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Report on Directed Contracts Concentration Model [REDACTED]

Prepared for the Commission for Regulation of Utilities and the Utility Regulator of Northern Ireland

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Executive Summary

The Commission for Regulation of Utilities (CRU) commissioned NERA to review and update the Regulatory Authorities' (RAs') Concentration Model (the "Model"). The Concentration Model determines the total volume of Directed Contracts (DCs) available to the market.

Background on Directed Contracts and the Concentration Model

The RAs introduced DCs to mitigate the risk of abuse of market power. DCs are forward hedging contracts that the RAs require ESB to offer to retailers at prices set by the RAs. Every quarter, the RAs set the volume of DCs that ESB must offer for upcoming quarters.

The RAs use the Concentration Model to determine the volume of DCs that ESB must offer. The Model assigns DCs based on an estimate of market concentration in the Day Ahead Market (DAM). It measures concentration using the Herfindahl-Hirschman Index (HHI). HHI measures market concentration based on ownership of supply only; it does not consider whether there is enough competition in supply to mitigate the risk of abuse of market power *given the level of demand*.

Recently, the Model has assigned zero DCs across all quarters. This result could be consistent with any of the following three mutually exclusive possibilities:

1. Reduced market concentration means the risk of abuse of market power in the SEM has declined, to the point that DCs may not be necessary;
2. The risk of abuse of market power in the DAM specifically has declined, but there may be more risk of abuse of market power in other SEM markets, so the RAs may need to consider whether DCs or an alternative tool can efficiently mitigate market power risks outside the DAM;
3. There is still enough risk of abuse of market power in the DAM that DCs may efficiently mitigate that risk, but the Concentration Model (in particular, the HHI metric) requires updating to be fit for purpose to measure market concentration given current DAM conditions. (This possibility does not preclude the risk of abuse of market power in other markets).

This report tests the third of these possibilities. We recommend updates to the Concentration Model and demonstrate the impact of these updates on assigned DCs in different scenarios.

We Recommend Updates to the Model

The three most material updates we recommend are:

1. **Replacing HHI with the Residual Supplier Index (RSI) as the measure of market concentration.** The RSI evaluates how much residual supply there is to meet demand *after excluding the largest supplier or suppliers*. Because it accounts for demand, the RSI approach provides a more contextualised estimate of the potential for abuse of market power than HHI. There is precedent for use of RSI in other markets (e.g., Germany and North American ISOs).
2. **Revising the treatment of wind and solar to better reflect DAM conditions.** We add solar to the Model; specify the ownership of all wind and solar units (previously the Model only specified ownership by ESB); and account for the different financial support schemes available to wind and solar units (which affect their incentives to participate in market power schemes).

3. **Allowing the Model to allocate DCs to entities other than ESB.** We allow any entity that owns dispatchable generation to be allocated DCs, based on that entity's contribution to RSI.

The Impact of Updates on DCs Depends on Model Parametrisation

To implement an RSI approach, the RAs must set values for four key parameters. These parameters establish the tolerance of the Model for market conditions that carry a risk of exercise of market power by large suppliers. As such, the four parameters play a similar role to the HHI threshold in the existing Model, which the RAs currently set at 1,150.

For each parameter, there is a range of reasonable values. We recommend that the RAs pick RSI parameter values that *collectively* reflect the RAs' tolerance for risk associated with market concentration in the SEM. While we provide guidance for the RAs on setting the parameters in the technical summary and body of the report, ultimately it is a matter of regulatory judgement.

We examined the impact of different parameter settings on DCs assigned by the RSI Model, using DC Round 31 (covering Q4 2025 to Q3 2026) as an illustrative example. Depending on the parameter settings, we found in the parametrisations we examined that DCs could be between 0 and 895 MW on average per quarter.

The parameter with the most impact on DCs is the X-RSI parameter, where X is the number of companies to exclude in the RSI calculation. The parameter determines whether the Model considers residual supply after excluding only *the single largest supplier*, or residual supply after excluding the *two largest suppliers*. In the parametrisations we examined: excluding one supplier (1-RSI) yields DCs in Round 31 between 0 and 293 MW on average per quarter, depending on the other three parameters; excluding two suppliers (2-RSI) yields DCs between 408 and 895 MW on average per quarter; and some 2-RSI parametrisations assign DCs to entities other than ESB.

We also examined how assignment of DCs varies across different market scenarios, including variation in gas and CO2 prices and supply and demand. Notably, in a scenario reflecting potential supply and demand in 2029 – with more renewable supply, the Celtic interconnector, and additional data centre demand – the Model assigned zero DCs under all parameter settings tested.

Conclusion and Recommendations

Overall, we recommend switching to the RSI Model because it provides a more contextualised estimate of market concentration than HHI. We recognise that the RAs must trade off the theoretical benefits of the updated Model against the implementation cost associated with changes, particularly as our 2029 sensitivity suggests that there may be no difference between the HHI and RSI Models in terms of assigned DCs in a few years' time (albeit this is only one scenario for supply and demand in 2029; the result would be different if for example further market consolidation occurs, renewable rollout is delayed, or more data centres are built).

We also recommend that the RAs investigate the second possibility outlined at the beginning of this Executive Summary, i.e., the risk of abuse of market power in other SEM markets that the Concentration Model does not capture. For example, the RAs could develop a model that accounts for network and system constraints, which would more closely proxy real-time dispatch and therefore would offer a better picture of potential market power in the Balancing Market.

Technical Summary

The Commission for Regulation of Utilities (CRU) commissioned NERA to review and update the Regulatory Authorities' (RAs') Concentration Model (the "Model"). The Concentration Model determines the total volume of Directed Contracts (DCs) that ESB (and/or potentially other companies) must make available to the market.

Background on Directed Contracts and the Concentration Model

The RAs introduced Directed Contracts (DCs) with the opening of the SEM in 2007. DCs are forward hedging contracts that the RAs require ESB to offer to retailers in the SEM at prices set by the RAs. There are three different DC products, applicable to different hours of the day: baseload products, which apply for all 24 hours; mid-merit products, which apply in daytime hours; and peak products, which apply in evening peak hours.[1]

Every quarter, the RAs issue a new round of DCs. In each round, the RAs set a volume of each DC product that ESB must offer for each of the subsequent four quarters. The RAs use the Concentration Model to determine the volume of DCs that ESB must offer. To do this, the Concentration Model forecasts market concentration in the SEM for the upcoming four quarters.

The Concentration Model calculates the DCs for the RAs to assign using the following process:

1. The Model takes the outputs of the (separate) SEM PLEXOS Model as an input. The specific inputs it takes from the SEM PLEXOS model include estimates of market data (i.e. generation, generation costs, SEM prices, etc.) from an unconstrained market for the quarters of interest. Since the modelled market is unconstrained, the Model provides a reasonable representation of the Day-Ahead Market (DAM); it does not represent actual dispatch, which depends on TSO redispatch actions in the Balancing Market (BM);
2. Using the inputs from the SEM PLEXOS Model, the Model calculates the market concentration for each hour of the quarters in question. The Model currently calculates market concentration using the Herfindahl–Hirschman Index (HHI). We recommend switching to using the Residual Supplier Index (RSI) as we discuss below; and
3. The Model assigns DCs based on its results for market concentration. The Model assigns DCs incrementally for each product type (i.e. baseload, mid-merit, and peak products) and period of time (each month or quarter) until it meets a threshold for the level of market concentration.

The key decisions on the design of the Concentration Model and the process to determine DC volumes are as follows:

- Decisions relating to how to model the SEM in PLEXOS. This report does not consider these decisions, as we take the RAs' SEM PLEXOS Model as given;
- Taking the SEM PLEXOS Model as given, decisions about how to measure market concentration within the SEM in each hour. These decisions pertain to the Concentration Model and as such are the subject of this report;

1 The exact set of hours in which mid-merit and peak hours apply (and MW of DC product delivered) vary by time of year and whether it is a weekday, as explained further in the body of the report.

- Some decisions are embedded in the design of the Concentration Model, such as the measure of market concentration to use, or how to assign ownership of each asset; and
- Others are parameters that the RAs must choose to calibrate the Concentration Model, for example, the threshold to apply to the measure of market concentration.

In this assignment, we reviewed several potential changes to the Concentration Model. The most material changes are:

1. Replacing the Herfindahl-Hirschman Index (HHI) with the Residual Supplier Index (RSI) as the measure of market concentration;
2. Revising the treatment of wind and solar to account for the different financial support schemes available to wind and solar units (i.e., RESS, REFIT, and NIRO); and
3. Allowing the Model to allocate DCs to entities other than ESB.

We discuss these in further detail below. We focus our attention primarily on the change from HHI to RSI, as this involves substantial reworking of the Model's internal structure. In contrast, the implementation of the other two changes mentioned above is relatively straightforward.

We Recommend Switching to an RSI-Based Concentration Model

Our assignment required us to weigh the advantages and disadvantages of using the Residual Supplier Index (RSI) instead of the Herfindahl-Hirschman Index (HHI) as the measure of market concentration in the Model. The CRU asked us to make a recommendation to the RAs as to whether the Model should continue to use the HHI metric or switch to an RSI metric.

The HHI and RSI measure market concentration in different ways:

- HHI is the sum of the squares of each generation company's market share. Higher concentration leads to a higher HHI. The maximum HHI value is 10,000, if one company is a monopoly, i.e. has 100 per cent market share. The existing Concentration Model calculates HHI in each hour. The Model then calculates average HHI across hours by month and type of hour (off-peak, mid-merit, and peak). It assigns DCs until the average HHI by month and type of hour falls below a target value of 1,150. The Model therefore has 30 separate targets of 1,150 (this is 30 rather than 36 because peak hours only occur in six months of the year).[2]
- RSI is a ratio of a) the total *residual* supply in the market after subtracting the supply of the largest company, or companies,[3] to b) market demand.[4] If one could remove the largest company and still exceed demand by 10 per cent, the one-player RSI metric would be 110 per cent or 1.1 expressed in decimals.

The body of this report describes these indices in more detail, including their calculation and precedent for their use from other jurisdictions.

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2 There are twelve months of off-peak hours, twelve months of mid-merit hours, and six months of peak hours (October to March). The final assignment of DCs is quarterly rather than monthly; in each quarter the Model assigns the maximum volume of DCs determined across the months within each quarter.

3 RSI may be measured by subtracting on the largest company only ("1-RSI"), or by subtracting the supply of the largest two or even three companies ("2-RSI" or "3-RSI").

4 The all-island electricity demand in the specific hour.

While both metrics have advantages and disadvantages, on balance we recommend switching to RSI for three reasons:

1. RSI directly assesses supply relative to demand, whereas HHI measures concentration in the abstract, without regard to demand. A relatively unconcentrated generation sector nonetheless could have a significant market power problem if there is very little surplus supply. A more concentrated generation sector with lots of surplus supply may have less of a market power problem. In such circumstances, HHI would be misleading.
2. The Model requires the user to specify a threshold for the index of market concentration to determine whether to assign DCs. For example, the RAs applied a threshold value for HHI of 1,150 in the most recent DC allocation round.[5] There is always some judgement required in the choice of threshold values. To aid in this exercise of judgement, it is helpful for the threshold values to have some natural interpretation. The thresholds used in RSI have some natural interpretation: an RSI of 1.0 or lower in a trading period means that the largest supplier (or suppliers) is *pivotal* in that period, i.e., that demand cannot be met without capacity from the largest supplier (or suppliers). While higher HHI values imply more market power potential (all else equal), HHI does not have a comparable intuitive threshold.
3. There is precedent for use of RSI (as well as HHI) to assess market concentration in power markets worldwide. We are not aware of any markets that are directly comparable to the all-island SEM in terms of size, level of interconnection, and generation type that we can look to as a benchmark. Nonetheless, other EU markets use RSI to assess market concentration (e.g., Germany). Unlike most EU markets, the SEM is centrally dispatched; we find that RSI is used in many of the centrally dispatched power pools in North America.

The RAs Must Set the Values of Four Parameters to Determine Directed Contracts Using the RSI-Based Concentration Model

We have developed an RSI-based version of the Model that the RAs could use to allocate DCs. To allocate DCs using the RSI-based model, the RAs must make decisions regarding parametrisation of that Model. Below, we describe the four parameters that the RAs must set and how they affect the allocation of DCs within the Model. We preface that discussion with a brief overview of the operation of the Model, to inform the RAs' decisions regarding parametrisation.

The RSI-based Model we have developed calculates RSI for every hour of the year-long modelling horizon. The calculation of RSI depends on:

- X-RSI, where X is the number of companies excluded (1-, 2-, or 3-RSI) (parameter 1); and
- Whether the model accounts for all available supply, or only supply offered at a price below a selected cost-competitive capacity threshold (parameter 3).

As for the existing HHI-based Model, the RSI-based Model takes as input the results of a forecast of an unconstrained SEM market from the Validated SEM PLEXOS Model, i.e., it is forward looking.

5 SEMC (26 November 2025), Round 33 of Quarterly Directed Contracts Q2 2026 to Q1 2027 Information Paper, SEM-25-066, p. 1

The Model assesses RSI in ten separate segments of the year, mirroring the ten DC products the RAs currently allocate.[6] Separately for each segment of the year, the Model calculates the percentage of hours in which RSI is below the selected RSI threshold (parameter 2). If the percentage of hours exceeds a selected limit (parameter 4), the Model assigns DCs to the supplier with the lowest average RSI across all hours in that segment. In other words, the Model allocates DCs to the party whose removal from the market results in the *smallest excess* of residual supply over demand (or *largest deficit*) on average. The Model then recalculates RSI with any allocated DCs subtracted from that supplier's capacity. The Model iterates this calculation and allocates more DCs until the percentage of hours in which RSI is below the RSI threshold is below the limit.

