MARKET PRICING AND REVENUE OUTCOMES IN AN ELECTRICITY MARKET WITH HIGH RENEWABLES – AN AUSTRALIAN CASE STUDY

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Overview

Given falling solar and wind energy technology costs and growing concerns over climate change and energy security, future electricity industries seem likely to feature a growing proportion of highly variable renewable generation. For restructured electricity industries with competitive market arrangements, the high capital yet low operating costs (short run marginal cost or SRMC) of these technologies poses some interesting challenges. In particular, growing penetrations of low SRMC renewable generation in energy only wholesale markets are likely to reduce spot electricity prices and hence market returns to all generators. The risk of insufficient revenue to recover both fixed and variable operation costs is one of the major concerns for generators. Concerns around revenue sufficiency are also shared by many policy makers and market regulators given that this might lead to resource adequacy challenges by promoting early retirement and deferred entry to the market [1, 2]. The Australian National Electricity Market (NEM) provides an interesting case study for analysis of high renewable scenarios, including their revenue implications. Previous studies have explored the technical feasibility and economics of high renewable scenarios in the NEM, including scenarios of 100% renewable energy [3, 4]. These studies, however, have not considered directly revenue implications. Meanwhile, some observers have raised questions about the feasibility of the NEM's energy-only market design in high renewable scenarios, including claims that a system composed of a majority of low SRMC generation may not deliver appropriate commercial incentives for assured resource adequacy [5].

This study aims to explore these issues within a possible future Australian NEM with high wind and PV penetrations. In particular, the study provides a quantitative analysis of spot market prices and generator revenue sufficiency within such an industry, with a view to assessing the viability of the present energy-only market and its mechanisms to ensure resource adequacy and hence long-term reliability.

Methods

This study uses a probabilistic generation portfolio modelling tool which extends the commonly applied load duration curve (LDC) based optimal generation mixes by using Monte Carlo simulation to incorporate key uncertainties into the assessment [6]. These uncertainties include future gas costs, carbon policies and electricity demand. The tool determines a probability distribution of annual revenue, operating costs and profits/losses of each generation technology for different possible generation portfolios. The "expected" annual revenue, operating cost and profit of each generation technology for a particular portfolio represent the average of all the simulated revenue, costs and profits from every Monte Carlo run. Generators obtain revenue through a spot market based upon the spot electricity price (or "market clearing price") in each period. The modelling assumes that generators bid into the market at their SRMCs and the spot price is the cost to supply the last MW of electricity to meet demand.

A 15% minimum synchronous generation requirement is applied in all dispatch periods to provide adequate system inertia and system stability [3]. This represents the minimum amount to which aggregate conventional generators can be turned down. In addition to the market revenue, conventional generators also receive a supplementary payment in periods in which they are dispatched out of merit order to satisfy the synchronous requirement. The supplementary payment is determined based upon the SRMC of the most expensive generator that is dispatched to meet the synchronous requirement.

Six different renewable scenarios for the NEM in 2030 are considered: 15%, 30%, 40%, 60%, 75% and 85% penetrations, by energy. Eight technologies are included: coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), co-generation, distillate, utility-scale PV (single axis tracking), wind (on shore) and hydro. The maximum spot price is set at $13,500/MWh, which is the current Market Price Cap (MPC) for the NEM. This price is triggered in periods when demand exceeds available generation capacity. The total installed capacity was determined so that each generation portfolio will, on average, meet the present NEM reliability standard of 0.002% annual unserved energy (USE).

PV and wind generation is incorporated into the modelling through the use of a residual (net) load duration curve (RLDC) approach to capture the chronology of PV and wind resource variability and its match to NEM electricity demand. As the lowest SRMC generation, PV and wind generation is given priority dispatch, subject to the minimum synchronous generation requirement noted above. With this approach, hourly simulated PV and wind generation is subtracted from hourly demand over the year to obtain residual demand, which is then rearranged to obtain a RLDC. It is this curve which has to be met by conventional technologies in the portfolio.

Results

The average spot price duration curve for the least cost portfolio in each renewable penetration for the 2% highest priced periods is shown in Figure 1. The graph shows that the magnitude of price spikes increases with higher renewable penetrations but the high price periods (e.g. greater than $500/MWh) are less frequent.

