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RESEARCH ARTICLE

The Significance of Time Constraints in Unit Commitment Problems

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ABSTRACT Electricity market clearing models are crucial for operational and investment planning in modern power systems. Two commonly used models for market clearing are the merit-order and unit commitment models. While the merit-order employs a snapshot approach and lacks precision in representing time-based variations in demand and generation, the unit commitment model incorporates crucial temporal constraints. This paper highlights the significance of temporal constraints in market clearing models, emphasizing the potential for significant errors in generation commitment if these constraints are not carefully considered. Using real data from the Irish electricity system, the impact of temporal constraints on intra-day market clearing is demonstrated, comparing with the merit-order rule with the unit commitment solution. The findings reveal 6% underestimation in market clearing prices when compared to unit commitment solutions. The minimum stable operating constraints of thermal units were identified as having the most substantial impact on the unit commitment solution. This study underscores the risk of significant errors in generation planning if temporal constraints are not adequately factored in, advocating for a more accurate approach for market clearing models.

INDEX TERMS Electricity markets, integer programming, optimization, unit commitment problem, merit order dispatch, linear programming.

NOMENCLATURE

SETS

$\mathcal{Z}$	Zones, indexed by z.
$\mathcal{G}$	Generators, indexed by g.
$\mathcal{R}$	Renewable generators, indexed by r.
$\mathcal{D}$	Loads, indexed by d.
$\mathcal{I}$	Interconnectors, indexed by i.
$\mathcal{L}$	Lines between zones, indexed by l.
$\mathcal{T}$	Time intervals, indexed by t.

PARAMETERS

$\mathrm{P}^{\mathrm{D}}_{d,t}$	Real power demands of load d.
R_z	Reserve requirement in zone z.
$\mathrm{S}^{\mathrm{to}}_l$, $\mathrm{S}^{\mathrm{fr}}_l$	To, From net transfer capacity of line l.
$\mathrm{P}^{\mathrm{G}-}_g$, $\mathrm{P}^{\mathrm{G}+}_g$	Min., max. real power generation output of generator g.
$\Delta\mathrm{P}^{\mathrm{G}-}_g$, $\Delta\mathrm{P}^{\mathrm{G}+}_g$	Min., max. ramp rate of generator g.
$\mathrm{P}^{\mathrm{R}-}_{r,t}$, $\mathrm{P}^{\mathrm{R}+}_{r,t}$	Min., max. generation from renewable generator r.
$f(p^{\mathrm{G}}_{g,t})$	Cost function of generator g.
$\mathrm{C}^{\mathrm{SU}}_g$, $\mathrm{C}^{\mathrm{SD}}_g$	Start up, shut down cost of generator g.
$\mathrm{T}^{\mathrm{U}}_g$, $\mathrm{T}^{\mathrm{D}}_g$	Min. up, down time of generator g.

VARIABLES

$p^{\mathrm{G}}_{g,t}$	Real power generation of generator g.
$p^{\mathrm{R}}_{r,t}$	Real power generation of renewable generator r.
$p^{\mathrm{L,to}}_{l,t}$, $p^{\mathrm{L,fr}}_{l,t}$	To and From real power flow on line l.

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$p^{\mathrm{I,to}}_{i,t}$, $p^{\mathrm{I,fr}}_{i,t}$	To and From real power flow on interconnector i.
$p^{\mathrm{V}}_{g,t}$	Reserve contribution of generator g.
$u_{g,t}$	Unit commitment of generator g.
$x_{g,t}$, $y_{g,t}$	Start up, shut down of generator g.

ACRONYMS

OPF	Optimal power flow problem.
UC	Unit commitment problem.
MO	Merit order problem.
RES	Renewable energy sources.

I. INTRODUCTION

The electricity systems are undergoing significant changes in operations and inputs, driven by a growing emphasis on renewable energy sources and the policy goals of reducing carbon footprint in the energy generation sector. Numerous countries have invested substantial resources in planning and expanding current infrastructure to accommodate the integration of renewable generation. A central challenge in system with high renewable penetration is the need to minimise the additional costs arising from management of uncertainty [1], [2].

Electricity market clearing models play a crucial role in operation and planning. These models include optimal power flow problem, the unit commitment problem, and transmission expansion planning problems [3], [4], [5]. Although electricity market clearing primarily addresses short-term time horizons (day-ahead to a few hours ahead of system operation), its implications extend to transmission system investment problems where operating conditions are based on merit-order solutions. Consequently, the research presented in this paper holds relevance for both operational and investment planning time horizons.

