Using Energy Storage to Manage High Net Load Variability at Sub-hourly Time-scales

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***Abstract*—High net load variability, driven by high penetrations of wind and solar generation will create challenges for system operators in the future, as installed wind generation capacities increase to unprecedented levels globally. Maintaining system reliability, particularly at shorter time-scales, leads to increased levels of conventional plant starts and ramping, and higher levels of wind curtailment, with sub-hourly unit commitment and economic dispatch required to capture the increased cycling burden. The role of energy storage in reducing operating costs and enhancing system flexibility is explored, with key storage plant characteristics for balancing at this time scale identified and discussed in relation to existing and emerging grid-scale storage technologies. Unit dispatches for the additional storage plant with varying characteristics highlight the unsuitability of energy only markets in incentivising suitable levels of flexibility for future systems with high net load variability.**

***Index Terms*—energy storage, wind energy, power system simulation, pumped storage power generation, battery storage plants**

I. Introduction

MANY power systems across the globe are increasing their levels of wind and solar generation capacity, as part of a drive to create a low carbon future and reduce reliance on fossil fuels. Integrating large shares of variable and uncertain renewable generation onto existing systems creates considerable challenges, e.g. efficient scheduling, system frequency regulation and grid stabilization [1]. In response, many system operators are focussing on incentivising flexibility and ramping capability [2], [3], [4].

High net load (demand not met by variable renewables) variability can place a considerable cycling burden on conventional plant, with more starts and shutdowns, and increased ramping required in order to maintain the supply / demand balance. Most large-scale wind and solar integration studies consider one year of simulated unit commitment and economic dispatch (UCED) at an hourly resolution [5], largely due to data availability and computation times. However, there is growing recognition of the importance of sub-hourly dispatch with high renewable penetrations [6]. Recent integration studies are considering sub-hourly balancing, for example phase 2 of the Western Wind and Solar Integration Study [7] contains detailed real-time ED at a 5-minute resolution. While wind power variability is not considered to have a major impact on system operations over very short time-scales (seconds - minutes) [8], wind power variability at very high penetrations can create a requirement for increased flexibility [9]. For isolated systems, with very high levels of installed wind capacity, concentrated over a relatively small geographical area, sub-hourly balancing will be particularly challenging.

Adopting traditional approaches to the UCED problem, hourly generation levels are taken as energy blocks with plant generation levels considered as step functions. There is no explicit consideration of the ability to meet the sub-hourly supply / demand balance, beyond linear ramp rate constraints being obeyed from hour to hour. These modeling assumptions are challenged at high net load variabilities, with finer granularity required to address this problem, as proposed in [10], which introduces a sub-hourly UC model which takes into account feasible energy delivery under large-scale wind integration. A new stochastic UC model is proposed in [11] which addresses both the sub-hourly variability and uncertainty of wind generation, by incorporating dispatch constraints which can reflect the associated sub-hourly variability. The PLEXOS modeling tool has previously been used to analyse sub-hourly dispatches at high wind penetrations [7], [12], and in [13] it is used to assess the impact of sub-hourly modeling in systems with high penetrations of renewable generation. Temporal resolutions from 60 min to 5 min are examined, with the higher resolution simulations capturing additional costs and showing benefits attributable to flexible resources. A similar method of UCED is used in this work (at a 15-minute resolution), but perfect foresight at a sub-hourly resolution is not assumed.

Grid-scale energy storage is one of many potential sources of grid flexibility which can aid variable renewable integration. The recent energy storage mandate in California [14], along with numerous planned demonstration projects [15] will ensure significant growth within the storage industry. Here, energy storage is considered in order to alleviate some of the operational challenges seen at high variable renewable energy penetrations at a sub-hourly time-scale. Energy storage can be effective in reducing wind curtailment levels, but, due to high capital costs per kW and per kWh, energy arbitrage alone is unlikely to result in a profitable business case [16], [17]. It is important to consider additional services which storage plant can provide, and the aggregate benefits from doing so [18]. Previous studies have introduced methods to estimate potential cost savings which can be achieved with energy storage at high penetrations of renewables, such as by using

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energy storage to hedge wind power uncertainty [19] or to reduce system imbalances [20]. Other studies have considered both the provision of load shifting and reserves at an hourly resolution [21]-[24]. At very high penetrations of variable renewables, the level of plant cycling required to maintain system balance increases significantly. Such cycling activity is greatly underestimated with hourly modeling.

Storage units have the ability to charge or discharge, typically possess higher ramp rates than conventional plant, are excellent providers of reserve, and depending on the technology, due to their fast response, can provide services without being dispatched, and are often well suited to high cycling levels [25]. These characteristics can result in considerable system efficiency improvements, reducing conventional plant cycling and allowing plant operation closer to rated power. Different storage plant characteristics will be examined, with a discussion of existing and emerging bulk energy storage technologies and their relative merits from a system perspective.

This paper considers load shifting, reserve provision and sub-hourly balancing, along with comprehensive thermal plant modeling, allowing for detailed analysis of conventional plant cycling at high penetrations of variable renewables. Insight is also given into the contribution that storage can make, through identifying important plant characteristics for minimizing system costs and reducing generator cycling, as well as the cycling behavior required of the storage plant itself. Comparisons are made with hourly analysis, highlighting the resulting inaccuracies, both in terms of costs and plant cycling and flexibility required.

Section II describes the methodology used to create the sub-hourly UCED schedules, and to complete the energy storage assessment, along with details of the test system and wind profiles. Section III outlines the simulation results, highlighting the importance of sub-hourly modeling, particularly in terms of conventional plant cycling. The importance of storage plant flexibility is captured, with detailed analysis both of its value to the system and the operational requirements of the different storage plant types. These results raise important questions about appropriately valuing and incentivizing storage participation in future electricity markets, which are discussed further in Section IV, while Section V concludes.

