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The impact of sub-hourly modelling in power systems with significant levels of renewable generation ☆

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HIGHLIGHTS

- This work investigates the impact of temporal resolution on power systems modelling.
- Increased temporal resolution captures more variability and costs.
- Increased resolution betters captures the inflexibilities of thermal units.
- Significant cycling and ramping of units is also captured.

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ABSTRACT

The objective of this work is to determine the impact of sub-hourly modelling of a power system with significant amounts of wind generation. This paper presents the modelling of the Irish power system for a one year period at 5 min, 15 min, 30 min and 60 min resolution simulations using a unit commitment and economic dispatch model assuming perfect foresight. The work examines how much operational costs increase with more accurate resolution. Results show that increased temporal resolution captures more variability in system load and renewable generation, and is necessary to capture the inflexibilities of thermal units that lead to more realistic estimations in total generation costs. Significant cycling and ramping of units is also captured in higher resolution modelling that hourly resolution modelling is unable to capture.

1. Introduction

Over 38 GW of wind power was installed globally in 2010 with a projected doubling in capacity over the next 5 years [1]. While wind energy generation is a clean and relatively cheap power source, it is not without its drawbacks, namely in the form of variability and unpredictability. Power system issues associated with wind energy's variability and unpredictability are well documented [2,3] and have been the focus of many wind integration studies such as in [4,5]. The integration of variable renewable resources such as wind power will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. In providing these capabilities, existing and planned thermal generation units will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day [6]. To assess the future impact of wind power on systems, wind integration studies usually simulate a future power system with large penetrations of wind power production and evaluate the system impacts in term of costs. These studies generally use sophisticated economic unit commitment and dispatch models to simulate the operation of the power system. A standard approach to determining the optimal unit commitment and dispatch in a power system subject to technical and economic constraints using mixed integer programming is given in [7]. Modelling the unit commitment and economic dispatch of a power system is not a trivial problem and to solve the problem sophisticated mathematical optimisation software and techniques are used to determine the least cost production schedule [8].

Many research and commercial models [9–12] have been used in recent wind integration studies [13–16]. A limitation with most of these studies and highlighted by [17] is that they run at hourly resolutions and impacts that occur inside the hour may be hidden. This means that start ups and ramp rates on conventional units are approximated by hourly rates. Recent work in [18] also highlighted the need to investigate hourly chronological simulation with sub

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hourly (5–15 min) simulation to investigate the fidelity of a models ability to capture the operation of the system. Although there is widespread interest in capturing these sub-hourly impacts in the modelling framework, it is not yet clear how important these impacts will be [19]. Note that while some studies undertake operational modelling that is performed on an hourly time step, they generally analyse sub-hourly wind and load data using statistical techniques to provide insight into the intra-hour impacts and variability characteristics [20].

The goal therefore of this paper is to investigate the value of sub-hourly unit commitment and economic dispatch modelling of an actual power system with a high level of wind penetration. This work presented in this paper is similar in concept to that of [21] in that a high resolution unit commitment and economic dispatch model is used to simulate a system. The work in this paper is different as it applies mixed integer linear programming (MILP) to solve the unit commitment and economic dispatch problem (unit commitment and economic dispatch are solved simultaneously) and aims to qualify and quantify the differences between high resolution simulations (i.e. 5 min) and hourly simulation results. This is important because in large power systems hourly simulation may have to be undertaken to keep the problem computationally manageable so it is useful to understand the implication of higher resolution modelling.

Section 2 provides a review of the model used in this analysis. Section 3 presents the modelling methodology used in this analysis and the test system. Section 4 presents the results and Section 5 draws conclusions.

2. Model

The software used throughout this work to solve the unit commitment and dispatch problem is PLEXOS [22]. PLEXOS is a power systems modelling tool used for electricity market modelling and planning [23,24] and [6]. The PLEXOS modelling tool is used by the Commission for Energy Regulation (CER) in Ireland to validate Ireland's Single Electricity market and has a history of use in Ireland [25].