The conventional *merit-order rule*, determining generation commitment based on marginal cost, is a traditional approach illustrated in Figure 1. However, this method has a significant drawback as it overlooks the dynamic properties of generators, neglecting temporal constraints like ramp-up/down capabilities and start-up/shut-down times. While the *unit commitment problem* (UC) addresses temporal constraints [6], the merit-order rule is favoured due to its computational simplicity and lower data requirements. The renewables have low operational expenditure and they are the first in the merit order stack, following by nuclear and fossil fuel generation. The flexibility of generation, the ability to ramp up and down, is generally associated with the fossil fuel generation which may be displaced by high penetration of renewables. This flexibility has a value for power system [7].

As the penetration of distributed generation increases at lower voltage levels, accurately predicting electricity demand at the transmission level becomes more challenging. Two crucial observations in this context are worth noting:

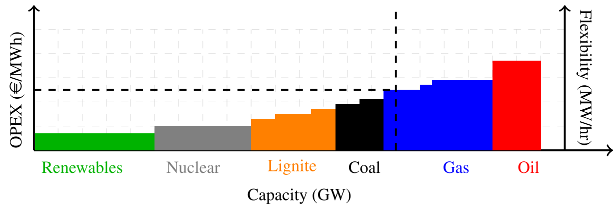
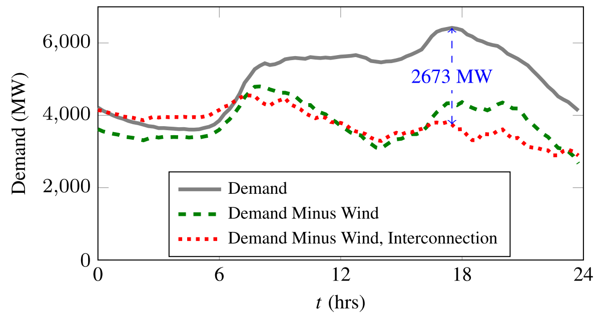
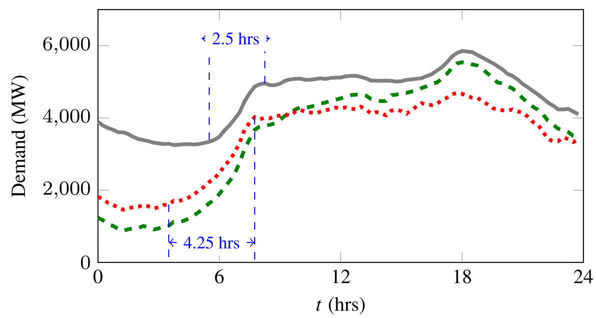


FIGURE 1. Merit-order approach to determine a generation mix to serve expected electricity demand. Generally, the ability of a generation type to flex increases with the marginal cost.



(a) 12-12-2017: A day with close to peak demand for electricity. Peak demand on the day is partly met by wind generation and interconnection. The peak in residual demand is shifted to morning.



(b) 03-02-2017: Change in generation from wind is making ramp of morning pick up longer and steeper.

FIGURE 2. Two representative days from Island of Ireland. The figure shows demand and residual demand (demand minus wind generation and demand minus wind + interconnection).

- the time of peak demand can be shifted by renewable generation, and
- the demand pick-up, typically occurring during the morning hours (6:00 am-9:00 am in Europe), may become steeper and longer.

Figure 2 illustrates the aforementioned two points using the real data from the Irish power system during the year 2017 [8]. Figure 2(a) shows a 42% downward shift in peak demand due to high wind penetration. On that particular day, the residual demand[1] peak occurred at 6 o'clock in the morning, an unexpected deviation. Figure 2(b) presents the extended duration of morning pick-up due to reduced wind penetration, with an approximately 70% increase in its duration.

Temporal constraints play a critical role in planning problems, yet there is a gap in understanding their signif-

[1]Residual demand is transmission system demand minus the renewable generation in a system.

icance, especially in market clearing models like the unit commitment problem.

Previous studies mainly focused on transmission expansion problems [9], [10], [11], [12], investigating ways to simplify the complexity by either model reduction or reducing input data. For instance, [9] highlights the importance of simulating over time series rather than snapshots for electricity capacity planning. Other studies like [10] and [11] focus on selecting representative days and hours respectively, while [13] introduces a heuristic to account for start-up and shut-down costs of thermal generators in the merit order stack. This heuristic, demonstrated using a case study of the Great British electricity system, enhances the accuracy of resulting marginal prices.

