Variable Generation, Reserves, Flexibility and Policy Interactions

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Abstract

Operational issues associated with the integration of variable generation (VG) have led system operators and researchers to re-evaluate how reliability services are procured and at what levels they are required. Ramping reserve constraints are now being proposed and applied by several system operators to address the increasing variability and uncertainty in system schedules. The increasing environmental, economic, geographic and temporal interconnectedness of power systems means that the impact of additional reserve products can no longer be assessed in isolation. Although additional reserve categories are a practical short-term solution, in the longer term, greater coherence is required between policy objectives and operational strategies to avoid suboptimal operation.

1. Introduction

Although security of supply remains an important driver for energy policy makers globally, climate change and environmental concerns are the main cause for the rapid increase in variable generation (VG) capacity. In order to meet CO_2 reduction targets and since the electricity sector has the clearest pathway to decarbonisation, governments have set ambitious renewable electrical energy targets. For example, California's Renewable Portfolio Standard target is for 33% of electrical demand in 2020 to be met by renewable energy [1], the equivalent target in Ireland is 40% [2] and in Denmark, due to the unique combination of technical expertise and substantial interconnection with its neighbours, the electricity sector target is 51.9% renewable energy by 2020 [3]. VG is a subset of all renewable energy sources, but the combination of relatively mature technologies and an ability to be deployed in a wide range of locations ensures that VG, particularly wind and solar generation, are set to continue as the dominant renewable energy sources.

The main aim of all power system research, planning, markets and operations is to minimise the long-term cost of electricity supply, subject to reliability constraints. Economic theory for competitive markets suggests that short run marginal cost pricing maximises global utility by driving markets towards their least cost solution. Decarbonisation, however, has introduced a new externality into the cost equation. Consistently reflecting this assumed cost across all time horizons is difficult and can lead to conflicting results. Until their costs reach grid parity, VG will be subsidised to help fulfil the broader societal goals and their treatment within markets must reflect this.

Due to the nature of their energy source, the power output of VG is both variable and uncertain. Although these attributes pose significant problems for system operators, since they are normally obliged by national or state directives to facilitate CO_2 reduction targets, operational strategies must be altered to meet the challenges imposed. The integration effects of variable generation (VG) have been well documented [4] [5] [6], however as the penetrations levels become higher, remedial actions due to increased variability can no longer be confined to technical solutions without risking suboptimal performance and outcomes which are contradictory to the policy objectives. This paper analyses some of the potential problems if a technical solution, such as a reserve product dedicated to counter VG imposed ramping shortages, henceforth referred to as a ramping product, is used instead of alternative policy options.

2. Reserves

The cost of operating a power system to a certain degree of reliability should reflect how much customers value such a level of reliability. System reliability targets have historically been met through the use of reserves. The economically efficient reserve level would deliver sufficient quantities to meet societal values [7]. In the absence of large-scale demand participation, research and industry unit commitment and dispatch algorithms have assumed an inelastic demand. Schedules have been optimised subject to a system price cap for electricity, which is an

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estimate for the value of lost load. Consequently, reserve levels have been designed on an ad hoc basis using operator experience and to provide a sufficient instead of an optimal level of reliability.

Reserve capacity is supplied by both online and offline generators and suppliers that are able to change and sustain their power output within a certain time frame. System reserve requirements are a function of system size, type and size of interconnection, market structure, as well as various historical practices. Like all other constraints, when binding, reserve constraints increase the expected total cost.

Operating reserves can be split into two broad categories – event and non-event reserves [8]. Both types are carried at all times, but whereas event reserves are only used (and consumed) by system operators to restore generation and demand balance after a system contingency, non-event reserves are routinely dispatched (without necessarily needing to be replaced) to maintain second to second supply-demand balance. Non-event, or balancing, reserves can be further subdivided into regulating and load following reserve. Regulating reserve aims to regulate the system frequency – increasing generation output when the system frequency falls and decreasing output when the system frequency rises. Load following reserve maintains the supply-demand balance by responding to inter-dispatch trends in net load, where net load is the system demand less the output of VG [8].

