

AN OPTIMAL PORTFOLIO OF NEW POWER GENERATION TECHNOLOGIES: AN ILLUSTRATION FOR SOUTH AUSTRALIA

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Overview

The levelised cost of generating electricity is the conventional methodology for comparing the individual MWh cost of a range of electricity generating technologies for new entrants. However, for practical purposes it is necessary to apply this methodology in the context of the existing technology portfolio in order to achieve least cost expansion planning. In addition, for intermittent technologies the value of the power plant will depend on the extent to which it can provide electricity during the high price “peak” periods. Further, the electricity system may value dispatchable power plants that can respond quickly to unpredictable changes in demand as well as maintaining the reliability of the system on a least-cost basis. This study develops a resources optimisation model for the electricity system in South Australia, which is one of five interconnected regions that form Australia’s National Electricity Market, under a range of assumptions regarding fuel and carbon prices in the context of feasible power generation technologies over the next 20 years.

The study considered the following technologies for future additions to the system based upon South Australia’s resource endowment: Open Cycle Gas Turbine (OCGT), Combined Cycle Gas Turbine (CCGT), on-shore wind, solar thermal (solar tower central receiver with six hours storage), and geothermal (both engineered geothermal systems (EGS) and hot sedimentary aquifers (HSA)). It is extremely unlikely that any new coal-fired plant will be constructed within the NEM in the foreseeable future.

Background

South Australia is part of Australia’s National Electricity Market (NEM) which operates over five interconnected regions that largely follow the state boundaries in Eastern Australia. The NEM is a common pool energy-only market for wholesale trading of electricity, where supply and demand are matched instantaneously in real time through a centrally-coordinated dispatch process. It is obligatory for all generators with a nameplate capacity of 30 MW or more to trade through the NEM. Generators offer price and associated quantity bids for five-minute dispatch intervals, with prices averaged over a thirty minute trading interval. The marginal generator (i.e. the highest accepted bid) sets the wholesale price, which then applies to all successful bids. The marginal generator is generally a fossil fuel generator. Thus, marginal bid pricing will include the carbon price, since this will be part of a fossil fuel generator’s short run costs¹.

Despite the interconnection between all regions in the NEM, there is a separate spot price for each region, for every trading interval. The main factors leading to significant price variations between the regions are: physical and technical limits on interconnector capacity in each region and dependence on different sources of fuel for regional supply. Other factors would include frequency control, total system load, testing and transmission outages, voltage control, and plant outages.

Electricity demand in South Australia is characterised by its very “peaky” demand profile, particularly in summer months. The mix of electricity generation capacity is dominated by gas (55%), wind (24%), and coal (15%), with minor contributions from hydro, biomass and diesel. Generated electricity in 2011-12² was provided by gas (50%), wind (26%), and coal (24%)³. On particular days, wind has accounted for up to 65 per cent of total generation in the state, and up to 86 per cent of generation for a trading interval. However, wind generation is generally lower at times of peak demand; on average, it contributes to less than nine per cent of supply at any given time during summer. Yet, there is evidence that wind generation is having a moderating impact on electricity prices in South Australia, with spot prices typically being higher at times of low wind.

The bulk of investment in wind energy in South Australia has been driven by the nationwide Mandatory

¹ A carbon price of A\$23/tonne CO₂ became effective in Australia on 1 July 2012 as an integral part of the *Clean Energy Act 2011*, which itself is a component of the Australian Government’s Clean Energy Future (CEF) plan. Full details of Australia’s carbon current pricing regime are available at:

<http://www.cleanenergyregulator.gov.au/Carbon-Pricing-Mechanism/Pages/default.aspx>

² Data are given for Australian financial years, which run from 1 July to 30 June the following year.

³ Nationally, wind accounted for just four percent of capacity and three percent of output in 2011-12.

Renewables Energy Target (MRET) scheme that was launched in 2001 by the Australian Government with the intention of achieving a target of 20 per cent of electricity generated in Australia from renewable energy sources by 2020. The scheme is scheduled to close in 2030, by which time it is anticipated that a mature emissions trading scheme would have made it redundant.⁴ Since 1 January 2011 the Renewable Energy Target (RET) has operated as two parts: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). The LRET is designed to encourage the deployment of large-scale renewable energy projects such as wind farms, while the SRES supports the installation of small-scale systems, including solar panels and solar water heaters.

Least-cost generation expansion modelling

This study developed a least-cost generation expansion model to determine a set of long-term generation options from a range of technologies which minimised the cost over time, taking into account future demand, carbon price, and gas price uncertainties. For this application, the long-term planning simulation module of a commercially available software, Plexos, was used.⁵

The model emulates the process performed by the dispatch system in the NEM, which schedules generators that minimise the dispatch cost, subject to the criteria that the reliability and security of the system is maintained. The model executes half-hourly dispatch using security constrained optimum generation dispatch with each generator bidding at its short-run marginal cost (SRMC).

