



<b>Title</b>	Efficient large-scale energy storage dispatch: challenges in future high renewables systems
<b>Authors(s)</b>	O'Dwyer, Ciara, Ryan, L. (Lisa B.), Flynn, Damian
<b>Publication date</b>	2017-09
<b>Publication information</b>	O'Dwyer, Ciara, L. (Lisa B.) Ryan, and Damian Flynn. "Efficient Large-Scale Energy Storage Dispatch: Challenges in Future High Renewables Systems." IEEE, September 2017. <a href="https://doi.org/10.1109/TPWRS.2017.2656245">https://doi.org/10.1109/TPWRS.2017.2656245</a> .
<b>Publisher</b>	IEEE
<b>Item record/more information</b>	<a href="http://hdl.handle.net/10197/9103">http://hdl.handle.net/10197/9103</a>
<b>Publisher's statement</b>	© 2017 IEEE. Personal use of this material is permitted. Permission from IEEE must be obtained for all other uses, in any current or future media, including reprinting/republishing this material for advertising or promotional purposes, creating new collective works, for resale or redistribution to servers or lists, or reuse of any copyrighted component of this work in other works
<b>Publisher's version (DOI)</b>	10.1109/TPWRS.2017.2656245

Downloaded 2026-05-01 23:49:08

The UCD community has made this article openly available. Please share how this access benefits you. Your story matters! (@ucd\_oa)



© Some rights reserved. For more information

# Efficient Large-Scale Energy Storage Dispatch: Challenges in Future High Renewables Systems

Ciara O'Dwyer, *Student Member, IEEE*, Lisa Ryan and Damian Flynn, *Senior Member, IEEE*

**Abstract**—Future power systems with high penetrations of variable renewables will require increased levels of flexibility from generation and demand-side sources in order to maintain secure and stable operation. One potential flexibility source is large-scale energy storage, which can provide a variety of ancillary services across multiple time-scales. In order for appropriate levels of investment to take place, and in order for existing assets to be utilized optimally, it is essential that market signals are present which encourage suitable levels of flexibility, either from storage or alternative sources. Suboptimal storage plant dispatch due to uncertainty and inefficient market incentives are represented as operational constraints on the storage plant, and the impact of these inefficiencies are highlighted. Thus changes required in operational practices for storage plant at different installed wind capacity levels, and the challenges that private storage plant operators will face in generating appropriate bids in a market environment at high variable renewable penetrations are explored. The impacts on system generating costs and storage profits are explored under different plant operating assumptions.

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

## I. INTRODUCTION

GRID-SCALE energy storage has been used in power systems for decades, largely in the form of pumped hydro storage (PHS). Historically, energy storage has been primarily used for energy arbitrage, which was of significant value to systems where large price spreads existed between baseload and peaking plant. It has also been widely used by systems with large inflexible baseload plant capacities, such as nuclear, filling the nighttime valley and allowing the units to remain online, while also providing valuable peaking capacity. With the decline of nuclear power plant installations [1], and reduced price spreads evident on many systems (a single fuel, natural gas, is often marginal in many systems, as opposed to, historically, coal and more expensive oil) the business case for energy storage has diminished [2], with a large decline in new grid-scale energy storage installations in recent decades.

The large-scale integration of variable renewable generation is having an impact on power system operations globally, with

This work was conducted in the Electricity Research Centre, University College Dublin, Ireland, which is supported by the Electricity Research Centre's Industry Affiliates Programme (<http://erc.ucd.ie/industry/>).

This publication has emanated from research conducted with the financial support of Science Foundation Ireland under Grant Number SFI/09/SRC/E1780.

The authors are with the School of Electrical and Electronic Engineering, University College Dublin, Ireland.

wind generation capacity expected to reach 428 GW by the end of 2015 [3], creating new challenges for many power systems. Renewed interest in grid-scale energy storage has been sparked by the growth of variable renewables, which increase net load variability, price volatility and network congestion and so improves the business case for energy arbitrage [4]. Energy storage can also reduce renewable energy curtailment and provide valuable flexibility, reducing the cycling burden placed on conventional plant, which face increased start / shutdown and ramping requirements in order to maintain the supply / demand balance [5]. However, it is widely acknowledged that arbitrage alone is unlikely to justify the high capital costs and efficiency losses of energy storage [6]. As such, the aggregation of multiple benefits are essential [7], and even then the justification for additional energy storage will be highly system specific and likely only take place at very high variable renewable penetrations [8] or for particular niche applications.

Valuing energy storage in an evolving power system is an active research area, with advancements in methodologies still required in order to aggregate multiple value streams. Studies which estimate the value of energy storage can be split into two main categories, either using engineering models or system models [9]. While the former typically assess the techno-economic performance of a specific storage technology using profit maximization strategies (usually using a price taker approach), system models search for least cost solutions from a system point of view, which would be representative of operation under a vertically integrated monopoly [10]. In theory, in a perfectly competitive market, operating decisions under profit maximization and system cost minimization should coincide. However, one prerequisite of a perfectly competitive market is access to good information [11]. At high variable renewable penetrations, future price uncertainty increases, which creates particular challenges for a storage plant operator in generating efficient bidding strategies, who must purchase energy from the grid, as well as offer its generation capacity [12]. While conventional generators have, if not static, certainly predictable marginal costs based on fuel and operation & maintenance costs, the marginal cost for a storage plant is highly variable. It depends on pumping costs and also, due to their energy limited nature, the opportunity cost, related to the foregone opportunity to use the stored energy at a later point in time. This is complicated further when reserves are provided along with energy arbitrage, with the cost of providing reserve dominated by the opportunity costs of withholding capacity from the energy market. In addition, reserve deployment in high renewables

scenarios will be difficult to predict, which has a large impact on future operations for an energy limited plant. An effective profit maximization algorithm must consider energy payments (with trading opportunities in multiple markets) as well as reserve payments (typically plant are paid both for capability and deployment) which introduces a great deal of uncertainty, both in value and volumes deployed.

Many algorithms have been developed in order to maximize storage plant profits [13]-[22], but these strategies are not well suited to storage plant operation at very high renewable penetrations, providing services in multiple markets. Strategies largely focus on systems with low variable renewable penetrations [13]-[19], [22], or concentrate on arbitrage profits alone [21]-[22]. Typically a price taker approach is adopted, where it is assumed that prices are predictable and storage plant operation does not impact on the price. The focus is usually on profit maximization for the plant owner, although studies also exist which consider the potential impact on the wider system [23], [24]. At very high variable renewable penetrations, developing effective strategies for storage plant operation will be crucial, in terms of profit generation for the plant owner and in terms of system cost minimization. Most profit maximization algorithms do not consider the impact of reserve usage on operations [13]-[15], or assume that fixed percentages of reserve are deployed [17]-[20], often with perfect foresight of system requirements. Preliminary results based on a pumped hydro plant in the Spanish market indicate that real-time usage of reserves lead to significant deviations in reservoir volumes and plant earning using a selection of approaches to estimate the real-time reserve usage compared to perfect foresight [25]. Future work has been identified to expand the model beyond a single day of operation and to consider intraday market participation and reserve provision when in pumping mode. Due to the limitations of the existing strategies, with increased price variability and uncertainty, storage plant operations will become less efficient.

In order for effective strategies to be implemented, access to information will be crucial in allowing storage plant to be operated for maximum benefit, in terms of system cost minimization and plant profit maximization. Current operational practices depend on asset ownership, as well as the market structure and the regulatory framework. In most liberalized electricity markets (including the EU), storage is classed as a generation asset, and, as such, system operator (SO) ownership is prohibited or heavily restricted [26]. Storage plant owners must participate in electricity markets (with typically less access to information than SOs [27] including wind and load forecasts, network and plant statuses), although country specific grid codes and regulations relating to energy storage are quite diverse, and examples of distribution network operator (DNO) and transmission system operator (TSO) ownership of storage exist in Italy and Belgium [28], [29].

It has been proposed by some that SOs should be allowed to operate storage assets as part of an optimization process [12]. Such an approach with an increased horizon can reduce

operating costs, and also maximize profits for storage plant owners. In the U.S., PJM alone optimizes PHS in the day-ahead market. However, despite the potential benefits, no SO fully optimizes PHS operations in the real-time market [4].

