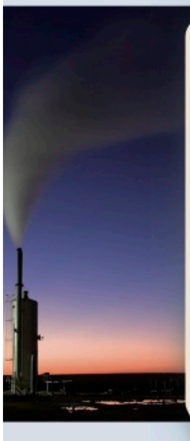

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SEN W.A. 100% Renewable Energy on the SWIS 2029

8 February, 2013

SEN W.A. 100% Renewable Energy on the SWIS 2029

1. BACKGROUND AND OBJECTIVES

Sustainable Energy Now Inc. has been commissioned to provide a brief of scenario/s which demonstrate the potential for WA's SWIS electricity grid demand to be fully met by a combination of renewable energy generation, efficiency, storage and demand-side management within the SWIS grid, by 2029.

While this aim may be achievable, SEN recognises that there are practical limits with diminishing returns, to achieving this by a certain time, and that some forms of fossil generation may linger for various reasons, and/or be converted to use renewable fuels as feedstock.

There are various combinations of renewable energy and complementary technologies which could meet the objective, and SEN has been asked to provide at least one which is high in concentrated solar thermal (CST) generation, with other possible scenarios as options. This report has used the SEN Renewable Energy Simulation to assist in modelling the scenarios, however, this software has limited capabilities and has not been independently checked and is therefore only intended as an illustration to aid in visualisation.

The option of a high voltage DC interconnector to the NEM grid in the Eastern States has not been considered in this report.

It should also be noted that 'fully renewable" does not mean 'zero carbon' as even the technologies here have embodied emissions factors, albeit low (<0.06 kg CO_2e / kWh) compared to coal fired electricity emission factors (> 1.0 kg CO_2e / kWh).

This study is a preliminary desktop investigation of the options, due to limited time. In particular, a detailed analysis of wind and solar data across the SWIS grid data was not conducted for this study and is required to determine the amount of biomass fired and other backup energy needed to cover periods of low wind speed and low solar radiation. Levelized costs of electricity and other parameters have been estimated by proportioning capacity factors of the various technologies against rated (maximum) capacity factors from references and shown in tables 1, 2 and 3. Due to the number of assumptions and projections both in this study and referenced studies, the information presented should be considered only approximate, for visioning and discussion purposes.

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2. EXECUTIVE SUMMARY

2.1 WA has among the best solar, wind and wave resources in the world and the potential to generate renewable energy from these resources is enormous.

2.2 A number of SWIS grid scenarios were investigated for this report summarised as:

- Scenario 1 Solar thermal dominant with backup biomass at solar CST plants;
- Scenario 2: Lower cost diverse mix with wind and solar PV dominant;
- Scenario 3: Business as Usual (BAU) without Carbon Capture and Storage or efficiency/waste reduction gains, following the fossil growth philosophy of the state government's Energy 2031 Strategic Energy Initiative as the basis.

Costs for generation, storage and transmission are summarised in the Tables 1 – 3.

2.3 Scenario 3 (BAU) does not include the cost of carbon capture and storage. Also, an additional gas pipeline will be needed to deliver gas to generators near Perth. Both of these works are likely to be required and would add many billions of dollars to the cost of the BAU scenario. Rising coal and gas prices, and to a lesser extent the price on carbon, will make fossil generation more expensive.

While renewable scenarios will require more capital expenditure than adapting the existing fossil fuelled grid, it will ultimately provide energy at less cost because technology costs of renewables are decreasing and there are no fuel costs, except for biomass. For example the Australian Energy Technology Assessment (AETA) has forecast the Levelized Cost of Electricity (LCOE) from new wind, biomass and solar PV power plants to be lower than generation from new coal fired plants even without being equipped with CCS while the cost of solar concentrated thermal with storage is likely to be only slightly more. (Ref: Australian Bureau of Resource and Energy Economics (BREE) "Australian Energy Technology Assessment).

2.4 The absence of interconnection with the NEM grid and the need for rotating generators that can control network voltages and frequency results in the requirement for a small amount of biomass-fuelled backup generation combined with pumped-hydro storage during times of low solar irradiance and wind velocity.

2.5 SEN scenarios outlined in the tables below utilise LCOE and capital costs adapted largely from; BREE *Australian Energy Technology Assessment (AETA)* 2012, Melbourne Energy Inst., 2011. *Renewable Energy Technology Cost Review 2011*.

2.6 Significant 'over-build' of wind, solar and biomass generation is included so that the proposed scenarios should provide sufficient dispatchable backup and storage for up to 3 consecutive days 4 times per year of coinciding minimal solar and wind conditions throughout the SWIS area. However, more widespread, detailed analysis of wind and solar records is required to confirm this assumption.

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Table 1.

Scenario 1: Solar CST dominant								
Technology	**Power capacity, MW 2029**	**Est. Energy GWh /yr**	**Cap. cost $/kW' (BREE, 2012 & ZCA 2010)**	**New plant cap. cost $bn**	**Rated capacity factor (CF)**	**LCOE $/MWh at rated CF**	**Est.(CF) for scenario*****	**LCOE at scenario CF**
Wind	**2,500**	6,242	$2,530	$6.3	0.38	$91	0.29	$121
Solar CST + storage	**3,500**	9,658	$8,308	$29.1	0.42	$187	0.32	$249
Solar PV large tracking + rooftop	**1,300**	2,050	$3,860	$5.0	0.24	$147	0.18	$196
Biomass backup (Solar CST co-firing + Collie/Kwinana)****	**2,800**	2,453	$500	$1.4	0.80	$89	0.10	$299
Wave	**500**	1,150	$5,900	$3.0	0.35	$222	0.26	$296
Geothermal	**300**	1,636	$7,000	$2.1	0.83	$156	0.62	$208
TOTAL & Weighted Average Levelized Cost of Energy $/MWh	**10,900**	**23,188**		**$46.9**		**$147**		**$215**
Pumped storage hydropower* (Assume servicing 50% of wind energy)	**500**	3,121	2,500	**$1.3**	0.80	$86	0.80	$86
Total Generation + Pumped Hydro				**$48.1**				
Weighted Average Levelized Cost of Energy (incl Pumped Hydro) $/MWh**						**$151**		**$221**
Storage solar CST	**3500**	n/a	n/a	n/a				

*Note: Pumped hydro ref for Capital Cost & LCOE: NREL, 7% discount rate. Cost of lower pond is minor factor.

**LCOE increased by the ratio of: total capital with pumped hydro / capital without pumped hydro.
*** LCOE's for this scenario are based on CF which is 75% of the CF at rated LCOE (excluding biomass which is the minimum considered necessary for backup/reserve).

**** Capital portion of LOCE assumed as 50% of full biomass plant. Therefore LCOE = (fuel cost+ratio of CFs x (capital component of LCOE-fuel component of LCOE). Fuel component is $ 59/MWh.

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Table 2.

Scenario 2: Lower-Cost, Wind and PV Dominant								
Technology	**Power MW capacity 2029**	**Est. Energy GWh /yr**	**Capital cost $/kW (BREE, 2012)**	**New plant cap. cost $bn**	**Rated capacity factor (CF)**	**LCOE $/MWh at rated CF**	**Est. CF for scenario*****	**LCOE at scenario CF**
Wind	**3,000**	7,789	$2,530	$7.6	0.38	$91	0.30	$117
Solar CST + storage	**1,500**	4,305	$8,308	$12.5	0.42	$187	0.33	$240
Solar PV large tracking + rooftop	**3,000**	4,920	$3,860	$11.6	0.24	$147	0.19	$188
Biomass backup (Co-firing)****	**2,500**	3,285	$500	$1.3	0.80	$89	0.15	$219
Wave	**500**	1,196	$5,900	$3.0	0.35	$222	0.27	$285
Geothermal	**300**	1,701	$7,000	$2.1	0.83	$156	0.65	$200
TOTAL GENERATION	**10,800**	**23,196**		**$37.9**		**$132**		**184**
Pumped storage hydropower*	**2,000**	3,895	2,500	**$5.0**	0.80	$86	0.80	$86
Total Generation + Pumped Hydro				**$42.9**				
Weighted Average Levelized Cost of Energy $/MWh**						**$149**		**$208**
Storage solar CST	**1500**	**n/a**	**n/a**	**n/a**				

*Note: Pumped hydro ref for Capital Cost & LCOE: NREL, 7% discount rate. Cost of lower pond is minor factor.

**LCOE increased by the ratio of: total capital with pumped hydro / capital without pumped hydro.

*** LCOE's for this scenario are based on CF which is 78% of the CF at rated LCOE (excluding biomass which is the minimum considered necessary for backup/reserve).

**** Capital portion of LOCE assumed as 50% of full biomass plant. Therefore LCOE = (fuel cost+ratio of CFs x (capital component of LCOE-fuel component of LCOE). Fuel component is $ 59/MWh.

Note: The CF's in the above tables are low because of the 'overbuild' of installed capacity and storage needed to meet the few low solar & wind energy events through the year.

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Table 3.

