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Pumped Storage in Systems with Very High Wind Penetration

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Abstract

This paper examines the operation of the Irish power system with very high levels of wind energy, with and without pumped storage. A unit commitment model which accounts for the uncertainty in wind power is used. It is shown that as wind penetration increases, the optimal operation of storage depends on wind output as well as load. The main benefit from storage is shown to be a decrease in wind curtailment. The economics of the system are examined to find the level at which storage justifies its capital costs and inefficiencies. It is shown that the uncertainty of wind makes the option of storage more attractive. The size of the energy store has an impact on results. At lower levels of installed wind (up to approximately 50% of energy from wind in Ireland), the reduction in curtailment is insufficient to justify building storage. At greater levels of wind, storage reduces curtailment sufficiently to justify the additional capital costs. It can be seen that if storage replaces OCGTs in the plant mix instead of CCGTs, then the level at which it justifies itself is lower. Storage increases the level of carbon emissions at wind penetration below 60%.

Keywords: Power System modelling, Wind Energy, Large Scale Energy Storage

1. Introduction

The past decade has seen a large increase in the level of installed wind power worldwide, particularly in Europe and more recently the US and China (Global Wind Energy Council, 2008). This is forecast to grow considerably over the

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next few decades, as concerns about peak oil and climate change have led many countries to mandate targets for renewable generation. As wind is currently seen as being second to hydro (much of which has been fully developed) as the most economic of the renewable sources in the short term, it is expected to make up the bulk of the new renewable generation. This has led to concern about the operation of systems which could be dominated by this uncertain, variable source of energy (North American Electrical Reliability Corporation, 2009). One solution suggested to deal with these characteristics is to use electrical energy storage. Here, energy produced from wind could be stored and used later, thereby giving the system operator control over the energy source. Pumped storage is the most widely utilized form of electrical energy storage and has been in use for the best part of a century. There are approximately 100GW of pumped storage facilities installed worldwide. However, the storage installed worldwide has to be located in areas with suitable geological formations. In many cases, the areas with best geological locations have already been used, so that new pumped storage will have to be installed in areas where it has traditionally been too expensive to justify its usefulness to the operation of the system. It is envisaged however, that with higher levels of variable and uncertain renewables, pumped storage will become a viable option for power systems, and some of these areas will be utilised. Other forms of storage, such as battery and Compressed Air Energy Systems (CAES), are also expected to become more popular, particularly with a reduction in their cost. However, the capital costs of batteries are currently very high, while CAES is, like pumped hydro storage, confined to areas with suitable geology, and also needs gas infrastructure nearby. Thermal storage, using heat pumps or electric boilers for example, may also be useful for integration of wind. These may all be useful in dealing with wind variability and uncertainty, due to these units' flexibility and ability to store energy from variable sources that might otherwise be wasted. The island of Ireland, which is used as the basis for this study, currently has approximately 300MW of storage with the ability to store 5 hours of energy. In the future, Ireland has sites suitable to install several hundred MWs of additional conventional pumped hydro storage (and possibly a far larger amount of seawater pumped storage) if it were seen to be justified.

In the past decade, there has been significant research done examining the possibilities of using storage technologies with wind power. Much of this has concentrated on using wind from one wind farm and maximizing profits for the wind farm owner by utilizing storage to provide a controllable form of generation, see for example (Garcia-Gonzalez, J. et al, 2008), (Castanuovo and Lopes, 2004), (Brown et al., 2008). However, when examined from a system point of view, this method of utilizing storage may not provide the maximum benefit that can be achieved from a storage source - to achieve the maximum benefit to the system, the storage should be operated most economically for the system.

Other research has concentrated on the impact of storage on the system in general. Most of this type of research has focused on the likelihood of endogenous investment in storage compared to other types of plant, normally Combined Cycle Gas Turbines (CCGTs). Sullivan et al. (2008) examined the

US system and found that storage can lead to more installed wind power, once there is enough wind power on the grid to make its flexibility sufficiently valuable. Swider (2007) has examined the addition of Compressed Air Energy Storage (CAES) to the system using an endogenous investment model. This showed that, at certain levels of wind power and certain capital costs, CAES can be economic in Germany for large-scale wind power deployment, taking into account the variable and uncertain nature of wind. Meibom et al. (2007b) and Kiviluoma and Meibom (2010) show the benefits of using thermal storage for wind integration, while Mathiesen and Lund (2009) examines various technologies for wind integration, showing that thermal storage can be very useful. The work here differs from Sullivan et al. (2008) and Swider (2007) in that it examines one year of wind on the system in a future date with and without storage, instead of a multi year investment model. The fact that the system is operated over one full year is important due to the temporal nature of storage and wind resources - its value to the system can therefore be better quantified. Ummels et al. (2007) examined the effect of storage on system operation over one year in the Netherlands. It was found that, though storage became more viable for the system with increasing levels of wind power, it never proved to be the best option for the system examined. In contrast, the unit commitment model used here includes a stochastic representation of wind to examine the effect of storage on the power system when the uncertainty of wind is taken into account. This is important in terms of storage as thus far, work carried out examining hourly operation of storage only accounts for the variability of wind power, and not its uncertainty - this is shown to have a significant effect on the results. Other work has concentrated on the benefit storage provides in relieving transmission congestion, as shown in Denholm and Sioshansi (2009) - this is not examined here. Other models, (Connolly et al., 2010a) and (Connolly et al., 2010b) have also examined the integration of wind energy into the Irish system. These models examine the energy system as a whole to analyse future portfolio development; in contrast this paper examines the detailed system operation, using hourly time resolution, stochastic rolling unit commitment and economic dispatch when a storage unit replaces another plant in a predefined portfolio. The realistic actual operation of storage and its interaction with the rest of the system for a particular year can then be observed.

The work in this paper examines very high levels of wind penetration - penetration here is defined as percentage of energy provided by wind that is used to meet load. The penetration level examined is higher than that of other work, as it is at higher levels that storage would justify its additional capital costs. This would occur at the point at which the additional capital costs of storage versus a conventional plant can be justified. Market rules and compensation of the market players, including bilateral contracts between wind and storage owners are not examined here - here a perfect market is assumed. If storage is a price taker then it should follow that in a sufficiently competitive market, the privately owned storage gives the same effect as that operated for system benefit. The work done in O'Neill et al. (2005), Sioshansi et al. (2008) and Sioshansi et al. (2009) has shown that in markets where there are non-convexities that

cannot be priced properly, as would be the case with storage, then the welfare-maximising benefits of storage may not be fully realised. Storage does not bid into the market here, but is used to reduce overall system operating costs.

