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Cost savings from relaxation of operational constraints on a power system with high wind penetration

Edward. V. Mc Garrigle, and Paul. G. Leahy, *Member, IEEE*

***Abstract*—Wind energy is predominantly a non-synchronous generation source. Large-scale integration of wind generation with existing electricity systems therefore presents challenges in maintaining system frequency stability and local voltage stability. Transmission system operators have implemented system operational constraints (SOCs) in order to maintain stability with high wind generation, but imposition of these constraints results in higher operating costs. A mixed integer programming tool was used to simulate generator dispatch in order to assess the impact of various SOCs on generation costs. Interleaved day-ahead scheduling and real-time dispatch models were developed to allow accurate representation of forced outages and wind forecast errors, and were applied to the proposed Irish power system of 2020 with a wind penetration of 32%. Savings of at least 7.8% in generation costs and reductions in wind curtailment of 50% were identified when the most influential SOCs were relaxed. The results also illustrate the need to relax local SOCs together with the system-wide non-synchronous penetration limit SOC, as savings from increasing the non-synchronous limit beyond 70% were restricted without relaxation of local SOCs. The methodology and results allow for quantification of the costs of SOCs, allowing the optimal upgrade path for generation and transmission infrastructure to be determined.**

***Index Terms*—System operational constraints, Wind energy, Non-synchronous generation, Wind curtailment, Unit commitment, Ireland.**

I. Introduction

THE link between global warming and man-made emissions is becoming more evident with time [1]. The dependence of EU member states on imported energy in the form of fossil fuels has given rise to EU policies to reduce the overall carbon intensity of energy usage, such as [2]. As part of this policy, the Republic of Ireland (ROI) and Northern Ireland (NI) have agreed to generate 40% of their electricity demand from renewable sources by 2020 [3], [4]. The generator technology type that will be used to deliver the majority of this target will be wind power [5]. This will result in a very large proportion, in the region of 30-37%, of all-island of Ireland (AI)[1] electricity coming from non-synchronous sources by 2020. There is no precedent for a system of this size to have such a level of non-synchronous generation without AC links to neighbouring systems. This has led to a situation where the ROI and NI transmission system operators (TSOs), EirGrid and SONI respectively, have implemented system operational constraints (SOCs) [6] in order to maintain acceptable levels of system stability.

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[1]All-island of Ireland (AI), consisting of Northern Ireland (United Kingdom) and the Republic of Ireland

A. System operational constraints (SOCs)

The effects of large penetrations of wind energy in electricity systems have been extensively studied in recent years [7], [8], [9], [10], [11], [12], [13], [14], [15]. As wind energy penetration begins to reach the technical limits of what is possible on present-day electricity systems it is becoming evident that more research is needed in relation to allowing higher levels of non-synchronous sources of electricity on to the system. This is necessary as AC systems require some amount of conventional synchronous generation on-line at all times in order to maintain overall frequency stability as well as local voltage stability.

It is shown in [14], [16] that issues such as frequency response and voltage control result in the requirement for incorporating SOCs [6] in dispatch modelling. The system frequency must be maintained within certain limits in the event of a loss of generation. This is achieved by maintaining synchronous generation machines online to provide inertia to the system. The majority of wind turbines, being non-synchronous double-fed induction machines (DFIGs) or full-converter machines, are not capable of providing inertia to the system [17]. Voltage control is important as it affects the efficiency of the transportation of the electricity. Voltage stability is maintained by the balancing of reactive power, mainly through the use of synchronous generation sources however reactive power cannot be transported over long distances and requires to be produced or consumed at nodes where voltages begin move outside their tolerances [14]. These problems lead directly to the need to maintain minimum numbers of conventional generators on-line in different urban parts of the AI system as well as system-wide limits on the relative proportion of non-synchronous sources of generation at any point in time as stated in [6], [18]. Devices such as STATCOMs and flywheels which would have the potential to allow for the relaxation of these constraints already existed [19]. It has been predicted that the permitted limit of system non-synchronous penetration (SNSP) on the AI system (Eqn. 1) will be raised to a value between 60-80% by 2020, with recommendations that a SNSP limit of 75% could be technically achieved [14].

$$\text{SNSP} = \frac{wind\ generation + HVDC\ imports}{system\ demand + HVDC\ exports} \quad (1)$$

where: SNSP is the system non-synchronous penetration, the instantaneous percentage of non-synchronous generation on the system; and HVDC refers to flows on high voltage direct current interconnectors.