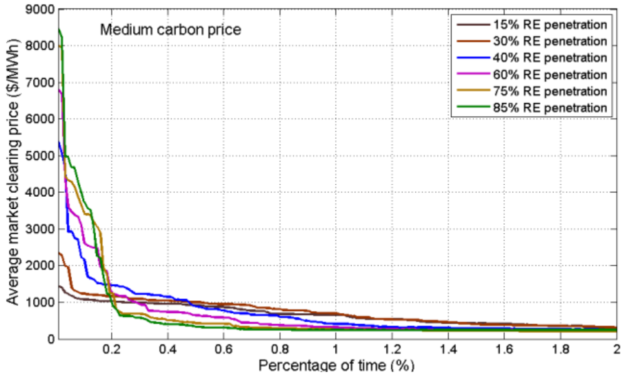

Figure 1. Average market price duration curve for the top 2%

For example, the average highest spot price in the 85% renewables scenario is around $8500/MWh compared to $1500/MWh in the 15% renewables scenario. However the number of periods where the spot prices are greater than $500/MWh is less than 0.4% of the time (35 hours per year) in the 85% renewables scenario compared to 2% of the time (75 hours per year) in the 15% renewables scenario. Since high spot prices in the model are driven by periods where unserved energy is occurring, the price duration curves illustrate that there are fewer periods of supply and demand imbalance as renewable penetration increases, but that the magnitude of unserved energy occurring in each of those periods is higher (unserved energy is concentrated into fewer periods as the renewable percentage increases, keeping in mind that the total USE for each generation portfolio is the same).

The annual average spot prices for different renewable penetrations are also shown in Figure 2, together with the expected annual revenue and operating profit of each technology in the least cost portfolio. The revenue and profit of each technology generally reduces as the amount of renewables increases due to lower annual average spot prices influenced by the low SRMCs of wind and PV. It appears that the profits of PV and wind significantly reduce with higher renewable penetration. This is particularly the case for PV as shown by its negligible operating profit at 85% renewable penetration (not yet taking into account the annual capital cost repayment).

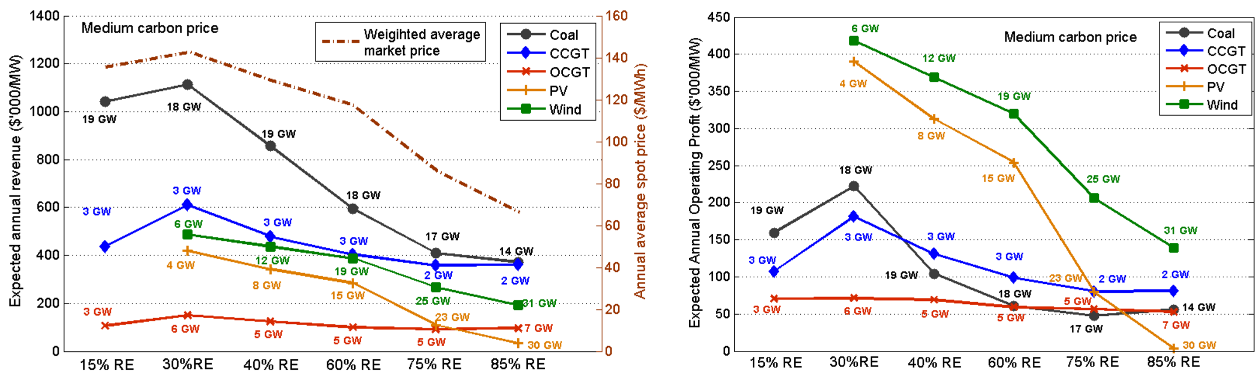

Figure 2. Expected annual revenue, average market price and operating profits of each technology for different renewable penetrations. The installed capacity of each technology is also shown on the graphs.

Conclusions

- As the amount renewables increases, the annual average price also reduces due to the low operating costs of wind and PV generation although the magnitude of price spikes is greater with high renewables.
- The reduction in spot price will result in reduced revenue and profit of generators and potentially lead to insufficient revenue. The revenue impacts on large-scale PV are very severe at high renewable penetrations.
- Changes in market mechanisms (such as higher MPC) are likely to be required to ensure long-term resource adequacy and revenue sufficiency in an energy only market.

References

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