The RSI calculation in each hour h can be represented by the following formula:

$$X\_RSI_h = \frac{\sum_{i=1}^{N} CCsupply_{i,h} - \sum_{i=1}^{X}\left(CCsupply_{i,h} - DC_{i,h}\right)}{Load_h}$$

In this formula, the index h represents hours and i represents suppliers. Suppliers are ordered $1, \ldots, N$ by total cost-competitive supply within hour h, supplier 1 being the largest.[7] $CCsupply_{i,h}$ is the cost-competitive supply[8] of supplier i in hour h; $DC_{i,h}$ are the Directed Contracts allocated to supplier i that apply in hour h;[9] X is the number of suppliers excluded in the RSI calculation (i.e., 1-, 2-, or 3-RSI), and N is the total number of suppliers in the market.

The allocation of DCs depends on the RAs' choices regarding the following four parameters:

1. **X-RSI, where X is the number of companies** excluded (i.e., 1-, 2-, or 3-RS1). There is precedent for both 1-RSI and 3-RSI from other jurisdictions. 3-RSI calculates RSI by removing the supply of the three companies with the largest shares of cost-competitive capacity in each hour. Thus, 3-RSI measures the vulnerability of the market to simultaneous withdrawal by the three largest entities. 1-RSI only removes the company with the largest share of cost-competitive capacity in each hour. Thus, the degree to which the RAs are concerned about simultaneous withholding and/or collusion may guide the RAs' choice of X-RSI.
2. **RSI threshold**. The model calculates the percentage of hours in which RSI falls below the selected threshold. The Model allocates DCs to generation companies until the percentage of hours below the RSI threshold is below a limit, as set by the RAs (see parameter 4 below). An RSI threshold of 1.0 has an intuitive interpretation: It identifies hours in which the largest supplier (or suppliers, if using 2- or 3-RSI) are pivotal. Pivotality means a single supplier has a sufficient share of capacity that they could withhold their capacity, and the remaining generation would not meet demand. There is also precedent for a threshold of 1.1, which

[6] Four baseload segments (one per quarter), four mid-merit segments (one per quarter), and two peak segments (in Q1 and Q4). This is a slight difference between the RSI and HHI Models: the RSI Model directly calculates DCs on a quarterly basis whereas the HHI Model calculates DCs on a monthly basis and then takes the maximum within quarter. See footnote 2 above and also Sections 2 and 4.4 for further details.

[7] This means that the supplier indexation varies hour-to-hour. For example, Supplier A may be supplier $i = 1$ and Supplier B may be supplier $i = 2$ in hour 1, but the order may reverse in hour 2 depending on how much of the two supplier's supply is cost-competitive in that hour.

[8] Cost-competitive supply is the supply capacity the Model deems competitive given the SEM price. This could range from all capacity, even if its cost is much higher than the SEM price, to only a subset of capacity near to the SEM price. The cost threshold at which capacity counts as cost-competitive is a parameter the RAs will need to set.

[9] Directed Contracts are allocated incrementally by product and quarter, not allocated separately by hour.

indicates that the market is close to pivotality. A threshold of 1.1 may identify conditions in which there is market power without any entity being pivotal, for example if there is a risk of plant outages or if the market clears but system conditions are tight.

3. **Cost-competitive capacity threshold (CCCT)** to apply for determining what supply resources are relevant for the RSI calculation. The RAs will need to decide whether to count all available capacity as supply in the RSI calculation or apply a CCCT. There is precedent from other jurisdictions for either using all capacity or setting a CCCT of 50 per cent, i.e., allowing all capacity that is priced below the market clearing price *plus 50 per cent* of the clearing price to be considered cost-competitive.[10] The RAs could reasonably determine a different CCCT is fit for purpose in the SEM, depending on how they set the other parameters of the model. The Concentration Model applies the CCCT to each hourly SEM price from the SEM PLEXOS Model.
4. **The limit on hours** that can be below the RSI threshold (defined as a percentage of all hours in a segment). There is precedent from other jurisdictions for a five per cent limit, but the RAs could adopt a different limit for the SEM, depending on how they set the other parameters.

We recommend that the RAs pick RSI parameter settings that *collectively* reflect the RAs' tolerance for risk arising from market concentration in the SEM, with due consideration that (i) DCs are not the only tool the RAs have to mitigate market power[11] and (ii) higher volumes of DCs can be detrimental to free price formation in the SEM. For example, the RAs may choose to set a lower CCCT if adopting a 1-RSI approach, but a higher CCCT (or counting all capacity regardless of costs) may reflect a comparable risk tolerance if adopting a 2-RSI or 3-RSI approach.

Different parameter settings will result in different volumes of DCs (or potentially no DCs under some settings). Table 1 below reports the DCs that result from the Model under seven different parametrisations, based on data from historical DC Round 31 (R31), which covers Q4 2025 to Q3 2026. The DC quantities shown reflect the sum of baseload, mid-merit, and peak DCs, by quarter and across companies (the detailed breakdown by product and company is available in Appendix B). Table 1 shows that the Model allocates between 0 and 895MW of DCs (on average for the year) for the different combinations of the parameters shown. For comparison, under the HHI approach R31 produced zero DCs.

We have selected this specific set of seven parameter settings to demonstrate the extent to which the volume of DCs varies as we vary one or more parameters. The parameter settings shown do not represent a recommended set of parametrisations that the RAs should use.

One could consider the 1-RSI model with a 1.1 threshold, 50 per cent CCCT, and limit of 5 per cent of hours as a baseline, based on previous research commissioned by the European Commission.[12] The result is 293 MW of DCs. The remaining parametrisations of the 1-RSI model are illustrations of how the results change if we relax one or more parameters.

For 2-RSI, we can use less strict parameter settings in general, and for illustrative purposes, because the market will only fail to clear (or fail to clear using cost-competitive capacity) if multiple

[10] We also recommend imposing a floor on the CCCT, as we discuss in Section 4.2.3.1. Since the CCCT is set as a percentage of the market clearing price, if the market clearing price is very low the allowance for cost-competitive capacity is relatively limited.

[11] For example, the MMU monitors all markets and can recommend enforcement action.

[12] See Section 4.2.4.

parties have simultaneously withdrawn capacity. A simultaneous withdrawal of capacity is less likely to manifest than a single withdrawal of capacity for any given set of market conditions. We show a representative selection of parametrisations for 2-RSI in Table 1.

Some of the 2-RSI parametrisations we considered allocate DCs to multiple companies. In particular, the parametrisations in the first two rows of the table below assign a small volume of DCs to EP as well as assigning DCs to ESB. In principle, both 1-RSI and 2-RSI parametrisations could allocate DCs to multiple companies.

Table 1: The Volume of DCs Depends on the Settings Chosen for Four Parameters (Illustrative Example of Seven Parameter Settings and the Resulting DCs for Round 31)

Input: Parameter Settings				**Output: Allocated DCs (MW)**[1]				
X-RSI	RSI threshold	Cost-competitive capacity threshold (CCCT)	Limit on hours	Q4 2025	Q1 2026	Q2 2026	Q3 2026	**Average**
2-RSI	1.0	No CCCT	5%	750	1350	990	490	**895**
2-RSI	1.0	100%	15%	540	700	770	320	**583**
2-RSI	1.0	No CCCT	15%	360	610	570	90	**408**
1-RSI	1.1	50%	5%	90	540	540	0	**293**
1-RSI	1.1	50%	10%	0	150	310	0	**115**
1-RSI	1.1	100%	5%	40	360	110	0	**128**
1-RSI	1.0	50%	5%	0	0	0	0	**0**

Notes: (1) The allocated DCs are the sum of DCs allocated across all products (baseload, mid-merit, and peak) and all companies within each quarter. (2) The parameter settings shown do not represent a recommended set of parametrisations that the RAs should use; other parametrisations are possible.
Source: NERA Analysis

For each of 2-RSI and 1-RSI, we consider different settings of the other three parameters. For 1-RSI we consider stricter settings for the other parameters (higher RSI threshold, lower CCCT, lower limit on hours) than we do for 2-RSI. Even though we choose stricter settings for the other parameters, the 1-RSI approach yields fewer DCs than the 2-RSI approach.

Among the 2-RSI parametrisations, the least strict of the three (the third row of the table) results in 408 MW of DCs on average. Imposing a CCCT or reducing the limit on hours increases the allocation of DCs.

Within the 1-RSI options we see that the strictest of the four options (the fourth row of the table) results in 293 MW of DCs on average. Setting a lower RSI threshold, relaxing the CCCT, or increasing the limit on hours reduces the allocation of DCs.

Across all parametrisations we see a similar pattern of DCs across quarters, with more DCs allocated in Q1 and Q2 of 2026 than Q4 of 2025 or Q3 of 2026. From a single year it is difficult to say whether this is a seasonal pattern that would appear in every year, or a specific outcome of this round (e.g., planned outages during Q2 2026 likely contribute to the higher DCs in this quarter).

The current HHI model produces DCs of zero for the same input data (Round 31). While the current HHI model produces DCs of zero, it has previously produced non-zero DCs. Factors contributing to the zero result from the HHI model likely include the addition of Greenlink (additional supply not owned by the existing companies) and the retirement of Moneypoint (removing a large source of supply for ESB).

The fact that the RSI model produces non-zero DCs for quarters in which the HHI model produces zero DCs is likely because RSI accounts for demand, whereas the HHI model does not. Demand in the SEM has been increasing over recent years. While wind capacity has also grown, wind generation can drop to low levels for periods of time, causing tight margins in the SEM in some hours. The HHI model does not consider supply relative to demand; it only considers concentration of supply in the abstract. The RSI model, on the other hand, explicitly considers the tightness of the margin of supply relative to demand. This is an advantage because it allows RSI to react to changes in supply and demand balance even if ownership concentration remains similar.

Under any chosen set of RSI parameters, the level of DCs from the Model will change from DC round to DC round, based on changes in supply and demand in the SEM. We ran sensitivity tests to examine how the level of DCs produced by the RSI model would change across three scenarios. These scenarios were (a) a high gas and CO2 price scenario (b) a low gas and CO2 price scenario and (c) expected conditions in 2029 (including the Celtic interconnector, increased renewable and thermal capacity, and increased load due to data centres). The results were as follows:

- The high gas and CO2 price scenarios produced lower DCs for those parametrisations with a CCCT. The higher prices increased the SEM clearing price, causing more gasoil peakers to count as cost-competitive capacity (thus increasing RSI and reducing DCs). The low gas and CO2 price scenario produced higher DCs for parametrisations with a CCCT. There was minimal change for parametrisations with no CCCT.[13]
- The 2029 scenario produced zero DCs across all RSI parametrisations. The impact of the increased supply outside the control of the owners of dispatchable generation (i.e., the Celtic interconnector and additional wind and solar) on RSI exceeded the impact of increased demand from data centres.

The latter result, in particular, suggests that in the future as the SEM becomes more interconnected and has more capacity from more suppliers, the Model may consistently produce zero DCs.

Other Features of the Model Also Affect the Calculated RSI and thus the Volume of Directed Contracts

The level of DCs from the Model depends on choices made in setting up the model. Some of the modelling choices are likely to materially affect the resulting DCs, for example, choices regarding the treatment of renewables and interconnectors.

As part of the assignment, we recommend several updates to the Model aside from switching to an RSI approach. The results reported in Table 1 above reflect all the recommended updates as well as the change from HHI to RSI. We recommend that the RAs implement these updates regardless of the choice of index used to measure market concentration. That is, even if the RAs decide to use HHI instead of RSI, we recommend implementing the updates set out below.

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13 Minor changes in DCs (c. 20 MW) in the parametrisations with no CCCT are due to small changes in the position of hydro, pumped storage, and batteries in the merit order.

We briefly describe the choices made in setting up the Model that are likely to materially affect the volume of DCs, and where relevant how we have updated these choices in the new Model.

- **For wind**, we recommend differentiating between capacity under a support scheme and capacity not under a support scheme, as well as based on the details of the support scheme.
  - The existing HHI-based Model treats all wind as supply both for the whole market (which might alleviate market power concerns) and for individual companies (which could contribute to market power concerns);
  - We recommend a change, so that wind supported by RESS counts as supply for the whole market but does not count as supply for individual companies.[14] This recommendation reflects that RESS is a two-way Contract for Difference (CfD) which insulates the wind unit from the market price, so the wind unit itself cannot benefit from a market power scheme;
  - We recommend counting REFIT- and NIRO-supported wind as supply belonging to individual companies. REFIT is a one-way CfD, so owners of REFIT-supported units benefit from higher prices in some hours.[15] NIRO is a supplementary source of revenue, so owners of NIRO-supported units benefit from higher market prices in all hours.
- We recommend **adding solar generation** to the Model and applying the same approach as used for wind generation (including differentiation by support scheme). The existing HHI-based Model does not include solar generation. The addition of solar should decrease estimated market concentration, because ESB owns a relatively small share of total installed solar capacity in the SEM.
- We recommend **including interconnector capacity** in the Model. This is consistent with the approach used in the existing HHI-based Model. We use the market price in Great Britain to set the cost of existing interconnectors in the Model (we propose to use the market price for France to set the cost for the Celtic Interconnector). We understand some stakeholders argue that interconnectors should not be part of the supply in the Model because the GB-SEM interconnectors do not participate in the DAM at present. However, DAM participants bid knowing the availability of the interconnectors (which are coupled in intraday auctions 1 and 2) and assetless units act as a virtual interconnector in the DAM. As such, despite interconnectors not directly participating in the DAM, the DAM operates as if interconnectors were participating. Since the Model only includes physical units and does not include assetless units, including the interconnectors more closely proxies the actual supply offered in the DAM.
- We recommend **adding storage resources such as batteries** by counting their generation (as scheduled by the SEM PLEXOS model) as supply for the RSI calculation. This is the same as the approach currently used for pumped storage in the existing HHI-based Model. It is a simplified approach that aims to account for the energy limited nature of these assets. The addition of capacity from other storage resources (e.g., batteries) as well as pumped hydro is new for this

[14] We refer to this as *atomising* the wind capacity supported by RESS. We discuss this further in Section 3.2.3.