Energy storage can be used to provide valuable flexibility to systems with high penetrations of variable renewable generation. However, storage plant operational requirements (in terms of charging and discharging profiles, and reserve provision and deployment) in future high renewable systems differ considerably from current practices. Regulations and market designs which have evolved around conventional dispatchable plant, and storage plant profit maximization algorithms which have been developed to operate within these structures, lead to inefficient storage plant operation at high penetrations of variable renewable generation. This paper estimates the cost of inefficient storage plant operation, as the operation of the storage plant is increasingly constrained (reflecting suboptimal dispatch due to uncertainty or inefficient market incentives) with increasing shares of wind generation capacity, highlighting the undesirable implications of existing methodologies, and the challenges facing private storage plant operators in a market environment. Constraints on the mode of operation, dispatch levels and reservoir targets reflect market practices and dispatch strategies. While these constraints may not be particularly onerous at low levels of variable renewable penetrations, the impact at high penetrations of renewables, representing future power systems, is of interest. The results provide valuable insight to policy makers, informing the ongoing debate surrounding storage plant ownership and operation [30], [12]. The results also highlight the weaknesses of existing storage dispatch algorithms, which is of interest to storage plant operators. Key topics for future research are also identified, particularly surrounding reserve deployment in future power systems, which is of particular relevance for operators of energy limited resources including storage and demand response, and is currently lacking in the literature.

The remainder of the paper is organized as follows: Section II describes the methodology used to perform the assessment, along with details of the test system and wind profiles. Section III describes a range of reserve scenarios which have been considered, before providing a description of each of the constraints in turn. Results are presented in terms of both system costs and plant profitability for different levels of installed wind generation. Section IV discusses the results, while Section V concludes.

## II. METHODOLOGY

A detailed system model is used to explore the impacts of suboptimal dispatch of large-scale energy storage at different wind energy penetrations. A market model of the Irish system has been adapted for these simulations [31]. Total system operating costs are estimated at 4 different wind generation levels, with and without an additional storage plant, in order to estimate an upper bound for potential cost savings. For initial simulations, the storage plant is free to provide energy

and/or reserve in order to minimize system costs. The system is modeled with up to 3 different reserve categories, a contingency reserve based on the largest in-feed, and flexibility reserve (raise and lower) based on forecast errors (see Section II.B). A number of different reserve scenarios (in terms of system requirements and storage plant provision) are considered. Storage plant operating constraints are then introduced which represent typical market rules and regulations, and weaknesses in existing energy storage dispatch strategies, which have little impact on typical storage plant operations at low wind penetrations (with predictable daily price evolutions for energy and reserve, with small interday variability in operations) but become much more significant when applied to high wind scenarios. The impact of these constraints on system operating costs and storage plant profitability are then analysed.

#### A. Unit Commitment and Economic Dispatch

System operating costs are obtained by solving the unit commitment and economic dispatch (UCED) problem using PLEXOS for Power Systems<sup>®</sup> [32], a power system modeling tool. Total generation costs are calculated using mixed integer programming (MIP) and the Xpress MP solver, with energy and reserve co-optimized. Operating costs are estimated for a 90 day period with UCED at a 15 minute resolution. The period modeled covers the winter months, with the highest system demands, intra-day demand spreads, wind capacity factors and hence, the highest flexibility requirements. The objective function minimizes total system operating costs:

$$\min \sum_{t \in T} \left\{ ens_t VOLL + \sum_{r \in R} ir_{r,t} VOIR_r + \sum_{i \in I} \left[ C_i^{SU}(v_{i,t}) + u_{i,t} C_i^{NL} + C_i^P(p_{i,t}) \right] \right\} \quad (1)$$

where  $T$  is the horizon and  $t$  is the interval. Energy not served,  $ens$ , and insufficient reserve,  $ir$  (for each reserve category,  $r$ , in the reserve set,  $R$ ,) are penalized via the value of lost load,  $VOLL$ , and the value of insufficient reserve,  $VOIR$ , respectively. These values were set artificially high to ensure that load and reserve are met at all times when technically feasible. Each generator,  $i$ , in the set,  $I$ , has a start-up cost,  $C^{SU}$  (and a binary start-up indicator,  $v$ ), a no-load cost,  $C^{NL}$  (depending on the online status,  $u$ ), and a production cost function,  $C^P$  (dependent on the unit active power output,  $p$ ). Reserve requirements are outlined in Section II-B below. It is assumed that a perfectly competitive market exists and strategic behavior of plant (based on an imperfect market, with market specific conclusions) is not considered. Marginal cost pricing is assumed and plant profits are estimated accordingly. Marginal costs of 0 are assumed for wind generators, although priority dispatch is not strictly maintained and wind may be curtailed in order to minimize costs, rather than current practices which give priority to wind generation insofar as the secure operation of the power system permits.

The economic dispatch for all units is generated based on 3 sequential deterministic simulations (a fourth simulation is required for some of the modeled constraints - see Section III-B). The Commitment decisions for those plant with longer start up times (greater than 6 hours) are made in the day-ahead simulations based on hourly data and day ahead forecasts (which reflects the inability of such plant to be started at short notice), which are then fed into 6-hour-ahead simulations (hourly data including 6-hour-ahead forecasts) where commitment decisions are made for any plant with medium start-up times (1-5 hours). These commitments are then fed into a real-time simulation which uses a 15 minute time step and realized wind and load variations. At this final stage, commitment decisions are made for the peaking plant, along with an economic dispatch of all units. All simulations include a 24 hour look-ahead, ensuring future system requirements based on available information are considered. This 3 stage simulation methodology captures the inability of less flexible plant to readily adjust to changing system requirements based on updated forecast information. Previous studies have highlighted the importance of flexible baseload plant operation [33], and more flexible operation of baseload plant with reduced start-up times can lead to increased efficiencies. In this paper 3.4 GW of plant (47% of dispatchable capacity) are assumed to have long start-up times. Actual start-up times will depend on the state of the plant (i.e. hot, warm or cold), although warm starts have been assumed here, reflecting the fact that for the slow units, hot starts would be infrequent due to the typically high start-up costs associated with these units.

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.

In order to maintain system stability and security, the instantaneous penetration from non-synchronous sources, e.g. wind power plant, is limited. A 75% system non-synchronous penetration limit is assumed, which is in line with the 2020 target in Ireland. A minimum number of 6 large synchronous units on line is also enforced in order to ensure system stability (a reduction of the current limit of 8 has been assumed, assuming the adoption of dedicated network devices) [34]. Additional constraints ensure regional stability (sufficient plant on a regional basis must be available for voltage control, depending on demand), ensure transmission constraints are reflected (with regional generation limits) and ensure sufficient availability of replacement reserve [34] (See Section II-B).

#### B. Modeling Wind Generation and System Reserves

The demand and wind (forecast and realized) profiles are scaled up from data for Ireland from 2011/12. Wind forecasts

are available 4 times per day: at 0 h, 6 h, 12 h and 18 h. For the day ahead forecast, the 12 h data is used, i.e. 12-36 hours in advance of dispatch. Similarly, for the 6 hour ahead simulations, the relevant updated forecasts are used.

The two base reserve categories modeled include a flexibility based reserve and a contingency based reserve, which are both dynamic and updated throughout the simulations. Extremely high penetrations of variable renewable generation are considered in this paper, which has a large impact on the balancing requirements of the system [35]. System operators are increasingly considering new ancillary services [36], [37]. The flexibility reserve is necessary to avoid large volumes of energy not served due to forecast error at the high wind penetrations considered (the reduction of scarcity events through the inclusion of a flexibility reserve has been demonstrated in an NREL study [38]). The flexibility reserve is based on the forecasted wind level, and 95% confidence intervals are calculated to ensure that the majority of forecast errors can be covered, following the methodology outlined in [39]. During the real-time simulation, flexibility reserve is no longer carried, but is essentially dispatched as required. As sub-hourly modeling captures most of the balancing requirements, activation of the remaining reserve category is driven by contingency events and should be infrequent. The contingency reserve requirement is equal to the largest in-feed and based on Ireland's tertiary operating reserve (TOR) which must be delivered within 90 seconds and maintained until 300 seconds, with low energy requirements due to the short duration. In terms of activation times and duration, it is comparable to ENTSOe's Frequency Restoration Reserve (FRR). A constraint ensures that there is sufficient capacity of fast starting units available to provide replacement reserve [34]. The third category of reserve, flexibility lower, is not considered as a base category of reserve but is included in an additional scenario, with requirements also based on 95% confidence intervals of the forecasted wind.

