Incorporating short-term operational plant constraints into assessments of future electricity generation portfolios

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ABSTRACT

This paper presents a post-processing extension to a Monte-Carlo based generation planning tool in order to assess the short-term operational implications of different possible future generation portfolios. This extension involves running promising portfolios through a year of economic dispatch at 30 minute intervals whilst considering operational constraints and associated costs including minimum operating levels, ramp rate constraints and generator start-up costs. A case study of a power system with coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT) and wind generation options highlights that incorporating operational criteria into the long-term generation investment and planning analysis can have operating, economic and emissions implications for the different generation portfolios. The extent of the impacts depends on the dispatch strategies; the carbon price; and the mix of technologies within the portfolio. As intermittent generation within power systems increases and carbon pricing begins to change the merit order, such short-term operational considerations will become more significant for generation investment frameworks.

Keywords: Monte Carlo simulation, generation planning, portfolio analysis, generation dispatch, operational constraints

1. Introduction

Decision making in generation investment and planning requires a long-term perspective amidst considerable uncertainties including expected future demand, fuel prices, plant construction costs, and wider policy settings such as carbon pricing or energy security concerns. Given its complexity and long planning horizon, most long-term generation investment and planning frameworks often do not consider the actual details of short-term electricity industry operation such as generating unit constraints and inter-temporal generation dispatch [1]. Many of such frameworks are based on the use of a Load Duration Curve (LDC), which is a simplified representation of demand profile, to determine a future optimal generation technology mix. While LDC based approaches are useful and straightforward to apply, they generally involve significant assumptions. An example is the incorporation of uncertainty into the analysis. Another limitation, and the focus of this paper, is that the use of a LDC removes information regarding the chronology (sequencing over time) of electricity industry operation. Effectively, the generation portfolio is dispatched to meet this demand curve from highest to lowest without any consideration of actual changes in demand over time and its potential implications for the physical operation of the generation. In reality, however, many generation technologies have significant inter-temporal operating constraints such as minimum operating levels, ramp rates, and start-up and shutdown times. There can also be significant operating costs associated with some inter-temporal operating decisions such as unit commitment (plant start-up).

The growing deployment of intermittent renewable generation sources, particularly wind and solar, increases the complexity of electricity industry operation including generation dispatch and scheduling [2], transmission grid operation and development [3] and ancillary services requirements [4]. Although renewables can hedge against the risk of fossil-fuel price volatility and reduce CO_2 emissions, they potentially pose significant operational challenges for conventional generating plants in the portfolio given their outputs are highly variable and somewhat unpredictable [5-7]. Conventional generating units may be required to ramp up/down and start/stop more frequently to accommodate the combined net variability of demand and renewable generation output, making the distribution of operating reserves and generation scheduling particularly important [8]. These changes are also likely to result in increased operating and maintenance costs.

With growing concerns regarding demand growth, climate change, and fossil-fuel price volatility, generation planning and investment methods have moved beyond just determining the least-cost generation mix to incorporate multiple objectives including cost-related risks, energy security, environmental impacts and social welfare [9, 10]. In addition, uncertainties over critical cost factors including fossil price, climate change policies and plant investment costs have, to some extent, been taken into account in long-term generation planning and investment frameworks [11, 12]. Generation portfolio planning frameworks are increasingly being applied in studies for analysing future generation investment and production scheduling from the perspective of both centralized electric utilities and individual power generation companies [13-15]. Mean Variance Portfolio (MVP) techniques have been widely employed to determine optimal future generation portfolio mixes with different cost and risk tradeoffs [16, 17]. Such techniques have also been used to examine the role of non- fossil fuel generation technologies, such as nuclear and wind, in hedging against price risk due to uncertainties in future electricity prices, fossil-fuel prices and climate change policies [6, 18]. Nevertheless, in a similar manner to many long-term planning frameworks, operational issues including unit constraints and inter-temporal generation dispatch are often overlooked in standard portfolio planning approaches [1]. Unfortunately these demand, energy security, and climate change concerns also have some significant implications for short-term electricity industry operation.

For these reasons there is growing value in incorporating potential operational and economic implications associated with the chronology of electricity industry operation into long-term generation investment and planning frameworks. Ignoring these aspects may lead to an inaccurate estimation of generation costs and emissions of generation portfolio options. Furthermore, some generation portfolios that appear attractive under standard long-term investment analysis might actually have questionable operational viability for expected demand patterns due to high levels of intermittent inflexible plant. A better understanding of short-term operational implications can help policy decision makers to identify appropriate options that can enhance the flexibility[1] of the electric system in order to accommodate high levels of renewable generation. This can be achieved through combinations of storage technologies, demand side options, expansion of transmission system infrastructure including smart grids, ancillary services and more sophisticated generation dispatch and unit commitment [19-21].

In previous work, a novel generation investment decision support modelling tool based on probabilistic generation portfolio analysis was presented for assessing future electricity generation portfolios under uncertainties [7, 22]. The tool combines Monte Carlo extensions to traditional deterministic LDC techniques with portfolio assessment methods that include calculating the efficient frontier containing optimal generation portfolios. Despite the capability of the tool in addressing uncertainties associated with long-term

[1] Flexibility implies the ability of a power system to withstand sudden and rapid changes in supply and demand in a reliable manner.

generation investment and planning, there are inherent limitations in the tool's ability to incorporate issues related with short-term electricity industry operation.

This study proposes a new method for addressing this limitation. In particular, a 'post-processing' extension to the existing generation investment tool is implemented to incorporate generating unit constraints and inter-temporal generation dispatch. The post-processing extension is then applied to a case study using the data from the Australian National Electricity Market (NEM) in order to demonstrate the capability of this extension method. Case study findings and results are then used to provide a high-level assessment of the potential impacts of short-term operational aspects on the technical viability, economics and emissions of generation portfolios that appear favorable from the initial generation portfolio investment and planning framework. Note that not all operational issues associated with the electricity industry are incorporated as this represents an extremely challenging computational task. The post-processing assessment includes indices of possible violations of operating constraints such as number of starts/stops, ramp rates, the economic and emissions implications of different dispatch strategies around minimum plant operating levels.

There are some studies which incorporate operational aspects into generation portfolio planning frameworks. These aspects include generating unit characteristics and constraints as well as actual dispatch decisions to account for the variability of wind power and ramp limits of conventional plants [1, 23]. For the conventional LDC optimal mix approaches, some of the operational aspects have also been incorporated into the analysis [24]. Nevertheless, these approaches, to date, have not generally included issues associated with cycling operation including starting and stopping of generating units as well as their associated costs.

This paper is organized as follows. Section 2 describes the Monte Carlo-based decision support tool including an example. The methodology for our post-processing extension is detailed in Section 3. Section 4 presents a case study. Results of the case study and its implications are discussed in Section 5 while Section 6 provides some concluding remarks.

2. Monte Carlo based decision support tool for generation investment and planning

The generation investment and planning decision support tool implemented in our previous work assesses the costs of possible future electricity generation portfolios given uncertain fuel prices, carbon prices, plant capital costs, and electricity demand. The tool extends conventional LDC methods by incorporating potentially correlated uncertainties for key cost assumptions and future demand using Monte Carlo Simulation (MCS). The expected costs, cost uncertainties and CO_2 emissions of a range of potential new-build generation portfolios in a given future year are directly obtained from several thousand scenarios with probabilistic input parameters. The cost spread for a generation portfolio can, for some distributions, be represented by variance and is referred to as 'cost uncertainty'. In our usage this carries a similar meaning to 'risk' in the economic and finance contexts. The tool applies financial portfolio analysis techniques to determine an efficient frontier containing optimal generation portfolios given possible tradeoffs between expected (average) cost and its associated cost uncertainty. The tool is not restricted to the use of normal distributions to model uncertainties therefore other forms of risk-weighted uncertainty measures and criteria beyond variance can also be applied [25].