[15] Owners of REFIT-supported wind can benefit from higher prices when those prices exceed the REFIT reference price. It may be reasonable to atomise REFIT-supported wind in the same way as RESS-supported if the market price is consistently substantially below the REFIT reference price, such that even after the exercise of market power the market price would likely remain below the REFIT reference price. If market prices were consistently at such low levels, REFIT-supported units arguably would not benefit from higher prices.

version of the Model. The addition of batteries to the Model could either increase or decrease estimated market concentration, depending on which companies own the batteries and where they place in the merit order. We recommend that the RAs keep the approach to modelling storage resources under review as the total storage capacity active in the DAM increases.

- We recommend **assigning generators to their ultimate owners**, i.e., if one company acquires or merges with another company in the SEM, then all the affected generators roll up to the same entity in the Model. This general recommendation is not new, but we have updated the assignment of ownership of specific units based on new information in this version of the model. Specifically:
  - We recommend counting Tynagh and Ballylumford plant as part of EP, following changes in ownership since the development of the existing HHI-based Model;
  - We have updated the assignment of renewables to reflect wind ownership for each owner of dispatchable plants in the SEM, where previously only ESB's wind ownership was tracked. This should increase estimated market concentration as it would increase the estimated market share of large entities other than ESB.
- We recommend that the Model allows **entities other than ESB to be assigned DCs**. We recommend the assignment to other companies be determined efficiently by the Model. This is a change relative to the existing HHI-based Model, which only allowed one other entity besides ESB to be assigned DCs.[16] The proposed RSI-based Model assigns DCs in increments, assigning the next increment to the company with the lowest RSIs after accounting for DCs already assigned. Thus, whether the Model allocates DCs to entities besides ESB depends on supply and demand conditions, the relative sizes of ESB and other entities (which may change over time with retirements and new additions), and the RSI parameter settings.

The above list describes those modelling choices which we expect could materially impact the RSI and DCs. The updated model that we have supplied to the CRU embeds other modelling choices which have less material impact on the RSI and DCs. We describe these in the body of this report.

Key Decisions for the RAs to Make

The primary decision required from the RAs is whether to keep the current HHI approach or switch to an RSI approach to measure market concentration.

If the RAs choose to switch to an RSI approach, the RAs will also need to set the values of the four key parameters used in the RSI calculation (as described above). We recommend that the RAs pick RSI parameter settings that *collectively* reflect the RAs' tolerance for market conditions that carry a risk of exercise of market power by large suppliers.

We summarise the impact of the four parameters on the assigned level of DCs in Table 2 below.

[16] NIE PPB was assigned DCs for the 2008/9 SEM market year (see Directed Contracts 2008/09, Quantification and Pricing, Decision Paper, SEM-08-051, 15 April 2008).

Table 2: The RAs Must Set the Values of Four Key Parameters to Calibrate the RSI Model

Parameter	Description of parameter	Impact of increasing parameter on DCs	Guidance on choice
X-RSI (where X is the number of companies excluded)	The X largest companies whose capacity the Model excludes when calculating RSI. 1-RSI excludes the largest in each hour, while 2-RSI excludes the two largest in each hour.	Excluding a higher number of companies **increases DCs.** This is because it increases the portion of supply that the Model subtracts from the market supply in the RSI calculation, reducing RSI. A lower RSI increases assigned DCs as the RSI threshold is harder to meet.	We recommend 2-RSI if the RAs are concerned about coordinated or simultaneous withholding by the two largest players, and 1-RSI otherwise. 3-RSI yields a high volume of DCs in most parametrisations we studied, which may compromise efficient price formation and market signals; if the RAs are concerned about simultaneous withdrawal by three players, a mitigant other than DCs may be required.
RSI threshold	The level of RSI below which the Model deems an hour to be at risk of market abuse. This is analogous to the HHI threshold used in the HHI version of the model.	A higher RSI threshold **increases DCs.** That is because a higher RSI threshold requires more supply to sit outside the effective control of the largest company (or companies, if 2-RSI).	The RAs' choice should reflect their overall concern with market concentration and near-pivotality, and the risk tolerance implied by their settings of other parameters: 1.1 is stricter (potentially appropriate with other less strict parameters) and 1.0 is less strict (potentially appropriate with other stricter parameters). The RAs could also consider values between 1.0 and 1.1 (or even above 1.1). Higher thresholds (e.g. 1.1) may most accurately capture the risk of abuse because the PLEXOS inputs are averaged across multiple runs, and so may understate the hour-to-hour variability of demand and supply (and thus instances of tightness).
Cost-competitive capacity threshold (CCCT)	The threshold for determining which supply capacity the Model includes in the RSI calculation.	A higher CCCT **reduces DCs.** This is because the total market capacity is higher, which increases RSI.	We recommend that the RAs set a lower CCCT if they have particular concerns about efforts to raise prices during off-peak and mid-merit periods.
Limit on hours below the RSI threshold	The limit on the percentage of hours allowed to be below the RSI threshold. The model assigns DCs until this limit is met.	A higher limit **reduces DCs.** It allows more hours to be at risk of market abuse (according to the definition established by the first three parameters).	We recommend setting a higher limit if the choices for the other three parameters are stricter, because the overall potential for abuse of market power in hours below the RSI threshold lower.

Source: NERA analysis.

1. Introduction

The Commission for Regulation of Utilities (CRU) engaged NERA to review and update the Regulatory Authorities' (RAs') Directed Contract (DC) Concentration Model ("the Model"). The Model determines the total volume of DCs that ESB (and/or potentially other companies) must make available to the market in a given round of DCs.

As part of this review and update process, we have critically assessed different aspects of the Model and make a series of recommendations on how the CRU could update the Model at this stage.

The primary (but not sole) update we recommend is the movement from a measure of market concentration based on the Herfindahl-Hirschman Index (HHI) to the Residual Supplier Index (RSI). We describe each of these indices in more detail in turn in Section 4.1 and refer to each approach throughout the report.

The Concentration Model is based on an unconstrained representation of the SEM, that is, one which does not account for network or system operational constraints. As such, the results of the Model are primarily relevant to examining market concentration and potential for exercise of market power in the Day-Ahead Market (DAM). The Model is less informative about market concentration in the Balancing Market (BM), where the TSOs must account for network and system operational constraints. If the RAs are concerned about market concentration in the BM, we recommend that they develop an alternative model that is based on a constrained representation of the SEM.

The remainder of the report proceeds as follows:

- Section 2 provides an overview of how the Model currently calculates DC volumes;
- Section 3 sets out the potential updates to supply resources in the Model. This includes changes in ownership of capacity, the treatment of different technology types (primarily wind, solar and batteries), and assumptions on the make-up of generation costs;
- Section 4 discusses potential updates to the calculation of market concentration within the Model. We principally consider the choice of market concentration measure (RSI or HHI) to assess concentration in the Model and the setting of parameters to implement the chosen measure;
- Section 5 discusses the results of our sensitivity analysis, showing the DCs assigned by the RSI model using four different sets of PLEXOS inputs (the base case and three sensitivities); and
- Section 6 summarises our recommended updates to the Model and key considerations for any future updates to the Model.

2. How the Concentration Model Calculates Directed Contracts

In this section we provide a brief overview of how the current version of the Model quantifies DC volumes.

The Model forecasts market concentration in the SEM, based on simulations of day-ahead market (DAM) outcomes for the upcoming four quarters for which the RAs will assign DCs. The Model currently evaluates market concentration using an HHI approach, which measures market concentration based on the sum of squared market shares. The Model operates as follows:

1. First, the Model takes as inputs the results of an unconstrained run of the SEM PLEXOS Model for the four quarters of interest. This PLEXOS model run provides hourly availability, generation, generation cost, and SEM price data for each hour. Since the modelled market is unconstrained, these PLEXOS results offer a reasonable representation of the Day-Ahead Market (DAM); they do not provide a good representation of actual dispatch, which is affected by TSO redispatch actions taken in the Balancing Market (BM).
2. Second, the Model calculates the HHI of each hour of the year. HHIs vary hour by hour due to differences in generator and interconnector availability and differences in SEM market prices (driven by variation in demand as well as supply). Within each hour, the Model includes in the HHI calculation only those resources whose costs are no more than 5 per cent above the hourly SEM price.
3. Finally, the Model assigns DCs. The Model calculates DCs by month and separately for baseload, mid-merit, and peak products. The Model assigns DCs incrementally, until the average HHI reaches 1,150 separately for each month and type of hour: off-peak, mid-merit and peak.[17]

Off-peak, mid-merit, and peak hours are determined by reference to the hours where the baseload, mid-merit, and peak DCs apply:

- Peak hours are identical to the hours where peak DCs apply (i.e. the four hours starting 17:00 and ending 21:00 during Q1 and Q4). There are no peak DCs or peak hours in Q2 and Q3;
- Mid-merit hours are all hours where mid-merit DCs apply, but peak DCs do not (i.e., excluding any peak hours). Within Q2 and Q3, these are the sixteen hours from 7:00 to 23:00, and within Q1 and Q4, these are the fourteen hours from 7:00 to 17:00 and 21:00 to 23:00; and
- Off-peak hours are all hours that are neither peak nor mid-merit hours. That is, the eight hours from 23:00 to 7:00 the next day.

Each hour of the year is tagged as one (and only one) of off-peak, mid-merit, and peak in the Model. To enable the separation of DCs by product type and quarter, the Model performs 30 separate average HHI calculations. The Model calculates 30 levels of DC volumes (in MW) which ensure the average HHI is no more than 1,150 separately for: off-peak hours (in all twelve months),

[17] There is a difference between the "baseload product", which is the product covering 24 hours, and "off-peak hours" which are the hours during which only baseload products apply (i.e. 23:00 to 7:00).

mid-merit hours (in all twelve months), and peak hours (in the six months: October to March). The Model sets the DC volume to zero if the HHI is below 1,150 prior to allocating any DCs.

If HHI is above 1,150 without any DCs, the Model incrementally assigns DCs to ESB. Each MW of DC reduces the MW size of ESB but not the MW size of the overall market, thus reducing ESB's market share, for the purposes of calculating the HHI. Hence, each MW of DCs causes HHI to fall.[18]

The Model calculates quarterly DCs by product (baseload, mid-merit, and peak) by taking the maximum allocated DCs across the three months in the relevant quarter, by product. For example, if the Model calculates peak-product DCs of 40 MW, 60 MW, and 55 MW for October, November, and December, respectively, the Model will assign 60 MW of DCs for the Q4 peak product.[19]

The Model initially calculates the required DCs without regard to how may DCs ESB has already sold for the quarters in question. As a final step, the Model calculates the incremental DCs to make available in the upcoming DC round. This calculation of incremental DCs includes an adjustment to account for the fact that DCs are assigned on a rolling four-quarter basis and so further DCs may be assigned for the quarter in future rounds.[20]

The remainder of this report describes our proposed updates to the Model. The main update is a shift from HHI to RSI as the measure of concentration in each hour, though we also propose other more minor updates (e.g., to reflect changing ownership shares and the changing resource mix on the system). The proposed updated Model follows the same overall process as the current Model but using RSI instead of HHI as the metric to assess market concentration.

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18 The Model reduces ESB's MW size by 80 per cent of the mid-merit DC volume on non-business days, matching the rule for the mid-merit product.

19 We suggest switching from this approach to calculating quarterly quantities directly if the RAs choose to adopt an RSI approach. We explain the rationale for this proposed change in Section 4.4.3.

20 As a hypothetical example of this final step, assume it is the second DC round where Q4 2025 products are sold, and assume that ESB sold 10 MW of Q4 2025 mid-merit DCs in the prior DC round. Assume the Model now calculates 91 MW of Q4 mid-merit DCs for ESB. The model then starts with the 91 MW, subtracts the 10 MW sold, resulting in 81 MW, and finally divides by three considering there are now three more rounds where Q4 2025 products will be offered (including the current round). This yields 27 MW of mid-merit Q4 2025 DCs that the Model determines ESB should make available in the current DC round.

3. Supply Resources, Ownership, and Cost-Competitive Capacity

In this section, we discuss the updates we considered to the representation of supply-side resources in the Model:

- Section 3.1 sets out our proposed changes to the assignment of ownership of dispatchable generation assets to reflect recent acquisitions of capacity;
- Section 3.2 sets out our proposed changes to the treatment of wind and solar in the Model, including accounting for ownership across companies and the treatment of resources that benefit from renewable support schemes (e.g., RESS);
- Section 3.3 sets out our proposal to add batteries to the Model and apply the same treatment for batteries that we currently apply to hydro and pumped storage;
- Section 3.4 explains why we propose to continue to exclude DSUs from the Model;
- Section 3.5 sets out our proposal to use generation scheduled in PLEXOS, even if deemed not cost-competitive, as a floor for a unit's cost-competitive capacity when calculating market concentration;
- Section 3.6 explains why we propose to continue to set a fixed price for units that are not scheduled to generate in PLEXOS;
- Section 3.6 explains why we propose to continue to exclude bid mark-ups from plant costs;
- Section 3.8 sets out our proposal to discontinue atomisation for Edenderry.

3.1. Changes in Ownership of Generation Assets

We have updated the model to reflect two changes in asset ownership that have occurred since our previous update of the concentration model. In both cases, EP has acquired controlling ownership of a conventional unit. We discuss each in turn below.

