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A National Electricity Grid For Australia

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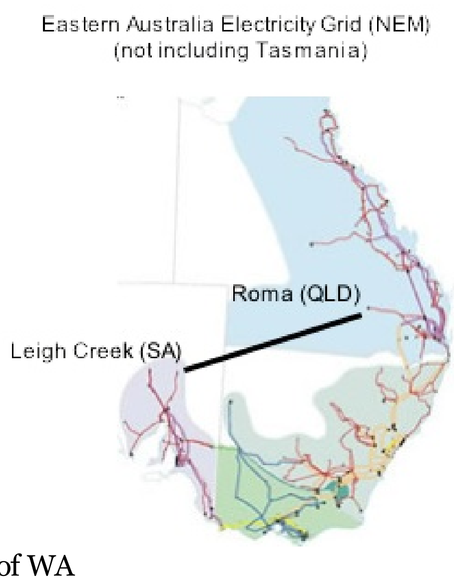
This is a guest post from ***Neil Howes****. Neil is an Associate Professor at the University of Sydney. The post describes a response to the "Carbon Pollution Reduction Green Paper" (27 August 2008).*

Executive Summary

We are proposing that the Government of Australia facilitates the replacement of 50% of Australia's base-load coal fired electricity generation by financing the building of a high capacity National Electricity Grid (NEG) by 2020. This will interconnect high value renewable energy sites for wind, solar and geothermal energy to enhanced hydro electricity pumped storage capacity enabling these low CO2e energy sources to provide base-load power to major retail and industry consumers.

The objective of the plan is to :

(1) Link the East Coast and Tasmanian electricity grids (known as the NEM - National Electricity Market) to the Western Australian electricity grid via a 1500Km high voltage DC (HVDC) connection between Norseman, WA and Pt August SA,



(2) Build a new 1000 Km HVDC connection between Leigh Creek SA and Roma, QLD to link the SA and QLG regions within the NEM, in order to access solar and geothermal sites in WA, SA, VIC,NSW and QLD.

This would also require;

(3) A high voltage AC (HVAC) extension and upgrade of the WA grid north of Norseman, via Kalgoorlie, to the proposed Pilbara local grid to access stranded natural gas (NG) power in WA mining communities and solar thermal sites in the NW of WA

(4) A HVAC interconnection from Norseman to Esperance and Albany wind power sites with increased capacity HVAC connections along the SW coast of WA t4 Perth. This infrastructure project will assist the development of all renewable energy resources, starting with developing wind resources along the SW coast of WA, West Coast of Tasmania, and coastal and highland wind sites in SA, VIC, NSW and QLD with an installed capacity of 28GW by 2020.

The second component of the plan is an expansion of the existing 1.2GW hydro pumped storage capacity to 6GW, to be located in the at existing Snowy and Tasmania hydro sites and additional sites in WA,NSW and QLD. As a start on replacing the remaining 50% coal fired base load beyond 2020 the development of other renewable energy sources should be started with the building of at least 4 concentrated solar thermal (CST) sites, each of 250MW capacity, and each with the capability to be expanded to 2GW capacity, and two geothermal sites in the Eyre Basin. These sites would be connected to the expanded NEG, with the aim of having more than 2GW solar and geothermal capacity by 2020 and the long term aim of replacing some of the remaining 11GW coal fired base-load capacity by 2035, if geothermal and CST can deliver lower cost power than coal fired power using carbon sequestration.

The third component is to increase the supply of renewable energy sources by tying “free” carbon pollution reduction permits given to high carbon intensity export industries to the financing of new renewable energy capacity per year equivalent to 2% of the total carbon permits, and a 5% per annum decline in the number of “free” carbon permits not auctioned.