It is viewed by EirGrid that as wind penetration increases, and if the network and market designs are not changed, that problems such as escalating constraints payments due to divergences between the unconstrained market model and the constrained dispatch model will emerge [20]. Relaxations of the SOCs are planned for the future and the effects of these on system operations are being investigated by EirGrid and SONI in the DS3 work program [21]. Previous studies have included SOCs in the form of a minimum conventional generation requirement [7], [8], [11], [12], [15] and studies that have not included these constraints have recognised their potential impacts on results [9], [10], [13], [22], [23], [24]. So far, the only study that has assessed the impact of relaxing these constraints in terms of wind curtailment and costs is [8], which looked at such effects on the NI system. It has also been shown in [15] that SOCs in the AI system will have a dramatic effect in terms of wind curtailment and generator dispatch in the future.

It is shown in [8] that relaxing the NI constraint requiring three large generators to be on-line at all times to two generators on-line results in wind curtailment dropping from 7.5% to the region of 1.5-5% and also indicates possible increases in OCGT generation. In [11] it was assumed that a minimum of 400MW of conventional generation is presently required on the Western Denmark system, but by 2025 it was assumed that 300MW would be sufficient due to stronger interconnection with neighbouring regions. This assumption was taken from [12] where the year 2008 was examined to find the lowest instantaneous level of conventional generation during periods of excess wind energy generation, which resulted to be 415MW. This was then assumed as a minimum technical feasible state of system operation. However, in 2012 wind generation in Western Denmark has been allowed to exceed demand through the use of interconnectors to export surplus generation [13]. The AI system has only two high voltage direct current (HVDC) interconnectors to the neighbouring Great Britain (GB) system with a combined capacity of approximately 950MW. This results in a situation where there is no reactive power or inertia support from neighbouring electricity systems [16] however it should be noted that EWIC which utilises voltage source converter (VSC) technology is capable of providing reactive power support through the use of power electronics [14]. Therefore care should be taken when comparing the SOCs assumptions of AI [6] to those of Western Denmark [12] due to the latter system's use of synchronous compensators as well as its strong AC interconnection to its neighbours, thus providing stability support.

A minimum number of large base load generators were required to be on-line at all times in the AI model of [7] in order to maintain sufficient inertia and reactive power. For NI, an examination of the effects of variable generation on conventional generators is shown in [23] and there is also a recommendation made for further research into the effects of the requirement for three large generators to be on-line at all times. While a "minimum on" constraint was not included in [22], [24], it is stated in [24] that such constraints would increase wind curtailment. In [22] the exact minimum required number of on-line generators was not obvious and therefore was neglected but recognised that its inclusion would increase wind curtailment. In studies of the GB system it is recognised that a minimum amount of conventional plant running at all times will be necessary to provide frequency response and also due to inflexible must-run units such as the nuclear plants which will result in wind curtailment [9]. The modelling of the AI Single Electricity Market (SEM) includes a "minimum on" inertia constraint [25], however such a constraint on the GB system is not included in the same study.

In a Europe-wide context it is recognised in [10] that wind curtailment may become necessary in central and northern Europe when a minimum number of on-line conventional generators is reached during high wind and low demand periods, in order to provide adequate response and reserve on the system. A review of several countries carried out by [13] recommended that further research be performed into issues associated with wind curtailment and states that wind curtailment resulting from the minimum stable generation limits of conventional generators will be a issue in the future as inertia requirements and frequency response of systems may suffer as wind penetrations increase.

II. The Model

A. System operational constraints relaxation scenarios

The objective of this scenario selection was to illustrate the effects of the relaxation of the five most influential SOCs listed in [6] which are shown in Table I in descending order of influence. The reader is referred to [6] for detailed descriptions of the individual SOCs. The five most influential SOCs were determined by quantifying the time each SOC spent in a binding position in the simulation of the base case model. The degrees to which the SOCs were relaxed are shown in Table I. The four SOCs, shown together in Table I, are constraints requiring minimum numbers of certain groups of conventional generators to be on-line at all times. These are "Dublin Generation" and "NI-North West Generation", for voltage control in their respective areas, followed by "NI-System Stability" and "ROI-System Stability" to ensure a sufficient amount of inertia is maintained on their respective systems. In contrast to the SOCs described above is the "Non-Synchronous Generation" constraint, applied for frequency stability reasons. This is a AI system-wide restriction on the percentage of non-synchronous generation, and was progressively relaxed from the base-case value of 60% to 80% [14] in steps of 5%, resulting in five SNSP scenarios.