Results from a previous case study of an electricity industry with coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), and wind generation supply options are used to demonstrate use of the tool [7]. Wind generation in the portfolios is assumed to be dispatched when available, and is therefore treated as negative demand. Because of the inherent time varying nature of wind generation, actual or simulated half-hourly wind generation estimates are subtracted from electricity demand to obtain a residual demand and then rearrange to get a residual LDC (RLDC) [26]. This RLDC is then served by thermal technologies in the portfolios.[2]

The expected yearly generation cost and cost uncertainty of different thermal generation portfolios obtained from the previous case study are shown in Fig. 1. An efficient frontier containing the estimated 'optimal' generation portfolios (labeled *A* - *E*) is represented by a solid line. Along the frontier, the expected cost cannot be reduced without increasing cost uncertainty and vice versa. This result is also the basis of the case study presented later in Section 4.

[2] Other emerging disruptive technologies including solar PV, electric vehicles (EV) and storage options can also be incorporated into the tool in a similar manner that wind was considered, which is through the modification of demand profiles and hence load duration curve. These technologies, however, are not considered in this paper given the main purpose of this paper is to demonstrate a post-processing technique for incorporating the potential impacts of short-term operational factors.

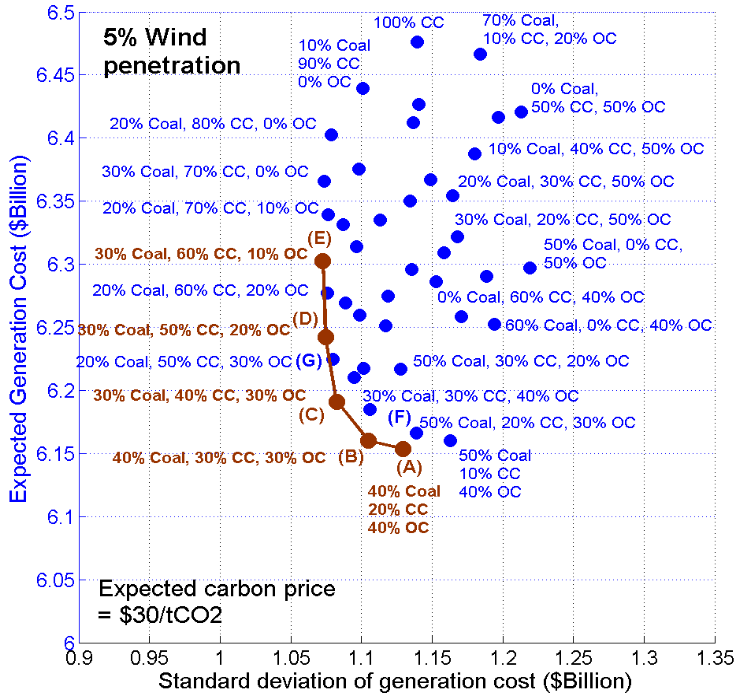


Fig. 1. Results from the tool showing the expected cost, associated cost uncertainty and CO_2 emissions of generation portfolios for a previously reported case study applying the tool [7].

Although the approach for incorporating wind generation into the portfolios captures the chronology of wind with respect to demand, the chronology of dispatch of the thermal plants to meet this residual demand was ignored. The main reason that operating aspects are not incorporated within the MCS process is due to potentially enormous computational task. This limitation is now addressed in this paper through a post-processing extension that is described in the next section.

3. Post-processing extension to the Monte Carlo based decision support tool

In this extension approach, the generation portfolios are taken from the initial MCS analysis and then run each through a year of sequential half-hourly economic dispatch to meet residual demand (demand net of intermittent generation). Conventional generating units in the different portfolios being assessed are dispatched to meet the residual demand in each 30-minute period over the year. A range of operating constraints for the different technologies is incorporated to assess their potential operating, economic and emissions implications for different generation portfolios. Note that uncertainties and hence the MCS are not incorporated in this post-processing extension given these have already been accounted for in the initial probabilistic portfolio analysis framework. Hence, the expected capital cost, demand, fuel and carbon prices are used for this single simulated year of economic dispatch. The results are then incorporated back into the tool as will be explained later. Unconstrained dispatch where the generators have no ramp rates, minimum operating levels or start-up and shut down costs results in the same annual industry cost estimation as emerges from the standard generation portfolio analysis. However, the dispatch is rerun by imposing the operating constraints and associated dispatch strategies (in particular, start-up/shutdown criteria for the different generation technologies as demand changes), to determine possible operating constraint violations of particular generating technologies and associated economic and environmental impacts. These operational constraints include minimum generation level and criteria to start-up/shutdown generating units during dispatch intervals.

Some key operating implications of constrained dispatch for different generation portfolios are measured by counting the number of start-ups, ramp-rate violations, and overall capacity factor of each generation technology within a portfolio over the year of simulated operation. Economic implications includes the impact on overall industry costs and hence, potentially, the efficient frontier of optimal generation portfolios due to additional start-up costs and increased running costs associated with imposing operating constraints. Emissions implications for our work are based on changes in the overall annual CO_2 emissions of the different portfolios.

The post-processing analysis in this paper is not intended to solve detailed economic dispatch, unit commitment and production scheduling. Minimum start-up/shutdown times and ramp rate constraints are not imposed but the implications of these constraints can still be assessed, at least in part, based on how often these constraints are violated by the simulated yearly dispatch. All generating units are assumed to be always available. Losses and network constraints are also ignored.

Table 1
Parameters of the post-processing extension model

Parameters	
I	number of generating units in a portfolio
i	index of generating units
T	number of dispatch period in a year
t	index of dispatch periods
N	number of technology types
n	index of technology types
F	number of fuel types
f	index of fuel types
$P_{i,t}$	output of generating unit *i* in dispatch period *t* (MW)
$\nu_{i,t}$	on-off decision variable indicating whether unit *i* is online or offline in dispatch period *t*
$P_i^{\min}$	minimum generation output of generating unit *i* (MW).
$P_i^{\max}$	maximum generation output of generating unit *i* (MW).
TOC	total operating cost ($)
TRC	total running cost ($)
TSC	total startup cost ($)
VC_i	variable operating cost of generating unit *i* ($/MWh)
$S_{i,t}^{fuel}$	startup fuel cost ($) for generating unit *i* in dispatch period *t*
$S_{i,t}^{carbon}$	startup carbon cost ($) for generating unit *i* in dispatch period *t*
$S_{i,t}^{other}$	other startup cost ($) include increased O&M and forced outages, unit life shortening, increased unit heat rate and startup manpower for generating unit *i* in dispatch period *t*
F_f^{start}	amount of fuel *f* used during the startup of generating unit (GJ)
F_f^{price}	price of fuel *f* ($/GJ)
CO_2^{price}	carbon price ($/t$CO_2$)
$CO_{2\,i,t}^{start}$	amount of CO_2 emissions (tCO_2) during a startup of generating unit *i* in dispatch period *t*
$CO_{2\,i,t}^{running}$	amount of CO_2 emissions (tCO_2) during the operation of generating unit *i* in dispatch period *t*