'Business as usual' per SEI2031 SWIS (Replace and expand existing fossil plant) Without: CCS, Efficiency / Waste gains									
Replacem't Technology	**Power capacity 2012, MW**	**Power Capacity est. 2029 (1.47x 2012x1.15), MW**	**Est. Energy GWh /yr 2029**	**Capital cost $/kW (BREE AETA)**	**Replacem't plant cost ($bn)**	**Rated capacity factor (BREE AETA)**	**LCOE $/MWh at rated CF* (BREE AETA)**	**Est. CF for scenario**	**Est. LCOE $/MWh, scenario CF*** **
Coal supercritical (No CCS)	2,317	3,916	20,879	$3,381	$13.2	0.83	$166	0.70	197
Combined cycle gas (No CCS)	274	463	2,116	$1,111	$0.5	0.83	$137	0.60	190
Open cycle gas (No CCS)	2,399	4,054	3,088	$723	$2.9	0.1	$253	0.10	253
**Other - IC (est costs scaled up from CCG) ** **	2	3	16	$800	$0.0	0.83	$137	0.80	142
TOTAL	4,992	8,436	26,101		$16.7				
Weighted average levelized cost of energy (LCOE)									**$203**

**Note : All LCOE (levelized cost of energy) figures assume a carbon price*
*** Capital cost estimated.*

**** Proportional to ratio of Rated and Estimated CFs. "Variable costs" difference is small because CFs are similar.*

Summarising the 3 tables above:

	Avg. LCOE, $/MWh	Generation Capital Cost, $bn	Other Capital Cost, $bn	Transmission Capital Cost, $bn
Scenario 1 Renewables - CST dominant	221	46.9	1.3	14
Scenario 2 Renewbles - Lower cost wind and PV dominant	205	37.9	5	14
Scenario 3 BAU, Replace/expand fossil generation	203	16.7	Gas supply system to SWIS generators (pipeline or other)	3.9

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3. ELECTRICTY DEMAND IN 2029

Assumptions:

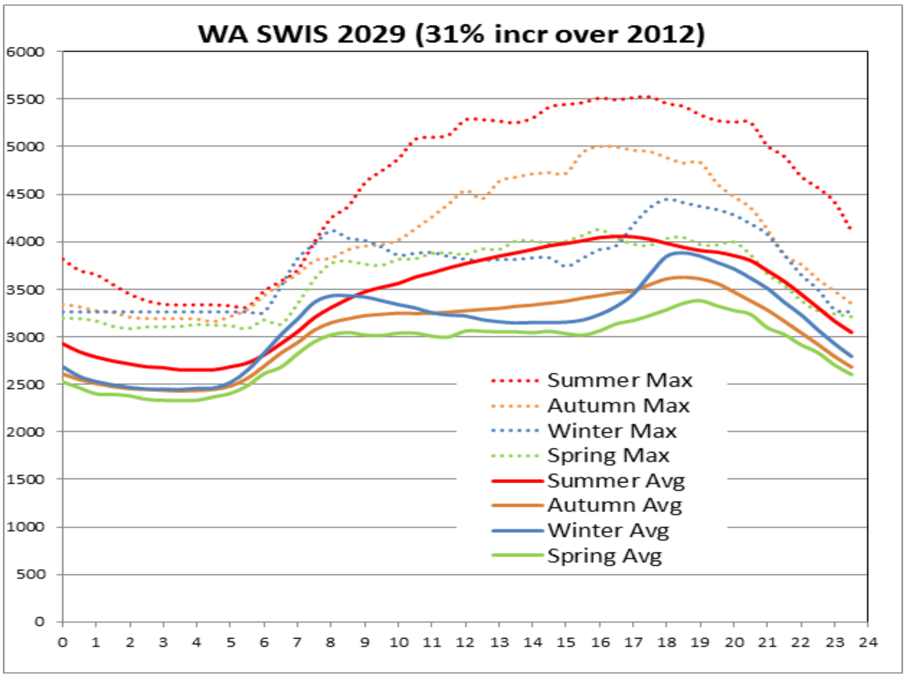
- The W. Australian Strategic Energy Initiative 2031 Directions Paper May 2011, projects electrical energy growth of 2.3%/yr. (Derived from electricity growth of 57% over 20 years).
- For the renewable energy scenarios, it is assumed that efficiency gains, waste reduction and displacement of electricity by direct solar water and space heating and geothermal 'Hot Sedimentary Aquifer' (HSA), reduces the rate of energy growth by 30%, resulting in a 1.6%/yr actual growth. Therefore it is assumed that demand reaches 23,000 GWhr/yr (23 TWh/yr) in 2029. (An overall increase of 31%).
- For the non-renewable energy scenario 3 (BAU) it is assumed that no gains in efficiency or waste reduction occur, resulting in a 2.3%/yr electricity growth, reaching 26,000 GWh (26 TWh) in 2029. (An overall increase of 47%).
- Plug-in Hybrid Electric Vehicles (PHEV) and Electric Vehicles (EV) increase demand negligibly by 800 GWhr/yr (0.8 TWh/yr). (Note 1)
- Electric Metro/light rail increases demand negligibly by 0.075 TWhr/yr (Note 2)

Notes:

1. PHEVs and EVs are assumed to reach 10% of the total WA passenger vehicle fleet by 2029. (See appendix for calculations). Power draw from PHEVs/EVs could be in the order of 1.2 GW if all were on a 4kW charge rate over an average of 2 hr; however this can be reduced by load shifting to a large extent as trials indicate most owners charge at home. In this case the load could be reduced to say 300MW over 8 hr overnight, and/or distributed over low demand periods in the day, so that peak demand is not increased
2. Capacity & size similar to Melbourne's Yarra Trams in 2009. (See appendix for calculations)

The average and peak power demand on the SWIS for the Renewable Energy Scenarios is shown in the figure below.

Figure 1. WA SWIS 2029 Load Demand Scaled Up from 2012 at 1.6%/yr, MW



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3.1. Supplying the demand for power and energy on the SWIS grid

A complementary mix of renewable generation will be geographically dispersed to maximise power and energy availability.

3.2. Backup Reserve

Dispatchable generation using biofuels or stored energy to cover for periods of low generation from renewable power stations. Sufficient backup plant will be in service at low output to provide 'spinning reserve capacity' to avoid generation overload following the loss of the largest online generator or large-scale rapid declines in output from wind or solar PV farms. The periods of low output is estimated to be for 2-3 days and 3-4 times a year. It will be provided from:

- Biomass
- Pumped hydro storage (for short or long periods - see scenarios)
- CST storage
- Geothermal

3.3. Voltage support/stability

There will need to be sufficient plant with voltage control/support capability (e.g. synchronous generators/synchronous condensers, SVCs, statcoms, wind turbines inverters and solar inverters with full-time voltage control capability) relatively close to the dominant system loads in the Perth region to control and support the network voltage. This is achievable with the pumped hydro, biomass generation (steam plant and high efficiency gas turbines), CST plant and wave generation planned for Perth metro and surrounding regions.

3.4. Dynamic spinning reserve

Online plant with fast power ramp-up/ramp down rates are necessary to control the system frequency especially during periods of fluctuating power output from wind and solar PV farms. This will be provided by biomass generation (just as it is being provided by fossil fuel generation at present), pumped hydro, STC w/storage and possibly wind farms with inertia characteristics.

3.5. Reducing Peak Power Demand

Peak power demand can be minimized by a combination of:

- energy efficiency
- waste reduction
- displacement of some generation by geothermal HSA for heating and cooling
- curtailable load (DSM)
- demand side management (DSM)

Curtailable load: Western Power currently has 100MW (TBC) of manually curtailable load, and this paper assumes this could be increased to 800MW by 2029 (800MW is 15% of the projected average summer peak of around 5,500 MW).

Demand Side Management: Smart Grid technology, cost reflective pricing, and potentially other techniques can be used to further tailor power demand by shifting loads.

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4. RENEWABLE ENERGY POWER SUPPLY PRIORITIES & CHARACTERISTICS

It is recognised that WA can have simultaneously low wind and solar weather events for periods of up to 2-3 days. To minimise the co-incident loss of power from wind and solar plants, they must be distributed over the southwest with proximity to the SWIS area.

Wave energy resources generally come from the steady circumpolar winds in the Southern Ocean and large weather events, so even in low weather events, a residual swell always remains, as shown in the wave energy section. Therefore a minimum generation capability can be established.

For this study, it is assumed the minimum available amount of wind and solar power (daytime only in respect of solar PV) is defined by their typical respective Capacity Credits. However it is recommended that a detailed analysis of historical data of actual low-weather events be made to confirm or adjust these values. Capacity Credit is a measure of the portion of the rated capacity which can be provided with a very high reliability. The Capacity Credit usually improves with aggregation of geographically distributed variable renewable generators and reduces as the percentage of their total power portion of the grid increases. (Ref: "The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and Impacts of Intermittent Generation on the British electricity network", UK Energy Research Centre):

> *"There is a range of estimates for capacity credits in the literature and the reasons for there being a range are well understood. The range of findings relevant to British conditions is approximately 20 – 30% of installed capacity when up to 20% of electricity is sourced from intermittent supplies (usually assumed to be wind power). Capacity credit as a percentage of installed intermittent capacity declines as the share of electricity supplied by intermittent sources increases."*

- *Capacity Credit for wind*:

It will be assumed that because scenarios presented have approximately 20% of total grid capacity supplied by geographically distributed wind farms, a 20% Capacity Factor would be possible.

- *Capacity Credits for Solar Photovoltaic (PV) and Solar Central Receiver Technology (CST)*:

For this report, the minimum capacity credit for solar PV and CST are assumed to be similar to those used in the planning for various Load-Serving Entities (LSE) in the USA, as below.

