The Role of Wind and Solar PV in Mitigating the Impact of Uncertainty in the Australian Electricity Industry

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***Abstract*— This paper assesses the value of wind and photovoltaic (PV) generation in mitigating the impact of future fuel price, carbon pricing and electricity demand growth uncertainty in the Australian National Electricity Market (NEM). A quantitative generation portfolio modelling tool which combines optimal generation mix techniques with Monte Carlo simulation to incorporate future uncertainty is employed. Different future investment scenarios for 2030 are considered, ranging from investing only in gas generation to different mixes of renewables and gas investment, through to investing primarily in renewables. Results suggest that future generation portfolios with a large share of gas-fired generation, particularly combined cycle gas turbine (CCGT), and minimal renewables are likely to have high cost, and exposed to considerable cost risk due to uncertainty. In contrast, future generation portfolios with high renewable penetration can provide a valuable reduction in the overall cost, associated cost risk and CO_2 emissions, assuming central estimates for gas and carbon prices. Although CCGT plant are projected to be high risk, the modelling suggests that gas peaking plants could play an important role in complementing renewable generation, meeting electricity demand at lower cost.**

Keywords-component; Australian National Electricity Market (NEM); renewable generation investment; Monte-Carlo.

I. INTRODUCTION

Australia currently sources in excess of 70% of its electricity from coal generation, which contributes around 35% of national emissions [1]. With international pressure to reduce greenhouse gas emissions, there is ongoing debate around the best way to reduce the emissions intensity of Australia's electricity supply. In particular some stakeholders argue that investment should focus on Renewable Energy (RE) generation, while others propose that a transition pathway via gas-fired electricity would be preferable [2].

There is broad agreement that "uncertainty is the new certainty", making investment decisions in long-lived electricity infrastructure increasingly challenging [3]. In Australia at present, uncertainty is particularly pronounced around future carbon prices and future gas prices. Carbon pricing was introduced in Australia on 1 July 2012, starting at a fixed price of $\$23/tCO_2$, with the intention of transition to an emissions trading scheme (ETS) with market set prices from 2015. A link to the EU ETS is now planned from 2014, which poses considerable future price uncertainty given current low prices and wider challenges for the EU scheme. More importantly, there is no bipartisan support for carbon pricing with the current Federal Opposition party and numerous State government's opposing any carbon price, Hence, the future for carbon pricing in Australia is particularly uncertain at present, and seems likely to remain so until there is far greater political and societal consensus on the need, and most appropriate policy framework for reducing greenhouse emissions.

For gas, three major joint ventures are currently in the process of establishing export facilities for Liquefied Natural Gas (LNG) on the east coast of Australia. When these facilities are commissioned (during the period 2014 to 2017), domestic gas prices are anticipated to "rise sharply… as prices converge towards LNG netback prices" [4]. However, the nature of such international linking remains unclear and international gas markets are themselves highly uncertain looking forward. This creates significant uncertainty over Australia's domestic gas prices over the medium to long term. The high emissions intensity and presence of some gas-fired generation means that these future carbon and gas price uncertainties flow through to create significant future electricity price uncertainties and broader energy security challenges in Australia [5].

In addition, there is large uncertainty over future electricity demand. Demand has plateaued then actually begun to fall over the past few years due to a number of factors including moderate economic growth, higher electricity prices, energy efficiency measures, changing industrial competitiveness and hence industry structure and an increased penetration of distributed RE [6]. Australian planning bodies continue to project future growth, however there is growing uncertainty regarding this given recent further falls in demand.

Previous studies exploring the future of the electricity sector in Australia have typically focused on a small number of generation portfolios, under a small number of scenarios (where a scenario incorporates various operating conditions including, for example, carbon and gas prices). For example, Molyneaux et al. modelled the costs and greenhouse emissions of two generation portfolios in 2035 (exploring investment in primarily gas-fired generation or renewable generation respectively) [7]. Elliston et al. modelled generation portfolios of 100% renewable energy and 100% fossil fuel power in 2030 under high and low cost

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assumptions [8]. The Australian Energy Market Operator (AEMO) modelled 100% renewable energy scenarios in 2030 and 2050 [9], and annually undertakes a National Transmission Network Development Plan (NTNDP) which explores a small number of scenarios (two were modelled in the 2012 NTNDP) [10]. Other stakeholders including industry participants and governments also undertake their own modelling studies. While such efforts can have considerable value, these studies consider only a very minor subset of the possible generating portfolios that might eventuate over time, and sample only a few of the possible market conditions under which those portfolios may need to operate. Factors driving their investigation of only very limited future perspectives include the complexity and interactions of such uncertainties, and the constraints of the models being used. Inevitably, however, such approaches inadequately account for the high degree of uncertainty over important driving factors such as gas and carbon prices. As such, they do not provide a detailed analysis of the future risks associated with particular choices.