In terms of generation planning approaches, [14] proposes a Benders decomposition method for a generation expansion planning problem with unit commitment, aiming to reduce the problem's feasibility set through constraints. Similarly, [15] presents a neural network-based method to simplify a unit commitment problem involving transmission constraints, capturing the temporal relationship between past line loading levels and removed transmission lines. Reference [16] introduces a new mixed-integer linear programming formulation for generation expansion, targeting the identification of flexible technologies to optimize the utilization of variable renewable generation. On the other hand, [17] tackles security-constrained unit commitment for generation expansion planning, suggesting an efficient solution by identifying redundant constraints.

Regarding economic dispatch, a two-part paper [18], [19] delve into pricing multi-interval economic dispatch of electric power under operational uncertainty. They investigate dispatch-following incentives for profit-maximizing generators, incorporating ramp rate constraints but omitting other temporal constraints. Notably, they point out that electricity markets are often non-competitive, advocating for explicit modelling of generators‘ strategic behaviours. Meanwhile, [20] evaluates the efficiency of locational marginal prices in real-time electricity markets, addressing inter-temporal constraints like ramp rates through multi-interval economic dispatch problems. Additionally, [21] studies the impact of temporal characteristics and system frequency limits of responsive load models on integrating demand response resources into power system scheduling. Lastly, [22] proposes a method to eliminate redundant constraints in the unit commitment model.

This paper discuss the importance of time-related constraints in solving market clearing problem, using the Irish electricity system as a case study. Exploring this system is particularly insightful because it operates as a single electricity market, meaning all generators sell their power into one pool, and it has only limited connections to the Great Britain electricity market. This setup offers a unique opportunity to closely examine how factors like wind power and dynamic constraints affect generators. Due to its limited interconnection with Great Britain, the Irish system provides a clearer picture of how wind power and temporal constraints impact generators. The clarity allows us to study these effects more effectively than in systems with more extensive connections. The paper offers valuable insights into the dynamics of market clearing problems, shedding light on crucial factors that influence the performance of generators in such systems.

The subsequent sections of the paper are organised as follows. Section II provides mathematical models of merit order and unit commitment problems. The unit commitment model presented here is an extended version, incorporating models of interconnection and transmission constraints within zones. Section III provides details about the Irish electricity system used as a case study in Section IV. The paper concludes with a discussion in Section V.

II. MATHEMATICAL MODEL OF UC AND MO SCHEDULING PROBLEMS

Consider a power network $\mathcal{N}$ consisting of a set of zones $\mathcal{Z}$. Let $\mathcal{R}$ and $\mathcal{G}$ denote the sets of renewable generators and thermal generators in the network, respectively. Let $\mathcal{T} := \{1, 2, \cdots, \mathrm{T}\}$ be the set of a give time horizon. The following subsections provide mathematical formulation of the merit-order (MO) and unit commitment (UC) problem.

A. POWER BALANCE AND POWER FLOW CONSTRAINTS

A power flow in electricity networks is based on two sets of equations: the nodal power balance equation and the branch flow equations. This section provides a mathematical formulation of these equations. Let $p^{\mathrm{G}}_{g,t}$ be the real power generation from the conventional generator g, and let $p^{\mathrm{R}}_{r,t}$ be the real power generation from the renewable generator r, in the time period t, respectively. The power balance equations are given as follows, $\forall z \in \mathcal{Z}, t \in \mathcal{T}$:

$$\sum_{g\in\mathcal{G}_z} p^{\mathrm{G}}_{g,t} + \sum_{i\in\mathcal{I}_z} p^{\mathrm{I}}_{i,t} + \sum_{r\in\mathcal{R}_z} p^{\mathrm{R}}_{r,t} = \sum_{d\in\mathcal{D}_z} \mathrm{P}^{\mathrm{D}}_{d,t} + \sum_{l\in\mathcal{L}_z} \left(p^{\mathrm{L,to}}_{l,t} + p^{\mathrm{L,fr}}_{l,t}\right) \tag{1}$$

where $p^{\mathrm{I}}_{i,t}$ denotes the real power contribution of the interconnector i, which can be positive (import) or negative (export) depending on the price differentials between interconnecting markets, $\mathrm{P}^{\mathrm{D}}_{d,t}$ is electricity demand, $p^{\mathrm{L,to}}_{l,t}$ and $p^{\mathrm{L,fr}}_{l,t}$ denotes the *to* and *from* real power flows on a line l that connects zone z and z', in time period $[t, t+1]$ respectively. The real power flows between the zones are constrained by the transmission capacity limits, and are modelled as follows, $\forall l \in \mathcal{L}, t \in \mathcal{T}$:

$$p^{\mathrm{L,to}}_{l,t} \le \mathrm{S}^{\mathrm{to}}_{l} \tag{2a}$$
$$p^{\mathrm{L,fr}}_{l,t} \le \mathrm{S}^{\mathrm{fr}}_{l} \tag{2b}$$
$$p^{\mathrm{L,to}}_{l,t} + p^{\mathrm{L,fr}}_{l,t} = 0 \tag{2c}$$

where $\mathrm{S}^{\mathrm{to}}_{l}$ and $\mathrm{S}^{\mathrm{fr}}_{l}$ are *to* and *from* real power transmission capacity limits between the zones. Equation 2c models the line loss in the transmission line l, which is assumed to be zero here.