### C. Test System

The plant characteristics are based on a simplified, isolated, future Irish portfolio. The test system (which is based on coherent wind, demand and generation data, but is not intended to accurately represent the existing, or future Irish power system) consists of 7345 MW of dispatchable plant, primarily gas plant, with combined cycle gas turbines (CCGT) providing mid-merit and some baseload, and open cycle gas turbines (OCGT) providing the peaking capacity - see Table I. There are also a number of baseload coal and peat plant - sufficient capacity to set the price at low demand levels, along with a number of peaking distillate plant at the top of the merit order. 216 MW of run of river hydro plant are also present on the base system. Four different installed wind capacity levels are examined: 0 MW, 2500 MW, 5000 MW and 7500 MW which represent 0%, 15.7%, 30.3% and 40.6% of the annual energy demand respectively. Reserve in the low wind cases is primarily provided by the gas plant (in excess of 70%) with the

TABLE I  
TEST SYSTEM PLANT PORTFOLIO

<i>Plant type</i>	<i>No. units</i>	<i>Capacity (MW)</i>
Peat	2	228
Coal	7	1901
Natural gas (base and midmerit)	14	4074
Natural gas (peaking)	4	349
Distillate (peaking)	11	577
Hydro (run of river)	15	216
Wind	~	0 - 7500
New storage	1	200

remainder provided primarily by the coal plant, while for the high wind cases, due to the merit order effect (as some of the mid merit gas plant are displaced) and the increased balancing requirements, coal plant provide higher levels of reserve (over 40% of system requirements) with similar quantities provided by the gas plant. For both the high and low wind cases, small quantities of reserve are provided by each of the remaining plant types. The system peak demand is 7000 MW with a total annual electricity requirement of 38 TWh. The test system has sufficient capacity, before additional wind or storage are included. This reflects the situation in Ireland, and indeed many other regions where over capacity currently exists. Additional storage in such systems must operate profitably in order to justify future investments. Fuel prices are taken from the central scenario of DECC's fossil fuel price projections [40] for the year 2025. A carbon price of €20 per tonne is assumed.

### D. Pumped Hydro Storage Plant

A variable speed pumped hydro plant is modeled, which is highly flexible compared to a fixed speed plant, with variable charging and discharging rates [41]. A simple, single unit closed-loop system is assumed, and inefficiencies are accounted for in the pumping cycle, with a round trip efficiency of 80% assumed, in line with existing modern pumped hydro facilities [42]. It is assumed that the storage plant operation is not impacted by transmission constraints. All storage operating decisions are determined in order to minimize total operating costs. 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 facility consists of a 200 MW plant, both in charging and discharging mode, with a 0.8 GWh energy capacity. The minimum generation capacity is assumed to be 50 MW, while the minimum pumping rate is assumed to be 120 MW. The full charging rate can be offered as reserve, while, when generating, the plant can provide all available headroom above the operating point as reserve, although contingency and flexibility reserve provision are mutually exclusive - i.e. both the flexibility raise reserve capability and the contingency reserve capability of the plant are 150 MW, although the combined sum is 150 MW also. As the focus of the paper is on the inefficiencies of plant dispatches caused by operating constraints, and the plant

dispatches are determined based on system cost minimization, it is important that the cost savings are significant relative to the total operating costs and the model performance relative gap. This informed the choice of plant size. Power balance for each time step is ensured with the following equation:

$$\sum_{i \in I} p_{i,t} - h_{sto,t} + dns_t = D_t \quad \forall t \in T \quad (2)$$

where  $T$  is the horizon and  $t$  is the interval.  $p_{i,t}$  represents the generator output from each unit  $i$ , in the set,  $I$  (including storage plant) and  $h_{sto,t}$  represents the pump load for the storage unit. The sum of generation, minus the pump load plus the demand not served,  $dns$ , must equal the system demand for all time steps. The energy content of the reservoir is described with equations 3 - 4:

$$E_{min} \leq E_t \leq E_{max} \quad (3)$$

$$E_t = E_{t-1} + \Delta t(p_{sto,t} - h_{sto,t} \times \eta) \quad (4)$$

Equation 3 ensures that the energy content  $E$  at a given time step  $t$  lies between the upper and lower limits of the upper reservoir, while equation 4 relates the energy content in the upper reservoir for a given time step  $t$  to the energy content in the preceding time step  $t-1$ , where  $\Delta t$  is the time step size in hours.  $p_{sto,t}$  and  $h_{sto,t}$  are the generation and the pump load respectively for the storage plant at a given time step  $t$ , and  $\eta$  represents the conversion efficiency for the pumping cycle.

The optimization horizon in PLEXOS is set to 24 hours with a further 24 hour look ahead, which ensures that realistic dispatches for energy storage are obtained through ensuring 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 would not be considered and the energy storage contents would be drained at the end of each optimization period. Such an approach also ensures that unit starts are scheduled appropriately for plant with high start-up costs.

### III. RESULTS

A number of modeling scenarios are introduced which are used throughout the results section. Some high level results for an unconstrained storage plant with "ideal" dispatches are initially presented, in order to highlight the operational differences in the storage plant for the different scenarios. The unconstrained storage plant simulations represent an upper bound for system cost reductions, as the commitments and dispatches of the storage plant can be optimized based on the real-time system requirements. In Section III-B each of the operational constraints are then introduced (including reservoir targets and commitment and dispatch constraints in different time-frames) with their impact on operating costs and storage plant profitability presented.

#### A. Scenarios

The value of a large-scale energy storage plant is system and location specific. This paper demonstrates, through a test case, the problems that can arise with increasing shares of variable renewables in dispatching storage plant efficiently due to uncertainty and inefficient market incentives. Reserve products are also system specific and have evolved over time to meet particular requirements for stability and security. As variable renewable penetrations increase, reserve products are being reviewed in many systems in order to meet the new challenges that arise. As such, scenarios have been modeled with different reserve product combinations included as part of the system requirements. Also, within a given market structure, provision of a given reserve product by a market participant will be optional and different strategies may be deployed in order to maximize profits. Four different scenarios capture storage plant participation in a subset of the available markets across the different wind generation levels. These scenarios represent operational practices - the plant possess the same technical characteristics for all scenarios and there are no capital cost implications.

A contingency reserve and a flexibility raise reserve are included as a system requirement in all 4 scenarios. 3 of the scenarios consider the storage plant providing energy in combination with a subset of these base reserve categories. Plant owners will strive to maximize profits, and participation in all available markets will not necessarily prove to be optimal. The relative value of the different reserves will also vary depending on wind penetrations (e.g. flexibility reserve is more valuable at higher wind levels, while the converse is true for the contingency reserve based on the largest in-feed), and will influence the strategic decisions of the plant owner. In a "contingency & flexibility reserve" scenario (CRes&Flex), both of the base reserve categories are provided by the storage plant, while in a "no contingency reserve" scenario (NoCRes) the storage plant provides only energy and flexibility reserve, and the "no flexibility reserve scenario" (NoFlex) the storage plant provides energy and contingency reserve only. A fourth scenario includes an additional reserve, flexibility lower (FlexLwr), which may be requested by the SO. It is not considered as a base reserve category as large upward ramps in wind production can be managed through curtailment, and carrying a "lower" reserve category may not form part of a least cost solution. The reserve categories, and their provision by the storage plant, are summarized in Table II.

1) *Storage Plant Dispatch*: Highlighting how the scenarios considered have a large impact on the behavior of the modeled plant, Fig. 1 shows the average dispatch over the 90 day period for the unconstrained storage plant at the 4 different wind levels (CRes&Flex (a) and NoCRes (b)), which highlights broad differences in the plant dispatches, depending on the services provided. The scenarios result in quite different dispatch profiles across the wind levels. As the storage plant is an excellent provider of reserve, it is rarely dispatched at maximum capacity in the CRes&Flex

TABLE II  
STORAGE PLANT RESERVE PROVISION SCENARIOS

	Scenario	CRes &Flex	NoCRes	NoFlex	FlexLwr
<b>System</b>	Contingency	Yes	Yes	Yes	Yes
<b>Reserve</b>	Flex Raise	Yes	Yes	Yes	Yes
<b>Requirement</b>	Flex Lower	No	No	No	Yes
<b>Reserve</b>	Contingency	Yes	No	Yes	Yes
<b>Provided</b>	Flex Raise	Yes	Yes	No	Yes
<b>by Storage</b>	Flex Lower	No	No	No	Yes