In order to encompass the range of uncertainties that could have a significant impact on the results, a set of scenarios was built to capture the space of future outcomes. These scenarios were based upon those developed by the Australian Energy Market Operator (AEMO), and focus upon high, medium, and low gas prices, future carbon price trajectories, and future patterns of electricity demand.⁶

The model was executed in stochastic mode in order to achieve an optimum generation expansion solution, with optimum energy-driven and capacity-driven investment opportunities in South Australia from the system perspective.

The model involves a number of constraints:

- An energy balance constraint, which ensures that the total electricity demanded at a given time is equal to the unserved energy at that time plus the sum total of the electricity dispatched by all the generation units at that time;
- A feasible energy dispatch constraint, which ensures that the level of electricity dispatched by a given generator is not greater than the maximum generating capacity of that generator;
- A feasible build constraint, that ensures that the built capacity (in MW) for a given new entrant technology does not exceed the value of maximum built capacity (as set in the model) for that technology in a year (or over a given planning horizon); and
- A reliability standard constraint, which ensures sufficient generation capacity to meet demand.

Model inputs

The model considered the cost parameters of the existing generators in terms of their fixed and variable operations and maintenance costs, combined with their technical constraints: ramp-up and ramp-down rates, thermal efficiency, combustion emission factor, fugitive emission factor, minimum stable generation level, forced outage and planned outage rate, auxiliary load requirements and marginal loss factor over the planning horizon. Variation of nameplate capacity of generators due to seasonal factors was based upon past experience.

The model expanded the generation capacity within the region based on the inter-region transfer capability. The interconnector transfer capacity limits the transfer of energy between Victoria and South Australia during any load block and affects the reserve sharing capability between the two regions.

The model incorporated the following list of new entrant generation technologies: OCGT, CCGT, geothermal HSA, geothermal EGS, solar thermal technology, and on-shore wind generation. The assumed cost and technical parameters for new entrant generation technologies are given in Table 1. As some of these technologies are

⁴ Details of the MRET scheme are available at:
http://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/Browse_by_Topic/ClimateChange/Governance/Domestic/national/Mandatory

⁵ Energy Exemplar

⁶ AEMO is responsible for the day-to-day operations of the NEM.

currently not mature, the model constrained the timing and build limit for those technologies over the planning horizon.

The annual energy and maximum demand (at 10%, 50%, and 90% probability of exceedance) forecasts during summer and winter months for South Australia under high, medium, and low growth scenarios were taken from AEMO (2011). From these forecasts, the model generated monthly load duration curves which captured seasonal variations in demand. The demand in each load block was determined by the model based upon hourly profiles for each year. These hourly demand profiles were projected from the reference year 2010/2011 using forecasted growth in annual energy, maximum winter demand, and maximum summer demand over the planning horizon.

The fuel price assumptions for existing and new generators in the model were provided by Intelligent Energy Systems (2011). Three levels for projected price levels were used, based upon high, low and “average” (of high and low) rates of change of gas demand. The price of coal was taken to be \$1.52/GJ (real) over the planning horizon, which represents the marginal cost of extracting coal from the Leigh Creek (South Australia) coal mine, plus a haulage charge. The price of oil was set at \$30/GJ (real) over the planning horizon.

The carbon price projections commenced at \$10/tonne CO₂ in 2013-14, before moving to a trading scheme from 2014-15 onwards, after which the price was increased by 4% (real) per annum.⁷

The model used the weighted average cost of capital (WACC) as a conservative proxy for the investment hurdle rate decision in the generation expansion modelling. ACIL Tasman (2010) proposed the use of post-tax real WACC for new entrant technology which was assumed to be 6.81% for all new generators in the model (9.81% in nominal terms). While this value may appear to be rather low, particularly in the aftermath of the global financial crisis, ACIL Tasman considered the value to be suitable for market modelling in the long run, which is the focus of this research.

