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Assessing Power System Flexibility for Variable Renewable Integration: A Flexibility Metric for Long-Term System Planning

Eamonn Lannoye* and Aidan Tuohy (Electric Power Research Institute)
Pádraig Daly*, Damian Flynn and Mark O’Malley (Electricity Research Centre, University College Dublin, Ireland)

*elannoye@epri.com; padraig.daly@ucdconnect.ie

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Abstract
Many countries around the world have instituted policies with the aim of increasing the amount of installed variable generation (VG), such as wind and solar. A consequence of increased penetrations of VG is that changes in their output must be met by the remainder of a system’s resources so that the demand-generation balance is maintained. This paper proposes a high-level methodology to assess power system flexibility. In this context, flexibility is the ability of a power system to deploy its resources to meet changes in the system demand and that of variable generation. The inclusion of such analysis at the long-term system planning stage will help to ensure that systems are optimally planned and operated with high levels of VG. Two case studies are presented which illustrate the flexibility assessment methodology and highlight some key issues relating to flexibility in the context of long-term planning.

Keywords
Flexibility, generation portfolios, variable generation, wind power generation, solar power generation.
1. Introduction

The installed wind and solar power generation capacity has risen sharply in the last 20 years in response to environmental, economic and energy security concerns [1], [2]. As the technology improves and capital costs decrease, the number of power systems with significant installed wind and solar capacity, relative to their system demand, will increase. Long-term planning for this scenario is prudent, given the lead time required to make physical and institutional changes to a power system’s infrastructure, and the effect of wind and solar generation on system operation [3], [4].

A significant barrier to the integration of renewable generation has historically been the perceived need for additional capacity for periods when renewable generators are unable to produce. While an understanding of the capacity adequacy of variable generation (VG) is maturing [5], [6], system operators are now also concerned with the magnitude and uncertainty of the ramps associated with VG [7]-[10]. Experience in ERCOT [11], Europe [12], and Midcontinent ISO [13] with wind and solar generation has highlighted the challenge posed by a large change in output from regional renewable VG production, particularly when system demand is changing in the opposite direction. Indeed, when determining the ability of a system to integrate VG, it is imperative to consider the variability of the system’s net load\(^1\), rather than considering the variability of each VG technology and system demand independently. Thus, the magnitude of ramps in VG production, up or down, the correlation of VG production with system demand, the time horizon over which ramps occur and the ability of a system operator to forecast future VG production must all be considered.

Power system flexibility has been defined as the ability of a system to use its resources to meet changes in its net load [14], [15]. Flexible resources are those which can change their output sufficiently quickly in response to a changing net demand, and include conventional generators, interconnection, demand response (DR) [16]-[18], energy storage [19] and controllable VG. Other factors which affect the availability of flexible resources include the strength of the transmission network [20], and the design of operational [7], market [21] and policy [22] measures.

Inadequate system flexibility may require a number of planning level decisions in order to rectify any potential deficit. The design of markets, cooperation with other markets, dependence on single fuel types, or the incentivisation of certain plant properties all require a high-level management strategy. In the case where additional flexibility will not be forthcoming, despite the best efforts of policy makers, planners and operators, flexibility limits will have repercussions on emissions targets due to the potential VG curtailment, as well as economic impacts if demand shedding is required. Thus, an understanding of the potential risks associated with system flexibility is important at the long-term planning stage. Furthermore, with significant volumes of VG installed at the distribution level, distribution system planning methods [23] may also need to incorporate flexibility considerations.

VG integration studies have been carried out in a number of systems worldwide to determine whether the current, or future, generation portfolios and operational arrangements are adequate when a target amount of VG is added [24]-[27]. These studies take the form of production cost modelling and/or frequency and voltage stability analysis [28], where schedules are created using unit commitment (UC) algorithms. UC simulation tends to be computationally intensive given the structure of the problem and the nature of the variables being optimised [29]. Furthermore, given the large number of sensitivities in UC studies, and the many permutations of possible outcomes, it is generally only possible to study a small number of the possible scenarios for a given portfolio of

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\(^1\) Net load is defined as the system demand which is not met by VG production.
generators. Thus, the outcome of integration studies do not explicitly characterise system flexibility; further analysis is required.

Flexibility metrics have been developed for long-term and operational planning time frames [14], [30]-[36]. Additional metrics have been developed to measure the flexibility of an electricity market design [37], to price ramping capability [38], and to assess the robustness of a transmission network to future generation locations [39]. One example of a system flexibility metric is the insufficient ramp resource expectation (IRRE) [14], which uses the outcome of production cost simulations to obtain a probabilistic measure that a system will have sufficient ramping capacity to meet changes in net load. The advantage of this detailed assessment is that operational constraints are directly included in the methodology. However, calculation of the IRRE is computationally intensive and the outcome requires an appreciation of the algorithm in order to best interpret the results.

In contrast with the IRRE, the flexibility assessment tool (FAST) [40] uses a minimal set of generator data, supported by VG production and demand characteristics to determine the VG penetration which a system may integrate before flexibility limits are exceeded. The advantages of the FAST methodology are that it reduces the computational and data burden, and that the methodology is highly intuitive. The disadvantage is that many simplifying assumptions are made which may result in over confidence, or an unnecessary concern, in the ability of a system to meet net load ramps. This paper proposes a flexibility assessment methodology that balances the detail of the IRRE and the accessibility of the FAST methodology: the number of periods of flexibility deficit (PFD) method.

