Interim Solution for Capacity Market marginal de-rating factors

Information paper to SEMC

16 May 2022

Executive summary

EirGrid and SONI are concerned that the capacity that may come forward in the upcoming Capacity Market auctions may not be sufficient to address the shortfall we have identified in the short to medium term. This is because:

- some of the units may now or in the future be subject to an Annual Run Hour Limit (ARHL);
- batteries may not contribute to capacity adequacy at the level implied by the current (T-4 derived) de-rating factors; and
- DSUs have shown in practice to have a much lower contribution to capacity adequacy than what is implied by the de-rating factors used by the SEM Committee in recent auctions based on fixed values since T-4 24/25.

Our analysis suggests there is a 'saturation' point for units with energy and/or run hour limitations[1]. Given the size of our system, this point can be reached even with a relatively small amount of such capacity. EirGrid and SONI therefore believe we need to act now to avoid inefficient outcomes and/or risk issues with capacity adequacy and secure operation of the system.

EirGrid and SONI have concluded that some of the current de-rating factors are not reflective of a unit's contribution to capacity adequacy:

- units with ARHL cannot contribute in the same way to capacity adequacy as units that can run continuously throughout the year, especially when there are significant volumes of such units on the system;
- the recent approach from the SEMC of reusing the T-4 24/25 storage de-rating factors ignores the 'cannibalisation' effect and therefore overvalues the contribution of energy-limited storage to capacity adequacy, in particular when it comes to storage with a shorter duration; and
- similarly to energy limited storage, the use of de-rating factors from previous determinations for DSUs ignores the 'cannibalisation' effect, and we have observed that the contribution from DSUs is well below that implied by the currently used de-rating factors.

In general, we should accept that because of this 'cannibalisation' effect, de-rating factors need to be dynamic and change in time in line with the underlying capacity. This applies to all units that face any form of limitation, whether that is run hour restrictions, energy limitations or resource availability.

To address the above in the short term, EirGrid and SONI propose the following to better reflect the contribution of different units to capacity adequacy:

- the use of a 'multiplier' to the base de-rating factors for units which may have different ARHL - this should result in a 'discount' of the effective de-rating factor for units that are restricted to a specific number of hours:
    - 0.14 DRF multiplier for units with an ARHL of 500h or less; and
    - 0.43 DRF multiplier for units with an ARHL of 1500h.

[1] This can also be seen from the evolution of the ISAC de-rating factors

- accept the outputs from the ISAC de-rating process for storage, and consider moving to a more 'marginal' approach by keeping the initial de-rating factors without 'scaling up' with the Storage Adjustment Factor;
    - this should result in a drop for the storage de-rating factors – in particular for storage with shorter duration;
- consider including a separate de-rating factor for storage with a duration of 8h (or greater) – although this may not be possible for the upcoming CM auction;
    - this should act as a further incentive for longer duration storage, which will be of greater value to the system going forward (as suggested by analysis we have undertaken); and
- accept the outputs from ISAC de-rating process for DSUs. – alternatively apply an ex-post adjustment of the de-rating factor for DSUs with the use of a 'multiplier' of 0.5, if we continue to adopt the de-rating factors from previous determinations.

EirGrid and SONI acknowledge that the existing de-rating methodology is suited to a power system where the biggest risk is the loss of a thermal power plant. In the longer term, it is EirGrid and SONI's view that a new capacity market design is needed. The new design should be consistent with the other markets including system services, energy, and renewable support schemes for a holistic effective and efficient answer to be delivered.

Future power system adequacy should be dimensioned against factors, such as, the extended loss of gas supply and no wind. New market arrangements are required to incentivise technologies that follow demand, complement weather dependent generation, and that manage future ramping uncertainties. It is crucial that the right value is captured in the right market to incentivise investments that deliver capacity adequacy, and operational capability in a power system with 80% renewables by 2030.

Background

Purpose of the paper

EirGrid and SONI are concerned that the new capacity that may come forward in the upcoming Capacity Market auctions may not be sufficient to address the capacity shortfall identified in the short to medium term. This is because:

- some of the units may now or in the future be subject to an Annual Run Hour Limit (ARHL);
- analysis carried out shows there is a 'saturation' point for energy limited units, in particular those with shorter durations;
    - both energy limited storage and DSUs may not contribute to capacity adequacy at the level implied by the current de-rating factors.

The purpose of this paper is to:

- clarify the current de-rating approach; and
- propose incremental changes that to help support more efficient outcomes in the Capacity Market and help deliver capacity adequacy.

We recognise that the potential solutions put forward in this paper are meant to be solely transitional. In the longer term, we expect there will be a re-design of the market to support long term capability procurement for a market where the risk moves from planning for winter peak demand adequacy against the loss of thermal units; to a system built on variable renewables where weather related risks impact system reliability throughout the year.

Generation adequacy

Generation adequacy has traditionally been assessed by calculating the loss of load probability (LoLP) for each trading period across the year. If there is not enough capacity/supply to meet demand, then the load must be reduced. This method of assessment may not predict load shedding, however, in any given period there is always a probability that demand cannot be met.

The reliability measure used in Ireland and Northern Ireland is the commonly used metric Loss of Load Expectation (LoLE). LoLE is the sum of the LoLP for trading periods for a single year. For Ireland the generation adequacy standard is 8 hours of LoLE per annum, and for Northern Ireland it is 4.9 hours of LoLE per annum.

With any capacity provider there is always the risk of being unavailable – for example, as a result of equipment failure. Such events are called forced outages, and the proportion of time a provider is unavailable because of such an event is the Forced Outage Rate (FOR). Generators can fail at any given time, and failures can happen simultaneously. Some technologies (such as wind and solar), however, are also restricted by other factors, such as weather conditions.

Going forward, the existing methods and metrics for assessing generation adequacy, may not be fit for purpose in a world with high levels of renewables. Other considerations, such as ramping capabilities, location of capacity, and provision of a wide range of 'ancillary/system services' are already becoming increasingly important –power systems will need appropriate capabilities, rather than just megawatts of capacity. This is something that is beyond the scope of this paper, but in the longer term we may be required to revisit our approach to how the security of supply of the electricity system is assessed.

Calculating Power System Adequacy

EirGrid and SONI estimate the LoLE using AdCal, an Excel based software tool. In simple terms, AdCal calculates the loss of load probability (LoLP) in each half-hour period for each year in a multi-year horizon. The LoLP are sums give the annual LoLE.

This can be explained with a simple example. Let us assume a three generating unit system. The table below shows the respective capacities and the probability of a forced outage rate for each one.

Unit	Capacity (MW)	Forced outage rate probability	Probability of being 'available'
A	100	5%	95%
B	150	10%	90%
C	200	15%	85%

We then create the space of all possible outcomes and define the available capacity for each state and the probability of this occurring. Finally, we can determine the probability of losing the load in a given period[2]. The table below shows this information for a given period assuming a demand of 320MW.

State	Units 'available'	Capacity 'available'	Probability of state	Can meet demand?	LoLP
1	A; B; C	450	72.675%	Yes	0
2	A; B	250	12.825%	Yes	0
3	A; C	300	8.075%	No	0.08075
4	B; C	350	3.825%	Yes	0
5	A	100	1.425%	No	0.01425
6	B	150	0.675%	No	0.00675
7	C	200	0.425%	No	0.00425
8	None	0	0.075%	No	0.00075
Total			100%		0.10675

The LoLE in this example is 0.10675 hours. This is then performed for each given period, and the sum of the LoLE in each period gives the overall annual LoLE.

[2] For simplicity we assume that one period has a 1 hour duration

Further details on how capacity adequacy is assessed can be found in Appendix 3 of the latest GCS 2021-30[3].