This paper employs a Monte-Carlo based generation portfolio modelling tool developed in [11] to examine the impact of uncertainty on the energy costs of various future generation portfolios for the Australian National Electricity Market (NEM). In particular, the value of RE such as wind and photovoltaic (PV) generation in mitigating the impact of uncertainty in future fuel prices, carbon prices and electricity demand is examined.

II. MONTE CARLO BASED GENERATION PORTFOLIO MODELLING

The modelling tool employed in this study extends the commonly applied load duration curve (LDC) based optimal generation mix techniques by using Monte Carlo Simulation (MCS) to formally incorporate key uncertainties which directly impact overall generation costs and other outcomes into the assessment. Outputs from the modelling tool consist of many thousands of simulations of generation costs and CO_2 emissions for each of the different possible future generation portfolios. These outputs are, therefore, a series of probability distributions that, for relatively simple distributions, can be described as an *expected* future value of annualised generation costs and CO_2 emissions, and the *standard deviation (SD)* in these (cost and emissions uncertainty or risk) for each portfolio.

The tool then applies financial portfolio methods to determine an Efficient Frontier (EF)[1] of expected (i.e. mean) costs and the associated cost uncertainty (i.e. SD) for each of the different generation portfolios. EF techniques provide a basis for explicitly analysing cost and risk tradeoffs among different generation technology portfolios. In particular, the EF is made up of those generation portfolios which offer the lowest expected cost for some level of cost uncertainty.[2]

Since the tool applies MCS techniques, it can support even more sophisticated risk assessments of different generation portfolios such as downside economic risks, value at risk (VAR) and other risk-weighted uncertainty measures. It also does not rely upon the use of normal distribution to model input uncertainties – any distributions can be used.

RE generation is incorporated into the model through the use of residual load duration curve (RLDC) techniques where hourly RE generation outputs in the time-sequential domain are subtracted from demand over the same time period. This is based on the assumption that RE is given the first priority in merit order dispatch due to their low operating costs by comparison with conventional generation technologies. The resulting residual (net) demand after accounting for RE generation is then rearranged in order of magnitude to obtain a RLDC. It is this curve which has to be met by conventional technologies in the portfolio.

The methodology and mathematical formulation of this modelling tool are described in detail in [11]. The model has previously been applied to portfolio analysis with wind generation in the context of the NEM [13].

III. SCENARIO DESCRIPTIONS AND MODELLING INPUTS

In this paper, the modelling considers a number of different generation investment scenarios in the NEM for 2030 under highly uncertain future fuel prices, carbon prices and electricity demand. The investment scenarios range from investing only in gas generation (no new RE) to different mixes of RE and gas investment, through to investing primarily in RE (with minimal gas). The scenario with high RE investment could be driven by factors including market expectations of very high gas and carbon prices or strong RE policies such as expansion of the existing Renewable Energy Target (RET) or Feed-in-Tariffs (FiTs). On the other hand, the scenario with high investment in gas-fired generation (with minimal or new RE) could occur due to a lack of government support for RE and a market expectation of continuing low gas prices and moderate to low carbon prices.

A. Generation Investment Scenarios for 2030

Four new generation investment options are considered in the model for this study: wind (on shore), utility scale solar PV (single axis tracking), combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT). Six different investment scenarios are assumed, which translates into different RE penetrations ranging from 0% to 90% of total annual energy demand. These investment scenarios are shown in Table I.

TABLE I. DIFFERENT GENERATION INVESTMENT SCENARIOS PERCENTAGE BY ENERGY

Investment Scenario	**% of RE generation**		**All other** (coal, gas, hydro, distillate, cogen)
	New PV	*New Wind*	
Gas World 1	0%	0% [a]	100%
Gas World 2	5%	10%	85%
Medium mix 1	10%	20%	70%
Medium mix 2	20%	30%	50%
RE World 1	30%	40%	30%
RE World 2	40%	50%	10%

a. Existing wind generation is included with "All other" category. The NEM currently sources 2.5% of annual energy from wind.