II. Methodology

System operating costs are obtained by solving the UCED problem using PLEXOS for Power Systems® [26], a commercially available power system modeling tool. Energy and reserves are co-optimized, minimizing the total generation costs using mixed integer programming (MIP) and the Xpress MP solver. Both forced and planned outages are included. Operating costs without any additional storage are compared to those for the same system with additional storage plant considering varying plant flexibility levels. As the objective function minimizes total system operating costs, with energy and reserve co-optimized, all storage operating decisions are determined accordingly. The on/off decisions for both charging and discharging are binary and are solved as part of the system unit commitment problem using MIP. The storage deployment is representative of decisions made by a vertically integrated utility, such that decisions made in a market environment could be different [22], as discussed further in Section IV.

The objective function recognizes fuel, carbon and start-up costs. Start-up and shut-down profiles are included for all generators to ensure that realistic profiles are achieved during the transition phases of operation, which is particularly important when considering the energy balance at sub-hourly time-scales. Other generator constraints include maximum and minimum generation levels, minimum up and down times, ramp rates and reserve response levels. Thermal plant are modeled with incremental heat rates, ensuring that plant inefficiencies at partial output are captured.

The optimization horizon in PLEXOS is set to 24 hours with a further 24 hour look ahead, which ensures that unit starts are scheduled appropriately for plant with high start-up costs. It also for creates realistic dispatches for energy storage, as it ensures that energy remains in storage at the end of each day, where appropriate, depending on future system needs. Without the additional lookahead, the future value of the stored energy is not considered and the energy storage contents would be drained at the end of each optimization period.

A. Unit commitment and system reserve requirements

This paper focuses on the management of high net load variability, which occurs at very high penetrations of variable renewable generation. Improved wind forecasting, rolling planning and fast markets with frequent re-dispatch and short gate closure times can significantly reduce the impacts of wind power uncertainty. However, sub-hourly wind generation variability is difficult to predict hours in advance, as wind power forecast models are typically tuned to minimize prediction errors over the horizon of interest, with natural variations over short timescales not the main focus. Perfect foresight has been assumed for the hourly wind data.

Multiple UCED simulations are completed for one full year of operation at a 15-minute resolution, modeling storage plant of varying flexibility levels, capacities and 3 levels of operating reserve requirements.

Often unit commitment studies produce decisions at an hourly resolution, ignoring the challenges of sub-hourly net load variability [27]. However, at the wind levels considered, it was found that in order to meet the sub-hourly balancing requirements, both additional load following and short commitment blocks were required. An additional load following reserve (essentially an increased requirement for slow response operating reserve) was introduced for the hourly simulations which compensates for 2 standard deviations of the net load variability over the course of the year based on the realized wind at a 15 minute resolution (similar methods for calculating load following requirements have been proposed for other systems [9]). The commitment decisions for those plant with longer start up times (greater than 15 minutes) are made based on the hourly data, which then feed into the 15 minute simulations where commitment decisions are made for the peaking plant, along with an ED of all units. The additional load following capacity is not carried for the 15 minute simulations, but the standard operating reserve requirements remain, with the additional reserved capacity activated as required during these simulations. As the sub-hourly modeling captures most of the balancing requirements, activation of the remaining reserve categories is driven by contingency events and should be infrequent. It is acknowledged that the activation of a storage plant to provide reserve impacts on its ability to provide future services due to its energy limited nature. However, it is assumed that the changes in dispatch will be small based on infrequent contingency events, and the small energy requirement of modeled operating reserves. Less valuable, slower acting reserve and off-line replacement reserve are utilized after the contingency event in order to restore system security. Replacement reserve adequacy is ensured using an operational constraint (see Section II.B).

The three categories of operating reserve are modeled with varying requirements for response time and duration, as outlined in [28]. The primary and secondary operating reserve (POR & SOR) requirements are set to 75% of the largest in-feed (up to 500 MW), while the tertiary operating reserve (TOR) requirement is set to 100% of the largest in-feed. POR, SOR and TOR must be delivered within 5, 15 and 90 seconds and maintained until 15, 90 and 300 seconds respectively, with low overall energy requirements due to the short durations. As the delivery times do not overlap, a single plant can provide all 3 categories of reserve simultaneously, although reserve provision is limited by plant ramp limits, placing a higher value on the faster acting reserves. Conventional plant reserve provision capability has been modeled in detail. An additional requirement accounts for load and wind power forecast errors, over the reserve activation period, in addition to forced outages [29], which results in minimal increases in fast acting POR requirements ($\approx$ 10 MW), but larger increases in the slower reserve categories ($\approx$ 130 MW for TOR). An additional dynamic reserve requirement is placed on the provision of POR, whereby a minimum level must be provided by dynamic sources, i.e. storage plant with fixed speed charging are precluded from contributing to this portion of POR. An additional 75 MW of static reserve is provided by one of the HVDC interconnectors, with a further 35 MW of interruptible load available at night.

The reserve rules and UC process adopted in this paper are informed by both current practices on the Irish system and future system needs at very high net load variabilities. Changes to current operating practices may include shorter scheduling intervals and intra-day trading, to reduce balancing costs and to ensure that the market is flexible enough to accommodate short-term forecasts [30], and new system services which incentivize plant flexibility [4].