An initial study was carried out in Tuohy and O'Malley (2009). This examined the operation of wind power at high wind penetration levels, assuming a perfect foresight for wind power. Here, this work extends the analysis by introducing the effect of the uncertainty of wind power using a stochastic unit commitment model. This ensures more realistic evaluation of the benefit of storage when compared to modeling under the assumption that wind can be perfectly forecasted. This can be seen to add significantly to the value of the wind, and therefore produces very different results from those seen in Tuohy and O'Malley (2009); additionally, a wider range of sensitivities are examined and a more thorough analysis of results is carried out. The model used is nearly identical to that employed in Meibom et al. (2007a) and Tuohy et al. (2009); the innovation here is due to the fact that the impact of storage is explicitly examined - those works did not address the effect of installing additional storage. This work also examines higher wind penetrations than those seen in Meibom et al. (2007a) and Tuohy et al. (2009), meaning the value of storage at higher wind penetrations can be assessed. Section 2 details the methodology used to assess the impact of storage, and presents the test system as well as the details of how storage is modelled. Section 3 presents the results. Both the likely operation of storage, and the effect this has on the rest of the system are examined. The effect this has on system costs, and whether or not this can justify the additional costs of building storage, is then presented. Sensitivities are then examined. Section 4 discusses the results, while Section 5 concludes.

2. Methodology and Test System

To examine the impact of pumped storage, the test system is simulated, with and without a pumped storage unit, so the value of its flexibility and ability to reduce curtailment can be quantified. Unit commitment is done using a stochastic unit commitment model, described in Section 2.1 and in the Appendix of Tuohy et al. (2009). The modelling of pumped storage is described in Section 2.2. Wind is added incrementally to the test system, as described in Section 2.3, so that different levels of installed wind are examined - this will show the effect of storage on higher penetrations of installed wind. There are also sensitivities carried out which are described in Section 2.4.2.

2.1. Unit Commitment and Dispatch

The Wilmar planning tool (Barth et al., 2006), (WILMAR, 2006) was designed to incorporate the uncertainty of wind power into the scheduling process using stochastic methods. This ensures more robust schedules are produced to cater for the uncertainty inherent in wind and load forecasts. This tool was then further developed into a full mixed integer unit commitment tool for the All Island Grid Study (Meibom et al., 2007a) and (Meibom et al., 2011), which

was carried out to examine the future Irish power system with high levels of renewables. Recent work (Tuohy et al., 2009) has shown the effect of incorporating the uncertainty of wind into the scheduling process using stochastic as opposed to deterministic methods, showing that stochastic optimization results in better performing and less costly schedules when compared with deterministic methods. Wind is represented stochastically by including multiple scenarios of future wind power production, based on expected forecast accuracy, in the unit commitment model. The expected least cost over all scenarios is then minimised by the objective function. The effect of ‘rolling’ planning, whereby the system is reoptimized as new forecasts become available is also examined in Tuohy et al. (2009). The model has an hourly resolution, with planning done for the next 36 hours on a rolling basis. Primary reserve, which is the reserve needed in shorter timescales, is estimated based on the largest in-feed to the system and the forecasted wind power production. Primary reserve varies depending on the largest online unit and the amount of wind forecasted; the largest in-feed possible is 420 MW, and additional reserve for wind and load forecast errors can range from close to 0 MW (with little or no wind) to approximately 100 MW. This is calculated based on the method described in Doherty and O’Malley (2005), which calculates additional reserve based on a combination of wind and load forecast error. Replacement reserve demand, which is the demand for reserve over longer timescales, is calculated based on the expected wind and load forecast error, with a different replacement reserve target for each scenario. More details of the model can be found in (Barth et al., 2006), (WILMAR, 2006) and (Tuohy et al., 2009).

2.2. Modelling of pumped storage

Pumped storage here is represented by a reservoir, with the inefficiencies associated with pumping and generating accounted for when filling the reservoir. When pumping, it is added to the demand, while the amount being pumped is subtracted from primary and replacement reserve targets, as pumping can be stopped to reduce demand on the system. When generating, it is treated as any conventional unit. Both pumping and generating are subject to ramping and minimum and maximum capacity constraints, as any other unit - however, a pumped storage unit usually has a very high ramping rate, which when examined on an hourly resolution means that storage can go from full pumping capacity to full generating capacity in less than one hour. Here it is assumed ramp up and ramp down from storage are the same.

The storage here, while it most closely resembles a pumped hydro storage plant, could also represent battery or other forms of energy storage. This paper refers to pumped storage as the round trip efficiency assumed (KWh produced divided by KWh stored) is 78%. This is consistent with current pumped storage technology, but would be different from other forms of storage such as battery storage. However, the same approach could be used to assess these types of storage. The capital costs assumed per MW installed in the results later would also need to be changed for different types of storage. The storage is optimized as part of the unit commitment and dispatch process to ensure it is used to reduce

total system costs. Compressed Air Energy Storage (CAES) may be modelled similarly, but would also have to take into account the usage of natural gas in these types of units.

For most of the results, pumped storage is assumed to be either pumping or generating, not both. This constraint is used as the most common setup for pumped hydro electricity is a reversible turbine / generator. To ensure there is energy in store at the end of the day, the marginal value of filling the store at the end of one day (i.e. the cost of increasing the energy in the store by 1 MW) gives the value of having energy in store at the end of the following day. For weekends, the value at the end of Friday is used for both days. This ensures the value of leaving energy in store is recognized. Storage is used from a system perspective, i.e. to reduce total systems costs given in the objective function, which is shown in the Appendix of Tuohy et al. (2009).

2.3. Test System

The test system used here is a possible plant mix for Ireland in 2020, with high levels of wind on the system. Ireland here includes the jurisdictions of both Republic of Ireland and Northern Ireland. Both the island of Ireland, operating as a single electricity market since 2007, and also Great Britain (GB), which is assumed to be connected by a 1000MW dc link in 2020, are modelled. Portfolio 5 from the All Island Grid Study (All Island Renewable Grid Study - Workstream 4, 2008) is used as the base portfolio. This is an optimised portfolio for the Irish system in 2020 using the methods described in Doherty et al. (2006). The net load that is seen on the Irish system for this study is 53.9TWh. The peak demand is 9.6GW, with 3.5GW minimum demand. Installed wind is 6GW in the base system used here. The GB system consists of 36 units, which represent the different fuel types, while 14GW of installed wind is assumed. This representation of GB is a refinement on the method used in Meibom et al. (2007a), where there was eight units, one for each fuel type. By splitting each fuel type into multiple units, a better representation of the GB system can be obtained. These are not modelled in as much detail as the Irish units, with no minimum up and down times and startup times or costs. The base system for Ireland consisted of the units shown in Table 1. It can be seen that the total conventional generation is 8596 MW - this is less than the peak demand on the system, however, both the interconnector and the installed wind are used to meet this demand. In the base system, the price of carbon was assumed to be €30/tonne. In contrast to Tuohy and O'Malley (2009) and Tuohy et al. (2009), the interconnection can be rescheduled intra-day meaning the system is more flexible and better able to respond to wind uncertainty. An additional constraint is included in the updated version of the model used here (compared to Tuohy et al. (2009)), in which a certain number of large conventional plant have to be online at all times, set here to be seven 400MW Combined Cycle Gas Turbines (CCGTs), or their equivalent. These can be run at part load (approximately 200MW), meaning that the minimum amount of conventional generation online is approximately 1400MW. This is about one third of minimum demand. This is to ensure enough inertia on the system to provide system stability (Gautam