Contingency and load following reserve adequacy have traditionally been assessed using hourly resolution unit commitment simulations. Apart from regulating reserve adequacy, sub-hourly simulation has typically been confined to snapshot analysis of system dynamic stability and fault analysis. However, the advent of high penetrations of VG has led to a blurring of the traditional timescale definitions of reserve [9]. No longer can non-event reserves be completely separated from contingency reserves, in large part due to the new phenomenon of *slow contingencies*. These unpredicted, non-instantaneous, yet large, net load ramps are caused by weather fronts moving across a region, gradually changing the output of wind and solar plant. Although these fronts can be forecast to some degree, the chaotic nature of weather ensures greater uncertainty in the net load forecast for longer time horizons. Along with instantaneous protection tripping of lines or generators due to faults, system events can now have durations of several hours. Reserves will be called upon to solve problems across increasingly broad time horizons. It is essential, therefore, that when designing each new reserve product that their impact is tracked across several time horizons and their interactions with previously existing reserve products are quantified.

This paradigm shift has resulted in renewed interest in the area of reserve classification and design [10]. Along with many proposed new deterministic reserve criteria (especially in the area of dynamic reserve targets [11]) significant research effort is being placed into optimal reserve requirements. Stochastic unit commitment endogenously solves for the reserves required to minimize the expected system cost subject to uncertainties in wind and demand [9] [12]. Although this method provides more robust and, in most cases, reduces long-term realised system costs, due to computational intensity they have been confined to planning and research tools. To date, it has not been possible to accurately and consistently distil the characteristics of stochastic scheduling into deterministic reserve rules [13], meaning that independent system operators (ISOs) have been unable to realize the perceived benefits without implementing stochastic unit commitment itself.

In order to reduce the computational effort involved in solving stochastic problems, researchers have considered representative days or a reduced number of scenarios, despite the time resolution of these models being one hour [9] [12]. In hourly resolution simulations, peaking capacity plant is dispatched to meet shortfalls in inter-hour online capacity. The start times of these plant are assumed to be negligible and, provided the spinning reserve target is sufficiently high, it is assumed that the dispatch can meet any inter hour net-load level.

Although appropriate when considering the resilience provided by event reserve, hourly schedules may be infeasible due to an incomplete formulation of the various inter-temporal constraints which can apply in reality [14]. Since sub-hourly demand series do not linearly interpolate between hourly values, the actual variations and ramping requirements will be larger in sub-hourly resolution models. Aside from the increased computational effort [14], certain constraints cannot be easily captured on an hourly level but access to high resolution data remains an issue [15] [16]. Higher VG penetrations lead to increased inter-temporal constraints due to increased generator cycling [17]. Therefore, analysing hourly and sub-hourly commitments in isolation from one another is becoming increasingly inappropriate.

3. Flexibility

Flexibility has been defined in [18] as “the ability of a system to deploy its resources to respond to changes in the net load”. In the short term a flexible plan can also be defined as “one that enables the utility to quickly and inexpensively change the system’s configuration or operation in response to varying market and regulatory conditions" [19]. Although it is often abridged to refer only to the amassing of ramping capability, both of the above definitions infer that flexibility is a multi-facetted attribute of a system.

Along with reducing the availability of traditional flexibility resources, the displacement within commitment schedules of large, dispatchable, fossil-fuel powered, bulk energy providing plant by tens to hundreds of smaller VG devices is also increasing the flexibility requirement. Higher VG penetrations result in greater net load uncertainty and variability. Consequently, unit commitment strategies which can cope with a wider range of net load outcomes, i.e. more flexible strategies, are required. This greater operational timeframe flexibility may be procured by changing the unit commitment formulation, however, neither the availability of, nor requirement for, operational flexibility are driven purely by the fraction of VG on the grid. Generator characteristics, market structures, interconnection, transmission system congestion and operational practices all affect the system flexibility.

The upper limit of operational flexibility is determined by the inherent fleet flexibility. Plant and fleet flexibility are a function of the generator characteristics including: ratio of maximum to minimum generation, run up/down rates, ramp up/down rates and minimum on/off times. A methodology to calculate flexibilities using combinations of these characteristics is given in [20]. Various other flexibility assessment methodologies have also been proposed [18] [21] [22].