De-rating factors

De-rating factors are aimed at evaluating the contribution of different technologies/capacity providers to generation adequacy. The value of the de-rating factors depends on the underlying scenario and assumed portfolio. The SEM Committee has opted for a marginal de-rating approach on the basis of a 'near-scarcity' underlying portfolio. This means that any generation portfolio that is used is only just 'adequate', and the marginal de-rating factor is the capacity's adequacy contribution of a notional additional unit of a specific technology, size and if applicable storage capacity/duration.

Defining de-rating factors for controllable generation has fairly strong link to the Forced Outage Rate, with larger units having a lower de-rating factor.

The de-rating process is more complex for energy-limited units. Their contribution to capacity adequacy is limited by the amount of energy that can be stored and they may not be able to effectively contribute over consecutive 'tight' trading periods. There is also a degree of 'cannibalisation' of the de-rating factors for energy-limited units – as more energy-limited units are added on the system, their ability to cover 'tight' trading periods without increasing the loss of load probability in other trading periods (when they need to withdraw energy from the system) diminishes.

[3] https://www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf

Current methodology for de-rating factors

The methodology for defining the marginal de-rating factors is based on a multi-scenario adequacy analysis. This comprises the following steps:

- develop a set of possible demand futures for a given future year, which will differ in terms of total annual energy and peak demand as well as half hourly profiling within the year;
- develop a collection of different 'adequate' generation portfolios;
- estimate the de-rating factor from the addition of a 'marginal' notional unit added to an already adequate generation portfolio – various notional units are tested for different technologies and sizes;
- the de-rating curves are then averaged across the different adequate portfolios associated with each demand scenario, and this gives one de-rating curve for each technology and demand scenario; and
- perform the "least-worst" regrets analysis to choose the demand forecast level.

Demand scenarios

The demand scenarios are constructed based on combining annual demand forecasts (total annual energy and peak) and demand profiles.

For the annual demand forecasts, we use the All Island Generation Capacity Statement low and high forecast to set the lower and upper boundaries; these are complemented by creating 8 intermediate decile demand levels, which results in ten annual demand forecasts. A range of half-hourly demand profiles are based on historical All-Island demand profiles. Each half hourly profile shape is based on the 10 demand levels, therefore providing a wide range of demand levels with varying demand shape. The demand is then also adjusted to account for non-market (de minimis) generation capacity; this is in line with the non-market generation assumed in the GCS.

Supply data for the underlying generation portfolios

The 'starting point' of each portfolio are the units included in Appendix 2 in the GCS.

Availability

The availabilities used for 'conventional' units are based on historical data and reflect the actual performance over the previous five years. The availabilities account for forced outage rates, scheduled outages, and ambient factors.

Multi-scenario adequacy assessment

The methodology then creates random generation portfolios from a set of candidate generators. Each random portfolio is assessed against a demand scenario to test if it manages to meet the LoLE adequacy standard. The portfolios that pass this test, then form the set of capacity adequate portfolios for this demand scenario.

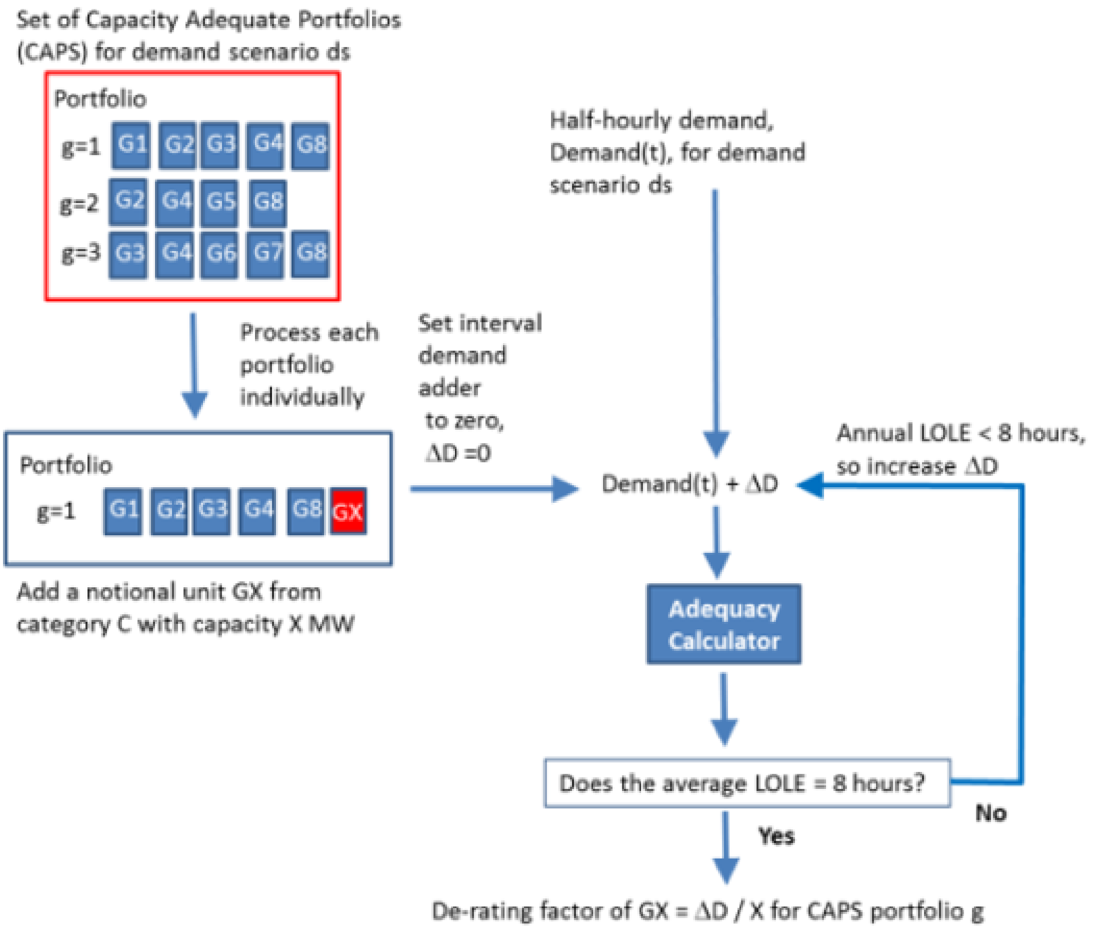
The Adequacy Calculator:

- first applies any reduction in available capacity as a result of ambient effects across the months/periods based on historical evidence;
- then schedules maintenance (scheduled outages) for the different generating units over the periods with the highest surplus (though scheduled outages are continuous blocks); and
- finally determines the loss of load probability in each half-hour given the forced outage rates for the different technologies that are not on scheduled maintenance.

In this final step the Capacity Calculator effectively creates the full list of all possible combination of units being 'available' or 'unavailable' and determined the LoLP for any given settlement period. This has already been presented with a simple three-unit example further above.