A base-case scenario was developed from [6] in which likely changes between the present day and 2020 were made to the SOCs. The changes are as follows: for AI constraints

TABLE I
BASE CASE AND RELAXED SYSTEM OPERATIONAL CONSTRAINTS SCENARIOS

Constraint	Code	Base-case	Relaxed
Dublin Generation, min-on	Dub(2/3)	2/3 (day/night)	1/2
NI-NW Generation, min-on	CPS(1)	1	0
NI-System Stability, min-on	NI-s(3)	3	2
ROI-System Stability, min-on	ROI-s(5)	5	4
Non-Synchronous Generation	SNSP	60%	65-80%

the "Inter-Area flow" is assumed to be at 2000MW both ways due to the proposed North-South interconnector being in place [5]; for the NI constraints the "Ballylumford Generation" and "Moyle Interconnector" constraints are ignored due to assumptions that transmission grid restrictions that give rise to these constraints will be mitigated through upgrades by 2020. The ROI "Replacement Reserve" constraint is increased to allow a maximum OCGT generation of 1034MW, this still keeps 300MW in reserve due to new OCGT generation to be added by 2020.

It was first necessary to determine the influences each of the five chosen SOCs have in isolation on the AI system. This was achieved by individually relaxing the four "minimum number of conventional generators on-line" constraints for all five SNSP values, the results of which are shown in Figs. 2 and 3.

The large number of combinations of constraint relaxation scenarios possible with five individual SOCs to be relaxed and five SNSP limits necessitated reducing the number of scenarios examined. Therefore, a SOC relaxation path was identified, based on relaxing the SOC with the highest associated cost saving first, followed by relaxation of the SOC with the second highest associated cost, etc. The path continued to the relaxation of the final constraint where all four "minimum number of conventional generators on-line" SOCs are relaxed. This scenario path was applied for each of the five "SNSP" constraint limits from 60-80% [14] in steps of 5%. For each SNSP scenario the other four SOCs are relaxed in order of influence on system operating costs (Dub(1/2), CPS(0), NI-s(2) and ROI(4)), as shown in Table I. This gives a full set of 20 scenarios showing the combined effects of relaxing the SOCs.

B. Scheduling

To simulate the effects of wind forecast errors and forced outages an interleaved simulation was created where two models run in step with each other. A day-ahead model and a real-time model pass information back and forth to each other and allow for detailed simulation of the real running of the AI electricity system. Both models optimise on a short-term schedule of 366 single-day steps with each day divided into 48 half-hour intervals plus six 1-hour look ahead intervals. This method of simulation replicates the inter-day trading of the Single Electricity Market (SEM) [26]. Due to prior knowledge, the maintenance schedules for the generators are included in the day-ahead run, however the forced outages are not. The same maintenance profile with the addition of forced outage profiles is used in the real-time model.

1) Day Ahead, Real time model interactions: The function of the day-ahead model is the creation of the day-ahead unit commitment schedule and IC generation schedules. The day-ahead model receives a wind forecast with an annual mean absolute error of 6%. Scheduling of the day-ahead model is carried out stochastically to account for the uncertainty in wind forecasts as shown in Fig. 1 and described in detail in [27]. The stochastic scheduling is carried out through the use of five different wind forecasts of varying accuracy with weighted probabilities of occurrence from which an optimum day-ahead schedule is created.

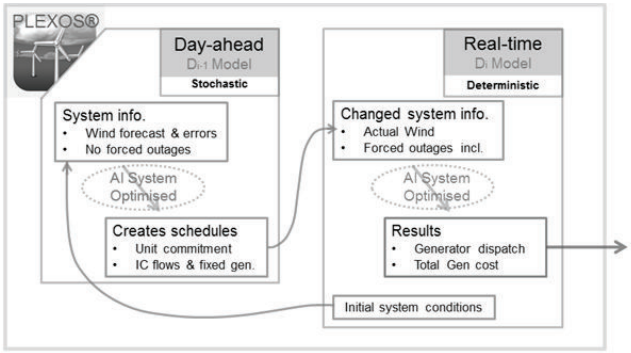


Fig. 1. Flowchart describing the simulation of day-ahead and real-time scheduling and dispatch in PLEXOS®

The day-ahead unit commitment schedule locks all the large generators on the SEM into a constraint that they must be on-line at the times in which the day-ahead unit commitment schedule commits them and are free to be dispatched upwards or downwards within their operational limits during this time. The day-ahead unit commitment schedule is only broken in the event of a unforeseen forced outage occurring. While the day-ahead unit commitment schedule may not be violated when the generators are committed, there is a "post unit commitment relaxation (PUCR)" feature in the real-time model that allows for large generators to be kept on-line or brought on-line outside the day-ahead unit commitment schedule. The model's use of PUCR is restricted as an additional cost of generation is incurred in the form of a start cost penalty and a penalty running cost. These penalty costs just influence PLEXOS® decision making in the scheduling process but are not reported in the results.