B. Test system

The high renewable energy penetration test system represents a plant portfolio for Ireland in 2025, based on the 2022 portfolio from the All Island Generation Capacity Statement 2013 - 2022 [31]. Some additional plant are retired and the peak demand is assumed to grow by a further 2.5% to 7.7 GW with a total annual electricity requirement of 41 TWh. The plant mix consists of 7442 MW of dispatchable plant, largely made up of gas plant with primarily combined cycle gas turbines (CCGT) providing the baseload and peaking capacity, and open cycle gas turbines (OCGT) providing the peaking capacity - see Table I. In addition, there are also a number of baseload coal and peat plant, along with a number of peaking distillate plant at the top of the merit order. 216 MW of run of river hydro plant and 292 MW of pumped hydro storage (PHS) are also present on the base system. The installed capacity of wind almost equals that of the dispatchable plant and supplies approximately 42% of the system's energy requirement.

TABLE I
TEST SYSTEM PLANT PORTFOLIO

Plant type	*No. units*	*Capacity (MW)*
Peat	3	346
Coal	3	855
Natural gas (base and midmerit)	13	4807
Natural gas (peaking)	4	349
Distillate (peaking)	11	577
Hydro (run of river)	15	216
Pumped hydro	4	292
Wind	$\sim$	7000
New storage	1	100-300

Two 500 MW interconnectors between Ireland and Great Britain (GB) have been included. The GB market is modeled as a single generator with 12 different heat rates which vary depending on the season and time of day, representing a generation merit order as outlined in [32], which has been found to follow closely price movements on the GB system. Flows on the interconnector are fixed at the hourly level.

In order to maintain system stability and security, the instantaneous penetration from non-synchronous sources, e.g. wind farm and d.c. import, is limited. A 75% system non-synchronous penetration limit is assumed in line with the 2020 target. Also, a number of operational constraints are included, ensuring system stability, sufficient replacement reserve capacity and locational voltage stability [28], which is the method currently used by the system operator to generate reserve constrained unit commitment schedules for the system.

The base fuel prices are taken from the central scenario in [33], which predicts rises in fuel prices from 2012 levels of 30% for coal to 122.9 USD per tonne, 20% for natural gas to 73.8 pence per therm and 11.6% for oil to 127.1 USD per barrel. A carbon price of 30 euro per tonne is assumed.

The demand profiles are scaled up from 15 minute realized profiles from 2009. The installed wind capacity is assumed to grow to 7 GW, with metered 15-minute wind farm generation data from 2009 used to generate the wind profiles, which are scaled up on a regional basis, recognizing regional growth patterns in wind farm installations. A percentage of the data has also been time-shifted to recognize further regional diversity.

C. Storage plant characteristics

A generic storage plant is represented with varying characteristics and flexibility levels, which are informed by typical

TABLE II
STORAGE PLANT CHARACTERISTICS

Plant	η (%)	*Min. Gen. (MW)*	*Min. Charge (MW)*	*POR (MW)*	*SOR (MW)*	*TOR (MW)*	*Daily Start Limit*
A	90	0	0	100	100	100	~
B	80	0	0	100	100	100	~
C	80	0	0	40	75	75	~
D	80	25	60	40	75	75	~
E	80	50	100	25	50	50	~
F	80	50	100	25	50	50	3

values for a variety of storage technologies. Six different storage plant (Table II) are added to the system in turn in order to identify those characteristics which are important to systems with high penetrations of variable renewable generation. Plant A & B are representative of highly flexible storage technologies, such as batteries or perhaps future ultra-large flywheels, while plant D, E & F are representative of pumped hydro storage with varying levels of flexibility. These characteristics could also be representative of compressed air energy storage, although such plant with their additional fuel requirements are not explicitly modeled. While the most flexible plant can operate anywhere within their ± 100 MW range, plants D $\rightarrow$ F have restricted minimum generation and charging levels which are characteristic of PHS. It is assumed that while generating, the 6 plant types can provide all available headroom above the operating point as SOR and TOR, while the less flexible plant are restricted in the volume of fast acting POR which can be provided. All categories of reserve can be provided simultaneously (see Section II.A). When charging, the full charging rate can be offered as reserve (across the 3 operating reserve categories). However, for plant D $\rightarrow$ F this capability is available only as static reserve (see Section II.A). Plants B & C bridge the gap between the aforementioned technologies.

The storage plant consists of a 100 MW plant both in charging and discharging mode, with an energy capacity of 0.3 GWh. Previous analysis on the Irish system [34] indicates that additional energy capacities of this order are sufficient to capture the majority of the cost savings and curtailment reductions. The characteristics examined include round trip efficiency, minimum generation and charging levels, three categories of operating reserve and a daily start limit. No end-of-day targets are set for the storage contents, as the desired operation will depend on the wind penetration and net load characteristics during the optimization period, and during the 24 hour look-ahead period. In addition to the base simulations, further simulations are completed with increased energy capacities (0.6 GWh and 0.9 GWh) and increased generator capacities (200 MW and 300 MW, both with energy capacities of 3 hours at rated output) for plants B & E. All additional units operate as a single plant and it is assumed that its operation is not impacted by transmission constraints.

