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Assessing the Economic Benefits of Compressed Air Energy Storage for Mitigating Wind Curtailment

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***Abstract*—Renewable energy generation in the All-Island of Ireland (AII) is set to increase by 2020 due to binding renewable energy targets. To achieve these targets, there will be periods of time when 75% of electricity will be generated mainly from onshore wind. Currently, the AII system can accommodate a 50% maximum permissible instantaneous level of wind generation. The system operators must make system-wide wind curtailment decisions to ensure that this level is not breached. Subsequently, the ability to limit wind curtailment using large-scale energy storage such as pumped hydroelectric energy storage and compressed air energy storage (CAES) is increasingly being scrutinized as a viable option. Thus, the aims of this paper are to estimate the level of wind curtailment on the 2020 AII system for various scenarios including with and without CAES, and assess and quantify the revenue loss due to wind curtailment using power systems simulation software PLEXOS.**

***Index Terms*—Compressed air energy storage (CAES), energy markets, PLEXOS, power system economics, power system modeling, power system operation, revenue, total generation costs, wind curtailment, wind power.**

NOMENCLATURE

AII	All-Island of Ireland.
CAES	Compressed air energy storage.
MSQ	Market schedule quantities.
RES	Renewable energy sources.
SMP	System marginal prices.
SNSP	System nonsynchronous penetration.

I. INTRODUCTION

THE TRANSITION to RES, namely wind and solar, has progressed rapidly as countries strive to meet binding renewable energy targets. In 2012, wind power provided 2.5% of global electricity demand and up to 30% in Denmark, 20% in Portugal, and 14.5% in Ireland [1]. This higher provision in European countries is driven by the European Commission's framework that put in place in 2009, built around 2020 targets for renewable energy (20%), greenhouse gas emission reduction (20%), and energy efficiency (20%) [2].

In particular, the governments of the Republic of Ireland (ROI) and Northern Ireland (NI) have set an ambitious target that requires 40% of electricity to come from RES, predominately wind, by 2020 [3]. The current and proposed 2020 level of installed wind capacity across the AII[1] is, and will continue to be, one of the highest global levels relative to the size of the system [4]. The transmission system operators (TSOs) Eirgrid and SONI are seeking to operate between 5000 and 6000 MW of wind capacity across the AII by 2020 [5]. This represents circa 37%–41% of the total generation capacity in 2020.

The increasing amount of wind capacity due for connection introduces a new challenge for the TSOs in maintaining the stability of the system. Currently, the AII system can accommodate a 50% maximum permissible instantaneous level of nonsynchronous generation such as wind. As a consequence, the TSOs must make system-wide curtailment decisions, particularly in the case of wind generation to ensure that this level is not breached.

Since 2003, curtailment has been highlighted by the Irish wind energy sector as a potential limiting factor to the long-term growth of wind farm development in Ireland. In the meantime, policy makers have taken limited action to effectively address this issue and enact mitigating measures. In 2011, curtailment levels for all wind farms across the AII averaged 2% with some wind farms experiencing no curtailment while others had levels of 7%–8% [6]. It should be noted, however, that during this year, outages on the Moyle interconnector (MI) between NI and Scotland and the only pumped storage plant in the AII resulted in higher levels of curtailment than would otherwise have been expected [7].

More recently, the Single Electricity Market (SEM) Committee for the AII has been considering matters associated with curtailment in tie-break situations. The committee decided that operational wind farms (both firm and nonfirm) will be turned down on an equal basis in a curtailment situation from March 1, 2013. Furthermore, compensation payments for curtailment will cease on the January 1, 2018, and the TSOs and SEM operator will be responsible for implementing this through the relevant grid code and market structure, respectively [8].

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[1]The ROI and NI are two separate jurisdictions with a common synchronous power system known as the All-Island of Ireland (AII).