3.1. Central economic dispatch objective and constraints

The generation output of each unit in the portfolio in each 30-minute dispatch period is determined based on a constrained central economic dispatch which also considers the chronology. The objective function of the dispatch is to determine outputs of generation units which minimize total operating costs in each dispatch interval subject to generating unit and demand balancing constraints as shown in Eq. (1) – Eq. (4).

$$Minimize \quad \sum_{i=1}^{I} VC_i . P_{i,t} . \nu_{i,t} \tag{1}$$

$$\nu_{i,t} = \{0,1\} \tag{2}$$

where VC_i is the variable operating cost of generating unit i (\$/MWh), $P_{i,t}$ is the output of generating unit i at period t (MW), I is the number of generation units and $v_{i,t}$ is on-off decision variable indicating whether unit i is online or offline in period t.

$$\sum_{i=1}^{I} v_{i,t} P_{i,t} = D_t \tag{3}$$

$$P_i^{\min} \leq P_{i,t} \leq P_i^{\max} \tag{4}$$

where D_t is the demand in dispatch period t (MW), P_i^{min} and P_i^{max} are the minimum generation and maximum output of generating unit i respectively.

Analysis is undertaken for two dispatch models with different start-up/shutdown criteria for generating units. These models represent two general approaches to minimum operating levels: 1) dispatch to keep all large thermal plant on-line by sharing loading reductions; and 2) dispatch to keep the lowest operating cost plants operating at highest possible outputs. These two dispatch models are referred as *Min Start/Stop* and *Max Low-Cost Gen* and are further explained in Section 3.1.1 and 3.1.2. The main assumption for both dispatch models is that every individual generating unit of the same technology type has the same operating and cost characteristics. Therefore, generating units of the same technology type are dispatched to generate equally when they are online as well as sharing the start-ups/shutdowns.

3.1.1. *Min Start/Stop* dispatch model

This dispatch model attempts to avoid the start-up/shutdown of generating units. Generating units of the lowest operating cost technology are dispatched at part-load to allow other generating units to remain on line although they are less economical to run. Start-ups and shutdowns only occur when the online generators cannot increase or reduce their output any further to satisfy demand in that period.

3.1.2. *Max Low-Cost Gen* dispatch model

This dispatch model attempts to avoid the start-up/shutdown generating units but subject to a condition that the lowest operating cost generating units have to operate close to their maximum capacity. The shutdown only occurs when online units cannot reduce their output any further without having to reduce the output of lowest operating cost generating units.

The main tradeoff between these dispatch models is between start-up costs and running costs. *Min Start/Stop* dispatch model saves on start-up costs but incurs higher running costs *Max Low-Cost Gen* dispatch model, on the other hand, incur higher start-up costs but saves on running costs since the lowest operating cost units are dispatched near their maximum capacity. Such tradeoffs between the dispatch models are analyzed in Section 5. The dispatch criteria of peaking plants such as OCGT units are the same for both dispatch models. OCGT units are dispatched only when coal and CCGT units have already generated at their maximum capacity (assuming that OCGT has the most expensive running costs of the plants which is valid for our assumed coal, gas and carbon prices). In practice, generation dispatch would likely fall somewhere between these two dispatch models. There are periods of low demand when it would be more economical to decommit high running cost units, and periods where low demand is likely to be short-lived, and hence it would be best to keep these units committed. As such, our two dispatch models provide a basis for comparing the extremes of these two general dispatch approaches among generation portfolios. Note also that actual generation dispatch and scheduling are far more complex than we model here as there are numerous additional factors and criteria that need to be considered such as reserve capacity, network constraints, maintenance schedules of generating plants and transmission networks, and forecasted demand.

For each generation portfolio, the number of generating unit for each technology type is determined from Eq. (5).

$$Number\,of\,unit_n = \frac{Installed\ capacity_n}{Unit\ size_n} \tag{5}$$

3.2. Operating costs and CO_2 emissions calculations

Total operating costs of each generation portfolio in a year consist of running costs and start-up costs as expressed in Eq. (6).

$$TOC\,(\$) = TRC + TSC \tag{6}$$

where TRC and TSC are the total running cost ($) and total start-up cost ($) of the generating portfolio in a year.

The total running costs of each generation portfolio is determined based on Eq. (7).

$$TRC = \sum_{t=1}^{T}\sum_{i=1}^{I} VC_i . P_{i,t} \tag{7}$$

where VC_i is the variable operating cost of generating unit i ($/MWh), $P_{i,t}$ is the output of generating unit i in the portfolio at period t (MW), I is the number of generating units in the portfolio and T is the number of dispatch period in a year.

The variable costs consist of variable operating & maintenance (O&M), fuel, and any carbon costs. Total start-up costs of each generation portfolio during a year consist of start-up fuel cost and start-up carbon cost of generating units in the portfolio, as expressed in Eq. (8).

$$TSC_{i,t} = \sum_{t=1}^{T}\sum_{i=1}^{I}(S_{i,t}^{fuel} + S_{i,t}^{carbon} + S_{i,t}^{others}) \tag{8}$$

where $S_{i,t}^{fuel}$, $S_{i,t}^{carbon}$, $S_{i,t}^{others}$ are the start-up fuel cost, start-up carbon cost and other associated costs during start-up of generating unit *i* in the portfolio at period *t* respectively.

Other potential costs associated with the start-up of generating units include increased O&M, increased forced outages, unit life shortening, increased unit heat rate, and start-up manpower [27]. The start-up fuel and carbon costs of generating unit *i* in period *t* are calculated from Eq. (9) – Eq. (10).

$$S_{i,t}^{fuel} = F_f^{start} \times F_f^{price} \tag{9}$$

$$S_{i,t}^{carbon} = CO_{2_i}^{start} \times CO_2^{price} \tag{10}$$

where F_f^{start} is the amount of fuel *f* used during the start-up of generating unit (GJ), F_f^{price} is the price of fuel *f*, $CO_{2_i}^{start}$ is the CO_2 emissions of generating unit *i* during start-up (tCO_2) and CO_2^{price} is the carbon price ($\$/tCO_2$).

CO_2 emissions of each portfolio is determined from Eq. (11).

$$total\ CO_2 = \sum_{t=1}^{T}\sum_{i=1}^{I}(CO_{2_{i,t}}^{running} + CO_{2_{i,t}}^{start}) \tag{11}$$

where $CO_{2_{i,t}}^{running}$ and $CO_{2_i}^{start}$ are the amount CO_2 emissions (tCO_2) during the operation and a start-up of generation unit *i* in dispatch period *t* respectively.

Finally, the ratio of the cost difference between the constrained and unconstrained dispatch is applied to adjust the expected costs of each generation portfolio and the efficient frontier obtained from the MCS portfolio based decision tool.

4. Description of the case study

The case study considers an electricity industry with coal, CCGT, OCGT and wind generation options based on that used in [7]. The data for this study including demand and wind generation, thermal plant operating characteristics and various cost parameters are based primarily on actual demand and wind generation data from South Eastern Australia, and a number of Australian specific consultancies studies. An example of a case study with a fixed wind penetration of 5% and a carbon price of $\$30/tCO_2$ is used to demonstrate the post-processing extension to the tool. The level of wind penetration is fixed at 5% to reflect the actual current level of wind penetration in this area. All monetary values are shown as Australian dollars. The potential shares of coal, CCGT and OCGT are varied from 0% to 100% in 10% increments resulting in 66 possible thermal generation portfolios.