III. RESULTS

The results for year long PLEXOS simulations for the base case (without additional storage) and for the 6 different storage

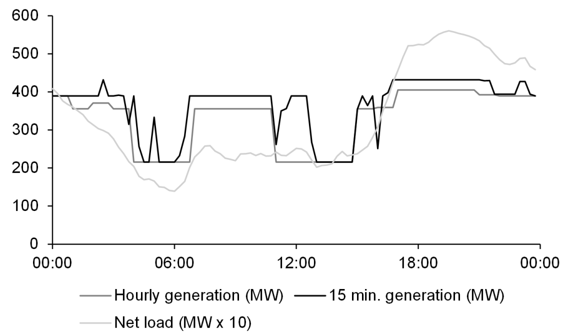

Fig. 1. Net load and CCGT generation - 15 minute vs. hourly dispatch

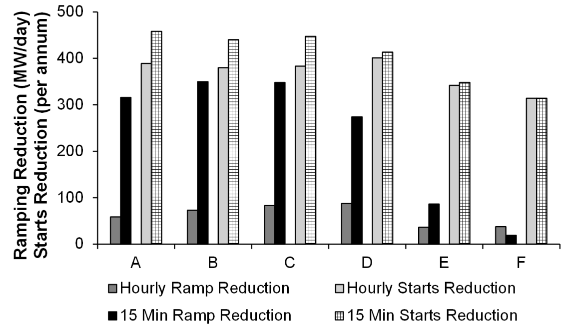

Fig. 2. Sub-hourly vs. hourly conventional plant cycling

plant types (Table II) are detailed, based on a total of 42 individual simulations (7 cases covering the base case and the 6 storage plant types, 8 cases (plant B and plant E for each of the 4 alternative plant sizings) plus 6 cases (plant B, plant E and the base case for each of the 2 reserve scenarios) with simulations performed at both hourly and 15 minute resolutions for each case). The results presented include: operating costs, unit starts and ramping, wind curtailment, CO_2 emissions and details of the storage plant's operation and dispatch. A comparison is also made between hourly and sub-hourly results in order to highlight the importance of the latter when facing high net load variabilities.

A. Hourly vs sub-hourly modeling

The importance of sub-hourly modeling is evident when the detailed plant dispatches are examined. Fig. 1 shows the dispatch of a baseload CCGT plant over the course of one winter day with both hourly and 15 minute results included, as well as the net load at a scale of 10:1. Although the general movements of the plant align, the additional cycling required to maintain balance at a sub-hourly timescale is significant and impossible to capture with standard hourly analysis. By ignoring the sub-hourly variability, hourly modeling consistently underestimates the ramping requirement and the necessary starts for all conventional plant types, with increased cycling seen for all modeled dispatchable plant. As such, the potential impact that a storage plant can have in reducing this cycling activity, in particular the ramping duty, is also underestimated. Fig. 2 shows the reductions attributable to additional storage to both starts and the absolute sum of power changes across

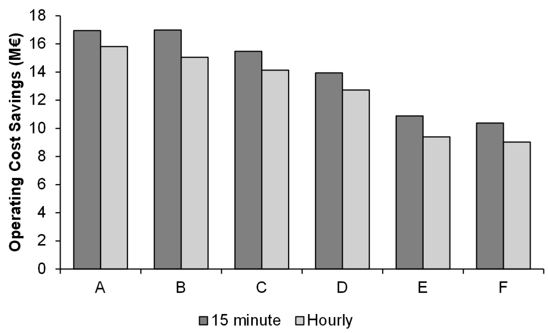

Fig. 3. Operating cost savings - 15 minute vs hourly (no load following)

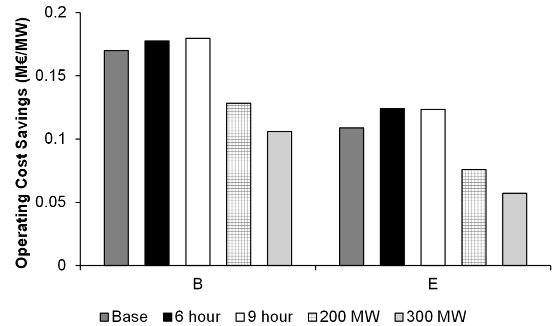

Fig. 4. Operating cost savings with changing plant capacity (discharge duration and rated power) 15 minute resolution

the day for conventional plant. The relative importance of storage plant flexibility is also not captured, with the different storage plant types exhibiting a much tighter spread in cycling reduction for the hourly results - e.g. the ramping reductions achieved with an additional storage plant have a range of 37 - 87 MW/day based on the hourly simulations vs. a range of 19 - 350 MW/day based on the 15 minute analysis. The remainder of this section will focus on the sub-hourly results unless specifically highlighted, where some hourly results are included for comparison purposes.

B. Operating cost savings

A clear trend of reduced cost savings with reduced storage plant flexibility can be seen, with the savings for plant F being ≈60% of the most flexible plant, Fig. 3. Both hourly results (without additional load following) as well as the 15-minute resolution results are included for comparison, highlighting how excluding sub-hourly balancing undervalues the additional storage plant. While the hourly analysis captures the majority of the cost reductions (90%), it does not capture the changes in conventional plant behavior which the storage plant can realize (reduced ramping and starts - see Section III.C) which is of significant interest. The reduced cycling may well be undervalued, as the ability of plant to cycle beyond their initial design considerations, and the costs of doing so over the lifetime of the plant, are still not fully understood, and is an active area of research.

With the exception of reduced efficiency (A → B, explored in more detail in Section III.E) each reduction in plant flexibility leads to a corresponding reduction in cost savings. The largest reduction (22%) occurs when moving from plant D → E, which have characteristics representative of variable-speed PHS and fixed-speed PHS respectively. Plant D has a greater ability to assist with system balancing (lower minimum generation levels, larger reserve capability), particularly in charging mode (due to variable charging rates). Plant F has similar characteristics to those of plant E, but with an additional limit of 3 starts per day imposed. Plant F still captures over 95% of plant E's cost savings, albeit with significantly different dispatch patterns (discussed in Section III.E).