The modelling assumes that there will be no new investment in coal-fired generation. There appears to be

[1] The efficient frontier concept is used in the Mean Variance Portfolio (MVP) theory for financial portfolio optimization [12].

[2] The novel aspects and the contributions of this modeling tool to existing generation planning and investment frameworks are described in [11].

growing consensus on this given its high emissions and high capital investment risk [14]. Furthermore costs of RE are becoming increasingly competitive with coal [3, 15], particularly with a carbon price in place. In addition the model assumes no new investment in hydro, distillate and cogeneration.

The existing NEM generation capacity and possible retirements are incorporated as shown in Table II. All existing capacity (including committed projects as of 2013) is assumed to remain in operation in 2030, with the exception of brown and black coal. All existing brown coal generation is assumed to be retired by 2030 and therefore is excluded from the modelling. Black coal capacity is varied between the simulations, with the model exploring a range of possible retirements (from no retirements to full retirement of all black coal capacity). Investment costs of the existing capacity of each technology are considered 'sunk' and therefore are not included in the calculation of annualised (capital and operating) industry generation costs.

The costs of building new or upgrading existing transmission facilities to access new RE is not included in the simulation. However, the costs of transmission are estimated to be relatively minor compared with the capital cost of generation in a move to a high renewable system [9]. Inclusion of transmission augmentation represents a relatively straightforward extension to the modelling which could be incorporated in future work.

TABLE II. EXISTING GENERATION CAPACITY AND ESTIMATES OF RETIREMENTS OF THIS CAPACITY DURING 2013 - 2030

Technology	Existing capacity in 2013 (MW)[a]	Remaining capacity in 2030 (MW)
Black coal	19,814	Varies from 0 to 19,814
Brown coal	7,294	0
CCGT	2,758	2,758
OCGT	7,415	7,415
Hydro	7,654	7,654
Distillate	586	586
Cogeneration	171	171
Wind	3,000	3,000

a Existing capacity includes committed capacity

B. Generation Portfolios and Dispatch

For each investment scenario (i.e. RE penetration level), different possible thermal generation portfolios were considered by varying the share of each fossil-fuel technology (black coal, CCGT and OCGT) in the portfolio from 0% to 100% of total installed fossil-fuel capacity.

1) Generation Dispatch

For each possible portfolio, generation output of each thermal technology in each period in the LDC (or RLDC) is determined using merit order dispatch based on short run marginal costs (SRMC) of each thermal technology in 2030.

PV and wind generation is given priority dispatch due to their low operating costs. As noted earlier, therefore, they are considered exogenous and treated as negative load.

Hydro generation is relatively unique amongst the technologies because it is dispatchable, but energy limited. To ensure that hydro dispatch within the model was captured appropriately, hydro was also treated as exogenous to the dispatch. The approach adopted was to subtract the aggregate hydro duration curve (rearranged in order of magnitude) from the RLDC in each scenario of PV and wind penetration. With this approach, historical hydro generation patterns are re-mapped onto the new net demand curve, better accounting for the fact that the future generation mix will likely be very different from that currently in use, and adjusting hydro dispatch accordingly. Energy constraints are also maintained at levels considered realistic for future operation [9].

To ensure realistic dispatch outcomes, the modelling assumes a hypothetical minimum of 15% synchronous generation in any one hour period. Previous studies have used this assumption in the NEM, to ensure sufficient system inertia to maintain a stable frequency and satisfy other important system security concerns (such as fault detection) [9]. Synchronous generation is provided by conventional generating plants, which are coal, CCGT, OCGT, hydro, distillate and cogeneration. This represents the minimum amount to which aggregate conventional generators can be turned down. Hence, PV and wind generation are 'capped' at 85% of demand in each dispatch interval. For high RE penetration cases, there are of course periods during which combined PV and wind outputs were greater than total demand. In such cases, energy from PV and wind was spilled. PV was given priority over wind in the dispatch due to the assumption of a lower variable operations and maintenance costs for PV.