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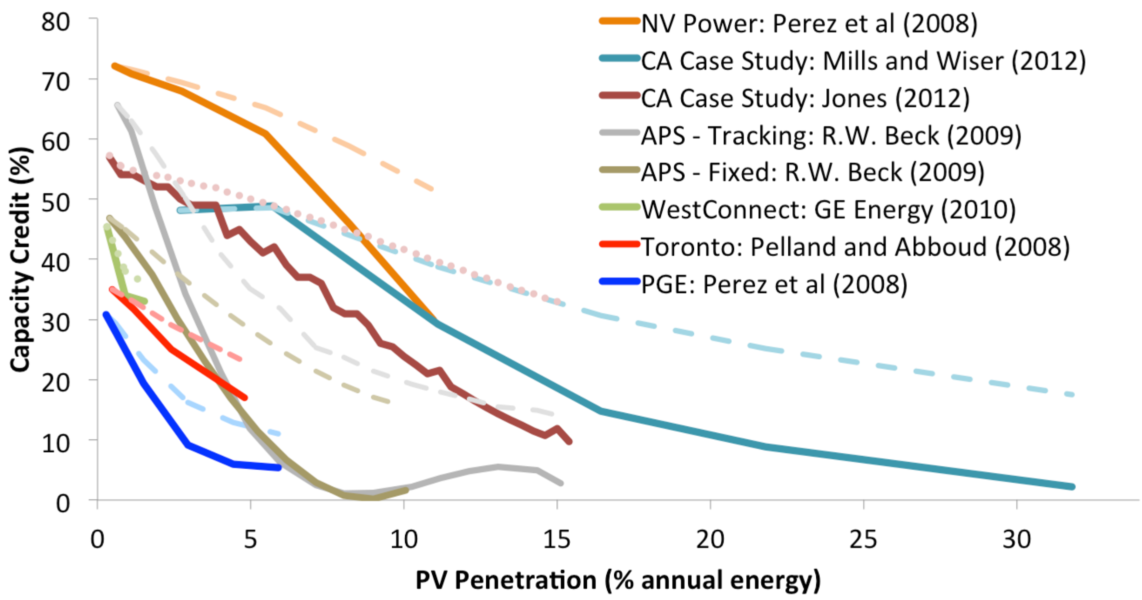
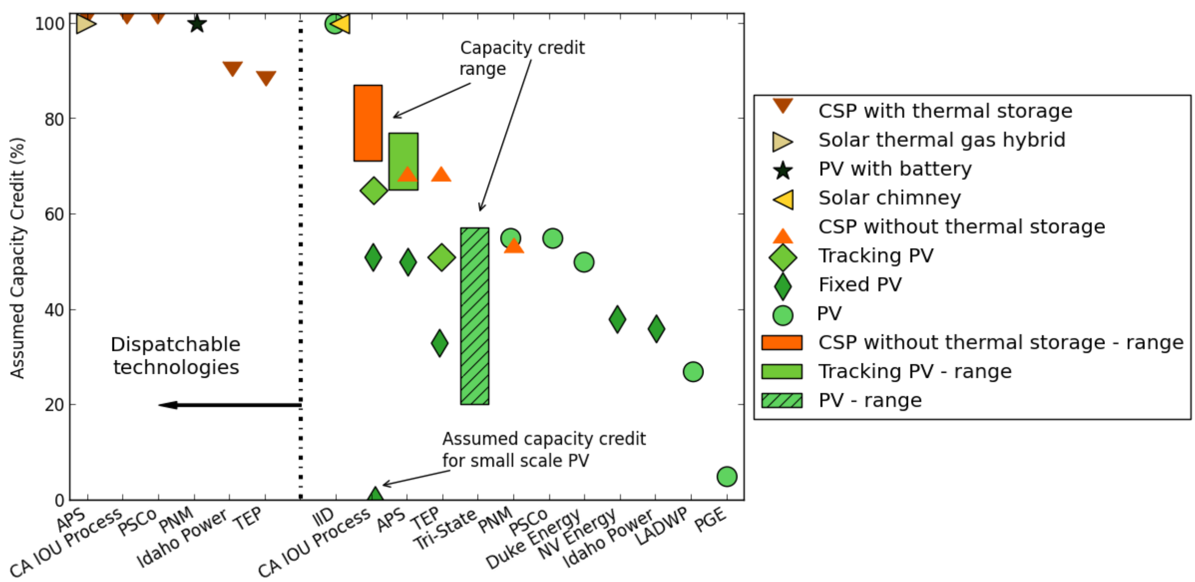
Figure 2. Capacity credit in relation to contribution of renewables to electricity generation



(Ref: "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes", Dec 2012, Ernest Orlando Lawrence Berkeley National Laboratory)

Figure 3. Capacity credit range



(Ref: "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes", Dec 2012, Ernest Orlando Lawrence Berkeley National Laboratory)

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Figure 4. Capacity credits applied by LSE's in planning studies.

Technology	Sub-category	Capacity credit range	LSEs within range
PV	Excluding Pacific Northwest	27% –77%	APS, CA IOU process, Duke Energy, LADWP, NV Energy, PNM, PSCo, TEP
	In Pacific Northwest	5% –36%	Idaho Power, PGE
	With lead-acid battery	100%	PNM
CSP	Without thermal storage or natural gas augmentation	55%–87%	APS, CA IOU process, PNM, TEP
	With thermal storage or natural gas augmentation	87%–100%	APS, CA IOU process, Idaho Power, PSCo, TEP

Note: Imperial Irrigation District (IID) appears to have assumed a 100% capacity credit for PV and a solar chimney. This assumption is excluded from the table because it is not supported by detailed analysis from IID or elsewhere. The California IOU process assumed small-scale PV would have a 0% capacity credit in its net cost ranking; this was also excluded from the table. Tri-State indicated that it estimated the capacity credit of PV to range from 20% to 57%, but it does not specify what value was used in its study. This range is also excluded from the table. All of these excluded values are shown in the corresponding figure.

Detailed weather modelling must be done to define the extent of this loss of renewable generation in low sun / low wind weather events, but for purposes of this study, the values in the table below are assumed.

Table 4. Assumed generation fraction of rated output, in low sun / wind weather events

	Summer	Winter
Wind	20%	20%
Solar PV	20%	10%
Solar CST	20%	10%
Wave	20% *	20% *

* Note that due to the fact that wave and wind energy levels do not necessarily coincide due to differences in timescale and origin, the renewable energy scenarios assume that 50% of the rated capacity are likely in good wave energy locations, even when solar and wind resources are low.

5. RENEWABLE ELECTRICITY COSTS

Costs of electricity generation from renewable energy sources are projected to decrease between 2012 and 2029, and it is assumed that as the renewable power plants are installed progressively over that period, the average costs over the period are applicable. Projected costs between 2012 and 2029 from various references, are per table 5 below. These levelized costs of energy (LCOE) assume they are utilised to their rated capacity factors, however, the Scenarios in this paper entail some ‘over-build’ therefore power plants are not utilised to their full capacity and duration, hence the LCOE is adjusted upwards accordingly, as shown in Tables 1 & 2.

Table 5. LCOE comparison generation technologies

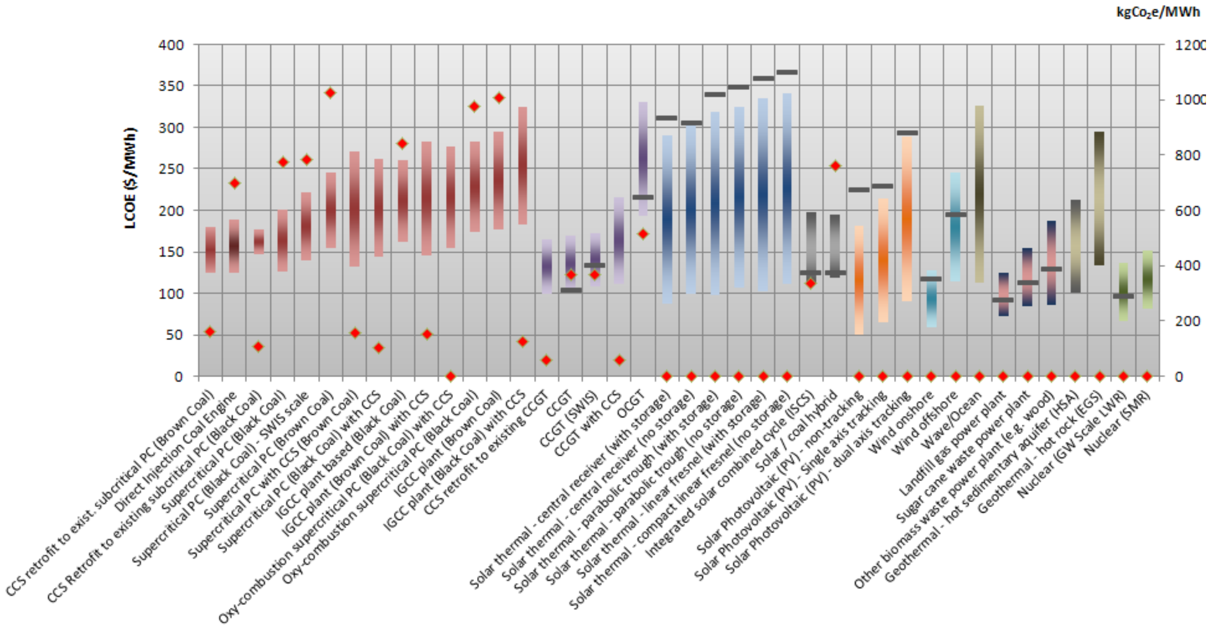
LCOE, $/MWhr	AETA at 2012 (NSW)	AETA at 2030 (NSW)	Melb. Energy Inst. (2012)	Melb. Energy Inst. (2029)	Figure used by SEN WA
Wind onshore	80-130	55-120	100-170	82-140	91
Solar PV (rooftop)	150-270	50-175	220-380	90-300	147
Solar PV (utility, fixed)	150-270	50-175	n/a	n/a	147
Solar PV (utility, 1-axis tracking)	165-225	65-210	n/a	n/a	147
Solar CST w/o storage	220-370	90-300	245-340	60-215	n/a
Solar CST with 6 hr storage	225-380	80-285	Similar to no-storage due to higher CF	Similar to no-storage due to higher CF	187 w/6-8 hrs storage*
Biomass (waste, wood)	75-160	80-180	n/a	n/a	89
Wave	n/a	110-320	n/a	n/a	222
Geothermal HSA	n/a		n/a	n/a	n/a
Geothermal HDR/EGS	n/a	130-285	n/a	n/a	156