Along with creating a higher requirement for flexibility, certain VG devices are also physically incapable of providing critical services, e.g. asynchronous devices cannot provide synchronous inertia. The combination of these two effects is that previously cheap, abundant and inherently available ancillary (non-energy) services, most of which enable flexibility, are becoming scarce [22]. As high levels of zero marginal cost VG may depress energy spot prices and reduce thermal unit capacity factors, revenue streams from ancillary services, such as reserves, may become increasingly important to conventional generators. Balancing reserves will also be required in greater volumes, and with greater regularity, but as the number of online large synchronised units decreases so does the availability of various reserves.

Flexibility is procured implicitly in deterministic schedules through reserve constraints. Since stochastic unit commitment explicitly procures flexibility, stochastic schedules can provide additional operational flexibility from a given generation fleet. However, the largest enabler of flexibility is not operational decisions. Instead, the best long-term solution is to increase the inherently available fleet flexibility. Improving interconnection and merging balancing areas increases the number of potential sources, but aside from greater pooling of resources, the largest potential increases are achieved through market signals making investment in flexible generation an attractive proposition.

Along with investment signals, several other market and operational practices can affect flexibility requirements and availability. Rolling planning, high-resolution markets and improved forecasting reduce flexibility requirements by reducing uncertainties through the use of more up to date information. Infrastructural upgrades, such as strengthening the transmission network or rolling out smart meters and associated communications links can reduce congestion and increase the availability of the pre-existing flexibility. Greater quantities of flexibility could be bluntly procured by increasing standard reserve targets, or new reserve products, whose formulations include the reliability of response or more accurate representations of unit technical constraints, can be introduced.

4. How System Operators are Responding

System operators across the globe are responding to flexibility reductions as a result of increasing VG penetrations. Increased hours of zero or negative prices of wholesale electricity are a market manifestation of reduced flexibility which have been reported in several jurisdictions [23] [24]. Concerns about reduced security or reliability are of greater concern to ISOs and although regulatory and market constraints may, in the short-term, limit the range of options available to individual operators, the breadth of solutions implemented to date reflects the multi-facetted nature of system flexibility.

At moderately low penetration levels or in large interconnected systems, the impacts of VG on system flexibility may not require significant change to operational practices. For example, PJM Interconnection, the regional transmission organization for the central eastern United States, does not foresee a need to change their current ancillary services to manage VG [25]. The Electricity Reliability Council of Texas (ERCOT) has approximately ten times the amount of VG connected to their less interconnected system, but also are not significantly reforming their ancillary services. Instead, they have created a ramp event forecasting tool and adjusted the requirements for certain reserves, such as regulating reserves, to reflect VG forecasts [26].

Large systems may experience the effects of reduced flexibility at almost any VG penetration level if the underlying generation fleet is sufficiently inflexible. Worldwide, ISOs with inflexible fleets are proposing additional augmented reserve products to tackle the increased flexibility requirement. Flexibility or ramping products, as these reserves are known, are specifically designed to offset the effects of decreasing amounts of dispatchable generation and increasing net load uncertainty. Historically low flexibility and ambitious renewable energy targets led California ISO (CAISO) to become the first ISO to include a flexible ramp constraint in their unit commitment in December 2011 [27]. Among other considerations, the combination of a coal dominated fleet and large industrial demand has led the Midcontinent Independent System Operator (MISO) to propose a ramp capability product despite having greater levels of interconnection and lower VG penetrations than ERCOT [28].

Although on a per MW basis their flexibility will be high, relatively small island systems are most susceptible to reductions in flexibility. In the absence of interconnection to neighbouring systems, the required flexibility must be provided by the limited number of online or available generators. Since system inertia is already low in island systems, further reductions due to VG penetrations can have significant consequences. In New Zealand it is proposed that asset owners be incentivised to provide inertial compensation [29], and in Ireland an inertial response product, whose payment is linked to the minimum stable generation level, is being proposed by the transmission system operator (TSO) [30].