The main purpose of incorporating PUCR into the real-time models is that it achieves a more realistic simulation of actual generator dispatch on the SEM. From studying the actual dispatch quantities versus the market schedule quantities of generators on the SEM it is evident that the large generators do not adhere strictly to the day-ahead unit commitment schedule [28]. The OCGT usage is also unrealistically high when the model of the AI system is placed under the constraint of following the day-ahead unit commitment schedule in terms of committing generators both on and off-line as shown in [29]. The dispatch quantities from SEMO report OCGT usage for

2011 at 195.5 GWh and 6.5 GWh for ROI and NI respectively, this in a region with a system demand of 35,700 GWh [5]. Therefore it was assumed that for 2020 OCGT generation would be at 200 GWh for the perfect foresight base scenario. It is assumed that wind forecast inaccuracies affect OCGT usage in 2011 and therefore this is comparable to the base case scenario with perfect wind foresight.

The variable a was used to control the degree of relaxation for the use of the PUCR technique and therefore OCGT usage in the base scenario. The variable is a multiplier for the addition of the cold start penalty cost for each large generator (Eqn. 2) if the generator is started outside day-ahead unit commitment schedule. The variable is used again as a multiplier for an addition of the average running penalty costs of each large generator (Eqn. 3) if the generator is committed outside day-ahead unit commitment schedule. If a is 0 then the RT model is not required to adhere to the DA schedule and if a exceeds 3 there is an almost fixed adherence to the day-ahead unit commitment schedule where OCGT usage exceeds 1100GWh [29]. A value of $a = 0.6$ was determined to result in a realistic level of OCGT generation of 200 GWh in the base case day-ahead perfect foresight scenario, and was then carried across all scenarios unchanged. This approach was used to avoid bias in the rescheduled running of individual large generators over others. The PUCR modifications can be described by:

$$GEN_{PUCR,S,C} = a\,(GEN_{Cold,S,C}) + GEN_{Cold,S,C} \quad (2)$$

$$GEN_{PUCR,R,C} = a\,(GEN_{Avg,R,C}) + GEN_{Avg,R,C} \quad (3)$$

where a = relaxation level variable; $GEN_{PUCR,S,C}$ = PUCR cold start penalty cost; $GEN_{Cold,S,C}$ = cold start cost of the generator; $GEN_{PUCR,R,C}$ = PUCR average run penalty cost; $GEN_{Avg,R,C}$ = average run cost of the generator (fuel cost by average heat rate).

C. AI system

The system demand was modified by means of weighted scaling from 2012 data to reflect the predicted total energy requirement and peak demand for 2020 in [5]. The start costs were taken from averaging the individual daily issued start costs for 2011 for each generator given in [30]. These are also presented in three bands allowing for different start costs to be taken depending on whether the generator is cold, warm or hot. This study used the modelling tool PLEXOS® (Energy Exemplar Pty., Adelaide, Australia) to simulate the mixed integer unit commitment/economic dispatch problem. PLEXOS® version 6.208 (R08) of was run on a Dell Precision T7500 with an Intel® Xeon® CPU of six X5650 cores running at 2.67GHz. The XpressMP solver was used at a relative gap of 0.5 for the day-ahead model and 0.05 for the real-time model with the average model run taking 18 hours.

D. Generation sources modified from present day to provide the 2020 base case

The predicted generation portfolio for the AI electricity system in 2020 is taken from [5] and changes from [31] are outlined in [27].

