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Pumped Hydro and Compressed Air Energy Storage at High Wind Penetrations

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***Abstract*—Energy storage is a widely used tool for balancing power systems and for providing increased operational flexibility - as such it can assist with the integration of variable renewable electricity generation. Grid-scale energy storage provides potential solutions to some of the technical and economic challenges which arise in systems with high penetrations of variable renewables, particularly on isolated systems. However, capital costs per MW are high, which means that variable renewable penetrations must reach significant levels before the operating cost reductions justify the capital expenditure. Optimum levels of grid-scale storage are explored, considering capital costs and potential operational cost savings for two storage technologies - pumped hydroelectric storage and compressed air energy storage. Grid-scale installations are found to achieve significant cost savings, particularly at high levels of wind generation. While the potential for savings is eroded significantly at high levels of DC interconnection, they remain high when non-synchronous penetration limits are increased.**

I. Introduction

WIND generation capacity is increasing globally and reached 282 GW by the end of 2012 [1], such that significant shares of electricity demand are being met with wind power. In 2012 approximately 25% of electricity demand was met by wind generation in Denmark, with an ambitious target of 50% by 2020. In Ireland, 16% of electricity generation was sourced from indigenous wind generation in 2012, with an expectation of reaching 37% by 2020 in order to meet a 40% renewable electricity target [2]. Increasing shares of variable renewable generation are creating new challenges for system operators, particularly on island systems, where the instantaneous non-synchronous penetration levels (from variable speed wind generators and DC interconnectors) must be controlled in order to maintain stability. In Ireland there is an operational limit of 50% for the system non-synchronous penetration (SNSP) [3], which can lead to wind curtailment, particularly at night time when the demand is low. The system operator hopes to increase this limit to 75% by 2020, subject to a number of grid code changes and the implementation of new system services [4].

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Bulk energy storage is one technique which can reduce curtailment, and reduce operating costs in systems with high wind penetrations. Other solutions include increasing the flexibility of conventional plant (enabling higher SNSP levels), increasing levels of interconnection with neighbouring systems, and the use of flexible demand. Bulk energy storage has been commonplace for decades, with primarily pumped hydro storage plant being used to perform energy arbitrage, and provide backup and reserve capability. Energy arbitrage was particularly valuable during the oil crisis of the 1970s when the price spread between baseload and peaking plant justified the high capital expenditure. Energy arbitrage can also be extremely valuable in systems with large amounts of inflexible baseload plant, such as nuclear power stations.

Opportunities for energy arbitrage have been decreasing, with many systems operating with a single fuel (natural gas) frequently on the margin. The efficiency improvements and reductions in capital costs of CCGT plant in recent decades, relative to pumped hydro storage facilities, erode the value proposition for investing in the latter when additional capacity is required [5]. At present, there is limited opportunity for merchant storage units to operate profitably [6]-[7], subject to particular market arrangements and the regulatory environment [8]. However, there has been much speculation in recent years as to the potential role that storage could play in the integration of variable renewable generation. Storage is also increasingly being valued by aggregating its benefits from multiple applications, rather than for arbitrage alone [9]. Additional roles such as the provision of ancillary services and the increasing use of storage for transmission & distribution upgrade deferral [10] should also be considered.

Adding bulk storage to a system invariably brings benefits in terms of operating cost savings and wind curtailment reductions. CO_2 emissions can also decrease with the addition of storage. However, reductions in emissions are not always seen, as bulk storage can also enable higher utilisation of high emission baseload plant, such as coal [11]. In order to estimate optimum levels of storage for a system, a cost benefit analysis must be completed, which considers both the potential for operating cost savings, as well as the capital costs associated with the additional storage plant.

Appropriate sizing of bulk storage on a large isolated system (Ireland) is explored. Two different study years, 2020 and 2025, have been considered. Ireland will have significant over-capacity on the system in 2020. Including the study year of 2025 allows for the impact of storage plant required for capacity to be examined, as well as higher levels of wind generation capacity. Two bulk storage technologies, pumped hydroelectric storage (PHS) and compressed air energy storage (CAES) are included. A detailed hourly resolution unit commitment and economic dispatch tool is used to evaluate the potential operating cost savings for the system which could be achieved with additional storage plant.