To meet national renewable energy targets, EirGrid and SONI, the TSOs for the island of Ireland, expect that instantaneous system non-synchronous penetrations of 75% will be required. In order for VG to provide 75% of demand for any duration, the flexibility required from the remaining synchronous generation is great. Along with the inertial response product, ramping products across various time horizons and several other flexibility enabling ancillary services are being proposed as part of their DS3 project [30]; the ultimate goal of which is to ensure the long-term provision of flexibility through investor incentives.

Since the problems of reduced flexibility are experienced during real-time operation, current solutions have tended to focus on operational time frames. Initiatives such as DS3 and Federal Energy Regulatory Commission (FERC) Orders No. 755 [31] and No. 1000 [32] are beginning to change that. Investors can now expect improved returns for more flexible units since generator payments will now reflect their total contribution to system security, not just their energy contributions.

5. Potential Concerns with Flexible Reserve Products

Even if the additional ramping reserve products are well designed and optimised to ensure the response required for all conditions, they will be subject to additional rules to ensure that they match the current services, which may have been designed on an incremental basis. They may also be subject to new shortcomings specific to their function, some of which are detailed below. As stated previously, increased VG is the main driver for increased system flexibility requirements. Therefore, unlike normal reserves, the success or otherwise of flexibility products should not be judged wholly on the level of reliability they provide or their ability to reduce system costs. Their effectiveness in furthering VG policy objectives should also be considered.

5.1. Implicit and Explicit Reserve Sources

The purpose of new reserve products, or increased reserve targets, should be to prevent system reliability from dropping below the societal acceptable level. The inclusion of a new reserve product may prove needlessly expensive unless all the current sources of reserves are accurately known, including all implicit and explicit reserve sources across all time horizons. Due to TSO prudency and conservatism, current commitment schedules routinely include safely margins to ensure that reliability targets are met [33]. Selective scheduling of demand valleys and peaks is an example of this.

Figure 1 shows a schematic representation of a forecasted system demand profile and associated net load forecasts. From an operators perspective the worst case scenario in terms of realised net load would be the highest possible net load peak, lowest possible net load valley and steepest morning rise. Avoiding insufficient/excessive supply during these critical periods is essential for normal operation, however, the mechanism to achieve this must be transparent. Operators have two choices: upward or downward reserve margins for the critical times can be increased or the net load forecast which is used in the unit commitment can reflect the worst case scenario rather than the median expected value.

Although explicitly carrying the margin as extra reserve or implicitly carrying it by augmenting net load forecasts achieves the same result, by implicitly carrying additional load following capability, its presence can easily be overlooked when analysing the magnitude of the reserves being carried. As a result, the need, or otherwise, for any new reserve product, may be misrepresented at certain periods of the day.

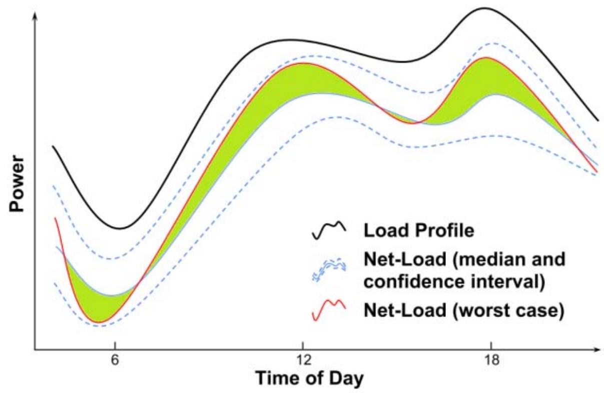

Figure 1. Sample forecasted load and net load profiles, the shaded area represents implicit reserve capacity

5.2. Schedule Efficiency and Effectiveness

The accuracy of all power system analysis is subject to the validation of the models; however, since flexible reserve products are being carried to counter VG forecast uncertainty, the treatment of forecast error distributions is critical. Wind forecast errors do not follow normal distributions due mainly to non-linearities in the turbine power curves. As shown in [34], an inaccurate representation of the distributions can lead to systems operating at completely different levels of reliability than expected. The absence of correlations between the wind uncertainty and generation outages means that isolating the corresponding reserves from one another will exceed the reliability requirement [8].