4.1. Demand profile and the installed generation capacity

The actual combined demand and wind generation in 30-minute intervals recorded for the states of South Australia (SA), Victoria (VIC), and Tasmania (TAS) in Australia, in 2009 was used for the simulation. The 30-minute total demand and wind generation are shown in Fig. 2. The residual demand that is to be met by conventional generators is obtained by subtracting wind generation from the total demand.

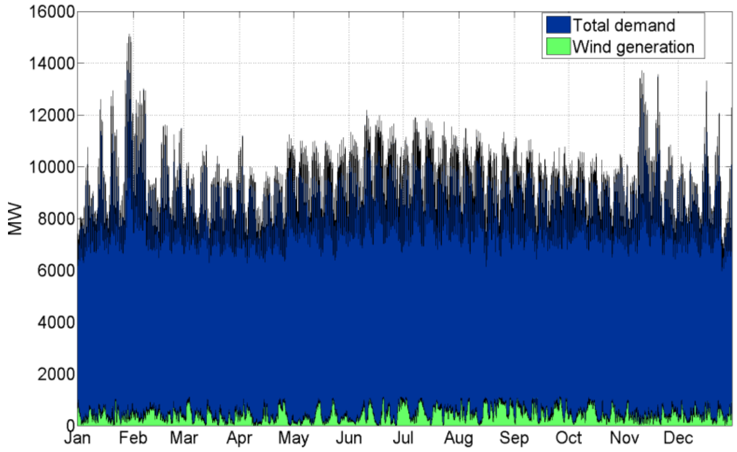


Fig. 2. 30-minute demand and wind generation in South Eastern Australia.

Based on the probabilistic approach for meeting expected demand shown in [7], the installed fossil-fuel generation capacity is 15.6 GW for 5% wind penetration. The numbers of units for each technology in the portfolio are determined from Eq. (5), and presented in Table 2 for different shares in the overall portfolio in 10% increments. Generation unit sizes for each technology are shown in Table 3.

Table 2
Number of generating units of each technology for different shares in the portfolio

Share of technology in portfolio (%)	Number of units Coal	CCGT	OCGT
10	2	3	10
20	5	6	20
30	8	9	31
40	10	13	41
50	13	16	52
60	16	19	62
70	19	22	73
80	21	26	83
90	24	29	93
100	27	32	104

4.2. Operating characteristics of generating units

The operating characteristics and cost parameters of each thermal generation technology used in the simulation are estimated from a number of consultancy studies for the Australia National Electricity Market [28, 29]. The amount of fuel used during a start-up are estimated based an assumption of hot start conditions where generating unit has been offline between 0-6 hours [30]. Other than fuel and carbon costs, there are other potential costs associated with starting up generating units including increased O&M, forced outages, unit heat rate, and manpower [27]. These costs are estimated to be 5 times, 3 times, and twice of start-up fuel costs for coal, CCGT and OCGT plants respectively [30, 31]. Table 3 shows the operating and cost parameters of each technology considered in the portfolios.

Table 3
Operating characteristics of each technology.

Characteristics	Coal	CCGT	OCGT
Unit size (MW)	600	500	150
Minimum generation (MW)	300	200	0
Ramp rate (MW/hour)	480	720	600
Fuel used during start-up (GJ)	2,500	1,500	200
Start-up fuel cost ($/start)	50,000	7,850	1,040
Full start-up costs ($/start)	250,000	23,550	2,080
CO_2 emissions during start-up (tCO_2)	187.5	90	12

The fuel used for starting up coal plants is typically diesel or fuel oil therefore the start-up fuel cost for coal plants is determined based on the price of diesel excluding excise. Fuel prices used for the simulation are estimated based on [28]. The greenhouse emissions intensity of each fuel type is calculated from [32, 33]. These values are shown in Table 4.

Table 4
Price and emissions intensity of each fuel type.

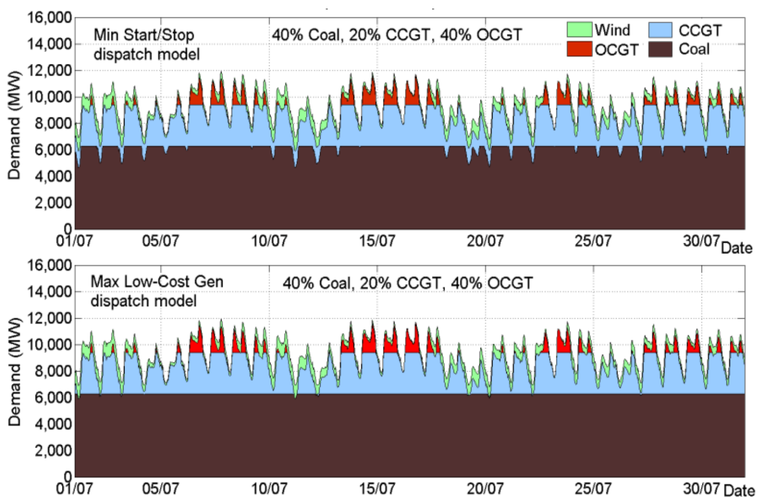
Fuel	Price ($/GJ)	Emission intensity (tCO_2/GJ)
Coal	0.6	0.09
Natural gas	5.22	0.06
Diesel oil	20	0.075

5. Simulation results and analysis

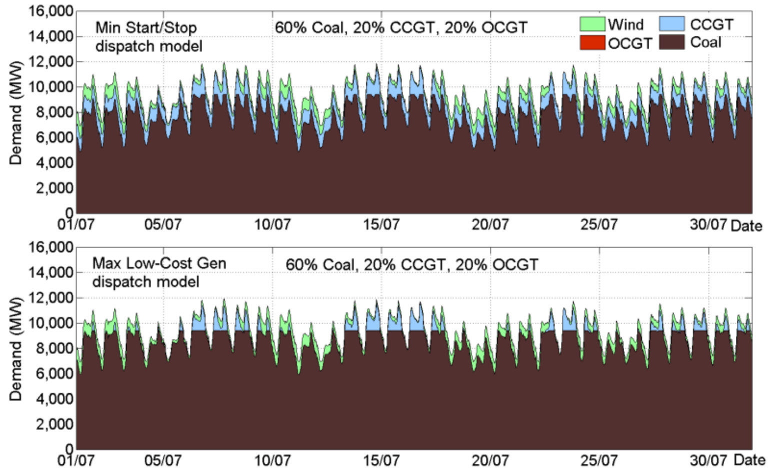
Generation outputs in 30-minute interval of each generating unit for both dispatch models are determined for each generation portfolio during the year. The operating, economic and emissions implications of incorporating operation aspects are demonstrated for generation portfolios on or near the efficient frontier given they represent the ‘first pass’ optimal portfolios. The impact on the efficient frontier is also assessed.

5.1. Implications of incorporating short-term operational aspect

Results from the generation dispatch for both dispatch models are illustrated in Fig. 3 showing examples of generation portfolios during a typical month of the year.[3]



(a)



(b)

Fig. 3. Generation patterns of each technology for one month of the year of two generation portfolios: (a) 40% coal, 20% CCGT, 40% OCGT and (b) 60% coal, 20% CCGT, 20% OCGT for both dispatch models.