Model constraints

The LRET scheme has a direct impact on investments in renewable energy technologies in the NEM, and thus imposes a constraint on the least-cost generation expansion modelling. Whilst the scheme sets broader NEM-wide targets for achievement of its objective of 41,000 GWh of renewable energy generation by 2020, the annual targets were scaled to reflect South Australia’s disproportionately high contribution to the scheme.⁸

Currently, the reliability standard for all regions of the NEM stipulates that, in the long-run, the maximum level of un-served energy should not be greater than 0.002% of its annual electricity consumption (AMEC, 2010). In order to ensure that the reliability of the system was met over the planning horizon the model used a capacity constraint for every year in the planning horizon, which ensured that there was sufficient generation capacity to meet the demand. Hence, the model used minimum capacity reserve margin as a proxy for meeting the reliability standard in the South Australian region of the NEM. The minimum capacity reserve margin in the model was set at 15%; this is consistent with international reserve margin benchmarks (Nelson et al., 2010)

It’s important to note that all the generators do not contribute their entire installed capacity in meeting the minimum reserve level in the region. The capacity contribution of each new entrant generator in the model was considered to be the installed capacity multiplied by a predefined contribution factor. This capacity contribution factor differs for each technology and it is usually based on the stability of fuel sources, energy storage capacity and auxiliary power usage of the power plant. The capacity contribution for new entrant generation technologies in the model was taken from AEMO’s (2011) modelling assumptions.

The model had annual build limit (in terms of installed capacity) for some new entrant generation technologies. The annual build limit for wind generation was 200 MW, geothermal HSA was 100 MW, geothermal EGS was 100 MW and solar thermal was 50 MW. In addition to annual build limit, the model also had regional build limits for new entrant technologies over the planning horizon. The regional build limit for geothermal HSA, geothermal EGS and solar thermal technology was set at 200 MW, respectively. In addition, the entry of some generation technologies which have not reached the stage of commercial deployment has been constrained in the model. WorleyParsons (2012), estimates that the earliest build year for solar thermal power plant with storage

⁷ This initial price is less than the \$23/tonne price that took effect from 1 July 2012 under the *Clean Energy Act 2011*. However, it is highly likely that this latter price will fall as Australia links up with the European Union Emissions Trading Scheme in 2015. Thus, the price trajectory used in this study can be thought of as a realistic long-term projection in the context of current carbon market developments.

⁸ Twenty per cent

would be 2016, while the earliest build for geothermal HSA technology would be 2020 and geothermal EGS 2025.

Results

The South Australian electricity market model determined the optimal capacity, technology and timing of new generation technologies based on the principle of least-cost generation expansion. In light of the uncertainties faced in the electricity market, the model was executed in stochastic mode in order to give the optimum generation expansion solution under uncertainty. In this section, the results obtained from the model under different constraints are discussed.

AEMO classifies investment opportunities in the NEM as ‘capacity-driven’, ‘energy-driven’ and ‘policy-driven’. Capacity-driven investments arise when there is supply scarcity during periods of high regional demand or high spot prices, therefore demand side investment or investment in peaking generators like OCGT is required in order to meet the demand in the short-run in the most economic manner. These investments primarily arise due to a shortfall in the reserve margin; hence, these investments help in maintaining the reliability of the system. While capacity-driven investment are made with the objective of capturing high electricity prices during peak demand, energy-driven investments arise in order to meet a specific quantity of energy demanded over longer periods. Therefore, average spot market prices play an important role in determining the level of generation capacity in energy-driven investments. Policy-driven investment opportunities primarily arise due to government policies. Currently, these investments are largely a result of market mechanisms adopted by the government in order to increase the penetration of renewable technologies in the NEM.

When this South Australian electricity model was executed with the minimum reserve level constraint, the model generated optimum energy-driven and capacity-driven investment opportunities in the region, from the systems point-of-view. In this scenario, the optimal capacity, technology and timing of new generation technologies in the region over the next 20 years is illustrated in Figure 1. The results reflect the reaction to the closure of a coal-fired power station in response to the introduction of Australia’s carbon pricing regime. Due to the closure of the Playford B station in 2013, the excess reserve margin capacity of the system fell dramatically and this forced the model to build OCGTs. In 2014, the model built an OCGT with installed capacity of 160 MW, this capacity being quadrupled by 2019 to 640 MW. Thereafter significant capacity was added to the region before reaching 1,600 MW of installed capacity by 2029.

The requirement for energy-driven investment was seen in 2022; when the model evaluated geothermal HSA technology as the most economic base-load technology (average capacity factor of 80% over the planning horizon) out of all of the new entrant technologies. The model built 100 MW of geothermal HSA technology in 2022, and this immediately doubled to 200 MW by 2024, which was the maximum regional build capacity for the technology in the model. After the system reached the maximum regional build capacity for geothermal HSA technology, the model built one CCGT in 2026 with installed capacity of 375 MW⁹. However, instead of being a base-load technology, the model treated CCGT as an intermediate generator with average capacity factor of 35 per cent each. As there were more requirement for energy-driven investment from 2029 onwards, the model built 200 MW of wind energy and geothermal EGS over the planning horizon.