Section II outlines the methodology, giving details of the unit commitment and economic dispatch tool used (Wilmar), as well as the test system under study. Details are given on the experimental design methodology which was applied to create a metamodel of the system. Results are presented in Section III, with cost savings explored for the introduction of both CAES and PHS. Analysis is also presented for CO_2 emissions and wind curtailment. Section IV contains a discussion of the findings and concludes.

II. Methodology

The Wilmar planning tool is a mixed integer unit commitment tool using rolling planning. Wilmar was previously used for the All Island Grid Study [12], which assessed the impact of integrating large amounts of wind generation onto the Irish system. Costs and emissions were examined for a number of possible plant portfolios for 2020. Within Wilmar, unit commitment and economic dispatch are completed at an hourly resolution, with a 36 hour horizon. Expected operating costs (including fuel, start-up and carbon costs) are minimised subject to a number of generating unit constraints and system constraints. An operating reserve requirement is incorporated (based on the largest infeed with an additional requirement based on the level of wind forecasted), as well as replacement reserve (based on the expected wind and load forecast error). An SNSP limit controls the fraction of the demand plus exports which can be covered by non-synchronous generation (i.e. wind generation and DC imports). A downward reserve constraint protects against over-frequency events on the system, which could arise during an interconnector trip when in export mode (maximum of 500 MW). The downward reserve capability of each conventional plant is assumed to match that of its primary operating reserve capability. It is assumed that a perfect market exists, and that the storage is operated to maximise the system benefit.

A. Test System

The 2020 test system consists of a plant portfolio for the island of Ireland, based on details published in the All Island Generation Capacity Statement 2012-2021 [14]. Wind and demand figures are based on the same source. The installed capacity, excluding wind generation, is 8.7 GW (including 292 MW of PHS), while the annual system demand is 41.2 TWh with a peak of 7.3 GW. The base case has 5.2 GW of wind generation capacity and there are 2 x 500 MW DC interconnectors between Ireland and Great Britain. Due to the over-capacity in 2020 it is assumed that any additional storage on the system is not required for capacity purposes and capital costs should be justified on operating cost savings alone. For the 2025 portfolio, 881 MW of older plant is retired and 700 MW of new plant (650 MW CCGT and 50 MW OCGT) are added to the system. Demand is assumed to increase by 5%, with wind generation capacity increasing to 7 GW for the base case. The Great Britain system is presented as a total of 80.2 GW of conventional plant along with 28 GW of wind generation capacity.

B. Modelling of Storage

This paper focuses on bulk energy storage, concentrating on two of the most suitable technologies for energy storage at scale. The operation of the storage plant is optimised as part of the unit commitment and dispatch process in order to minimise total operating costs for the system. Details of the objective function are contained in [12].

PHS plant use electricity to pump water to an elevated reservoir where the potential energy of the water is stored, before being later released through turbines to generate electricity. Here, the PHS units have a defined pumping efficiency of 78%. The pumping load is added to the demand, while the plant operates similarly to conventional plant when in generating mode, with appropriate operating constraints. Energy balance for the pumped hydro storage plant is ensured using the equation:

$$S_{i,t-1} + \eta_i \cdot C_{i,t} - P_{i,t} = S_{i,t} \quad \forall i \in I^{PS}; \forall t \in T \tag{1}$$

where S is the storage plant contents in MWh, η is the plant efficiency, C is the storage plant charging capacity in MW and P is the power generation in MW. I^{PS} is the set of pumped hydro storage units and T is the set of time steps. The storage contents in a given hour are calculated based on the storage contents from the previous hour with any loading in the previous hour (scaled by the plant efficiency) added on and any generation subtracted. Additional constraints enure that the maximum and minimum storage levels and plant charging and discharging limits are respected. A further constraint also ensures that a plant cannot be simultaneously in charging and discharging mode.