1) Wind: The AI wind time series are modified from 2011 ROI and NI wind time-series. ROI wind data was taken from [32] and NI wind data was given by SONI on request. Total installed capacity and capacity factors are shown in Table II. The wind generation time series were adjusted by a multiplier to match the long term average capacity factors of each TSO region. It should be noted that the presence of wind curtailment in the 2011 data introduces a slight underestimate of actual wind availability into the scaled 2020 data. This results in a total wind energy availability of 14.2TWh and when accounting for wind curtailment this results in wind accounting for on average approximately 32% of total generation. Wind forecasts are also included in the day-ahead model. An annual wind forecast error of 6% MAE was assumed based on work presented in [27] and the wind forecast time-series were created with an ARMA model as detailed in [27]. An assumption was made that wind curtailment will take place within the jurisdiction of its origin unless it is more economical for the AI system as a whole for it to take place in the other jurisdiction.

2) Tidal: Tidal generation is most likely to be a priority dispatch, non-synchronous source of generation and is assumed here to be curtailable [33]. It is represented by a sine wave of period 12 hours and 25 minutes which is manipulated to obtain the desired capacity factor associated with tidal energy in [5]. This was considered acceptable due to the low penetration of tidal energy on the system however is recognised to be a simplification.

TABLE II
SPECIFICATION OF ADDED AND MODIFIED GENERATION SOURCES

Generation type			
Non-synchronous	**Installed capacity**		**Capacity factor**
ROI Wind	3786 MW		31.7 %
NI Wind	1278 MW		31.4 %
NI Tidal	154 MW		20.0 %
Storage (PHES)	**Operational range**		
Generating	4x(5-71.5) MW		n/a
Pumping	4x(0 or 73) MW		n/a
Non-wind priority	**Installed capacity**		**Target capacity factor**
Peat	345.6 MW		75.0 %
CHP	161 MW		89.5 %
Waste to Energy	94 MW		80.0 %
Biomass	195 MW		80.0 %
Hydro	216 MW		n/a
Interconnection	**Installed capacity**		**Target usage**
	Summer	**Winter**	
AI (export)	910 MW	950 MW	2200 GWh
AI (import)	910 MW	950 MW	1500 GWh
Conventional	**Installed capacity**		
ROI (total)	7024.7 MW		n/a
NI (total)	1965 MW		n/a

3) Non-wind priority dispatch generating units: The modelling of non-wind priority dispatch generators was considered

carefully as these make up on average 14% of generation and have direct effects on OCGT usage and wind curtailment results. Priority dispatch plant shown in Table II are modelled with an almost free, near zero generation cost in order to create a lower priority than wind energy which is modelled with zero cost, in keeping with [34]. It was found that due to SOCs and high levels of wind generation the non-wind priority dispatch generators were not being dispatched at sufficiently high capacity factors, shown in Table II, taken from [34]. Therefore constraints were developed to reflect how these generators are actually dispatched. These constraints are: to commit the plant whenever available; a maximum energy usage per month which imposes a capacity factor; a chosen penalty imposed if the plant is not run at its maximum capacity; and a penalty attached to ramping up and down. The constraints are applied continuously with the exception that the "run at maximum capacity" constraint is lifted during times of wind curtailment as well as the ramp rate charge being removed during the first and last hour of wind curtailment taking place. These four constraints were placed on all of the priority dispatch generators individually. It is noted that the assumption of the priority dispatch plants ability to ramp will have an effect on wind curtailment and total generating costs as the reality is not known.

E. Interconnection and Great Britain

It is assumed that in 2020 interconnector capacity between AI and GB will remain unchanged from the present, with the two HVDC interconnectors [5] shown in Table II. Using GB prices from [35] which were manipulated by scaling the prices' magnitude and volatility, the interconnector flows were adjusted to target annual interconnection flow rates, shown in Table II, reflecting the predicted AI exports and imports for 2020 [36]. The spatial correlation between AI and GB wind energy generation [37] was also taken into account.

III. Results

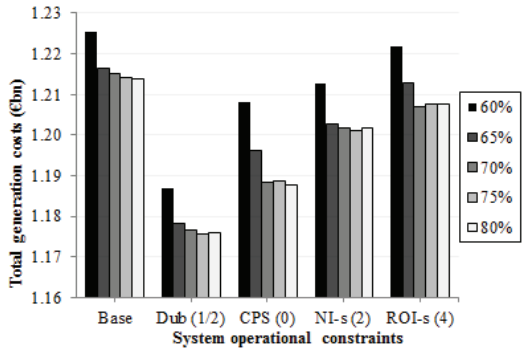


Fig. 2. The AI total generation costs (€m) for AI at different SNSP percentage limits and minimum number of large conventional generator on-line constraints individually relaxed

A. Effects of individual system operational constraints

Simulating the effects of relaxing individual SOCs allows for the SOCs to be ranked in order of influence on costs, which was necessary for ordering scenarios in the combined SOC effects investigation. Fig. 2 shows clearly that, for all SNSP values, relaxing Dub(2/3) is the most influential SOC followed by CPS(1), NI-s(3) and finally ROI-s(5). It is interesting to note however that in terms of reducing wind curtailment, relaxing the SOC CPS(1) is the most beneficial, as shown in Fig. 3.