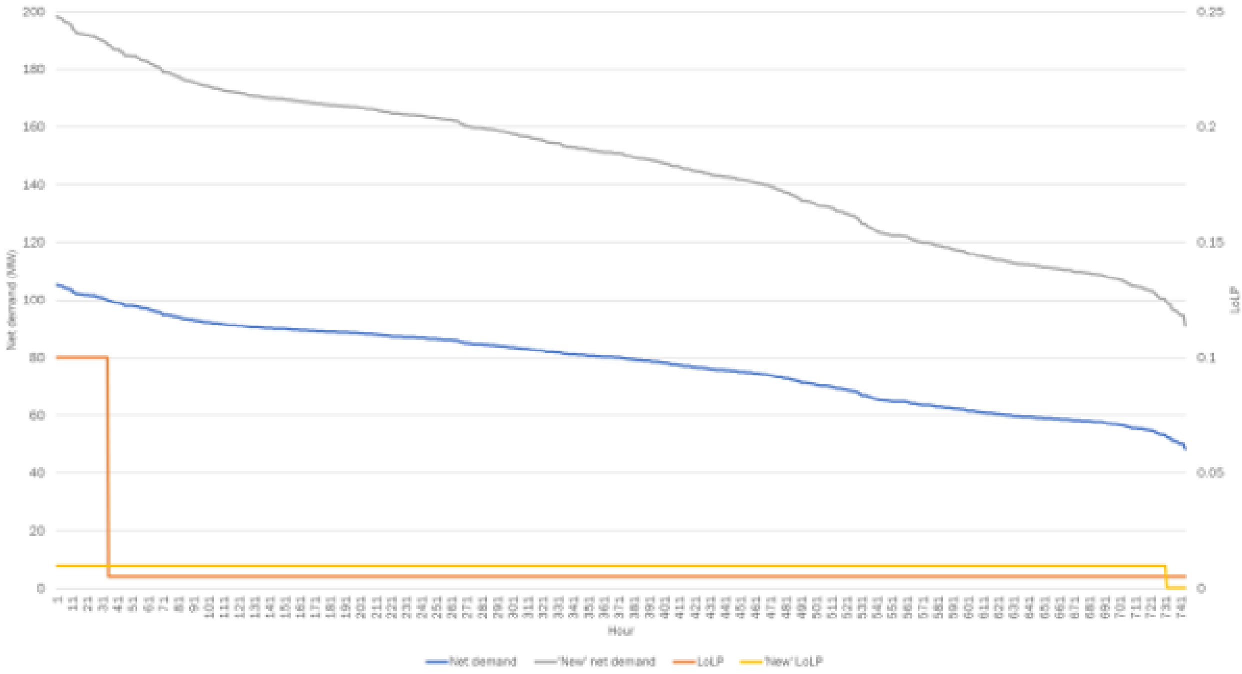
Marginal de-rating factors

The following schematic shows the process for estimating the de-rating factors for different technology classes and sizes.



The marginal de-rating factor for a given technology and a given unit size is then defined as the ratio of the change in demand from a balanced position under a given adequate portfolio to get to the same LoLE level (<8 hours) and the capacity of the unit.

This is best explained with the following schematic (simplified example), which shows the initial demand duration curve (blue) and LoLP (dark orange), and the 'new' demand duration curve (grey) and LoLP (light orange). The overall LoLE is equivalent in the two cases, but the demand has increased. In this case the 'notional' unit that has been added is 100MW, and the required average change in demand is around 68MW. As we have already described the ratio of the average change in demand and the unit size gives the de-rating factor of the unit. So, in this case, the de-rating factor of this unit is 0.68.



The above process is used for the marginal de-rating factors of controllable, non-energy limited units.

De-rating factors for intermittent generation

The de-rating factors for onshore wind and solar PV are based on the respective capacity credits.

De-rating factors for storage

The process for the storage de-rating factors is as follows:

- first notional storage units are added to an existing portfolio and the initial de-rating factors are defined in a similar way as for non- energy limited units (by looking at the change in adequacy);
- estimate a Storage Adjustment Factor, which is used to scale up the initial de-rating factors as determined in the first step.

The overall storage methodology for Initial De-rating Factors is not that dissimilar to that used for other units (such as Gas Turbines). However, as all storage is treated as a new unit, this does ignore the presence of existing storage. A correction is achieved with the use of the Storage Adjustment Factor. This effectively scales up the initial DRFs bringing them much closer to an average de-rating factor.

The methodology does account for:

- impact of storage duration on de-rating factors with high duration storage having a higher de-rating factor; and
- impact of size of the storage unit (in MW) with de-rating factors dropping with size.

The steps involved in determining the final de-rating factors for storage are presented below.

1. Calculate Initial Marginal DRFs for a range of generation sizes and storage volumes.

These are obtained by adding a range of units to an existing portfolio and noting the change in adequacy

2. Calculate the DRF of all Existing Storage (**DRF_{Ex}**)

The DRF for Existing Storage is obtained by removing all storage from the existing portfolio and noting the change in adequacy

3.Calculate the DRF of the Reference Storage Unit (**DRF_{Ref}**)

The Reference Storage Unit represents the average storage unit already on the system. Its DRF is read from the Initial Marginal DRF table.

4. Calculate Storage Adjustment Factor

Storage Adjustment Factor = DRF_{Ex}/DRF_{Ref}

5. Calculate Final Storage DRF values

Mulitiply Initial Marginal DRFs by the Storage Adjustment Factor. This gives the Final DRF values.

Limitations and potential changes

What are the limitations of the current methodology?

We have identified the following limitations with the current approach taken towards the final determination of some of the de-rating factors:

- there is no distinction between a project under a specific controllable technology class (such as gas turbines and steam turbines) that can run continuously for the whole year and one that can run for <1500 hours per year;
  - run hour restrictions can impact on the ability of such units to effectively contribute to capacity adequacy;
- the recent approach from the SEMC of reverting to the T-4 24/25 storage de-rating factors ignores the 'cannibalisation' effect and therefore overvalues the contribution of energy-limited storage to capacity adequacy, in particular when it comes to storage with a shorter duration;
- similarly to energy-limited storage, the use of de-rating factors from previous determinations ignores the 'cannibalisation' effect for DSUs, and we have observed that adequacy contribution of DSUs is well below that implied by the currently used de-rating factors.

Possible interim changes to the de-rating factors

To address the above in the short term, EirGrid and SONI propose the following potential solutions to better reflect the contribution of different units to capacity adequacy. The thinking behind and the supporting analysis for these recommendations is included in the respective Annexes (Annex A for run hour limited units and Annex B for energy limited units and DSUs).

Run hour limited units

EirGrid and SONI propose to have some form of differentiation for units which have CM framework, this can be achieved with the use of a 'multiplier' to the base de-rating factor. Based on our analysis the 'multiplier' should be:

- 0.14 DRF multiplier for units with an ARHL of 500h or less;
- 0.43 DRF multiplier for units with an ARHL of up to 1500h.

Furthermore, any units with ARHL should ensure they are fully compliant with the respective Grid Codes when it comes to minimum generation.

We propose this 'multiplier' to be applied only to new units rather than existing units connected to the system as of today. Further consideration is needed on how existing units are treated, to ensure efficient exit signals are provided over the long term.

Energy-limited storage

> We recommend using the outputs from the ISAC de-rating process, instead of reverting back to de-rating factors estimated in previous determinations, and consider moving to a more 'marginal' approach for de-rating factors for energy limited storage. This means keeping the Initial De-rating Factors without 'scaling up' with the Storage Adjustment Factor. With this change, de-rating factors will decrease, in particular for storage with shorter duration.
>
> We believe we should also consider including a separate de-rating factor for storage with a duration of 8h (or greater) to further incentivise longer duration storage.

DSUs`

> Our starting point is to adopt the outputs from the ISAC de-rating process, which captures the 'cannibalisation' effect. Alternatively, we recommend applying an ex-post adjustment through a 'multiplier' to the T-4 24/25 DSU de-rating factors.
>
> This multiplier should be 0.5 if we again revert to the T-4 24/25 DSU de-rating factors.

Annex A – Run hour limited units

What are the limitations of the current methodology?