In contrast, CAES plant use electricity to compress air, which is typically stored in underground caverns. When required, the stored energy is released by using the compressed air in a gas turbine cycle. For the CAES plant, as natural gas is used, an energy ratio and heat rate must be defined, along with a compressor efficiency. Typically, the energy ratio is defined as the ratio of electrical energy input to electrical energy output and can be greater than 1, as the energy obtained from the combusted natural gas is included. The CAES plant is modelled here with incremental energy ratio and heat rate slopes to account for varying efficiencies at different output levels, but for clarity, uniform heat rates and energy ratios are shown. The energy balance equation for the storage plant contents is as follows:

$$S_{i,t-1} + \eta Chg_i \cdot C_{i,t} - D_{i,t} = S_{i,t} \quad \forall i \in I^{CS}; \forall t \in T \tag{2}$$

As with the pumped hydro plant, S is the storage plant contents in MWh and C is the storage plant charging capacity in MW. ηChg represents the efficiency of the charging cycle, and D is the discharge rate of the compressed air in MW. I^{CS} is the set of CAES units. The storage contents in a given hour are calculated based on the storage contents from the previous hour with any charging in the previous hour (scaled by the plant charging cycle efficiency) added on and any discharge of compressed air subtracted. The discharge rate of the compressed air is coupled with the power generation of the plant using equation (3):

$$D_{i,t} = ER_i \cdot P_{i,t} \quad \forall i \in I^{CS}; \forall t \in T \tag{3}$$

where ER is an adjusted energy ratio and P is the power generation in MW. The power generation and the charging capacity of the CAES plant are decoupled, with a charge to discharge ratio of 1:2 assumed here. The natural gas usage is calculated using equation (4):

$$F_t = HR_i \cdot P_{i,t} \quad \forall i \in I^{CS}; \forall t \in T \tag{4}$$

where F is the fuel usage in GJ and HR is the heat rate of the plant in GJ/MWh.

The system under evaluation has considerable over-capacity in 2020. As such, the additional storage plant are added to the system and are not considered as replacement for future builds. Operating cost savings obtained over the course of a year will be estimated. Capital costs are also estimated and net benefits are assumed when the operating cost saving exceeds the annual capital costs of the plant. A life time of 30 years has been assumed for both the PHS and CAES plant. For 2025, the storage plant replace new build plant which have been added between 2020 and 2025. 3 different plant sizes are considered: 50 MW, 350 MW and 650 MW. The larger plant replace the same capacity of CCGT plant on the system, while the smaller 50 MW plant replaces a 50 MW OCGT.

C. Experimental Design

Experimental design is used to create an approximate metamodel of the system in terms of a number of input parameters (factors). It is an efficient method of gathering information about the system within a limited number of runs. The result is a second order regression model, which captures both linear and quadratic effects from each input parameter as well as interactions between them. It is not intended to accurately predict the response at all points, but rather to highlight areas of interest for further investigation.

Five different input parameters (factors) are considered, encompassing two major design choices for a new storage system (energy and power capacity), as well as three of the more significant factors which will influence the optimum solution (wind level, SNSP limit and interconnection level). For higher levels of interconnection, additional 500 MW interconnectors are added. Using a 5 factor, 3 level custom design with JMP software [13], four different outputs (responses) are analysed - reduction in operating costs, reduction in operating costs less annualised capital costs, CO_2 emissions and wind curtailment reduction. The levels considered for each factor are shown in Table I.

TABLE I
FACTOR LEVELS FOR EXPERIMENTAL DESIGN

Factor	*Level 1*	*Level 2*	*Level 3*
Generator Capacity (MW)	50	350	650
Storage Capacity (hr)	2	6	10
Wind (GW) 2020 / 2025	4.4 / 6	5.2 / 7	6 / 8
SNSP Limit (%)	50	62.5	75
Interconnection (MW)	1000	1500	2000

TABLE II
FACTOR LEVELS FOR SCENARIOS A-I

Scenario	*Wind (GW)*	*Intercon (MW)*	*SNSP (%)*	*Capacity (hr)*
A	High	1000	50	10
B	High	1000	50	2
C	High	1000	75	10
D	Base	1000	50	10
E	Base	1000	50	2
F	Base	1000	75	10
G	Base	2000	50	10
H	Base	2000	75	10
I	Low	1000	50	10

III. Results

81 different scenarios have been modelled for all four responses (outputs). Nine scenarios have been selected (see Table II) in order to highlight the impact, across all generator capacities, of changing each of the remaining factors.