Impact of rising gas prices

In general, renewable technologies have high capital cost and fixed O&M cost, but they have low/negligible variable O&M cost. While fossil-fuelled technologies are less capital intensive and have a lower fixed O&M cost than renewable technologies, their variable O&M cost, fuel cost and emission cost makes up a considerably higher proportion of their SRMC. As a result of this, there is significant cost certainty in the LCOE for renewable technologies once the investment is made. However, uncertainty in the fuel cost and the carbon price makes it difficult to estimate the SRMC of electricity for fossil-fuelled generators. From the sensitivity analysis of LCOE, CCGTs were found to be more sensitive towards fuel price and carbon price assumptions than OCGTs. Intuitively this was a somewhat surprising result, so the LCOE for CCGT was analysed in order to understand the effect of these uncertainties in the context of the South Australian electricity market.

The LCOE for CCGT was calculated based on the carbon price, fuel price and capacity factor estimates obtained from the modelling results in the previous section; this is graphically represented in Figure 2. This figure shows that the LCOE for new entrant CCGT in the South Australian electricity market in the future would be higher than the LCOE estimates for some renewable technologies, particular wind (\$90/MWh) and geothermal (104-138 \$/MWh). There are two reasons for the sharp increase in LCOE for CCGT, they are high gas prices and low

⁹ This is the minimum size of the new entrant CCGT technology set in the model.

capacity factor. While high gas prices are expected in the future, low capacity factor of CCGT may be attributed to the low annual energy requirement in the South Australian electricity market for base-load, most of which can be met by wind power, and the high degree of peakiness in demand. Hence, in line with least-cost generation expansion, CCGTs are not ideal base-load generation technology for the South Australian electricity market.

Energy, capacity and policy-driven investment opportunities

When the South Australian electricity model was executed with the minimum reserve margin and regional LRET constraint, the model generated optimum energy-driven capacity-driven and policy-driven investment opportunities in the region. In this scenario, the optimal capacity, technology and timing of new generation technologies in the region over the next 20 year is represented by Figure 3.

As a result of the LRET constraint, the model built substantial amounts of wind technology in the region. The model built 200 MW of wind energy every year from 2012-2022 and the total installed capacity in the region reached 2,300 MW by 2023. The amount of capacity-driven investment in the region remained similar to the results discussed above. The model built the first OCGT in 2013 with nameplate capacity of 160 MW, this capacity quadrupled by 2023, reaching a total installed capacity of 1,600 MW by 2030. As a result of the LRET constraint solar thermal technology was built in 2016, and reached the maximum regional built, i.e. 200 MW, by 2019. The model treated solar thermal technology as an intermediate generator with average capacity factor of 37 per cent over the planning horizon. Also due to the LRET constraint, the model built geothermal HSA technology much earlier than in the previous scenario: 100 MW of geothermal HSA technology was built in 2019, and this figure reached the maximum regional build capacity of 200 MW by 2020.

Current investment

The current investment interest in South Australia is primarily in renewable energy and peaking gas-fired generators (OCGTs). According to AEMO (2012a, pp. 3-22), more than 4,000 MW of generation capacity based upon geothermal, gas, and wind energy technologies has been publically announced in South Australia. However, the majority of these projects are in the initial stages of development and none have progressed to the 'committed' or 'advanced' stages of development, as defined by AEMO.

While no large-scale solar power plants have been registered with AEMO, there is a substantial amount of interest by market participants to build large-scale solar power plants in the NEM, and in South Australia in particular, with capacity totalling 1,288 MW (AEMO, 2012a, pp. 2-26). Hence, in line with this interest the regional build capacity for solar thermal technology in the model had been increased from the 200 MW to 350 MW over the planning period. Similarly, the regional build capacity for geothermal HSA technology in South Australia has been lifted to 500 MW over the planning horizon. This increase in capacity is in line with the total capacity of publically announced geothermal projects in the region (AEMO, 2012a, pp. 3-22).

Energy and capacity-driven investment opportunities

In order to determine the energy and capacity-driven investment opportunities under revised renewable energy constraints, the model, as before, was executed with the minimum reserve margin constraint. For such a scenario, the net new capacity addition from various generation sources is graphically presented in Figure 4.

As seen in the previous results, there exists considerable capacity-driven investment opportunity in the region, which is because of its peaky load duration curve. The model built considerable amounts of OCGT in this scenario from 2014, beginning with a plant with nameplate capacity of 160MW. This capacity quadrupled to 640 MW by 2019, and thereafter the total installed capacity reached 1,600MW by 2031. Unlike the previous energy and capacity-driven solution, the model did not build any CCGT. Instead, significant geothermal capacity was built, starting with 240 MW of net generation capacity in 2024 which reached total installed capacity of 500 MW by 2030. As a result of significant geothermal penetration, only marginal amount of wind energy was added by the software in this scenario. The model built 126 MW of installed wind generation capacity in 2031.