B. SPINNING RESERVE CONSTRAINTS

Spinning reserve is a type of operating reserve and is defined as the extra power a synchronised generator can provide to the system. Let $p^{\mathrm{V}}_{g,t}$ denotes the contribution of generator g to spinning reserve during the time period t. The spinning reserve constraint is modelled as follows, $\forall z \in \mathcal{Z}, t \in \mathcal{T}$:

$$\sum_{g\in\mathcal{G}_z} p^{\mathrm{V}}_{g,t} \geq \mathrm{R}_z \tag{3}$$

where R_z denotes the required spinning reserve in zone z.

C. INTERCONNECTION CONSTRAINTS

Interconnection in this paper is defined a transmission link between two asynchrnous systems. The interconnection may be modelled in the following two ways:

1) INTERCONNECTION FLOWS BASED ON HISTORIC DATA

An interconnection may be modelled based on the historic data of trades between two market zones. In this approach, the variable modelling interconnection in Equations (1) is fixed, and is modelled as, $\forall i \in \mathcal{I}, t \in \mathcal{T}$:

$$p^{\mathrm{I}}_{i,t} = P^{\mathrm{I}}_{i,t} \tag{4}$$

where $P^{\mathrm{I}}_{i,t}$ denotes a given scenario on contribution of the interconnection i during the time period t, respectively. This contribution can be positive (import) or negative (export).

2) INTERCONNECTION FLOWS BASED ON MARGINAL PRICE

Interconnection may be modelled using a marginal price $C^{\mathrm{I}}_{i,t}$ associated with the interconnection i during the time period t, respectively. The optimization model determines the optimal contribution of the interconnection in each time period. The transmission capacity constraints on the interconnection are modelled as follows, $\forall i \in \mathcal{I}, t \in \mathcal{T}$:

$$-\mathrm{P}^{\mathrm{I,to}}_{i} \leq p^{\mathrm{I}}_{i,t} \leq \mathrm{P}^{\mathrm{I,fr}}_{i} \tag{5}$$

where $\mathrm{P}^{\mathrm{I,to}}_{i}$ and $\mathrm{P}^{\mathrm{I,fr}}_{i}$ are *to* and *from* interconnection capacities. A term $C^{\mathrm{I}}_{i,t}p^{\mathrm{I}}_{i,t}$ is added to the objective function that captures the cost of import/export taking place at time t on the interconnector i.

D. GENERATION CONSTRAINTS

The constraints on generation units are an important part of the overall unit commitment problem. These constraints include capacity, ramping, minimum up and down time of units and availability generation capacity of renewable source. This section provides a mathematical model of aforementioned constraints. Let $u_{g,t}$ be a binary variable for generator g in time period t, which is *one* (*zero*) if the generator g is *on* (*off*) at the start of the time period t. In the following, constraints related to capacity, start-up, shut-down and commitment of thermal generation are presented.

1) GENERATION CAPACITY CONSTRAINTS

The generation from conventional generators is bounded by the following inequality constraints, $\forall g \in \mathcal{G}, t \in \mathcal{T}$:

$$p^{\mathrm{G}}_{g,t} + p^{\mathrm{V}}_{g,t} \leq u_{g,t}\mathrm{P}^{\mathrm{G+}}_{g} \tag{6a}$$

$$\mathrm{P}^{\mathrm{G-}}_{g} u_{g,t} \leq p^{\mathrm{G}}_{g,t} + p^{\mathrm{V}}_{g,t} \tag{6b}$$

where $\mathrm{P}^{\mathrm{G-}}_{g}$, $\mathrm{P}^{\mathrm{G+}}_{g}$ are the lower and upper bounds on the generation output of generator g, respectively. When the generator is switched on ($u_{g,t} = 1$) in the time period t the variable $p^{\mathrm{G}}_{g,t}$ is free to take any value within the given bounds. When the generator is switched off ($u_{g,t} = 0$) the constraint (6) will force the variable $p^{\mathrm{G}}_{g,t}$ to take the value of zero.