Subsequently, the decision to remove compensation for curtailment by 2018 will be of major concern to investors in the wind energy sector. It is, therefore, essential that ongoing work including: Eirgrid's DS3 and Grid 25 programs are delivered on time in order to minimize the occurrences of curtailment. These programs involve developing financial incentives for enhanced plant performance, operational policies, system tools, and additional grid infrastructure development.

Large-scale energy storage such as pumped hydroelectric energy storage (PHES) and CAES also allows curtailed wind energy to be stored until it is required [9]. Currently, only one 292 MW PHES plant exists in the AII and has been operational since 1974. However, despite PHES being considered a mature technology, further development in the AII has ceased mainly due to the lack of suitable sites, high initial capital costs, and environmental impact concerns.

Apart from PHES, CAES is the only commercial large-scale storage technology to have been deployed at utility scale, and a number of research projects have analyzed CAES as a solution to improving wind integration and reducing wind curtailment [10]–[12]. An appraisal of the geological conditions and the potential of underground gas storage and CAES deployment were undertaken in Larne, NI [13]. Results indicated that Larne is the only place in NI and one of the few places in the AII, which has salt deposits potentially suitable for CAES [13], [14]. Hence, the potential exists for a 268-MW CAES plant to be connected to the AII system [14].

In summary, CAES can reduce wind curtailment and improve the long-term growth of wind farm development in the AII. Thus, the aims of the paper are 1) to estimate the level of wind curtailment on the 2020 AII system for various scenarios including with and without CAES and 2) to assess and quantify the revenue loss to wind generation due to the termination of wind curtailment compensation.

II. Compressed Air Energy Storage

A. Overview of Technology

CAES is a hybrid form of storage and is a modification of the conventional gas turbine (GT) technology. A CAES plant consists of a power train motor used to drive a compressor to compress air into a reservoir, a high- and low-pressure turbine, and a generator. The reservoir is either an aboveground vessel/pipe or an underground geologic formation such as salt, rock, and saline aquifers.

A CAES plant operates similarly to a conventional GT with the compression and expansion stages occurring independently or concurrently depending on the plant type. During the compression stage, excess electricity or off peak low cost electricity is used to run a chain of compressors which injects air into the reservoir.

During the expansion stage, when electricity is required, pressurized air is released from the reservoir and used to run a turbine which produces electricity. In order to improve the power output of the turbine, natural gas is used in the combustion cycle. This allows electricity to be generated using only 33% of the natural gas required to generate the same amount of electricity as a conventional GT [15].

CAES plant designs are categorized based on the method of managing heat from compression and expansion of the air. These categories are diabatic, adiabatic, and isothermal. In diabatic CAES (often referred to as "conventional" or "first generation" CAES), the heat of compression is removed and dissipated during compression and the air is reheated during expansion [16]. Second-generation CAES is similar to first generation except a modified design that leads to improved compression and/or expansion stages using air injection techniques to increase efficiency.

In adiabatic CAES (referred to as "third-generation" CAES), the heat of compression is stored in a solid or fluid and returned to the air during expansion [16]. Therefore, no natural gas is required to heat the compressed air in the combustion chamber. Similarly, in an advanced adiabatic (AA) CAES plant, the waste heat is captured and rereleased into the compressed air, so that no gas co-combustion to heat the compressed air is required. The key benefits of adiabatic and AA CAES are higher efficiencies and reduced carbon emissions as there is no fuel consumption required during generation.

In Isothermal CAES, the compression and expansion stages are conducted in a slow manner to ensure that the air is maintained at an approximate constant temperature through heat exchanges with the environment [16]. The theoretical efficiency of isothermal CAES approaches 100% for perfect heat transfer to the environment. However, in practice, perfect thermodynamic cycles are not obtainable as some heat loss occurs. In conclusion, both AA and isothermal CAES are still at the research and development stage and it could be sometime before large-scale deployment occurs.