The Best Available Techniques (BAT) for Large Combustion Plants (LCP) are described in BAT12 and BAT40. Within the BAT there are minimum efficiency targets and emission limits. If new gas turbine technologies cannot meet these requirements, they will be subject to limited running of 1500 hours on average per year over a five-year period. The SEM-21-107[4] was published in December 2021, and highlighted the position from the Environmental Protection Agency (EPA) in Ireland that technologies (in addition to Combined Cycle Gas Turbines) can be compliant with the BAT requirements without being subject to annual run hour limitations. As a result, de-rating factors were not configured to reflect the potential for run hour limitations. EirGrid and SONI engaged with the SEM Committee on several occasions in relation to ongoing concerns around run hour limitations.

EirGrid and SONI retained Jacobs to provide expert advice in relation to the requirements in BAT and whether Open Cycle Gas Turbines (OCGT) connected to the 50 Hz system could meet these requirements. Jacobs undertook a desktop review and concluded that only six (6) units could be complaint, and only at higher generation levels (approximately 70% load and above).

The ability to be compliant does not necessarily mean that all units that are being licensed will not be subject to run hour limitations. We have seen that new Gas Turbines that have been awarded Capacity Market contracts end up being configured in a way that means they are subject to restricted operation.

Currently all units that fall under a specific controllable technology class (such as gas turbines and steam turbines) face the same de-rating factors. De-ratings do change depending on the size of the unit. However, some of the existing gas turbines (as well as some that are being developed) face limitations in terms of the number of hours they can operate, as we have already discussed above. These range from 250h up to 1500h per annum, based on planning and BAT issues.

The current Capacity Market de-rating process does not distinguish between a project that can run continuously for the whole year and one that has restricted running; for example a unit limited to less than 1500 run hours per year. Not providing a categorization for ARHL de-rating factors, means there is no differentiation to incentivise unrestricted run hour unit configurations.

Run hour restrictions can impact on the ability of such units to effectively contribute to capacity adequacy. This can be best explained with a simple example. Imagine there are 1000 hours each year with a high LoLP. A unit that can operate for 500 hours can only contribute and ensure that the same security standard is retained in only half of these periods (even when ignoring the potential for a forced outage). In the remainder of the periods it is not permitted to generate and has therefore no

[4] https://www.semcommittee.com/sites/semc/files/media-files/SEM-21-107%20Info%20Note%20re%20the%20Application%20of%20Annual%20Run%20Hour%20Limits.pdf

contribution to generation adequacy. Its de-rating factor is therefore lower than a unit that does not face any such restrictions.

In practice, the degree to which (if at all) the de-rating factor of a run hour limited unit diverges from a similar one with no such restrictions depends on:

- the amount of such run hour limited units on the system; and
- the 'steepness' of the net demand curve (driven by the wider underlying characteristics of the system in terms of demand profile and renewable output).

For both run hour limited units and storage units (discussed below), there are similar trends for the de-rating factor:

- the more such units are on the system the lower the de-rating factor of the marginal addition; and
- the 'flatter' the net demand curve the lower the contribution to generation adequacy.

Without a change in the respective incentives and the continued use of the same de-rating factors irrespective of run hour limitations, there are two possible scenarios:

- either we risk capacity adequacy issues as some units are not permitted to operate due to the emissions limits; or
- we procure large volumes of run hour restricted units, at a significant cost to consumers, which is an inefficient way for delivering security of supply.

We are working towards a future market that will allow for increased levels of non-synchronous generation (with an SNSP close to 100%) and removing the existing unit constraints. We expect this to be achieved with the use of innovative provision of system services. However, this will still take some time and there will be a need for unit constraints (to manage inertia and voltage primarily) to remain in place throughout the 2020s. If all new units developed have some form of run hour limitations, this limits the 'tools' we have at our disposal to run the system securely. An example of is the following – future Northern Ireland Transmission Constraint Groups, may be limited to selecting from four existing 'large sets' (down from six), particularly if new units have run hour restrictions of less than 1500 hours per annum (these units with ARHL may be constrained off in order to preserve run hours for times of system stress).

Possible interim changes to the de-rating factors for ARHL units

A downward adjustment (either mandatory or voluntary) for units with run hour limitations has previously been explored. This adjustment could reflect an estimate of how emissions limits could reduce the unit contribution to security of supply.

One way of enforcing this downward adjustment would be to apply a scaling factor ('multiplier') on the initial de-rating factor. Each unit could provide the TSO with an estimate of its maximum run hours for a particular year. If this is below a specific threshold set by the RAs, this would be converted into a scaling factor. The threshold could, for example, be the number of weekday peak hours in the winter period – e.g. 4 hours per weekday in months November through March. This scaling factor would then apply to the unit's base de-rating factors. As an example, a unit states that, due to emissions restrictions, its running will be limited to 170 hours. This is compared to the number of winter peak hours, around 340. It will then have a scaling factor of 0.5 applied to its de-rating factor.

We have explored a range of different approaches for approximating the actual contribution of run hour limited units to capacity adequacy. At this stage, we will present the different methodological approaches we have so far considered and the range of de-rating factors our initial analysis suggests. Going forward, we believe we may need to more fundamentally adapt the existing ISAC process to model run hour limited units.

One of the potential solutions is to attempt to better account for the run hour restrictions within AdCal. We can see two options for restricting the run hour limited units in AdCal:

- forcing the availability of such a unit to zero for specific continuous periods to allow operation, which is equivalent to the run hour limitation; or
- limiting the number of consecutive periods the unit can 'run' in the same way as energy-limited technologies.

The above two options can also be combined to give a more realistic representation of how a run hour limited controllable unit would probably operate. For example, we have created the below 'cases'. Given that AdCal works on the basis of weeks, a 250 h unit has been approximated by a 300 run-hour equivalent unit.

The table below shows the different approaches taken to model the run-hour limited units within AdCal.

	'Energy Limited'	'Unlimited'
"1500 run-hour equivalent"	5-hour storage/ 9 wk SOD	No Storage / 43 wk SOD
"300 run-hour equivalent"	2-hour storage / 30 wk SOD	No Storage / 50 wk SOD

There are pros and cons with each option. The choice of when the unit is unavailable (through the Scheduled Outage Duration (SOD)) can have a strong impact on the de-rating factor. If the unit unavailability is concentrated in months with low LoLP, this should result in a small drop in the de-rating factor. However, if the unit is assumed to be unavailable in months with high demand and higher LoLP then the de-rating factor will be much lower.

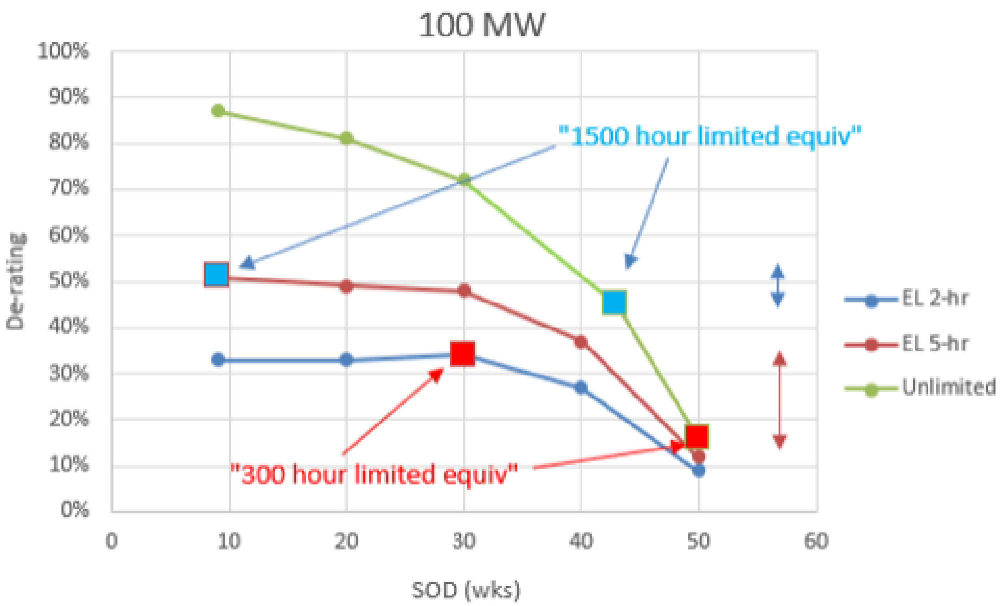
Treating a run-hour limited unit as a 'storage' unit is not realistic and has the potential to ignore the contribution of the unit when there are several consecutive periods with high LoLP. A controllable unit can arguably run throughout extended peak periods (for example in winter months) and be in general more focused in winter periods.