2) RAMPING CONSTRAINTS

Thermal generators need time to change their operating point. The amount by which a generator can change from its current operating point is given by its up-ward and down-ward ramping rates. The ramp-rate constraints are given as follows, $\forall g \in \mathcal{G}, t \in \mathcal{T}$:

$$-\mathrm{P}^{\mathrm{G+}}_{g}(1-u_{g,t}) - \Delta\mathrm{P}^{-}_{g} \leq p^{\mathrm{G}}_{g,t} - p^{\mathrm{G}}_{g,t-1} \tag{7a}$$

$$p^{\mathrm{G}}_{g,t} - p^{\mathrm{G}}_{g,t-1} \leq \Delta\mathrm{P}^{+}_{g} + \mathrm{P}^{\mathrm{G+}}_{g}(1-u_{g,t-1}). \tag{7b}$$

where $\Delta\mathrm{P}^{-}_{g}$, $\Delta\mathrm{P}^{+}_{g}$ are down-ward and up-ward ramp rates of the generator g. Note that constraints (7) are only active when generation unit is *on* during the consecutive times periods, and are redundant otherwise.

3) MINIMUM UP AND DOWN TIME OF UNITS

Thermal generation units need time to ramp up and down. For example, if a decision is made to switch on a generator g at time t and the start up time of generator g is (say) q then the unit has to be started at $(t-q)$. In order to model situation like these, minimum up and down times are used.

Let $x_{g,t}$ and $y_{g,k}$ be the start-up and shut-down binary variables for generator g in the time interval t, respectively. Variables $x_{g,t}(y_{g,k})$ are 1(0) if the unit g is started(shut) in the time period t. These binary variables are connected to commitment variable via following constraint:

$$x_{g,t} - y_{g,t} = u_{g,t} - u_{g,t-1} \tag{8}$$

The minimum up and down times are modelled using the following constraints:

$$\sum_{k=t-\mathrm{T}^{\mathrm{U}}_{g}+1}^{t} x_{g,k} \leq u_{g,t} \quad \forall\, t \in [\mathrm{T}^{\mathrm{U}}_{g}, \mathrm{T}] \tag{9a}$$

$$\sum_{k=t-\mathrm{T}^{\mathrm{D}}_{g}+1}^{t} y_{g,k} \leq (1-u_{g,t}) \quad \forall\, t \in [\mathrm{T}^{\mathrm{D}}_{g}, \mathrm{T}] \tag{9b}$$

where $\mathrm{T}^{\mathrm{U}}_{g}$ and $\mathrm{T}^{\mathrm{D}}_{g}$ are minimum up and down time of generator g, respectively. T denotes the end of time-horizon.

4) RENEWABLE GENERATION BOUNDS

Let $p^{\mathrm{R}}_{r,t}$ denotes the renewable generation output from generator r in time period t, and is modelled as follows:

$$\mathrm{P}^{\mathrm{R}-}_{r,t} \leq p^{\mathrm{R}}_{r,t} \leq \mathrm{P}^{\mathrm{R}+}_{r,t} \tag{10}$$

where $\mathrm{P}^{\mathrm{R}+}_{r,t}$ denotes the available renewable generation, and $\mathrm{P}^{\mathrm{R}-}_{r,t}$ denotes the part of the renewable generation that can not be curtailed. Note that the lower bound can be non-zero (or equal to the upper bound) to model the situations when part (or all) of the renewable generation is embedded and not curtailable.

E. OBJECTIVE FUNCTION

The overall objective function is to minimize the cost of electricity generation to meet a given demand. The objective function has following components

$$\mathrm{C}^{\mathrm{G}}_{t} = \sum_{g \in \mathcal{G}} f(p^{\mathrm{G}}_{g,t}) \tag{11a}$$

$$\mathrm{C}^{\mathrm{S}}_{t} = \sum_{g \in \mathcal{G}} x_{g,t}\mathrm{C}^{\mathrm{SU}}_{g} + y_{g,t}\mathrm{C}^{\mathrm{SD}}_{g} \tag{11b}$$

$$\mathrm{C}^{\mathrm{I}}_{t} = \sum_{i \in \mathcal{I}} \mathrm{C}^{\mathrm{Int}}_{i,t} p^{\mathrm{I}}_{i,t} \tag{11c}$$

$$\mathrm{C}^{\mathrm{R}}_{t} = \sum_{r \in \mathcal{R}} \mathrm{C}^{\mathrm{Crt}}_{r,t}(\mathrm{P}^{\mathrm{R}+}_{r,t} - p^{\mathrm{R}}_{r,t}) \tag{11d}$$

where (11a) is the overall cost of generation, (11b) is the cost of switching on/off generating units, (11c) is the cost (profit) of import (export) using interconnections and (11d) is the cost of curtailment of the renewable generation, for time period t, respectively.