For the moderate carbon price of \$30/tCO_2 assumed, coal plants still have the lowest operating costs, and therefore are dispatched to provide base-load generation while CCGT units are considered to be the intermediate load following plants. The OCGT units are only operated during the high demand periods when coal and CCGT are at maximum output. The generation patterns of each technology depend considerably on the mix of generation technologies in the portfolio. Generally, the base-load generating units in *Min Start/Stop*

[3] Simulation results consist of 30-minute generation dispatch for every generation portfolio for an entire year. Fig. 3 is just an example to illustrate the difference in generation patterns between the two dispatch models over a particular month (in this case July).

dispatch model are required to alter their outputs more frequently compared to *Max Low-Cost Gen* dispatch model in order to avoid shutting down other online generating units although they are less economical to run. As one would expect, these different generation patterns subsequently influence the cycling of generating units, the number of start-ups/shutdowns, operating costs, and emissions of the generation portfolios.

5.1.1. Operational implications

For both dispatch models, the average numbers of start-ups of generating units for the considered generation portfolios is shown in Fig. 4. Since CCGT units are considered to be the system marginal generators, they would incur more frequent start-up/shutdown than the base-load coal units, especially for *Max Low-Cost Gen* dispatch model. Among the candidate generation portfolios, coal plants do not incur any start-up/shutdown in either dispatch models since all the coal units can still operate above their minimum operating level even during low-demand periods. However, for portfolios with a large share of coal (60% and greater) such as portfolio *F*, the base-load coal units are required to vary their outputs more often to follow the demand pattern. The OCGT units are not often required to start-up since they are rarely dispatched. For *Min Start/Stop* dispatch model, CCGT units of each portfolio are rarely shutdown (and hence start-up) since any coal or CCGT units can still operate above their minimum operating levels in all periods.

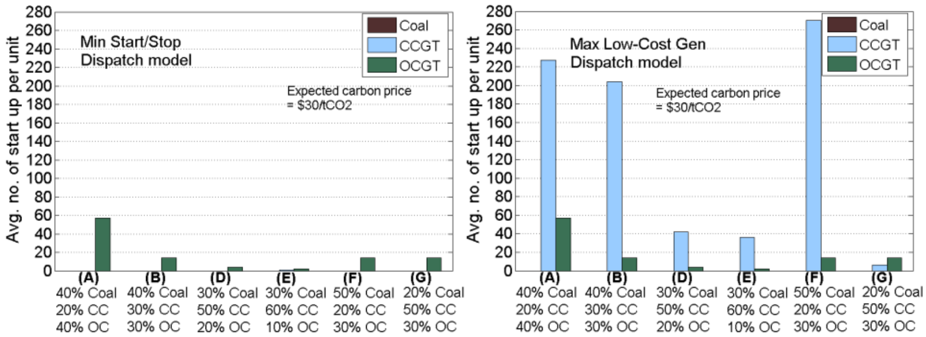


Fig. 4. Average number of start-ups for each generating unit within the different portfolios for both dispatch models.

For *Max Low-Cost Gen* dispatch model, CCGT units generally incur far more frequent start-ups since this dispatch model attempts to operate the base-load coal units near their maximum capacity as possible by shutting down CCGT units. Portfolio *A* (40% coal, 20% CCGT, 40% OCGT) has the highest number of average start-ups per unit for CCGT - around 220 starts per year. For portfolios with none or small shares of coal such as portfolios *C*, *D* and *E*, CCGT units are rarely required to start-up/shutdown since all the base-load coal units in these portfolios are always operated at their maximum capacity.

Recall that *Max Low-Cost Gen* dispatch model attempts to avoid start-up/shutdown once the lowest cost base-load units are operated near their maximum capacity.

The capacity factors of each generation technology for the six candidate portfolios are shown in Fig. 5. For both dispatch models, coal plants in every portfolio have very high capacity factors corresponding to their role as base-load generation. The capacity factors of CCGT are between 30-80% for *Min Start/Stop* dispatch model and between 10-80% for *Max Low-Cost Gen* dispatch model. For portfolios *C*, *D* and *E*, which have none or small shares of coal, the capacity factor of each technology are almost the same for both dispatch models for the same reason as explained above for the number of start-ups. The capacity factors of coal plants in *Max Low-Cost Gen* dispatch are generally higher than those of *Min Start/Stop* dispatch model. This is because the base-load coal units in *Min Start/Stop* dispatch model are often operated at part-load in order to permit CCGT units to remain online. On the other hand, the capacity factors of CCGT in *Min Start/Stop* dispatch model are generally higher than those in *Max Low-Cost Gen* dispatch model.

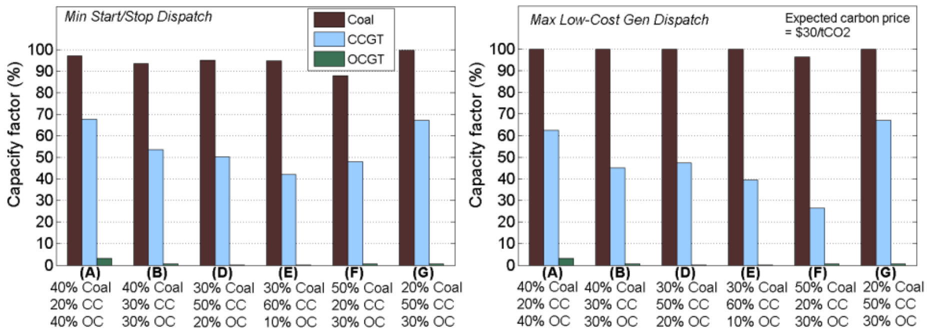


Fig. 5. Capacity factors for each technology for both dispatch models.

With regard to ramping requirements, none of the generation portfolios was unable to meet the maximum ramps (residual load changes over half an hour) for the simulated year of operation. This is because all the portfolios have sufficient fast response gas generation plants. Based on the operating patterns of generating units for each of the candidate generation portfolios, there appear to be no major concerns regarding the operational viability of any of the generation portfolios for either dispatch model. The highest number of start-up of CCGT units among the portfolios is about 220 times for the year. This number is still within the range of the more recent CCGT units of around 250 starts per year, which is expected to increase to over 350 starts in the near future given technology advances [34]. The results also highlight that, other than the dispatch model, the frequency of start-ups and the capacity factor of each technology depend on the mix of generation technologies in the portfolios.

5.1.2. Economic implications

This section assesses the potential economic impacts of imposing these operating constraints on the candidate generation portfolios. The economic tradeoffs between the two dispatch models are also examined. The estimated 'full' start-up costs of a thermal generating unit consist of fuel, carbon and other potential costs as indicated in Section 4.

Fig. 6 shows the total operating costs of the candidate portfolios for the two dispatch models for the case of 'full' start-up costs. The total operating cost is categorized into running cost and start-up cost. The difference in the operating costs between the constrained and unconstrained dispatch are also shown on the secondary vertical axis of the graph. Generally, for both dispatch models, incorporating short-term operating aspect increases the overall generation costs of portfolios due to increased running costs as well as additional start-up costs. However, for portfolios with relatively small shares of coal (i.e. 20%) the cost increases are very small. This is due largely to two factors. First, the infrequent start-ups of generating units in these portfolios which results in minimal start-up costs. Second, coal units in these portfolios are always dispatched near their maximum capacity in both constrained and unconstrained dispatch; hence the differences in the running costs between these dispatch cases are very small.