A. Operating Costs Savings

Figs. 1 - 4 show the operating cost savings with the addition of storage on the Irish power system for both technologies and both study years. The PHS plant (Fig. 1 & Fig. 3) show significantly higher cost savings compared to the CAES plant (Fig. 2 & Fig. 4). As discussed in section II.B, a specific charge to discharge ratio of 1:2 has been assumed for the CAES plant. Hence, for a given generator capacity, the CAES plant have a charging capacity half that of the modelled PHS plant. As such, there will be reduced capacity for curtailment reduction and the provision of reserve when in charging mode. Increasing this ratio may yield increased operating cost savings, subject to changes in capital cost investments.

There are a number of drivers to the changes in operating cost savings seen with the addition of a storage plant to the system. As well as reducing curtailment, storage plant can reduce cycling of baseload plant, bringing increased efficiencies to the system. Also, storage plant are typically highly flexible in generating mode and have the ability to provide significant levels of reserve, which enables less flexible conventional plant to operate more efficiently, closer to their maximum output. Examining the dispatches for the 2020 system with and without a 650 MW PHS plant, with high (6 GW) wind generation capacity and a 50% SNSP limit (scenario B) yielded a 25% reduction in baseload starts and a 3% increase in average conventional plant loading. The storage plant provided an average of 62 MW of operating reserve throughout the year compared to an average generation output of 89 MW (197 MW for the hours of operation). 37% of the 19.5M euro operating cost savings can be attributed to reduced CO_2 emissions.