2) Installed Generation Capacity

Installed capacity of PV and wind are determined by assuming a capacity factor of 34% for PV and 41% for wind [9].[3] Installed fossil-fuel (coal and gas) generation capacity is determined using a probabilistic approach to ensure that there is sufficient capacity to meet the expected demand for at least 99.998% of the time during the year. This is consistent with the current NEM reliability standard which is set at 0.002% of unserved energy per year. Table III shows the installed capacity of PV, wind and conventional generation calculated for each RE penetration.

TABLE III. INSTALLED GENERATION CAPACITY AND RESIDUAL PEAK DEMAND FOR DIFFERENT PV AND WIND PENETRATIONS.

Penetration		Residual peak demand (GW)	Installed capacity (GW)		
New PV	*New Wind*		*New PV*	*New Wind*	*Conventional*
0%	0%	32	0	0	45
5%	10%	29	3.8	6.2	41
10%	20%	27	7.5	12.4	40
20%	30%	26	15.1	18.6	38
30%	40%	25	22.6	24.8	37
40%	50%	24	30.2	31	36

The capacity of each generation technology for each combination of PV and wind penetration is shown in Fig. 1, which indicates that PV and wind have the potential to displace fossil fuel technologies as RE generation increases. Note that fossil fuel capacity on the graph consists of coal, CCGT and OCGT. For coal, only the existing capacity is considered while the capacity of CCGT and OCGT consists of both new and existing plants.

[3] The study assumes technology improvement out to 2030.

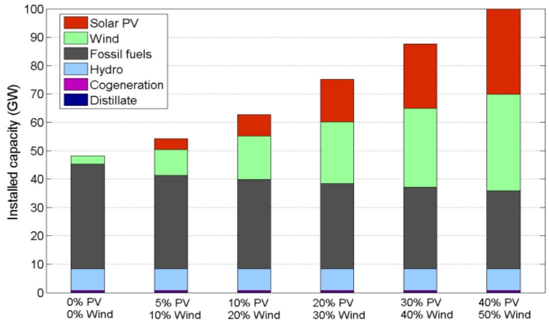

Figure 1. Installed generation capacity for each investment scenario.

For each scenario of RE penetration, different possible permutations of 'fossil-fuel' generation portfolios were considered by varying the share of black coal (existing), CCGT and OCGT in 10% intervals. This resulted in 66 generation portfolio combinations. With this approach, the modelling essentially considers different cases of black coal retirements from zero (all remains) to 100% (all retired). The amount of existing capacity of CCGT, OCGT, distillate, cogeneration and hydro is fixed for every possible generation portfolio as shown in Table II. The maximum capacity of black coal in 2030 is capped at existing capacity (19,814 MW) hence generation portfolios which consist of black coal exceeding this amount were removed as infeasible solutions.

C. Modelling Inputs

1) Demand, PV and Wind Profiles

Hourly electricity demand for 2029-2030 was obtained from AEMO's 100% RE study in the case of moderate growth, which corresponds to the 50% 'probability of exceedance' (POE) case [9]. The demand profile provided by AEMO is based on the historical 2009-10 demand pattern.

Hourly wind and solar output profiles in 2030 for each investment scenario (i.e. each PV and wind penetration) are simulated based on historical hourly traces of 1-MW onshore wind and solar PV (single axis tracking) generation in different locations across the NEM provided by AEMO [9]. To be consistent with the demand profile, 2009-10 data was used as a reference year for these generation profiles. Hourly PV and wind generation was scaled up to the desired penetration level. To construct a hydro duration curve, actual hourly hydro generation output was obtained from AEMO using 2009-10 as the reference year [16].

RLDCs for different PV and wind penetrations are illustrated in Fig. 2. As shown in the figure, minimum synchronous generation has been taken into account.

2) Generator Data

Existing plant parameters were obtained from the AEMO NTNDP, calculated as the average for all of the existing plant for each technology type [10]. New entrant generation parameters for each technology were based on the 2030 cost estimates from [17] averaged over all NEM regions. It is assumed that any existing fuel contracts will have expired by 2030, such that existing generators will be purchasing fuel at the same prices as new generators. Annualized capital costs are calculated using a weighted average cost of capital (WACC) of 10%. Expected fuel prices are also based upon an average of NEM regions for the "medium" projection case from [17]. For OCGTs, an uplift of 20% was applied to the gas price in any investment scenario, accounting for their lower purchasing power given smaller generation volumes. The parameters for new generators are shown in Table IV.