Due to fast and accurate response capabilities, and high partial load efficiencies, storage can be an extremely effective provider of reserve. Reserve requirements at high wind generation penetrations is an evolving area of research, with an increasing emphasis on variable requirements based on probabilistic forecasts [35]-[36]. Alternatively, future systems may use stochastic UC in order to create more robust plant schedules, accounting for wind production uncertainty [37], or reserve could be procured from competing sources, e.g. demand response. In acknowledging that operating cost savings can be reduced by lowering the reserve levels carried on the system, a sensitivity analysis with reduced requirements (80% and 90% of the base requirements across all categories) is performed. This analysis was completed for the base system, with the addition of plant B (highly flexible, 80% efficient) or plant E (fixed charging rate, with limited reserve capability and minimum generation requirement). With the lower reserve requirements, plant B's cost savings drop by up to 41%. The savings from the less flexible plant E, which provides less reserve and higher levels of arbitrage, are impacted somewhat less, with savings reductions of 30% for the 90% reserve requirement, which level off as the requirement is reduced to 80%. These results highlight the enormous cost savings which can result from storage plant providing high levels of reserve, and the weakened business case for energy storage if reserve requirements can be reduced / sourced elsewhere.

The shift in the operation of energy storage, from the traditional diurnal load shifting to larger shares of ancillary services and system balancing, places a reduced emphasis on stored energy capacities, with previous analysis showing that modest capacities (2 - 3 hours at rated output) are sufficient to capture the majority of the cost savings [34]. For example, the cost savings for plant B increase by less than 6% (from 0.17 to 0.18 MEuro / MW) when the energy capacity is trebled from 3 to 9 hours, Fig. 4. The less flexible plant E shows a stronger dependence on energy capacity sizing, with increases in cost savings for both the 6 and 9 hour plant in the region of 14% (from 0.109 ro 0.124 MEuro / MW). The modest increases in operating cost savings will only be justified at relatively low capital costs per MWh, which may be achieved with some technologies, e.g. compressed air energy storage. Indeed, bulk storage technologies such as PHS or CAES would typically have storage capacities closer to those of the 9 hour plant. It should be noted that the additional storage plant is not required for capacity purposes on the system examined.

The marginal value of energy storage fell with increasing

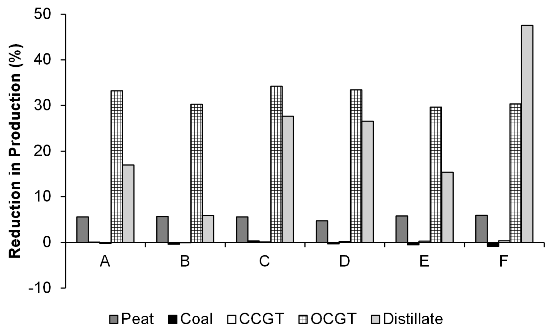

Fig. 5. Reduction in conventional plant production (%) 15 minute resolution

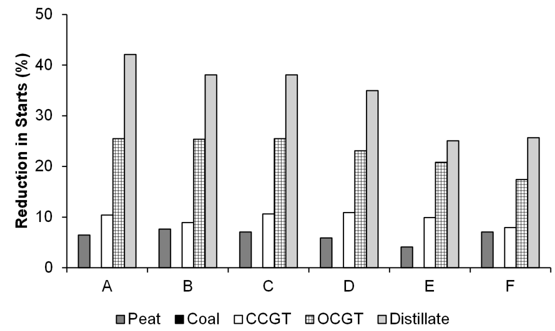

Fig. 6. Reduction in conventional plant starts (%) 15 minute resolution

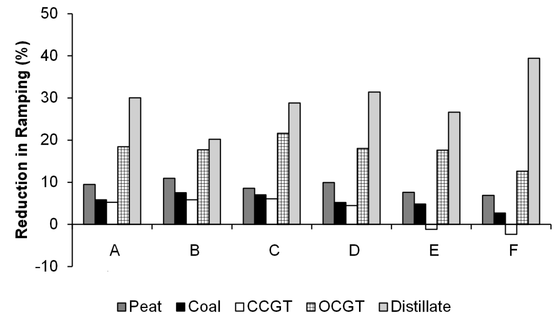

Fig. 7. Reduction in conventional plant ramping (%) 15 minute resolution

installed capacity, as the balancing provided by previously installed capacity reduces opportunities for further cost savings, reducing the average savings per MW of the storage plant, Fig. 4. Appropriate sizing of additional storage will depend largely on the capital costs of the relevant technology.

Large increases in operating cost savings can be achieved with increasing storage plant flexibility, although detailed, technology specific, cost benefit analyses would be required to ascertain whether the additional capital costs are justified. While capital costs for battery energy storage systems are currently higher than PHS (at least 50% higher per kW for long duration systems [38]) the drive to reduce capital costs of many emerging technologies is likely to narrow this gap. Modest energy storage capacities (3 hours at rated output) are sufficient to capture the majority of the cost savings, particularly for the most flexible (and most valuable) plant.

C. Conventional plant production and cycling

Due to efficiency losses, additional energy storage acts as a net load, and requires increased production levels. The increased system energy requirements were largely met by reductions in net exports, which is facilitated through the storage of cheap electricity for later use within the system, and increases in wind penetrations as curtailment is reduced. Most conventional plant types have reduced production levels with the addition of storage, as seen in Fig. 5, which shows the reduction in energy production by plant type, as a percentage of their total annual output in the base scenario. Production levels for baseload coal and CCGTs remain largely unchanged, with changes of less than 1% in ether direction. The less flexible baseload peat plant has reduced production levels of up to 6%, while the largest changes in production occur for the peaking plant (OCGT and distillate) with reductions of up to 34% (49 GWh) and 47% (3.3 GWh) respectively. With the addition of storage, peaking plant are used less to provide both peaking capacity and sub-hourly balancing.