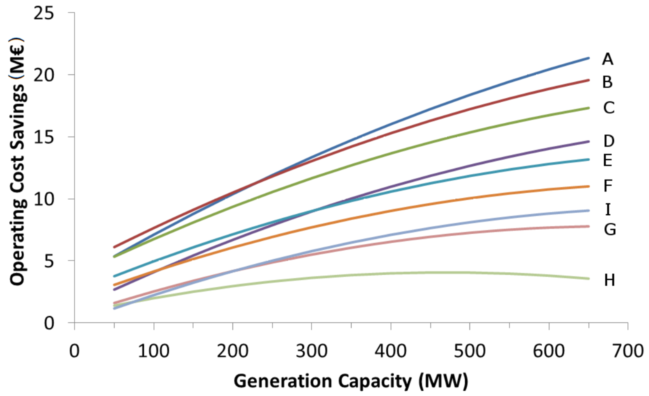

Fig. 1. Operating cost savings - PHS 2020

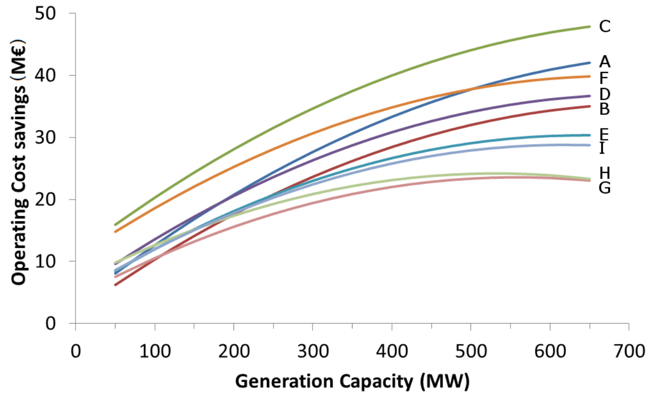

Fig. 3. Operating cost savings - PHS 2025

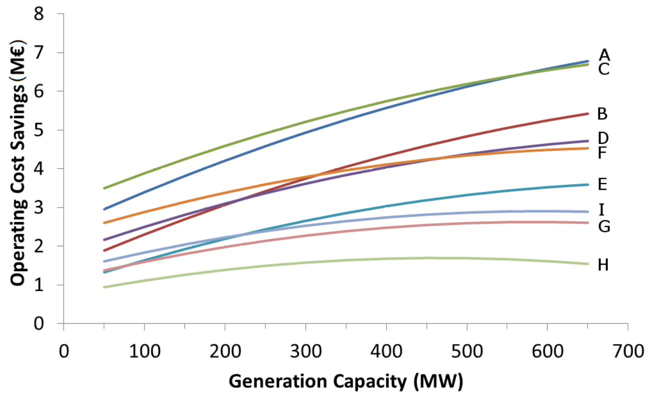

Fig. 2. Operating cost savings - CAES 2020

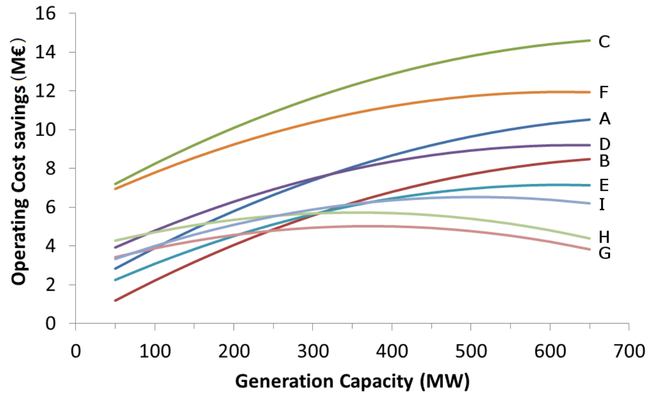

Fig. 4. Operating cost savings - CAES 2025

For both storage technologies, the cost reductions increase significantly between 2020 and 2025 (approximately twofold), largely driven by the increase in wind generation capacities which have been considered (compare 2020 case A (Fig. 1 & 2) to 2025 case I (Fig. 3 & 4), both with 6 GW of installed wind generation). In addition, the 2020 system has considerable over-capacity - as such, the additional storage plant is not required to provide capacity, but rather to increase efficiencies on the system, with reduced plant cycling and a reduction in curtailment. One of the sources of reduced operating costs for the system is a reduction in start costs, which the storage plant is not explicitly rewarded for.

For all cases (Fig. 1 - 4), increasing the storage capacity (in hours) has a much lower impact on operating cost savings than increasing the maximum generating capacity (scenarios B&E vs. A&D). The majority of the curtailment reductions can be achieved with a relatively small energy storage capacity (see Section III.C) with matching reserve capabilities when the plant is operating. The SNSP limit has minimal impact on the potential operating cost savings for the CAES plant in 2020, and only reduces slightly the potential for cost savings for the PHS plant in the same year (C&F vs. A&D). However, by 2025, higher SNSP limits provide an opportunity for increased operating cost savings for both technologies. Although the high SNSP scenarios result in much less curtailment (and fewer opportunities for storage plant to add value by reducing curtailment) the higher net load variability increases the need for system flexibility in order to maintain system stability. As expected, scenarios with high levels of interconnection consistently show the lowest operating cost savings, followed by the low wind scenarios (G, H & I).

B. Capital Costs

In order to determine whether the capital costs required for a new storage plant are justified, the operating cost savings for one year are compared to the annualised capital costs for

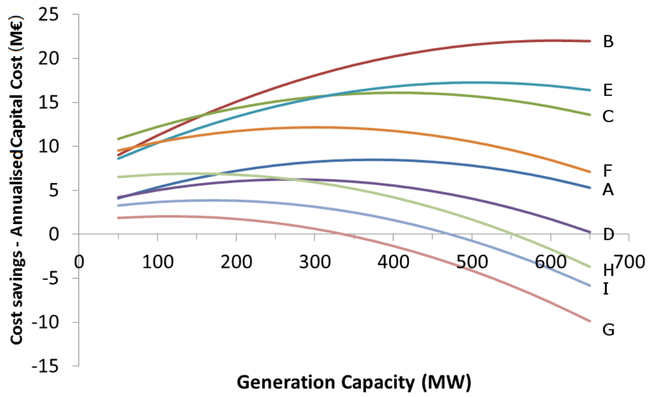

Fig. 5. Op. cost savings - annualized capital costs PHS 2025 (DR 8%)

each technology. Published estimates (in \$/kW and \$/kWh) have been assumed [15]. In order to account for economies of scale, these have been adjusted based on estimates for a number of completed and planned bulk storage plant [16]. Capital costs for storage plant are extremely site specific and highly variable. As such, the results here are intended to highlight the relative value provided by energy storage capacity vs. generator capacity. It also highlights how optimum levels of storage will be highly dependent on the remaining input assumptions (wind capacity, levels of interconnection, SNSP limit).