B. Review of Developments

CAES is more than 40 years old, dating from the 1970s when it was first deployed as a means of providing energy during peak demand and bridging supply shortfalls from slow ramping base load plants [17]. At present, there are two first-generation diabatic CAES plants in operation, one in Huntorf, Germany where a 290-MW plant was constructed in 1978 and another in Alabama, USA where a 110-MW plant was constructed in 1991 [10]. They were mainly built for their black start capabilities and peak shaving services.

Some pilot CAES plants have been built in Japan and Italy (25 MW) and are proposed for Israel and Russia. In the United States (U.S.), construction of a diabatic 317-MW CAES plant near Tennessee Colony, Texas is due to commence in Spring 2015 [18]. Moreover, it will be the first CAES plant to be built in the U.S. since the plant in Alabama.

In Europe, the idea of developing CAES is obtaining momentum due to the deployment of intermittent wind and solar power plants. In particular, the TSOs in the ROI and NI are in discussion with an energy company about the connection of the proposed 268 MW CAES plant in the Larne area, NI [19]. This plant has been listed as a one of the projects of community interest within the European Union and is envisaged to be listed as critical infrastructure under the SEM [20].

The European Commission has supported the first AA CAES plant due for construction in Germany by 2016, entitled the "ADELE" project [21]. The aim of this project is to further advance the necessary components for this technology and to develop the basic concept for the first AA CAES plant.

The world's first 1.5 MW Isothermal CAES plant is located at SustainX headquarters in Seabrook, New Hampshire, USA [22]. The process involves capturing the heat produced during compression, trapping it in water, and storing the warmed air–water mixture in pipes. When electricity is required by the grid, the isothermal expansion delivers electricity with no requirement for natural gas combustion.

III. Methodology

A. Modeling Software

The main proprietary modeling software used in different countries for power systems modeling include EMCAS, PLEXOS, EnergyPLAN, WASP IV, and WILMAR [23]. The most common modeling software used for AII system modeling are WILMAR and PLEXOS. The WILMAR planning tool was first issued in 2006 and was originally used to study wind variability in the Nord pool system. It was then modified to analyze the Irish system as part of the All-Island Grid Study [24].

PLEXOS is an integrated energy software tool developed by Energy Exemplar and is used for power and gas market modeling worldwide [25]. Since 2007, PLEXOS has been used in Ireland by the TSOs, Commission for Energy Regulation (CER), and SEM participants to validate and forecast SEM outcomes [26], [27]. Moreover, it is considered by academia as a well-proved tool for policy analysis and development in the AII [11], [28]–[31]. Therefore, PLEXOS version 6.208 R04 was used to build and run the models for the analysis presented in this paper.

B. Base Model Verification and Validation

The CER provides publically accessible calibrated backcast and validated forecast PLEXOS models annually [27]. The CER uses these models to monitor gaming by simulating the SMP and market outcomes in the SEM.

In this study, the CER 2010 backcast model is used to replicate the actual ex-post SMP and MSQ observed in the SEM. The PLEXOS modeling configuration, which provided the best replication of the ex-post data across the simulation horizon, was then used to inform any recommendations for the 2011–2012 validated forecast model.

The CER 2010 backcast model was run for 365 days at 30 min intraday trading periods. The technical and commercial characteristics for each generator participating in the SEM were defined by submitted technical and commercial offer data [27]. This consists mainly of no load costs, start costs and start cost times, actual availabilities, min up/down times, and minimum stable level (MSL). This represented the exact data submitted by the generators to the SEM operator, which was verified by the CER.

A comparative validation analysis was conducted between the backcast model outputs and the actual market outputs. The mean absolute percentage errors (MAPE) were 6.1% and 7.7% for average daily SMP and annual MSQ, respectively. The backcast model produces a profile for the average daily SMP, which is consistent with the actual market. It was noticeable that there were regular price spikes and dips for the on-peak and off-peak hours, respectively. Also, it generally produces higher off-peak SMP than the actual market, whereas on-peak prices are lower than observed in the actual market.