Table 1: Types of unit in Irish plant portfolio used in base system for study

Type of unit	No	Capacity (MW)	Fuel (€/GJ)
Combined Cycle Gas	15	4533	5.91
Open Cycle Gas	13	1356	6.23
Coal	5	1257	1.75
Gasoil	9	383	10.0
Peat	3	345	3.71
Base RE	1	306	2.78
Hydro	1	216	
Tidal	1	200	
Total	47	8596	

et al., 2009). At higher demand, even though the percentage of demand met by conventional plant will be lower, the inertia on the system is still assumed high enough with this constraint. Ongoing work at the Irish system operator is investigating the percentage of demand plus export which needs to be met by conventional plant; the constraint here on conventional plant will result in conventional generation somewhere between the 15% and 30% of demand plus export seen as a minimum in Eirgrid and SONI (2010). A 500 MW storage unit is assumed to be able to provide the same amount of inertia as a CCGT. The unit commitment model used here, which aims to minimise costs, is very similar to the actual Irish Single Electricity Market (SEM). It is a centralised unit commitment market. Participants are paid the system marginal price, which includes an uplift mechanism to ensure start-up and no load costs are recovered - this is not modelled here as the results examined are cost rather than price based. Storage in the SEM and in this work is run by the system operator, and contracted to them to reduce system costs. The fuel prices shown here are those that were used for the All Island Grid Study, using 2005 projections. While this means they are not new (current IEA projections are for higher prices), they are nonetheless consistent with the results of that study, which was used as the basis for the current Irish government wind targets. It should also be noted that they still contain a realistic profile over the year, which is as important when evaluating storage as the actual level of prices

The next section examines the way the portfolio was altered as storage was added to the system at increasing levels of installed wind.

2.4. Portfolio development

The above portfolio was developed in a number of ways for the work carried out here. It should be noted that when changing the portfolio, the aim was to keep the reliability the same for all different cases; this was achieved by running the simulation for a year (in deterministic mode) to ensure hours of lost

load remained the same. This then resulted in both storage and wind replacing conventional plant. This section presents the way the thermal portfolios were developed under three different headings - firstly, the developments to the thermal portfolio that were made when adding storage, secondly the sensitivities in terms of model setup that were carried out, and finally the way the thermal portfolio changed as additional wind was added.

2.4.1. Addition of storage to portfolio

As storage was added to the system, conventional capacity was removed, to ensure that a fair comparison could be made between results with and without storage. In this study, it was initially assumed that 500MW capacity of storage, with 5GWh (10 hours) energy storage, could replace 500MW conventional plant. This is consistent with the size of pumped storage currently being installed worldwide, and is used as the base case. The largest current unit on the Irish system is in the order of 500MW, so this was decided upon as the capacity. Five GWh was chosen as 10 hours is seen as a good size for a pumped storage plant. However, sensitivities were run around storage size when examining the results, as mentioned in 2.4.2 below and are reported later in Section 3.4. In the cases examined in Sections 3.1 to 3.3, one 400MW Combined Cycle Gas Turbine (CCGT) and one 103MW Open Cycle Gas Turbine (OCGT) were replaced by storage. Deterministic simulations (assuming a perfect foresight of wind) were made to ensure that the performance of the system in meeting load and reserve targets remained sufficiently close when storage was added, and it was found that, for the wind levels examined, the 500MW/5GWh storage could replace 500MW conventional without compromising system performance - i.e. ability to meet demand and reserve targets. This is set here to be a maximum of 8 hours per year where demand cannot be fully met.

2.4.2. Portfolio Sensitivities

Three main sensitivities in the make up of the portfolio were also carried out, which are reported in Section 3.4. The first of these was to use storage to replace 5 103MW OCGTs in the thermal plant mix, instead of the CCGT and OCGT in the base case. These are more flexible, but less efficient plant, and so the fuel use of the system would be expected to be different. The second sensitivity replaced the interconnection with conventional plant (1000MW interconnection was replaced with 2 400MW CCGTs and 2 103MW OCGTs). As storage and interconnection offer similar benefits in terms of flexibility and ability to reduce curtailment, a system without interconnection may offer more opportunities for storage to provide value. For these first two sensitivities, the system was run deterministically as a test to ensure the performance remained the same in terms of meeting load and reserve targets, as described previously for portfolio development. While portfolio optimization with storage was not carried out, it can be seen that as the remaining system consists of existing plant, new combined cycle and new open cycle gas turbines, the choices that could be made in terms of plant portfolio options are limited to whether the plant removed is open cycle or combined cycle gas. The final sensitivity was to

change the size of the energy storage. Instead of 10 hours (or 5GWh) of storage, 1, 3, 5 and 15 hours were examined. This meant that the possible benefits of optimizing storage size could be assessed. Unlike other portfolio changes, here the performance in meeting load and reserve targets was allowed to change, from 8 hours loss of load per year or better used previously, so as to examine the importance of storage capacity (in hours) to the results. Results relating to this are given in Section 3.4. This is the only part of this paper in which the performance of the system was allowed deviate from the accepted reliability level of 8 hours loss of load per year.

2.4.3. Increasing installed wind levels

To examine the effect storage has at different levels of wind penetration, wind was added to the base system. As the amount of wind installed on the system increases, it would be expected that the incremental capacity credit of wind will decrease, as shown in the report by (Holttinen et al, 2007). This shows that wind has a capacity credit and can therefore replace conventional plant to some extent and maintain reliability. The reliability of the system should stay the same so that an equal comparison across wind levels can be made of the benefits of storage. Using the capacity credit of wind from Doherty and O'Malley (2005) as a basis for the likely capacity credit of wind in Ireland, wind was added and conventional units removed. While the wind has a capacity factor here of approximately 34%, its capacity credit becomes significantly smaller as increasing levels of wind are installed on the system - this is due to the fact that wind output is correlated over a large region (Ensslin et al., 2009). An initial deterministic simulation for each level of installed wind (assuming perfect foresight of wind) ensured that the amount of hours demand and reserve was not met is reasonable, i.e. if demand was met less than approximately eight hours per year, then the amount of conventional capacity removed for wind was deemed adequate. Otherwise, less conventional capacity was removed, and the system re-simulated until a satisfactory performance level was reached. It can be seen from Hasche et al. (2011) that multiple years of data are required to obtain the actual capacity credit of wind power. Fig. 1 shows the capacity of conventional plant that was actually removed from the system for every 1MW of wind added versus the amount of wind installed, from 6GW to 12GW of installed wind.