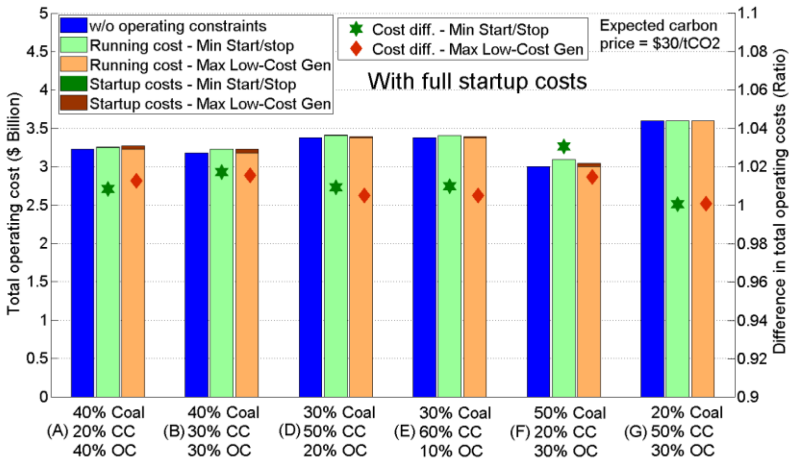


Fig. 6. Total operating costs of generation portfolios and the difference in the operating costs between the constrained and unconstrained dispatch for both dispatch models for the case of estimated full start-up costs.

There are tradeoffs between the two dispatch models in terms of running costs and start-up costs components in the total operating costs. Fig. 6 also shows that, in general, the total operating costs of *Min Start/Stop* dispatch model are higher than those of *Max Low-Cost Gen* dispatch model. This is due to the high running costs of *Min Start/Stop* dispatch model as a result of the part load operation of the coal units. The proportion of start-up costs is still very small, representing less than 2% of total operating costs. Generally, *Min Start/Stop* dispatch model incurs higher running costs as a result of the part load operation of the coal units to permit higher operating cost CCGT units to remain online. *Max Low-Cost Gen* dispatch model, on the other hand, would lead to higher start-up costs, particular for portfolios which incur high number of start-ups such as portfolio A (40% coal, 20% CCGT, 40% OCGT) and F (50% coal, 20% CCGT, 30% OCGT). Furthermore, there are tradeoffs between generation costs and emissions for each dispatch model as will be discussed later in the paper.

The difference (ratio) in the total operating costs between constrained and unconstrained dispatch, as shown in Fig. 6, is used to adjust the overall expected generation costs of generation portfolios obtained from the MCS decision support tool, which was introduced in our previous works. Fig. 7 compares the expected generation costs and cost uncertainty of generation portfolios between the cases with and without incorporating the operating constraints for both dispatch models. Note that the cost uncertainty of each portfolio, which represented by the standard deviation, is unchanged since this study does not consider additional uncertainties associated with short-term operation. Hence the expected generation cost of each portfolio for the three cases are vertically aligned as shown by the dash lines. The original efficient frontier without the operating constraints is compared with the modified efficient frontiers for each dispatch model.

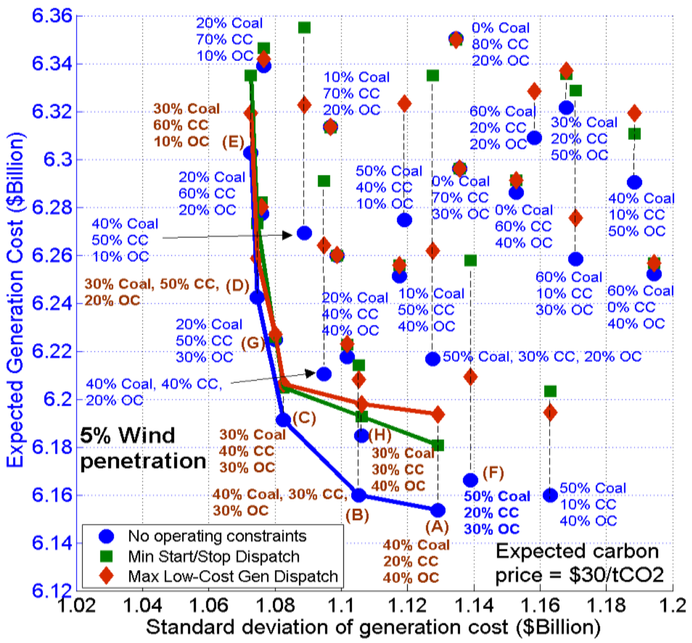


Fig. 7. Efficient frontiers after incorporating the operating constraints.

Incorporating the operating constraints generally increases the overall industry generation costs of portfolios for both dispatch models as shown previously. However, the extent of the cost impacts varies according to the generation portfolio. As a result such cost impacts affect the relative cost-risk profiles of generation portfolios and the efficient frontier. As shown in Fig. 7, portfolio *B* (40% Coal, 30% CCGT, 30% OCGT) is replaced by portfolio *H* (30% Coal, 30% CCGT, 40% OCGT) on the efficient frontier since the cost increase of portfolio *B* is relatively higher than other portfolios on or near the efficient frontier when operating constraints are included.

Whilst the economic impacts of considering operating constraints are relatively limited for this case study, they do have an impact on which portfolios lie on the efficient frontier. Neglecting these constraints in the long-term portfolio investment and planning framework, therefore, may impact selection of the most appropriate portfolio in some cases.

5.1.3. CO_2 emissions implications

The impacts of incorporating the operating constraints on the CO_2 emissions of generation portfolios are shown in Fig. 8 for both dispatch models.

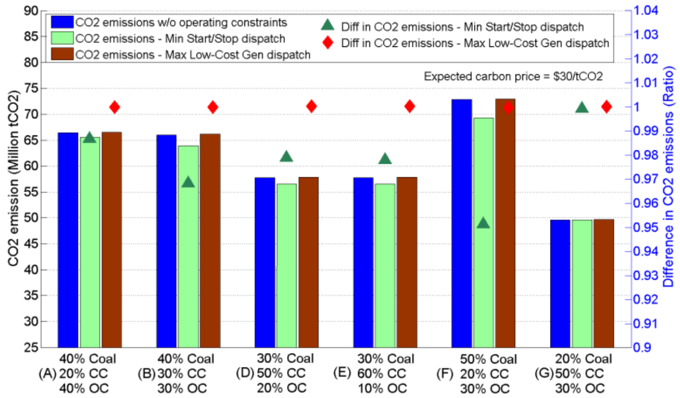


Fig. 8. Total CO_2 emissions of generation portfolios for both dispatch.

Incorporating the operational aspects resulted in emissions reductions for *Min Start/Stop* dispatch, particularly for portfolios with large shares of coal such as portfolio *F*. This is because high emitting coal plants are dispatched at lower load factors under this dispatch in order that the CCGT units, which have lower emissions intensity, remain on-line. Again, for portfolios with small shares of coal such as portfolio *G*, the differences in the CO_2 emissions between constrained and unconstrained dispatch are negligible for the same reasons as previously discussed. For *Max Low-Cost Gen* dispatch model, it appears that the CO_2 emissions of the portfolios are about the same with the unconstrained dispatch case given that coal plants are operated near their maximum capacity, which is also the case in the unconstrained dispatch.