Unlike other forms of flexible generation, storage can also be used to increase system load at times of low or negative net load, reducing the need to cycle inflexible baseload plant. Combined with the ability to provide peaking capacity and system balancing, conventional plant starts are greatly reduced for most plant types (coal starts remain unchanged), Fig. 6. A reduction in the effectiveness of the storage plant in lowering starts occurs as the flexibility of the plant decreases, which is closely correlated with the operating cost savings. Moving from plant D to E (fixed charging rates and lower reserve capabilities), the less flexible plant is not as effective in managing the sub-hourly balancing, which means that expensive peaking plant starts are required more frequently.

Additional storage plant also reduces the overall ramping requirement for conventional plant. The reduction in ramping activity (all changes in plant output, both up and down) for the different plant categories is shown in Fig. 7, which is positive for all conventional plant types with the addition of flexible storage, with some small increases for the CCGT plant with the addition of a less flexible storage plant. A general reduction in the effectiveness of the storage plant in reducing ramping activity is seen as the flexibility of the additional storage plant reduces. While large ramping reductions are seen for distillate plant with the addition of the least flexible storage plant (F), the total ramping requirement of these plant across all scenarios represents less than 0.5% of the ramping requirement of the combined conventional plant fleet.

Reducing the system reserve requirement results in 15% fewer conventional plant starts for both 80% and 90% reserve requirement. With fewer peaking plant starts necessary for sub-hourly balancing, one of the potential value streams for additional storage has already been reduced. Adding storage in the reduced reserve requirement scenarios results in lowered plant start reductions (21.7% reduction with the full reserve requirement, down to 11.7% at the 80% requirement), following a similar pattern to the reductions in potential cost savings.

Increasing the energy storage capacity has a modest impact on reducing thermal plant starts (less than 10% improvement). Increasing the generator capacity has a larger impact, with 25% and 50% fewer starts with the addition of the 200 MW and 300 MW plant respectively, relative to the 100 MW plant.

All results discussed in this section have been at a 15 minute resolution. The hourly resolution results for conventional plant production, starts and ramping (Fig. 5-7) show similar trends - i.e. additional storage is effective in conventional plant cycling reduction, particularly for peaking plant, but being less effective for storage plant with reduced flexibility. However, the hourly results fail to capture the level of plant cycling required to maintain system balance at high net load variabilities (see Fig. 2) and are not represented in detail.

A significant cycling burden is placed on conventional plant when high net load variabilities and sub-hourly timescales are considered, driven in part by the increased reserve requirements at high penetrations of variable renewables. This can effectively be moderated with additional storage plant with modest energy storage capacities.

D. Wind curtailment and CO_2 emissions

For the base scenario wind curtailment is 8.05% (1492 GWh). Up to an additional 0.2% (36 GWh) of the available wind energy can be utilized with the addition of a 100 MW storage plant. Curtailment reductions are seen to increase slightly as the plant efficiency decreases (A $\rightarrow$ B), which is a function of how the different plant types are operated (see Section III.E). In general, the storage plant's effectiveness in reducing curtailment worsens with reduced plant flexibility, with the least flexible plant capturing 65% of the curtailment reductions achieved with the most effective plant B.

While curtailment levels remain largely unchanged for the different system reserve scenarios, large reductions in curtailment are seen when the storage plant's energy capacity is increased, particularly for the inflexible plant E with increases of 54% in curtailment reduction seen for the 9 hour plant (27 $\rightarrow$ 43 GWh). For the flexible plant B, used primarily for reserve rather than arbitrage, the increases are significantly lower, at 24% (36 $\rightarrow$ 45 GWh).

The CO_2 intensity is calculated for the Irish system for each scenario, and the percentage change is calculated for each additional storage plant. While curtailment reduction contributes to CO_2 intensity reductions, so too do the cycling reductions (reduced starts and improved thermal plant efficiencies) and changes in the plant mix in meeting the demand. When a high percentage of the baseload is made up of carbon intense fuel sources, such as coal, emissions may increase with the addition of storage. However, for all the storage plant considered here, CO_2 intensity decreases by up to 1.3% (3.2 tonne CO_2 per GWh). Due to the complex factors determining the emissions reduction, there is no strong correlation between plant flexibility and the calculated reductions, with additional storage plant effecting an average reduction in CO_2 intensity of 1% (2.58 tonne CO_2 per GWh).

While curtailment reductions are of significant value, they are not necessarily the main driver of CO_2 reductions. The large impact that storage plant can have on conventional plant operations and cycling must also be considered.

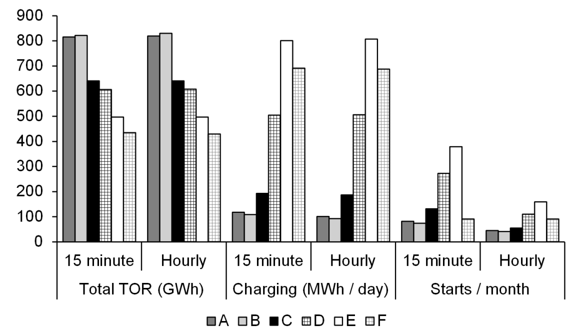

Fig. 8. Storage plant operation: reserve, charging load and starts

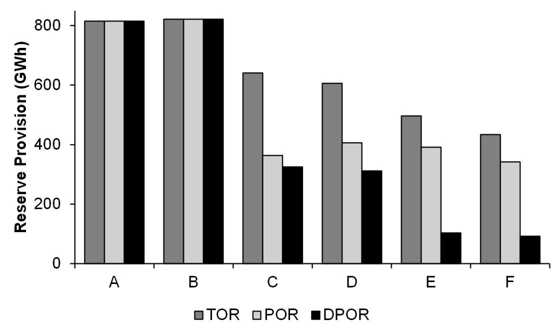

Fig. 9. Storage plant reserve provision: TOR, POR and dynamic POR. 15 minute resolution