In order to demonstrate the proposed flexibility assessment metric, the methodology is applied to the island of Ireland power system and the power system in Hokkaido Prefecture, Japan. These systems are similar in terms of maximum system demand, however, the demand profiles, VG production profiles, operational policies, market designs and the flexible resources in each system differ significantly. Therefore, while each system may be adequate from a generation capacity perspective, system flexibility for each is likely to be significantly different.

The paper continues in Section 2 with an outline of the PFD flexibility metric. The metric is applied to the two case study systems, the results of which are presented in Section 3. A discussion of the strengths and weaknesses of the methodology, and of the case study results, are included in Section 4. Section 5 concludes.

2. Methodology

The assessment of flexibility involves three stages: calculation of (i) the flexibility available from resources, (ii) the requirement for flexibility, and (iii) the balance between the availability and the requirement. The flexibility assessment methodology proposed here uses a merit order commitment and dispatch to calculate the flexibility available, and then compares this availability to the flexibility requirement, which is calculated from net load ramps.

It is worth noting that this high-level methodology does not directly assess the flexibility provided or constrained by a system's operational or market policies. Nor is the availability of transmission system capacity to manage changes in net production from each resource during periods of net load ramping considered, as done so by [20]. The methodology proposed here is appropriate for the early stages of the planning process. The following sections outline the data requirements, the importance of ramping time horizons, and the flexibility assessment process.
2.1. Data Requirements
Synchronised system demand and VG production time series are required to determine the net load ramps – which are the key determinant of flexibility – and to schedule resources. Characteristics including maximum capacity, minimum stable generation level, ramp rates, start-up times, forced outage rates and no-load and marginal costs are required for conventional generators, so that the resources can be committed and dispatched. With the rise of DR in ancillary service markets [41], it will be increasingly important to recognise the flexibility provided by DR. Electric vehicles [42], storage heaters [43] and thermostatically controlled loads [44] are all sources of flexibility to the system. As flexibility providers, there are key differences between DR and conventional generation. DR is energy limited, and for the time scale(s) of interest, knowledge of the quantity, duration and usage limits of DR flexibility is necessary. It may be the case that a single commercial/industrial DR provider, or residential aggregator, cannot provide a sustained response for a given duration, e.g. 1 hour (due to thermal inertia/storage limitations). However, system operators could schedule such resources sequentially to yield the desired system response for an extended period of time. It is important to also capture the energy pay-back period associated with thermostatically controlled loads coming back online following the provision of upward flexibility. Switching such loads back online, particularly if in coincidence, is a potential short-term sink of flexibility. Characteristics for any interconnectors or energy storage resources, as well as details of agreements for reserve provision over each interconnector, constraints on the levels of flow via interconnection, and the round trip efficiency of each storage resource, are also required. Finally, any reserve targets which require a response from online resources in the event of a contingency, and/or VG/demand forecast error, are required so that these can be included in the merit order, since they are sources or sinks of operational flexibility.

2.2. Time Horizon and Ramp Direction
The magnitudes of the changes in net load are a function of the time horizon over which they are determined. For example, changes in net load over short time horizons (e.g. 10 minutes) are likely to be small relative to the net load ramp over a 10 hour time horizon. Therefore, it is important to consider the flexibility of a system for a number of time horizons. Furthermore, the resources available in each time horizon may vary, e.g. offline resources may be in a position to come online and provide flexibility if the time horizon is longer than the start-up time for that unit, whereas flexibility from DR and storage may only be available at shorter time horizons. Given that the net load ramps are calculated as the difference between net load observations, the time resolution of the system demand and VG production series is important. If the resolution is high then the flexibility may be determined for a wide range of time horizons (e.g. with 5 minute resolution, time horizons between 5 minutes and 24 hours could be calculated). Coarser time resolutions, such as hourly data, mean that short time horizons, such as intra-hourly ramps, cannot be examined. The time horizons studied may coincide with those which are important operationally, such as a demand/VG forecast horizon or the start-up time of a dominant generation technology type.

In addition to the time horizons considered, the direction of the net load ramp is important. Those resources available to meet increasing net load (up ramps) may not be the same as those available to meet decreasing net load (down ramps). Flexible resources face different constraints in each direction: minimum generation levels and offline status of conventional generation, the storage level and mode of operation of pumped, compressed air and/or battery storage, etc., affect system downward flexibility. The maximum capacity and start-up times of conventional generation, the energy limits of DR, and again the status of storage, etc., affect system upward flexibility capability. To fully assess the flexibility of a system, analysis may be carried out for both increasing and
decreasing net load, and for a range of time horizons. It is assumed here that up ramps will be the limiting factor, given that either the ability to reduce/curtail generation or the ability to disconnect generators are available to a system operator (with sufficient notice) for a given situation of downward ramping deficit. As a consequence, downward ramps are not considered further here, however this is not to say that they can be ignored.

2.3. Available Flexibility
The flexibility available at any given time depends on the state of each resource at that time. Production scheduling in planning models is typically carried out using a UC tool and may include certain constraints necessary for the operational security of the system, which may be computationally intensive. Here, a simplified commitment and dispatch methodology is employed which is shown later to acceptably approximate UC schedules for high-level planning purposes.

2.4. Merit Order
An alternative to UC is the merit order approach, where the merit order curve is essentially a short-run power supply curve given by the average cost of energy for each unit at maximum output [45], [46]. At each observation the demand is assumed to be price inelastic up to the market ceiling. This provides a simple rule for resource commitment: units are committed at each observation in a net load time series in order of increasing average cost at maximum output until sufficient capacity to meet the net load is online.