The results show that *Min Start/Stop* dispatch model represents a more appropriate option for reducing overall emissions in this particular case study. However, as has been previously shown, the total operating costs of *Min Start/Stop* dispatch model can be higher.

Hence, there are tradeoffs between CO_2 emissions and generation costs of portfolios for both dispatch models.

5.2. Sensitivity analysis for different expected carbon prices

In power system and electricity market operation, sensitivity analysis is seeing increasing use. Sensitivity factors relating to power system operation include, for example, losses, voltage, generator constraint shift factors and area-based constraint shift factors [35]. On the other hand, sensitivity factors relating with the electricity market are those which have economic impacts on generation technologies such as financing costs, fuel prices, climate policies such as carbon pricing. Sensitivity analysis in this paper focuses particularly on carbon pricing given there is high uncertainty surrounding carbon pricing policies in many countries and the level of future carbon price likely to be required to deliver effective action on climate change.

Carbon pricing affects the operating costs of generating plants and the relative competitiveness of high-emission technologies such as coal-fired generators. An increase in carbon price may, therefore, result in a change in the merit order dispatch and subsequent dispatch pattern of generation portfolios. Hence carbon pricing is seen as one of the essential measures in curbing emissions in the electricity sector [36].

The generation dispatch and the operating pattern of generating units in each portfolio do not change with varying carbon price until a certain carbon price is reached which results in a change in the merit order between coal and CCGT generating plants. For this case study, a change in merit order takes place a carbon price of \$60/tCO_2. From this carbon price and above, CCGT units are dispatched as base-load generators while coal units are operated as intermediate-load generators. This results in frequent output changes including starts/stops. Coal units have high start-up costs and are relatively inflexible due to their typically low ramp rates and high minimum operating levels. Therefore, for a high carbon price, the operational and economic implications associated with the inclusion of the short-term operating constraints may be quite significant.

Under these circumstances the *Min Start/Stop* dispatch model does not present major operational implications since coal units are kept online most of the time by reducing the output of base-load CCGT units. Furthermore, the base-load CCGT units are quite flexible since they have low minimum operating levels. For the *Max Low-Cost Gen* dispatch model, however, there are significant questions regarding the operational viability on the coal units since they are required to start/stop frequently and vary their outputs to follow the demand pattern. The average start-ups for coal units obtained from the simulations are between 80-250 starts/unit/year depending on the portfolio. These number are significantly higher than the typical number of start-ups for coal units, which is about 20 per year without the need to replace major parts due to fatigue effects [37]. Furthermore, the inclusion of the operating constraints results in the violation of the ramp rate constraints of the coal units between 15-30 times per year. Such operating patterns for *Max Low-Cost Gen* dispatch model would also result in significant economic implications.

The expected generation cost of the portfolios and the efficient frontier for a carbon price of \$60/tCO_2 are shown in Fig. 9. The figure also shows the cost changes when the operating constraints are incorporated for both of the dispatch models. The generation portfolios on the efficient frontier (portfolio *I* and *J*) are not affected by the inclusion of the operational aspect regardless of the dispatch model. This is due to the negligible share of coal in these portfolios. Hence, it is unlikely that the choice of optimal generation portfolios for a high carbon price will be affected by the incorporation of the short-term operational aspect. However, the introduction of a high carbon price into an industry with major coal generation could have significant operating cost implications.

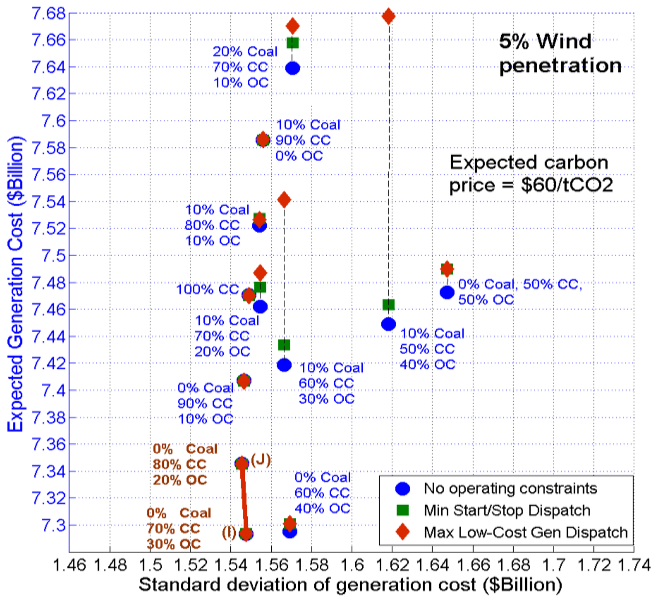


Fig. 9. Expected cost and the efficient frontier of a carbon price of \$60/tCO_2.

Fig. 10 shows the proportion of running costs and start-up costs of both dispatch models for the case of estimated 'full' start-up costs. The difference in the total operating costs is also shown on the graph. This graph highlights the significance of start-up costs for portfolios which contain some shares of coal. From the graph, it is quite apparent that *Min*

Start/Stop dispatch represents a lower cost alternative than *Max Low-Cost Gen* dispatch model.

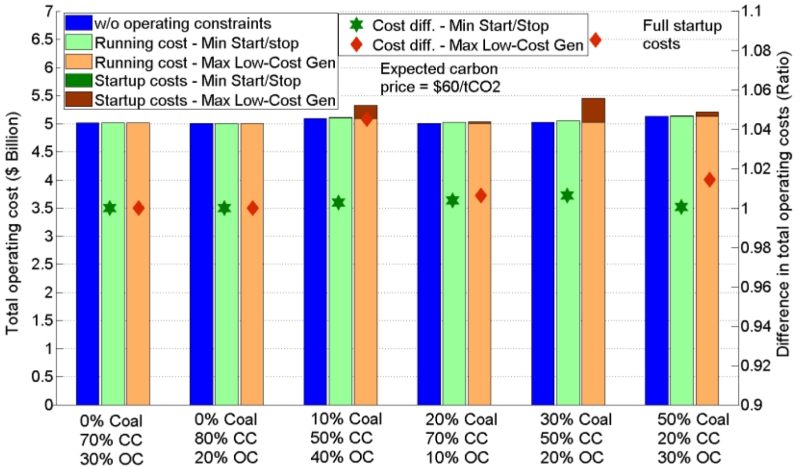


Fig. 10. Total operating costs of generation portfolios for both dispatch models showing proportion of running costs and full start-up costs.

Similar to the case with a moderate carbon price of $30/t$CO_2$ presented in the previous section, there are tradeoffs between overall industry generation costs and associated CO_2 emissions for both dispatch models. While, *Min Start/Stop* dispatch model results in lower generation costs, the CO_2 emissions of generation portfolios which contain some shares of coal are considerable higher than those of *Max Los-Cost Gen* dispatch model and the unconstrained dispatch cases. By avoiding the start-up/shutdown of generating units as in *Min Start/Stop* dispatch model, the CCGT units are operated more often at part load to enable the coal units to remain online. Hence, Min Start/Stop dispatch model results in higher CO_2 emissions due to the high emission factor of coal plants.