In this set-up PLEXOS co-optimises hydro, thermal, renewable, and reserve classes and no heuristic or sequential approach is taken. Modelling is carried out using mixed integer linear programming that aims to minimise an objective function subject to the expected cost of electricity dispatch and a number of constraints. The objective function of the model includes operational costs, consisting of fuel costs and carbon costs; start-up costs consisting of a fuel offtake at start up of a unit and a fixed unit start-up cost. Penalty costs for unserved energy and a penalty cost for not meeting reserve requirements are also included in the objective function. Fuel consumption is calculated using piecewise linear functions as in [26]. System level constraints consist of an energy balance equation ensuring supply (net pumping demand) meets regional demand at each simulation period. Water balance equations ensure water flow within pumped storage units is conserved and tracked. System operational constraints unique to this work are described in the next section. Constraints on unit operation include minimum and maximum generation, maximum and minimum up and down time and ramp up and down rates. Constraints in relation to each unit's ability to provide reserve are also included. Start up/shutdown profiles and times are enforced via run up rates. This means that units cannot 'block load' and cannot provide reserve or capacity during a start-up period. This is shown in Fig. 1 for an exemplarily 300 MW unit with a minimum stable level of 120 MW, a run up rate of 2 MW/min and a ramp up rate of 3 MW/min. The unit is committed at 01:00 and must then follow its start profile or run up rate of 2 MW/min to the minimum stable level. Assuming a 15 min simulation interval this takes 4 periods. Once the unit reaches minimum stable level it can ramp at a regular ramp rate of 3 MW/min up to maximum capacity. This is in contrast to the block loading method where the unit can instantaneously come online at the minimum stable level.

Ancillary services within the model are optimised using techniques set out in [26]. In chronological mode PLEXOS solves for each period and maintains consistency across the full problem horizon. Temporal resolutions settings in relation to solving are user defined and flexible. Users can choose interval lengths of 1 min to multiple hours in hourly, daily or weekly steps over the full problem horizon (typically 1 year or more). For example, a model run with an optimisation length of 1 h and period of 1 day with a horizon of 1 year will run 365 individual daily optimisations at a resolution of 1 h each. To avoid issues with intertemporal constraints (i.e. unit commitment of large units and storage end levels) at the simulation step boundaries a 'look ahead' period is used. This look ahead period is user defined. Look ahead means that the optimiser is given information about what happens ahead of the period of optimisation and solves for this full period (i.e. simulation period + look ahead period) however only results for the simulation period are kept. The look ahead period shares the same temporal resolution as the optimisation interval (see Table 1).

Within the model maintenance schedules for generation units can be fixed exogenously if a known maintenance schedule is available, otherwise the model can determine an optimal maintenance schedule based on the annual maintenance rate for each unit. The objective function of the maintenance scheduling formulation is to equalise the capacity reserves across all peak periods. Outages for units are calculated based on Monte Carlo simulations. In this work outages for all models occur at the same periods. At simulation run time PLEXOS dynamically constructs the linear equations for the problem using AMMO[1] software and uses a solver to solve the equation. In this work Xpress MP [27] with a duality gap set to 0.2% is used with a solver timeout at 800 s. These setting were chosen based on previous PLEXOS simulations on large systems. All simulations were checked for correct completion.

3. Approach and methodology

We developed a detailed PLEXOS model of the All Island (AI) power system for the year 2020. The model was run at varying temporal resolutions (5 min, 15 min, 30 min and 60 min) to investigate the effect of increased model resolution on results. All model simulations assume perfect foresight so as to isolate and examine the effect of increased model resolution on simulation results. Note that all model simulations share the same model inputs as well as maintenance and forced outages patterns and times.

3.1. Test system

The 2020 generation portfolio is taken from EirGrid's (Ireland's transmission operator) All-Island Generation Capacity Statement 2012–2021 [28] which gives projections of generation capacity out to the year 2021. The 2020 power system includes approximately 8320 MW of synchronous generation (coal, peat and hydro plant, OCGT's, and CCGT's). In total the All Island system has 72 individual units with 2 interconnectors to Great Britain (GB) and 1 pumped storage plant comprised of 4 individual units. Details of the 2020 power system are provided in Fig. 2. Further details of the system in relation to adequacy and reliability can be found

[1] AMMO performs a similar role in PLEXOS as other mathematical languages such as AIMMS, AMPL, or GAMS but is written exclusively for PLEXOS.