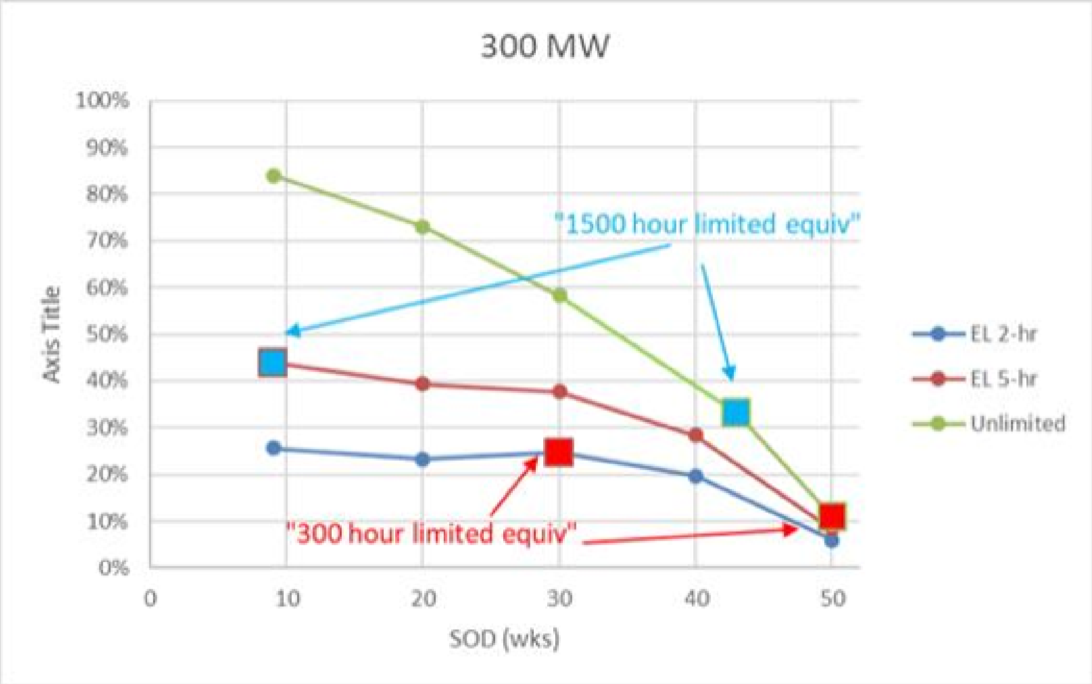
The below figure shows the results from some initial analysis with AdCal. We have modelled a 100MW unit and a 300MW as:

- a unit with no energy limitations (green line);
- a unit with a 5h limitation; and
- a unit with a 2h limitation (blue line).

All these cases are then assessed for different Scheduled Outage Durations (SODs) to give a de-rating curve depending on an underlying assumed 'forced unavailability'. The de-rating factor for the 'unlimited' case starts off very close to the initial de-rating factor for Gas Turbines when the SOD is low. It then drops as we assume more extended 'unavailability'. The 1500h limited equivalent results in a de-rating factor of around 48% in the case of the 100MW unit. The 300h limited equivalent results in a de-rating factor of around 17%.

Treating the Gas Turbine as 'energy limited' has a strong impact on the de-rating factors at the same level of SOD, and in particular at low SOD levels. We can also see that the SOD has little impact on the de-rating factor when the units are treated as 'energy-limited'.





As shown in the above charts, the AdCal analysis we have undertaken suggests the following ranges (depending on unit size and approach) for units with ARHL:

- 0.33-0.51 marginal DRF for the 1500h unit; and
- 0.11-0.34 marginal DRF for the 300h unit.

This, in turn, means 'multipliers' for units with ARHL in the range of:

- 0.38-0.57 DRF multiplier range for the 1500h unit; and
- 0.13-0.39 DRF multiplier range for the 300h unit.

In addition to the analysis performed with AdCal we have also carried out some further assessment[5] to better understand and help communicate the issue with extensive run hour limited capacity on the system.

The figure below shows:

- the demand duration curve[6];
- the demand net intermittent renewables duration curve; and
- the demand net intermittent renewable net storage curve[7].

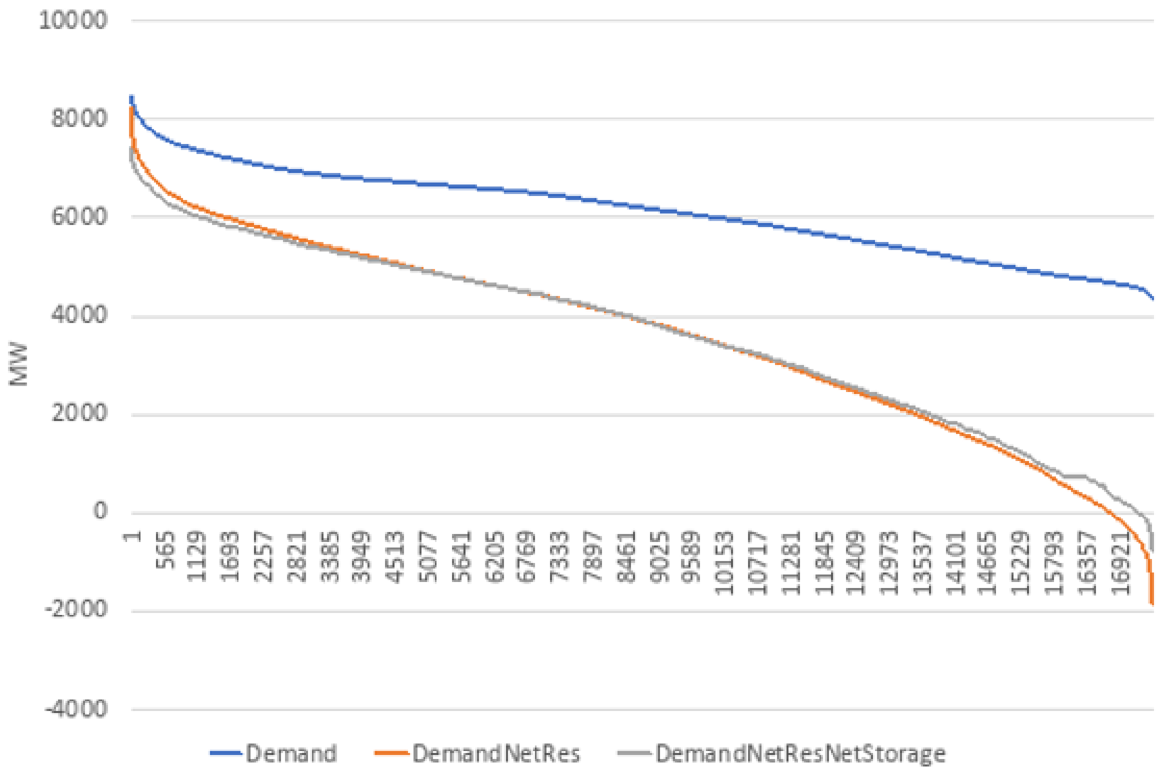
[5] This case assesses a single demand profile and demand forecast (closer to the median) and one Capacity Adequate Portfolio

[6] Based demand and renewables profiles from 2011 (which is a fairly typical year)

[7] Accounting for the contribution of storage and DSUs.