It should be noted that total generation costs do not include the cost of renewable tariffs. It also should be noted that due to varying usage of interconnectors and the PHES, total generation varies from scenario to scenario. This results in the total generation cost being distorted and therefore it was necessary to scale the total generation costs of all scenarios against the base-case total AI generation in order to maintain consistency across different modelling scenarios. The total generation for all scenarios is shown in Table III.

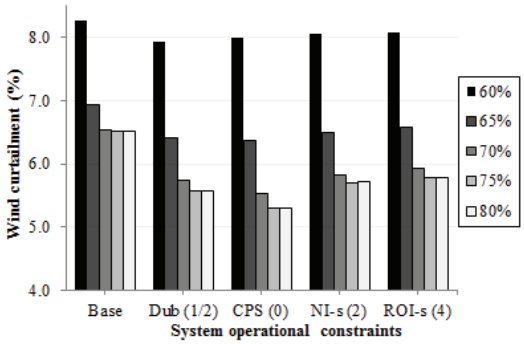


Fig. 3. The percentage of AI wind curtailment at different SNSP percentage limits and minimum number of large conventional generator on-line constraints individually relaxed

B. Combined system operational constraints effects

The results of combined SOC relaxations are presented in order of the greatest influence, with the most influential SOCs relaxed first and relaxed SOC(s) carried forward to subsequent scenarios. Large decreases in both total generation costs and wind curtailment are evident in Figs. 4 and 5 as the constraints are progressively relaxed.

IV. Discussion

The results presented here show the strong effects that relaxation of SOCs has on the future AI system in terms of total generation costs, wind curtailment and generator dispatch by technology type.

A. Costs

It is evident in Fig. 2 that the two SOCs associated with voltage stability, Dub(2/3) and CPS(1), are the most costly constraints on the AI system. This result was not expected as initially it was assumed that ROI and NI system stability SOCs would be the most influential along with the system-wide SNSP limit. It is shown that relaxing the constraint Dub(2/3) has the biggest impact in terms of generation cost savings and regardless of the SNSP the limit imposed, this yields an

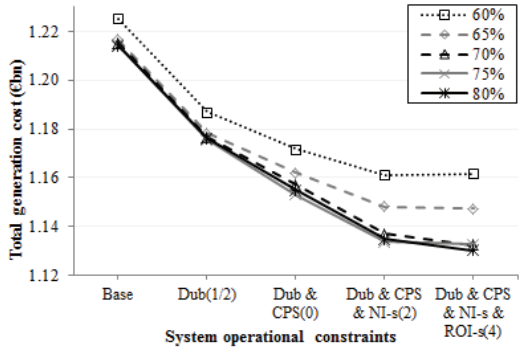


Fig. 4. Total AI generation costs (€m) at different SNSP percentage limits and minimum number of large conventional generator on-line constraints relaxed in cumulative combination from left to right

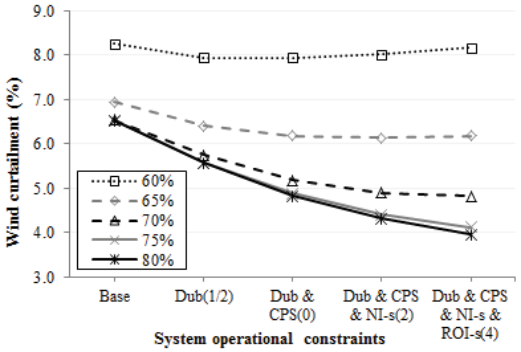


Fig. 5. The percentage of wind curtailment for AI at different SNSP percentage limits and minimum number of large conventional generator on-line constraints relaxed in cumulative combination from left to right

TABLE III
TOTAL AI GENERATION (TWH/YR) AT DIFFERENT SNSP PERCENTAGE LIMITS AND MINIMUM NUMBER OF LARGE CONVENTIONAL GENERATORS ON-LINE CONSTRAINTS RELAXED IN CUMULATIVE COMBINATION FROM LEFT TO RIGHT