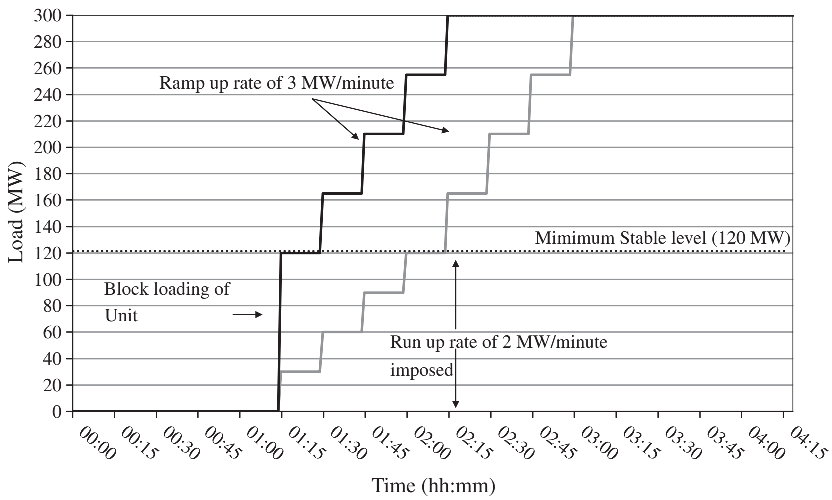

Fig. 1. Example of run up rate and block loading for a thermal unit.

Table 1
Optimisation configuration for each simulation.

Optimisation interval (min)	Optimisation period (day)	Optimisation period 'Look ahead' (h)	Optimisation horizon (year)
5	1	6	1
15	1	6	1
30	1	6	1
60	1	6	1

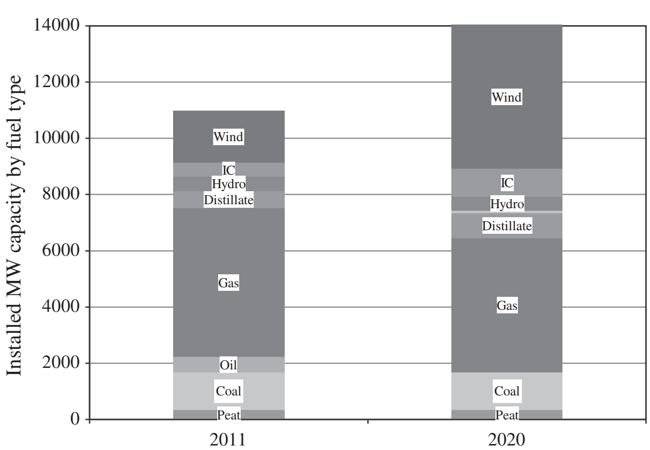

Fig. 2. Generation portfolio for All Island System 2011 and 2020 [29].

at [30]. The system has 5200 MW of installed wind capacity which meets approximately 40% of annual electricity demand.

3.2. Data sources and model setup

The PLEXOS model was populated with individual unit characteristics and technical details such as minimum stable generation, load dependant heat rates, minimum up and down times, ramp rates, start up and shutdown profiles, regulation points and ranges for reserve provision (see Section C for detailed discussion of treatment of reserves). Technical details in relation to these parameters were taken from Irelands Commission for Energy regulation validated PLEXOS market model [25]. Information on the provision of each generation unit to reserve classes is taken from [29] and assumed to be the same for 2020. Annual and peak electricity demand assumptions for the All-Island system are also taken from [28]. Annual demand is estimated to be 41 TW h with a peak of 7.2 GW. The demand profile for 2020 was created in PLEXOS by linearly scaling up a 15 min demand file for the year 2011, thus assuming no change in demand profile due to electrification of heating or transport. Realised wind power production data for 2020 is taken from actual 15 min metered wind generation 2011 from Eirgrid and scaled up directly to match 2020 installed wind capacity. All data was quality controlled before use. In periods where wind curtailment was occurring actual forecast data was used. The annual capacity factor for wind data is 31% which is typical of an average wind year for Ireland. Data is upscaled from the raw 15 min data to 5 min using a linear interpolation method.