The merit order solution represents the lowest possible cost solution to meeting the net load, since the methodology minimises costs for each time horizon individually, rather than considering the forecasted net load or other constraints such as resource start-up times and costs, ramp rate constraints etc. There is an implicit assumption that the net load is perfectly forecasted at each observation.

2.5. Merit Order Curve Calculation
The merit order curve can be calculated using the methods laid out in [45]. The average cost at maximum output ($AC$) for each generator and energy storage resource is calculated as in (1).

$$AC = \frac{NLC + Capacity \times MC}{Capacity}$$ (1)

where $MC$ is the marginal cost of each resource, $NLC$ is the no-load cost and $Capacity$ is its maximum capacity. While these values are readily available for generators and storage units, the treatment of flows over interconnectors requires some judgement. The no-load cost of an interconnector is usually zero, while the marginal cost will change depending on the energy price in neighbouring systems. Hence, an interconnector may be treated as a multi-unit generator. For example, a single 400 MW interconnector may be split into two sub-units (e.g. two 200 MW units: IC-1 & IC-2). Based on experience, the marginal cost of each sub-unit can be set based on its cost relative to other resources. It may be the case that imports typically commence before a certain resource is committed. The average cost for the first sub-unit of the interconnector is then set just above the average cost of the last committed resource. This process is repeated for each sub-unit of the interconnector. The merit order is then deduced by ranking the resources in order of increasing $AC$. An example merit order, for illustrative purposes, is given in Table 1.
Table 1: Example merit order

<table>
<thead>
<tr>
<th>Unit</th>
<th>No-Load Cost (€/h)</th>
<th>Marginal Cost (€/MWh)</th>
<th>Capacity (MW)</th>
<th>Average Cost (€/MWh)</th>
</tr>
</thead>
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<tr>
<td>Coal</td>
<td>1000</td>
<td>20</td>
<td>500</td>
<td>22</td>
</tr>
<tr>
<td>IC 1</td>
<td>0</td>
<td>24</td>
<td>200</td>
<td>24</td>
</tr>
<tr>
<td>Gas</td>
<td>400</td>
<td>25</td>
<td>200</td>
<td>27</td>
</tr>
<tr>
<td>IC 2</td>
<td>0</td>
<td>28</td>
<td>200</td>
<td>28</td>
</tr>
<tr>
<td>Storage</td>
<td>250</td>
<td>40</td>
<td>125</td>
<td>42</td>
</tr>
</tbody>
</table>

2.6. Commitment and Dispatch

The net load, $NL_t$, at a given time period, $t$, is calculated according to (2), where non-dispatchable generation may include VG and run of river hydro with little storage capacity:

$$NL_t = \text{System Demand}_t - \sum \text{Non Dispatchable Generation}_t$$

The net load is ranked to form the net load duration curve, Figure 1. Each generator is initially assumed to be perfectly reliable. Beginning with the least cost generator, blocks of generation are added until the net load is met. Interconnectors and storage devices are initially assumed to act as generators; exports and the charging demand associated with storage are included later. It can be seen from the illustrative case in Table 1, which is committed and dispatched in Figure 1, that the coal unit is always online and that the first part of the interconnector commences production when the net load reaches 500 MW and gradually increases its production up to maximum capacity, as per Table 1. The costly storage unit only serves net load for 25 hours of the year, when the net load is at its highest (see insert in Figure 1).

Figure 1: Net load duration curve for the merit order of the example portfolio (Table 1). A 400 MW interconnector has been split into IC-1 and IC-2 sub-units.
The energy consumed by the storage units, including an allowance for the cycle efficiency losses, must be replaced. It is assumed here that such consumption occurs at the lowest net load hours. This assumption may be relaxed if more details about the operation of storage units are known. Since exports over interconnectors will increase production, this should also be incorporated in the merit order. The intersection of the merit order curve and the export trigger price results in a net load level below which exports may occur. In the example system, this occurs at 500 MW. Once exports are included, the system is re-dispatched as shown in Figure 1. In this case the coal unit increases its output to 500 MW to meet the combined export and consumption from storage. The final step in preparing the merit order is to ensure that generators respect their minimum stable generation level (MSG). If a committed resource is dispatched below its MSG, the output of the previously dispatched generator is decreased accordingly. This represents the most basic form of commitment and dispatch, however a number of possible improvements, such as the inclusion of reserve, are possible.

System operators carry reserves to meet unpredicted events in a system and/or for load following. Hence it is important to include reserve in the merit order process since the number of units online may be altered as a result, which may affect the available flexibility. Most systems incorporate a reserve category which corresponds to the loss of the largest infeed (generator output and/or import via interconnection), or a certain proportion of the demand. In order to include the indirect effect of contingency reserve on flexibility, the predetermined contingency reserve target is added to the net load duration curve before the merit order is performed.

So that the diurnal cycle of net demand can be recognised, an inter-hourly net load ramping adjustment may be included. The net load ramping adjustment corresponds to the average up ramp in net load for each hour. For each hour of the year, (e.g. 6 a.m.) the average change in net load over six hours is calculated over all similar hours in the year. The average ramp is then added to the net load energy requirement and sufficient capacity is committed to meet both. The net load ramping adjustment is necessary to mimic the inter-temporal constraints which are in force in reality, ensuring that predictable cyclical ramping will be provided for. A more conservative (and costly) approach would be to choose the 90th (or similar) percentile of net load changes as the adjustment.