Energy, capacity, and policy driven investment opportunities

In order to determine the energy, capacity and policy-driven investment opportunities under revised renewable energy constraints, the model was executed with both the minimum reserve margin and the LRET constraint. For this scenario, the net new capacity addition from various generation sources is given graphically in Figure 5.

Under this revised renewable energy constraint, the model built less wind energy and more geothermal and solar thermal technology over the planning horizon. The model built 200 MW of wind energy every year from 2012 – 2019, and the first solar thermal plant in 2016 with 100 MW capacity. The latter reached the regional build limit of 350 MW by 2019. Thereafter the model built 260 MW of geothermal HSA technology by 2020, reached total

capacity of 400 MW by 2021. As a result of this significant geothermal and solar thermal penetration the model built fewer OCGTs, the first being in 2014 with capacity of 160 MW, and this quadrupled by 2025 before reaching the installed capacity of 1,280 MW by 2030.

Summary of results

From the modelling results under the various scenarios it may be concluded that there is significant capacity-driven investment opportunity in the South Australia, in spite of the retirement of the Playford power plant in 2013. This highlights the peaky nature of demand in the state. In order to meet the peak demand and maintain the reliability of the region in the long-run, significant capacity of OCGTs was built by the model under all the scenarios.

From the results it may be concluded that the major requirement for energy-driven investment will occur after 2020. In order to fulfill the base-load generation requirements in South Australia, the model considered geothermal HSA plant more suitable than a CCGT- which is less capital intensive than the geothermal plant. The model did not build significant volumes of CCGTs because of the high gas price expectations. Further, the model considered geothermal HSA technology more economical than geothermal EGS technology; this was also reflected in the LCOE estimates for the technologies.

The demand projections in the model were based on AMEO's forecast in 2011. However, more recent forecasts by AEMO have shown a decline in demand in South Australia as a result of: sluggish growth in demand from industrial users due to a decline in exports, moderate GDP growth and high electricity prices; significant penetration of solar PV roof top panels at the load center; and reduced demand from retail customers due to rising electricity prices (AEMO, 2012b, p. 13). Large industrial demand makes up approximately 15 per cent of the state's annual demand, and the Olympic Dam mining expansion was anticipated to significantly increase long-term future industrial power demand in the state (AEMO, 2012b, p. 11). However, with the shelving of the Olympic Dam expansion, demand forecasts are expected to drop even more in the future. As a consequence of all these factors, reduced energy-driven and capacity-driven investment opportunities may be expected in South Australia in the future.

The state is endowed with good renewable energy resources; hence, there is significant policy-driven investment opportunity in the region. Wind energy is the most cost-competitive and technologically mature renewable energy resources out of all the new entrant generators considered in the model. Not surprisingly, therefore, the model built significant amounts of wind energy under the LRET constraint. But despite its installed capacity, due to its intermittency wind energy makes very little contribution towards meeting the maximum energy demand (8 per cent contributing factor) in the state. A study done by ElectraNet (2012, p. 13) reveals that the existing transmission network could support approximately 2300 MW of wind generation in the region; this implies that wind generation capacity can roughly be double in the coming years without any additional cost on the system. ElectraNet (2012) also noted that wind generation was typically seen during period of medium and low demand, as a result of this there is a need to transport the excess wind generation from the region to the rest of the NEM. In this regards, ElectraNet and AMEO (2012) have commissioned a joint feasibility study to evaluate economic transmission upgrades between South Australia and other load centers in the NEM.

Also under the LRET constraint, the model built solar thermal technology, which was not otherwise built in any other scenario. Unlike wind, solar thermal with storage can serve as a base-load generator in the region. However, its LCOE is not competitive when compared against other generation technologies (see BREE (2012)).

Significant penetration of intermittent generation sources in the systems would have an impact on the power flow characteristic on the transmission system. This research doesn't consider the impact of such harmonics on the systems; however, ElectraNet has already commissioned a report which would investigate the impact of renewable energy sources on the reliability of the system in South Australia.

Investment outlook for generation assets

Over the past decade the investment pattern in NEM has undergone paramount shift from coal to gas generation and in recent times a combination of investment in gas-fired generation and wind technology has been favoured. While the investment trend has changed drastically over the last decade, the electricity generation mix has remained relatively stagnant in the NEM. The share of generation from coal-fired generators has largely remained stable and has only diminished marginally over the past few years.

However, more specifically, in South Australia the generation trend has changed over a number of years, whereby contribution from fossil-fuelled generation has decreased and generation from wind energy has increased.