Fuel and carbon prices are taken from [30]. Seasonal gas prices are assumed whereas coal and distillate prices remain static throughout the year. Daily start-up costs for individual plants are taken from actual market data for each day in 2011 from SEMO, Ireland's Single Electricity Market Operator [31]. Intra-regional transmission is not modelled in this analysis however both the existing 500 MW Moyle Interconnector and the planned 500 MW East–West interconnector to Great Britain are included as well as and North–South tie line which connects the north and south of the All-Island system is included. The GB system is modelled as a single gas unit and assumes that gas-fired generation is the marginal plant in the GB system as in [25]. Operational constraints on the requirement of minimum number of thermal generators online are assumed based on recent work by Eirgrid. A constraint restricting the amount of wind generation in the model in a given period is enforced based on [32]. This requirement in this modelling work states that the amount of wind generated, when added to imports, must not exceed 70% (working assumption in [32] is between 60% and 80%) of the sum of system load and exports, i.e.

$$(\mathrm{Wind\,Gen} + \mathrm{Import})/(\mathrm{System\ Load} + \mathrm{Export}) \leq 0.7. \qquad (1)$$

Pumped storage is modelled as having 3 distinct phases which are as follows: (1) Pumping mode: the plant has 4 fixed speed pumps which each draw a load of 71.5 MW and can provide full quantity for reserves. (2) In spin mode each unit can provide 5 MW of power but no more than 2 units can be in spin mode at any one time. (3) In generation mode each unit can provide a minimum of 40 MW and up to a maximum of 73 MW. As all units share a common penstock they are not allowed to generate and pump at the same time. Water in the storage has no 'value' other than the value of the thermal generation it can replace. Thus the optimisation will use all the water possible to minimise thermal costs. The use of the '*look ahead*' period (see Table 1) ensures the reservoir does not empty at the end of each simulation step by providing a natural shadow price equal to the dual variable of the water balance constraint. This represents the future value of water held in the storage and is used to initialize neighbouring simulation steps.

3.3. Treatment of reserves

In Ireland's grid code a number of reserve categories are defined [33]. Operating reserve, as defined in the Irish system, is divided into four parts: primary, secondary, tertiary 1 and tertiary 2. An overview of Ireland's operational reserve requirement is provided and contrasted to other systems in [34]. In this model setup operating reserve requirement for 2020 are assumed to be the same as 2012 however for simplicity and to reduce simulation times only one reserve category (TOR1) is taken into account, i.e. power plant restrictions concerning POR and SOR are not taken into account. This simplification will lead to an underestimation of the required online capacities reserved for providing dynamic reserves. The primary driver for the requirement of reserve category TOR1 is the size of the largest in-feed which is the interconnector to the GB system (500 MW). A minimum requirement for the reserve is also fixed. Operating reserve can only be supplied by units that are fully synchronised (i.e. they cannot contribute to reserve while on a start profile). Certain units can only provide reserve above a regulation point which is 50% of their maximum capacity as per [33]. 50 MW of static reserve is provided by interruptible load and 100 MW of static reserve is held on the interconnectors. Replacement reserve is modelled by keeping enough peaking units offline to cover requirements. The value of reserve not met is fixed lower than the value of demand not met so the model has the option to draw down reserve to ensure demand is met.

4. Results

The detailed PLEXOS model of the 2020 All Island power system was run at 5 min, 15 min, 30 min and 60 min resolution with configurations as per Table 1.