E. Storage plant operation

The 6 modeled storage plant have very different dispatch profiles, varying from a mostly off-line provision of reserves, to high capacity factors and large volumes of energy arbitrage. Reserve provision, charging load and starts are discussed for the 6 modeled storage plant and shown in Fig. 8 (hourly and sub-hourly). The total TOR provided by storage throughout the year reduces significantly as the plant flexibility decreases, which is correlated with the potential for operating cost savings. The reserve provision resulting from both the hourly and sub-hourly analysis are well matched. As all categories of operating reserve can be provided simultaneously, for the most flexible plant, identical quantities of reserve are provided across all categories. However, as the storage plant flexibility decreases, lower quantities of the higher value reserves are available. Plant C $\rightarrow$ F are all limited by their ramp rate and response time in the amount of POR that they can provide (see Table II). Furthermore, plant C & D are limited in the amount of dynamic POR that they can provide when charging by the minimum charging rate available, while plant E & F cannot provide dynamic POR while charging, see Fig. 9.

The charging load (and capacity factor) increases as plant flexibility decreases, with a small decrease for plant F, as plant cycling is limited. The charging load resulting from the hourly analysis is underestimated for the flexible plant (A & B) by about 15% when compared to the sub-hourly results, although are found to be well matched for the less flexible plant. The generating capacity factors of the plant range from 3.65% for plant B to 26.75% for plant F. Despite plant B's low capacity factor, due to the 0 MW generation capability, some form of reserve is provided for 99% of its operational hours compared to 84% for plant E. The less flexible plant (D $\rightarrow$ F) need to be on-line in order to provide reserve, so are dispatched more frequently, providing higher volumes of energy arbitrage. Increasing the system load is one method of reducing wind curtailment in a system with non-synchronous penetration limits. However, comparing the charging load (Fig. 8) to the curtailment reductions discussed in section III.C, it is apparent that energy arbitrage is not the main driver of the curtailment reductions. Providing significant levels of reserve allows conventional plant to be de-committed for some of the low net demand operating hours, which can also lead to reduced curtailment levels. A general trend of increased storage plant cycling is seen with reduced flexibility, with a five fold increase in starts seen moving from the most flexible plant (A & B) to plant E (plant F has a 3 starts per day limit imposed). Due to the unit efficiency decrease moving from plant A to B, the less efficient plant is cycled less and provides slightly higher levels of reserve, which contributes to its effectiveness in curtailment reduction. The shift in reduced arbitrage and increased reserve provision results in similar overall cost savings for the year. However, storage plant efficiency improvements will be more critical for investors aiming to maximize profits, particularly for plant providing significant levels of arbitrage rather than reserve.

As previously highlighted in Fig. 2, hourly modeling underestimates the starts and ramping requirement of conventional plant. The same is true of the additional storage plant, with hourly modeling resulting in many fewer starts, particularly for the least flexible storage plant, and a much tighter range of plant starts when transitioning from A $\rightarrow$ F, Fig. 8. Hourly modeling has failed to capture the true variation in optimal storage plant dispatches when used to minimize operating costs with high net load variabilities.

Optimal storage plant operation also changes with a reduced reserve requirement. Considerably fewer thermal plant starts are required for the base system (15% reduction in thermal plant starts) which alters the optimal dispatch profiles for the additional storage plant. The less flexible plant E generates less, provides less reserve and is started less frequently. On the other hand, the flexible plant B provides similar levels of production and reserve but is cycled more frequently, as the relative value in load shifting increases compared to meeting the lowered reserve requirement.

Increasing the plant's energy capacity also changes how the plant is operated throughout the year. For the flexible plant B similar levels of reserve are provided, but with increasing levels of energy arbitrage (increases of 45% and 53% for the 6 hour and 9 hour plant respectively). Increasing the energy capacity for inflexible plant E results in increased reserve provision (up to 6%), with a more modest increase seen in energy arbitrage (up to 4%). The most significant change in storage plant operation is the level of cycling required when the plant's energy capacity is increased. A 15% reduction in cycling to an average of 2 starts per day occurs for the flexible plant B, while plant E sees a 38% reduction in starts across the year. The extremely high levels of cycling required of the inflexible storage plant, with a 0.3 GWh capacity, is driven in part by the low energy capacity assumed. Although PHS plant have significant benefits over thermal plant in terms of cycling ability, there is currently limited experience in PHS operation at these levels of starts, which will impact on the service life of the plant equipment as well as the overall plant efficiency through the loss of water during start up [39].

The base system contains 292 MW of PHS. As expected, operation of the existing plant is also impacted when additional storage is included. The capacity factor of the existing plant is reduced by 25% and 18% with the addition of the 100 MW plant B and E respectively, and further increases to 42% and 31% when plant B and E are sized at 300 MW, which more than doubles the storage capacity on the system. The fall in the marginal value of energy storage, with increased installed capacities is indicated. Although 592 MW of energy storage is small compared to the 7 GW of installed wind generation, the larger storage capacities are only required for a small number of operating hours throughout the year which weakens the business case for the larger plant sizes.

The most flexible (and valuable) plant, while providing high levels of reserve, actually operate with the lowest capacity factors, which raises questions about incentivizing and rewarding their operation in future systems.