3.1.1. EP UK Investments Ltd 80 per cent ownership of Tynagh

We understand that in 2019 EP UK Investments Ltd ("EP") acquired an 80 per cent ownership stake in Tynagh (with the remaining 20 per cent owned by Mountside Partners Limited).[21] This ownership change is not reflected in the current version of the Model. We recommend assigning 100 per cent ownership of Tynagh to EP.

A potential reason to keep Tynagh as a separate company would be if the agreement with EP included a ringfencing arrangement, where Tynagh continued to operate as a separate company and EP, despite its ownership, did not have operational or market control of Tynagh. We understand that EP does have operational control of Tynagh, so we do not recommend keeping

21 Competition and Consumer Protection Commission (30 September 2019), Determination of Merger Notification M/19/025 EP UK Investments Limited – Tynagh Energy Limited, URL: https://www.ccpc.ie/business/wp-content/uploads/sites/3/2019/08/Public-Determination-M-19-025-EP-UK-Investments-Tynagh-Energy.pdf. Accessed on 18 December 2025.

Tynagh as a separate company.[22] Even if a ringfencing agreement were in place, we would recommend that the RAs review the agreement to ensure the entities are sufficiently separated before adopting separate treatment in the Concentration Model.[23]

We considered assigning 80 per cent of Tynagh's capacity to EP and 20 per cent to Mountside Partners Limited as an alternative to assigning all capacity to EP. There is some conceptual support for this approach as presumably only 80 per cent of the benefit of any higher prices received by Tynagh would flow to EP.

However, we do not recommend the 80-20 split ownership approach as:

- First, we understand that EP effectively has control of Tynagh in the SEM. Theoretically, then, EP could withhold all of Tynagh, not just 80 per cent, as part of a market power scheme;
- Second, the difference in the Model results is minimal when comparing an 80 per cent assignment versus a 100 per cent assignment of Tynagh to EP. In the RSI-based Model, there is only an effect on DCs in the small number of RSI parametrisations where EP also receives DCs;[24]
- Third, the current Model infrastructure is unable to handle joint ventures. Each unit is assigned to a single owner. While we have considered updating the model to handle multiple ownership, doing so would require material effort and add complexity. We agreed with the CRU that the cost of implementing this change outweighs the potential benefit, given the first two points above.

We recommend the RAs continue to monitor the market to see whether partial ownership of power plants becomes more common. If partial ownership becomes more common, then the RAs should consider updating the Model to accommodate partial ownership.

3.1.2. EP UK Investments Ltd 100 per cent ownership of Ballylumford

In 2019, Energia Group, Energia Customer Solutions NI, and Power NI Energy Ltd executed a Business and Asset Transfer Agreement that rationalised the Group's retail presence in Northern Ireland under the Power NI brand. Under this arrangement, PowerNI Energy Ltd Power Procurement Business (PBB) retained commercial control of the Ballylumford units until the end of 2023, when EP assumed commercial control of the Ballylumford site.

From the end of 2023, EP assumed commercial control of the Ballylumpford site. As a result, we no longer consider it accurate to assign ownership to a separate Power NI entity (Power NI Energy Ltd Power Procurement Business (PBB)). Instead, for market concentration purposes, it is more

[22] We understand from the CRU that EP are the main commercial decision makers for Tynagh.

[23] The RAs have addressed ringfencing previously in the Concentration Model. See for example the 2006 SEM Decision Paper on the Directed Contract methodology, which states "Regulatory Authorities accept the NERA ringfencing recommendations and will treat the unregulated generation affiliates of ESB PG and NIE PPB as separate from ESB PG and NIE PPB for purposes of the HHI calculation."

SEM (8 December 2006), Market Power Mitigation in the SEM, Directed Contract Quantification Methodology, Decision Paper, AIP/SEM/208/06, p. 11

[24] To implement the RSI Model, the RAs will need to set values for four key parameters. We discuss the parametrisation options and their impact on DCs in Sections 4.2 and 4.3.

accurate to treat EP as the owner. We recommend updating the Model to assign EP as the owner of all Ballylumford units (B10, B31, B32).

3.1.3. EP and TotalEnergies Joint Venture of Established for All EPH Power Generation Assets

On 17 November 2025, TotalEnergies and EP announced the establishment of a 50-50 joint venture between the two companies to operate and develop EP's flexible power generation across a selection of European countries.[25] We understand that this joint venture will have ownership of all of EP's stakes in thermal generation assets that operate within the SEM.[26]

Given the joint venture will acquire all of EP's existing generation assets, the new joint venture will have the same market power incentive to operate these assets and same market position as EP would otherwise have had. As such, the Model should treat the joint venture equivalently to its treatment of EP and does not require any update. We recommend no change to the Model following the establishment of the joint venture. However, should EP or TotalEnergies develop or acquire any generation or storage assets outside of the joint venture in the future, the RAs may need to re-open the treatment of the joint venture to account for this.

3.1.4. Impact on DCs of assigning additional capacity to EP

Table 3.1 below shows the effects on the HHI-based Model of assigning EP 100 per cent ownership of Tynagh and Ballylumford. The results compare HHI before and after this change in ownership using the outputs of the current SEM PLEXOS Model for R30.[27] In all periods, both before and after the update, the market concentration is under the threshold of 1,150 and no DC volumes are assigned.

These results show the impact of this change in ownership in a previous round, but in future rounds the exact impact may differ. We recommend that the RAs treat these results as merely indicative of the approximate magnitude of the impact of this change for rounds other than R30.[28]

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25 EP website (17 November 2025), URL: https://www.epholding.cz/en/press-releases/totalenergies-and-eph-establish-a-joint-venture-to-operate-and-develop-flexible-power-generation-assets-in-selected-european-countries/. Visited on 11 December 2025.

26 That is: Ballylumford, Kilroot, and Tynagh.

27 We used the 2024 version of the SEM PLEXOS model for this analysis. This version of the model is slightly different to the previous version of the SEM PLEXOS model that the RAs used when *assigning* DCs at R30. Therefore, the DCs reported in the column "Average HHI Before Ownership Update" may differ from the DCs actually assigned at R30.

28 Here and throughout the report, the effects of any changes may vary across Model rounds. That is because the effects of individual changes may vary as the underlying market changes.

Table 3.1: Assigning Ownership of Tynagh and Ballylumford to EP Increases HHI by Up to 10 Per Cent in Round 30, but the Increased HHI Remains Below the 1,150 Threshold for DCs

Quarter	Product	Average HHI Before Ownership Update	Average HHI After Ownership Update	Difference	Difference (%)
Q3 2025	Baseload	554	554	0	0%
Q3 2025	Mid-Merit	904	922	18	2%
Q3 2025	Peak	-	-	-	-
Q4 2025	Baseload	678	679	1	0%
Q4 2025	Mid-Merit	786	803	17	2%
Q4 2025	Peak	867	930	63	7%
Q1 2026	Baseload	734	736	2	0%
Q1 2026	Mid-Merit	854	872	18	2%
Q1 2026	Peak	884	955	71	8%
Q2 2026	Baseload	676	681	5	1%
Q2 2026	Mid-Merit	842	877	35	4%
Q2 2026	Peak	-	-	-	-

Source: NERA analysis of Round 30 data using 2024 SEM PLEXOS model results.

3.2. Wind and Solar

We propose a number of updates to the treatment of wind and solar units in the Concentration Model. In particular, we propose that in this round of updates to the Model we:

- Add solar capacity to the Model;
- Specify whether wind and solar capacity is owned by entities other than ESB that also own dispatchable generation;
- Atomise only that renewable capacity which is supported by the RESS scheme, to account for the fact that RESS is a 2-way CfD and as such RESS-supported units do not benefit from market power schemes that increase the SEM price;
- Include curtailed wind and solar as supply when measuring market concentration.

We also discuss that in future, the RAs may want to add a further renewable category to account for offshore wind (at present, the Model only includes onshore wind).

3.2.1. Adding solar capacity to the model

Currently, the Model does not include solar capacity in its calculation of market concentration. Given that solar capacity is now substantial and continuing to grow, we recommend including solar capacity in the Model. We recommend treating solar the same as wind in the Model.

3.2.2. Specifying ownership of both wind and solar units

The current iteration of the Model only explicitly specifies ownership of wind units for ESB. The Model currently assumes that ESB owns 12 per cent of all wind capacity. All other wind capacity is split equally amongst a predetermined number of notional owners (currently five) which are treated as separate entities for the HHI calculation.

In reality, owners of dispatchable generators other than ESB also own large wind and solar portfolios (e.g. SSE, Bord Gáis, etc.). We recommend updating the Model to reflect current wind ownership shares for all named companies in the Model that is, for all companies that own at least one of the dispatchable generation resources included in the SEM PLEXOS Model.[29]

We have calculated wind and solar ownership percentages using data provided to us by the CRU and the TSOs as well as publicly available data. On the basis of these calculations, we recommend applying the ownership percentages for the named companies as set out in Table 3.2 below. We have shared the underlying analysis of wind and solar ownership with the CRU.

The table shows that we allocate most solar capacity to "other owners". The "other owners" category includes both capacity assigned to owners without dispatchable generation in the SEM and capacity connected behind the customer's meter (i.e., distributed generation), since we do not have data on ownership for the latter. The fact that we allocate more solar than wind capacity to "other owners" primarily reflects the relative prevalence of distributed solar generation.

Table 3.2: Estimated Wind and Solar Ownership Shares by Company

Name	Wind Percentage Ownership	Solar Percentage Ownership
ESB	11.5%	9.6%
Bord na Móna	4.5%	0.0%
SSE	18.3%	1.2%
Energia	11.5%	0.7%
Bord Gáis Energy	3.9%	8.8%
Other Owners	50.2%	79.6%

Note: "Other Owners" includes both owners without dispatchable generation in the SEM and distributed wind and solar resources which are not registered in the SEM. Any party that owns dispatchable generation in the SEM and does not appear in the table does not own any wind or solar per the methodology set out below.
Source: NERA analysis of wind and solar registration data from the CRU and public data sources.

We use the following methodology to derive these ownership percentages:

- We use a spreadsheet provided to us by the CRU that contains all registered wind and solar units in the SEM (all units with a "GU_" number). This spreadsheet includes the capacity of the units and the name of the party that has control of the units in the SEM;

[29] The supporting spreadsheet to the 2024-2033 SEM PLEXOS Model entitled "PUBLIC -- GEN DATA 2024-2032", worksheet "Generator Data" contains the list of relevant dispatchable power plants.

- We aggregate the wind and solar capacity by the name of the party that controls the units in the SEM.[30] We discussed with the CRU the relative merits of assigning renewables capacity to the technical owner of the capacity versus assigning it to the party to which the unit is registered in the SEM. We decided to assign capacity based on the party to which the unit is registered in the SEM as:
  - This is consistent with how renewables capacity was assigned to entities in prior Model updates;
  - It is reasonable to assume that the party that controls the resource in the SEM will have influence on use of the resource as part of a market power scheme;
  - The technical owner may have some commercial arrangement with the party that controls the resource in the SEM where generation and / or the revenues from the resource flow to the controlling party; and
  - We found several examples where the entity to which the resource is registered in the SEM references the renewables resource on its webpage even though that entity does not technically own the resource. This provided further anecdotal support for our approach.

  Nonetheless, the RAs may wish to re-assess from time to time the question of whether to assign renewables to the technical owner or the controlling party in the SEM.
- For each entity, we divide the entity's total wind or solar capacity by the approximate total wind or solar capacity in the SEM. We obtain the total wind and solar capacity from the 2025-2034 All-Island Resource Adequacy Assessment (AIRAA), as published by the TSOs.[31]
- The Model multiplies the resulting percentages by the wind and solar generation in the model in each hour to arrive at the wind and solar supply tied to each owner in each hour.

Our approach means the Model:

- Considers all wind and solar (whether distributed or grid connected) as part of the supply in the Model;[32] and
- Only considers registered units with GU_ numbers when assigning supply to owners. This is particularly important for solar, since a large portion of currently installed solar is distributed solar.

A material quantity of the wind and solar in the SEM is registered to companies that do not have dispatchable generation. In the current HHI model, it is important to account for these owners in

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30 We consolidate certain parties that are identifiability part of the same overarching company. Some consolidations are obvious (different variations of the same corporate name); for others we relied on information provided by the CRU.

31 We also reviewed the 2023-2032 Ten-Year Generation Capacity Statement, which was the precursor to the AIRAA, to identify the approximate level of wind and solar capacity installed around the same vintage date of the spreadsheet of registered wind and solar units in the SEM that the CRU provided us.

EirGrid and SONI (May 2025), All-Island Generation Capacity Statement 2025-2034; and EirGrid and SONI (January 2024), Ten-Year Generation Capacity Statement 2023-2032;

32 This approach is consistent with how the SEM PLEXOS Model is set up: the SEM PLEXOS Model includes distributed generation (whether from renewables or non-renewable resources) and similarly includes all load including load served by distributed generation, based on the capacity published in the precursors to the AIRAA, the Ten-Year Resource Adequacy and Generation Capacity statements. The Model is based on SEM PLEXOS Model data.

some way, since the relative amount of consolidation affects the calculation of HHI. In the RSI model, the level of wind consolidation outside of the major companies does not affect the RSI.[33] Based on our analysis of the level of concentration of wind and solar among entities that do not own disputable plants, we recommend 28 so-called "other wind owners" and 36 so-called "other solar owners". These parameters only affect the HHI calculation.

Under a 1-RSI approach, we expect the decision to assign wind and solar to entities aside from ESB to have little if any effect on the results, so long as ESB remains the largest company and the only company to which the model assigns DCs in practice.[34] Nonetheless, this update ensures that the Model is neutral with respect to owners and the assignment of DCs.

Under a 2-RSI or 3-RSI approach, assigning wind and solar to entities aside from ESB could impact Model results. Under the HHI model, assigning wind and solar to entities aside from ESB affects the HHI materially.