Details of Proposal

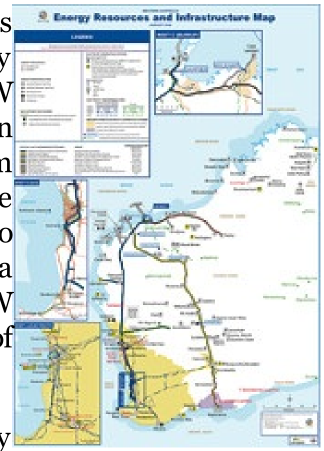
Renewable energy targets of 20% for 2020 will require more than 1GW of additional renewable energy electricity production capacity to be installed per year, and would allow 70% of the carbon reduction targets to be met if this replaces 50% of coal consumption at existing coal fired power plants. The traditional use of coal burning electricity generation plants has been to provide a low cost base load capacity of 22GW, with less than 5GW flexibility, for a total coal-fired capacity of 27GW. The balance of the 49GW capacity is provided by peak gas turbines using NG (12.5GW capacity) and hydro-electricity (8.5GWcapacity), but 78% of the electricity produced is from coal-fired generators.

Carbon capture and sequestration (CCS) may be possible to be retro-fitted to existing coal fired power plants, but the costs are unknown, and the time to install such CO2 abatement devices is uncertain. If retro-fitting is implemented net electricity production will be reduced by about 40%, and it is unlikely that new coal-fired capacity will be build until the costs of carbon capture and sequestration are known. The industry may choose to convert to NG as an energy source, or modify generators to reduce power generation during off-peak low priced periods. All of these scenarios will result in a reduction of base-load electricity capacity by 2020.

Wind power electricity production is a proven low CO2 renewable electricity source, but point sources are intermittent, requiring back up power generation. Interconnecting wind generation sites over a 3,000 km geographical region greatly enhances reliability. As an example it has been estimated that wide geographic dispersion ensure more than 20% of capacity most of the time and reduce maximum peak production to about 50% of capacity. Wind power is price competitive now with nuclear, NG fired thermal but not coal-fired thermal generation. Solar energy matches peak power demands, but the best solar sites are distant from consumption. Prices for concentrated solar thermal(CST), based on overseas experiences are presently higher than wind power but few sites have been operating and costs are expected to rapidly decline as more solar thermal sites are built world-wide.

Australia has exceptional wind, solar and geothermal potential resources. The best wind resources are along the SW coasts of WA, W coast of Tasmania, the southern coasts of SA and VIC and the far N coast of QLD. More localised good sites are also available on the NSW tablelands. The best solar sites are located in the low rainfall regions of central Australia and especially in the WA Pilbara plateau, a region using considerable diesel and NG energy for mineral and LNG exports, but lacking electric grid capacity. The WA government has announced plans to develop a local grid in the Pilbara region and expects that power demand will exceed the present 3GW used in the SW region of WA. Large geothermal resources are present in the SA Eyre Basin, but distant to present electric grid connections.

Australia has exceptional pumped storage hydro resources and could expand this capacity to absorb energy during off peak periods, but most of this infrastructure is located in SE Australia and Tasmania. Presently hydro provides 6.7% of electricity generation but up to 18% of short term peak capacity (8.5GW). This could be expanded to 13.5GW by the addition of 5GW pumped storage capacity, to the existing 1.2GW capacity, if improved transmission capacity was available.



WA presently generates most electricity by NG, duel coal /NG fired gas turbines and some coal. It also has considerable power generation by stranded diesel or NG gas turbines, located in the gold fields and at NW shelf oil and gas fields especially the LNG facilities at Karratha. Expansion of wind power is limited in WA to the South-West Interconnected System (SWIS) grid off-peak load of 1.7GW. An expansion of the SWIS grid to the gold fields and Pilbara, interconnecting Albany and Esperance grids to Norseman and Perth and a 2 GW HVDC link to East Coast and Tasmania via Pt Augusta, could allow an expansion of WA wind resources to 6GW capacity, provide a saving of peak NG use and increase the security of supply in case of a NG supply failure(as occurred at Varanus Island).

The wind resources of SW of WA are considerable and geographically isolated from East-Coast locations. Interconnection of west-coast and east-coast grids would enhance overall wind-power reliability. WA has very little opportunity for hydro-electric pumped storage but does have limestone caverns in the SW suitable for developing compressed air / NG assisted gas turbine generators as a off peak energy storage. If successful this capacity could be expanded to make better use of WA's NG resources and reducing CO2e from NG used for electricity production. Other pumped storage systems such as tidal-assist could be explored on the NW shelf region.