The discrepancies between the SMP and the MSQs can be attributed to PLEXOS's tendency to over-schedule generators, which reduces the shadow price but increases the uplift by a similar amount. The shadow price makes up most of the SMP and relates to the incremental short run marginal cost bids from generators comprising of fuel and carbon costs. The uplift component covers the generator's start-up and no-load costs. Therefore, there are some instances where higher uplift was caused by the cost recovery method in PLEXOS for generators that only ever ran at MSL during the year. This effect was also observed in previous validation studies, and it is recommended that MSL and ramp rate uplift filters be kept on [27] and [32].

C. 2020 Model Description

The CER-validated forecast model of 2011–2012 was used as a starting point from which the 2020 model for this analysis was developed. The 2020 model was populated with the individual generator techno-economic parameters for new entrants and retirements, which have signed agreements and confirmed dates to connect to the AII system over the next 10 years [5]. Similarly, the system demand and wind capacity for 2020 were obtained from Eirgrid and SONI [5]. A simplified Great Britain (GB) system and interconnections to the ROI and NI were created in the model as per the validated forecast model [27].

A main constraint restricting the amount of nonsynchronous generation, mainly wind, on the AII system is enforced in the model. This is known as the SNSP limit and is a measure of the nonsynchronous generation on the AII system at an instant in time as shown by (1) [33]. Based on extensive research by the TSOs on high wind penetration levels, an SNSP limit was identified as an all-encompassing indicator for the operational ranges allowing secure operation of the AII system [33]

$$\frac{\text{Wind generation} + \text{imports}}{\text{System demand} + \text{exports}} \leq \text{SNSP} \tag{1}$$

where the SNSP limit ensures that the amount of wind generation, when added to interconnector imports, does not exceed the sum of system demand and interconnector exports. The system demand includes the pump storage and CAES consumption when in pumping mode.

The PLEXOS simulation engine reads the input data such as system demand and wind data as shown in Fig. 1. It simulates 366 individual daily optimizations at half-hourly intervals ensuring that the generation portfolio meets demand at least cost while taking into account the generator's techno-economic parameters. Generator and system-wide constraints are also enforced for each simulation period. Similar to the SEM, the

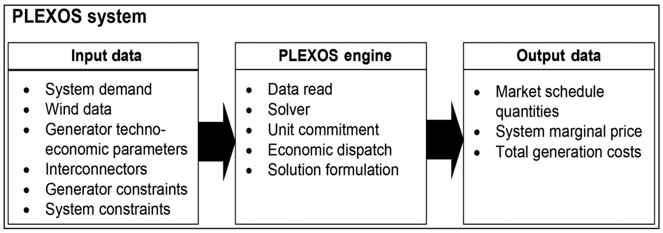

Fig. 1. PLEXOS system modeling structure.

TABLE I
SCENARIO DEFINITIONS

Scenarios	SNSP (%)	Wind capacity (MW)
BAU	50	3600
EOC	75	5211
BAU+CAES	50	3600
EOC+CAES	75	5211

TABLE II
GENERATION CAPACITY PORTFOLIO

Generator type	Installed capacity (MW)
Coal	1235
Gas	5550
Oil	241
Distillate oil	694
Peat	346
Hydropower	216
Pumped hydro storage	292
Onshore wind	3575[2]/5186[3]
Offshore wind	25
Waste to energy	89
Wave	93
East–west interconnector	500
Moyle interconnector	450
Total	13 306[2]/14 917[3]

[2]BAU and BAU+CAES scenarios.
[3]EOC and EOC+CAES scenarios.

solver calculates SMP and MSQ for each period; therefore, providing an accurate representation of the dispatch of generators in the AII system.

D. Model Scenarios

Table I shows the scenarios simulated in this analysis. Two main operational scenarios: 1) business as usual (BAU) and 2) enhanced operational capability (EOC) have been considered with the remaining two scenarios containing a CAES plant as an additional generator.

A description of each scenario is as follows.