	System operational constraints scenarios				
SNSP	**Base**	**Dub(1/2)**	**CPS(0)**	**Ni-s(2)**	**ROI-s(4)**
60%	40.34	39.97	39.40	39.18	38.84
65%	40.37	40.07	39.41	38.98	38.72
70%	40.40	40.13	39.44	39.04	38.59
75%	40.43	40.10	39.42	38.97	38.65
80%	40.39	40.13	39.51	39.09	38.63

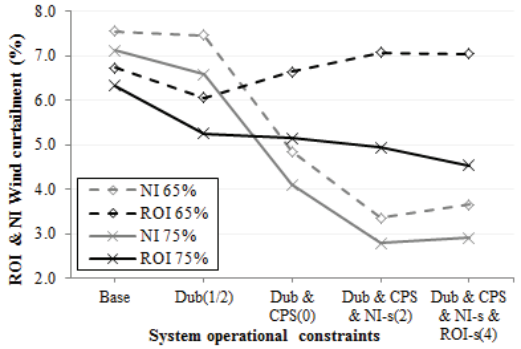


Fig. 6. The percentage of wind curtailment in NI and ROI at 65% and 75% SNSP percentage limits and minimum number of large conventional generators on-line constraints relaxed in cumulative combination from left to right

almost constant saving of €38 million per year (3.1% of total system costs). Therefore the Dub(2/3) should be considered as a priority to be relaxed first, subject to the cost and feasibility of the required grid upgrades.

On examination of the combined effects of relaxing the five most influential SOCs there are potential savings of €95 million per year or 7.8% of total generation costs. This illustrates the need for investment in the AI electricity system to help mitigate the issues associated with reactive power and inertia that will be present in the future electricity system highlighted in [16], [14].

The most striking result from this work, shown in Fig 4, is the lack of reduction in total generation costs when the SNSP limit is raised above 65% unless both of the two most influential constraints, Dub(2/3) and CPS(1), are relaxed first. This strongly indicates that tackling system-wide problems requiring a SNSP limit of 65% is a secondary concern to that of "minimum on" SOC's requiried for local voltage and reactive power control. It is also interesting that savings are limited when the SNSP limit is relaxed past 70%, even if all the other SOCs are also relaxed. This would indicate that further relaxation of the Dub(1/2) or the NI-s(2) constraints may be necessary in order to deliver further reductions in total system cost.

B. Wind curtailment

A low level of wind curtailment is very desirable to ensure maximum use of generation assets. In Fig. 5 it is shown that wind curtailment is strongly influenced by changes to SOCs. There is the potential to reduce wind curtailment to 4.0% if the five most influential SOCs are relaxed, this is in comparison to the base-case scenario prediction that wind curtailment will be 8.3% if the SOCs are not relaxed from present-day values. With today's prices this equates to €42 million extra a year worth of wind energy not being utilised.

Unlike total generation costs, wind curtailment is influenced more strongly by the reductions in the SNSP SOC than the four other "minimum-on" SOCs. Increasing SNSP beyond 70% offers little gain, in terms of wind curtailment, unless the other SOCs are relaxed first. It is also shown that with an increase in the SNSP limit beyond 75% there is little benefit in terms of wind curtailment if all other four SOCs are relaxed. This aspect, similar to total generation costs, would indicate that further relaxation of the Dub(1/2) or the NI-s(2) constraints may be necessary before wind curtailment can be reduced further.

Following from the assumption made on how wind curtailment is managed in the AI system, prioritising optimisation of the system as a whole, it is interesting to note how relaxation of the SOCs causes a regional imbalance in wind curtailment. It is shown in Fig. 6 that NI stands to gain in terms of

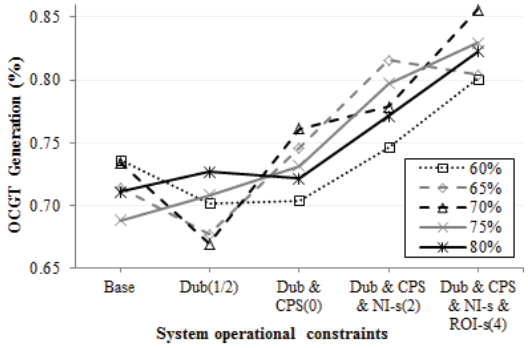


Fig. 7. OCGT generation as a percentage of total generation for AI at different SNSP percentage limits and minimum number of large conventional generators on-line constraints relaxed in cumulative combination from left to right