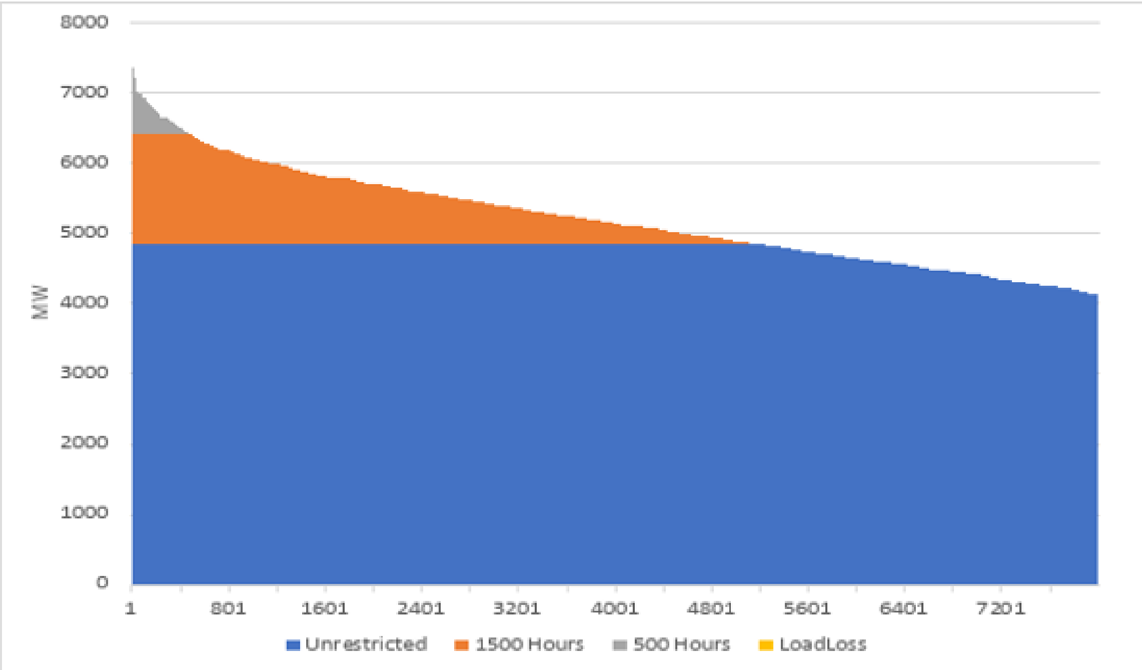
Batteries have a strong contribution at the 'top end' of the net demand duration curve, but perform less well in the middle of the duration curve. This is because this includes periods which are well below the daily peak, so storage is less likely to generate and may even have to charge.

The 'top end' of the duration curve appears to be quite 'peaky' (albeit less so when battery/DSU capacity is netted off). This suggests there is scope for some volume of plants with very limited running hours.



We then 'dispatch' unrestricted plant (and interconnection) against this duration curve, allowing 8 hours of insufficient capacity[8]. In the figure below we show the top 8000 half-hours (4000 hours).

[8] We have added 418MW hours of capacity with a 1500h limitation to meet the 8h standard. We note that this analysis is not detailed enough to form an assessment of capacity requirement.



In this case we see that for a 'market based' net demand curve:

- units with a 500h restriction operate for 250 hours; and
- units with a 1500h restriction operate for 2400 hours.

This analysis:

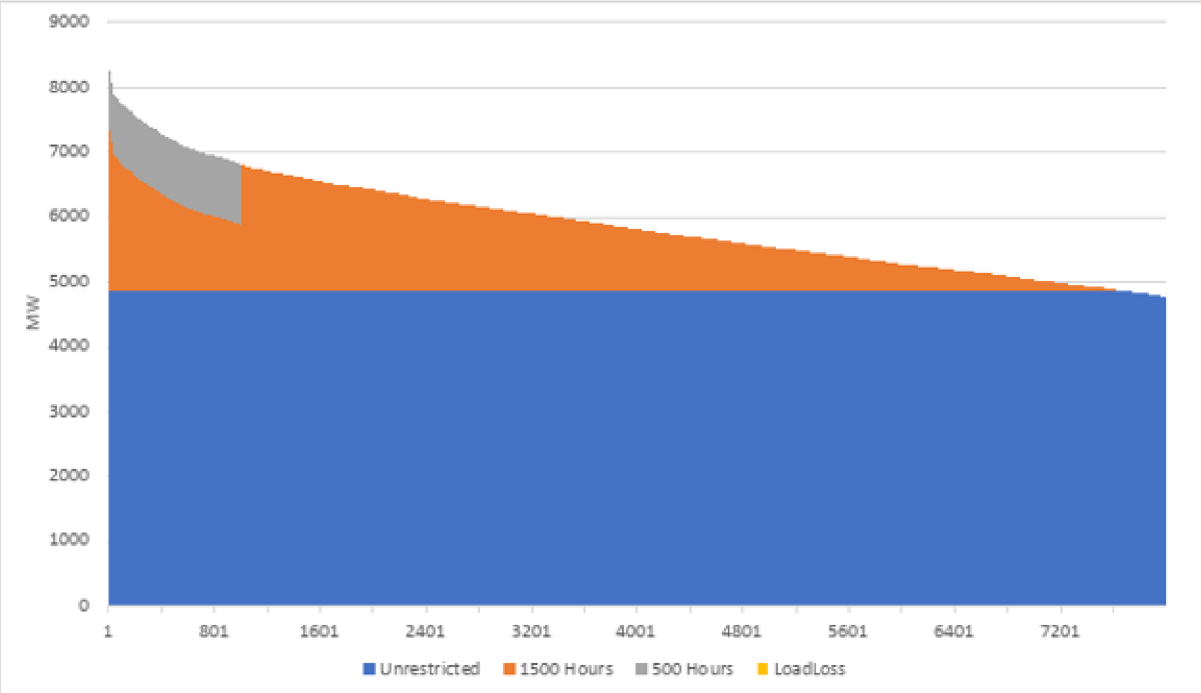
- assumes an ideal market to utilise run hour limited units at times of scarcity; and
- ignores any potential 'out-of-merit' operation for meeting certain constraints, as well as dispatching such units for ensuring secure operation of the system other than for capacity adequacy.

The operational running requirement is important. As system operators it is EirGrid's and SONI's role to ensure secure operation of the power system. All analysis we have presented so far focuses on a 'market' approach. This means having enough capacity to meet demand and does not include other operational security requirements. When EirGrid and SONI operate the power system in real time they inevitably run units for a wide range of system security reasons. These reasons include following the loss of a unit activating replacement reserve, starting units to support system voltage, and covering a wide range of operational uncertainties such as ramping requirements; for example when there are weather events like the wind arriving late or falling away unexpectedly.

In any case, even with this 'market' approach (which ignores running units for other system reasons), our analysis shows that if more units with run hour limitations (beyond existing and those that we expect to come online in the near term) are added to the system, then we may face a risk in terms of capacity adequacy as outlined in the example below.