1) BAU represents the current operational network constraints with a 50% SNSP limit and an installed wind capacity of 3600 MW. The interconnector flows are set as a fixed input based on the outputs from a market unconstrained model run for this analysis. This approach replicates the current SEM rules, whereby interconnector nominations are determined by the ex-ante market dispatch schedule. Operating reserve requirements are assigned to each generator based on current operational policy. Hence, this scenario is considered to represent a realistic real time operation of the system.
2) EOC is the BAU scenario with a 75% SNSP limit instead of 50% and an installed wind capacity of 5211 MW was assumed to achieve the required 37% of electricity from wind by 2020. It represents the possible operational network constraints if enhanced system services are implemented by 2020.
3) BAU + CAES is the BAU scenario with a CAES plant included in the AII generation portfolio. The CAES plant only contributes to energy requirements in this scenario.
4) EOC + CAES is the EOC scenario with a CAES plant included in the AII generation portfolio. In this scenario, the CAES plant contributes to energy and operating reserve requirements, which are explained in more detailed in Sections III-E and III-F.

E. Main Model Assumptions

The AII system demand is expected to increase 12% between 2011 and 2020 based on the median demand forecast by Eirgrid [5]. The median demand forecast is considered to reflect the latest projections for the AII based on the future economic climate and has been used for several AII case studies. The annual system median demand is estimated to be 41.2 TWh with a peak demand of 7.3 GW. Accordingly, the 2011 demand time series profile is linearly scaled to reflect the 2020 median demand forecast.

A breakdown of the generator types used for the scenarios simulated in this analysis is shown in Table II.

Onshore wind capacity varies for each scenario and it is assumed that no more offshore wind will be developed in the AII prior to 2020. It is assumed that only 25 MW of installed offshore wind capacity exists from a single wind farm at Arklow Bank, Co., Wicklow, Ireland.

Wind generation is modeled under the assumption of perfect foresight in aggregated form, split into 13 regions. The capacity for each region is based on the proposed regional distribution of renewable capacity by Eirgrid [34]. Each region has an associated half-hourly profile, which represents the wind availability in that region in each half hour as a percentage of total installed capacity in that region. These profiles were developed from historical time series data from 2011.

The general approach is to model wind generation with zero short run marginal costs (fuel, carbon, and start costs equal zero) based on the assumption that it will always run when available, due to its priority dispatch status. Similarly, predictable price takers peat, wave, waste, and CHP generators are assigned zero short run marginal cost to ensure that they are dispatched fully when available.

Modeling the GB system is required in order to determine the interconnector flows between SEM and GB. Gas generation has been the predominant marginal plant type on the GB system and a high correlation between the cost of gas generation and the GB electricity price has been determined [27]. A single gas generator of 2000 MW with multiband heat rates, variable operating and maintenance (VOM) costs, and 1100 MW of load was, therefore, used to represent the GB system.

The CER also adopts this simplified GB representation to determine SEM outcomes. GB wind is not modeled and significant data collection is required to create a complete GB system. Moreover, including the complete GB system in each scenario would significantly increase the computational time and so the approach described is applied.

The complete transmission network is not included in the model and localized network constraints are not modeled. Instead, the model consists of system-wide constraints and three separate nodes representing the ROI, NI, and GB systems. It is assumed that adequate transmission capacity as per Eirgrid's Grid 25 program has been built by 2020 to accommodate increased levels of wind capacity on the system.

There is a restricted flow of 450 MW in the NI–ROI and 400 MW ROI–NI directions at present due to system security issues. However, the full rating of the north–south transmission line between NI and ROI is assumed to be in place by 2020; therefore, flows of 1500 MW both ways are set within the model [35].

The MI links NI to Scotland, and flows on the MI are largely driven by arbitrage of the relative prices in the two systems. The MI is limited to exporting 300 MW and importing 450 MW November–March and 410 MW April–October. However, there is uncertainty in relation to the actual maximum import and export capacity of the MI for the foreseeable future due to an undersea cable fault [19]. The east–west (EW) interconnector between the ROI and GB nodes, maximum flow was assumed 500 MW both ways.