WA has the best solar resources in Australia, but the locations in the NW of the state are isolated form the SWIS grid. Worley Parsons in collaboration with major mining companies located in the Pilbara region of WA are investigating the feasibility of building multiple 250MW CST sites. If one or more CST stations were sited along the northern Gold fields NG pipeline, and connected to Perth and Eastern Australia grids, CST stations in Western and Eastern Australia would extend the solar power generation time by 2-3 hours, matching peak power demand and avoiding the need for any solar energy storage.

The Federal Government could use some of the funds obtained from the proposed Carbon Pollution Reduction Permit Scheme, to assists in the financing and building of a high capacity National Electricity Grid including a 1,500 km HVDC(>1000Mw) transmission link between Port August and Norseman. An interconnected 1000Km HVAC line(440,000 volts) running NW from Norseman via Kalgoorlie, parallel with the gold field NG pipeline, and increase capacity between Kalgoorlie and Perth could be funded by private operators, as could an increase in the existing 500MW capacity HVDC of the Bass Straight Link. Additional HVAC capacity would be required to connected the local Esperance and Albany grids to Norseman and to Perth via the high wind potential sites along the SW coast.

These upgrades would be to enable financing and building of an additional 5GW total pumped storage input capacity at Hydro Tasmania , Snowy Hydro and Brisbane-Gladstone locations(total 6GW input). This would not involve the building of any additional dams, but may require the raising of lower dam structures, and the building of additional generators. Present pumped storage at Tumut 3 power station(600MW) is only used in 3 of the 6 250MW generators, and would allow pumped storage input capacity to be increased from 600MW to 1200MW.

The Tasmanian west-coast has high quality wind power resources, but limited capacity to use more than 1GW peak power. Tasmania has many interconnecting storage reservoirs, but only limited capacity (500MW) to absorb off peak power from the mainland via the Tasman-Link. Existing generators have 2000MW capacity, but this is used at only 50% of capacity due to water availability. The building of 3GW of pumped storage capacity in Tasmania would enable 5GW wind capacity, including local base load use, export of up to 1GW by expanding the 500MW Tasman-link.

The Far-North QLD coast has high wind power resources, but these are distant to major energy consuming industries at Gladstone and the SE of the state. An expanded HVAC capacity of the QLD grid and interconnection via Roma to Leigh Creek would enable 2GW wind capacity in the Far-North to either displace QLD NG or coal-fired capacity or to supplement SA and WA demand.

A national maximum of 28GW wind power capacity would be required to replace 11GW of coal fired base-load power(assuming a 35%capacity factor for wind). This would require an additional 6GW in WA, 5GW in Tasmania, 2GW in QLD and the balance 15GW from SA,VIC and NSW . There would be no capacity problems to add 2GW of solar and geothermal capacity by 2020 as solar will always be generated at peak power demand times, provided the local peak demand load and export grid capacity is not exceeded. Until a demonstration plant has been built and operating costs determined we should not anticipate more than 2GW solar capacity could be built by 2020.

At the lowest off peak demand period (3-5.30am local time) 20GW of power is presently consumed from 20GW coal fired production (27GW capacity). If this capacity is reduced by 50%(14GW) it would be possible to reduce coal-fired base load by 11 GW and would have the ability to absorb 6GW from pumped storage regeneration, and 10GW from remaining coal, giving the maximum that could be absorbed by wind of 16GW. However the 2-3 h W-E displacement of the off peak (3-5.30am) low, would allow an additional 2GW to be absorbed by flattening the off-peak low. Expanding wind capacity at the most dispersed sites(SW of WA, west coast Tasmania, eastern tablelands of NSW and far NE coast of QLD) will give the most improvement in wind reliability and especially reduce peak wind loads. The peak of wind production WA and SW Australia are likely to occur on different days as weather patterns take 2-4 days to travel across the continent. Peak 5-7pm loads in summer are also displaced by 3 h differences in summer time zones. An expansion of the pumped storage in-put capacity from 1.2GW to 6GW, would enable hydro to supply at maximum levels (8.5GW) for longer periods, providing lower level reservoirs have sufficient capacity. During rare prolonged low wind periods, and low hydro dam levels, off-line coal fired reserve capacity could be activated and some industry use curtailed as was done in WA following the Varanus Island interruption.