Recent studies of the NEM by Nelson, et al. (2010) and Frontier Economics (2010), along with opinions expressed by industry participants in the report by Deloitte (2011) note that:

- 1) As a result of policy uncertainty (specifically carbon price) investors are discouraged to invest in the capital intensive base-load technologies like CCGT, while less capital intensive investment options with flexible options like OCGT are favoured instead.
- 2) As a consequence of the LRET policy, significant investment in renewable energy is being made in the NEM and consequently there is less of a requirement for investment in traditional fossil-fuelled generation technologies.

Investment in base-load generation technologies will be deferred as long as there is policy uncertainty in Australia. Policy uncertainty surrounding carbon price is the most significant amongst investors. Though carbon policy is the main source of uncertainty, there are combinations of other facts which have caused lack of investment in base-load generation. These are: low pool prices, uncertainty surrounding the gas prices, and, impact of the LRET policy which has led to significant renewable energy generation in the NEM (Deloitte, 2011, p. 10).

Low wholesale electricity prices

Historically the wholesale price of electricity has remained low in the NEM as a consequence of which most of the base-load generators haven't been able to achieve adequate return on their investments. Steed and Laybutt (2011, p. 11) estimate that in the past decade generators have staked up economic losses worth \$6 billion as a result of low wholesale pool prices. However, they expect the wholesale electricity prices to rise in the future as a result of reduced reserve margins and LNG netback domestic gas prices.

According to Australian Treasury modelling wholesale electricity prices will rise significantly until 2030, even without a carbon price. The surge in prices will primarily be driven by rising gas prices and higher capital cost of replacement technologies which would enter the market to meet the rising demand. The SKM MMA (2011) and ROAM Consulting (2011) reports forecast similar price rise, however, the extent of the increase in both the reports differs. The main reason for this difference lies in the assumption of cost for coal-fired technology, where ROAM Consulting presumes higher costs than SKM MMA, which is thereon reflected in the wholesale prices.

The electricity price forecast obtained from simulating the South Australian electricity model in this study indicate that the wholesale electricity prices in the region would rise over the planning horizon as a result of rising gas and carbon prices.

Investment outlook for coal and gas generators

Currently, none of the coal generators in the NEM are considering new investments in coal-fired generation assets. The highest priority for coal generators at present is to maintain their asset value, which is steadily falling as a result of the carbon price uncertainty as well as the LRET policy. This has impacted the discount rate of coal generators, where 'sovereign risk' is being added to the risk profile of these generators due to the carbon policy uncertainty in Australia (Deloitte, 2011).

Apart from the carbon policy, Deloitte (2011) cites a combination of other factors which are affecting investments in coal generators.

First, it has become increasingly challenging to raise debt for new coal generators in the current environment. Banks have become aggressive in lending to coal-fired generators as a result of revenue uncertainty and lending is currently being offered on a 'deeply discounted basis' (Deloitte, 2011, p. 43). Also, it's become very difficult for existing generators to refinance their assets due to uncertainty in the asset value in the future. For old, inefficient and highly carbon intensive generators refinancing is even harder as banks see a reputational risk in supporting such projects under the current circumstances.

Second, low pool prices have significantly impacted the profitability of baseload coal generators in the NEM. In this light, Alinta had recently decided to reduce the operational parameters of the Northern power plant in South Australia; the power plant would operate for six months in a year, during summer time, in order to receive high pool price.

Third, as a result of the LRET scheme, significant investment is being made in renewable generators in the NEM. This in turn impacts the pool prices and reduces the pool of funds available to finance other technologies.

On the other hand, there has been considerable amount of interest to invest in gas-generators in the NEM. According to Deloitte (2011, p. 35) gentailers¹⁰ in the NEM, who have significant gas generators, have indicated interest in gas based investments. However, generators who are not 'portfolio gas players'¹¹, i.e., they don't have substantial retail position or upstream gas position, have totally different views to new investments in gas-generation. The difference in views is because there is considerable uncertainty over revenue from gas generation as a result of fuel price risk on the East Coast. Non-gas players acknowledge that ownership of fuel is critical in obtaining the benefit of low emission generation that would ultimately flow to the gas developer by higher gas prices. Hence, these generators are considering gas investments in Asian markets instead.