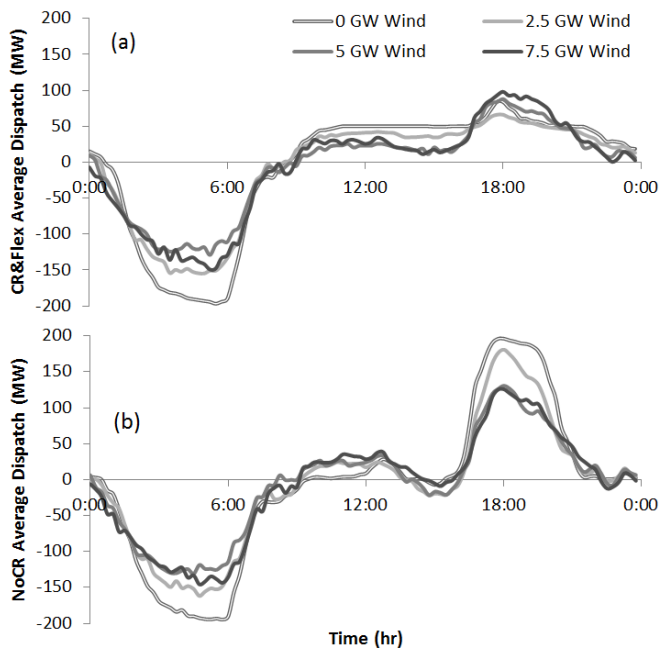


Fig. 1. Average daily dispatch (generation & pumping (-ve)) of plant (CRes&Flex & NoCRes Scenario)

scenario - rather it spends longer durations throughout the day generating close to its minimum generation level of 50 MW, while simultaneously providing large quantities of contingency reserve. Plant generator output increases towards the evening peak, but typically maximum output is not reached. In contrast, for the NoCRes scenario (no contingency reserve provided), the generation capacity is saved to meet the largest peaks in demand, particularly the evening peak (18:00) when it is typically dispatched close to its maximum output. Across all 4 scenarios, as wind generation is added to the system, a flattening of the storage dispatch profile occurs, as increasingly both pumping and generation are required at other times of the day in order to meet the needs of the varying net load.

Fig. 2 shows the average daily reserve provision by the storage plant taken from the 6 hour ahead simulation, whereby a decision must be made between the provision of flexibility reserve or contingency reserve (see Section II-D). In general, reserve provision is low at 7 am when the storage plant is typically neither pumping nor generating. At lower wind levels the plant primarily provides contingency reserve (as flexibility

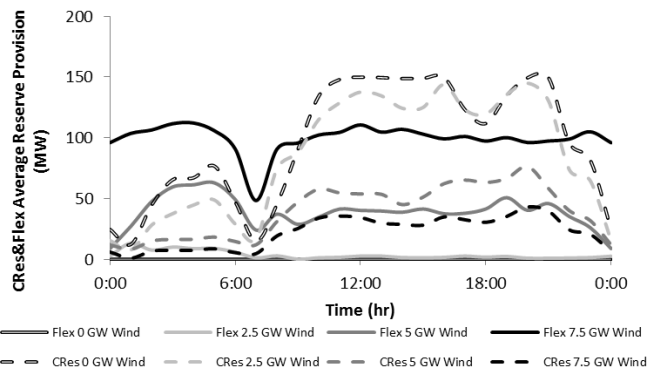


Fig. 2. Average daily reserve provision (Flexibility Raise and Contingency Reserve (CRes&Flex Scenario))

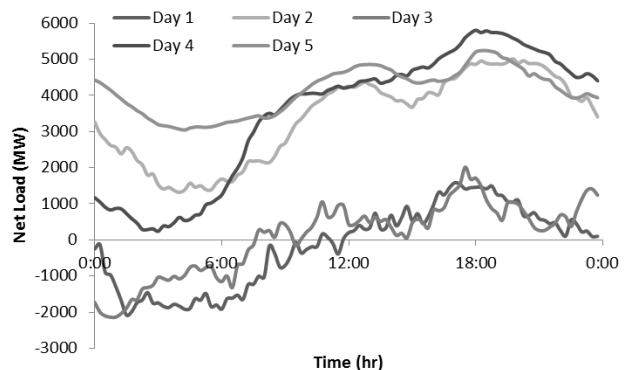


Fig. 3. Net load on 5 separate week days (7.5 GW wind generation)

reserve requirements are low) and a dip in reserve provision can be seen to coincide with the evening peak as generation increases (and reserve capacity decreases). At 7.5 GW of installed wind capacity the storage plant primarily provides flexibility reserve (due to higher requirements and value). At 5 GW of installed wind capacity the reserve provision by the storage plant is more evenly split between the reserve categories, although the contingency reserve provision falls at night (the reserve requirement based on the largest infeed will be low when demand is low and wind generation allows for those units online to be dispatched close to minimum generation levels), although during the day slightly higher levels of contingency reserve are typically provided.

While Fig. 1 shows a flattening of the average dispatch profile as wind generation increases, there is also an increase in the day to day variability of the dispatch profiles. Five non-consecutive weekdays have been selected from the 90 day simulation period, with large variations in net load (Fig. 3) and the corresponding unconstrained dispatches are shown in Fig. 4. Interestingly, the interday variability in the dispatches of the storage plant in the CRes&Flex scenario (a) is much smaller than that for the storage plant dispatched in the NoCRes scenario (b), where the plant state (charging / discharging) in a given hour may vary considerably from day to day. In the

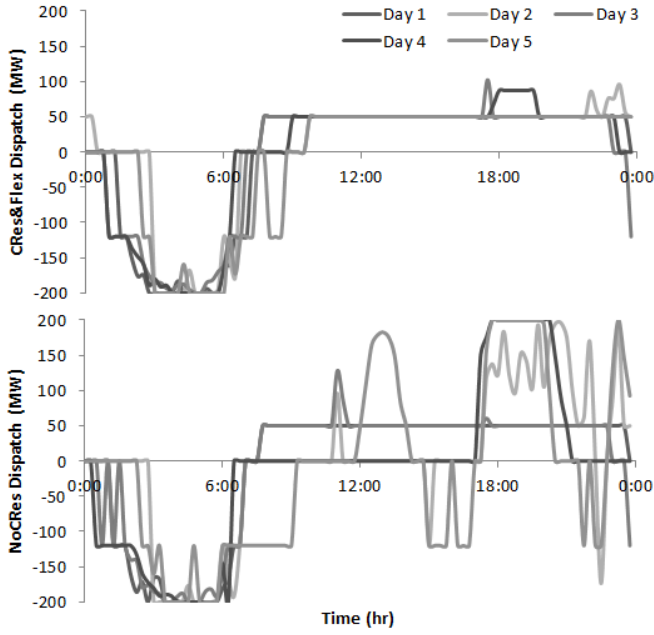


Fig. 4. CRes&Flex & NoCRes scenario dispatch on 5 separate week days (7.5 GW wind generation)

CRes&Flex scenario (a), the plant is not typically deployed to provide flexibility reserve during the day, but is rather held at minimum generation level, providing contingency reserve and taking advantage of the plant's good part-load efficiency. However at night, when fewer thermal plant are committed, flexibility reserve from the storage plant is more likely to be deployed and more variability in the plant dispatch in charging mode is evident. Without an incentive to provide reserve in real-time, the NoCRes plant (b) is more likely to be dispatched at maximum capacity during the peak net load hours, rather than at minimum generating capacity over a longer period. More intraday variability can also be seen in the plant dispatches as flexibility reserve is deployed, although this variability remains small for those days corresponding to low net load (and high wind) as the curtailed wind is exploited to provide much of the balancing (Reduced balancing requirements at very high wind levels is highlighted in Fig. 5 which demonstrates how, when curtailment is required, the wind generation is dispatched to follow the load (14:30 - 17:00 and 18:00 - 00:00), requiring less balancing from the dispatchable plant. It should be noted, however, that while dispatching wind generation in such a way is feasible, policies vary from system to system. Without accessing this flexibility from the wind generation an increasing role for the storage plant would exist.) Identifying those times of peak net load, and high system prices in advance makes operating decisions at high wind generation levels particularly challenging, both in terms of reducing operating costs and in terms of maximizing profits for the plant owner.