It may also be desirable to account for VG production uncertainty [47], [48]. Two forms of uncertainty could be accounted for: (i) the day-ahead forecast error of wind and/or solar active power generation could be captured by adding a factor to the reserve target calculation. (ii) The uncertainty associated with the magnitude of wind and/or solar production ramps, and hence the unpredictability of net load ramps, could be allowed for by adding a factor to the net load ramping requirement calculation.

Once the resources that are online at each observation in the net load duration curve have been identified, the system is re-dispatched to meet the original net load duration curve without the reserve target, while ensuring that all resources which were identified as being online, remain so. The effect is to ensure that there is always some flexibility available from online resources to meet changing net load. Once the production schedules are known for each resource, a system’s flexibility may be analysed.

2.7. Available Flexibility

2.7.1. Online Flexibility

Having selected the time horizon(s) of interest, the flexibility available at each index, \( i \), in the net load duration curve can be calculated from the merit order. Figure 2 illustrates the online flexibility
each resource could offer, if each resource's ramp rates did not limit changes in production. For simplicity of illustration it is assumed here that all units have a MSG of 0 MW and are dispatched as in Figure 1. It must be noted that if an interconnector is split into sub-units for dispatch purposes, then all parts of the interconnector are online and available to offer flexibility when the cheapest part of the interconnector is scheduled, as seen in Figure 2.

The online flexibility, \( Flex^{\text{online}} \), that a resource, \( r \), may offer over a certain time horizon, \( h \), is bounded by its ramp rate limit, \( RR \), and the available headroom for the unit, as expressed in (3).

\[
Flex^{\text{online}}_{i,h,r} = \min(\text{Online}_{i,r} \times min(RR_r \times h, \text{Capacity}_r - \text{Production}_{i,r}))
\]  

(3)

where \( i \) is the index of the net load duration curve, and \( \text{Online} \) is the Boolean online variable for each resource. \( \text{Production} \) and \( \text{Capacity} \) are the active power output and maximum output of each resource, respectively.

![Figure 2: Total generation and online flexibility at each index of the net load duration curve, for each resource, in the example portfolio](image)

### 2.7.2. Offline Flexibility

Additional flexibility may be available by starting offline resources, depending on the start-up time, \( \text{StartTime} \), of each resource and the time horizon under scrutiny. Resource offline flexibility, \( Flex^{\text{offline}} \), is given by (4):

\[
Flex^{\text{offline}}_{i,h,r} = \left( \min(RR_r \times (h - \text{StartTime}_r), \text{Capacity}_r) \right) \times (1 - \text{Online}_{i,r})
\]

\( \forall h \geq \text{StartTime}_r \).
2.7.3. Total Available Flexibility

The total flexibility available, for a given time horizon, at each index in the net load duration curve, is calculated by summing the offline and online flexibility from each resource in the resource set, $R$. The total available flexibility for the example system, at each index, is shown in Figure 3, over a time horizon sufficiently long to allow all units to come online to provide flexibility from an offline state. The coal unit does not provide any upward flexibility since it is always at maximum output. It can be seen that the total flexibility is lowest when the net load is highest, since unit capacity is required to meet demand.

![Figure 3: Total system flexibility at each index in the net load duration curve of the example portfolio](image)

2.8. Flexibility Requirement

The next step is to calculate the net load ramps, which serve as the requirement for flexibility. The net load ramp, $NLR$, at give time period, $t$, over a time horizon, $h$, is the difference between sequential net load levels, as shown in (5).

$$NLR_{t,h} = NL_{t+h} - NL_t \quad (5)$$

where $|NL|$ is the length of the net load time series. Each ramp in net load can be paired with the net load level at the start of that ramp. If the net load ramps are sorted according to their corresponding net load levels, from maximum net load to minimum, this rearranges the net load ramps to match the net load duration curve, which has been used in the merit order calculation. Therefore, the net load ramp at each index in the net load duration curve is known, which can be compared to the total available flexibility. If the time of day is noted when sorting the net load to form a net load duration curve, it is possible to associate the time observations with a net deficit of flexibility.
The net deficit of flexibility, $D$, is determined by subtracting the total available flexibility from the net load ramp, as shown in (6). Positive values indicate periods of insufficient flexibility to meet upward changes in the net load:

$$D_{i,h} = NLR_{i,h} - \sum_{r} (Flex_{i,h,r}^{\text{online}} + Flex_{i,h,r}^{\text{offline}})$$  \hspace{1cm} (6)$$

The number of positive observations of the net deficit of flexibility represents a similar metric to the insufficient ramp resource expectation (IRRE) proposed in [14]. The IRRE is the expected value of the number of observations in a net load time series for which the net load ramp cannot be met. The IRRE is a probabilistic value determined using extensive production cost modelling. The method proposed here requires considerably less computational effort and is deterministic in nature. The number of periods of flexibility deficit, $PFD$, shown in (7), is employed here to characterise the flexibility of a system, where $\#D$ is the number of observations in the deficit time series:

$$PFD_{h} = \#D_{i,h} \in \mathbb{R}^+.$$  \hspace{1cm} (7)$$

The reserve made available for contingencies must not be made available to meet the net load ramps, which can be achieved by imposing the contingency reserve requirement on the net load ramps at each time observation. An advantage may still accrue to the system operator however, given that more units will tend to be online, with the potential for greater headroom from each unit than otherwise.