3. Results

The simulations were run for 5 different levels of installed wind - 6 GW, 7.5 GW, 9 GW, 10.5 GW and 12 GW. These correspond to 34% to 68% of total system demand, if all the energy produced from wind can be used, i.e. no curtailment due to wind being in excess of system demand. The model was implemented in the GAMS modelling language, and solved using the CPLEX solver, with a duality gap of 0.1%. Many of the simulations presented here were also run at 0.01%, however, for speed reasons the duality gap was increased -

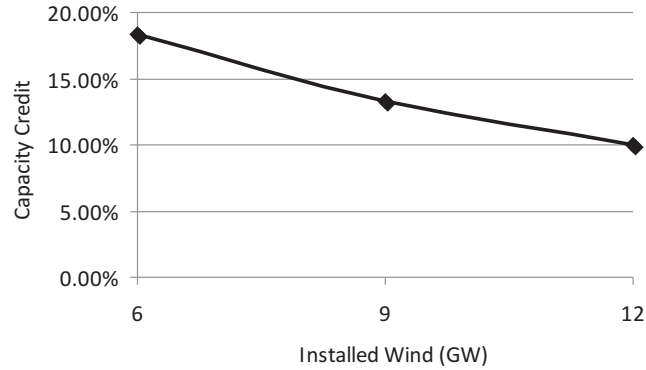


Figure 1: Amount of conventional capacity displaced as wind added to system at 6 GW , 9 GW and 12 GW of installed wind

a comparison of the results for the same cases at different duality gaps showed very little significant differences in the results examined here. Rolling planning was carried out every 3 hours, with a one hour time resolution. Each case took approximately 1.5 days to solve on a computer with a 2.0GHz dual core processor. Three main aspects of the simulation results are presented here. Firstly, the curtailment of wind is examined. Next, the implications this has on system operation and capital costs is examined. The levels of wind at which storage starts to justify its large capital cost are then shown. Then, the effect storage has on operation of systems with high wind penetrations is shown. Here, the operation of storage as well as emissions and import/ export are examined. Sensitivities which were outlined in Section 2.4.2 are presented in Section 3.4.

3.1. Curtailment and increased wind penetration due to storage

The main advantage offered by storage over a conventional plant is the fact that excess wind energy can be stored instead of curtailed. From Fig. 2 it can be seen that the curtailment on the system is quite low at 6GW of installed wind. However, at approx 9GW installed wind (wind produces approximately 51% of total energy requirement if no curtailment), there is a significant increase, with the rate of increase growing with installed wind. Above 9GW of installed wind, a significant portion of the wind is wasted. Storage can reduce this, as shown, and therefore capture more of the wind generated. This implies that adding storage to the system allows greater use of existing wind, but only at very high wind levels. It can also be seen that, when an assumption of perfect foresight is made for wind and load the curtailment is underestimated - this is due to the fact that if the wind could be perfectly known, the system would be better operated and there will be less periods when wind needs to be curtailed. Obviously this is unrealistic, but it shows the impact that uncertainty of wind has on curtailment, and therefore shows the benefit that the flexibility of storage gives when dealing with wind uncertainty - this is a result for this work which

cannot be shown in models which assume perfect foresight as in (Sullivan et al., 2008) and (Ummels et al., 2007) .

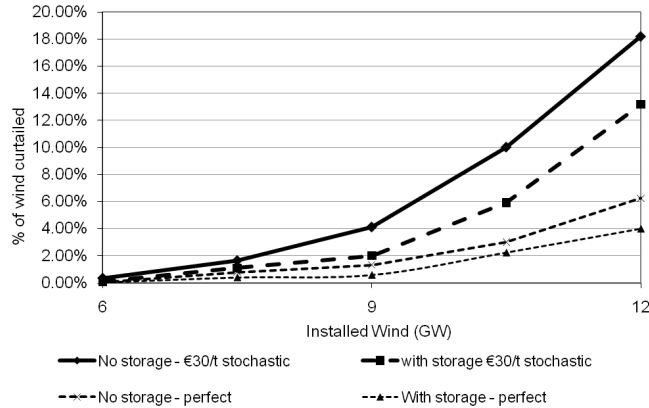


Figure 2: Percentage of wind curtailed with and without storage, for both stochastic and perfect foresight modeling of wind, € 30/t carbon

As storage reduces curtailment, it can help maximize the penetration by energy of wind. As many countries have wind penetration targets which are set by energy (such as Ireland (Government White Paper, 2007) which has a 40% target for renewables - mainly wind - by 2020 and the EU with targets for different countries), this means that, if these targets are high enough, storage will delay the need to invest in installing new wind power. Demand growth for the test system is based on projection from 2006; it is now likely that Irish demand in 2020 will be lower; this will have the effect of increasing curtailment at the same GW of installed wind, making storage look more beneficial. However, the government targets are for 40% of energy, not an actual GW number, therefore the GW installed may also be lower by 2020, which may mean curtailment levels will remain as they are shown here. This shows that, if evaluating storage from a system benefit point of view, the demand is also a significant factor. Lower demand may also mean more curtailment would be needed to ensure sufficient inertia on the system, also affecting results.

3.2. Effect on system costs and economic analysis

This section presents the results in terms of effect on system costs and the subsequent examination on whether or not the results would justify building storage on this system, from a system costs perspective. Fig. 3 shows the operating cost savings due to storage for a given installed wind capacity - this is change in costs for both GB and Ireland, as any change in the Irish system will change the schedules for the GB system, which will be reflected by a change in the import and export on the interconnection. These costs include fuel, start-up costs and carbon costs. When replacing 1 CCGT and 1 OCGT, storage actually

increases system costs below a given level of installed wind - this is due to the inefficiency of storage, which will increase the use of coal and base load gas units compared to the units storage is assumed to replace, i.e. 1 CCGT and 1 OCGT.

As more wind is installed, storage can be used more to reduce curtailment, as shown earlier in Fig. 2. As wind energy would otherwise have been wasted, this reduces system operating costs above a certain level of installed wind - this reduction is therefore greater than the increase in fuel consumption. Increasing the cost of carbon dioxide to €60/tonne is shown to increase the additional costs seen at lower levels of wind, while also increasing the savings seen at higher levels of wind. However, there is not a very significant difference, which would be expected here as gas is generally the marginal unit on the Irish system - coal would not become marginal until very high carbon prices were seen. Gas is a low carbon fossil fuel and is on the margin at most times in the Irish system, so therefore would not be significantly affected by carbon price. The results for an assumption of perfect foresight are also shown in Fig.3. Cost savings are underestimated if perfect foresight is assumed above 9GW, due to the underestimation of curtailment at these levels of wind, as shown in Fig. 2. There is a slightly higher cost saving achieved with storage when perfect foresight is assumed below 9GW of wind, due to being better able to operate the system when wind is known perfectly in advance. This is due to the fact that, with perfect foresight of wind assumed, wind is less likely to need to be curtailed, and therefore the possible cost savings due to curtailment are lower. This also shows the benefit that the flexibility of storage can bring to a system - storage is flexible enough to deal with the uncertainty of wind forecasting and therefore can help reduce costs on the system.