2) *Operating Cost Savings & Plant Profitability:* As the modeled system is isolated and has no other large-scale storage

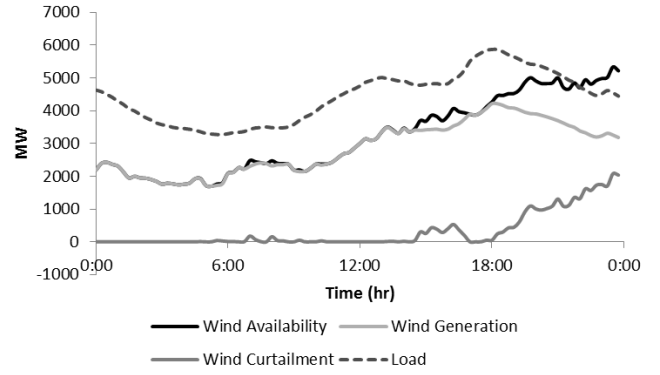


Fig. 5. Wind Availability, wind generation and wind curtailment and load for 1 day (7.5 GW wind generation)

installed, the cost savings achieved by the additional storage plant (i.e. the difference in system operating costs with, and without, the storage plant) are significant (see Fig. 6) and range from €6.5m at no/low wind generation capacities up to €15m at 7.5 GW of installed wind capacity, where the additional flexibility provided by the storage plant allows the system to be operated much more efficiently (i.e. less cycling and higher efficiencies achieved from conventional plant [5]). It can be noted that in some scenarios (CRes&Flex and NoFlex) that potential operating cost savings reduce slightly as the installed wind capacity increases from 0 - 2.5 GW. Increases in variable renewable generation with close to zero marginal costs has a large impact on electricity prices, suppressing electricity prices with average prices typically reducing with increasing installed capacities of variable renewables [43], [44]. However, for energy arbitrage it is the price spread which is important. As well as average prices reducing, increased wind penetrations also have an impact on price variance, which studies have shown can initially decrease at low shares of wind generation, but as penetrations increase further, the opposite effect occurs, partly driven by zero (or even negative) electricity prices [45]. High price variances directly translate to higher earnings for an energy storage plant [46].

Storage plant profits are also estimated, with calculations based on the 6 hour ahead price for flexibility reserve and the real-time energy and contingency reserve prices:

$$\begin{aligned}
 PROFIT = & \sum_{t \in T} ((p_{RT_t} - h_{RT_t}) \cdot \lambda_{RTE_t} \\
 & + CR_{RT_t} \cdot \lambda_{RTCR_t} + FR_{6H_t} \cdot \lambda_{6HFR_t}) \quad (5)
 \end{aligned}$$

where  $T$  is the horizon and  $t$  is the interval.  $p_{RT}$  and  $h_{RT}$  represents the generation and pump load of the storage plant and  $\lambda_{RTE}$  represents the system marginal price for energy from the real-time simulations.  $CR_{RT}$  and  $FR_{6H}$  represent provision by the storage plant of the contingency reserve (from the real-time simulation) and the flexibility reserve provision (from the 6 hour ahead simulation) respectively, while  $\lambda_{RTCR}$  and  $\lambda_{6HFR}$  represent the system marginal price for contin-

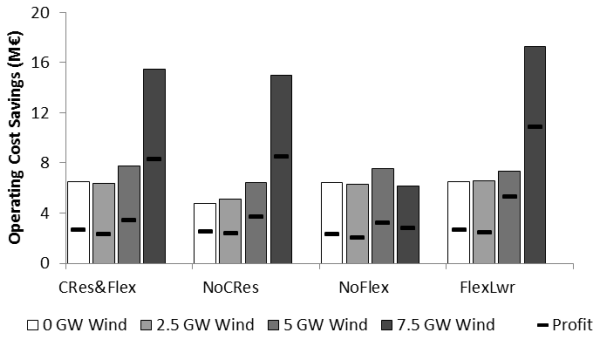


Fig. 6. Operating cost savings and storage plant profitability at 4 different wind levels

gency reserve (from the real-time simulation) and flexibility reserve (from the 6 hour ahead simulation) respectively.

Energy and reserve are co-optimized. In such markets, units should be compensated with at least the lost opportunity cost for providing additional energy instead of reserve. This compensation is automatically embodied in the reserve price, which is equal to the dual variable associated with the constraint defining the reserve quantity for each time step [47]. In practice, payments for ancillary services are system specific and are based on some combination of availability and deployment. Indeed, in an imperfect market storage plant dispatch for profit maximization and cost minimization may not align (see Section IV), although strategic plant behavior is not considered in this paper and in the long-term may be disincentivized. As such, the profits shown here are indicative only, and will vary depending on specific market mechanisms. The storage plant profits are of the order of half the cost savings (€2.7 - 8m), in line with previous studies [10].

Contingency reserve is extremely valuable to the system up to 5 GW of wind. The lack of provision of contingency reserve by the NoCRes storage plant results in reductions in cost savings of between 17% and 27% (reducing with increasing wind) compared to the CRes&Flex scenario where both base reserve categories are provided by the storage plant. However, at 7.5 GW of wind, the cost saving compared to the CRes&Flex scenario is just 3.5% lower. As the wind capacity increases from 0 to 7.5 GW the requirement for contingency reserve drops by 25% as committed plant are increasingly dispatched closer to their minimum operating point (note, for the test system, a minimum of 6 large synchronous plant must be on line at all times to ensure system stability, as discussed in Section II). Plant profitability in the NoCRes scenario is actually slightly higher relative to the CRes&Flex scenario as the plant uses the additional capacity to engage in more profitable arbitrage.

The converse is seen for the NoFlex scenario, whereby cost saving reductions and profits relative to the CRes&Flex scenario are relatively unchanged up to 5 GW wind (less than 3%), but at 7.5 GW of wind generation there is a 60% reduction in system cost savings (66% reduction in storage plant profit),

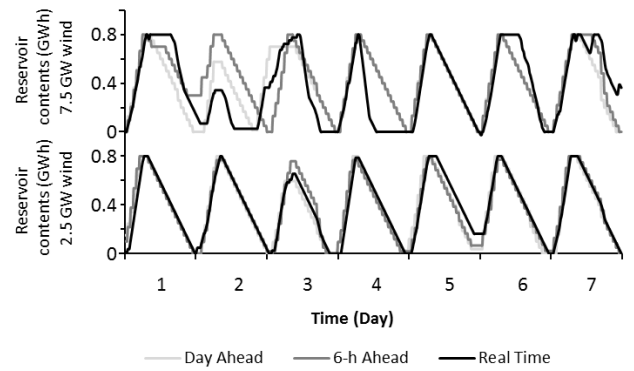


Fig. 7. Reservoir contents (unconstrained) at 2.5 & 7.5 GW wind

explained by the simultaneous reduced / increased requirement for contingency reserve / flexibility reserve respectively.

The importance of flexible plant operations at increasing wind generation levels is highlighted in Fig. 7, which shows the storage plant reservoir contents for one week of operation (CRes&Flex scenario). At 2.5 GW of installed wind, optimum plant operation (in terms of cost minimization) is still highly predictable, with pumping and generation schedules following a typical diurnal pattern with little change from day-ahead to real-time. At 7.5 GW of installed wind generation, the optimum dispatch can vary considerably from day to day and, indeed, as the horizon changes from day ahead to real-time, due to the variability and uncertainty of the net load.

The potential for cost savings in the FlexLwr scenario (which includes the additional flexibility lower reserve category) are closely matched to the CRes&Flex scenario up to 5 GW of wind, but at 7.5 GW the potential operating cost savings increase by a further 11% (Fig. 6), which highlights the effectiveness of energy storage in providing flexibility products and the improved business case for energy storage when additional products exist.

### B. Constraint modeling

The results presented so far have been based on unconstrained storage plant dispatches, with decisions made as part of a system cost minimization. The importance of flexible storage plant operation as penetrations of variable renewables increase is evident from Fig. 4, demonstrating through the high variability in dispatches, the inadequacy of storage dispatch algorithms which do not consider high penetrations of variable renewables (although the variability is dependent on the services provided). Furthermore, from Fig. 7, the variability and uncertainty of the net load at high wind penetrations leads to large variations in the stored energy content of the reservoir, both day to day and as the horizon moves from day ahead to real-time, highlighting the impact of storage plant utilization in compensating for forecast errors and the inadequacy of assuming perfect foresight of reserve utilization.