We consider a case where demand (incl. reserve) is higher when compared to the central expectation[9]. We then add a further 930MW (de-rated) of 1500h units to get to the same security standard (8h), Now, the 500h restricted units 'run' for 500 hours, and the 1500h units 'run' for 1509 hours –marginally exceeding the corresponding run hour limitations.

The below figure shows the operation of the various units on the system and from this we can infer the de-rating factors for each type. Again, we only we show the top 8000 half-hours (4000 hours).



An unrestricted unit can reduce the hours the 1500h restricted unit needs to run by operating over all half-hours over which a limited hours plant would be otherwise running. This is 3845 hours. An incremental 1500h restricted unit could 'run' for 1500 hours and a 500h restricted unit could run for 500 hours. This suggests a marginal de-rating (in addition to normal outage/size de-rating) of:

- 1500/3845= 0.39 marginal DRF for the 1500h unit; and
- 500/3845=0.13 marginal DRF for the 500h unit.

These results are consistent with the values estimated with AdCal. They fall within the range we have defined, albeit closer to the lower end of the spectrum. These, in turn, mean the following 'multipliers' for units with ARHL:

- 0.43 DRF multiplier for the 1500h unit; and
- 0.14 DRF multiplier for the 300h unit.

[9] Demand has been scaled up by 11% (increasing the peak by around 930MW) and the storage capacity has remained unchanged.

To illustrate the principle first let us assume a 100 MW unrestricted plant which has a base de-rating factor of 0.906. Next let us assume that a 100 MW unit has a run hour restriction of 1,500 hours. The 'base' marginal de-rating factor, which is 0.906, is multiplied by 0.43, so that the 'effective' marginal de-rating factor is 0.39. Furthermore, let us assume a unit has a run hour restriction of 300 hours. The 'base' marginal de-rating factor, which is 0.906, is multiplied by 0.14, so that the 'effective' marginal de-rating factor is 0.13.

It should be noted that the underlying generation portfolio, the expected capacity additions, and the demand profile have a strong impact on the resulting marginal de-rating factors for run hour limited units:

- with very few run hour limited capacity on the system, then the marginal de-rating factors for these units would be fairly close (if not the same) as those for similar units with no restrictions;
- additional storage on the system would further 'flatten' the net demand duration curve and would exacerbate the issue with run hour limitations; and
- if demand becomes 'flatter' in the future (for example due to more data centre demand), then a smaller increase in ARHL capacity would be required before the run hour limits 'bind'.

In summary, our proposal is for a multiplier to be applied to the 'base' de-rating factors for units with ARHL. The multipliers we are putting forward, are those that should be applied to the 'base' de-rating factors so that the resulting product of multiplier and 'base' de-rating factor is equivalent to the effective de-rating factors for units with ARHL, in line with our analysis.

Annex B – Energy limited storage and DSUs

What are the limitations of the current methodology?

Energy-limited storage

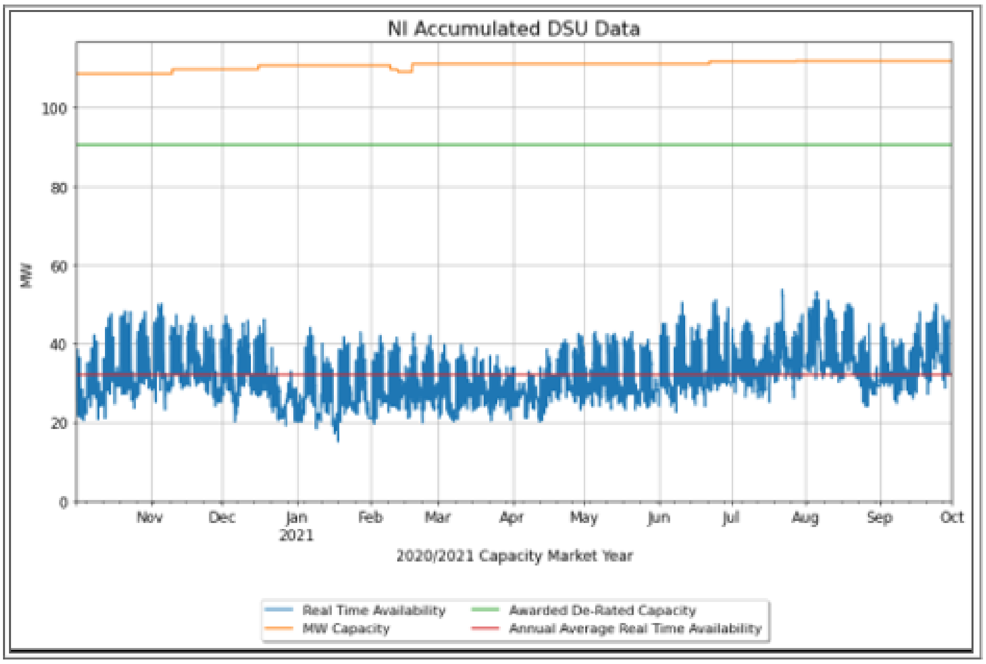
The currently used de-rating factors for energy-limited storage technologies may potentially overestimate their contribution to capacity adequacy as they ignore the 'cannibalisation' effect as a result of further capacity additions.

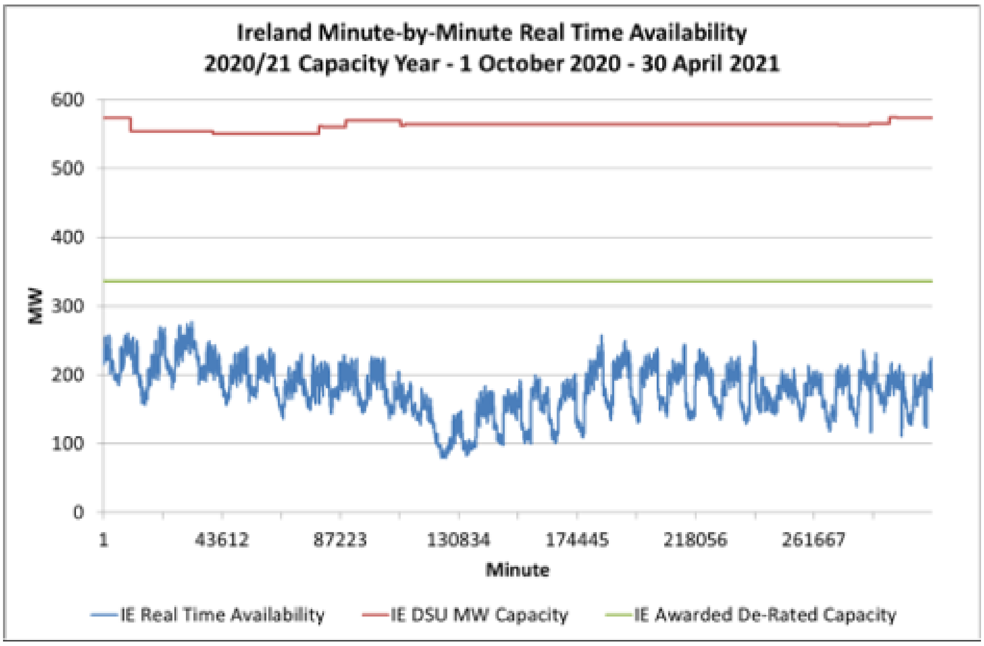
The more storage we have on the system the lower the contribution to capacity adequacy. This is captured in the ISAC methodological approach. Storage tends to reduce net demand at peak periods and increase net demand at 'loose' periods, as it charges in low priced periods and discharges in high priced periods. This then effectively results in a much 'flatter' net demand profile. With very high levels of storage you would ultimately end up with storage having a de-rating factor close to zero. The Capacity Adequate Portfolios used for the determination of the initial de-rating factors do include some estimate of 'existing' storage on the system, so this impact is captured for the initial de-rating factors.