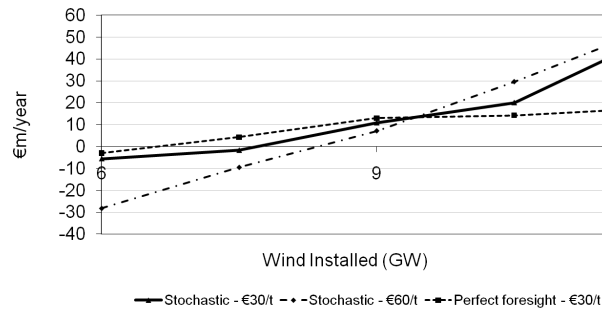


Figure 3: Operating cost (fuel, carbon plus startup) savings for system with 500MW/5GWh storage replacing 500MW conventional plant (400MW CCGT and 103MW OCGT), for carbon costs of €30/tonne and €60/tonne, and stochastic and perfect foresight optimization

To justify the replacement of conventional plant with storage for a given installed wind capacity, the additional capital costs of pumped storage would have to be accounted for by savings in fuel costs over its lifetime. However, as storage costs would be very site specific, only general details are examined here, with some basic assumptions on project economic evaluation. By taking the

Net Present Value (NPV) of the fuel savings over the lifetime of a storage unit, the additional capital costs that are justified can be estimated. Fig. 4 shows this for 2 different discount rates, with a 20 year lifetime assumed. As can be seen, lower discount rates make the additional justified costs higher for a given installed wind capacity - however, it does not have a very significant impact on results until very high penetration levels are reached. While a discount rate of 4% can be seen to improve the benefits storage brings in terms of costs, the differences are not very significant until very high levels over approximately 10 GW are reached.

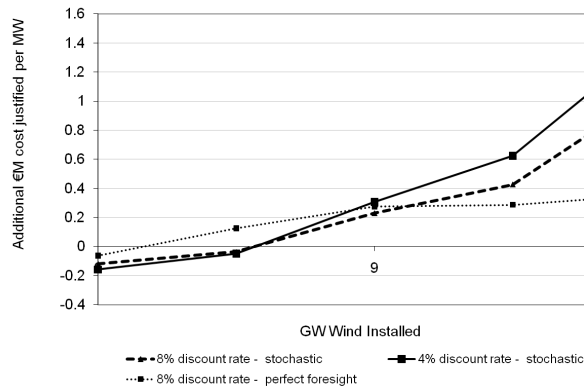


Figure 4: Additional capital costs justified for storage at given installed wind levels, for a variety of discount rates, and stochastic and perfect foresight optimization, €30/tonne carbon

As an example, at the same capital costs as a CCGT, pumped storage would not justify itself until approx 7GW of installed wind capacity (the point at which the lines cross €0M additional cost justified in Fig. 4). However, current indications are that pumped storage has a capital cost approximately €900k / MW more than that of a CCGT (approx €1.5m / MW versus €600k / MW (US Energy Information Agency, 2007)) - this break even point occurs at approximately 10 GW - 11 GW of installed wind, depending on discount rate applied. However, an advantage of pumped storage is a longer lifetime than conventional plant. If 40 years operational lifetime is assumed for storage, and 20 years for a CCGT, then storage would still be assumed to have a value after 20 years, when a CCGT would not. If a longer lifetime is assumed, the breakeven point would occur at a lower justified cost - for example if only €250k was needed to be justified, then it would occur at 8.5 - 9GW of installed wind, or 48% - 51% of energy from wind. This is lower than if lifetime isn't considered, but still represents a very high level of installed wind. It can be seen that the additional capital costs justified will depend on specifics of the actual plant, such as lifetime and discount rate assumed - changing discount rates or financial parameters will move the justified cost curve left or right, while changing lifetime or initial capital costs moves the breakeven point up or down. However, it can

also be seen that the results are not very sensitive to these parameters - the level of installed wind needed to justify storage would be somewhere in the region of 9GW, or approximately 50% of energy, if storage has a longer lifetime but costs an additional €700k to €900k / MW. Fig. 4 gives an indication of when this will occur. Therefore, for storage to justify its additional capital costs, the wind installed on this system would be between 7GW to 11GW (approximately 42% to 55% of energy from wind). It can also be seen that assuming perfect foresight of wind when simulating storage operation at very high installed wind will make the case for storage worse, as the cost savings are not as high due to the fact that the curtailment seen is lower when wind can be forecast perfectly. Even at 12GW of installed wind, only an additional €350k is justified per MW. Therefore, uncertainty of wind is an important factor in justifying installation of storage, due to the flexibility of this type of plant. The remainder of the results examined in this paper are for the stochastic case only, as this is the most realistic case - the results shown here for an assumption of perfect foresight are given to indicate the benefits that the flexibility of storage can bring to a system in which wind is not forecasted perfectly. A discount rate of 8% is used for the remainder of economic results; as can be seen a lower rate would make storage look better, but not by a large amount.

3.3. Effect of pumped storage on other aspects of system operation

As shown in Meibom et al. (2007a), at penetrations of wind power on the 2020 Irish system below 34% of energy, the hourly operation of storage is not significantly driven by wind, and more likely to depend on load. This is due to the fact that overall system costs are taken into account when scheduling the system. At these levels of wind, it is best to just use the wind to reduce demand, instead of storing it and incurring the energy loss. However, as shown in Figs. 5 and 6, as more wind comes on the system (greater than 34% or 6GW), there is a shift from the traditional method of pumping during the night and generating at peak hours, to more days with pumping occurring during the day and generating occurring at off peak hours. This would be due to the fact that, with higher levels of wind, there would be more times when wind would be marginal - i.e. it would be wasted if it was not used to fill the store, due to the fact that other units need to be kept online to provide system inertia. The 7.5GW, 9GW and 10.5GW results lie between the 6GW and 12GW results.

Fig. 7 shows the average net exports from Ireland to GB for 6 GW and 12 GW of installed wind by hour of day. As can be seen, these follow a similar pattern to the pumping of the storage as shown in Fig. 6, showing that the interconnection carries out many of the same functions as storage - i.e. reduces curtailment, increases utilisation of cheaper units and offers flexibility to the system for dealing with high amount of variable wind. As can be seen here, the system examined has an average output from wind which is almost constant throughout the day - wind is not significantly higher here at any particular time. As additional wind is installed on the system the interconnection is used more to export.