Private plant operators will seek to maximize profits, and dispatches in a market environment are subject to a number

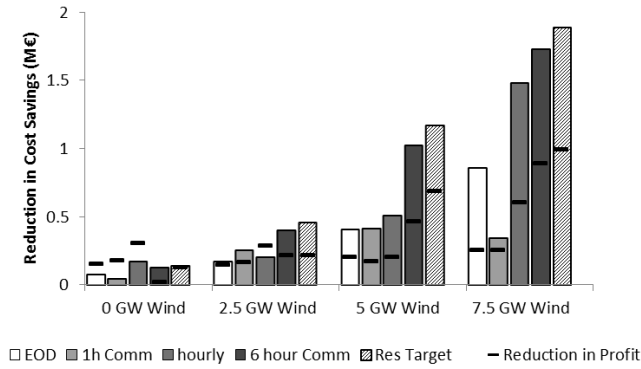


Fig. 8. Reduction in cost savings and storage plant profitability due to storage plant operational constraints - CRes&Flex Scenario

of operational constraints, driven by market rules and incentives, and also increasing price uncertainty at high variable renewable penetrations. A number of such constraints are modeled (e.g. end of day reservoir targets and hourly storage plant dispatches), as discussed in the remaining section. While system costs are minimized in each of the 3 simulation stages, operational decisions for the storage plant made in advance, based on available (imperfect) forecast information, reduce the realizable flexibility of the plant and highlight the impact of generation and price uncertainty on storage plant scheduling, and the uncertainty surrounding reserve deployment. This reflects real world operations for a storage plant, as decisions are made for deployment in advance of realized wind and load data, and also without perfect foresight of reserve utilization. Each constraint results in increased system costs (and reduced plant profitability) upon its introduction, and the impact of the constraint typically increases with increasing wind levels. The reductions in cost savings (relative to a free dispatch, whereby plant commitments and dispatches are optimized at each simulation stage, and there are no constraints on the reservoir volume) are summarized for the CRes&Flex scenario in Fig. 8. Constraint details and the significance of these results are described in more detail below.

1) *End of Day Reservoir Targets (EOD)*: Storage plant which are sized to provide daily load leveling are typically operated with an end of day reservoir target. In the absence of a significant look ahead period, end of day targets are used to obtain efficient dispatch strategies, although previous work has highlighted the importance of optimization strategies over longer durations [14]. Longer term scheduling (with weekly targets) is particularly important for plant with large energy capacities and the advantages of variable end of day targets have been demonstrated [48]. An end of day constraint is used to explore the impact of this practice at increasing wind energy penetrations, whereby the reservoir is emptied at the end of each day. Due to the diurnal pattern which emerges at low wind levels, the impact is minimal until wind levels increase to 5 GW (> 30% energy demand) and above, where optimization over longer horizons becomes more beneficial due to the inter-

day variability of the net demand (and system price). As shown in Fig. 8, at 7.5 GW of wind generation capacity the cost is 5.5% (€0.85m) of the potential cost savings from the freely dispatched plant (Fig. 6), although storage profits are only reduced by 3%.

2) *Hourly Storage plant Commitments (1h Comm)*: Typically, the storage plant mode is not optimized in real-time [4], i.e. while energy and reserve can be co-optimized, the decision to pump / generate / remain idle is rather based on previous market commitments. A 1-hour commitment constraint represents the resulting lack of flexibility, whereby commitments (pump / generate / idle) are "locked in" at an hourly resolution. A fourth simulation stage is introduced to model this constraint, whereby commitments for those plant with slow and medium start up times are fed into an intermediate simulation stage which uses realized data at an hourly resolution. The resulting commitment decisions for the storage plant are fed into the final real-time simulation. The storage plant pumping / generating level is still allowed to vary based on the realized 15 minute data. The impact is minor at low wind energy penetrations, but as wind penetrations increase, the reduced flexibility caused by hourly commitment decisions results in reduced cost savings and plant profits of up to 5% or €0.4m at 5 GW of wind, although this falls slightly to €0.35m at 7.5 GW installed wind generation capacity (Fig. 8). While flexibility requirements increase for the 7.5 GW wind level, there will also be increased occurrences of excess reserve availability due to the minimum units online constraint (see Section II-A).

3) *Hourly Storage Plant Dispatch (Hourly)*: Energy storage has the potential to play a significant role in providing valuable flexibility at sub-hourly time-scales [5], but it is important that it is incentivized to do so through compensation based on sub-hourly settlements [4]. The plant is further constrained by fixing the pumping load and generation levels for the sub-hourly dispatches, based on the hourly results (using the fourth intermediate simulation stage as outlined for the 1h Comm constraint above), eliminating the plant's potential for sub-hourly balancing. Again, the impact increases with increasing wind generation capacity as the sub-hourly net load variability also increases. The reduction in system cost savings and storage plant profitability are up to 9.5% (€1.48m) and 7.3% (€0.61m) respectively (see Fig. 8) when the sub-hourly flexibility of the storage plant can no longer be accessed.

4) *Impact of Uncertainty on Plant Commitment (6h Comm)*: Intra-day trading allows participants to change their position based on updated forecasts and system status. However, storage plant operators can only make optimal dispatch decisions when sufficient information is available. Increased price uncertainty will undoubtedly lead to less efficient scheduling, impacting on the plant value. While PHS plant can change their mode of operation quite quickly (~ 6 - 10 minutes), for plant operating in electricity markets, the mode of operation is typically defined in advance, and subject to a degree of uncertainty. Here, commitment decisions for the storage plant are locked in based on the 6 h forecast commitments (generating and pumping

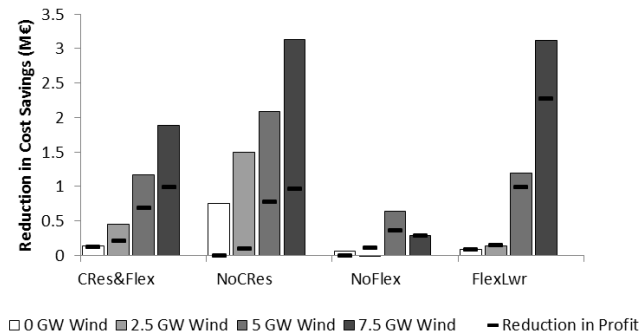


Fig. 9. Reduction in cost savings and storage plant profitability compared to unconstrained dispatch - Res Target constraint

levels can be re-optimized). While the 1h Comm constraint allows for optimal commitments, albeit at an hourly resolution, the impact of suboptimal commitment due to forecast error is explored with this constraint. At high wind penetrations (5 - 7.5 GW), reductions in potential cost savings and plant profitability are up to 13% (€1.0 - 1.7m and €0.47 - 0.89m respectively) - see Fig. 8.

5) *Reservoir Target Volumes (Res Target)*: As variable renewable penetrations increase, the storage plant is increasingly used to provide flexibility reserve and real-time balancing, the requirements for which increase with increasing penetrations of wind generation [49]. However, flexibility reserve deployment is difficult to predict. Although the absolute value of the balancing provided (based on the real-time simulated plant dispatches) is somewhat correlated to the wind generation levels, the energy net requirement could be positive or negative (depending on the forecast error) and the variability is extremely high. As shown in Fig. 7, reservoir volumes should be allowed to change from earlier schedules, but this may impact previous commitments. To ensure that a storage plant can meet future obligations made in previous markets, a reservoir volume constraint (Res Target) ensures that energy levels in the reservoir align with targets based on the 6 h-ahead simulations, reducing the real-time balancing capability of the plant. Potential cost savings of the plant are reduced by over 15% (€1.9m), while profitability is reduced by up to 20% (€1m) - see Fig. 8.

The results in Section III-A (Fig. 6) give some insight into the viability of the different plant operating strategies (i.e. which products to provide) and reserve scenarios at different levels of installed wind generation capacity for the unconstrained storage plant. However, the strategies are not uniformly impacted by the constraints, which are more indicative of plant operation in a market environment. Fig. 9 shows the reductions in cost savings resulting from the Res Target (relative to an unconstrained dispatch) constraint across the 4 scenarios. The NoCRes scenario yielded strong profits and closely matched (within 3.5%) the CRes&Flex cost savings for the unconstrained simulations at high wind (Fig. 6). As seen in Fig. 4, the optimal dispatches are highly

variable as the plant is heavily exploited to provide flexibility reserve and sub-hourly balancing, leaving the plant particularly vulnerable to each of the operating constraints. Considering constrained operation at 7.5 GW of wind generation capacity, cost savings in the NoCRes scenario are up to 13% lower compared to the CRes&Flex scenario. For the NoFlex scenario, the constraint costs are typically lower, as the dispatches are relatively predictable and impacted least by uncertainty from wind production and reserve deployment, which improves the business case up to high (5 GW) levels of wind generation capacity (after which profitability collapses - see Section III-A2). At high wind penetrations, the constraints also have a large impact on the FlexLwr scenario, particularly in terms of plant profitability. However, the value of the storage plant remains highest when the storage plant can provide the additional category of reserve.