F. THE UNIT COMMITMENT PROBLEM

The unit commitment problem is a mixed-integer linear programming problem that is solved over a given time horizon and is given as follows:

$$\min \sum_{t \in \mathcal{T}} \left(\mathrm{C}^{\mathrm{G}}_{t} + \mathrm{C}^{\mathrm{S}}_{t} + \mathrm{C}^{\mathrm{I}}_{t} + \mathrm{C}^{\mathrm{R}}_{t}\right) \tag{12a}$$

$$\text{subject to} \quad (1-3), (4 \text{ or } 5), (6-10) \tag{12b}$$

$$u_{g,t}, x_{g,t}, y_{g,t} \in \{0, 1\} \tag{12c}$$

where (12b) is the set of constraints for the UC problem, (12c) models the unit commitment, start-up and shut-down variables as binary.

G. THE MERIT ORDER PROBLEM

The merit order problem is a linear programming problem that is solved for each time-step and is given as follow, $\forall t \in \mathcal{T}$:

$$\min \sum_{t \in \mathcal{T}} \left(\mathrm{C}^{\mathrm{G}}_{t} + \mathrm{C}^{\mathrm{I}}_{t}\right) \tag{13a}$$

$$\text{subject to} \quad (1-3), (4 \text{ or } 5), (6), (10) \tag{13b}$$

$$u_{g,t} \in [0, 1] \tag{13c}$$

where (13c) relaxes the commitment variables to continuous variables.

H. SOLUTION APPROACH

The unit commitment and the merit order problems are implemented in PYOMO, which is a power algebraic modelling language [23]. To solve the optimisation problems, Gurobi is used as a solver [24]. Default settings of the solver was used to converge to the optimal solution. The implementation of the models is available in [25] and the Irish test case is available in [26].

III. IRISH ELECTRICITY SYSTEM

The Irish transmission system is operated by two transmission system operators: System Operator Northern Ireland (SONI) in Northern Ireland and EirGrid in Republic of Ireland, but as a Single Electricity Market. Figure 3(a) shows the High-voltage transmission map of Ireland [8] and Figure 3(b) shows the representative model that is used in this paper. The Irish system is divided into two zones, one for each transmission system operator, to model the transmission constraint within the Island of Ireland and between the two countries. Details regarding generation capacities, reserve requirements, interconnection capacities and scenarios for renewable generation penetration built for demonstration are provided in the following sections.

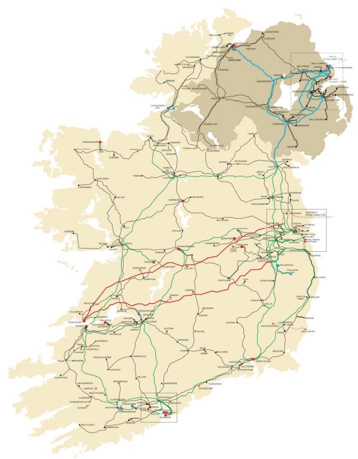
A. TRANSMISSION NETWORK

Northern Ireland is connected to Scotland via HVDC link, named East-West interconnector, with an interconnection capacity of 500 MW. Republic of Ireland is connected to Wales with an HVDC link, named Moyle interconnector, with an interconnection capacity of 500 MW. Despite 1000 MW of interconnection capacity between Great Britain and Ireland, the full capacity can not be utilized because of various technical and security constraints on either side of the border. The available *to* and *from* interconnection capacities are obtained from [27] and are presented in Figure 3(b).

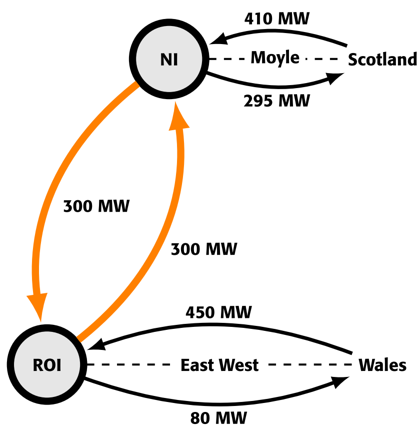
The border between Northern Ireland and Republic of Ireland is a key transmission bottleneck with very little network capacity at present, and long standing plans to implement a network reinforcement that have yet to be decided and implemented. There are currently only three transmission connections between the Northern Ireland and Republic of Ireland, and modelling the transfer capacity helps to demonstrate the overall limitations of the current network, while also aiming to ensure that there are not particular biases in the dispatch of generating units from either country. In this paper, 300 MW transmission capacity is considered between Northern Ireland and Republic of Ireland [27].