* While capital cost increases with increasing storage, the LCOE is less affected due to the proportionately larger amount of energy dispatched.

Ref: http://www.csiro.au/en/Organisation-Structure/Flagships/Energy-Transformed-Flagship/United-States-Australia-Solar-Energy-Collaboration.aspx

Fig 5. Range of electricity technology costs at 2029.

Ref: BREE AETA Report



6. RENEWABLE ENERGY SCENARIOS FOR THE SWIS GRID

Numerous scenarios which meet the requirements for a reliable adequate SWIS energy supply are possible, but in the two scenarios presented (Tables 1 and 2), the aim is to:

- Diversify the mix of renewables
- Disperse renewables geographically
- Balance best renewable resources with proximity to existing grid and load centre (Perth)
- Acknowledge the reduction of peak power as required, by the use of demand-side management load-levelling/shifting capacity
- Ensure sufficient energy & power backup supply to cover for short and extended (several days) low-solar & wind weather events. Solar CST storage (with biomass backup), Biomass, pumped-hydro, wave (derated) and geothermal are suitable.

6.1 Scenario 1 – Concentrated Solar Thermal dominant with backup Biomass at CST plants.

This scenario seeks to achieve a large part of generation by CST (3500 MW). In addition to this there are 2500 MW of wind farms and, 1300 MW of solar PV which are 'non-dispatchable' resources, relying on the intensity of wind and solar radiation. Backup (dispatchable) generation is also required for several 2-3 day periods through the year, and this is mainly provided by 2800 MW of biomass generation co-fired at the CST plants (by biomass delivered from the wheatbelt on existing rail lines), pumped ocean storage with 300 MW capacity, 300 MW of geothermal and a derated amount of wave energy.

Due to the substantial 'over-build' (10,900 MW, for 5,500 MW maximum demand) required to cover periods of low wind and sun and the high cost of solar CST, this scenario is relatively expensive - $46.9 billion for new power plants. An additional $13.9 billion is required for new 330 kV substations and HVAC transmission lines connecting to the dispersed solar and wind farms. Two pumped hydro storage ponds using dams or ocean cliffs with seawater, would be needed. These would be located at dams near Perth, at either end of the grid, north of Geraldton and east of Albany and would cost about $1.3 billion.

Figure 6. Locations of proposed renewable energy generation for scenario 1

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Table 6. Summary of proposed generation for Scenario 1

Name	Type	Size (MW)	Sub-tot MW
Albany	Wind Farm existing	21.6	
Collgar	Wind Farm existing	206	
Denmark	Wind Farm existing	1.6	
Emu Downs	Wind Farm existing	79.2	
Grasmere	Wind Farm existing	13.8	
Kalbarri	Wind Farm existing	1.7	
Mt Barker	Wind Farm existing	2.4	
Walkaway	Wind Farm existing	89.1	
Albany	Wind Farm	40	
Australind	Wind Farm	40	
Badgingarra	Wind Farm	130	
Cape Leeuwin	Wind Farm	55	
Collie East	Wind Farm	200	
Dandaragan	Wind Farm	332	
Denmark	Wind Farm	40	
Donnybrook	Wind Farm	40	
Dwellingup	Wind Farm	40	
Fremantle	Wind Farm	6.4	
Horrocks	Wind Farm	200	
Kojonup	Wind Farm	150	
Lancelin	Wind Farm	132.5	
Merredin (Collgar extension)	Wind Farm	44	
Northcliffe	Wind Farm	40	
Pinjar	Wind Farm	250	
Three Springs (Warradarge)	Wind Farm	250	
Walkaway (Mumbida)	Wind Farm commissioning	55	
Windy Harbour	Wind Farm	40	2500
Garden Island	Wave Generator	250	
Albany	Wave Generator	250	500
Collie East	Fixed Solar PV Farm	300	
Perth	Roof-top PV existing	230	
Perth B	Roof-top PV	730	
Greenough River	Fixed Solar PV Farm existing	10	
Greenough River extension	Fixed Solar PV Farm	30	1300
Morawa	Solar Thermal Farm	500	
Kalgoorlie	Solar Thermal Farm	200	
Southern Cross	Solar Thermal Farm	500	
Geraldton	Solar Thermal Farm	500	
Dalwallinu	Solar Thermal Farm	500	
Hyden	Solar Thermal Farm	500	

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Merredin	Solar Thermal Farm	500	
Paynes Find	Solar Thermal Farm	300	3500
Landfill Gas	Biomass Facility existing	21.5	
Narrogin	Biomass Facility	15	
Northam	Biomass Facility	23.5	
Collie East	Biomass Facility	150	
Kwinana	Biomass Facility	150	
Pinjar	Biomass Facility	20	
Manjimup	Biomass Facility	20	400
Co-located evenly between all biomass plants except Paynes Find	Biomass CRT backup	2400	2800
Mullewa	Geothermal HAS Station	300	300
GENERATION	**TOTAL**	**10900.3**	
E. Albany	Hydro storage	150	
N.Geraldton	Hydro storage	150	
Darling Range dams	Hydro storage	200	500

6.2 Scenario 2 – Lower Cost:

The strategy for proportioning the various renewable generation other technologies is to maximise the use of the lowest-cost renewables, using a combination of biomass and pumped-hydro for backup. This scenario utilises:

- Wind (increased to 3000 MW)
- Solar CST(reduced to 1500 MW)
- Solar PV (increased to 3000 MW) with large tracking solar farms
- Pumped Hydro increased to 2000MW
- Biomass configuration: at 2500 MW, slightly lower than Scenario 1.
- Wave Energy configuration: as per Scenario 1
- Geothermal HDR/EGS configuration: as per Scenario 1

New transmission connections and costs are as per Scenario 1 with minor differences in connectors.

This scenario still entails 'over-build' of wind, solar CST and biomass with a total of 10,800 MW of generation to provide for a maximum peak of 5,500 MW. The cost for this is estimated at $38 billion for new generation, significantly less than Scenario 1.

More pumped hydro storage with total power capacity of approximately 2,000MW is needed and would cost about $5 billion. Nominally 500MW would be located at dams near Perth increasing the size of those in Scenario 1, to be used primarily for load balancing and grid stability purposes. The remainder is two large cliff-top ponds located north of Geraldton and east of Albany.

6.3 Scenario 3 - Business as usual (BAU)

The BAU scenario assumes the same mix of fossil fuel generation concentrated at Collie and Kwinana with a minor amount of wind, and that SWIS demand is scaled up account for growth to 2029 without gains in efficiency or waste reduction, resulting in a 47% increase in demand plus a 15% spinning reserve for peak demand. This scenario assumes that the power stations are all replaced at a cost of $16.7 billion, but without being CCS equipped. Cost of implementing this, if viable would add significantly to both capital costs and LCOE. $3.9 billion would be required to replace some transmission infrastructure or increase its capacity, but there would be no pumped storage required.

In addition, the increased demand will require an increased gas supply to SWIS generators, in the form of a new pipeline or other has not been costed.

As the scenario capacity factors did not differ much from the cited maximum CF, scenario LCOE's were adjusted proportionally by applying the formula:

Cost per megawatt hour = Max.CF * LCOE at max. CF / scenario CF

6.4 Transmission Infrastructure

Upgrades to existing Transmission:

It is assumed that upgrades of existing transmission infrastructure is required regardless of whether 'Business as Usual' (BAU) fossil generation or renewables are used, and the estimated costs for the scenarios within this report are included.

New transmission connections for renewable energy scenarios 1 and 2:

For new transmission lines and substations to connect each of the renewable generation plants to the main 330 kV transmission infrastructure, refer to Table 7.

Based on the proposed new renewable energy generation there will have to be major augmentations of the existing 330kV transmission backbone. Additional double circuit 330kV transmission lines in the North Country Region, Eastern Goldfields Region and south of Muja and Collie Power Stations will be required to transfer large amounts of power from large scale 'remote' wind farms, solar PV/solar thermal plants, biomass and wave generation and pumped storage to the existing 330kV 'backbone' of the SWIS. Each of the 500MW solar farms in scenario 1 will be expected to act as spinning reserve for the others, as such the proposed strengthening of the transmission infrastructure reflects this.