4.1. Total generation costs

Results in terms of total generation costs, generation only costs and start-up costs are presented in Table 2 at varying temporal resolutions. Total generation cost is the cost including fuel, variable operations and maintenance costs, start and shutdown costs and emissions costs. Generation cost is the total variable cost of generation. All simulations were executed on a workstation with Intel Xeon 3.0-GHz processors with 12 GB of RAM running Microsoft Windows 7 64 bit. The longest simulation (5 min resolution for a year) took approximately 70 h of run time, while the shortest simulation (60 min resolution for a year) took approximately 3 h.

It can be seen that total annual generation costs are higher for the higher resolution simulations. The difference between the 60 min resolution and 5 min resolution is €16.3 M for the year modelled and equates to an increase of approximately 1% in total generations costs. These differences are not attributed to one single event and occur as small cumulative changes throughout the year. The increase in cost is due to the models ability to capture more variability at higher temporal resolutions and also a better portrayal of the flexibility/inflexibility of thermal units is achieved at higher temporal resolutions. Total annual generation for thermal generation categories is shown in Table 3.

In general across all simulations the operation of baseload coal and peat generation units is not affected by simulation resolution. Baseload gas units initially increase generation at the 30 min resolution simulations however as simulation resolution increases older and less flexible baseload CCGT units are unable to ramp sufficiently to meet changes in demand. Newer more flexible mid merit CCGT units are called to generate more and are cycled more frequently to respond to changes in load as resolution increases. At the highest resolution simulations, flows across the interconnector are reduced and the AI system imports marginally more electricity to deal with fluctuations in net load. Annual generation from flexible OCGT units and pumped storage are seen not to be effected greatly by increased model resolution however in the 5 min resolution simulations pumped storage shows a decrease in annual generation this is due to a significant increase in start ups (see Table 5) which limits its ability to generate.

Levels of wind curtailment in model simulations are low at 0.5% for the 60 min resolution simulations, but increased model resolution shows marginally lower levels of wind generation and higher associated levels of wind curtailment as shown in Table 4.

At higher temporal resolution simulations start profiles of power plant become increasingly important. As units are not allowed to block load, the number of start-ups and related costs for more flexible units increase. Table 5 shows the average number of start-ups of units for each temporal resolution simulation for the year. This is the sum of all the start-ups in that category divided by the number of units in that category. In general all units start more often as model resolution is increased; however given the number of units in each category the increase in start-ups for most categories is modest. The number of starts for pumped storage units increases significantly as simulation temporal resolution increases. Each generation unit in the pumped storage plant increases from

Table 3
Total annual generation (Gwh) For each generation category.

	60 min Simulation	30 min Simulation	15 min Simulation	5 min Simulation
Base load gas	3475	3503	3484	3363
Mid merit gas	12,547	12,575	12,642	12,642
GAS OCGT	99	101	99	99
Coal	7674	7674	7600	7637
Peat	2600	2600	2596	2589
Pumped storage	362	361	366	347
Pump energy	517	516	522	494
Wind	13,980	13,970	13,961	13,952
Import to AI	2080	2070	2081	2095
Export from AI	3056	3068	3063	2985

Table 2
Total generation costs for each temporal resolution (€ billions).

	60 min Resolution	30 min Resolution	15 min Resolution	5 min Resolution
Generation cost only	€1.491	€1.493	€1.495	€1.501
Generator start & shutdown cost	€0.062	€0.064	€0.067	€0.070
Total generation cost	€1.553	€1.556	€1.563	€1.570

Table 4
Levels of wind curtailment for each simulation resolution.

	60 min Simulation	30 min Simulation	15 min Simulation	5 min Simulations
Wind curtailment	0.52%	0.59%	0.65%	0.72%

Table 5
Average annual number of start ups per unit for each generation category.

	60 min Simulation	30 min Simulation	15 min Simulation	5 min Simulation
Base load gas	40	42	43	45
Mid merit gas	27	28	28	30
GAS OCGT	58	61	63	65
Coal	8	8	9	11
PHES	817	1191	1867	3446

an average of approximately 2 starts per day to 9 starts per day as model resolution increases from 60 min to 5 min. The unit is used to respond to increased ramp events in both the generation and pumping modes. These flexible resources are shown to be increasingly important as more variability in wind and demand and lack of flexibility in thermal units is captured by the model.