### 2.8.1. Resource Outage Effects

Thus far it has been assumed that all resources are perfectly reliable. This over optimistic assumption may skew the resulting $PFD$. In order to remove this assumption, the merit order and flexibility assessment can be repeated with the removal of each resource in turn. There are $(R + 1)$ PFD values for each time horizon, where $R$ is the number of resources in the system. Using a weighting system based on the forced outage probabilities ($FOP$) of each resource, $r$, shown in (8)-(10), a final PFD value, $PFD_{FINAL}$, is determined. Due to the computational efficiency of the PFD methodology, the calculation of a weighted average is not burdensome. In cases where forced outage probabilities are not available from the provided data, data can be taken from [49].

$$PFD_{FINAL,h} = PFD_{SYS,h} \frac{Coeff_1}{Coeff_1 + \sum_{r=1}^{R} Coeff_2} \frac{Coeff_2}{Coeff_1 + \sum_{r=1}^{R} Coeff_2} \frac{Coeff_2}{Coeff_1 + \sum_{r=1}^{R} Coeff_2} \frac{Coeff_2}{Coeff_1 + \sum_{r=1}^{R} Coeff_2}$$  \hspace{1cm} (8)$$

$$Coeff_1 = \prod_{r=1}^{R} 1 - FOP_r$$  \hspace{1cm} (9)$$

$$Coeff_2 = FOP_r \prod_{j=1, j \neq r}^{R} 1 - FOP_j$$  \hspace{1cm} (10)$$

The $PFD_{FINAL}$ can be normalised by the number of upward ramps in the net load ramp time series for each time horizon. The magnitude of the difference between the PFD values for each scenario
when a resource is removed and the final PFD value indicates the sensitivity of the system's flexibility to the loss of a particular resource.

2.8.2. Analysis of Flexibility Surplus and Deficit
The PFD values may vary significantly according to the time horizon, identifying horizons of greater risk. An analysis of the net deficit of flexibility, $D$, for the time horizon(s) of greatest risk may offer insight into the potential challenge(s) faced by a system operator. For example, if the mean deficit and surplus of flexibility are close to zero, relative to the magnitude of the largest net load ramp for that time horizon, the PFD value is likely to be sensitive to small changes in the net load time series, the generation portfolio, or the scheduling procedure. Consequently, this may indicate that the system is significantly more reliable if the deficit is close to zero, from a flexibility perspective. However, if the average deficit is large and the standard deviation of the deficit of flexibility is small, greater operational and planning changes may be required to increase the flexibility of the system.

3. Case Studies
Systems with similar demand profiles and with similar reliability (i.e. ability to meet peak demand) may have significantly different flexibility characteristics. Two systems are considered which have comparable peak system demand values, but different penetrations of installed VG capacity and different resources available to meet net load ramps. The flexibility of the island of Ireland power system (case study 1), and the power system in Hokkaido Prefecture, Japan (case study 2), are assessed.

3.1. Case Study 1: Ireland and Northern Ireland
The population on the island of Ireland is 6.4 million and the peak winter demand was 6.2 GW in 2013, which is set to rise to 7 GW by 2020 [50]. The system has two 500 MW interconnections to Great Britain, and 2.4 GW of installed wind power capacity at the end of 2013 met 19.1% of system demand. The governments of the Republic of Ireland and of Northern Ireland have set targets for 40% of electrical energy to be met by renewable generation by 2020. The system in 2020 is assumed to have 4.5 GW of installed wind generation, which is sufficient to meet the renewable target [50]. Gas-fired units largely dominate the Ireland generation portfolio; the isolated nature of the system means that the portfolio has historically been required to be relatively flexible.

The flexibility of the 2020 Ireland system is determined using the PFD methodology with projected hourly resolution net load data. Table 2 presents calculations of system flexibility for 6 indexes of the 2020 Ireland system net load duration curve, i.e. net load, online, offline and total flexibility, the flexibility requirement, and resulting flexibility deficit (or surplus). Table 2 highlights the extent to which flexibility requirements can vary in a system with high VG penetration. Although the online and offline system flexibility do not change for the chosen hours, the system flexibility requirement changes significantly – due to the different net load ramps experienced at each period. It can be seen that a significant ramp occurs during the 6,247th index of net load, resulting in a deficit of system flexibility. The 6,249th index has no flexibility requirement, as there is no (hourly) net load ramp. A flexibility requirement at longer or shorter time horizons may still exist. In each hour shown, there is 260 MW of spinning reserve online (for contingency reserve), however, this must not be made available to meet the net load ramps.
Table 2: Flexibility data for 6 consecutive indexes in the net load duration curve, Ireland 2020

<table>
<thead>
<tr>
<th>Index (of 8784)</th>
<th>Net Load (MW)</th>
<th>Flexibility Requirement* (MW)</th>
<th>Online Flexibility (MW)</th>
<th>Offline Flexibility (MW)</th>
<th>Total Avail. Flexibility (MW)</th>
<th>Flexibility Deficit** (MW)</th>
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<tbody>
<tr>
<td>6245</td>
<td>188.39</td>
<td>692.45</td>
<td>144</td>
<td>1922</td>
<td>2066</td>
<td>-1373.55</td>
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<tr>
<td>6246</td>
<td>188.11</td>
<td>32.35</td>
<td>144</td>
<td>1922</td>
<td>2066</td>
<td>-2033.65</td>
</tr>
<tr>
<td>6247</td>
<td>185.93</td>
<td>4211.63</td>
<td>144</td>
<td>1922</td>
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<td>6248</td>
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<td>144</td>
<td>1922</td>
<td>2066</td>
<td>-1599.91</td>
</tr>
<tr>
<td>6249</td>
<td>181.20</td>
<td>-</td>
<td>144</td>
<td>1922</td>
<td>2066</td>
<td>-2066.00</td>
</tr>
<tr>
<td>6250</td>
<td>179.25</td>
<td>535.59</td>
<td>144</td>
<td>1922</td>
<td>2066</td>
<td>-1530.41</td>
</tr>
</tbody>
</table>

* The flexibility requirement is the net load ramp, for the time horizon of interest (hourly in this case). The net load ramp is the difference between net load values of consecutive time periods, which is then matched to the respective index in the net load duration curve.