We recommend that the RAs update the ownership percentages regularly, e.g. yearly.

3.2.3. Atomisation of wind and solar capacity subject to certain renewable support schemes (e.g., RESS)

Some wind and solar units are in receipt of financial support which mean they do not benefit from higher SEM prices. For example, the Renewable Electricity Support Scheme (RESS) in Ireland is a two-way contract for difference (CfD), which ensures units receive a fixed strike price for their electricity. In this case, the owner of the supported units has no incentive to exercise market power to increase the SEM price paid to these units when they generate. We account for this in the Concentration Model by *atomising* wind and solar capacity that is in receipt of such financial support.

In terms of the Concentration Model, atomisation of capacity means that the Model counts it in the overall market's supply but does not count it in any individual owner's supply.[35] As such, atomised capacity is that which we believe has no basis to benefit from a market power scheme.

In the HHI-based model, atomisation always reduces the HHI (i.e. less concentrated) but has a larger impact if the atomised capacity belongs to the largest owner. In the RSI model, atomisation increases the RSI (i.e. less concentrated) if the largest owner's (or owners', for 2- or 3-RSI) capacity is atomised.

It is possible to atomise any generation capacity, but we focus on the decision to atomise wind and solar in this section.

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[33] It is theoretically possible that in a mostly or fully decarbonized future a company that only owns renewables and storage could have market power that merits mitigation with DCs. The proposed Model is already set up to accommodate that possibility – the model user simply needs to add such a company to the list of companies that the Model considers for DCs. While presently the list of companies the Model considers for DCs is limited to the companies that own dispatchable power plants, it is straightforward to add other companies to that list.

[34] Even with ESB as the largest company overall, other companies can still affect the level of DCs assigned to ESB if they have RSIs below the RSI threshold in certain hours.

[35] The term "atomisation" reflects the idea that not counting atomised capacity towards any individual owner's supply is mathematically comparable to splitting the capacity amongst an infinitely large number owners, so that each owner has only an infinitesimally small amount of capacity (i.e. an atom's worth).

In the current Model, no wind is atomised, and the Model has never previously atomised wind.

In our present assignment, we have carried out a conceptual assessment of wind atomisation, including conversations with subject matter experts and the MMU. Based on our assessment, we recommend atomisation of wind and solar capacity that is subject to a support scheme in which the capacity does not benefit from higher SEM prices (including the RESS 2-way CfD). The corollary is that one should not atomise capacity which *can* benefit from higher SEM prices. We recommend applying this approach when determining which wind and solar to atomise.

We also considered the treatment of units in receipt of other forms of financial support:

- **Ireland's Renewable Energy Feed-in Tariff (REFIT) Scheme**: The REFIT scheme is a 1-way CfD. Under a 1-way CfD, the wind or solar benefits from price upside relative to the contract price and so may have an incentive to raise prices above the contract reference price. We do not recommend atomising such capacity, given the 1-way nature of the CfD.

  However, when SEM prices are substantially below the REFIT contract price, one could argue that REFIT units do not benefit from higher prices. If the incrementally higher prices from exercising market power remain below the contract price, REFIT-supported units would not receive incremental benefit from the exercise of market power.

  We considered whether to atomise a fixed percentage of the capacity supported by REFIT, to approximate the partial benefit to REFIT-supported units from increasing SEM prices. Ultimately, we decided against this option and recommend non-atomisation of REFIT units for the following reasons:

  - Prices have been relatively high in the SEM since and even before the invasion of Ukraine, due to higher natural gas and CO_2 prices and the relatively tight supply conditions in the market. The higher the price, the more likely an owner of a REFIT wind or solar plant might benefit from the exercise of market power;
  - Even if SEM prices were to fall, they could in future rise again to levels where REFIT-supported wind and solar do not receive support payments.

- **Northern Ireland's Renewables Obligation (RO) scheme**: We understand that the RO scheme in Northern Ireland provides a supplementary source of revenue for renewables in addition to the market price. As such, these renewables still would receive the benefit of higher SEM prices and so have an incentive to exercise market power. We therefore do not recommend atomising renewables under the RO scheme.

- **Renewables whose output is sold under power purchase agreements (PPAs) or similar private arrangements that fix the price paid to the owner of the renewables plant**: While some renewables plants may sell their power under such arrangements, we do not recommend accounting for these arrangements when deciding how much wind and solar to atomise.

  The details of any such contracts would matter to the decision of whether the contracted capacity should be atomised, e.g., the terms of the deal, who is buying and who is selling, the role of the owner versus the party to whom the resource is registered. Understanding these details would be time consuming and would require information to which neither we nor the CRU team has access, as far as we are aware.

We summarise our proposed treatment of different renewable support schemes in Table 3.3 below.

Table 3.3: Recommended Treatment of Wind and Solar Under Different Support Schemes in the Concentration Model

Support Scheme	Description	Treatment in the Model
Renewable Electricity Support Scheme (RESS) in Ireland	A 2-way CfD for renewables where the supported generator receives a top-up equal to the difference between the market price and the strike price if an hourly price is below the strike price and pays back the difference between the market price and the strike price if an hourly price is above the strike price.	All capacity is atomised.
Renewable Electricity Feed-In Tariff (REFIT) in Ireland	A 1-way CfD that tops-up renewable generators if the average market price is below the unit's REFIT contract price. If the average price is above the contract price, the scheme has no effect so the generator benefits from price upside but is protected if prices are lower.	No capacity is atomised.
Renewable Obligation (RO) in Northern Ireland	The RO scheme pays a fixed GBP per MWh for each MWh of electricity generated by the supported renewable generator.	No capacity is atomised.
Power Purchase Agreements (PPAs)	Renewable generators may sign private agreements to sell their power to third parties via PPAs. These arrangements may include terms that affect a generator's incentives to utilise the resource.	No capacity is atomised.

Source: NERA analysis.

Other approaches to atomisation we considered (and rejected) are:

- **Atomising all wind and solar:** one could argue that wind and solar generate when available, so intentionally withholding capacity from the market would be difficult in practice and easy to detect. This may support atomisation of all wind and solar, including wind and solar that could benefit from higher market prices (on grounds that it apparently could not participate in a market power scheme). We do not recommend atomising all wind and solar, for two reasons:
  - First, and primarily, a classic market power scheme involves withholding some capacity so that capacity which remains online benefits from higher prices. Wind or solar could be the capacity that remains online within a market power scheme; and
  - Second, even if withholding wind and solar capacity may have challenges, it is not impossible. This is particularly true for the DAM, in which market participants bid based on a *forecast* of wind and solar availability rather than true availability. As mentioned in Section 1, the focus of this Model is to provide a representation of the DAM (rather than e.g., real-time dispatch).
- **Atomising no wind and solar:** one could argue that even if RESS-supported wind and solar capacity does not itself benefit from higher market prices, the owner of that capacity could attempt to withhold it strategically to increase market prices for the benefit of its other units. This may support atomisation of *no* wind and solar. On balance, we do not recommend this approach. The ultimate aim of the market power assessment in this Concentration Model is to determine the assignment of DCs. DCs are designed to mitigate the risk of abuse of market

power by reducing the *incentive* for large providers to exercise market abuse through requiring them to sell a certain portion of their output at a fixed price. RESS contracts also require providers to sell the output of the capacity under contract at a fixed price. For the specific question of assignment of DCs, then, it is consistent with the logic of DCs as a tool for market power mitigation to atomise RESS-supported capacity. However, in other contexts or for other market power mitigation mechanisms, it may be necessary to consider the potential for providers to withhold capacity from RESS-supported units as part of a market power scheme.

Ultimately, the decision on whether to atomise wind and solar capacity to account for financial support schemes available to renewables is the RAs' to make. Arguably, there is a strong case for atomisation of RESS-supported resources and for non-atomisation of RO-supported resources. With REFIT, the case for or against atomisation is dependent on market conditions. We suggest no atomisation given current market conditions, but the RAs may wish to review this decision in the future, particularly if market prices collapse to a level where there seems little to no chance wind or solar under REFIT would receive any benefit from higher market prices.

3.2.4. Treatment of wind and solar curtailed by PLEXOS

PLEXOS may curtail wind or solar in cases where there is insufficient load to absorb all output or when it is economic within an unconstrained model to curtail (e.g., to avoid start-up or shut-down costs for a thermal generator). The current Model does not consider curtailed volumes as part of supply for the purposes of measuring market concentration.

Under current conditions, PLEXOS rarely curtails wind, so the decision to include or not include curtailed wind does not materially affect the results of the Model.[36] In the future, PLEXOS may curtail more wind and solar as total wind and solar generation grows.

We recommend the Model includes curtailed wind and solar as part of the supply, rather than ignoring it. If a non-renewable generator withholds capacity in an hour with curtailed renewable output, then that renewable resource would potentially no longer be curtailed. In this way, curtailed wind and solar volumes help prevent market power abuse as they are part of the wider supply of capacity that could generate. Therefore, we should include curtailed wind and solar as part of the supply.

3.2.5. Provision for offshore wind

We considered how to treat offshore wind in the Model. Ultimately, we agreed with the CRU team that we should not make any updates to the Model to accommodate offshore wind at this time, since offshore wind will not be relevant to runs of the Model for several years.

Nonetheless, we offer the following considerations on how to treat offshore wind in the Model.

- We recommend that, in future, the RAs adapt the Model to include offshore wind as a third category of renewables, alongside onshore wind and solar;

[36] The SEM PLEXOS Model is an unconstrained model that does not impose any limits on non-synchronous generation and does not account for transmission constraints. That is why the SEM PLEXOS Model does not curtail significant quantities of wind, even though material amounts of wind are curtailed (or constrained off) in Ireland and Northern Ireland at the point of real-time dispatch.

- Treating offshore wind separately to other renewables will allow the direct assignment of offshore wind generation to its owners. This will make it easier to track generation from offshore wind (since offshore wind will have a higher capacity factor than onshore wind) and allow the RAs to implement decisions about atomisation specific to offshore versus onshore; and
- We understand offshore wind will be supported by 2-way CfDs under the ORESS scheme. The RAs may consider atomising offshore wind supported by 2-way CfDs, in line with our recommendation for onshore wind and solar under RESS. That said, the quantities of generation from offshore wind are likely to be large. If and when offshore wind becomes a major portion of SEM generation, we recommend the RAs critically assess whether ownership of offshore wind could contribute to a market power scheme even if under a 2-way CfD.

3.3. Storage Resources: Hydro, Pumped Storage, and Batteries

Hydro and pumped storage capacity is currently included in the Model. Batteries are not currently included in the Model. We recommend including batteries in the Model.

There is no practical difference between pumped storage and batteries from the perspective of the Concentration Model. Both technologies store energy over time and losses cause the resource to discharge less energy than drawn from the grid for charging. Including batteries is thus consistent with the inclusion of pumped storage.

All hydro and pumped storage is currently treated as cost-competitive capacity in the Model based on the generation output as scheduled in PLEXOS. The Model has followed this approach since its creation, and we recommend maintaining this approach for hydro and pumped storage and extending it to batteries.

The SEM PLEXOS model currently limits the battery capacity that can be scheduled in PLEXOS. This limit is set at 30 per cent of capacity for each battery until December 2026, and 50 per cent thereafter.[37] The limit was based on feedback from stakeholders and the RAs in the last SEM PLEXOS validation exercise, to reflect both constraints on battery participation implied by market arrangements and limited incentives to participate in energy markets while the DS3 arrangements for system services still apply. We maintain this 30 per cent capacity limit in the Concentration Model. In general, the inputs to the Concentration Model are consistent with the decisions made in the validation of the SEM PLEXOS Model. Decisions about how to forecast the SEM are addressed in the validation of the SEM PLEXOS Model, and the Concentration Model implicitly adopts the same decisions.

Representing the *potential* output of these assets in the Model (rather than only that output which is scheduled in PLEXOS) would be relatively difficult, as the assets are energy limited. That is, the resources to generate depend on limited water inflow (in the case of hydro) or by the need to charge (in the case of pumped storage or batteries). Therefore, the decision to dispatch a hydro, pumped storage unit, or battery involves a relatively complex multi-period forward-looking

[37] NERA (12 March 2025), SEM PLEXOS Backcast and Validation, 2024-2032, pp. 39-40. Link: SEM-25-010 SEM PLEXOS Model Validation 2024-2032 Backcast Report.pdf (last accessed 18 March 2026)

optimisation problem, based on uncertain future factors (future water inflow and future charging opportunities).

Using PLEXOS scheduled generation is a (simplified) way of accounting for the fact that these units are energy limited.

Conceptually, allowing the unit's full potential capacity to be included in each period would lead the Model to *understate* the degree of market concentration, because it would *overstate* the true available capacity across all periods.

Using scheduled generation, on the other hand, likely leads the Model to *overstate* market concentration slightly, as we do not account for the additional cost-competitive capacity of hydro, pumped storage, and battery units that might be available in a given period.

We recommend that the RAs keep this approach under review. Presently, the portion of generation from batteries in the SEM is relatively low. As the share of dispatchable storage assets in the SEM increases, the modelling of the capacity of these assets will become increasingly important for the final allocation of DCs.

3.4. Demand Side Units (DSUs)

DSUs are not currently included in the Model. We recommend no change.

DSUs conceivably can combat market power abuse by providing additional supply when conditions are tight. Conceptually, one could include DSUs in market concentration metrics.

However, in practice we understand that DSUs may be of limited value in combating market power in the Concentration Model under most circumstances, due to the high prices they require to dispatch (for demand side units, dispatch involves reducing load rather than generating). The 2025-2034 All-Island Resource Adequacy Assessment suggests that in principle the DSU capacity in the SEM could be c. 900 MW in 2026.[38] From our previous work validating the SEM PLEXOS Model, we understand that the majority of this DSU capacity requires a very high price to be dispatched, particularly if over a shorter-term period, since many DSUs offer into the market with a significant shutdown cost.

