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Operational flexibility of future generation portfolios with high renewables

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HIGHLIGHTS

- The study integrates long-term planning modelling under uncertainties with detailed operational modelling.
- Different generation portfolios were modelled for the Australian National Electricity Market.
- Imposing minimum synchronous generation constraints can be very expensive for high renewable portfolios.
- The cost and technical impacts associated with ramp rates, minimum operating levels and startup costs are less significant.

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ABSTRACT

The costs and technical implications of thermal plant operating constraints within high renewable electricity systems are receiving growing attention. However, many future scenario modelling studies take limited consideration of such constraints. In this study, different generation portfolios were modelled over a year's dispatch for the Australian National Electricity Market (NEM), to examine operational impacts and the costs of different power plant operating constraints. As the level of variable renewable energy (VRE) increases, thermal plants are subject to frequent cycling (ramp up/down and start/stop) as they are dispatched to accommodate the outputs of VRE. However, the extent of the operational impact depends on the mix of conventional technologies within the portfolio. Many coal and gas operational constraints were found to be inexpensive, even in a 85% renewable scenario with primarily wind and solar generation. The combined impact of ramp rate constraints, minimum generation constraints and start-up costs was found to add only 0.1–3% to total annual system costs. In contrast, a minimum synchronous generation (SG) constraint (intended to maintain minimum levels of system inertia) was found to have a significant impact on system costs when the renewable energy penetration exceeds 40%, and a moderate cost of greenhouse emissions is assumed. For a renewable share of less than 40%, the SG requirement has negligible impact since synchronous generators are already supplying at least 40% of the demand in each dispatch period. A 50% SG requirement increases total system cost by 20% in a 85% renewable portfolio. Similarly, costs are increased by 10% in a 60% renewable portfolio. This suggests significant value in investigating measures that minimize the need for a stringent SG constraint in a future carbon constrained world.

1. Introduction

Recent growth in variable renewable energy (VRE) in many electricity industries, particularly wind and solar photovoltaics (PV), has increased the complexity of electricity industry operation and affects the way in which conventional generating plants are operated [1]. Given their variable, somewhat unpredictable and partly dispatchable nature, there are concerns over the potential operational and economic impacts of integrating variable renewable sources into power systems. Wind and solar power increase the variability of net demand to be met by dispatchable generation, which may create operational challenges for thermal plants by necessitating frequent cycling, including ramping and startup/shutdown [2]. Large thermal plants may have technical limitations and additional costs associated with cycling. Another challenge is that wind and PV are non-synchronous and therefore cannot provide synchronous inertia response (initial frequency response) and high fault feed-in currents to the system [3–5]. One of the operational practices to manage the low inertia issue is to impose a minimum synchronous generation (SG) requirement, also known as the system non-synchronous penetration (SNSP) which has been used in the Irish system [6–8]. However, there are questions over the suitable levels, and the cost associated with applying SG constraints [9]. Some studies have examined issues relating to minimum SG constraints but mainly from a technical and power system operational perspective [7,10–13].

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In order to integrate high levels of VRE into a power system, it is important that future generation portfolios have adequate flexibility to cope with frequent and sudden changes in generation arising from increased variability and uncertainty while maintaining system reliability [11,14]. There are a number of energy system modelling tools that can be used to address a wide range of question including the integration of renewable energy [15].

Although flexibility can be enhanced in the short-term through changes in operational practices and equipment modifications, it needs to be considered during planning stages [16]. In this regard, long-term generation planning and investment modelling needs to reasonably capture actual operating characteristics of generating plants and flexibility of future generation portfolios in responding to changes in net demand [17]. In addition, long-term generation planning models need to account for the costs associated with increased cycling and additional constraints in order to capture the value and incentivize flexibility capabilities of each generation option. Nevertheless, due to the associated complexities and the long planning horizon, traditional electricity industry planning models often rely on the use of Load Duration Curve (LDC) techniques, where operational chronology is removed for computational tractability. Hence, they generally ignore the actual details of electricity industry operation and key inter-temporal characteristics of generating plants such as minimum generation, maximum ramp rates, startup times and costs [18]. Neglecting these operation aspects may mean that generation portfolios selected by long-term planning models may not be operationally viable or economically efficient in practice, particularly at high penetration of variable renewables.

This paper examines the technical feasibility and economic impacts of electricity industry operational constraints on future generation portfolios obtained under long-term portfolio modelling, including high renewable penetrations. The study integrates the long-term generation portfolio modelling under future uncertainties developed in previous work, MC-ELECT [19], with detailed operational modelling in PLEXOS, a commercial power market modelling software tool [20] to solve a 30-min constrained generation dispatch. Using the Australian National Electricity Market (NEM) in 2030 as a case study, the modelling considers a range of generation portfolios with different renewable penetrations, carbon pricing possibilities and minimum SG requirements.