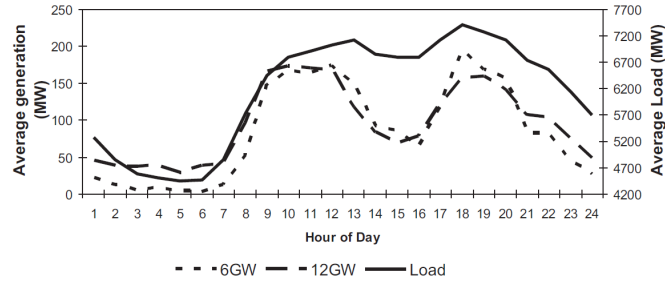


Figure 5: Average generation from storage by hour of day for different installed wind levels

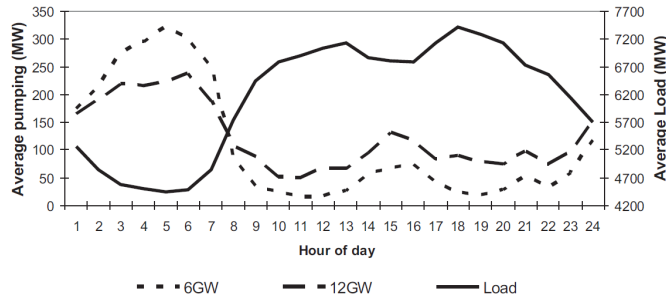


Figure 6: Average pumping from storage by hour of day for different installed wind levels

Fig. 8 gives the change in net export from Ireland to GB, in terms of the Irish demand, when storage replaces conventional plant. As GB is generally cheaper, due to cheaper fuel costs and base loaded nuclear (with the exception of very high wind periods in Ireland), it is beneficial for Ireland to be importing more often. As would be expected, with more wind on the Irish system, Ireland goes from being a net importer to a net exporter. What can be seen is that storage always results in Ireland importing more often, as it can take advantage of the storage to either store cheaper energy from GB or keep excess wind in store to use in place of importing from GB later.

One other aspect of system operation worth examining here is the production of carbon dioxide. Fig. 9 shows the results for this system. These figures are for both the GB and Ireland system together, as while there may be a reduction in Ireland emissions, this may be matched by an increase in GB emissions and therefore this needs to be taken into account. As can be seen, there is an increase in emissions when storage is added until approximately 11.5GW of installed wind. With storage available, the cheaper coal units are used more to fill the store. Therefore, this will cause an increase in carbon dioxide emissions, which is greater than the decrease caused by the additional energy supplied by wind which is possible with storage.

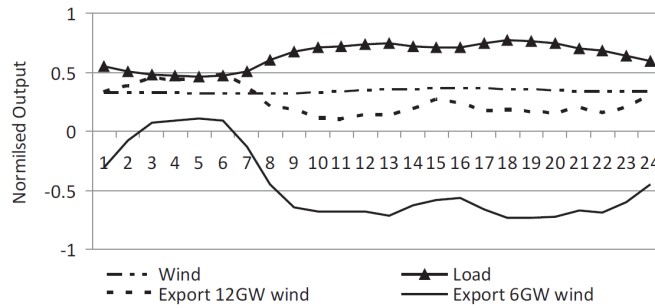


Figure 7: Average net export and wind from Ireland to GB by hour of day for different installed wind levels

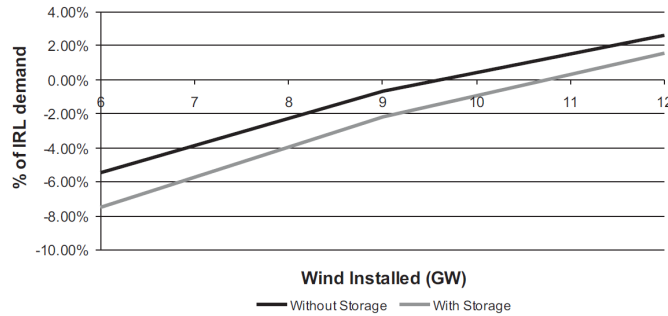


Figure 8: Net export, as a percentage of total Irish demand, with and without storage, for stochastic optimization, €30/tonne carbon

3.4. Sensitivities

The base case that was examined here was a 500MW / 5GWh (i.e. 10 hours of storage) unit replacing 400MW of CCGT and 103MW OCGT in the test system described in Section 2.3 for various installed wind levels, with results given in the previous two sub sections. This section reports results of sensitivities that were examined as described in Section 2.4.2.

Fig. 10 shows the cost savings seen when storage replaces five 103MW OCGTs on the system, instead of one CCGT and one OCGT which was also shown earlier in Fig. 3. As can be seen the storage always produces cost savings at this level of wind when replacing OCGTs. The reason storage saves more costs when replacing OCGTs is due to the fact that storage is replacing a less efficient unit. As wind on the system increases, the additional savings made when storage replaces OCGTs instead of a CCGT remain approximately the same, at around €250k.

The best cost savings in Fig. 10 can be seen when replacing OCGTs, so storage can justify the most additional capital costs when replacing OCGTs due to increased fuel savings. However, the additional costs that it needs to

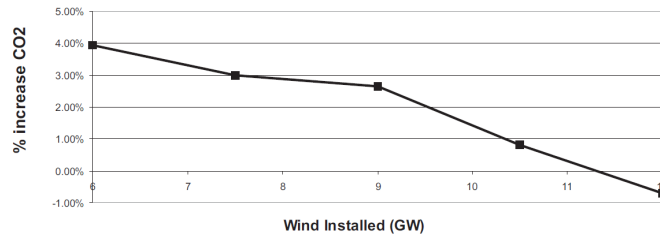


Figure 9: Increase in carbon emissions when storage replaces conventional plant, for stochastic optimization, €30/tonne carbon

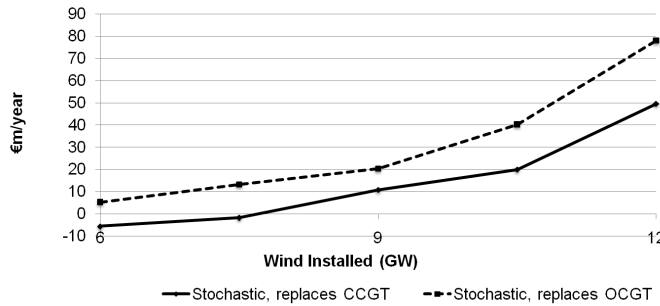


Figure 10: Operating cost (fuel plus carbon) savings for system with 500MW/5GWh storage replacing either 1 CCGT and 1 OCGT or 5 OCGTs, stochastic optimization, € 30/tonne carbon

justify are greater as OCGTs are considered to cost approximately € 400k / MW, while CCGTs cost approximately €600k / MW or 50% more (US Energy Information Agency, 2007), so it is replacing a cheaper unit. Fig. 11 shows the justified costs for replacement of CCGTs and OCGTs with a discount rate of 8%. The difference in justified costs between replacing a CCGT or replacing OCGTs at 6GW of installed wind is approximately €250k / MW - therefore it can be seen that when replacing OCGTs, storage is better justified, however, not significantly so as OCGTs cost €200k / MW less. These results do not take into account the effect increased cycling due to wind will have on different types of units - it would be expected that the cycling costs incurred by CCGTs would be higher than that incurred by the more flexible OCGTs.