According to Nelson et al. (2010) carbon policy uncertainty will ultimately have an impact on the type of gas generation, i.e. CCGT and OCGT, which would be built in the future. OCGT is an ideal peak load generator and its 30 to 40 per cent less capital intensive than a CCGT with the same capacity. Main risk for gas-fired generation is in the fuel price and to some extent the carbon price; these will have an impact on the merit order of dispatch in the NEM. Hence, there is significant uncertainty over revenues from gas generators in the future. In the previous chapters, it was noted that OCGT was less sensitive to fuel and carbon price risk than CCGT. This along with the fact that OCGT is less capital intensive and it has the flexible option of being able to convert into a CCGT in the future makes it a preferred generation technology under uncertainty for investors. While OCGT lowers the capital risk for an investor, Nelson et al. (2010) notes that the short to medium term impacts are dire for the power industry because increase in OCGT investments would raise the overall cost of supply of electricity. Nelson et al. (2010) remarks that until there is more certainty, investors in general will strive to minimise the capital cost risk by investing in an OCGT and maintaining the security of supply in the NEM.

According to the Blyth and Yang (2006) the answer to the ultimate question; will the gas prices remain low?, would not only determine the generation choice between an OCGT or CCGT, but also more generally between coal and gas generators.

In this matter, it's interesting to look at the situation in Western Australia (WA) where investments in new coal generators are being planned. These investments are primarily being driven by high gas prices in the state, which are already linked to the LNG netback prices. Also, long-term contracts for coal in WA provide considerable fuel price certainty to generators. According to Deloitte (2011, p. 34) one of the coal-fired power plants in the state is on track to refurbish a 40 year old plant at expected cost of \$100 million. Apart from high gas prices, coal investments are being considered in WA as the wholesale electricity market there is designed such that there is certainty of capacity payments to base-load generators and intermittent generators are paid proportionate to their average capacity factor.

Impact on the merit order of dispatch in South Australia

As a result of the CEF package the merit order of dispatch in the NEM is expected to change, whereby carbon intensive coal generators would become less economic compared to the cleaner generation technologies like gas. Historically, the coal-fired generators in Port Augusta have supplied base-load generation to the SA electricity market.

In order to understand the effect on the merit order of dispatch in context of the CEF package and the rising gas prices in the future, the expected SRMC of base-load generators in the region has been considered over the planning horizon; this data was obtained from the SA electricity market model.

As a result of rising gas prices, the merit order of dispatch for efficient coal generators, like Northern, remained unaffected despite the carbon price- which has been progressively rising every year in the model. However, older and inefficient coal generators, such as Playford, become less economic when the carbon price is substantial. In 2015, when the carbon price was assumed to be \$38/tonne in the model, the SRMC for Playford becomes the highest amongst other base-load generators in the region. Hence, despite the carbon price coal-fired generators in general will remain more economic than gas generator as a result of rising gas price.

¹⁰ These are vertically integrated generation companies with a retail arm.

¹¹ Examples include AGL and Origin which have interest in coal seam gas. Also, TRU energy has entered in arrangements for access to coal seam gas in New South Wales.

Investment outlook for renewable generators

On-shore wind generation is the most mature generation technology out of all the renewable generators, thereby; significant investment in on-shore wind capacity has been seen in the NEM as a result of the LRET scheme (AEMO, 2012a, pp. 2-15).

However, the Investment Reference Group Report (2011, p. 59) notes that the balance sheet of renewable generators is much weaker compared to incumbent fossil-fuelled generators. Therefore, investment in renewable energy would require significant amount of debt financing. In order to secure debt financing, these generation assets need to be able to secure revenue stream for 10-15 years. However, it's challenging for generators to secure these revenue streams due to the carbon policy uncertainty and the LRET scheme. The Investment Reference Group Report (2011, p. 60) notes that the prices of Large Scale Generation Certificates (LGCs) are not high enough to support investments in renewable energy in the short-term. As a result of subdued prices most of the generators in NEM have stalled investment in large-scale renewable energy. Presently, there is significant gap between the LCOE of wind generators, and the current market price of LGCs and the wholesale electricity prices. However the Investment Reference Group Report (2011, p. 60) states that higher spot prices in the future as a result of the CEF legislation will spur investment in renewable energy even if the LGC prices remain at the current levels. According to Deloitte (2011, p. 42) some generators note that investment in OCGTs rather than CCGTs is partly driven by the LRET scheme because OCGTs are ideally suited for dealing with intermittency of renewable energy sources.

The capital intensity of geothermal technology, considering the unpredictably over the drilling cost, the transmission cost of connecting these resource to the grid as well as the uncertain nature of geothermal resource in Australia, is the main source of concern for geothermal investments in the NEM.

While the LRET scheme has increased the attractiveness of solar energy in the region, generators are keen to develop these resources only if the government provides grants to build such assets because the LCOE for solar technology is significantly higher than the wholesale electricity prices. An example of this is seen in South Australia, where Alinta has pledged to convert the Playford facility into solar thermal technology if the State and Federal Government provide funding assistance for the project. In order to increase large-scale solar generation in Australia, the government launched the Solar Flagship Program in 2009. While the funding program changed in 2012, the government recently awarded \$130 million for 159 MW solar photovoltaic projects across two sites in New South Wales.