The paper is organised as follows. Section 2 provides an overview of the previously applied generation portfolio planning model and PLEXOS Model. Section 3 presents the methodology. Section 4 provides a description of the case study. Results and analysis are discussed in Section 5 followed by the conclusions.

2. Generation planning and dispatch models

Power system modelling can be categorised according to timeframes to suit different purposes. Long-term electricity planning models are used to determine optimal capacity expansion plan over multiple decades based on long-term supply and demand assumption. They provide a high-level overview of how the power system is evolving. Generally, long-term capacity expansion models have low temporal resolutions and do not account for details of power system operation as well as constraints on the supply and demand side [21]. On the other hand, dispatch simulation models, or often known as production cost models, simulate the operation of a power system, given a certain capacity mix, over a relative short period, typically one year but at high temporal resolution, typically sub-hourly. Production cost models determine the least cost dispatch of generating plants to meet demand in each period subject to a number of power system constraints.

There have been a number of previous studies which integrated long-term generation planning models with short-term constrained generation dispatch in order to capture the operational implications associated with VRE [2,18,21,22]. The most common approach is to interlink between long-term models and dispatch simulation models [21,23,24]. This method involves taking the generation portfolios obtained from long-term models and simulate the power system model with detailed inter-temporal operational aspect. Despite their valuable contributions, there remain some important aspects that require further consideration.

In this paper, a long-term generation portfolio planning model is integrated with a short-term dispatch simulation model. The main contribution of the paper is the way in which uncertainties are incorporated in the long-term planning model through the application of Monte Carlo simulation techniques. The efficient generation portfolios obtained under the novel long-term planning model are then passed through to the dispatch simulation model, enabling a set of efficient generation portfolios to be evaluated under the actual power system operation conditions. This approach allows a number of efficient generation portfolios to be compared rather that just considering just a single "optimal" generation portfolio that is typically obtained from deterministic long-term generation planning models.

2.1. Monte Carlo based generation portfolio modelling

A long-term generation portfolio investment and planning tool, 'MC-ELECT', developed in previous work, extends load duration curve (LDC) optimal generation mix techniques by using Monte Carlo simulation to incorporate key future uncertainties [19]. The expected costs, cost risks and CO_2 emissions of a range of generation portfolios in a given future year are obtained from several thousand scenarios with probabilistic input parameters. The outputs can be described as an 'expected' (average) future value of annual portfolio costs. For standard input probability distributions, the cost spread of a generation portfolio can be represented by the standard deviation and is referred to as 'cost risk'. Financial portfolio techniques are then used to determine an Efficient Frontier (EF) which contains optimal portfolios in terms of expected cost and associated cost risk [25]. MC-ELECT was employed to analyze future generation portfolios with different renewable penetrations in the Australian National Electricity Market (NEM) for 2030 [26]. Fig. 1 illustrates the previously calculated optimal generation portfolios for different renewable penetration levels, ranging from 15% to 85%. This result forms the basis of the case study presented in this paper. MC-ELECT has been applied to analyze a number of actual electricity industries [27–29].

The main limitation of MC-ELECT is that it relies on LDC, which removes operational chronology for economic dispatch, and hence

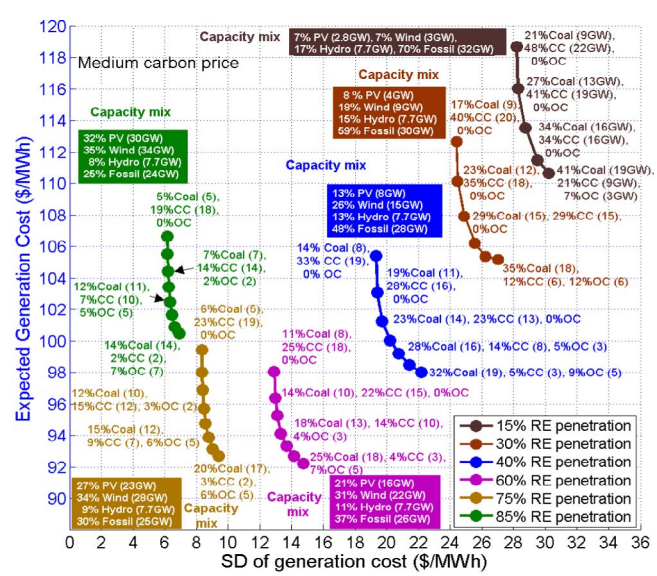

Fig. 1. Results from an Australian case study showing the efficient frontier of generation portfolios for different renewable penetrations in 2030 [26].

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