For the 2020 system, capital costs are not justified for any of the scenarios, based on the modelling assumptions used. Fig. 5 shows the results for a PHS plant in 2025 with a discount rate (DR) of 8%. Those scenarios with the overall maximum benefit for the system consist of plant with 2 hours of storage capacity (B & E). The additional benefits seen by increasing the storage capacity to 10 hours, as seen in section III.A, do not justify the increase in capital expenditure. For a discount rate of 8%, scenarios with high levels of interconnection or low wind (G, H&I) have negative overall benefits for larger plant sizes, with optimum plant capacities in the region of 100 - 200 MW, compared to 500 - 600 MW for scenarios B & E. For a 4% discount rate, the optimum plant size increases, with positive benefits seen across all scenarios and plant sizes.

Capital costs for a CAES plant are very competitive compared to other technologies, particularly per kWh. Initial findings show that capital costs for a CAES plant are also justified for the 2025 scenario, with a stronger justification for a larger energy storage capacity. Detailed analysis has not been completed at this time due to insufficient cost data availability.

C. *Wind Curtailment and CO_2 Emissions*

Reductions in curtailment for the modelled PHS plant are more then double those from the CAES plant, due to the increased charging capability of the pumped hydro plant based on the modelling assumptions used. While the PHS plant reduce curtailment in the base wind scenario in 2020 by up to 2.4% of generated wind energy (385 GWh), the CAES plant reduces curtailment by 1.1% (168 GWh). The storage plant are matched for output, resulting in the CAES plant storing less energy per cycle, as natural gas is also used. As discussed in Section III.A, an alternative charge to discharge ratio may impact on the potential for curtailment reduction. For both technologies the curtailment reduction increases more than twofold when moving from 2020 to 2025. The modelled curtailment reductions increase almost linearly with generator capacity (see Fig. 6), and for all four cases considered the scenarios follow a similar intuitive pattern. As expected, systems exhibiting the highest levels of curtailment (high wind, low interconnection, low SNSP limit) provide the greatest opportunities for curtailment reduction. The generator capacity (which is coupled with the charging capacity) has a larger impact on the potential for curtailment reduction than the energy storage capacity, as periods of low net load resulting in wind curtailment are typically short in duration on the system considered.

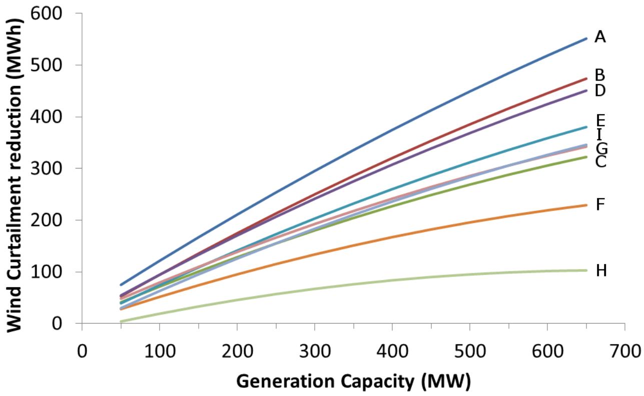

Fig. 6. Reduction in Wind Curtailment CAES 2025

In general, CO_2 reductions are seen during both study years, for both technologies. Minor increases are seen for some high interconnection scenarios, due to increased baseload coal production imported from Great Britain. Reductions in CO_2 emissions are in the range of -0.1 to +0.6 Mtonnes (1 - 5% of emissions generated by the Irish system). Interestingly, those scenarios demonstrating the largest reduction in emissions are the high SNSP limit scenarios, indicating that the reduction is not driven by curtailment reduction, but rather by reduced plant cycling and improved conventional plant loading.

IV. Discussion & Conclusions

Significant benefits can be brought to the Irish power system with the addition of further bulk storage. Wind curtailment reductions (up to 385 GWh for the base wind scenario in 2020) increase almost linearly with storage plant size. However, curtailment could be reduced significantly by the planned increase of the system non-synchronous penetration limit to 75%. Although opportunities for curtailment reduction collapse under the high SNSP scenarios, significant operating cost savings are still seen. Curtailment reductions are not the main driver of the realised operating cost savings. This is particularly evident for the 2025 cases when the maximum savings are seen at the 75% SNSP limit. Instead, the savings are driven by the storage plant's flexibility, with storage plant used extensively to supply reserves and allow the system to operate more efficiently with reduced start up costs and and more efficient loading of the conventional plant. The high SNSP scenarios also provide the greatest opportunity for CO_2 emission reductions. At 75% SNSP the increase in net load variability places an increased cycling burden on conventional plant, providing an opportunity for storage to bring about considerable efficiency improvements in the operation of the power system.