#### IV. DISCUSSION

The isolated nature of the modeled system generates large cost savings with the addition of a storage plant. It is well understood that the marginal value of energy storage falls as installed capacities increase, as the balancing provided by previously installed storage plant reduces opportunities for further cost savings [5], [50]. Alternative sources of flexibility and reserve will also impact on the value of a storage plant. While the simulations focus on storage plant operations, suboptimal dispatch of other flexible resources (demand response, interconnections) will also lead to inefficiencies. It should be noted that the cost of inefficient plant operations applies to existing storage plant installations, as well as new investments. As penetrations of variable renewables increase, the importance of system flexibility also grows, and it is essential that market mechanisms are in place which incentivize and allow the full value of each resource's flexibility to be accessed [51].

A storage plant can participate in multiple markets, providing a range of services, with operational strategies selected in order to maximize profits. In general, the greater the number of services provided by the storage plant, the greater the value (the largest cost reductions were achieved in the FlexLwr scenario, where 3 reserve categories were provided by the storage plant). However, depending on the wind penetration level, alternative strategies may be viable, particularly when imperfect dispatches, reflecting wind and load uncertainty and inefficient market signals, are considered (constrained operation). The provision of contingency reserve is particularly valuable at low to moderate wind penetrations. Providing only contingency reserve and energy (NoFlex) leads to more predictable plant dispatches and leaves the plant less susceptible to suboptimal dispatch, leading to increased cost savings and profitability once all constraints have been included. However, at extremely high wind penetrations, providing flexibility reserve becomes essential (both in terms of profitability and system costs) as both the requirement for flexibility reserve increases, and the number of conventional plant typically on-line and available for reserve provision decreases.

As mentioned in Section III, the profits presented in this paper are indicative only and calculated based on system prices resulting from least cost optimization. However, in a perfectly competitive market, storage plant profit maximization and system cost minimization coincide [52]. The modeled constraints highlight many inefficiencies that will arise due to imperfect market conditions and the high degree of uncertainty which will exist in future high renewables power systems. Other imperfect behavior, such as short-term strategic decisions to maximize profits, are not captured. However, market design should disincentivize actions which would generate super-normal profits for plant operators (e.g. under utilization of the asset [7]). The generated dispatches act as a suitable benchmark for the potential value that storage plant can realize on the system and market rules should ensure that the assets are used to maximize social welfare.

In order to improve the efficiency of storage plant dispatches at high variable renewable penetrations, changes in operational practices are essential. Markets are adapting to facilitate the wide-scale integration of variable renewables (e.g. fast co-optimized energy and ancillary services markets with dynamic reserve setting [35]). When high volumes of flexibility reserve are required, with a great deal of uncertainty surrounding their deployment, rolling optimization is advantageous, whereby new dispatches can be generated based on the current status of the plant and updated system needs. PHS dispatch algorithms need to evolve to handle such uncertainty, as well as the increased volatility of energy and ancillary services prices. Look ahead periods are required, with typical end of day reservoir targets inadequate at high wind generation penetrations. Ideally, the mode of plant operation should be optimized closer to real-time, and it is essential that plant are adequately rewarded for providing sub-hourly flexibility. In order for a storage plant to generate efficient schedules, access to relevant information which may influence prices is essential, including wind and load forecasts and the status of larger plant. For profit maximization, algorithms must capture the price uncertainty in both energy and reserve products, as well as reserve deployment volumes. However, the modeling and forecasting of prices in balancing and ancillary services markets is rare in the literature [53] and further research is required, particularly for high renewables scenarios. An increased understanding of reserve deployment, particularly for high renewables scenarios, is also required. Methodologies need to be developed to forecast real-time use of committed reserves, as this has an impact, not only on reservoir levels, but also on profitability, as participants in reserve markets are typically paid both for availability and reserve deployment [54]. For example, a detailed study of historical reserve usage on the Spanish system has identified a positive correlation between months with high levels of wind production and reserve deployment [55]. In addition, real-time usage of reserves leads to significant deviations in reservoir volumes and storage plant earnings [25]. The implications of this trend for energy storage operation, at very high wind energy

penetrations, requires further attention, in order to capture the uncertainty of reserve deployment. Even in a transparent market environment, where all relevant information is available to storage plant operators, the increased volatility in prices will require significant processing capability, and independent plant operators who are unable to undertake sophisticated analysis could be disadvantaged. SOs are likely to be in a better position to optimize schedules for storage plant facilities. However, storage plant operation by SOs is typically prohibited due to potential conflicts of interest (e.g. suboptimal scheduling in order to influence congestion rents or storage plant profits) but there are calls for current policies surrounding ownership and operation to be revisited [30]. The SO is responsible for real-time balancing, and hence can make informed decisions about real-time usage, while also considering future system needs, without severely constraining the capacity of a storage plant to meet those real-time balancing requirements (the costly impact of constraining the plant capacity was demonstrated with the Res Target constraint). Previous studies [12] indicate that the increased dispatch efficiency which could be achieved by an SO not only reduces system costs, but also maximizes profits for the storage plant owner. As balancing requirements increase, SOs will increasingly control larger volumes of energy, between traditional reserve and new ramping products, which may be required. As such, checks and balances will be required in order to ensure that conflicts of interest do not arise. In such an environment it may be prudent to consider placing partial control of the storage plant in the hands of the SO, as part of a transparent optimization process. Note that the debate surrounding storage plant ownership also has implications for the use of storage as a network asset (e.g. deferring investment). In the absence of nodal prices, the services would be required by a regulated actor, who may be prohibited from owning or operating this class of asset.

## V. CONCLUSION

At increased penetrations of variable renewable energy, traditional storage operational practices will lead to suboptimal plant scheduling. Electricity markets must ensure that their regulations are not unduly constraining storage plant operation, and that the potential flexibility of the plant is incentivized, valued and rewarded in order for maximum cost savings (and storage plant profitability) to be achieved. Indeed, many of the operational constraints will impact on other sources of flexibility, particularly energy limited demand response. Advances are required in large-scale energy storage dispatch strategies, and changes to current practices are essential. Achieving efficient dispatch strategies, providing multiple services in future systems with high penetrations of variable renewables is highly complex. A specific challenge facing energy limited plant operators is providing large volumes of highly uncertain flexibility products (in terms of quantities and timing), while maintaining the capability to meet future commitments. This uncertainty must be captured, and further research is required in modeling and forecasting of prices in

balancing and ancillary services markets, as well as reserve deployment in high renewable scenarios. Given the difficulties involved, the SO may have a future role here in order to improve system efficiency, although conflicts of interest would need to be resolved.