The use of the Storage Adjustment Factor means that the resulting de-rating factors are much closer to an average de-rating factor rather a marginal one. It has already been described how the currently used storage de-rating factors overestimate the benefit of new storage to capacity adequacy. This approach (which applies the Storage Adjustment Factor) may need to be reviewed if there are significant volumes of storage attempting to be connected to the system, to bring the resulting de-rating factors closer to the 'marginal' de-rating principle.

DSUs

We currently procure 85-95MW of de-rated DSU capacity in Northern Ireland and 350-400MW of de-rated DSU capacity in Ireland (based on the de-rating factors used). However, on average, the TSOs can only rely on around 35MW of DSUs in Northern Ireland and around 175-200MW of DSUs in Ireland. This is shown in the figures below.





The use of the de-rating factors from previous determinations continues to ignore the increased adoption of short duration DSUs and their impact on the de-rating factors. Further to this, there also appears to be a mismatch between real-time availability and the de-rated capacity for DSUs (as shown above).

Possible interim changes to the de-rating factors for energy-limited storage and DSUs

Energy-limited storage

The ISAC de-rating process does already to some extent capture the 'saturation' effect, and we believe that the outputs of this should be used for setting de-rating factors. We are minded to consider an adjustment to the current de-rating methodology for storage technologies to better reflect the expectation of additional storage 'cannibalising' its own contribution to capacity adequacy. This can be done in the following ways:

- changing the overall approach and allowing some combination of demand and capacity scenarios to have on average 8h of LoLE, rather than ensuring the standard is met in all cases of Capacity Adequate Portfolios;
    - we would expect that this will result in lower marginal de-rating factors for storage technologies, though we have not fully assessed this yet;
    - this would be difficult to technically implement in the current ISAC framework;
- with the marginal de-rating for storage being determined on the basis of a portfolio that includes existing storage and without the 'scaling up' currently used to account for the contribution of existing storage on the system;
- the de-rating factors reflecting an average value based on the marginal de-rating for the delivery year and one from a subsequent year (for example after 5 years) to account for the drop in capacity contribution going forward as more storage is added on the system;
    - this latter approach is more complex and will require modelling an additional year, but also take a view on more long-term storage deployment.

We have carried out some analysis to better understand the impact of storage de-rating factors assuming a move towards a more 'marginal' approach and without using the 'scaling up' factor, which is currently used.

The approach for this analysis is as follows:

- we create a collection of demand and intermittent RES cases based on the historical profiles from 2008-17, and combine these with the annual demand level and the installed RES capacities from the 2021-30 GCS for 2026/27;
- the remainder of the capacity mix is based on the capacities from the GCS as a starting point and complement this with a mix of battery storage, DSUs[10] that have already cleared in previous auctions and generic OCGTs to deliver an adequate portfolio;
- we then also add some small capacity notional storage units with different durations;
- interconnectors are modelled assuming fixed flows and netted off demand in line with the de-rating from the 2021-2030 GCS.

These different demand cases are combined with the underlying capacity portfolio and stochastic outage profiles to undertake an LoLE assessment. Additional OCGTs are added to get to the desired LoLE of 8h. The model can then output the de-rating for the different notional storage units we have included. The marginal de-rating is the load factor of the respective storage unit averaged across the periods where there is load loss (and weighted against the probability of losing the load in a given

[10] The mix of new storage and DSU is simplistic and we have assumed a mix of 2h and 5h storage and DSUs plus some unrestricted DSUs.

hour). We also assessed some sensitivities, adding an additional 500MW of storage (one based on a 2h and one based on a 4h duration), and scaling up the demand up to get back to the same LoLE.

This analysis suggests:

- significantly lower de-rating factors[11] than those that have been used so far for storage in the I-SEM CRM; and
- the de-rating factors drop sharply as additional storage capacity is added with the biggest impact on short duration storage (2h and less) – the de-rating almost halves when 500MW of storage is added.

The sensitivity in particular clearly shows the impact of 'cannibalisation'. There is a very sharp drop in the de-rating factors as additional energy-limited storage capacity is added to the system. The table below compares the de-rating factors we have estimated with those used from the previous determination.

Storage Duration (h)	Baseline	+500MW 2hr	+500MW 4hr	CM 2024/25
1	19%	9%	11%	24%
2	30%	17%	18%	40%
4	48%	34%	31%	61%
6	57%	46%	43%	77%

We have not looked at longer durations (for example 8h). This is something we want to explore further to understand whether there is a need to include additional categories for storage, rather than simply including a >6h category.

Further to this analysis, we have also reviewed the storage de-rating factors used in some other jurisdictions and compared those with the ones used in I-SEM. These are presented below.

[11] We have however applied a 77% availability to all storage. If we had used a higher availability, the resulting de-rating factors would be higher for longer duration storage.

Storage Duration (hr)	I-SEM 2024/25	GB	Belgium	France
0	0%	0%	0%	0%
0.5	14.1%	9.98%		
1	24.2%	19.96%	11%	25%
1.5	32.3%	29.94%		
2	39.6%	39.73%	19%	46%
2.5	46.5%	48.97%		
3	52.5%	56.18%	28%	59%
3.5	56.9%	61.54%		
4	60.5%	64.86%	36%	70%
4.5	63.6%	67.45%		
5	67.2%	69.48%		80%
5.5	71.8%	94.61%		
6	77%	94.61%	52%	88%
8	77%	94.61%	65%	97%
Unlimited	77%	94.61%	100%	

Sources: National Grid ESO Electricity Capacity Report, Elia Préparation de l'enchère CRM Y-4 pour la période de livraison 2025-26 and RTE

DSUs

When it comes to DSUs we have observed that the actual real-time available capacity (as we have shown further above) is well below the implied de-rated capacity. We have previously proposed lower de-rating factors for DSUs, but so far, the original T-4 24/25 values have been used.

DSUs can behave differently when compared to storage units. They would not always need to be 'on' over consecutive periods and could be activated more than once during a period of scarcity. In theory, this then means they could have a greater contribution when compared to storage with the same duration. However, this is not necessarily what we have observed in practice.

The issue with DSUs is further exacerbated by the lack of appropriate incentives in the case of under-delivery. We do note that some DSUs may be contributing in line with the stated de-rating factors. As such it could be prudent to apply different 'multipliers' to specific classes of DSUs depending on measured historical performance (if this is possible to determine).

In Belgium, limits on consecutive periods of activation based on demand side response service level agreements are incorporated in the de-rating factors. Whilst in France, consecutive activation hour/day limits are incorporated into de-rating factors . These two examples provide for alternative options (or at least a precedent for a differentiated approach).

In any case, we believe that the ISAC de-rating process does capture the 'cannibalisation' effect and results in de-rating factors that appropriately reflect the DSU capacity contribution. However, if the outputs of this process are not adopted, a 'multiplier' would need to be applied to ensure we do not overstate the degree to which we can rely on DSUs for capacity adequacy.

Our preliminary ISAC analysis for the T-4 24/25 auction implies that the de-rating factors for energy limited DSUs should actually be almost halved based on the reapplication of de-rating factors from the T-4 24/25. This large difference between the de-rating factors from the previous determination and our current analysis is explained by:

- updating outage statistics (and applying a higher outage factor);
- improvements in the way we model DSUs; and
- an increase in the DSU capacity in the underlying portfolio.

Should the future DRFs for Energy limited DSUs be reverted to the T-4 24/25, it is the TSOs' position that a multiplier of 0.5 should be applied to the DRFs for DSU units with short durations.