** Positive values indicate periods of insufficient flexibility to meet upward changes in the net load.

To assess the accuracy of the PFD methodology, Figure 4 compares the flexibility assessment results using the PFD metric to that using the IRRE metric (following the methodology proposed in [14]), for the 2020 Ireland system. It can be seen in Figure 4 that the PFD follows a similar trajectory to the IRRE, with the peak PFD value (5.7%) in the 5 hour time horizon coincident with the peak IRRE value (4.4%). For time horizons greater than 5 hours, the IRRE is higher than the PFD, as zero IRRE is unlikely due to the IRRE considering a distribution of flexibility available at each net load level. The simultaneous peak in IRRE and PFD corresponds to the start-up time of the dominant technology type in the Ireland power system: the combined cycle gas turbine (CCGT). The PFD can be seen to be a good approximation of the IRRE since it identifies critical time horizons which should be addressed at the early planning stages.

![Figure 4: Flexibility assessment comparison: periods of flexibility deficit (PFD) vs insufficient ramp resource expectation (IRRE), Ireland 2020](image)

Figure 4: Flexibility assessment comparison: periods of flexibility deficit (PFD) vs insufficient ramp resource expectation (IRRE), Ireland 2020.
Further analysis is then carried out for the most challenging time horizon by determining the relative frequency of the 5 hour flexibility shortfalls at each hour. Figure 5 shows that shortages of upward flexibility in 2020 are loosely concentrated around two events: the morning rise in demand (4 a.m. to 8 a.m.) and the evening peak (5 p.m. to 8 p.m.). Since the net load ramping adjustment includes an annual average for each hour, resources are not optimised to manage each morning rise individually. It is seen in Figure 5 that 25% of flexibility shortages in 2020 occur between 4 a.m. and 8 a.m. with a further 25% between 1 p.m. and 5 p.m. Given that system operators understand the daily demand cycle from experience, confidence should be gained that the system can operate successfully at similar PFD values. Unit commitment instead of the merit order methodology would remove this issue.

Figure 5 also shows the relative frequency of flexibility shortages for the Ireland system in 2009 when 1.3 GW of wind generation met 10% of system demand. The market model produced by the Irish Commission for Energy Regulation [51] is used for the 2009 case. In comparison to the 2020 system, the 5 hour shortages of flexibility in 2009 are heavily concentrated at hours before 6 a.m., due to the dominance of the morning rise in determining major 5 hour net load ramps. As the amount of wind generation capacity increases, the influence of system demand on the variability of the net load diminishes. As a result the distribution of shortages of net load is likely to become more uniform and less predictable, as seen in the transition between 2009 and 2020. Therefore, while in 2009 it was safe to assume that the system operator would be able to predict significant ramps and act accordingly, as the penetration of VG increases, the importance of forecasting is significant since net load ramps become less predictable and are not restricted to certain times of day. Furthermore, the effect of additional VG is to counteract the demand ramps in the morning, while causing issues at other times of the day. As a result, it is important to consider the system net load variability, rather than ramping requirement specific to a single resource type.
3.2. Case Study 2: Hokkaido, Japan

Hokkaido Prefecture is an island situated directly to the north of the Japanese mainland, with a population of 5.5 million and a winter peak demand of 5.8 GW in 2010. The system is operated by the Hokkaido Electric Power Company (HEPCO) and is connected to the mainland power system by means of a 600 MW HVDC interconnection. The generation portfolio consists of nuclear, coal, hydro and oil units, with 180 MW of installed wind power capacity in 2010. In contrast to the Ireland power system, Hokkaido does not enjoy access to an international natural gas pipe network, hindering the development of flexible gas units. The generation portfolio shown in Appendix A.2 is assumed, summing to 7.6 GW of total installed generation capacity. So as to mimic operational practice, nuclear units are assumed to be not available for ramping.

The flexibility of the Hokkaido system is assessed under four scenarios. Contingency reserve requirements are considered for all four scenarios:

1. As it was in 2010 (180 MW of installed wind generation), without the net load ramping adjustment considered.
2. As it was in 2010, with the net load ramping adjustment considered.
3. With 1 GW of installed wind generation, and the net load ramping adjustment considered.
4. With 1 GW of wind generation and a 600 MW hydro pumped storage facility installed, and the net load ramping adjustment considered.

The PFD of the Hokkaido system for scenarios 1 and 2 are shown in Figure 6. It can be seen that the net load ramping adjustment is an important part of improving the fidelity of the merit order solution; its exclusion could result in overestimation of a system’s periods of inflexibility. The assumptions surrounding the adjustment, as outlined in Section 2.6 will affect the flexibility which is assumed to be available due to operator foresight. The baseline assumption (used in Figure 6) was to include the average ramp at each hour as an addition to the net load, requiring the commitment of extra resources, but which is not dispatched for. In Figure 7, two sensitivities on this assumption are presented. In Figure 7(a) the PFD is determined with net load ramp adjustments varying from an average 1 hour ramp up to an average 8 hour ramp at each time period. The results indicate a trend of reducing risk as the ramp horizon considered increases. This is due to the larger ramps which may occur in that time, in turn committing extra generation. In Figure 7(b) a comparison between selecting the average ramp expected at each hour, and the 90th percentile of ramps at each hour is demonstrated. It can be seen that the system risk is seen to decrease when the 90th percentile of ramps is considered in comparison to considering the mean ramp.