B. GENERATION CAPACITIES

On the Island of Ireland, there is a total of approximately 10 GW of thermal generation capacity. The wind generation capacity is approximately 3.6 GW of electricity. Northern Ireland has 1 GW of wind generation capacity and the



(a) High voltage electricity transmission system on the island of Ireland



(b) Representative transmission system model of the Ireland. The transfer capacities are obtained from [27]

FIGURE 3. High-voltage electricity transmission network in the Island of Ireland.

TABLE 1. Electricity generation mix on the Island of Ireland and cost assumptions used for generation.

Fuel Type	Units	Capacity (MW)	Capacity (%)	% in NI	% in ROI	Cost(€/MWh)
Coal	5	1331	13.93	4.98	8.95	51
Gas	24	5858	61.33	16.01	45.32	57
Gas Oil	14	712	7.45	4.06	3.39	137
Gas Oil Peat	1	118	1.23	0.00	1.23	137
Oil	4	594	6.22	0.00	6.22	141
Peat	2	233	2.44	0.00	2.44	87
Waste	4	146	1.53	0.19	1.34	87
Hydro	15	292	3.06	0.00	3.06	45
Pumped St.	4	268	2.81	0.00	2.81	45
Total	73	9552	100.00	24.24	74.46	-

remaining is in the Republic of Ireland [28]. A public version of the generation capacities and dynamic parameters was published by the Irish market operator SEM that is used in this paper [29]. In this data, the thermal generation fleet in the Island of Ireland is made up of seventy-three individuals units. Nineteen of which are in Northern Ireland and fifty-four are in the Republic of Ireland. A full breakdown of the generation fleet, which is used for simulations in this paper is outlined in Table 1. Technical parameters of thermal generation like cost data, ramp rates, up and down times an minimum stable operating points are taken from [29].

C. RESERVE REQUIREMENTS

The two market clearing models provide a provision of extra capacity which must be available to compensate for planned and unplanned outages of generating plants as well as variations demand. The reserve requirement for the simulations presented in this paper is set at 300 MW in Northern Ireland and 500 MW in the Republic of Ireland [30].

D. SCENARIOS

1) GENERATION FROM WIND POWER

Although there is around 3.6 GW wind capacity installed in Ireland, not all of this accessible for dispatch all of the time. To address this issue, realised data from year 2019 is used to model hourly variation in penetration of wind power generation in each zone.

2) DEMAND

The case study in this paper utilises demand data sourced from the online dashboard of EirGrid, the electricity system operator in Ireland [8]. The demand data is in hourly resolution and presents diurnal and seasonal trends.

3) INTERCONNECTORS

The power flow across two interconnectors is challenging to model purely base on price differences. This is because the trading mechanism of interconnections is complex and the flow of power through either interconnector varies independently and continuously depending on either markets' needs, system operator needs and contracts that might have been struck forward market. Taking these complexities into account and to ensure an accurate and representative model of interconnection penetration is achieved, actual realised hourly data for year 2019 was assembled.

IV. RESULTS

The developed models are tested on an hourly historic data for the year 2019. The planning time horizon chosen for the unit commitment problem is 24 hours, with an hourly resolution. Each day in 2019 was treated independently in the analysis. To better account for boundary effects related to the start and stop of thermal units, the unit commitment problem was solved for a time period of $[-2+0, 24+2]$ hours.

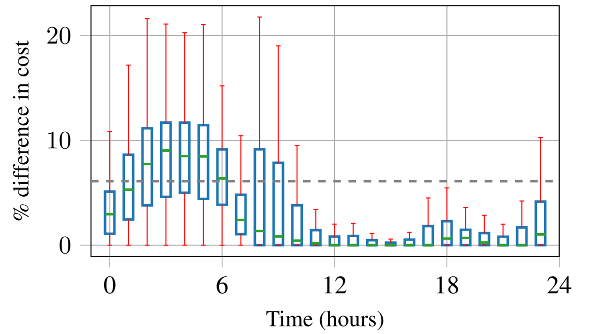
The decision to extend the planning period by 2 hours at both the beginning and end of the 24-hour planning time-period was informed by empirical testing. The results show that 2-hour extension effectively captures the essential boundary effects. This is one of the standard approaches in literature to cater the boundary effects, where another approach is to use rolling time horizon [31], with fixing initial conditions from a prior run of the model.

Figure 4(a) presents average percentage difference in cost between the unit commitment and the merit-order problems over the course of a day. The average difference across 24-hours of 365 days is approximately 6%. Notably, the most substantial disparity in cost between the two models occurs during the early hours of the planning horizon, specifically between 2:00 am and 5:00 am. This divergence is attributed to the fact that the start-up time for fossil fuelled thermal generators averaged around 4 hours. The unit commitment model, incorporating a look-ahead component, committed generators in anticipation of rising demand and the need for flexibility during morning demand peak. In contrast, the merit order model lacked a look-ahead component, committing generators without foresight into future demand patterns.