If the RAs adopt a set of RSI parameters that includes a threshold for cost-competitive capacity (e.g., a percentage of the estimated SEM price, as discussed in Section 4.2.3), DSUs are unlikely to appear as cost-competitive capacity in the Concentration Model.[39]

The SEM PLEXOS model outputs include only c. 19 MW of DSU supply. This reflects the low observed typical DSU supply levels. The decision to align supply in the SEM PLEXOS Model with observed supply in practice was a modelling choice in the validation of the SEM PLEXOS Model. The inputs to the Concentration Model are consistent with the decisions made in the validation of the SEM PLEXOS Model, including the use of 19 MW of DSU supply. Decisions about how to forecast the SEM are addressed in the validation of the SEM PLEXOS Model, and the Concentration Model implicitly adopts the same decisions.

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[38] EirGrid and SONI (May 2025), All-Island Generation Capacity Statement 2025-2034, Table 5.13 and Table 5.15.

[39] We have not tested this explicitly.

If the RAs retain the alignment between the Concentration Model and the SEM PLEXOS Model, the small volume of DSUs in the SEM PLEXOS Model means the inclusion or exclusion of DSUs will not materially affect the results of the Concentration Model.

The RAs may wish to reconsider DSUs in later updates to the Concentration Model and/or the SEM PLEXOS Model, particularly if the importance of DSUs in the SEM grows or as their usage or typical market bidding changes.

3.5. Using Scheduled Generation as a Floor on a Unit's Cost-Competitive Capacity

The current Model determines cost-competitive capacity for each unit by comparing total generation costs per MWh to the SEM price (plus 5 per cent). However, there can be, and in practice are, many occurrences where a unit generates in PLEXOS but does not register as cost-competitive capacity. For instance, a CCGT may continue to operate for a small number of hours where its variable per-MWh operating costs are substantially above the SEM price if these loss-making hours are followed by hours with higher SEM prices, because by continuing to operate it avoids shut-down and start-up costs.

Generation plant that are online and generating could either contribute to or help to mitigate a market power scheme. Thus, we recommend updating the Model to include a unit's actual generation as a floor on its cost-competitive capacity. That is, we recommend the model includes both any capacity below the cost-competitive capacity threshold (even if it does not generate in the PLEXOS model) and any capacity which does generate in the PLEXOS model.

We would recommend this update for both the RSI-based and the HHI-based model, but it is particularly important for the RSI model.[40] RSI metrics consider the supply that serves load plus surplus supply over and above the supply that serves load. Having actual generation be the floor on cost-competitive supply ensures that that all supply that serves load counts as supply in the RSI calculation.

3.6. Pricing of Units that Do Not Generate in PLEXOS

The Model currently assigns a cost of 10,000 EUR per MWh to any unit that does not generate in PLEXOS. The 10,000 EUR per MWh level represents a price so high, that the unit would not count in the Model as cost-competitive for nearly any level of the cost-competitive capacity threshold.[41] However, these units do count as cost-competitive capacity in RSI parametrisations without a cost-competitive capacity threshold.

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40 That is, for an RSI model with a cost-competitive threshold. Under an RSI approach without a cost-competitive threshold, there is no consideration of cost-competitiveness and so there is no need for a floor on cost-competitive supply. See Section 4.2.3 for discussion of the use of a cost-competitive threshold under an RSI approach.

41 For example, a 100 per cent cost-competitive capacity threshold would require a SEM price of 5,000 EUR per MWh to allow one of these units to count as cost-competitive capacity in the Model. This is above the DAM price cap of 4,000 EUR per MWh.

Only a few of the most expensive peakers do not generate in PLEXOS over the course of a quarter. Were those units to run in PLEXOS (or in the actual market), they would have a high average cost per MWh, but it would be much less than 10,000 EUR per MWh.

We considered adjusting the Model so that it would assign a cost to these units in line with what their averages costs might be if they were to generate, rather than 10,000 EUR per MWh. We ran initial tests of this and determined that it made very little difference in DC volumes, so deprioritised it for further development.[42]

We recommend continuity of the current approach, that is, assigning a cost of 10,000 EUR per MWh to units that do not generate in PLEXOS. However, if the number of generators that do not generate in PLEXOS increases substantially in future runs, the RAs could consider calculating costs for these units in line with what their average costs might be if they were to generate, including VO&M start-up costs. For example, as renewable penetration increases the RAs may find that some dispatchable thermal units are not running in some quarters. The RAs may nonetheless want to include such units as cost-competitive capacity in the market concentration analysis.

3.7. Bid Markups

We also assess whether the Model should consider bid markups when determining the cost of generation units. We do not recommend updating the Model to consider bid markups when determining the cost of generation units.

The SEM PLEXOS Model allows generators two ways to bid above their marginal fuel and CO2 costs:

1. **Variable operation and maintenance (VO&M) costs:** VO&M costs typically reflect the costs of consumables when operating the plant as well as avoided maintenance or outage costs. VO&M costs in the SEM PLEXOS Model can be per MWh, per hour, or per start; or
2. **Bid markups:** Bid markups in PLEXOS are additional adders to a generator's bid, where these adders typically reflect some opportunity cost not related to VO&M. For example, a generator may have a bid markup if it has a fuel contract with limited annual volumes. Such a generator rationally may bid higher in the market so its overall fuel usage will stay below its contractual limits.

VO&M costs are included in the Model but bid markups currently are not. We investigated the feasibility of including bid markups in the Model. The specific output fields tracked by PLEXOS make it challenging, as a practical matter, to arrive at a simple approach for blending bid markups with others costs to arrive at an overall cost and markup measure. While we identified some candidate approaches, we concluded that they were too complex to implement within the scope of the project given the effect of incorporating bid markups on results is likely to be small.[43]

[42] The RAs could replace 10,000 EUR per MWh with the maximum average costs across all units that *do* generate in PLEXOS as a placeholder to test whether the choice to set a price of 10,000 EUR per MWh could have a material effect on DCs in parametrisations with a cost-competitive capacity threshold. As mentioned above, we expect the effect on DCs to be minimal.

[43] We made this assessment based on what we learned through our review of all units' costs and markup data as part of our assignment to update and validate the SEM PLEXOS Model.

We therefore recommend the RAs continue with the current approach of considering fuel, CO2, and VO&M costs, but not bid markups, when determining the relevant costs for each generating unit in the Model. The RAs may wish to revisit the issue of bid markups at a future point. PLEXOS frequently expands the options for tracking outputs from model runs so a future update to PLEXOS may make it feasible to incorporate bid markups using a simpler approach.

3.8. Edenderry

Currently, 30 per cent of Edenderry's competitive capacity is atomised[44] to reflect the approximate share of its generation which is under a subsidy program related to biomass generation. This is a legacy from an earlier version of the Concentration Model applicable at a time when Edenderry ran on peat and the Model atomised all peat-fired capacity due to the support payments to peat-fired generation. We recommend no longer atomising any portion of Edenderry:

- We understand Edenderry's subsidy scheme is part of REFIT. To the extent that the REFIT scheme for Edenderry is similar to the REFIT scheme for wind and solar, it would be consistent with our recommendation for the treatment of REFIT-supported wind and solar not to atomise Edenderry (although we have not reviewed the details of REFIT for biomass);
- The decision to atomise or not atomise part of Edenderry has no effect on DCs under an RSI approach. Since Bord na Móna, Edenderry's owner, is not one of the top three largest companies in the SEM, the atomisation or non-atomisation of Edenderry has minimal effect on assigned DCs even under a 3-RSI approach;
- Even under an HHI approach, the effect is minimal, as the HHI is primarily set by the largest companies. ESB, EP, SSE, and Energia are all larger than Bord na Móna;
- It is not clear whether having only a portion of the output under a subsidy scheme materially reduces an incentive to exercise market power. While further assessment could help answer that question, such assessment seems unnecessary, given the other reasons to remove the partial atomisation.

If a larger generation company were to acquire Edenderry, or if Bord na Móna were to become itself a much larger generation company, the RAs could revisit the question of atomisation of Edenderry.

44 We explain the concept of atomisation in Section 3.2.3.

4. Methodology for Calculating Market Concentration and Allocation of Directed Contracts

In this section, we consider the potential updates to the methodology for calculating market concentration and the allocation of DCs in the Model:

- Section 4.1 considers the choice of HHI versus RSI to measure market concentration and explains how these measures differ both mechanically and conceptually;
- Section 4.2 discusses the key parameters the RAs must set if they were to choose an RSI approach. These are: X-RSI (where X is the number of companies excluded from the RSI calculation), the RSI threshold, the cost-competitive capacity threshold (CCCT), and the limit on hours allowed to be below the RSI threshold (defined in percentage terms). We consider precedent for setting these parameters from other jurisdictions;
- Section 4.3 sets out our recommendation on the use of the RSI approach and how the RAs could think about setting these key parameters;
- Section 4.4 sets out our recommendation that multiple companies should be eligible to receive DCs, and explains how we have set the RSI Model up to allocate DCs across companies and calculate quarterly DC volumes; and
- Section 4.5 discusses the results of the RSI approach under illustrative parameter settings.

4.1. HHI Versus RSI

The scope of work established by the CRU for this engagement included a specific request to *"assess if alternative measures of market concentration/market power exist and are more relevant for the SEM (e.g. Pivotal Supplier Tests/Residual Supplier Index tests or variants of such tests)."*

4.1.1. Calculation of HHI versus RSI

The Model currently uses an HHI approach to measure market concentration. HHI calculates market concentration in hour h as the sum of squared market shares of each company, i.e.:

$$HHI_h = \sum_c \left(Cost\ Competitive\ Company\ Supply_{h,c} - DC\ Volume_c \right)^2 \times 10{,}000$$

A large HHI value in a given hour suggests there is greater concentration in the market in that hour. Assigning DCs reduces the market share of the company assigned DCs, thus reducing the measure of HHI.

Pivotal supplier-based models or residual supplier-based models ("RSI models"),[45] use a different measure of market concentration. RSI models measure the concentration of the market *given demand in that market*.

We calculate company c's RSI in hour h as follows:

[45] PSI and RSI tests rely on the same fundamental calculation, and we view PSI tests as contained within RSI approaches. Essentially, using an RSI threshold of 1.0 reflects a PSI test.

$$RSI_{h,c} = \frac{Total\ Cost\ Competitive\ Supply_h - Max(0, Cost\ Competitive\ Supply_{h,c} - DC\ Volume_c)}{Load_h}$$

An RSI value near to or below 1.0 in an hour suggests there is greater potential for market abuse within that hour because the supplier may be near to or at pivotality, whereby their capacity is required to serve load. Assigning DCs to company c will increase its RSI as less of its capacity is subtracted from the total supply (per the formula).

An RSI approach typically considers a market level X-RSI, where the supply of the X largest suppliers in that hour is subtracted from total supply.[46] For example, 1-RSI subtracts the largest supplier in each hour. If the company assigned DCs is the largest supplier in that hour, then the 1-RSI in that hour will fall as one assigns more DCs. We provide more detail on the calculation of RSI in the remainder of this section.

4.1.2. Choice of HHI versus RSI

There are a number of advantages to switching to an RSI model:

1. An RSI approach measures market concentration with direct reference to load and the extent to which that the largest suppliers' capacity is required to serve load. This approach incorporates more contextual information to assess generators' potential to abuse market power, with different results in tight supply conditions versus times of excess supply;
2. RSI as a metric has an intuitive interpretation. An RSI value less than 1.0 indicates that a generator's capacity is required to serve load; it is therefore a pivotal supplier. An RSI value above 1.0 indicates that it is not. In contrast, HHI as a metric is more difficult to interpret as a standalone figure and cannot be measured for an individual company;
3. There is precedent for the use of RSI approaches in other markets, as we discuss below in Section 4.2.4. Using a similar approach in the SEM would align the market with this precedent and allow it to learn from or adapt tools from these other markets;
4. The RSI approach naturally focuses on market concentration in the most concerning hours, given the practice of having no more than a given percentage of hours have RSIs below a certain threshold. In contrast, the current Model looks at average HHI. An approach that looks at average concentration could fail to identify that there is a problem if the problem only arises under certain system conditions.[47] Therefore, we view focusing on the most critical hours as the better approach since it will account for this kind of temporary market power.[48]

Nonetheless, there are also reasons to support an HHI approach:

[46] We considered, and rejected, the use of a company-specific RSI. We explain this option and our reason for rejecting it in Appendix D.

[47] Theoretically an HHI analysis could also focus on the most concentrated hours, but we are not aware of precedent for such an approach.

[48] One consequence of focusing on critical hours and accounting for temporary market power is that DCs may be variable quarter to quarter. We explain this in Section 4.5.

1. The HHI approach is simpler as the RAs must set only one key parameter: the HHI threshold. RSI by contrast requires the RAs to set values for four parameters: X-RSI, the RSI threshold, the CCCT, and the limit on hours;[49]
2. HHI increases given increases in market concentration beyond the largest unit, which at least directionally addresses the risk of tacit collusion or simultaneous withdrawal by multiple large companies.[50] A 1-RSI approach does not consider potential negative effects of market concentration beyond the largest company. A 2- or 3-RSI approach does consider the effect of potential tacit collusion or simultaneous withdrawal but does so in a way that does not differentiate the importance of the relative sizes of the largest companies;[51]
3. HHI has precedent as a measure of concentration to evaluate potential mergers, including in the electricity generation sector. This precedent supported the decision to use in the Concentration Model when the RAs first introduced the model at the outset of the SEM.[52] The US Federal Energy Regulatory Commission uses HHI for various regulatory purposes, including merger analysis or whether to regulate prices in certain markets.[53]

While no metric is perfect, we consider that the RSI is more relevant to assess market concentration in the SEM on balance, particularly because it accounts for demand and captures the variation in the tightness of the market (i.e., demand vs. supply) across hours.