Cost: The cost of double circuit 330kV lines would be at least $3m per kilometre and single circuit 330kV $2m per kilometre. There will be a significant cost for 330kV switchyards and substations at the end of these lines - assume $50m each. Total cost of new transmission infrastructure (including a rail link Narrogin – Collie) is estimated to be $13.9 billion for both renewable energy scenarios.

Table 7. New transmission infrastructure for renewable energy

Connecting from	Connecting to	Length (Km)	Peak Renewable Power Flow (MW)	New lines needed	cost $/km	$cost million
Perth	Eneabba	279	866	330d	3	837
Perth	Merredin	312	1544	2*330d	6	1872
Merredin	Southern Cross	100	1165	2*330d	6	600
Three Springs	Perth	303	2819	3*330d	9	2727
Three Springs	Geraldton	164	2394	3*330d	9	1476
Eneabba	Geraldton	147	0			0
Three Springs	116.94E, 28.74S	100	935	330d	3	300
116.94E, 28.74S	Paynes Find Solar Thermal Farm	80		330s	2	160
Collie East	Kojonup	122	1149	2*330d	6	732
Kojonup	Albany	175	1170	2*330d	6	1050
Collie East	Kondinin	275	825	330d	3	825
Merredin	Kondinin	140	786	330d	3	420
Kondinin	119.76E, 32.10S	196	480	330s	2	392
Collie East	Bunbury	85	21			0
Bunbury	Capel	30	21			0
Capel	Busselton	30	22			0
Collie East	116.11E, 34.33S	121	1332	330d	3	363
116.11E, 34.33S	115.27E, 34.19S	108	144			0
Albany	Albany Wind Farm	14	780	330d	3	42
Leg 1	Emu Downs Wind Farm	17	22			0
Leg 6	Walkaway Wind Farm	5	2			0
Leg 12	Collgar Wind Farm	10	14			0
Leg 3	Landfill Gas Biomass Facility	10	653	330d	3	30
Leg 10	Mt Barker Wind Farm	2	2			0
Leg 19	Grasmere Wind Farm	0	0			0
Leg 6	Greenough River Fixed Solar PV Fa	18	351	330s	2	36
Leg 8	Morawa Solar Thermal Farm	15	469	330d	3	45
Leg 4	Kalgoorlie Solar Thermal Farm	3	239	330s	2	6
Leg 1	Eneabba Wind Farm	5	250	330s	2	10
Leg 6	Eneabba B Wind Farm	17	300	330s	2	34
Leg 18	Cape Leeuwin Wind Farm	6	55			0
Greenough River F	Mullewa Geothermal Station	36	354	330s	2	72
Landfill Gas Bioma	Garden Island Wave Generator	24	647	330d	3	72
Albany Wind Farm	Denmark Wave Generator	27	534	330d	3	81
Leg 11	Narrogin Biomass Facility	2	50			0
Leg 2	Northam Biomass Facility	7	400	330d	3	21
Leg 17	Collie East Biomass Facility	0	1028			0
Leg 33	Kwinana Biomass Facility	6	400	330d	3	18
Leg 6	Geraldton Tracking Solar PV Farm	12	250	330s	2	24
Leg 1	Badgingarra Tracking Solar PV Farn	11	250	330s	2	22
Leg 1	Pinjar Wind Farm	5	300	330s	2	10
116.11E, 34.33S	Northcliffe Wind Farm	40	40			0
Leg 4	Southern Cross Solar Thermal Farn	6	469	330d	3	18
Geraldton	Geraldton Solar Thermal Farm	56	581	330d	3	168
Leg 5	Dalwallinu Solar Thermal Farm	51	456	330d	3	153
Leg 13	Hyden Solar Thermal Farm	13	483	330d	3	39
Leg 1	Pinjar Biomass Facility	3	50			0
Leg 34	Denmark Wind Farm	16	286	330s	2	32
Leg 10	Ongerup Wind Farm	113	400	330d	3	339
Leg 12	Bruce Rock Wind Farm	0	300	330s	2	0
Leg 4	Merredin Solar Thermal Farm	11	465	330d	3	33
Leg 8	Paynes Find Solar Thermal Farm	4	473	330d	3	12
Leg 44	Geraldton Wind Farm	47	111	330s	2	94
Leg 17	Manjimup Biomass Facility	0	50		2	0
	TOTAL KM	3892				0
			Total Transmission Lines			$13,165
			Switchyards @ $50m (av.)		50	$0
					TOTAL	$13,165

7. RENEWABLE ENERGY TECHNOLOGIES FOR THE SWIS GRID

7.1 Energy storage: Pumped storage hydropower

Of the various forms of energy storage, pumped-hydropower and biomass appears to be most suitable for W.A. (Biomass storage is included in biomass generation). Compressed air and batteries are other storage options but are generally about 10 and 100 times (respectively) smaller in capacity than hydro and much more expensive. There are no suitable underground caverns for air storage in the SWIS area.

Stand – alone hydropower is not possible in the SW of WA because flow is limited and suitable sites have already been dammed or occupied by other infrastructure (e.g. rail line along Avon River). For these reasons pumped hydropower - between two dams on a river or between a cliff-top pond and the ocean – are the main renewable energy storage back-up options for large-scale wind and solar in WA. They are envisaged to be:

- Small pumped hydropower plant(s) near Perth for instantaneous backup reserve as well as helping with grid stability countering voltage fluctuation. A system of 500 MW capacity could be built by constructing lower storage reservoirs, headrace pipes and hydro plant on the Wellington and or Serpentine Dams.
- Pumped ocean-storage hydropower plants located at the northern and/or southern ends of the SWIS grid to absorb some of the high wind energy in those areas and provide up to 1500 MW of backup power.

Sites close to the coast of sufficient elevation (90 - 100 m) to provide the necessary head are rare in the South West and some are on land with high conservation values. However there are a few sites that may be suitable within 100 km of Geraldton and Albany

Hydro energy is generated by two-way turbines which can act as pumps and generators, and is calculated by the formula:

$E = mghe$

where m = mass of water, g = force of gravity and h = head (height), e = efficiency factor

Efficiency factors for the proposed cliff top system with 100 m head are applied twice – when water is pumped up and when it flows back, giving a round-trip efficiency of approximately 76%, made up of pipe friction loss (6%) and turbine efficiency loss (18%). Pipe friction increases as diameter is reduced and distance increased. To keep friction losses low, short large diameter pipes are required

The proposed cliff-top storage with 1500 MW capacity would comprise 19 headrace tunnels or pipes about 5 m in diameter less than 1 km in length feeding 80 MW hydro generators, with intake / discharge into the ocean. Two 900 ha cliff-top clay / membrane sealed ponds 10 m deep would provide 1500 MW of power for 24 hours. The engineering works are capital intensive, each pipe being equivalent to the Perth Rail tunnel. The capital cost of pumped ocean storage is rounded up 12% from that stated in Fig.7 below, to $2500 to account for higher costs in W.A. of LCOE of $86/MWh is estimated from Table 9…. below, assuming 10% discount rate, life of 80 years and adding 7% for additional operating and maintenance of sea water systems

Table 8. Cost estimation for pumped ocean storage hydropower		
US NREL cost estimate (Fig 7 below)	2,230	dollars per kW capacity
Capital cost in WA including large sea water ponds add 12%	2500	dollars per kW capacity
Levelized Cost of Energy (LCOE)	8.6	c/kWh
Levelized Cost of Energy (LCOE)	86	dollars per MWh

Figure7. Capital cost breakdown for pumped storage hydropower

NATIONAL RENEWABLE ENERGY LABORATORY (NREL) | COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES

The capital cost breakdown for the pumped-storage hydropower plant is shown in Figure 18.

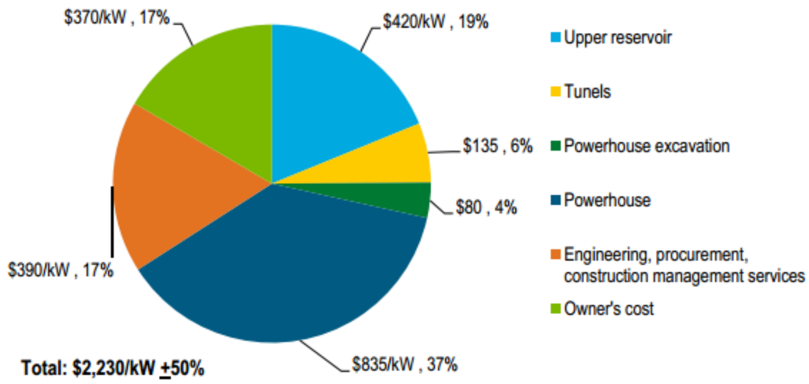

Figure 18. Capital Cost breakdown for a pumped-storage hydropower plant

Table 9.

Table 6.1: Sensitivity of the LCOE of hydropower projects to discount rates and economic lifetimes

Investment cost (USD/kW)	Discount rate (%)	LCOE (US cents/kWh)	Lifetime (years)	LCOE (US cents/kWh)
1 000	3	1.7	80	1.5
1 000	7	2.5	80	2.4
1 000	10	3.2	80	3.2
2 000	3	3.5	80	2.9
2 000	7	5.1	80	4.8
2 000	10	6.5	80	6.3
3 000	3	5.2	80	4.4
3 000	7	7.6	80	7.3
3 000	10	9.7	80	9.5

Note: base case assumes an economic life of 40 years, a 45% capacity factor and 2.5% of capital costs per year for O&M.
Source: IPCC, 2011.