## REFERENCES

- [1] J.P. Deane, E.J. McKeogh and B.P. Ó Gallachóir. "Techno-economic review of existing and new pumped hydro energy storage plant," *Renew Sust Energy Rev*, vol. 14, no. 4, pp. 1293-1302, 2010.
- [2] P. Denholm, E. Ela, B. Kirby, O. Ma, M. Milligan. "The Role of Energy Storage with Renewable Electricity Generation," Tech Report NREL/TP-6A2-47187, National Renewable Energy Laboratory, 2010.
- [3] WWEA "WWEA Bulletin Special Issue 2015," World Wind Energy Association, Bonn, Germany, 2015.
- [4] E. Ela, B. Kirby, A. Botterud, C. Milostan, I. Krad, V. Koritarov, "The role of pumped storage hydro resources in electricity markets and system operation," NREL/CP-5500-58655, National Renewable Energy Laboratory, 2013.
- [5] C. O'Dwyer and D. Flynn. "Using energy storage to manage high net load variability at sub-hourly time-scales," *IEEE Trans. Power Syst.*, vol. 30, no. 4, pp. 2139-2148, 2015.
- [6] B. Nyamdash, E. Denny and M. O'Malley. "The viability of balancing wind generation with large scale energy storage," *Energy Policy*, vol. 38, no. 11, pp. 7200-7208, 2010.
- [7] R. Sioshansi, P. Denholm, T. Jenkin and J. Weiss. "Estimating the value of electricity storage in PJM: arbitrage and some welfare effects," *Energy Economics*, vol. 31, no. 2, pp. 269-277, 2009.
- [8] A. Burtin, V. Silva, "Technical and Economic Analysis of the European Electricity System with 60% RES," EDF R&D, 2015.
- [9] A. Zucker, T. Hinchliffe, A. Spisto, "Assessing Storage Value in Electricity Markets. A Literature Review," Joint Research Centre, 2013.
- [10] P. Denholm *et al.* "The Value of Energy Storage for Grid Applications," Technical Report NREL/TP-6A20-58465, National Renewable Energy Laboratory, 2013.
- [11] S. Stoft, *Power System Economics: Designing Markets for Electricity*. Piscataway, NJ, IEEE Press, 2002.
- [12] B. Kirby. "Co-optimizing energy and ancillary services from energy limited hydro and pumped storage plants," *Proc. of HydroVision International 2012*, Tulsa, Okla., 2012.
- [13] N. Lu, J. Chow and A. Desrochers. "Pumped-storage hydro-turbine bidding strategies in a competitive electricity market," *IEEE Trans. Power Syst.*, vol. 19, no. 2, pp. 834-841, 2004.
- [14] P. Kanakasabapathy, K. Shanti Swarup. "Bidding strategy for pumped-storage plant in pool-based electricity market," *Energy Conversion and Management*, vol. 51, pp. 572-579, 2010.
- [15] C. C. Tsai, Y. Cheng, S. Liang and W. J. Lee. "The co-optimal bidding strategy of pumped-storage unit in ERCOT energy market," *North American Power Symposium*, Mississippi, 2009.
- [16] J. Donadee. "Optimal operation of energy storage for arbitrage and ancillary service capacity: the infinite horizon approach," *North American Power Symposium*, Manhattan, KS, 2013.
- [17] S. J. Kazempour, M. P. Moghaddam, M. Haghifam and G. Yousefi. "Risk-constrained dynamic self-scheduling of a pumped-storage plant in the energy and ancillary service markets," *Energy Conversion and Management*, vol. 50, pp. 1368-1375, 2009.
- [18] M. Chazarra, J. Perez-Diaz and J. Garcia-Gonzalez. "Optimal operation of variable speed pumped storage hydropower plants participating in secondary regulation reserve markets," *11th International Conference on the European Energy Market*, Krakow, Poland, 2014.
- [19] R. Deb. "Operating hydroelectric plants and pumped storage units in a competitive environment," *Electr. J.*, vol. 13, no. 3, pp. 24-32, 2000.
- [20] J. Pinto, J. de Sousa and M. Neves. "The value of a pumping-hydro generator in a system with increasing integration of wind power," *8th International Conference on the European Energy Market*, Zagreb, 2011.
- [21] N. Lohndorf, D. Wozabal and S. Minner. "Optimizing trading decisions for hydro storage systems using approximate dual dynamic programming," *Operations Research*, vol. 61, no. 4, pp. 810-823, 2013.
- [22] T. Muehe. "Optimal operation and forecasting policy for pump storage plants in day-ahead markets," *Appl. Energy*, vol. 113, pp. 1089-1099, 2013.
- [23] T. Guo, G. Liu, L. Yu and V. Koritarov, "Adjustable speed pumped-storage hydro-generator (PSH) evaluation by PLEXOS," EE-2013-10-30-01, Energy Exemplar, 2013.
- [24] A. Tuohy and M. O'Malley. "Pumped storage in systems with very high wind penetration," *Energy Policy*, vol. 39, no. 4, pp. 1965-1974, 2011.
- [25] M. Chazarra, J. Perez-Diaz, J. Garcia-Gonzalez and A. Helseth. "Modeling the Real-Time Use of Reserves in the Joint Energy and Reserve Hourly Scheduling of a Pumped Storage Plant," *Energy Procedia*, vol. 87, pp. 53-60, 2016.
- [26] J. Vasconcelos, S. Ruester, X. He, E. Chong and J.M. Glachant. "Electricity Storage: How to Facilitate its Deployment and Operation in the EU," Think Project, 2012.
- [27] X. He, E. Delarue, W. D'Haeseleer and J. M. Glachant. "Coupling electricity storage with electricity markets: a welfare analysis in the French market," KU Leuven (Working Paper), 2012.
- [28] DG Energy. "DG ENER Working Paper: The future role and challenges of Energy Storage," January 2013.
- [29] A. Shivakumar *et al.* "Business models for flexible production and storage," INSIGHT\_E Policy Report, 2015.
- [30] IEA-RETD "Policies for Storing Renewable Energy: a Scoping Study of Policy Considerations for Energy Storage (RE-STORAGE)," IEA Renewable Energy Technology Deployment, Utrecht, 2016.
- [31] CER 'Validation of Market Simulation Software in SEM to end 2013,' Commission for Energy Regulation, Ireland, 2013.
- [32] PLEXOS for Power Systems by Energy Exemplar, Website, 2013. <http://www.energyexemplar.com>
- [33] N. Troy, D. Flynn and M. O'Malley. "Multi-Mode Operation of Combined-Cycle Gas Turbines With Increasing Wind Penetration," *IEEE Trans. Power Syst.*, vol. 27, no. 1, pp. 484-492, 2012.
- [34] EirGrid 'Operational Constraints Update 30th June 2015,' EirGrid, Ireland, 2015.
- [35] J. Riesz, J. Gilmore and I. MacGill. "Frequency control ancillary service market design: insights from the Australian National Electricity Market," *The Electricity Journal*, vol. 28, no. 3, pp. 86-99, 2015.
- [36] M.I. Alizadeh, M. Parsa Moghaddam, N. Anjday, P. Siano and M.K. Sheikh-El-Eslami. "Flexibility in future power systems with high renewable penetration: a review," *Renewable and Sustainable Energy Reviews*, vol. 57, pp. 1186-1193, 2016.
- [37] EirGrid, 'DS3 Programme,' [Online]. Available: <http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/>
- [38] I. Krad, E. Ibanez, and E. Ela. "Quantifying the potential impacts of flexibility reserve on power system operations," *Proc. IEEE Annu. Green Technol. Conf.*, New Orleans, 2015.
- [39] D. Lew *et al.* "The Western Wind and Solar Integration Study Phase 2," NREL/TP-5500-55588, National Renewable Energy Laboratory, 2013.
- [40] Department of Energy and Climate Change "DECC Fossil Fuel Price Projections," Department of Energy and Climate Change, London, 2014.
- [41] M. Matos Fernandes. "Connection of the first pump-storage variable speed machines in Portugal: TSO main requirements," *11th Wind Integration Workshop*, Lisbon, November 2012.
- [42] X. Luo, J. Wang, M. Dooner, and J. Clarke. "Overview of current development in electrical energy storage technologies and the application potential in power system operation," *Applied Energy*, vol. 137, pp. 511-536, 2015.
- [43] L. Hirth. "The market value of variable renewables," *Energy Economics*, vol. 38, pp. 218-236, 2013.
- [44] D. Keles, M. Genoese, D. Möst, S. Ortlieb, and W. Fichtner. "A combined modeling approach for wind power feed-in and electricity spot prices," *Energy Policy*, vol. 59, pp. 213-225, 2013.
- [45] T. Mobius and F. Musgens. "The effect of variable renewable energy sources on the volatility of wholesale electricity prices: a stylized full cost approach," *12th International Conference on the European Energy Market (EEM)*, Lisbon, 2015.
- [46] D. Wozabal, C. Graf, and D. Hirschmann. "The effect of intermittent renewables on the electricity price variance," *OR Spectrum*, March 2013.
- [47] PLEXOS Integrated Energy Model Help Files, 2016. <http://www.energyexemplar.com>
- [48] J.P. Deane, E.J. McKeogh, B.P. Ó Gallachóir. "Derivation of intertemporal targets for large pumped hydro energy storage with stochastic optimization," *IEEE Trans. Power Syst.*, vol. 28, no. 3, pp. 2147-2155, 2013.
- [49] H. Holtinen *et al.* "Methodologies to determine operating reserves due to increased wind power," *IEEE Trans. Sust. Energy*, vol. 3, no. 4, pp. 713-723, 2012.

- [50] C. O'Dwyer and D. Flynn. "Pumped hydro and compressed air energy storage at high wind penetrations," *12th Wind Integration Workshop*, London, November 2013.
- [51] B. Kirby. "Selling Power System Flexibility: Ancillary Service and Real-Time Energy Market Challenges for Storage," *ASME Dynamic Systems and Control Conference*, San Antonio, Tx., 2014.
- [52] A. Castillo, D.F. Gayme. "Profit maximizing storage allocation in power grids," *52nd IEEE Conference on Decision and Control*, Florence, 2013.
- [53] R. Weron. "Electricity price forecasting: a review of the state-of-the-art with a look into the future," *International Journal of Forecasting*, vol. 30, no. 4, pp. 1030-1081, 2014.
- [54] J.I. Perez-Diaz, M. Chazarra, J. Garcia-Gonzalez, G. Cavazzini and A. Stoppato. "Trends and challenges in the operation of pumped-storage hydropower plants," *IREnewable and Sustainable Energy Reviews*, vol. 44, pp. 767-784, 2015.
- [55] C.A. Diaz, P. Gonzalez, F.A. Campos and J. Villar. "Spanish secondary reserve requirements, clearing and usage," *11th International Conference on the European Energy Market (EEM)*, Krakow, 2014.