4.2. RSI Model Assumptions and Parameters

If the RAs decide to use an RSI approach, the RAs must set the values for several parameters to implement it. There are four key parameters:

1. **X-RSI**, where X is the number of companies to exclude from the market for the RSI calculation (i.e. the largest supplier, the two largest suppliers, etc);
2. **The RSI threshold:** The value of RSI below which the RAs consider that the market is at risk of abuse;

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49 HHI also utilises a cost-competitive capacity threshold, but it is not as crucial a parameter as it is for RSI. Increasing the CCCT in the HHI Model will not necessarily have a material change on the resulting HHI or resulting DC volumes. However, for RSI, all things equal, the choice of CCCT will likely have a material effect on RSI and DC allocations. Increasing the CCCT increases the RSI and reduces DC volumes, all things equal.

50 Tacit collusion is when competing firms implicitly coordinate their actions to increase their profits without explicit agreement. This could involve two (or more) generating companies jointly raising their bid prices to increase clearing prices without formal communication, instead reflecting an uncommunicated mutual understanding.

51 For example, consider two scenarios: (a) the largest companies have 27 per cent, 25 per cent, and 23 per cent, respectively, of the capacity in the market; or (b) they have 55 per cent, 10 per cent and 10 per cent, respectively, of the market. We may have more concerns about market power in the second market versus the first market due to the large market share of one body. A 3-RSI approach would treat these markets equally as the total share of these three players is 75 per cent in both markets. An HHI approach does differentiate between these two markets due to the squaring of market share, meaning the second market has a materially larger HHI than the first market.

Similarly, a 1-RSI approach does not differentiate between two markets with the same sized largest player, even if one market has similarly sized second and third largest players and the other has much smaller other players.

52 SEM Committee (22 September 2006), AIP/SEM/144/06, Section 5.5.

53 See for example, FERC website, Market Based Rates Standards, URL: https://www.ferc.gov/industries-data/natural-gas/intrastate-transportation/market-based-rate-standards. Visited on 28 November 2025; and FERC (March 2011), Analysis of Horizontal Market Power under the Federal Power Act.

3. **The cost-competitive capacity threshold (CCCT):** Used to determine which supply capacity is used in the RSI calculation; and
4. **The limit on hours** in which the RSI can fall below the RSI threshold, defined as a percentage of all hours in the segment of the year relevant to a given DC product.

4.2.1. X-RSI: number of companies excluded

We calculate the X-RSI in each hour h as:

$$X\_RSI_h = \frac{\sum_{i=1}^{N} CCsupply_{i,h} - \sum_{i=1}^{X}\left(CCsupply_{i,h} - DC_{i,h}\right)}{Load_h}$$

Where X defines the number of companies we exclude from the market in the RSI calculation:

- 1-RSI subtracts only the cost-competitive capacity of the largest supplier in that hour. The largest company may vary hour by hour, meaning different companies are removed in different hours;
- 2-RSI subtracts the total cost-competitive capacity of the top two largest suppliers; and
- 3-RSI excludes the three largest suppliers, and so on.

In theory, the RAs could choose to remove any number of the top largest suppliers. We observe precedent in other markets for 1-RSI and 3-RSI tests, but also suggest the RAs consider 2-RSI. Excluding four or more companies could make the RSI essentially meaningless, particularly in the SEM. For example, if all resources from ESB, EP, SSE, and Energia were not available it would be very difficult to serve the load in the SEM.

Although there is precedent for use of 3-RSI in other markets (particularly in the US), the SEM is a small enough market, with enough concentration, that it may be challenging to serve load without the top three companies in many hours. It would likely require a very large volume of DCs to effectively mitigate the incentive for the exercise of market power if one assumed that the three largest companies might simultaneously withdraw capacity in an attempt to abuse market power (whether in coordination or acting unilaterally).[54] A very large volume of DCs may compromise effective price formation and the ability of the market to send efficient signals for dispatch and investment. Therefore, we recommend the RAs consider using either 1-RSI or 2-RSI to allocate DCs. If the RAs are concerned about simultaneous withdrawal by three or more market participants, alternative tools to mitigate market power other than DCs may be required.

We recommend the RAs reflect on their level of concern that the largest companies in the SEM may simultaneously seek to raise prices, versus concerns about a single firm exercising market power. If the RAs have a high level of concern about simultaneous withdrawal, the RAs might consider adopting a 2-RSI approach (or a 3-RSI approach, though as explained above a 3-RSI approach may result in a very large volume of DCs). If simultaneous withdrawal is less of a concern, then the RAs may choose to use a 1-RSI metric. However, selecting a 1-RSI approach

[54] Were three or more large entities in the SEM to simultaneously withdraw capacity (in coordination or otherwise), this certainly would be problematic for the SEM, but the RAs have other tools available rather than using DCs to address such a problem. In other words, DCs do not bear all the burden of preventing market power abuse.

would not imply an absence of concern about simultaneous withdrawal; rather, it is the degree of concern about simultaneous withdrawal that should guide the choice of 2-RSI or 1-RSI.

Satisfying an RSI threshold is more challenging under a 2-RSI than a 1-RSI approach. Thus, we recommend the RAs consider setting laxer values for the remaining three parameters under a 2-RSI versus 1-RSI approach. We consider each of the remaining three parameters in turn below.

The RAs do not necessarily need to select a 2-RSI approach even if they have serious concerns about simultaneous withdrawal and/or collusion in the SEM. The RAs have multiple tools to monitor and mitigate potential market power abuse, including relating to explicit or tacit collusion. Ultimately, it is up to the RAs to select the RSI parameters they view as best fit for the SEM (or HHI parameters if the RAs decide to continue to use HHI in the Model).

4.2.2. RSI threshold and limit on hours below that threshold

An RSI approach requires setting an RSI threshold and a limit on the percentage of hours allowed to be under that threshold.

4.2.2.1. Application of limit on hours: annual versus by quarter and product

Our proposed RSI-based Model requires separate adherence to the limit on hours: a) by quarter and b) for each of off-peak, mid-merit, and peak hours. This approach continues the approach of the current HHI-based Model, which requires separate adherence to the HHI target by quarter and for each of off-peak, mid-merit, and peak hours.[55] We recommend continuation of this approach, for two reasons.

- It is computationally and conceptually straightforward in the Model to have the RSI (or HHI) criteria align with the DC contract structure of separate DCs by quarter and product type (peak, mid-merit, and baseload); and
- In energy markets, market power can be short-term (specific to certain quarters or certain types of hours) and nonetheless impose substantial costs on consumers. It is therefore prudent to consider whether there is market power in specific subsets of hours, rather than only examining data at high levels of aggregation.

For example, consider a case with a 5 per cent limit on hours, where 7.5 per cent of hours are below the RSI threshold in Q1 and Q4 but 2.5 per cent of hours are below the RSI threshold in Q2 and Q3, prior to assigning DCs. Under an annual approach, no DCs would be assigned since 7.5 per cent and 2.5 per cent average to 5 per cent.

A quarterly assignment will assign no DCs in Q2 and Q3 but will assign some in Q1 and Q4 to separately meet the limit in those quarters. We view this as a reasonable approach as it helps to ensure the market power in each quarter is taken into account. The lack of market power in some quarters should not diminish our concern about market power in other quarters.[56]

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55 The current HHI-based Model goes even further, requiring separate adherence to the maximum average HHI criterion by month (not just by quarter) – see Section 4.4.3 above.

56 This implies that the volume of DCs may be variable quarter to quarter. We discuss this further in Section 4.5.

Similarly, consider a case where 2 per cent of off-peak hours are below the RSI threshold and 6.5 per cent of mid-merit hours above, prior to assigning DCs (assume there are no peak hours, i.e. this is a summer quarter). As there are 16 mid-merit hours and 8 off-peak hours, the average for the quarter would be 5 per cent, so one would apply no DCs absent separation across hour types.

The Model using separate hour type assignments will assign some mid-merit DCs in this circumstance until only 5 per cent of mid-merit hours are below the RSI threshold. Assigning DCs in this way helps to ensure that the market power in each type of hour is taken into account.

Under the current approach of separate requirements by quarter and hours type, the actual annual percentage of hours below the RSI threshold in the Model will be the same or less than the chosen limit.

4.2.2.2. Setting values for the RSI threshold

The RSI threshold is the value of RSI below which the Model deems the market to be at risk of potential abuse. Common RSI thresholds are 1.0, indicating pivotality, and 1.1, indicating a tight market near pivotality. Generally, we recommend either 1.0 or 1.1 as choice of RSI threshold. Any value in between would also be reasonable.

We would not recommend an RSI below 1.0 as the threshold, since 1.0 (indicating pivotality) is a natural “floor” on an RSI threshold. In principle the RAs could consider any value equal to or higher than 1.0. There is precedent for the use of 1.0 or 1.1 as a threshold.[57]

4.2.2.3. Setting values for the limit on hours

We recommend 5 per cent as a reasonable value for the limit on hours allowed to fall below the RSI threshold. Five per cent is commonly used in RSI analysis (see the discussion of precedent in Section 4.2.4) and strikes a reasonable balance between allowing some but not too many hours with RSIs that carry risk of abuse of market power. To be clear, using a limit of 5 per cent of hours below the RSI threshold does not endorse market power abuse in those hours nor mean we expect there to be market power abuse in those hours. Instead, the threshold is a reasonable input to the Model for the purposes of assessing DCs.

Five percent is not the only conceptually reasonable limit on hours. The RAs could consider combining stricter settings for other RSI parameters, e.g. a 2-RSI approach, a higher RSI threshold, or a lower CCCT, with a higher limit on hours. For example, we report estimated DCs when setting the limit on hours to be 10 per cent or 15 per cent, for some settings of the other three RSI parameters.

4.2.3. Setting the cost-competitive capacity threshold (CCCT)

The cost-competitive capacity threshold (CCCT) determines which supply is used in the calculation of RSI (or HHI). This includes both the market-wide supply and the supply of any individual company. The outturn value of RSI (or HHI) therefore depends on the CCCT.

57 There is no objective rationale for the use of 1.1 precisely. If the RAs prefer a somewhat stricter RSI threshold such as 1.12 (hypothetically), that would not be unreasonable even if it is not common in our experience. In all cases, we recommend the RAs set the various RSI parameters as a package, considering how they interact.

The HHI-based Model currently defines the CCCT as 5 per cent above the SEM price. That is, in each hour, a unit is cost-competitive if its cost is less than the SEM price or no more than a 5 per cent premium above it. While 5 per cent is reasonable for an HHI-based approach, an RSI-based approach requires a materially higher CCCT, or alternatively it may be reasonable to deem all available capacity as cost-competitive.

In the extreme, consider a CCCT of 0 per cent. In this case, conceptually, the only supply that counts in the RSI calculation would be the supply that serves load. In this case, every generation company, even the smallest, would be pivotal with a company RSI below 1.0 in nearly all hours. As such the volume of DCs would need to match the load in the SEM to reach market RSI of 1.0. A 5 per cent CCCT would also yield a high volume of DCs.

There is precedent for use of a CCCT of 50 per cent, from the PJM. The RAs could also consider using a lower CCCT (e.g. 40 per cent). There is also precedent for applying RSI without a CCCT (i.e. all capacity is included regardless of cost), e.g., in the European examples cited below. The RAs could consider 100 per cent as an alternative to the choice of 50 per cent or no CCCT. A 100 per cent CCCT would still exclude the most expensive units in the SEM in the lower priced hours.

We recommend the RAs make the choice of CCCT while accounting for the other RSI parameters. For example, since a 2-RSI approach is a relatively strict approach, we would recommend a less strict value for this parameter, such as 100 per cent or no CCCT. With a 1-RSI approach, any of the CCCT options could be reasonable.

4.2.3.1. Floor on hourly CCCT

We recommend including a floor, in EUR per MWh, on the CCCT.

In some hours the estimated clearing price from the SEM PLEXOS model may be low, near or even below zero. Low prices may become increasingly common as renewables take up a higher portion of SEM load.

Since our CCCT is set as a percentage of the clearing price, the capacity that is counted as cost-competitive may be quite restricted if the clearing price is low. For example, if the clearing price is 20 EUR per MWh with a 50 per cent CCCT, then only units with costs below 30 EUR per MWh would qualify in the RSI calculation. This could result in low RSI precisely at a time when abuse of market power may be harder to achieve due to the high availability of renewable generation.

We recommend setting a floor on the CCCT that allows the RSI calculation to include some thermal generation capacity even in hours where prices are very low due to high renewable availability.

We recommend the Model includes a floor that roughly mimics the average costs of a typical CCGT in the SEM. We estimate this floor using gas and carbon prices from the SEM PLEXOS model, as well as other cost data from the SEM PLEXOS validation exercise. The RAs should update the gas and carbon prices that feed into the floor calculation in each round of DCs. The other parameters used to set the floor do not need to change from round to round, though the RAs should review them alongside the rest of the Model as part of regular Model reviews.

This floor is irrelevant if the RAs choose not to set a CCCT.

4.2.4. Examples of RSI parameters from other markets

The Pennsylvania-New Jersey-Maryland Interconnector (PJM, a regional grid in the eastern US) and the California Independent System Operator (CAISO, the regional grid in California) use *ex ante* mitigation, based on RSI calculated for individual hours rather than across the full year: [58]

- PJM and CAISO both use a 3-RSI < 1.0 standard to identify hours in which to apply mitigation. A limit on hours is not needed for this *ex ante* assessment;
- PJM uses a CCCT of 50% (which is used on an hourly basis). CAISO counts all capacity (regardless of cost) in its assessment.