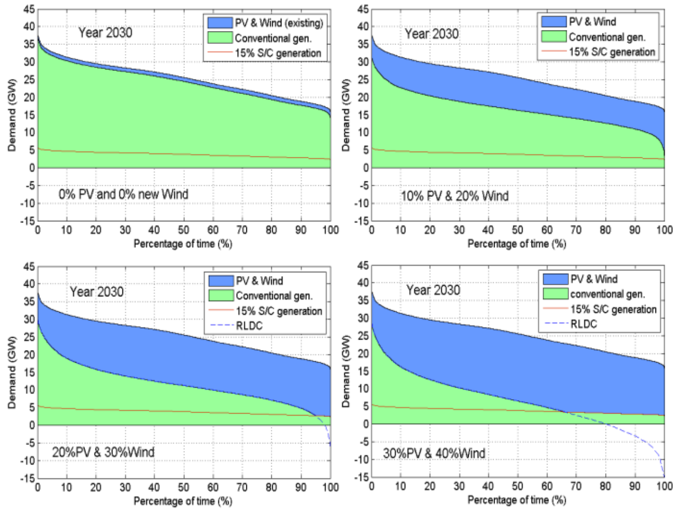

Figure 2. Residual load duration curves for different RE penetrations.

TABLE IV. NEW GENERATOR CHARACTERISTICS

Parameters	**CCGT**	**OCGT**	**Wind**	**PV**
Plant life (years)	30	30	30	30
Overnight capital cost ($kW)	1,113	751	1,816	2,197
Fixed O&M cost ($/MW/yr)	10,000	4,000	40,000	38,000
Variable O&M cost ($/MWh)	4	10	12	0
Thermal efficiency (%)	50	35	n/a	n/a
Heat Rate (GJ/MWh)	7.27	10.29	n/a	n/a
Emissions Factor (tCO_2/MWh)	0.37	0.52	0	0
Expected fuel price ($/GJ) (varied according to a probability distribution)	11.65	14	0	0

IV. MODELLING UNCERTAINTIES

Lognormal distributions were applied to future gas and carbon prices to reflect the asymmetric downside risks associated with their future value. Electricity demand uncertainty was modelled by assuming a normal distribution of residual peak demand in the RLDC for each case of RE penetration. Both lognormal and normal distributions can be characterized by their mean (expected value) and SD.

A. Fuel and Carbon Price Uncertainty

The mean and SD of fuel prices were determined from the 2030 estimates provided in the 2012 AETA report, which also provides projections for low, medium and high price scenarios [17]. The central projection of fuel prices was applied as the mean, while the SD was approximated based on the spread between the low and high case scenarios.

For carbon prices, mean and SDs were obtained from Australian Treasury Modelling of carbon prices in Australia in 2030 [18]. This modelling included two scenarios: a low carbon price case (corresponding to a 5% reduction in emissions by 2020) and a high carbon price case (corresponding to a 25% reduction in emissions by 2030). For this modelling, the mean carbon price was based upon a scaling between these two scenarios (adjusted by CPI to March 2013 dollars). The SD was obtained using the same approach as the fuel prices.

Correlations between fuel and carbon prices are also accounted for when modelling these uncertainties, given that their movements have exhibited a considerable historical correlation in the EU and UK markets [19]. Correlations were estimated from historical trends in OECD countries.

Table V shows the assumed expected fuel and carbon prices in the low, as well as their SDs.

TABLE V. FUEL AND CARBON PRICES

Fuel and Carbon Price	**Expected value**	**Standard deviation**	
		%	*Absolute*
Black coal ($/GJ)	1.9	6%	0.1
Natural gas ($/GJ)	11.7	30%	3.5
Carbon price ($/t$CO_2$)	91	40%	36

Correlated samples of black coal, gas and carbon prices are generated from their marginal lognormal distributions using a multivariate Monte Carlo simulation technique described in [11]. The distributions of 10,000 simulated coal, gas and carbon price simulations as well as the scatter plots highlighting their correlations are shown in Fig. 3.