Since stochastic unit commitment minimises the total expected costs across multiple stochastic inputs and provides the long run least cost solution, the efficiency of deterministic schedules is often benchmarked against stochastic schedules. Significant research is being undertaken by [12] [35] to formulate so-called "clever" deterministic reserve schedules to mimic stochastic reserve. It has been shown, however, that since the expected cost of energy, if reserves are required, is not accounted for in deterministic unit commitment schedules, they will only approach stochastic efficiency in certain circumstances [36]. This increases the chance that a deterministic model will schedule reserves to off line, faster starting, and high marginal cost units. Incomplete representation of the cost of a reserve option or the value of flexibility means that the resulting scheduling efficiency is dependent on realised system conditions.

Both CAISO and MISO have reported that the introduction of ramping products reduces price volatility by reducing the number of flexibility constrained time periods [27] [28]. Price volatility, however, is not necessarily a bad thing. Although it may increase the investment risk of generators, it can provide strong incentives for demand-side programs, which are an alternative strategy to improve system reliability.

5.3. Greater Flexibility is not Guaranteed

While flexible ramping products and constraints should increase system flexibility within their operational time horizon, their effect on longer term flexibility depends on various system characteristics and operating conditions.

During periods of low load or high VG penetrations, inflexible base load units are likely to be part-loaded. Although this part loading ensures a certain availability of reserves, ramping constraints, rather than capacity constraints, may limit the reserve that these units can provide. Therefore, further reductions to their output level will not necessarily result in increased flexibility within the ramp constrained time horizons.

If base load generators have inherently low ramping capabilities, for example coal or nuclear plant, commitment schedules with significant part loading may have low short term flexibility. Hence, in high VG scenarios, faster ramping plant may be committed to supplement the regulating or load following capability of the base load generators. Since these additional generators are not required to provide energy, the size of unit that is committed is dependent on the expected ramping requirement and associated reserve target.

For example, under a low 15 minute reserve (regulating or ramping) target a combustion turbine (CT) may be sufficient. Due to their naturally low minimum stable generation levels, the remaining units do not need to be backed off significantly. However, their relatively low maximum capacities and short start-up times means that while the 15 minute capability has sufficiently improved to meet the target, the net effect of starting such a unit is likely to be marginal.

If, as is likely with the introduction of ramping products, the 15 minute target was increased, a steam unit (SU) with a high capacity may be started instead. Once online, the 15 minute capability of the system would be significantly improved over the previous case. Steam units, however, will have much higher minimum stable generation levels than CTs and so to maintain the same total generation, the base load generators will have to be backed off correspondingly.

On a 15 minute basis, the base load generators must already have been ramp constrained in order to warrant the starting of an additional unit. If the base load generators are ramp constrained at longer time horizons, for example within the hour, the net effect of starting the SU instead of the CT could be reduced system capability within the hour. Assuming that the SU could go from an offline hot state to maximum generation in one hour, the reduction in capability would be equal to the minimum generation level of the SU less the minimum generation of the CT.

This reduction in flexibility is caused by the creation of inaccessible (within a time horizon) generator headroom. If a generator is ramp constrained, backing that generator off further will increase its headroom but it does not make any additional capacity available within the ramping period. Thus, the capability of the base load units within the hour will remain constant and since, when the SU is online, it must be at or above its minimum stable generation, its capability within the hour has dropped by the same level. Again the lack of value placed on flexibility within a commitment would drive such results and, although highly stylised and simplified, these examples highlight how a seemingly risk averse action could have negative consequences for system reliability.

5.4. Contradictory Objectives and Outcomes

In the transition from vertically integrated utilities (VIUs) to supply-side markets, significant issues have been encountered surrounding the treatment of ancillary services: from dwindling frequency response in the US eastern interconnection [37] to complete market collapse and rolling blackouts in California [38]. Performance disincentives also exist: generators can be financially penalised for performing potentially system saving actions [39], and base load generation may be benefiting from their own inflexibility [40]. The root cause of all these problems are market structures incentivising inappropriate generator behaviour. Ramping products are particularly susceptible to this problem because of their highly specialised purpose. Since ramping products are a response to increased VG penetrations and increased VG penetrations are associated with environmental and emission reduction policies, high CO2 intensity or other environmentally unfriendly solutions are not coherent options.