This plan will require the building of 3GW wind capacity or the equivalent solar and geothermal, per year. With the existing 6.7% of electricity by hydro generation we would expect about 40% of electricity production would come from renewable sources by 2020, but most importantly coals contribution declining from 78% to 40%, with a smaller reduction of NG generated power. High intensity CO2e export industries such as aluminium refining and smelting assistance could be tied to the financing and building annually wind or other renewable energy, representing 2% of their power consumption. Assistance in the form of “free” permits would be reduced by 5% per year, so that in 10years the CO2e intensity of high CO2e emitting exports would drop by 50% without any decrease in export volumes.

Economics

Australia has one of the lowest wholesale electricity prices in the world, the present off-peak power prices are as low as 1.2cents/kwh, and average less than 4c/KWh. With a carbon permit price of $20/tonne CO_2e(equivalent to 2cents/KWh), coal-fired generators will have incentives to reduce production in these periods, saving coal consumption up to the free permit level. This is difficult in many power plants, although some reduction is possible. If coal-fired plants are able to be modified to economically generate power for less than 12h per day, the existing infrastructure could be maintained for peak and shoulder load power. Carbon permits or cash incentives could be used to pay some of the costs of these modifications. While these costs are unknown, they should be easier to model and implement than carbon capture and sequestration.

NG is a more expensive fuel and would increase by an additional 1cent/KWh due to a $20/tonne CO_2e permit price. A very large pumped storage capacity would flatten the demand curve increasing off-peak prices by 1-3cents/Kwh, and lowering peak prices. Thus we expect at least a 2cents /Kwh increase in base load electricity prices to 4cents/Kwh, and peak costs also rising due to NG price increases, costs of pumped storage and CO_2e costs, by 1-2 cents/Kwh to 5-10 Kwh. This will greatly benefit the economics of wind generation which cannot match production to peak demand. The building of 28GW wind capacity will change the shape of the power supply curve.

It would be more difficult to reduce the remaining 13GW coal capacity but this would still give a 40% reduction in actual coal CO_2e, since this 13GW would not all be used as entirely base-load. If all coal burning was replaced by wind would need at least 60GW capacity, and would have a problem with absorbing >30GW during high wind and low demand periods, or meeting peak power demands in low wind periods. Replacing the 13GW coal capacity(10GW base load) with solar and geothermal would only require 12-15GW capacity as night-time low peak of 20GW could be replaced by 12GW NG and the balance by geothermal and hydro in low wind periods.

Is it realistic to project the building of 28 GW wind and 2GW solar capacity by 2020? At an estimated installed cost of $2000 per kWh capacity, building 3GW per year will cost $6Billion per year. A large part of the materials required are structural steel which can be sourced locally. In 2008 it is estimated that the US will add 8GW wind capacity from a mixture of locally manufactured and imported wind turbines. Several years would be required to increase wind capacity to 3GW unless most turbines were imported. When completed, 28GW of wind capacity will save each year the combustion of >20million tonnes of coal (export value >$2.5Billion), saving 100million tonnes CO_2e at a price of $1.5Billion (that doesn't have to be paid by another emitter). The cost of additional 2,500Km HVDC transmission lines would be an additional 2.5 Billion with 5GW pumped storage financed by electricity supply insurance. The present wholesale value of this power would be 7500 x10,000,000 kWh x 4cents =$3Billion per year. Carbon permit costs are going to raise coal fired base load costs by 2cents/kWh, to 6cents/kWh, so would still need a small subsidy for wind and CST. However prices of thermal coal have risen by $80 a tonne implying an additional price rise of 2cents/kWh, so wind power may be competitive at 8cents/kWh.

Summary

Australia needs to reduce its reliance on coal-fired electricity before 2020, by replacing a significant portion of the coal-fired base-load generation with renewable energy sources. While Australia has excellent wind, solar and geothermal resources they are dispersed and long distances from present electricity consumption. A truly Nation Electricity Grid connecting the CST resources and industry of the Pilbara region of WA, and the wind resources of the SW region of WA, with the SE and NE of Australia and Tasmania will allow these renewable energy resources to be developed to reliably provide 40% of Australia electricity production by 2020, reduce CO_2e, and provide additional options to CCS to further reduce carbon dioxide pollution by >50% in 2050.