7.2 Biomass

There is potential to supply 9600 GWh per year from sustainable sources of woody and waste biomass, enough to generate about 40% of the total electricity demand in 2029. However, in the scenarios presented, the need for this has been reduced to a minimum, to approximately 10% and 14% of the total annual energy demand for Scenario 1 and 2 respectively.

Table 10.

Potential for Biomass Energy in Western Australia	
Dry biomass (oil mallee) from 10% of WA grain belt (0.1*14mHa * 2.6t / ha/ yr.)*	3,640,000 tons/yr
Straw and wood (plantation) waste**	2,000,000 tons/yr
Annual BIOMASS FUELED ELECTRICITY generated @ (1.7 MWh/dry ton)	9600 GWh
Total annual generation WA South West Grid 2029	23,000 GWh
Potential TOTAL BIOMASS FUELED ELECTRICITY % of total energy sent out in 2029	42%

**B. Rose (pers. com) **D. Harrison, Verve Energy (pers. com)*

The least cost configuration would be biomass storage as solid, at source and/or generation plant. All new fuelled thermal power plants built must be compatible with biomass combustion – i.e. fluidised bed (for solid biomass fuels), gasification (syngas produced from biomass or electrolysis using renewable electricity) or renewable liquid fuels (such as bio-oils). A strategy for production of renewable fuels from biomass and electro-chemical means is a pre-requisite for any 100% renewable energy plan.

A least cost strategy for renewable fuelled electricity would include:

- Chipping and pelleting plants located at hubs in agricultural areas and waste processing centres serviced by existing by rail.
- Railing biomass chips and pellets to CST plants for co-firing and/or Collie/Kwinana (about 2 c/ t km), combusting the biofuel in modified existing coal fired generation units and new pyrolysis gas fired units.

Biomass energy from modified large coal power plants is estimated to cost $118/MWh, compared with $148/ MWh for new smaller regional power plants. Biomass co-firing of CST plants is assumed to be similar cost.

Assumptions for supplementary heating of CST with biomass:

- The CST system's molten salt storage, boiler and steam turbine are used
- Fuel is plantation grown woodchips (cost approx. $58 per MWh)
- Woodchips are used to fire a heat exchanger which heats the stored molten salts
- Additional infrastructure installed : burner and heat exchanger
- Woodchips are delivered to the CST plants by existing rail lines
- LCOE adjustment for actual capacity factor CF which difference of CF from reference, by proportioning the LCOE capital cost component of plant and O&M plus fuel cost. i.e.LCOE = (Levelized capital cost component at max. CF x ratio(Max. CF / actual CF) + fuel cost. See Tables 1 and 2.

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Two 150MW of biomass fired gas / steam turbine generation is needed comparatively near to Perth as the main area of demand (Collie and Kwinana) to aid with grid stability. There are technologies being developed such as flywheels, dynamic inverters and low cost battery storage, along with the proposed pumped hydro, that may, closer to 2029, make the requirement of this biomass unnecessary.

Table 11.

Biomass fired electricity cost calculation		
Assumed price delivered to rail *	\$70	per green tonne 45% moisture
Delivered biomass price per dry tonne (10% moisture)	\$94.50	per dry tonne 10% moisture
Add \$4/ tonne for 200 km average rail haulage to CST plants &/or Collie/Kwinana @ 2c/ tonne km***	\$98.50	per dry tonne 10% moisture
fuel price per MWh electricity @ 1.7 MW h per tonne dry biomass	\$57.94	MWh
LCOE for sugar cane waste plant (free fuel) in 2020 **	\$60-120	MWH
Small regional power station < 50 MW, assuming LCOE for OM fuel steam thermal plant is median price for bagasse plant with free fuel (\$90) plus fuel cost (\$56) / MWh	**\$148**	**per MWh**
Modified Collie Coal power station 300 MW units, assuming capital and other operating costs \$60/MWh plus fuel cost \$58/MWh	\$118	per MWh ****
Biomass co-firing of solar CST molten salt storage assuming capital cost of heat exchanger \$30/ MWh, fuel cost \$59 /MWh	\$89	per MWh

*Abadi et al, 2012.

**AETA, 2012

***Oakajee Rail Network Report, 2009

*****Note: that supercritical black coal (without storage) is forecast to cost \$110 - 145/ MWh in 2020 (AETA, 2012)*

Most of the biomass fired electricity would be sold as dispatchable backup power and therefore its capacity factor may be low. Spot prices on the NEM currently range from \$40 to \$250 per MWh depending on demand (BREE, 2012). At times when demand is high and back-up is needed prices are in the range \$100 – 250 per MWh and may peak at over \$1000 for brief periods.

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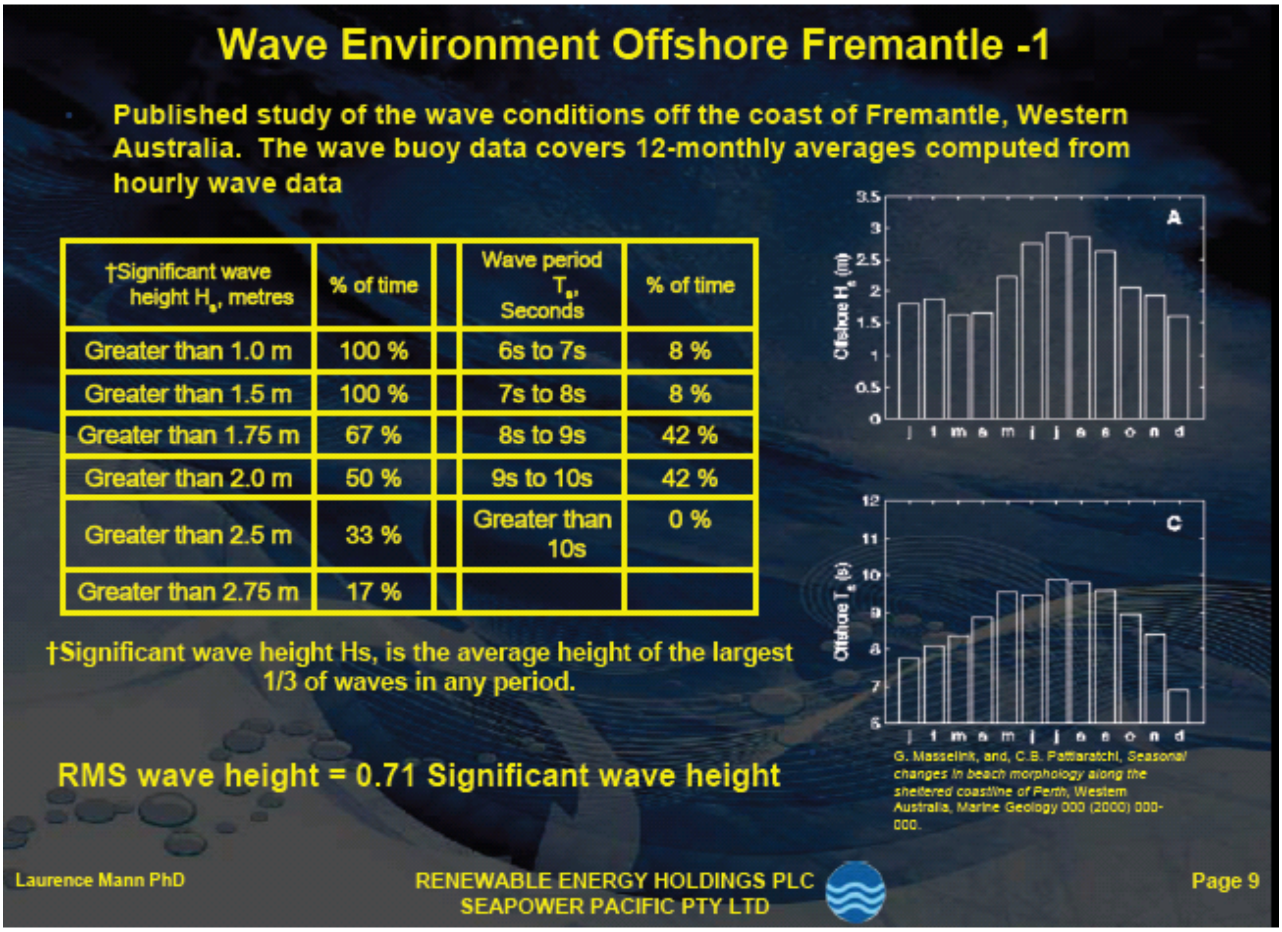
7.3 Wave Energy configuration:

There are a number of wave energy technologies available, but one of the potential candidates for this scenario is the CETO subsurface buoy system of Carnegie Wave Energy Corporation, of WA (http://www.carnegiewave.com/).

This technology is in the commercial demonstration phase of development and projects of up to 5MW capacity are in progress, the latter at Garden Island, WA. Prior discussion with CWE in 2010 indicated that deployment of 120 MW could be achieved by 2020 (Ref: WA Renewable Energy Scenarios Discussion Paper, SEN 2010, http://sen.asn.au/files/SEN_REscenarios_discussionpaper_web.pdf) and development appears to be going to plan at this stage. It has been assumed that with implementation experience, up to 500 MW could be installed around SW WA by 2029, in a number of good wave energy sites from Geraldton south around to Albany, tying in with load centres via existing and new transmission infrastructure . It is possible that a mix of this and other technologies could be installed to make up this generation capacity. Costs used are per BREE AETA 2012 report.