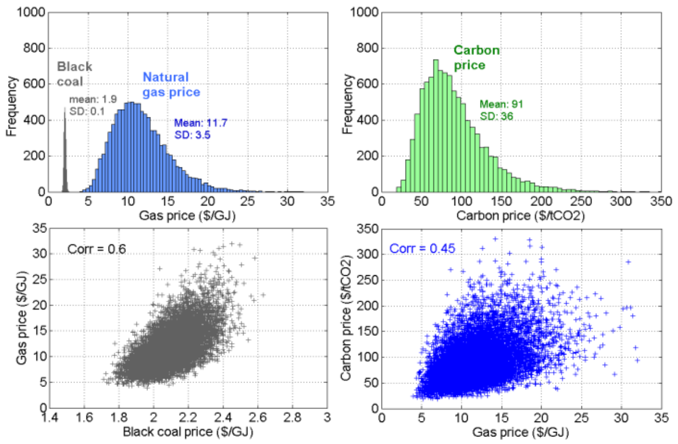

Figure 3. Correlated distributions of fuel and carbon prices over 10,000 Monte Carlo simulations and scatter plots showing their correlations.

B. Electricity Demand Uncertainty

Demand uncertainty is modelled as the uncertainties in the RLDC for each scenario of PV and wind penetration. AEMO's forecast 50% POE peak demand was applied as the mean peak demand. The SD of peak demand was determined based the difference between AEMO's 10% POE and 50% POE peak demand estimates. The SD was approximated as 5% of the central projection. To create the RLDC used in each simulation, the reference RLDC (central projection) for each PV and wind penetration scenario was then adjusted by scaling the whole net RLDC as required to match the desired peak demand for the particular simulation. The uncertainty in the RLDC was therefore modelled as vertical shifts in the reference RLDC, thus maintaining the same shape.

There were some instances in which the simulated residual peak demands exceeded the installed conventional generation capacity, resulting in unserved energy. Unserved energy was valued at $12,900/MWh, which is the current market price cap in the NEM. The cost of unserved energy was included in the overall cost in each Monte Carlo run.

V. MODELLING RESULTS AND ANALYSIS

For each investment scenario, the costs and CO_2 emissions of each possible conventional generation portfolio were calculated for 10,000 simulations of uncertain fuel prices, carbon price and electricity demand[4]. The analysis is focused on generation portfolios on the efficient frontier (EF) which are considered optimum in terms of costs and risks. Other generation portfolios are not presented in this paper.

Optimal generation portfolios on the cost-risk EF for each of the investment scenarios are shown in Fig. 4, which also indicates the percentage share and capacity of PV, wind and hydro generation. The share of distillate and cogeneration are not displayed given their relatively low contributions. The tradeoffs in terms of expected cost, cost risk (SD of cost) among portfolios can be seen on the EF. As the combined PV and wind penetration increases from 0% to 70%, reductions in both overall generation cost and cost risk are observed, as indicated by the downward movement of the EF. As an example, the expected costs of optimal generation portfolios in the case of 0% RE penetration are in the range of $112 - 122/MWh, compared to $95-104/MWh in the case of a 70 % RE (30% PV, 40% wind) penetration. This is in addition to significantly lower cost risk as indicated by the lower SD of cost in the case of higher RE penetrations. Although costs start to increase once the RE penetration reaches 90%, the cost is still lower than in the cases with very low RE penetration (i.e. 0% - 15% RE penetration).

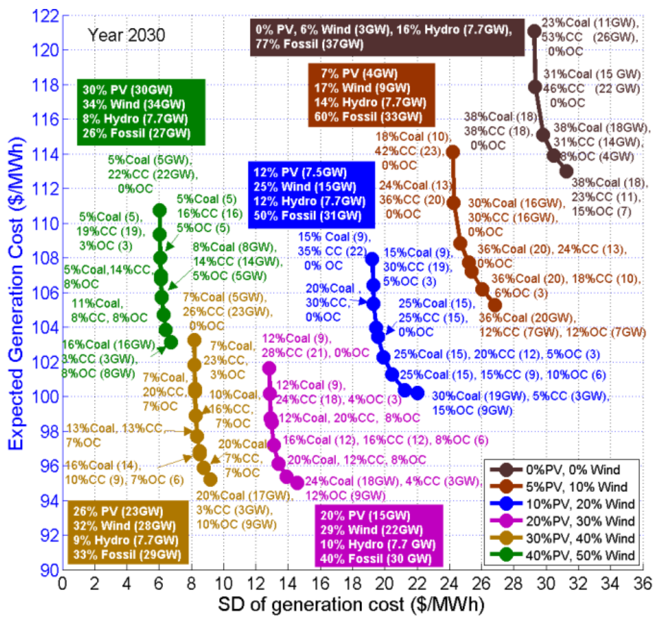

Figure 4. Efficient frontiers containing optimal generation portfolios for different RE penetrations. The capacity of each technology in each portfolio is presented (as shown in brackets).