At 30-min resolution simulations and even more so in higher resolution simulations ramp rates become binding in the model formulation. This is evident in the development of shadow prices on the ramp constraints of units within the model. Table 6 shows the maximum instantaneous ramp up price for each generation category over the course of the year. This represents the price that the system would be prepared to pay to gain one more megawatt of ramping up response from that category of unit at that time and generally occurs when a unit has come online and is ramping from a minimum stable level to maximum capacity. The 60 min simulations do not capture the effect of ramp constraints, while mid merit units which have reasonably responsive ramp rates are only captured in 15 min to 5 min simulations.

Fig. 3 shows the annual average ramping up and down intensity for each category of generation. Ramping up intensity is defined as the total sum of ramping up throughout the year for all units in that category divided by the total ramping up time for those units as defined in Eq. (2). Ramping down intensity is similarly defined for ramping down events.

$$\text{Ramp Intensity Up} = \frac{\text{Max}(0, \text{Generation}_{(t)} - \text{Generation}_{(t-1)})}{(\text{Total Minutes Spend Ramping Up})} \tag{2}$$

Note that '*Total minutes spend ramping*' are modelled times and dependant on model temporal resolution. A 60 min resolution model assumes a fast acting OCGT turbine takes 60 min to ramp to maximum capacity whereas a 5 min resolution model captures a more realistic ramping time. Fig. 3 also shows the maximum average value for each category as a single capped line.

Table 6
Maximum shadow price on ramp up constraint (€/Mw).

	60 min Simulation	30 min Simulation	15 min Simulation	5 min Simulation
Coal	€0.00	€42.34	€74.50	€149.50
Base load gas	€0.00	€37.93	€72.36	€117.00
Mid merit gas	€0.00	€0.00	€37.15	€80.14
Gas OCGT	€0.00	€0.00	€0.00	€74.17

All categories of unit experience increased ramping intensity with increased model resolution. This is particularly significant in certain generation categories such as the mid merit gas which experiences an almost threefold increase in ramping intensity when moving from 60 min to 5 min resolution simulations. Moreover, the role of the pumped storage unit becomes more prominent in higher resolution simulations with significant ramping intensity at both the 15 min and 5 min simulations. This increase in ramping intensity is due to more ramp-up and down events associated with capturing greater wind and load variability with increased levels of model resolution. It is also due to a decrease in actual time spent ramping up and down as shown in Table 7, which shows the annual average time spend ramping up per unit for each category. This clearly demonstrates that generator ramping intensities cannot be estimated from models using lower temporal resolution.

5. Discussion and conclusion

This work examined the modelling of a power system with significant levels of wind generation at varying temporal resolutions from 60 min to 5 min resolution. It was shown that higher resolution simulations capture costs that are not accounted for in lower resolution simulations and lead to more realistic estimations of total generation costs however as demonstrated in the results these costs were relatively small in the context of the full system costs. In terms of benefits of higher resolution modelling, it appears from this research that hourly or 30 min simulations are adequate for the task at hand when system costs are solely of interest. In the case presented, 5 min simulation results were approximately 1% higher than hourly simulation results. While this is a small number in relative terms it equates to capturing approximately €16 M extra in system costs (for the case examined), solely by increasing model resolution. However it must also be borne in mind that model assumptions such as fuel price, demand assumptions could have a stronger impact on resulting total system costs. Higher resolution simulations show benefits over traditional hourly simulation when the flexibility of system in terms ramping and evaluation of flexible resource such as pumped storage is of interest.