The model applies historic transmission loss adjustment factors to all generators to account for the possible losses within the AII system. Planned and unplanned maintenance for each generator during the year is considered. The former is assigned manually based on the 2011 schedule and the latter is modeled as a random event.

The number of high inertia generators required online for system stability is applied as per the 2013 Transmission Constraint Groups (TCGs) requirements [36]. There are also constraints applied on certain groups of generators and maximum export capacities within certain regions. Including these constraints within the model allows for a more realistic real time system operation.

The reserve requirements for 2020 are set based on modified TCGs requirements to take account of the increased amount of wind generation on the AII system. Three categories of operating reserve were modeled: 1) primary operating reserve (POR), 2) secondary operating reserve (SOR), and 3) two classes of tertiary operating reserve (TOR1 and TOR2). It is assumed that the reserve categories will remain unchanged as a result of the TSOs DS3 program to refine the system services products [26].

TABLE III
OPERATING RESERVE REQUIREMENTS

Category	Requirement of largest in-feed (%)	Minimum dynamic requirement (MW)
POR	75	165
SOR	75	165
TOR1	100	165
TOR2	100	165

For each reserve category, there is a total requirement and a minimum dynamic requirement. The total requirement ranges between 75% and 100% of the largest electricity in-feed depending on the reserve category [36]. This was based on an assumed largest in-feed of 500 MW, corresponding to the largest generator on the AII system, which is the EW interconnector. The minimum requirement for each reserve category is fixed at 165 MW. The total requirement as a percentage of the largest in-feed and minimum dynamic requirement is outlined in Table III.

Certain generators are assigned reserve capacities for each reserve category for the provision of dynamic reserve. Static reserve provision of 35 MW of interruptible load is assumed to be provided from the PHES plant during pumping mode for static reserve [37], [38]. The MI and EW interconnectors are assumed to hold 75 and 50 MW of static reserve, respectively.

In summary, this analysis employs a deterministic model using a set of main assumptions based on published data. The analysis assumes perfect foresight for wind generation and system demand with no significant rules changes to the SEM or to the broader market by 2020. The analysis, therefore, applies the current SEM rules and assumes the current bidding principles and methodology for calculating the various cost and revenue streams remain unchanged.

F. Modeling of Storage

A simplified modeling approach for the PHES plant is adopted for the market unconstrained model. PHES is modeled as four separate units similar to hydro units, which are allowed to run from a zero level up to maximum capacity. In the pump mode, the units are also allowed to pump from a zero level up to maximum pump capacity. During the simulations, PHES is forced to refill to a predefined target by the end of each day. This approach was used previously for PHES modeling in the SEM [39].

However, the real-time operation of the PHES plant is rather different. For all scenarios, the PHES has three distinct modes: 1) spin, 2) min, and 3) pump. In spin mode, each unit can provide 5 MW but no more than two units can be in spin mode

TABLE IV
CAES PLANT TECHNICAL OPERATING DETAILS [41]

Parameters	Value	Units
Maximum compression	200	MW
Minimum compression	60	MW
Ramp rate for compression	40	MW/min
Maximum generation	270	MW
Minimum generation	67.5	MW
Ramp rate for generation	54	MW/min
CAES heat rate	4.265	GJ/MWh
CAES storage capacity	3	GWh
Compressing efficiency	80	%
Part load energy ratio (kWh_{in}/kWh_{out})	0.83	

at any one time with the remaining two units providing a minimum generation level of 35 MW. In min mode, each unit can provide between 40 and 73 MW, which contributes to both POR and SOR. The PHES units share a common penstock; therefore, a constraint to prevent concurrent generation and pumping is set within the model. In the final mode, pump mode, the PHES four fixed speed pump units can each draw a load of 71.5 MW from the AII grid and can provide full capacity for POR. Again, these three operational modes were adopted previously for real-time PHES modeling in the AII system [30].