The PFD results (Figure 6) highlight that the 3 hour time horizon presents the largest risk to the Hokkaido system from a flexibility perspective. This result is intuitive, given that the system must rely on online flexibility exclusively for time horizons less than 3 hours (since the shortest start-up time of all but one resource is 3 hours or longer, Appendix A.2). It is assumed that changes to the interconnection schedule are not available for time horizons less than 6 hours. The peak PFD value of 3.8% when the net load ramping adjustment is included indicates that the system will not be able to meet some of the upward ramps in the 3 hour time horizon. 58% of all instances of 3 hour flexibility deficits occur during the night time, before the morning rise. However, it is known that this system operated successfully in reality, even with a fleet of inflexible nuclear, coal and oil generators. It can be seen from both results that the system operators currently employ accurate demand forecasts in operational planning, which allow time for plant to prepare to start-up when required.
Taking a closer look at the 3 hour flexibility, Figure 8, the cumulative density functions (CDF) of the surplus and deficit of flexibility show that the mean surplus is 778 MW when compared to a maximum 3 hour net load upward ramp of 1,645 MW. The importance of the surplus and deficit CDF is to highlight the robustness of the results to a change in the modelling assumptions: the closer the mean deficit and surplus flexibility values are to 0, the greater the sensitivity of the result to assumptions. The interconnector contributes to the flexibility surplus as the 600 MW capacity remains offline due to its high marginal cost. This indicates that when the system has sufficient flexibility, the PFD is unlikely to be affected by imperfections in the assumptions made. However, Figure 8 also shows that during periods of insufficient (negative net surplus) flexibility, a small favourable change in the net load, resource portfolio or modelling assumptions may result in a
significant improvement in the PFD, since the mean of the distribution occurs at -126 MW, relatively close to zero. In this case the result is sensitive to the modelling assumptions.

Figure 8: Distribution of net surplus of flexibility for the 2010 Hokkaido system with net load ramping adjustment considered

Using the same demand time series, the wind capacity is scaled up to 1 GW and a 600 MW pumped storage unit is added. It is assumed that the pumped storage unit is the most expensive unit operating in the system. Figure 9 shows that the increased wind generation will cause the PFD to increase significantly for all time horizons less than 3 hours. However, when coupled with the development of 600 MW of pumped storage, it can be seen that the flexibility issues surrounding further integration of wind generation has been mitigated, as the system is better able to manage the increased variability.
Figure 9: Impact of installed wind power and hydro pumped storage capacity on the periods of flexibility deficit (PFD) for the Hokkaido system. All scenarios shown (2, 3 & 4) consider the net load ramping adjustment

4. Discussion

The methodology and metrics presented in this paper aim to inform long-term system planning by increasing awareness of the operational challenges associated with variable generation. This in turn allows independent/transmission system operators to devise means to incentivise sufficient flexibility to ensure security of electricity supply to the final consumer.

The PFD metric presented here is not a conclusion in itself for a particular system, however, identifying certain characteristics of the periods of flexibility deficit allow firm conclusions to be reached. The incidence of peak values in periods of flexibility deficit is important since it highlights those time horizons that the system will find most challenging from a ramping perspective. By determining the most serious risk horizon, system operators can adjust market designs or similar incentives to ensure that sufficient new capabilities are added to a system to ensure security of supply. If the PFD peaks occur at short time horizons (e.g. less than 4 hours), more online flexibility is required since offline resources may not be in a position to start in time. Mitigation strategies may be operational decisions, such as dedicating reserve to meet net load ramps, improving the operational availability of interconnectors, or including net load ramp forecasts in the scheduling process. Other options may require policy intervention, such as the regulations required for the development of DR programs to provide flexibility at short notice, or to promote the construction of new fast starting resources, such as gas turbines, which are in turn dependent on the gas infrastructure.

As the peak PFD time horizon increases, the diversification of the start-up times of existing resources plays a significant role. Peak PFD values at longer time horizons (> 8 hours) may be symptomatic of
insufficient capacity, or an extremely inflexible resource portfolio. Figure 4 shows a significant peak of insufficient flexibility for the Ireland system at the 5 hour mark, which is related to the start-up time of the CCGT units in the system. An inference which could be drawn from this is that a greater number of faster starting resources are needed. Sufficient incentives and preparation must be in place to attract the development of such resources. In the case of the Ireland system, this might have implications for the design of capacity support mechanisms, as well as an increasing dependency on gas as a single fuel source if combustion turbines are built in response.

As well as determining the PFD, it is important to compare the distribution of periods of flexibility shortages for an existing system to a planned future system flexibility requirement. As was highlighted in the Ireland example, as the distribution of flexibility shortages becomes more uniform as variability increases, more effort is required to schedule the system to avoid flexibility shortages, Figure 5. More detailed analysis, such as that found in [14], should also be carried out at a later planning stage.

The high risk levels (14% PFD) found in the Hokkaido system in the scenarios without energy storage indicated a risk level which could have significant planning implications. Understanding this risk in advance allows long-term planning/policy level changes to be made, such as the diversification of fuel supply to include more flexible generation technologies, or the development of the regulatory framework often required to develop storage projects.