Policy decisions have been made inferring the long term value of increased renewable generation. If, however, these value judgements are not reflected in market signals, market outcomes may well not reflect the policy objectives. The continuing need, in certain jurisdictions, for VG to benefit subsidies suggests that current CO2 taxes / permit prices are too low to drive the electricity sector to evolve naturally towards lower CO2 intensive energy sources. Although the advent of shale gas has allowed the US to shift to lower CO2 intensive generation the consequentially depressed global coal price has lead Europe in the reverse direction. The use of these currently low CO2 prices in short term market operations will consequentially result in disparity between actual CO2 reductions and those intended by a policy with a higher CO2 abatement value.

It has been shown, in the case of Ireland, that 1 MW of wind power has the same CO2 reduction as a 0.66 MW reduction in load [41]. Without regulatory change, the reduction in CO2 achieved for each additional MW of VG installed could fall short of what is possible. Potential causes include increased reserve targets, which increase part-loading and reduce generator thermal efficiency [15], and perhaps even perverse disincentives inherent in unit commitment techniques, which may favour inflexible but lower expected cost (coal) units over more flexible but efficient (gas) units [42]. Although none of the above problems are guaranteed, they show that even if environmental policies succeed in further increasing VG capacity, unless they are backed up by coherent integration/operation policies their ultimate objectives might fail or fall short of what is desired.

5.5. Markets and System Operator Mandate

Aside from markets quirks, which can result in outcomes acting against the underlying policy intention, markets may still fail to provide what is intended without careful design. Since flexibility is such a broad concept, ensuring a market delivers flexibility is difficult. Unless all the desired attributes of a flexible generator are either mandated in a grid code, compensated using long-term contracts, or equivalent products are traded in a competitive market, which also rewards quality of response, new capacity will not necessarily provide the required flexibility. These new markets should not favour technology types but should provide appropriate opportunities for emerging technologies such as synthetic inertia, demand response, compressed air energy storage, synchronous condensers, electric vehicles, etc. While the additional rules associated with ramping products, which differentiate them from other reserve products, ensure greater certainty in the amount of operational flexibility that is procured, their effectiveness in providing long-term market investment signals can only be assessed after sufficient time has elapsed.

The integration of renewable energy devices is the first major policy directive to be faced by many ISOs. The breadth of options available to ISOs is, however, somewhat reduced in comparison to VIUs. ISOs may be constrained from taking actions which interfere with market operations. VIUs can mandate flexibility in all its forms, even construct highly flexible plant, such as pumped storage, which may struggle to make a profit in competitive markets [43]. Clear direction is therefore required by ISOs from their regulators and policy makers. Policy changes should take account of the current ISO mandate and, where necessary, regulatory change should follow. All ISOs already have the ability to alter the reserve schedules in response to reliability concerns. Flexible reserve products are a practical and easily achievable tactic to counter the increasing flexibility requirement; however, if there are cheaper or more effective solutions, such as increasing interconnection or enabling a technology to compete fairly in the market, the ISO's mandate should be updated to ensure that the best solutions are chosen.

6. Conclusion

Integration effects are not unique to wind and solar generation [44] [45]. For example, a new interconnector or large generator can increase the size of the largest infeed, and thereby increase the contingency reserve requirement. Ramping products are, however, a direct response to the perceived reliability reduction at high VG penetrations. Like all operational practice changes, great care should be taken to quantify the total effect of any additional reserve product, and not just the intended effects.

Any possible inferred shortcomings of the proposed industry solutions must be framed within their context. ISOs must solve problems that are beginning to appear now. They do not have the luxury of starting completely from scratch as the regulatory change required may take too long. Prudent system operators will always be proactive in finding solutions and avoiding reliability issues. The quality of these solutions depends on the range and accuracy of the tools available to them. While researchers and industry can help improve the knowledge base, policy makers and regulators are key to ensuring clear and consistent guidelines for what system operators should do and how to assess the effectiveness of their solutions.

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