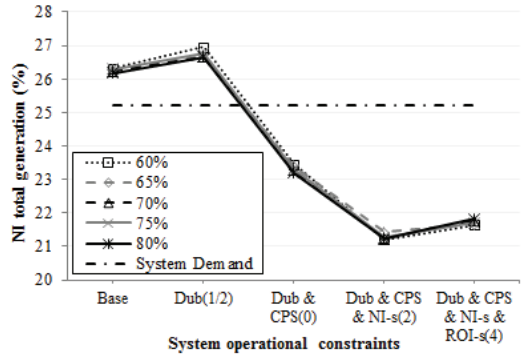


Fig. 8. Total NI generation as a percentage of total AI generation for at different SNSP percentage limits and minimum number of large conventional generators on-line constraints relaxed in cumulative combination from left to right

reduced wind curtailment, corresponding with [8], however this is at ROI's expense. This may lead to possible issues in the future regarding ROI wind farms being penalised with greater curtailment than NI wind farms, or may lead to a need for a new constraint to equalise wind curtailment between the two jurisdictions.

C. Conventional generator dispatch

There is evidence of a small increase in OCGT usage with continued relaxation of the SOCs. On average for all SNSP scenarios there is an increase of an extra 0.11% (44 GWh/yr) of total generation coming from OCGT from relaxing the four "minimum-on" SOCs. This is due to a higher frequency of extreme peaks and troughs in the conventional generation profile to accommodate the added wind energy resulting from relaxing the SOCs.

With the relaxation of the NI SOCs there is a dramatic shift in generation away from NI, shown in Fig. 8, leading to NI being supported by ROI and GB through the Moyle interconnector. This shift in the relative proportions of total generation between the jurisdictions is a result of the NI local SOCs artificially keeping NI generation higher than would be the case in an unconstrained AI market model. This generation shift towards ROI also contributes to it being more efficient to curtail wind in ROI rather than NI, shown in Fig. 6, as ROI already has a generation surplus.

V. Conclusion

This work quantifies the effects on total generation costs, wind curtailment and generator dispatch of relaxing the SOCs currently imposed in order to maintain a safe, stable and reliable electricity system. In doing so, it illustrates the need for further investment to mitigate problems associated with voltage stability and inertia requirements to allow for the relaxation of the SOCs.

There are potential savings in total generation costs of 7.8% when the five most influential SOCs are relaxed. There are also large savings to be made with SOCs being individually relaxed. Most notably, if the Dub(2/3) SOC constraint requiring two large generators in the Dublin area to be constantly on-line by day and three by night is relaxed to Dub(1/2), one by day and two by night, there is a saving of 3.1% of total system costs regardless of the SNSP limit.

Wind curtailment is greatly affected by SOCs. There is the potential to reduce wind curtailment from 8.3% to 4% when the five most influential SOCs are relaxed. In the future, an issue may arise between the two jurisdictions, ROI and NI, over where best to curtail wind energy for the benefit of the system as a whole. It has also been shown that relaxing the SOCs affects the dispatch of conventional generators such as OCGTs, with increased usage of OCGTs as SOCs are relaxed. There is also a big effect on the relative contribution to total generation from the two jurisdictions when the NI SOCs are relaxed, with NI needing to be supported from ROI and GB in this case.

The issue of relaxing SOCs, while important for Ireland in the next 5-10 years, will probably also become important for larger systems in the future if present trends in the installation of non-synchronous sources such as wind, HVDC or photovoltaics continue. The GB synchronous system may find similar issues becoming apparent in the next 10-15 years as well as in the synchronous systems of Continental Europe in the next 30-40 years.

Grid reinforcement and technical improvements to wind and conventional generators such as synthetic inertia will allow for an increase in the permitted limit of non-synchronous generation on the system. However, this will only deliver cost savings in conjunction with measures to relax other SOCs primarily associated with local voltage control, such as introduction of non-synchronous generators with greater reactive power control. It has been demonstrated that increasing the SNSP limit beyond 65-70% has limited value without prior relaxation of the other SOCs and it is also shown that there is limited value in increasing the SNSP limit beyond 70-75% even if all other influential SOCs are relaxed.

In this study a rigorous framework has been developed for comparing system cost savings associated with grid reinforcements and generator upgrades. This has been applied to clearly demonstrate the case for investment in transmission

and generator upgrades in order to allow for more flexible system operation with lower generation costs and reduced wind curtailment.

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