. None of the proposed generator types has ever been built. Previous estimates for wind power and solar power have often proved to be gross underestimates. Our estimates include projections of cost reductions due to learning rates as does the Plan. However, there is evidence that real costs have been increasing for decades so the learning rate reductions have to be considered uncertain.

The Plan calls for electrified rail lines to run from the pelleting plants in the wheat growing areas to the solar power stations but the capital cost for lines was not included. We have included an estimate for this as discussed in 4.4.

There is uncertainty on the downside due to potential technological break-throughs which might make the learning curve rates forecast by various sources: Sargent and Lundy, NEEDS, DOE, IEA and ABARE achievable. BZE projects a cost reduction of some 50% for solar and wind over the decade. We will consider this to be the downside uncertainty.

There are several uncertainties on the upside:

1. A qualified estimator will state that the uncertainty on the upper end is as high as 100% for a conceptual estimate involving a particular design using mature technology for a particular site. The Plan and our estimates are for a concept that does not involve mature technology, without specific site surveys and without a system design for a totally redesigned electricity system.
2. Previous estimates for solar thermal plants over the past two decades have often underestimated the cost of the actual plants. For example, the estimated cost of Solar Tres / Gemasolar increased by 260% between 2005 and 2009 (when construction began).
3. A loss of load probability (LOLP) study would be essential to accurately estimate the generating capacity and transmission network requirements before this Plan was executed.
4. The wind power contribution to reliability is based on an assumed firm capacity of 15%. Many consider this highly optimistic. Should the LOLP study suggest a significantly lower firm wind capacity, then much more solar thermal and biomass capacity would be required, increasing the total capital cost.
5. Some consider that almost none of our hydro resource could be used in the way assumed in the Plan to back up for low sun and low wind periods. If this proved to be the case then more solar and biomass capacity would be required.
6. All existing CST pilot plants have been built in areas that are relatively close to the necessary infrastructure such as road, water, gas mains and a work force. This will not be the case for most of the 12 sites proposed for Australia.

In Table 9, we have used a downside uncertainty of 50% and an upside uncertainty of 260% for solar plants and 200% for the other components.

5 Electricity Costs

The wholesale electricity cost, the price paid to the generator, makes up between 30% to 50% of retail electricity prices so any significant increase in the wholesale cost will impact consumer electricity prices. The Plan claims that wholesale prices will rise from the present $55/MWh to $120/MWh after 2020 (p122).

Table 10 shows estimates for the cost of electricity from solar thermal plants and wind farms for different years. It is clear that the Plan estimate for solar is significantly less than the other estimates. This would suggest a significantly lower capital cost for solar in the Plan than anticipated by these other assessments. The Plan does not offer an electricity cost for wind farms.

Table 10 –Estimates of levelised cost of electricity

LCOE	Solar Thermal A$/MWh			Wind A$/MWh		
	Min	Max	Mid	Min	Max	Mid
ZCA2020	50	80	65	na	na	na
ABARE 2015	240	525	383	110	230	170
ABARE 2030	140	360	250	90	200	145
DOE/EIA 2016	290	290	290	170	170	170

Based on the ABARE electricity cost estimates shown in Table 10 for solar thermal and wind, if the ratio of energy generated is 60% solar and 40% wind then the wholesale electricity price would need to be, at a minimum, $270/MWh by 2020 to cover the cost of generation.

However this is not a total system cost. The wholesale cost of electricity would be about $500/MWh based on the capital cost of $1,709 billion, the supply of 443 TWh/a, a lifetime of 30 years and real interest rate of 10% pa.

If the capital cost is at the low end of the range, $885 billion, the electricity cost would be about $270/MWh. If the capital cost is at the high end of the range, the electricity cost would be about $1200/MWh.

The $500/MWh cost is over 4 times the cost proposed in the Plan and nearly 10 times the current cost of electricity. The low end of the estimate, $270/MWh, is more than twice the estimate proposed by the Plan and 5 times the current cost of electricity. The high end of the range is over 10 times the cost proposed in the Plan and over 20 times the current cost of electricity.

6 Implementation Timeline

The Plan is not economically viable; therefore it will not be built to the timeline envisaged in the plan. As an example of how unrealistic the timeline is, the Plan assumes 1000 MW of CST will be under construction in 2011. This is clearly impossible. The first plant with 100MW peak capacity and just 10 hours of storage won't be on-line in the USA until 2013 at the earliest. It could be years before Australia can begin building plants with 17 hours of storage.

Trying to schedule the proposed build is making a category error. It is unlikely that any project manager would touch it. The project is simply not scoped.

We expect only demonstration plants will be built until there is confidence that they can become economically viable. We doubt any solar thermal plants, of the size and availability proposed in the plan, will be on line before 2020. .

7 Conclusions

We have reviewed the "*Zero Carbon Australia – Stationary Energy Plan*" by Beyond Zero Emissions. We have evaluated and revised the assumptions and cost estimates. We conclude:

- The ZCA2020 Stationary Energy Plan has significantly underestimated the cost and timescale required to implement such a plan.

- Our revised cost estimate is nearly five times higher than the estimate in the Plan: $1,709 billion compared to $370 billion. The cost estimates are highly uncertain with a range of $855 billion to $4,191 billion for our estimate.

- The wholesale electricity costs would increase nearly 10 times above current costs to $500/MWh, not the $120/MWh claimed in the Plan.

- The total electricity demand in 2020 is expected to be 44% higher than proposed: 449 TWh compared to the 325 TWh presented in the Plan.

- The Plan has inadequate reserve capacity margin to ensure network reliability remains at current levels. The total installed capacity needs to be increased by 65% above the proposed capacity in the Plan to 160 GW compared to the 97 GW used in the Plan.

- The Plan's implementation timeline is unrealistic. We doubt any solar thermal plants, of the size and availability proposed in the plan, will be on line before 2020. We expect only demonstration plants will be built until there is confidence that they can be economically viable.

- The Plan relies on many unsupported assumptions, which we believe are invalid; two of the most important are:
    1. A quote in the Executive Summary "*The Plan relies only on existing, proven, commercially available and costed technologies*."
    2. Solar thermal power stations with the performance characteristics and availability of baseload power stations exist now or will in the near future.

8 References

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