Increased levels of interconnection can be extremely beneficial when integrating large amounts of variable renewable generation onto a power system. Cross border trading can reduce the need for flexible capacity necessary to manage the variable generation, and reduced levels of curtailment are required, as excess wind output can be easily exported. As such, with increased interconnection, the potential for a storage plant to reduce operating cost savings is limited, but still justified for smaller plant sizes / higher wind levels.

Due to a number of modelling assumptions associated with system reserve requirements, the cost savings estimates presented here are conservative. While four categories of operating reserve exist on the Irish system, only one of these reserve categories has been modelled in Wilmar. Future work will include the additional reserve categories. As storage plant are typically highly flexible and are well suited to providing sizeable levels of reserve across multiple categories, this will likely show a significant increase in operating cost savings. Current practice on the Irish system limits the amount of reserve which can be provided from storage plant (50% reserve limit from storage, wind and interconnectors). However, many storage technologies can demonstrate high levels of dynamic control of the power delivered. Hence, there is a strong argument for removing storage in generating mode from this constraint, which would also impact on the potential for operating cost reductions. All scenarios have assumed a single level of plant flexibility (ramp rate, minimum generation level and reserve capability as % of generator capacity). Future work will consider varying levels of plant flexibility, in terms of ramp rate, minimum generation level, reserve capability and variable speed pumping. For the CAES plant a specific charge to discharge ratio of 1:2 has been assumed which limits the ability of the plant to reduce curtailment and provide reserves when in charging mode. The assumed set-up may be sub-optimal and future work will consider sensitivities surrounding plant configuration.

The unit commitment model used here has an hourly resolution. At very high wind penetrations, the net load variability at a sub-hourly time scale can result in additional operational challenges which have not been addressed here. Opportunities exist for appropriate storage technologies to play an important role in power system balancing at these time scales.

While the storage plant modelled are effective in reducing operating cost savings, by increasing the efficiency of the system as a whole, other sources of flexibility also exist which could result in similar system-wide benefits. Demand response has the potential to provide many of the benefits which have been demonstrated. It is likely that future power systems will incorporate higher levels of both grid-scale storage and demand response. Demand response and energy storage should be analysed jointly in order to appreciate the impacts and potential interactions that exist when operated at scale simultaneously.

The storage in this model is dispatched in order to minimise total operating costs for the system. While a strong case has been made for justifying capital expenditure on storage based on reduced operating costs, the profitability of a privately owned and operated storage unit is less certain. Indeed, strategic operation of a storage plant to maximise profits may yield lower system savings, depending on the market rules. Market arrangements require further attention in order to ensure the optimum operation of privately owned storage plant, and to incentivise investment in suitable storage technologies which can provide optimum system-wide solutions. Also, many of the benefits provided by the storage plant (e.g. reduced conventional plant starts) are not easily rewarded in a competitive energy market. Current market designs and the regulatory environment are limiting the deployment of grid-scale energy storage and potentially under-using storage compared to the welfare optimum [8]. Deployment rates of grid-scale energy storage (beyond subsidised demonstration projects) will depend on these issues being addressed.

Despite the conservative cost savings estimates demonstrated in this paper, by 2025 the cost savings are considerably higher than the annualised capital costs for most plant sizes and scenarios. The plant size (MW output) has a larger impact on the result (both cost savings and curtailment reductions) than the storage capacity (MWh). Hence, when considering capital costs, the overall benefit is significantly higher for a PHS plant with a smaller energy storage capacity (2 hours at maximum capacity) than the larger energy storage capacity (10 hours at maximum capacity). Opportunities exist for storage to play a significant role in improving the efficiency of power systems with high penetrations of wind generation. Storage plant operation for arbitrage alone is of limited value, and the ability of a storage plant to be used for additional applications such as the provision of ancillary services will be crucial. It is important the market environment is capable of incentivising and rewarding appropriate storage technology deployment and operation in order for maximum social welfare to be achieved.

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