From Fig. 4, the EF for each RE penetration is quite steep which suggests that the cost risk varies modestly among optimal generation portfolios within each RE penetration level by comparison with the expected cost.

As the RE penetration increases, the mix of the optimal generation portfolios contain less coal and gas technologies

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[4] A number of simulations involving greater than 10,000 runs suggested that more simulations would not significantly change modeling outcomes.

(in both percentage and installed GW terms) as they are replaced by PV and wind. Fig. 5 presents the generation mix, expected cost, associated cost risk and CO_2 emissions of the 'lowest cost' generation portfolio for each RE penetration level. The total installed generation capacity is seen to increase quite considerably, from close to 50 GW in the case without new PV and wind to about 100 GW in the case of 90% RE (40% PV, 50% wind). This increase is explained by the additional PV and wind capacity required to replace fossil-fuel (coal and gas) capacity due to the low capacity factors of these highly variable renewables.

The capacity of coal and OCGT in the least cost portfolio changes only very slightly as RE penetration levels increase (16-18 GW for coal and 7-9 GW for OCGT). By contrast, CCGT capacity is greatly affected by an increase in RE penetration, falling from around 11 GW to 3 GW as the combined PV and wind penetration level increases from 0% to 30%. This suggests that although OCGTs are less efficient and have a higher operating cost than CCGTs, they still have an important role to play in partnering with renewables to provide high reliability at lowest cost.

Fig. 5 also shows that the cost risk and CO_2 emissions decline quite significantly with higher RE penetrations while the overall cost is minimised at a RE penetration of 70% (as previously shown in Fig. 4). Note that from 0% to 70% RE penetration, the overall cost reduction occurs despite an increase in overall generation capacity.

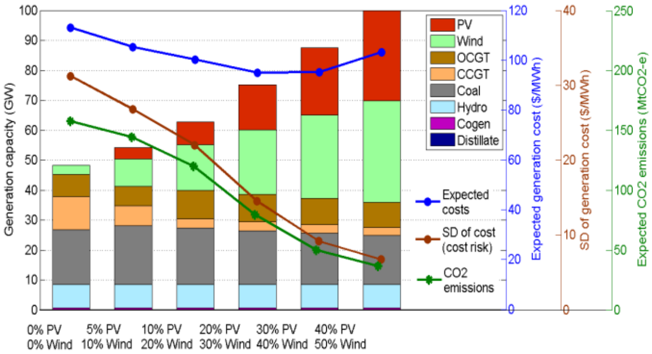

Figure 5. Installed capacity, expected costs, CO_2 emissions and SD of generation costs (cost risk) of the least cost generation portfolios in each scenario of RE penetration.

VI. CONCLUSIONS

This paper provides an analysis of the potential impact of carbon prices, gas prices and electricity demand uncertainty on least-cost future generation portfolios in the NEM by comparing a number of generation investment scenarios involving gas and renewable generation for 2030. A Monte-Carlo based generation portfolio modelling tool was employed to assess the expected costs, associated cost risk and greenhouse gas emissions of different possible generation portfolios based on the cost estimates and hourly wind, PV and demand projections for 2030.

Our modelling results show that for widely accepted estimates of future gas and carbon prices, significant investment in renewable generation not only leads to reductions in the overall system cost and greenhouse gas emissions of the Australian NEM, but also helps to reduce exposure to cost risks due to significant uncertainty in these gas and carbon prices. By contrast, future generation portfolios with a large share of gas-fired generation, particularly CCGT, and consequently far less renewables are likely to be exposed to considerable cost risk due to these uncertainties. Furthermore the modelling has highlighted that gas peaking plants could play an important role in complementing renewable generation in future portfolios to reliably meet electricity demand at lower cost.

There are, as always, limitations in these modelling exercises that mean their findings need to be considered with suitable caution. Nevertheless, the modelling undertaken highlights that a shift to renewable generation can potentially decouple electricity price from future gas and carbon price uncertainty and therefore provide increased energy price security. Finally, further enhancements to the work are clearly possible. For example, the modelling did not include sensitivities with different scenarios of gas and carbon prices. These and other issues will be considered in future work.

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