A CAES plant is represented within the model by a PHES plant coupled with a GT plant using constraints to replicate the operation of the CAES plant. In compression mode, the PHES plant draws power from the grid to compress air; whereas, in generation mode, both the PHES plant and GT generate power. A constraint limiting the combined output of the PHES plant and GT plant is set based on the maximum generation capacity of the CAES plant. This approximation of the CAES plant configuration was used previously for other case studies [11], [40]. The details of the CAES plant used for this analysis are shown in Table IV and are assumed to represent the plant, which will be connected to the AII power system in 2020.

At present, it is unclear which reserve categories the CAES plant will contribute toward for the AII system. Therefore, the CAES plant's reserve capabilities are based around the contributions in which the existing open-cycle GTs and PHES provide for generation and pumping in the AII system, respectively. The contribution of the CAES plant to generation and pumping reserve capabilities is assumed as 30 and 100 MW for each reserve category (POR, SOR, TOR1, and TOR2), respectively.

G. Cost Data

Fuel prices are based on predictions for 2020 from two main sources [42], [43]. A carbon tax of €30/t CO_2 based on the European Union emissions trading scheme was applied to fossil fuel burning generators. This was a realistic figure based on the carbon taxes used for previous AII case studies, which ranged between €15/t and €45/t CO_2 [28], [42], [44]–[46]. Generator VOM costs were obtained from several sources [45]–[47] and start costs were derived from historic start costs [27]. Cost data for the CAES plant were based on Thorner *et al.* [41]. All cost data were normalized to 2012 values using consumer price indices [48].

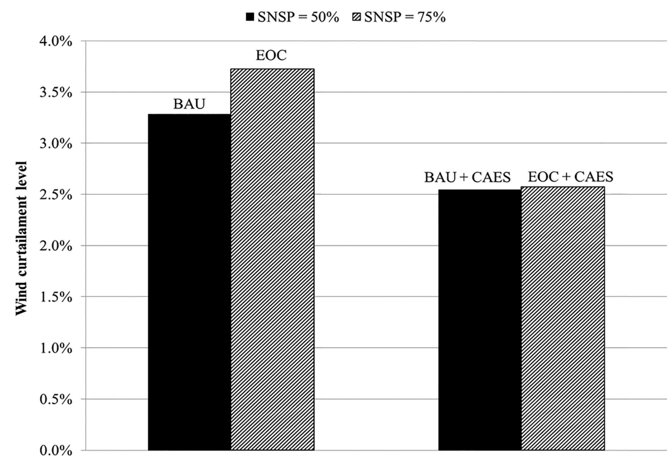

Fig. 2. System wide wind curtailment levels.

IV. RESULTS AND DISCUSSION

A. System-Wide Wind Curtailment

The main result from this analysis is an estimate of the system-wide wind curtailment levels in the 2020 AII system for various scenarios including with and without CAES. The current AII system can accommodate a maximum SNSP limit of 50%; however, if mitigation measures are introduced, an operational limit of 75% SNSP is possible. The impact that this increase has on the system for different scenarios is shown in Fig. 2.

The wind curtailment levels are reduced due to the addition of the CAES plant in the BAU + CAES and EOC + CAES. The difference between the EOC and the EOC + CAES wind curtailment levels are 1.2%. For instance, when a curtailment event occurs in the EOC + CAES scenario, for each 100 MW of increased demand created by the CAES plant in compression mode, it allows 75 MW of wind to remain connected and increases the synchronous generation by 25 MW to satisfy the SNSP limit. Similarly, for the BAU + CAES scenario, CAES allows 50 MW of wind to remain connected to the AII system.

B. Economic Assessment

A comparison of the wind generation revenue loss as a result of wind curtailment is presented in Table V. The pool revenue (product of price received in €/MWh and generation in MWh) is the revenue collected by each generator in the SEM. Therefore, the revenue loss is a product of average annual price received and the amount of wind curtailed for each scenario.