As a result of uncertainties regarding carbon and gas prices, and the demand response to any price volatility, no technology provides a clear overall least-cost option under all scenarios. As might be expected, "peaky" demand, the high level of (intermittent) wind capacity, and volatile gas prices favoured OCGT technology, with high wholesale prices offering a natural hedge against the latter.

Fuel price risk is the main source of concern for investments in CCGT technology, although generators with an upstream gas position have a natural hedge against this risk. In addition, the less capital intensive OCGTs can have the cycle "closed" when deemed appropriate. The "peaky" nature of demand in SA makes this an ideal strategy for meeting any future increase in base load demand. In addition, the modelling indicated that geothermal technology HSA technology was to be preferred on a cost basis to CCGT for base load, largely due to high gas price expectations. However, this result is predicated upon geothermal becoming commercially viable by 2020.

Australia's Large-scale Renewable Energy Target has led to a significant on-shore wind capacity being installed in SA, and the model built significant additional future capacity. However, much of the additional output will need to be transmitted to other NEM States as output is generally high only in periods of medium and low SA demand. Solar thermal technologies would not be financially viable without significant subsidies, in addition to the LRET.

Conclusions

Investment in liberalised electricity markets is characterised by long-lived assets and significant market and regulatory uncertainty. Least cost generation expansion modelling for SA under different scenarios has indicated that there is considerable capacity-driven investment opportunity for OCGT, due to the very "peaky" demand in the region and the high level of intermittent wind generation capacity. For base load, geothermal has a clear cost advantage over CCGT, with fuel prices the main source of concern for investments in the latter. On-shore wind capacity will also remain competitive, due to carbon prices and subsidies.

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Table 1: Technical and cost data for new entrant generators

	CCGT	Geotherm EGS	Geotherm HSA	OCGT	Solar	Wind
Nameplate capacity (MW)	374	10	20	160	10	100
Capital cost (\$/kW)	139	7	14	40	0	0
Heat Rate (GJ/MWh)	7.272	-	-	10.84	-	-
Variables O&M Charge (\$/MWh)	4	0	0	2.5	0	0
Auxillary load (%)	3	15	7	1	10	0.5
Fixed O&M Charge (\$/kw/year)	10	170	200	9	60	40
Planned Outrage Rate (%)	4	7.2	7.21	1	6.105	5
Forced Outage Rate (%)	4	3	3	2	2.3	1.6
Capital Cost (\$/KW)	1062	10600	7000	985	8308	2530
Economic Life (years)	30	30	30	30	30	20

Source: WorleyParsons (2012)

Figure 1



Figure 2

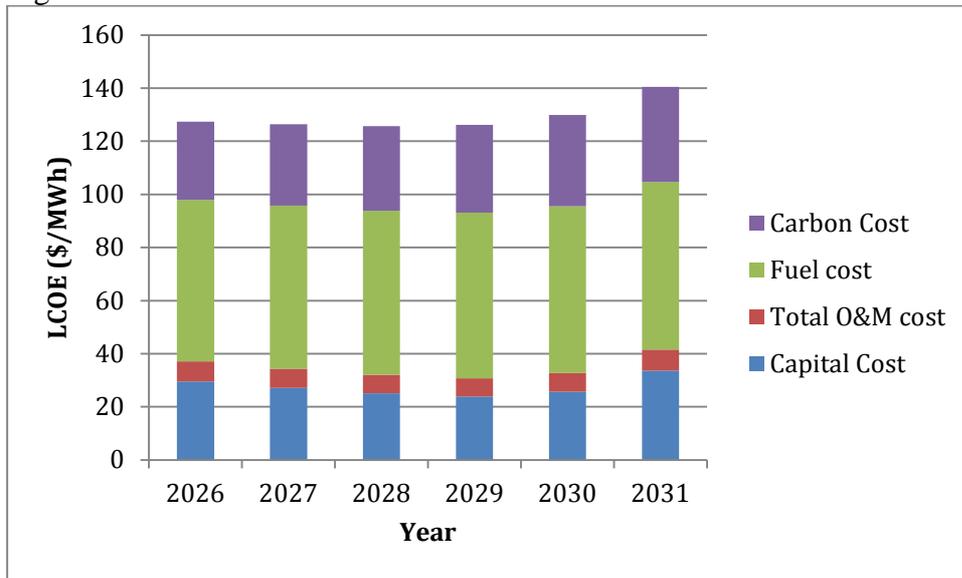


Figure 3



Figure 4



Figure 5