IV. Discussion

In order to understand the impact that high net load variability has on conventional plant cycling, sub-hourly modeling is essential. Through detailed sub-hourly analysis, it was found that at the wind generation levels considered, all plant types displayed significantly higher levels of cycling (starts & ramping). Energy storage can play a role in mitigating this cycling burden by providing balancing services and system reserve. Cycling costs were examined in detail in [7] and found to increase significantly at high wind penetrations, although these costs were small when compared to total fuel and operating & maintenance costs for most units. In the system examined here, the increase in cycling will be higher due to: higher wind penetrations (energy $\approx$ 42%), the synchronously isolated nature of the system and a higher concentration of the wind resource. The changing dispatch requirements of plant, originally designed for baseload operation, is already creating economic challenges for many plant owners, and may lead to accelerated plant closures in the future.

Historically, grid-scale energy storage has been used to provide diurnal load shifting, particularly in systems with large amounts of inexpensive, inflexible baseload plant. For such an application, storage plant flexibility is not paramount. Conversely, with high penetrations of variable renewables, storage plant flexibility has a very large impact on potential cost savings, with the ability to provide reserve without being dispatched, and variable charging rates being particularly valuable. The importance of storage plant flexibility is not fully captured using hourly analysis.

The storage plant's flexibility has a large impact on the optimal dispatch profile generated for each of the additional units. Of note is the level of cycling required of the storage plant in order to minimize system operating costs. The most flexible plant are started 2-3 times per day. Similar performance could be achieved with a battery system providing contingency reserve (with infrequent dispatch) and a level of load shifting, or aggregated storage installations at a distribution level. Although this level of cycling would still be beyond the capability of most battery systems with a reasonable lifespan expectation, increasing cycle life is an intense area of research with promising outlooks for some technologies including Li-ion and vanadium redox flow batteries [38]. For systems with high regulation and load following requirements, the storage plant cycle life is paramount if it is to play a role, with flywheels being particularly suited to this application. However, flywheels are currently limited in terms of energy capacities and typically operate with a 15 minute discharge duration, versus the 3 hour duration assumed here. Perhaps contrary to expectation, storage plant cycling (and production levels) increases as their flexibility is reduced. The operation of plant E (similar characteristics to fixed-speed PHS) which is started several times per day is in stark contrast to how existing PHS facilities are operated. However, limiting the daily cycle limit to more realistic levels (plant F) still allows for the majority of the cost savings to be captured.

Operating reserve is extremely valuable in the system considered, due to the very high penetrations of wind generation assumed, which is due both to the increased reserve requirements, as well as the lower capacities of conventional plant on-line at times of high wind generation. The ability of the flexible storage plant to provide reserve at short notice due to the 0 MW generation limit is extremely valuable and is heavily exploited, as can be seen through the low generation capacity factors and high levels of reserve provision, see Fig. 8. The ability to provide these services without being dispatched is the key difference driving the different dispatches of the flexible / inflexible plant. Plant C & D have identical characteristics, with the exception of their minimum generating and charging levels. Plant D sees a significant increase in both its capacity factor and starts as the plant must be available on-line and constantly cycled in order to provide maximum value to the system. The same is true of the other inflexible plant, with plant E either in charging or discharging mode for over 7000 hours throughout the year. While the inflexible plant performs higher levels of arbitrage, which can be used to offset conventional plant cycling, the flexible plant are also available to do so when this is of high value (i.e. high net load variability) and the more flexible operating range allows these plant to be utilized more effectively to reduce cycling activity across all conventional plant types.

In all the simulations performed the storage plant were dispatched in order to minimize total operating costs, and hence more closely represent the decisions of a vertically integrated monopoly, rather than in a market environment. However, a system operator could dispatch a storage plant as part of an optimization process, with a longer look ahead horizon, as proposed in [40]. Privately owned storage plant, operated in order to maximize profits, would likely result in significantly different dispatch profiles [41]. Access to information also plays a key role in terms of dispatch decisions. Private operators would often have inferior information (e.g. wind and load forecasts, status of generation fleet) compared to system operators [42]. However system operators are currently prohibited from owning any generation assets (including storage) in many regions [43], which further limits the potential role that energy storage can play.

The market or regulated environment in which a storage plant is operated will play a crucial role in maximizing the potential benefits which it can provide. The analysis in this paper has shown that the most valuable plant, from a system perspective, are also dispatched the least, and would make the lowest profits in an energy only market. While additional revenue could be generated via capacity payments, again the flexibility of the plant is not rewarded. Indeed many of the improved efficiencies in system operation resulting from additional storage are not easily rewarded in a market environment (e.g. reduced conventional plant cycling). Whether the market alone can incentivize the levels of flexibility required to operate grids efficiently at high levels of variable renewables remains an open question, which has implications not just for storage, but also for other sources of flexibility such as demand response. In order to maximize the potential benefits that storage can provide it is essential that the system values and rewards the efficiencies that storage can bring and encourages suitable levels of investment.

V. Conclusion

Sub-hourly UCED analysis is important for systems with very high wind penetrations, as hourly analysis underestimates the levels of conventional plant cycling, for all plant types, required to maintain supply / demand balance. Energy storage can reduce cycling and improve the efficiency of the system as a whole, with significant operating cost savings. However, hourly analysis also underestimates the level of storage plant cycling required in order to minimize system costs, and the potential cost savings which can be generated. Varying the storage plant's flexibility has a large impact on its potential to generate cost savings, with reductions of up to 40% when the storage plant's flexibility is limited. Of particular value is 0 MW minimum generation (i.e the ability to provide services without being dispatched) and variable charging rates (i.e. the ability to provide balancing while charging or discharging). High levels of storage plant cycling are required to provide maximum value, particularly for less flexible storage plant. However, limiting the storage plant's cycling capability only has a marginal impact on potential cost savings.

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