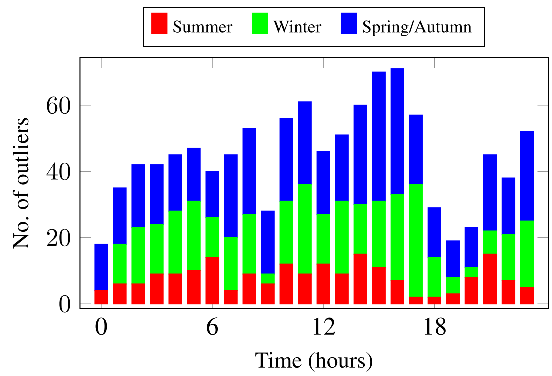
Figure 4(b) provides additional insights on the number of outliers in each hour of the planning time-horizon. Notably, a higher frequency of outliers was observed during 15:00 to 16:00 hours, despite the rest of the data exhibiting relatively small variability. The figure also highlights that the summer season contributes to a smaller number of outliers compared to the winter season, where demand was higher. The results highlight the interplay of several factors influencing the results from the unit commitment and merit-order problems, shedding light on the temporal and seasonal variations in their outcomes.

Table 2 presents three relaxed versions of a unit commitment model. The first variant, labelled as `UC-MSL`, involves relaxing the minimum stable operating constraints. The second, denoted as `UC-RR`, represents the unit commitment problem excluding the ramp rate constraints. Finally, the third model `UC-MinT`, is a unit commitment model without including the minimum up/down time constraints. These variations were compared against full formulation of the unit commitment model to asses their respective performance.

The results demonstrates the constraint with the most substantial impact on the solution is associated with the minimum stable operating point. The UC-MSL variant, yields a solution that is approximately equal in performance to a merit-order solution. On the other hand the removal of the minimum time constraints (UC-MinT) introduces an error of approximately 3.5%. Despite this error, it is less pronounced compared to the relaxation of the minimum stable operating point constraints. The finding suggest that the minimum time constraints play comparatively less dominant role in influencing the solution. Surprisingly, the ramp rate constraints, exhibit the least impact in our case study. this implies that the removal of ramp rate constraints has a relatively minor effect on the overall cost difference when compared to the other relaxation constraints



(a) Percentage difference in marginal cost of UC and MO models over a day with hourly resolution. Demand, wind generation and interconnection flows data was used for the year 2019. The mean percentage difference in cost of approximately 6%.



(b) Number of outliers in each time interval for the year 2019. The outliers are then divided into seasons.

FIGURE 4. Results of solving UC and MO models on the Irish network with the background data from the year 2019.

TABLE 2. Modified unit commitment models by removing constraints.

Model	Comments
`UC-MSL`	Minimum stable operating point constraint removed from the unit commitment formulation
`UC-MinT`	Minimum up and down time constraints removed from the unit commitment formulation
`UC-RR`	Ramp rate constraints removed from the unit commitment formulation

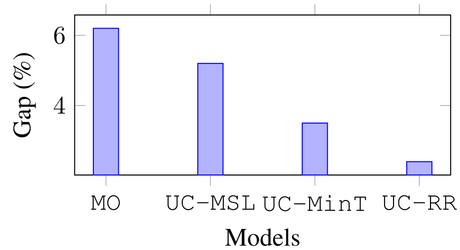


FIGURE 5. Percentage difference in cost (gap) between merit-order models, models derived by relaxing constraints in the unit commitment model from the unit commitment solution.

V. CONCLUSION

The paper explores different electricity market clearing models, specifically comparing the merit-order and unit commitment models. The models are tested on an Irish test case, with a planning horizon of 24 hours. Results show that the average error between the simplistic merit-order model and the more complex unit commitment model is approximately 6%. A key aspect of the investigation involved a deeper exploration on the observed differences between the two models. The paper explores the impact of minimum stable operation constraints in the unit commitment problem, finding that they significantly influence the model's performance. Beyond numerical disparities, the findings offer valuable insights into the trade-offs associated with relaxing specific constraints within the unit commitment model. This understanding is essential for practitioners in the electricity market, as it sheds light on the delicate balance between model complexity and accuracy. Our future research will focus on the impact of market clearing models on system reliability, flexibility and addressing transmission-related challenges. By delving into these dimensions, the research aims to provide a more holistic understanding of the intricate interplay between market clearing models and multifaceted aspects of power system operations.

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