Carnegie technology continues to develop and is currently in the CETO V design version. In lieu of commercially proprietary performance information on the latest design, SEN uses available data for the CETO III buoys which are nominally rated at 240kW each. As a worst-case condition for power generation, in the locations these would be placed, (i.e. lowest expected sea state with significant wave height (Hs) of 1.5m), the buoys would generate approximately 20% of this power, 100% of the time as the table below indicates.

Figure 8. Wave environment offshore Fremantle



†Significant wave height H_s, metres	% of time		Wave period T_s, Seconds	% of time
Greater than 1.0 m	100 %		6s to 7s	8 %
Greater than 1.5 m	100 %		7s to 8s	8 %
Greater than 1.75 m	67 %		8s to 9s	42 %
Greater than 2.0 m	50 %		9s to 10s	42 %
Greater than 2.5 m	33 %		Greater than 10s	0 %
Greater than 2.75 m	17 %			

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7.4 Geothermal Energy Configuration

The geothermal resources in Western Australia are shown in Fig. 9 indicating areas of heat of 120 deg. C or higher, which is generally considered the lower limit which is economically feasible for generating electrical power. An example of this is the 3.4MW Unterhaching Geothermie plant which uses the “Kalina Cycle” for improved conversion efficiency. Lower temperature resources however, are able to be used for direct heating, air-conditioning, desalination, and other.

Figure 9. Geothermal resources in the SW of Western Australia.

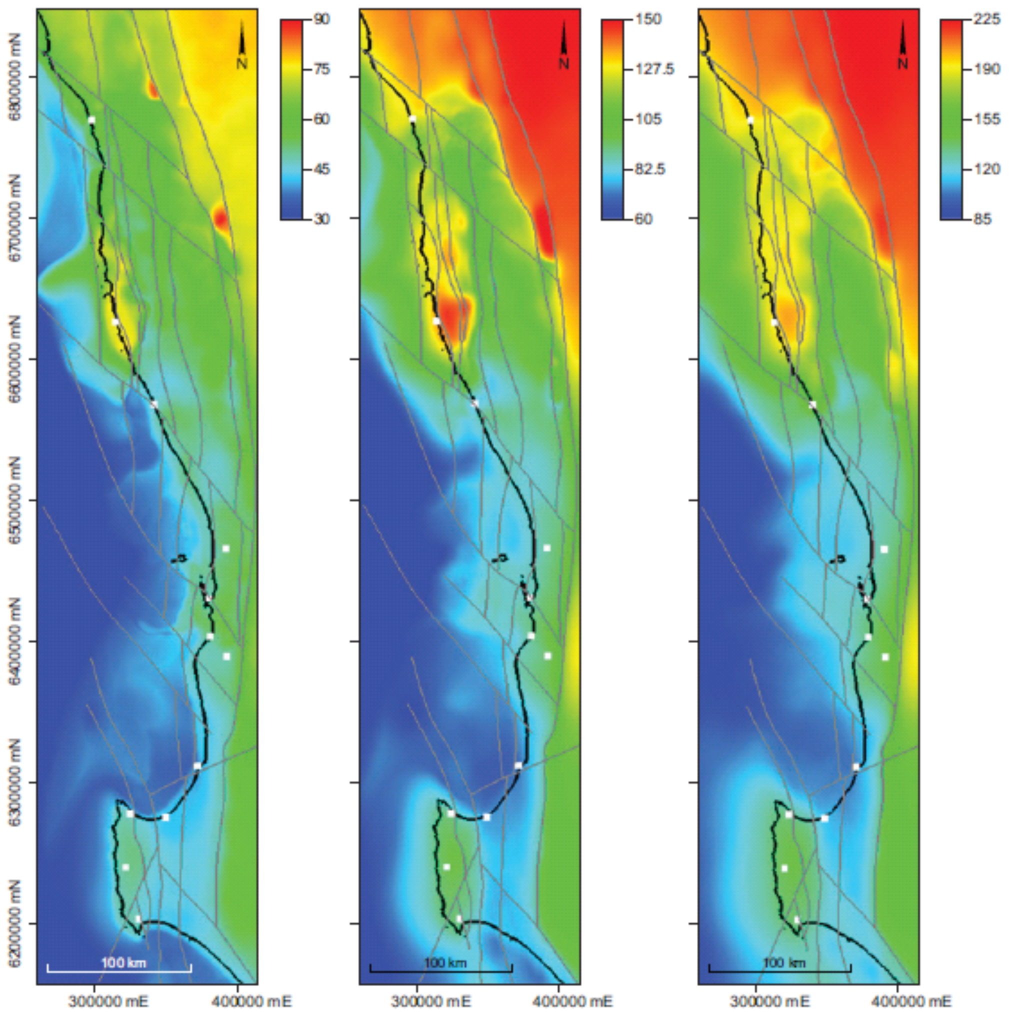

Figure 4.9: Temperature (°C) at -1 km AHD. Coastline (black line), major cities (white squares), and fault network (grey lines) are projected at 0 m AHD.

Figure 4.10: Temperature (°C) at -3 km AHD. Coastline (black line), major cities (white squares), and fault network (grey lines) are projected at 0 m AHD.

Figure 4.11: Temperature (°C) at -5 km AHD. Coastline (black line), major cities (white squares), and fault network (grey lines) are projected at 0 m AHD.

Ref: http://www.geothermal.org.au/final_reports/Project3%20Hydrothermal%20Modelling%20in%20the%20Perth%20Basin%20WEB.pdf)

The anticipated sites with suitable for generating electricity are estimated to occur near the SWIS (in the "Perth Basin") only Northeast of Geraldton.

There are two potential options for harvesting geothermal in Western Australia, as summarised below.

Hot Sedimentary Aquifer (HSA):

HSA resources are generally in porous materials which makes drilling and heat extraction relatively straightforward. There are several geothermal energy companies in WA and one example of work-in-progress with this technology is that of Green Rock Energy which has received $5.4 million of LEED funding for a 25MW+ plant. (Ref: http://www.greenrock.com.au/media/2012_06_25___ASX___Announcement_LEED_Funding_success_FINAL.pdf). Their "prospective drilling target is focusing on identification of zones where natural fractures are likely to provide sufficient permeability for the flow rates necessary for commercial geothermal fluid production".

7.5 Hot Dry Rocks (HDR)/Engineered Geothermal Site (EGS):

This energy conversion technology by Geodynamics Ltd, (Ref: http://www.geodynamics.com.au/home.aspx) is presently in the development stage as it has had some setbacks, which it appears to be overcoming methodically. Furthermore, geothermal resource exploration in WA has been slowed by lack of availability of drilling rigs.

As the future success and deployment rate is difficult to predict, its contribution to the overall mix of renewable generation has been estimated to be approximately only 300MW by 2029.

This technology is capable of electricity generation at rated capacity continuously (apart from downtime), and depletion rates are estimated to allow 20 years at a site. If the plant is moved to another site, it is expected that the original site will regenerate to prior temperatures within decades.

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7.6 Implementation Rate

To reach the necessary installed capacity of the 2029 scenario 2, the rates of deployment are per Table 12. Compared to installation timeframes of existing renewable generators, these are achievable, provided forward planning and coordination is done. Examples of forward planning for renewable energy generation are in practice in California, Texas and Queensland, known as "Renewable Energy Zones" (Ref: http://www.westgov.org/rtep/219 http://rti.cabinet.qld.gov.au/documents/2009/jun/qld%20renewable%20energy%20plan/Attachments/Qld%20Renewable%20Energy%20Plan.pdf)

Table 12. Implementation rates by 2029

	Tot. Installed Capacity, MW in 2029 Scenario 2	Approx. Avg. Implementation Rate, MW/yr over 16 years
Wind	3000	180
Solar PV (utility, commercial, residential)	3000	180
STC w/storage	1500	90
Pumped-hydro storage	2000	120
Biomass	2500	150
DSM (demand side management)	800	50
Wave	500	30
Geothermal	300	20

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APPENDICES

Appendix 1:

SWIS Electrical Energy Demand from PHEV & Evs:					S. Gates		5/01/12											
Notes:	Ref Aust Bureau of Statistics, Motor Vehicle Census (Jan 2012) http://www.abs.gov.au/AUSSTATS/abs@.nsf/Lookup/9309.0Main+Features131%20Jan%202012?OpenDocument																	
Inputs:																		
2012 WA Total Vehicle Fleet	1,970,000																	
Passenger Vehicle portion of total WA vehicles	11	%																
PHEV, EV portion of Passenger vehicles	0.01	%																
Rate of growth of PHEV,EV	75	%/yr																
Rate of growth of WA Passenger Vehicle fleet	2.2	%/yr																
Avg kms driven per year per PHEV,EV	14000	km/yr	38	km/day														
Electrical Energy consumption	0.2	kWhr/km																
Charge efficiency	90	%																
Max charge rate ea EV,PHEV	4	kW																
Calculated:	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
No of Passenger Vehicles	2.0E+06	2.0E+06	2.1E+06	2.1E+06	2.1E+06	2.2E+06	2.2E+06	2.3E+06	2.3E+06	2.4E+06	2.4E+06	2.5E+06	2.6E+06	2.6E+06	2.7E+06	2.7E+06	2.8E+06	2.9E+06
No of PHEV, EV	22	38	66	116	203	356	622	1,089	1,906	3,336	5,838	10,216	17,878	31,286	54,751	95,814	167,675	293,431
Percentage PHEV,EV of total Passenger Vehicles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.4%	0.7%	1.2%	2.0%	3.5%	6.0%	10.3%
Tot PHEV,EV Elect Energy Consumption, MWhr/yr	67	118	206	361	632	1,107	1,936	3,389	5,930	10,378	18,162	31,783	55,620	97,335	170,336	298,088	521,655	912,896
Tot PHEV, EV Power consumption, MW	0	0	0	0	1	1	2	4	8	13	23	41	72	125	219	383	671	1,174