During the long-term planning stage, there are many uncertain factors that test the robustness of a plan, e.g. fuel price uncertainty, changes in government policy, etc. There are also a multitude of potential future generator and demand-side unit combinations. To ensure robustness against such uncertainty in the planning time horizon, it may be prudent to apply the PFD flexibility metric to a range of future plant portfolios (derived from generation expansion models that capture new technologies [52], [53] and fuel price risk [54]). In this way, the robustness of future system flexibility could be assessed for a wide spectrum of possible scenarios.

5. Conclusions
Power system flexibility is becoming an increasingly important issue as the penetration of variable generation (VG) increases in many systems. Familiarity with the operational flexibility challenges will be required at all levels of the planning process so that suitable plans are devised. A high-level flexibility analysis methodology has been shown here to give insight into the likely issues which may arise with the development of VG.

The use of the periods of flexibility deficit (PFD) metric in the case studies has highlighted the importance of both capacity and the overall flexibility of the system. The benefits of flexible generators, energy storage and interconnection demonstrate that there are usually a number of options to increase the flexibility of a system.

The adoption of flexibility assessment at the long-term system planning stage may allow appropriate decisions to be taken to increase the installed VG capacity towards meeting environmental aims, while also ensuring that the power system is sufficiently secure and economic to operate.
Appendix. System Case Study Data

A.1. Ireland and Northern Ireland

The model of the Irish system (system demand, wind generation and generator data), at an hourly resolution, is taken from the All-Island Generation Capacity Statement [50] for 2020, and from the market model produced by the Irish Commission for Energy Regulation [51] for 2009.

A.2. Hokkaido

The system model of Hokkaido includes the conventional generators and interconnection listed in Table A.1. Initially – Scenarios 1 and 2, 2010 – 180 MW of wind generation was modelled by converting wind speed data to wind power data using a power curve, since no forecast data similar to that for the Irish example were available. Wind speed data taken at ground level of Sapporo airport (south-west region), at half hourly resolution, was scaled to 80 m and converted to wind power using the power curve of an ENERCON E-82 E3 3 MW wind turbine [55]. During 2010, 180 MW of wind capacity met 1.1% of system demand with a capacity factor of 26%. The installed wind capacity was later increased to 1 GW. In order to account for the smoothing effect on variability when geographical diversity increases, the 1 GW wind capacity was split into 4 regions. The wind speed time series was then shifted by -30, 30 and 60 minutes from the original time series and converted into wind power. The resulting time series met 6% of system demand.

Table A.1: Resource details of Hokkaido system

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Nuclear</th>
<th>Large Coal</th>
<th>Small Coal</th>
<th>Oil</th>
<th>Distillate</th>
<th>IC</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. units</td>
<td>3</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Max capacity (MW)</td>
<td>579-912</td>
<td>350-700</td>
<td>125-175</td>
<td>250-350</td>
<td>280</td>
<td>600</td>
</tr>
<tr>
<td>Min gen. output (MW)</td>
<td>450-700</td>
<td>105-210</td>
<td>37.5-52.5</td>
<td>75-105</td>
<td>84</td>
<td>0</td>
</tr>
<tr>
<td>Ramp rate (MW/min.)</td>
<td>0</td>
<td>4-21</td>
<td>1-2</td>
<td>8-11</td>
<td>8</td>
<td>50</td>
</tr>
<tr>
<td>Start-up time (hr)</td>
<td>36</td>
<td>20-36</td>
<td>5</td>
<td>3</td>
<td>0.5</td>
<td>1</td>
</tr>
<tr>
<td>Forced Outage Prob.</td>
<td>0.02-0.03</td>
<td>0.03-0.04</td>
<td>0.05-0.06</td>
<td>0.04-0.06</td>
<td>0.03</td>
<td>0.05</td>
</tr>
</tbody>
</table>

The system also contains 1,200 MW of largely run-of-river hydro power plants with modest storage capacity, and a non-dispatchable 50 MW geothermal unit. A constant 450 MW of hydro generation is assumed to be available year round, based on the ratio of minimum to maximum monthly precipitation. The remaining hydro production is assumed to be proportional to the rainfall in excess of the minimum monthly precipitation in each month, and to the daily demand cycle. The demand time series for 2010 was received through personal communication with Junji Kondoh of the Energy Technology Research Institute, National Institute of Advanced Industrial Science and Technology, Ibaraki, Japan.

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References


Biographies

Eamonn Lannoye is a senior research engineer at the Electric Power Research Institute International. He received his PhD degree in electrical engineering from University College Dublin, Ireland in 2013. His current research interests include power system flexibility and operational tools to integrate variable generation and variable generation forecasting for system operations. He is a member of CIGRÉ.

Pádraig Daly is a PhD student at the Electricity Research Centre, University College Dublin, Ireland. His current research interests are in power system operation with high levels of variable and non-synchronous renewable generation, and applying the principles of design thinking for next generation power system operation. He is a student member of CIGRÉ.

Aidan Tuohy is a technical leader at the Electric Power Research Institute (EPRI). He received his PhD degree in electrical engineering from University College Dublin, Ireland in 2009. He has worked at...
EPRI since 2010 in the area of bulk power system integration of variable generation. His current research interests include power system flexibility to integrate variable generation, integration of distributed energy resources on the bulk system and variable generation forecasting for system operations.

Damian Flynn is a senior lecturer in power engineering at University College Dublin. His research interests involve an investigation of the effects of embedded generation sources, especially renewables, on the operation of power systems. He is also interested in advanced modelling and control techniques applied to power plant.

Mark O’Malley is the professor of Electrical Engineering at University College Dublin, and director of the Electricity Research Centre. His research interests include power systems, grid integration of renewable energy, and energy systems integration.