As interconnection could be seen in Fig. 7 to operate very similarly to storage, it was decided to remove interconnection and replace it with conventional plant, as described in Section 2.4.2. The most interesting result to note here is the cost savings that storage could provide if it replaces conventional plant on a system with no interconnection. As it is now the only flexible option to deal with curtailment, the cost savings are significantly higher as shown in Fig. 12. The cost savings seen here when examined with Fig. 4, imply that at 6 GW of

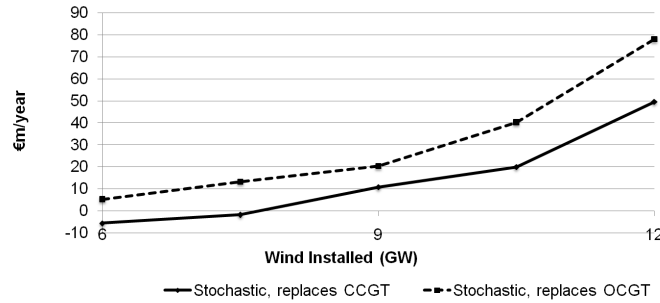


Figure 11: Additional capital costs justified for storage at given installed wind levels, for a discount rate of 8%, replacing 1 CCGT and 1 OCGT or 5 OCGTs, €30/tonne carbon

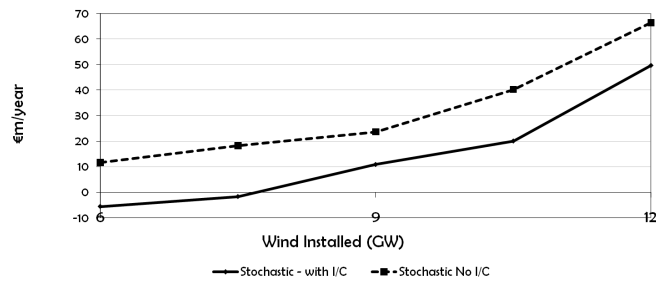


Figure 12: Cost Savings when 500MW/5GWh storage replaces conventional plant (400MW CCGT and 103MW OCGT), with and without interconnection, stochastic case, €30/tonne carbon

installed wind, the fuel and carbon costs saved by storage would be enough to justify its additional capital costs, if no interconnection was available to other systems. This is expected as interconnection may provide the same benefit of flexibility at times of low demand and high wind in reducing curtailment as wind may be exported, assuming that the other system can import at this time. Additionally, if the other system can export at times of high demand and low wind, flexibility is also provided. As well as this interconnection increases geographical diversity of wind resources, and offers greater smoothing of the variability seen. Note that the interconnection is used in this work to reduce costs to their maximum extent across both regions. In reality, there may be some restrictions as to how flexibly it could be used in terms of intraday rescheduling of the flows. This sensitivity also highlights the possible effect of an increase in wind in GB similar to that seen in Ireland; if wind was to increase in GB the interconnector may not be available as assumed for the earlier results and therefore flexibility would have to be provided by Irish units and storage. As seen, storage would be more beneficial if GB wind was to increase significantly beyond the amount forecast at present, which was used in the model. Studies such as Pyory (2009) have examined the effect of increased wind on both islands and show that wind

is not as correlated as may have been assumed previously.

The effect of storage size was also examined as described in Section 2.4.2. Instead of assuming 10 hours of energy in store, 15 hours, 5 hours, 3 hours and 1 hour of energy were examined. Traditionally, 10 hours is considered enough as load follows a well defined shape and most or all value of storage would come from arbitrage within 1 day. As more wind comes on the system this would be less true, as some high wind days may be followed by low wind days, meaning longer storage horizons could be beneficial (Denholm and Sioshansi, 2009). As each schedule in this model is carried out over a 24-36 hour period, it would be expected that 15 hours is a long enough period of time, and extending this period would not have a great effect on results using this model - a longer horizon than 36 hours may be able to take better advantage of a larger store.

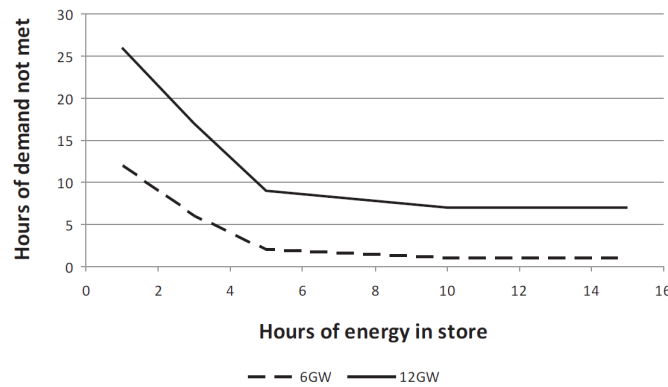


Figure 13: Performance of system in meeting demand targets versus energy capacity of store, for stochastic optimization, €30/tonne carbon

Fig. 13 shows the effect of storage size on the number of hours where load cannot be met. As stated in Section 2.4, when storage with 10 hours of energy replaced conventional plant, it was ensured that system performance remained the same. The portfolio was designed to have 8 hours loss of load expectation (LOLE). The performance of the system with or without storage remains the same at the various wind levels examined when there is 10 hours of storage. Storage here does not add to performance of the system; the performance of the system does change slightly as in Fig. 13 when wind levels change, but the performance with and without 10 hours storage remained consistent. However, as can be seen, the performance of the system decreases as the energy that can be stored in the reservoir decreases. This would be expected as if less energy can be stored, then there is more likely to be hours when nothing is left in store when it is needed, especially at higher wind levels. With less than approximately 5 hours of storage, the performance of the system drops off markedly. However, it can be seen that, from approximately 5 hours, the performance of the system is satisfactory - at greater than 10 hours, the system performance does not improve. This implies storage cannot fully replace conventional plant on the

system if its reservoir is not large enough. With less hours of energy in store 500MW of storage may not be able to replace 500MW conventional plant. This leads to the idea that storage has a capacity value (Garver, 1966) which is dependent, not only on forced outages as other plant, but also on the size of its store and the amount of wind. Therefore, at high wind penetrations, storage would need to be large enough if it is to adequately replace conventional plant. This idea is something that could be explored in further work. However, it will also need to take into account the size of the storage available, as well as the capacity of the pump and generator. This is similar to sizing other forms of storage, e.g. gas storage, and could be examined in a similar fashion.