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Appendix 2: Calculation - Metro/Light Rail energy consumption

Using City of Melbourne Yarra Trams; ref. info 2009:

Yarra Trams data states 100MWh for 8 months operation

For 12 months:

100 * 12 / 8 = 150 MWh/year

for 501 trams:

501 * 150MWh = **75.15 GWh/year = 0.075 TWh/yr**

Appendix 3: Calculation - Pumped-Hydro Energy Storage

Using dam/s near Perth – Example: 5 GWhr from Wellington dam:

Use 25GL (14%of tot dam cap of 186 GL), with 167m height (full) above sea level (34m deep), with 100m fall to new lower dam.
http://www.watercorporation.com.au/d/dams_storagedetail.cfm?id=18320)

Inputs:	Symbol	Value		Conversion		
Volume	V	2.50E+10	L	25	GL	
Height	h	100	m			
Density	rho	1	kg/L			
Round-trip Potential-to-Electrical energy conversion efficiency.	e	0.75				
Calculated:		Equation	Value		Conversion	
Energy	Ep	=rho*V*g*h	2.45E+13	Nm	6,813	MWhr
Electrical Energy	El	=Ep*e	1.84E+13	Nm	5,109	MWhr

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Appendix 4: Storage options

(extracted from "Variability of Wind and other Renewables: Management Options and Strategies", Int'l Energy Agency).

Hydro storage facilities, whether in the form of pumped-hydro or hydro reservoirs, have played a key role in many countries in providing several grid balancing services. Their advantages are the potential for large-scale electricity storage (>1000MW capacity, depending on location), fast response times and relatively low operating costs. A fully loaded hydro facility can replace a conventional power station for several hours if needed. However, beyond hydro storage, there has been very little commercially available storage technology that operates on today's electricity grids. The main reason is that large-scale grid integration replaces to a certain extent the function of storage, as discussed in the previous sections and that other storage technologies are as yet not cost competitive. Storage systems within the grid have to compete against other technologies for the operational reserve services they could provide, and there is no a priori advantage to storage systems over generators for example. Only hydro-storage systems have a long history of utilisation and are thus well established in today's markets.

Certain storage systems such as flywheels and certain battery types could become viable to provide specific support services for renewables in the frame of bridging very short-term output fluctuations (less than one minute) which also has the advantage of minimising the impact of power quality issues. One fundamental problem with storage is that where energy is converted from one type to another, conversion losses and thus inefficiencies are inevitably incurred, see table 3 below for details. This is true for batteries and hydrogen fuel cells (where electrical energy is converted to chemical energy storage) and flywheels (where electrical energy is converted to kinetic energy).

Table 3: Various storage technologies and typical technical performance

Storage technology	Typical round-trip efficiency (in %)	Typical capacity
Pumped-hydro station	~80	>100 MW - >1000 MW
Compressed air storage	~75	>50 MW - >100 MW
Flywheel	~90	>1 kW - >50 kW
Conventional batteries	~50 - ~90	>1kW - >10 MW
Flow battery	~70	~15MW
Hydrogen fuel cell	~40	>50 kW - >1 MW

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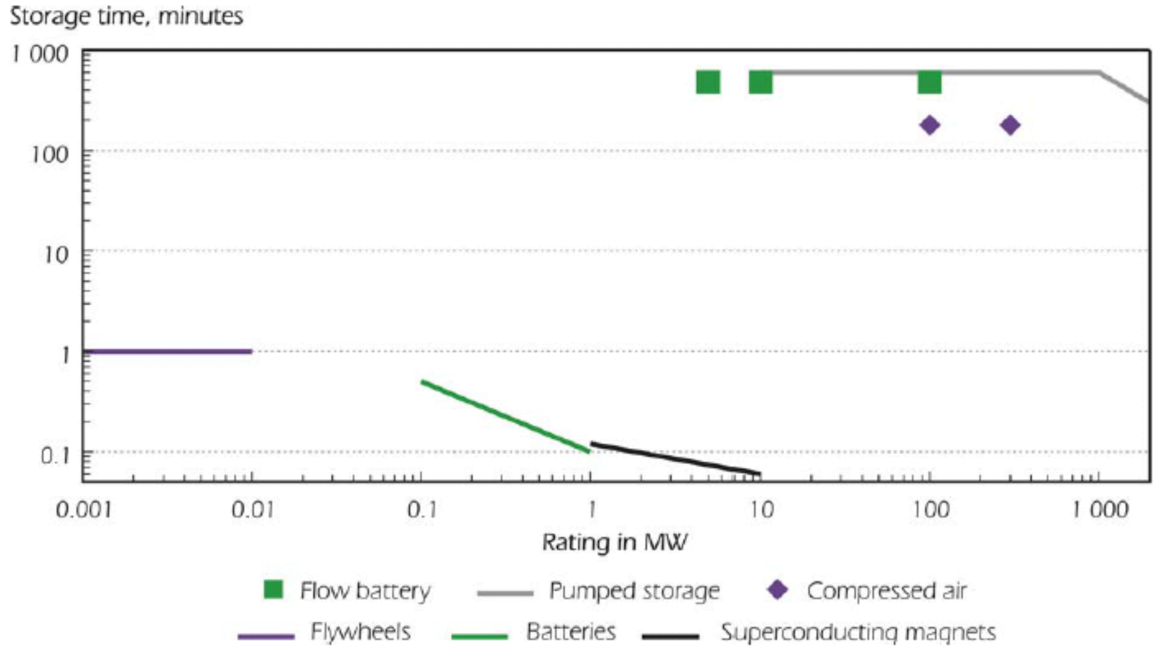
Figure 7: Time and power rating of various electricity storage options



Source: Milborrow 2001a.

Appendix 5: Calculation - Energy Potential for Biomass: Dry Mallee Woodchips

Energy content is 19.5 MJ/kg = 5.41 kWh/ Kg = 5.4 MWh per tonne.

Assume generation efficiency 35% = 1.9 MWh per tonne of dry chips.

Allow 10% for drying and handling; say 1.7 MWh electricity per tonne.

Comparison with Estimated mallee biomass from Great Southern

Bartle, Abadi et al calculated that up to 3 million tonnes of wet biomass could be produced if 10% of the Great Southern (400 – 700 mm rainfall) were planted to mallee. Great Southern is about 2.1 million Ha and is the highest yielding dry land agricultural area.

Assuming 10% dry weight is 55% of the wet weight this is up to 1.65 million tonnes of dry woodchip or pellet from the Great Southern. In terms of electricity generation this is 1650000*1.7/1000 = 2800 GWh or 10.5% of projected 2029 generation.

Appendix 6: Pumped storage power calculations

Cliff top storage 1170 ha in area, 10 m deep with headrace tunnels 5 m diameter and 1 km long

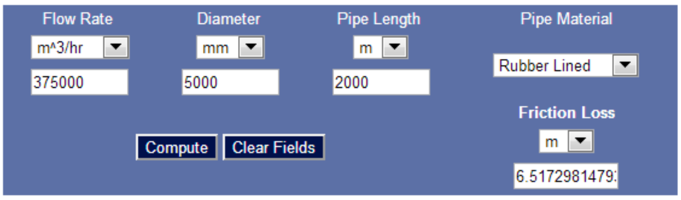
	E= mgh; 1 cu m water falling 1 m height=	9810	joules
		0.00981	MJ
		0.002725	kWh
	1 cu m water falling 1 m height	0.000002725	MWh
375,000	cu m falling 100 m in 1 hr.	102	MWh
	Corrected for 75% efficiency and density 1.02=	78.1734375	MWh
	Power of turbine = MWh/1hour	78	MWh

25 turbines with 5m diam. headrace tunnels about 1 km long would provide about 2000 MW of power

Cliff –top storage *Headrace diam. 5 m* *Length 1 km*

Vol. Cu m (pond 1170 ha, 10 m deep)	full discharge time through 1 pipe (days)	discharge time hrs.	flow rate (cu m/hr)	vel. approx. m/sec	x-sect area of head race sq m
117,000,000	13	312	375,000	5.31	19.63

Notes: 1/ Friction loss for water travelling 2 ways in 1 km pipe 5 m in diameter is about 6 .5 M head, or 6.5% for a 100 M head
2/ Turbine efficiency is > 90% (http://en.wikipedia.org/wiki/Water_turbine), http://www.mpoweruk.com/hydro_power.htm
Friction calculation http://www.tasonline.co.za/toolbox/pipe/velfirc.htm



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