The trade-offs for higher resolution simulations are problem size, higher resolution data procurement and simulation run-times, which take significantly longer for higher resolution simulation. The implementation of 5 min or 15 min simulations in larger systems may not be practicable or may not be useful in systems with low levels of variable renewable generation. The system examined here is a relatively small system with a particular set of generation characteristics and high levels of wind generation; however the implementation of higher resolution simulations in this system offers insight into the effect of high levels of wind generation. It is shown that the number of start-ups for thermal generation units increases but this increase is modest for all thermal unit examined. The number of start-ups for the pumped storage units increases significantly and is seen to play a more important role in managing variability at higher resolution simulations. Ramp rates can become binding at higher resolution simulations and the development of shadow prices on ramp constraint offers useful information into the cost of the constraint. This information could be used by developers or investors to gauge what investment should be made on flexible plant. Ramping intensity and ramp times are also effected by model resolution. In higher resolution

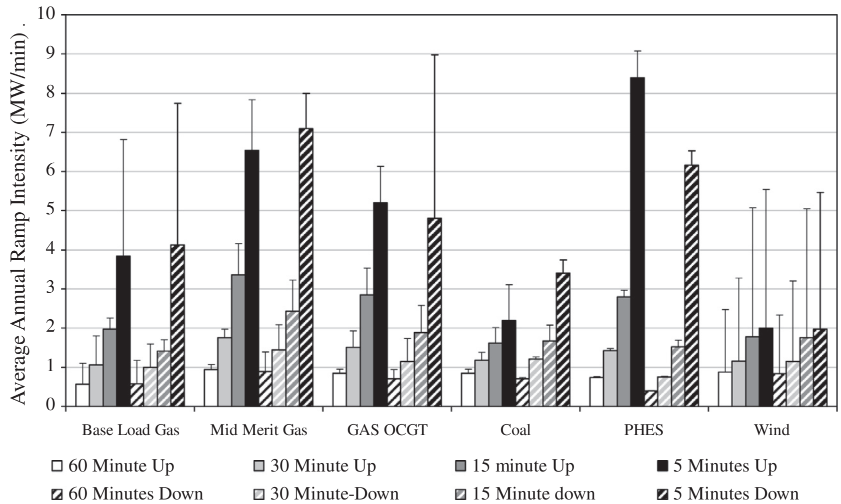

Fig. 3. Modelled annual average ramping intensity (up and down) for each simulation configuration for each generation type.

Table 7
Average hours ramping up per unit for each generation category.

	60 min Simulation	30 min Simulation	15 min Simulation	5 min Simulation
Base load gas	419	333	286	170
Mid merit gas	605	473	400	323
GAS OCGT	28	23	17	12
Coal	486	462	436	455
Peat	724	565	482	328
PHES	688	505	441	404

simulations all units ramp more significantly over shorter periods and in particular the pumped storage units experience a large increase in ramping intensity.

While this work offers useful insights into the operation of a power system with high levels of wind generation it has a number of limitations. Only one year of wind data was analysed and results are representative for that year. Result in terms of costs may change, however key results such as increased ramping activity and start-up should remain similar. The All Island test system used is a relatively small system with a specific generation portfolio and profile. In larger systems with more flexible generation, issues such as ramping and cycling of plant may not be as relevant particularly in systems where wind variability may be smoothed over larger geographic regions.

All simulations in this work assume perfect foresight and do not consider stochastic optimisation techniques to analyse a number of scenarios of wind data and load. This was done so as to isolate and examine the effect of increased model resolution on the system. Stochastic optimisation techniques would lead to an estimation of higher costs over perfect foresight assumptions but their implementation in very high simulation resolutions (5–15 min simulations) would be challenging from a problem size and solving time viewpoint.

Acknowledgement

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Appendix A.

In the PLEXOS software the formulation applied to each generator is customised according to the data and options defined. Equations are simplified or removed where possible in order to maximise performance. Here we describe a 'typical' formulation for generating units in the Irish SEM. Formulations for other systems will vary.

In the following we describe the equations that model unit commitment and dispatch of generating units. They ignore the following which are considered in the full scale formulation:

System energy balance and transmission, Heat rate and start costs, Cooling states, Initial conditions, Ramp rates, Ancillary services, End effects e.g. optimising future shutdown decisions.