The revenue loss decreases substantially as a result of increasing the SNSP limit to 75%. The addition of the CAES plant further decreases the revenue loss and in turn increases the revenue for wind generation by €10 million for the EOC + CAES scenario. Wind curtailment levels above 5% have been suggested to have significant economic risk for the long-term growth of wind farm development in Ireland [35]. Moreover, compensation payments for wind curtailment will cease on the January 1, 2018. Therefore, the results suggest that increasing

TABLE V
REVENUE LOSS COMPARISON

Scenario	SNSP (%)	Wind curtailment level (%)	Revenue loss (€ million)
BAU	50	3.3	22
BAU+CAES	50	2.5	17
EOC	75	3.7	35
EOC+CAES	75	2.6	25

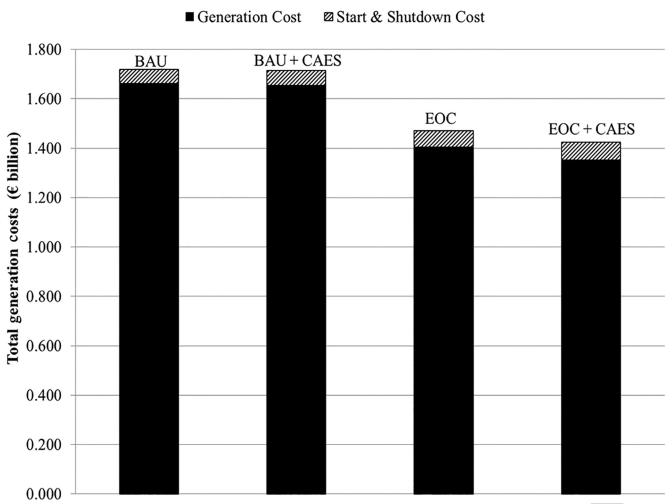

Fig. 3. Total generation costs for each scenario.

the SNSP limit to 75% and utilizing a CAES plant mitigates wind curtailment and reduces the economic risk.

Furthermore, due to the addition of the CAES plant, the pool revenues for most of the other generator types increased. This is mainly due to an increase in the average annual SMP from €65/MWh to €68.5/MWh for the EOC and EOC + CAES scenarios, respectively. This is beneficial for some of the generators as they are paid a higher price from the pool but this has a knock-on effect to the electricity consumer.

The overall economic benefit of moving from 50% to 75% SNSP limit and the inclusion of the CAES plant can be quantified by comparing the total generation costs for the AII system. Fig. 3 presents the total generation costs (including VOM cost, fuel cost, start and shutdown costs, and emissions costs) for each scenario over the year 2020.

The higher SNSP limit and the inclusion of the CAES plant leads to lower total annual generation costs. The CAES plant's benefit to the system results in a reduction in costs of 3.3% compared to the EOC scenario. This equates to €50 million over the year 2020. This reduction cannot be attributed to a single event but occurs as minor cumulative changes over the year. From a technical perspective, this reduction is due to the CAES plant's ability to provide additional flexibility to the AII system.

Moreover, based on a capital cost of €0.6 million/MW for the CAES plant and annual savings of €50 million, the payback period is less than 4 years for the AII system. However, the payback period would differ for a private investor and a detailed cost-benefit analysis would determine whether it is a viable technology.

V. CONCLUSION

The economic benefits of CAES to wind generation were evaluated using the power systems and market modeling software PLEXOS. Based on the modeling conducted, it was determined that a 270-MW CAES plant in conjunction with a 75% SNSP limit can reduce wind curtailment levels to 2.6% in 2020.

It was also shown that the addition of CAES increases the revenue for wind generation by €10 million for the EOC + CAES scenario. This is beneficial to the wind farm developers, as it reduces their economic risk and encourages development. Furthermore, CAES can contribute to the AII system other than avoidance of wind curtailment. For instance, it can reduce total annual generation costs by 3.3% relative to the proposed 2020 EOC scenario. These benefits are external to a private financial assessment of a CAES project but should be considered in an overall cost-benefit analysis.

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