A range of carbon prices is also used to simulate the generation dispatch and operating patterns of each generation portfolio, From the operating perspective, carbon pricing does not affect the generation dispatch and operating pattern of generating units in the portfolios until at a high carbon price which results in a change in the merit order as shown earlier, However, in terms of the economic impacts, carbon pricing affects the operating cost of portfolios in both the running costs and the start-up costs component. For a high carbon price where coal is no longer the cheapest operating cost generation, the potential operating and economic impacts of incorporating the short-term operational aspect can be significant for portfolios which contain coal. This is particularly the case for *Max Low-Cost Gen* dispatch model since the coal units are subjected to frequent start-ups/shutdowns as well as ramping. Hence, *Min Start/Stop* dispatch model represents a more economically and operationally viable option. However, there are tradeoffs since *Min Start/Stop* dispatch model would result in higher overall emissions, More importantly, however, at a high carbon price, the inclusion of the operational aspect does not appear to affect the choice of optimal generation portfolios obtained from the tool given that only portfolios without coal are considered optimum in terms of the expected costs and cost uncertainty.

Increasing wind penetration is also expected to have significant operating, economic and emissions impacts on generation portfolios. Higher wind penetration poses addition operational challenges for conventional generating units due to increased cycling operation including start-up/shutdown and ramping. A preliminary analysis of different wind penetrations is shown in Fig. 11 and Fig. 12 which show the percentage of start-up costs in total operation costs of generation portfolios for different wind penetrations for carbon prices of $30/t$CO_2$ and $60/t$CO_2$ respectively. The figures suggest that the share of start-up costs in total operating costs of generation portfolios generally increases with increasing wind penetration. This is due to thermal generating units are being dispatched to starts/shutdowns more frequently. The rate of increase depends on the technology mix in the portfolios.

The post-processing extension could be applied to explore the full operational, economic, and emission implications of different wind penetrations. Other sensitivities, such as fuel prices, can also provide useful insights. Such analysis represents a possible future area of work.

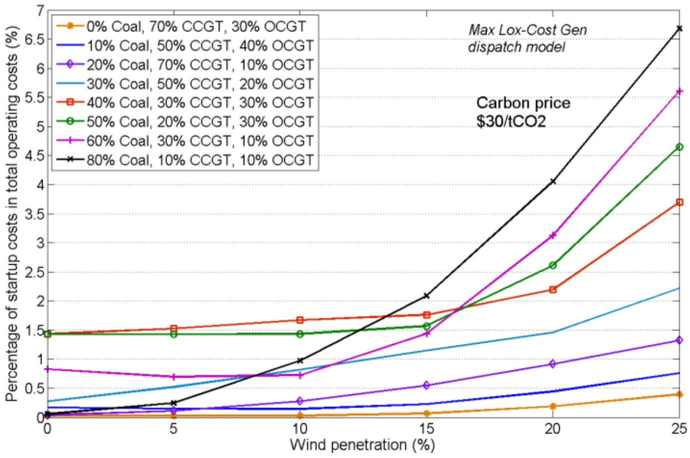


Fig. 11. Share of start-up costs in total operating costs for different generation portfolios for a carbon price of $30/t$CO_2$.

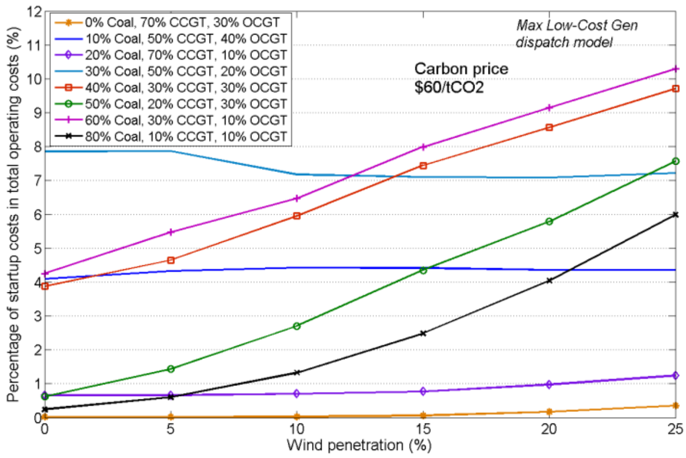


Fig. 12. Share of start-up costs in total operating costs for different generation portfolios for a carbon price of $60/tCO_2$.

6. Conclusions

This paper demonstrates a post-processing extension for incorporating the short-term electricity industry operation into the Monte Carlo based decision support tool for long-term generation investment and planning. The paper applies the post-processing extension to assess subsequent operational, economic and emissions implications for generation portfolios using a case study of an electricity industry with coal, CCGT, OCGT and wind generation options with a moderate carbon price of $30/tCO_2$ and a fixed wind penetration of 5%. Two dispatch models are applied; one that attempts to minimize unit starts/stops (*Min Start/Stop* dispatch), and another which attempts to dispatch the lowest cost units near their capacity (*Max Low-Cost Gen* dispatch). There are potential tradeoffs between the two dispatch models in terms of running costs, start-up costs and emissions.

The results show that incorporating the short-term operational aspects can have some operating, economic, and emissions impacts for candidate generation portfolios that emerge from the initial investment planning analysis framework. The extent of the impacts depends mainly on three factors: the dispatch strategy relating to the unit start-up/shutdown criteria, expected fuel and carbon prices, and the mix of technologies in the portfolio. From an operational perspective, there were no violations in the ramp rates in our case study, while the average numbers of start-ups of thermal units did not appear overly excessive. In terms of economic impacts, operationally constrained dispatch generally increases the overall costs of the portfolios due to some combination of increased running costs and additional start-up costs for the generating units. Such cost increases can affect the efficient frontier and hence possible choice of generation portfolios. For a high carbon price which results in a change in the merit order between coal and CCGT, the potential operational and economic impacts of incorporating the short-term operational aspects can be quite significant for portfolios which contain coal given their slow ramp rates and high start-up costs.

This post-processing extension to the investment and planning decision support tool provides some insights into how different future generation portfolios might be impacted by different dispatch strategies. The results may seem to suggest that these operational constraints have only moderate impacts on the most appropriate generation portfolios and the overall industry costs obtained from the initial generation investment planning analysis. However, in future low-carbon electricity industries with high levels of intermittent renewable generation and high carbon prices, these operational impacts are likely to be far more significant due to changes in the merit order and increased cycling of thermal generating units. The implications associated with different wind penetrations and carbon prices will be fully explored in future work. In addition, other new technologies such as solar PV, electric vehicles (EV) and smart grids can potentially be considered given their increasing deployment in the electricity industry and highly promising characteristics.

The contribution of this paper is twofold. First it proposes a post-processing extension method to incorporate some key short-term operational aspects into generation portfolio investment analysis. This method enables investment and policy decision-makers to undertake a ‘first pass’ assessment of potential operational issues associated with candidate electricity generation portfolios. The paper’s second contribution is the application of this extension method to provide a high-level assessment of the technical, economic and emissions implications of such issues considering two different generation dispatch strategies. Although the case study data is Australian specific, the results and findings do highlight the potential technical, economic and emissions implications of incorporating short-term operational aspects, which can have broader relevance for generation planning and investment decision-making in many electricity industries around the world.

Despite the valuable features of the post-processing extension to the tool, there are still some limitations. For example, the constrained generation dispatch does not incorporate the minimum synchronization and shutdown times of generating units. These issues are ignored primarily because of the potentially excessive computation time required to include them. However, the post-processing extension to the generation investment and planning tool is certainly sufficiently flexible to incorporate more sophisticated generation dispatch simulations and this is a potential area of future work.

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