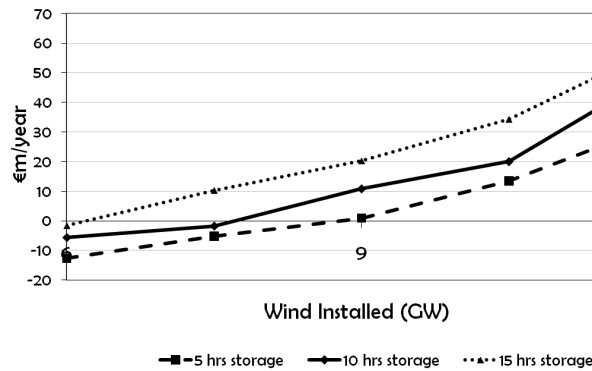


Figure 14: Cost Savings when 500MW storage replaces conventional plant (400MW CCGT and 103MW OCGT), for different size of energy storage, stochastic case, €30/tonne carbon

The cost savings associated with storage for different sizes of energy storage are shown in Fig. 14. Here, the results for storage sizes of 3 hours and 1 hour are not shown, as these can be seen to be unreliable in Fig. 13, and therefore a fair comparison could not be made when examining costs. What can be seen, as expected, is that the larger the storage size, the greater the cost savings that can be made. However, there is not a very significant difference. This would imply that having a larger storage size would give slightly more favourable results in terms of when storage becomes a good option compared to conventional plant - however, larger storage sizes will generally mean more expensive capital costs.

4. Discussion

The first aspect of the results to note is the fact that this work does not examine portfolio optimization (Awerbuch, 2006) - it assumes a direct choice between storage and conventional plant. It is assumed that the wind is built, and then operation of the system with and without storage is examined. This would obviously not be the case in reality, with other flexible options, such as demand side management, increased interconnection with other systems, widespread deployment of electric vehicles also being possible. These would all offer much

the same benefit of storage, i.e. to reduce wind curtailment. However, no cost comparison is conducted here. It is shown here that having less connection to other systems would make storage more favourable - similarly it would be expected that additional interconnection would reduce the benefits of storage. There is also no extensive work done on how these different technologies would work with each other - i.e. whether demand response as discussed in Sioshansi and Short (2009) would work better or worse in conjunction with storage, or examining the benefits that different technologies can bring as in Mathiesen and Lund (2009). It would be expected that these technologies would compete to offer the same basic advantage to power systems which is their flexibility and ability to reduce curtailment. As gas is generally the unit on the margin in the system studied here, higher gas prices, while having some impact, would not be expected to significantly affect results. The marginal cost difference between OCGTs and CCGTs would increase, as would the difference between wind when on the margin and gas. This would increase the benefits brought by storage, but as shown with carbon price increases in Fig. 3, the gas price increase would need to be very high to cause a large change in the trend seen. Curtailment, which is seen as the main driving factor in when storage is worth building, would remain the same at high gas prices

As systems do start to reach the penetration levels studied here, other aspects of system operation, such as frequency and voltage stability, may become significant enough to hinder the growth of wind penetration. However, it should also be taken into account that this work was carried out for a specific system, and the levels at which storage start to make a positive impact might be different for those with different plant mix. There is also no examination here for the profitability of the storage unit - this would be influenced by other aspects such as market structure, plant mix and transmission infrastructure. The benefits storage provides versus conventional plant in terms of ancillary services (due to shorter start up time), are also not examined here, as this model is limited to hourly operation. This work has also shown the benefit of improving the forecasting performance for wind energy (Figs. 2 and 3). If better performing forecasting can be obtained, then the need for flexible type plant such as storage can be reduced.

While these results are for the Irish system with 6 GW of wind, some general results can be taken with regard to applicability to other systems. Firstly, it can be seen that storage increases its value to systems when curtailment becomes significant. The level of curtailment will depend on the wind variability and the operation of baseload plant on the system; if there is a large portion of baseloaded plant on the system which cannot be turned off easily, curtailment may be higher than that shown here and therefore storage may become valuable at a lower level. Likewise, systems with higher wind variability may mean more times when wind exceeds demand and therefore curtailment increases. The market design may also influence the value of storage; here operation of a system similar to the current Irish market is assumed, meaning that the usage of flexibility from all flexible sources is optimized to reduce system costs over a daily period; in reality, certain market features such as long term bilateral contracts

on interconnection may limit the flexibility available and therefore storage may be undervalued in this work. Therefore, when applying these results to real world systems, the key parameters may be examined in the sensitivities would appear to be the underlying plant mix, the variability of wind and the usage and valuation of flexibility in operations and markets.

Additionally, real world markets would likely not be operated using stochastic techniques. Therefore, the results shown here, while more realistic than those which are seen using an assumption that wind can be perfectly forecast, are different than those which would transpire in real markets; real markets may operate storage differently. Storage is operated here to reduce total expected operating costs, and therefore real world markets may not operate this resource in the exact same way; however a market operating to reduce societal costs should produce results very similar. Real world markets would introduce inefficiencies in terms of dealing with forecast uncertainties, which storage would be useful to mitigate. . It has been shown in Tuohy et al. (2009) that stochastic optimization results in reduced operating costs compared to deterministic methods; it is not clear how real markets would use stochastic techniques to take advantage of this.

5. Conclusions

This paper examines pumped storage in a system with high wind penetration. It is seen that the major advantage offered by storage is a reduction in wind curtailment at times of high wind. However, due to the high capital costs and inefficiencies of pumped storage, storage does not justify itself from a systems economics basis until greater than approximately 48% to 51% of energy is obtained from wind on the test system, which is a possible plant mix for the Irish system in 2020. It can be seen that replacing OCGTs instead of CCGTs gives more of a cost savings, which justifies increased additional costs for pumped storage - however, as OCGTs are cheaper per MW to build than CCGTs, this additional cost justified is not very significant. It is shown that accounting for the uncertainty of wind when modelling the unit commitment and dispatch of the power system is important in terms of capturing the benefit of the flexibility offered by storage - if wind could be perfectly forecast, storage would likely not justify its additional capital costs at the levels studied here. This points to the importance of including forecast uncertainty when evaluating pumped storage, as the actual curtailment seen will be far higher than that assumed in models which assume perfect foresight. At the same time, other longer term factors such as fuel price, carbon price and the capital costs of equipment will also influence results significantly. However, while these effects are real world effects, what was shown here is that modeling assumptions can also be important in evaluating pumped storage.

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