A.1. Nomenclature

A.1.1. Indices

t	Dispatch interval (either 5, 15, 30 or 60 min)
i	Generating unit
k	Run up or run down interval

A.1.2. Decision variables

$\mathrm{GenLoad}_{i,t}$	Load of generating unit i at the end of dispatch interval t
$\mathrm{GenOn}_{i,t}$	Binary (0,1) variable indicating if generating unit i is operating during dispatch t
$\mathrm{GenStart}_{i,t}$	Binary (0,1) variable indicating if generating unit i started in dispatch interval t
$\mathrm{GenStop}_{i,t}$	Binary (0,1) variable indicating if generating unit i shut down at the beginning of dispatch period t

A.1.3. Data

Note that the following values are recalibrated by the simulator depending on the duration of dispatch intervals:

$[\text{Rating}]_{i,t}$	Rating of generating units i in period t
$[\text{MaxCapacity}]_i$	Maximum power of generating unit i
$[\text{MinStableLevel}]_i$	Minimum stable level of generating unit i
$[\text{RunUpTime}]_i$	Number of intervals that generating unit i takes a run up
$[\text{Start Pr ofile}]_{i,k}$	Generating unit i load in run up interval k
$[\text{RunDownTime}]_i$	Number of intervals that generating unit i takes to run down
$[\text{Shutdown Pr ofile}]_{i,k}$	Generating unit i load in run down interval k

A.2. Formulation

A.2.1. Generation rating

Generator load must not exceed the maximum unit rating:

$$\text{GenRating}_{i,t}:$$
$$\text{GenLoad}_{i,t} - [\text{Rating}]_{i,t}.\text{GenOn}_{i,t} \leq 0\forall i,t$$

A.2.2. Generator maximum with run up

Generator load must not exceed the maximum power or the relevant start profile level during the run up period:

$$\text{GenP}\max\text{Start}_{i,t}:$$
$$\text{GenLoad}_{i,t} - [\text{MaxCapacity}]_i.\text{GenOn}_{i,t} + \sum_{k=1}^{[\text{RunUpTime}]_i}([\text{MaxCapacity}]_i - [\text{StartProfile}]_{i,k}).\text{GenStart}_{i,t-[\text{RunUpTime}]_{i+k}} \leqslant 0\forall i,t$$

A.2.3. Generator minimum

Generator load must be at or above the minimum stable level except during periods of run up or run down:

$$\underset{i,t}{\text{GenPmin}}:$$
$$\text{GenLoad}_{i,t} - [\text{MinStableLevel}]_i.\text{GenOn}_{i,t} + \sum_{k=1}^{[\text{RunUpTime}]_i}([\text{MinStableLevel}]_i - [\text{Startprofile}]_{i,k}).\text{GenStart}_{i,t-[\text{RunUpTime}]_i} + \sum_{k=1}^{[\text{RunDownTime}]_i}([\text{MinStableLevel}]_i - [\text{Shutdown Profile}]_{i,k}).\text{GenStop}_{i,t+k-1} \geq 0\forall i,t$$

A.2.4. Generator start and stop definition

Unit operating state can change only if a start or stop has occurred:

$$\text{GenStartStop}_{i,t}:$$
$$\text{GenOn}_{i,t} - \text{GenOn}_{i,t-1} - \text{GenStart}_{i,t} + \text{GenSto}_{i,t} = 0\forall i,t$$

A.2.5. Generator minimum up time

Generating unit must be running if started in any dispatch interval looking back over the minimum up time:

$$\text{GenTurnOn}_{i,t}:$$
$$\text{GenOn}_{i,t} - \sum_{k=t-[\text{MinUpTime}]+1}^{t}\text{GenStart}_{i,k} \geq 0\forall i,t$$

A.2.6. Generator minimum down time

Generating unit must not be running if shutdown in any dispatch interval looking back over the minimum down time:

$$\text{GenTurnOff}_{i,t}:$$
$$\text{GenOn}_{i,t} - \sum_{k=t-[\text{MinDownTime}]+1}^{t}\text{GenStop}_{i,k} \leqslant 1\forall i,t$$

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