The Southwest Power Pool (SPP) has also used pivotal supplier analysis as a tool in evaluating market power.[59] SPP considered 0-RSI, 1-RSI, 2-RSI, and 3-RSI analysis to assess the level of market power in the Western Energy Imbalance Service (WEIS) market.

There is also precedent for a full-year formal threshold test in Germany, which uses 1-RSI < 1.0, and a limit of 5 per cent of hours to determine if a supplier has a dominant market position.[60]

Consultants working on behalf of the European Commission in 2007 also suggested the use of a full-year RSI test, where the test is 1-RSI < 1.1 and a limit of 5 per cent of hours.[61] They provide the following commentary on the setting of parameter values:

> *"Previous studies that have used this measure have attempted to apply a threshold value to the computed hourly indicator. The threshold states that if the value of the RSI is less than 110% (1.1) for more than 5% of the time, then this is indicative of a market structure that is likely to be open to non-competitive behaviour. This threshold test and the threshold itself was developed by the CAISO and as applied indicates potentially troublesome periods as those where the residual supply is less than 110% of the market demand for electricity and whether or not this systematically occurs in more than 5% of the time.* ***The threshold itself is not the result of in-depth economic analysis but rather based on knowledge of market functioning but as such one may consider tailoring the threshold for each country****." [emphasis added]*

As noted in the commentary above, the preferred setting of RSI parameters for the SEM may differ to other countries, given the relatively small size of the SEM, that it is an island system, and its high penetration of renewables.

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58 Monitoring Analytics (14 November 2024), State of the Market Report for PJM 2024 Q3, p. 236; and FERC (October 2014), Price Formation in Organized Wholesale Electricity Markets AD14-14-000, p. 5.

59 Southwest Power Pool (August 2020), Western Energy Imbalance Service (WEIS) Market: Market Power Study, p. 54.

60 Bundeskartellamt (August 2023), Wettbewerbsverhältnisse im Bereich der Erzeugung elektrischer Energie 2022, para. 93.

61 London Economics (February 2007), Structure and Performance of Six European Wholesale Electricity Markets in 2003, 2004 and 2005, Part I – Methodology and Results of Belgium and France, p. 123.

4.3. Recommendation on the Use of RSI and Setting of RSI Parameters

We recommend switching to RSI. The RSI approach has the following advantages:

- RSI directly assesses supply relative to demand, whereas HHI measures concentration in the abstract without regard to demand. Thus, the RSI considers how tight a market is as well as how concentrated it is. RSI is likely to have an advantage in ascertaining the risk of abuse of market power in a wide variety of supply and demand situations;
- RSI has an intuitive interpretation, where an RSI of 1 or less implies pivotality. Pivotality means that supply cannot meet demand without the largest supplier, or suppliers. While higher HHI values equate to higher risk of abuse of market power (all else equal), specific values of HHI do not have a comparable intuitive interpretation;
- There is precedent for use of RSI in power sectors outside of the SEM.

The RSI approach requires the RAs to set values for four key parameters: X-RSI, the RSI threshold, CCCT, and the limit on hours below the RSI threshold. For each, there is a range of values the RAs could reasonably consider.

We recommend the RAs set parameter values with full consideration of how the parameters work together.

Each parameter has stricter or laxer options, with stricter options leading to higher volumes of DCs, all things equal. We would not recommend choosing the strictest setting for each parameter nor would we recommend choosing the least strict for each. Rather, strict choices for one or more parameters could indicate less strict choices for the other parameters, and vice versa.

We set out in Figure 4.1 a suggested process for setting the values of the four parameters. The process includes illustrative examples of the impact of each parameter, for a given setting of other parameters. The overall impact of a setting a specific value for a given parameter will depend on the settings of other parameters. For example, in Figure 4.1's "Example A" the impact of moving from 1-RSI to 2-RSI is an increase in average DCs of 1,897 MW. This impact is specific to the case where the RSI threshold is 1.1, the CCCT is 50 per cent, and the limit on hours is 5 per cent. If we instead consider "Example B", where the RSI threshold is 1.0, there is no CCCT, and the limit on hours is 15 percent, the impact of moving from 1-RSI to 2-RSI would be an increase in average DCs of 408 MW.[62]

In Appendix B, we provide a more detailed table showing how the allocated DCs vary across different parameter settings. The table shows the breakdown of DCs across DC products (baseload, mid-merit, and peak), across quarters within the representative round, and across companies.

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[62] Part of the reason that the difference in DCs is *smaller* in Example B than Example A is that the volume of DCs has a *lower bound* of zero. The 1-RSI model will hit zero DCs at stricter values of other parameters than will the 2-RSI model. As we relax the other parameters further, the gap in DCs between the 1-RSI model and 2-RSI model must necessarily fall (since the volume of DCs under 1-RSI stays constant at zero while the amount of DCs under 2-RSI continues to decline). Eventually, there will be some combination of the other parameters that leads the 2-RSI model to hit zero DCs as well. At this point there will be no difference in DCs between the 1-RSI and 2-RSI models.

Figure 4.1: Suggested Process for Setting the Value of the Four RSI Parameters

Step 1: Choose 1-RSI or 2-RSI

Rationale	Impact	Example A[1]	Example B[5]
Choose 2-RSI if concerned about simultaneous withdrawal by largest players.	2-RSI gives more DCs than 1-RSI.	**293** MW DCs with 1-RSI **2,190** MW DCs with 2-RSI	**0** MW DCs with 1-RSI **408** MW DCs with 2-RSI

Step 2: Choose RSI threshold

Rationale	Impact	1-RSI Example[2]	2-RSI Example[6]
Set ***higher*** than 1.0 if more concerned about concentration and near-pivotality, if other parameters less strict, or if concerned about hour-to-hour variability of supply and demand.	***Higher*** RSI thresholds give more DCs.	**0** MW DCs with 1.0 **293** MW DCs with 1.1	**408** MW DCs with 1.0 **1,028** MW DCs with 1.1

Step 3: Choose cost-competitive capacity threshold (CCCT)

Rationale	Impact	1-RSI Example[3]	2-RSI Example[7]
Set ***lower*** CCCT if particularly concerned about prices in off-peak and mid-merit periods.	***Lower*** CCCTs give more DCs.	**20** MW DCs if no CCCT **128** MW DCs at 100% **293** MW DCs at 50%	**408** MW DCs if no CCCT **583** MW DCs at 100% **688** MW DCs at 50%

(Threshold is % above market price)

Step 4: Choose limit on hours below RSI threshold (in percentage terms)

Rationale	Impact	1-RSI Example[4]	2-RSI Example[8]
Set ***higher*** percentage if other parameters less strict, because the overall potential for market abuse in hours below the RSI threshold is lower.	***Lower*** percentages give more DCs.	**48** MW DCs with 15% **115** MW DCs with 10% **293** MW DCs with 5%	**408** MW DCs with 15% **605** MW DCs with 10% **895** MW DCs with 5%

1. *For RSI threshold = 1.1, CCCT = 50%, limit on hours = 5%.*
2. *For 1-RSI, CCCT = 50%, limit on hours = 5%.*
3. *For 1-RSI, RSI threshold = 1.1, limit on hours = 5%.*
4. *For 1-RSI, RSI threshold = 1.1, CCCT = 50%.*
5. *For RSI threshold = 1.0, CCCT = no CCCT, limit on hours = 15%.*
6. *For 2-RSI, CCCT = no CCCT, limit on hours = 15%.*
7. *For 2-RSI, RSI threshold = 1.0, limit on hours = 15%.*
8. *For 2-RSI, RSI threshold = 1.0, CCCT = no limit.*

Source: NERA analysis

The first step of the process set out in Figure 4.1 is to decide whether to adopt a 1-RSI or 2-RSI approach. We recommend that the RAs consider choosing 2-RSI if they are particularly concerned about simultaneous withdrawal of capacity in the SEM (whether through collusion – explicit or tacit – or uncoordinated unilateral action).

- All things equal, a 2-RSI will assign more DCs than a 1-RSI. In the parametrisations we have tested, the distribution of DCs across product types also varies between 1-RSI and 2-RSI, with 1-RSI yielding relatively more baseload and mid-merit DCs. This is because we typically adopt a lower CCCT in 1-RSI parametrisations. We explain this in more detail when we discuss step 3, below.
- The choice of 1-RSI or 2-RSI does not affect whether companies other than ESB might receive DCs. The Model can allocate DCs to two companies under a 1-RSI approach and one company under a 2-RSI approach.[63]
- A 2-RSI approach is stricter than a 1-RSI approach, so if the RAs adopt a 2-RSI approach we would encourage laxer choices for the other parameters.
- The RAs could consider a 3-RSI approach, but this may result in a very high volume of DCs. In test runs, we found that we had to allow a relatively high limit on hours and/or apply no CCCT to allow a 3-RSI model to reach a solution with a volume of assigned DCs less than c. 1.25 GW.

The second step of the process is to select an RSI threshold. In general, the RAs should set a higher RSI threshold if they are relatively more concerned about market concentration and near-pivotality. We recommend that the RAs consider the overall strictness of their parameter settings: 1.1 is stricter (potentially appropriate with other less strict parameters) and 1.0 is less strict (potentially appropriate with other stricter parameters). The RAs could also consider values between 1.0 and 1.1 (or even above 1.1).

The RAs may want to consider a threshold greater than 1.0 because the SEM PLEXOS model may understate the hour-to-hour variability of demand and supply in the DAM (and thus instances of system tightness). The Concentration Model relies on projections of supply and demand in each hour derived from the SEM PLEXOS model. These projections are an average of five separate simulations of market outcomes, each based on historical data with some random shocks. Since the results are averaged, they will smooth out some of the variation in the supply from weather-dependent renewables (in particular, wind) or in demand. Variation in supply and demand should, in expectation, create more periods in which the largest single supplier or largest two suppliers (under either a 1-RSI or 2-RSI approach, respectively) would be in a position to dictate the market clearing price by withholding capacity. Therefore, the model based on averages across simulations may somewhat underestimate the opportunities for abuse of market power; setting a higher RSI threshold serves to counterbalance this risk.

The RAs may particularly want to consider an RSI threshold greater than 1.0 if using the 1-RSI approach. In practice any simultaneous withdrawal or tacit collusion is not likely to be perfect, and so under a 2-RSI approach the RAs may be more willing to tolerate risk that the two largest suppliers together would be in a position to dictate the market clearing price.

The third step of the process set out in Figure 4.1 is to set the CCCT. We have tested CCCTs of 50 per cent and 100 per cent as well as no CCCT, but the RAs could consider other values for this parameter. In general, we recommend that the RAs set a stricter CCCT if they are particularly concerned about potential abuse of market power in off-peak and mid-merit hours.

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[63] For example, a parametrisation with 1-RSI, 1.15 RSI threshold, 50% CCCT, and 5 per cent limit on hours allocates DCs to two companies, while a parametrisation with 2-RSI, 1.0 RSI threshold, no CCCT, 1.0 RSI threshold, and 15 per cent limit on hours allocates DCs just to ESB.

In peak hours, prices are likely to be high enough that there will be little difference in capacity that is counted as cost-competitive across the three values of the CCCT parameter. The choice of CCCT value has more impact in the off-peak and mid-merit hours, when prices are lower.

Finally, in the fourth step the RAs must set the limit on hours below the RSI threshold. The RSI model sets DCs to allow an acceptably low percentage of hours that are at risk of market abuse, where the other parameters (X-RSI, RSI threshold, and CCCT) determine what constitutes an "at risk" hour. The harder it is for the Model to deem an hour to be at risk from the first three parameters, the more hours one might tolerate the Model deeming at risk. We recommend the RAs consider 5 per cent as well as percentages above 5 per cent. While we have not seen examples of markets using percentages above 5 per cent, the RAs could consider a higher percentage such as 10 or 15 per cent, under a 2-RSI approach, if the RAs view that as more suited to the context of the SEM. As we discuss above, European guidance recommends that parameters be tailored to each market.

Ultimately, the setting of RSI parameters is up to the RAs based on their tolerance for the risk of abuse of market power in the SEM, their view of the level of DCs reasonable to address it, and their view of the best way to conceptualise the risk of abuse of market power under an RSI approach.

4.4. Allocation of Directed Contracts to Companies

As discussed in Section 2, the Model assigns DCs iteratively until the conditions established by the RAs' setting of the four RSI parameters are met. The current (HHI-based) Model assigns DCs incrementally, until the average HHI reaches 1,150 separately for each month and type of hour: off-peak, mid-merit and peak. The RSI Model also assigns DCs incrementally until the percentage of hours below the RSI threshold is below the limit set by the RAs.

The companies that are eligible to be allocated DCs, and the process by which DCs are allocated across those companies, are design features of the Model. We discuss how the current Model deals with each, and our recommended changes, in more detail below.

4.4.1. Eligibility of companies other than ESB for DCs

In recent years, the Model has only assigned DCs to ESB. However, in the 2008/9 SEM year, the Model also assigned DCs to NIE PPB.[64] The current Model allows the user to set up to two companies to be eligible for DCs. The user selects which two.

In consultation with the CRU, as part of our RSI-based model we have developed a proposed approach that assigns DCs to the largest companies, based on an algorithm where all companies are treated equally. Unlike the current Model, there is no requirement for the user to pre-select companies that are eligible for DCs, and the number of companies that can receive DCs is not restricted to two. Whether DCs in practice are assigned to companies beside ESB depends on the state of the supply and demand mix, market concentration, and the RSI parameters set.

64 SEM Committee (15 April 2008), Directed Contracts 2008/09, Quantification and Pricing, Decision Paper, SEM-08-051.

In principle, this change does not require the use of an RSI approach to market concentration. An HHI-based Model could also allow a wider set of companies aside from ESB to be assigned DCs.

The case for assigning DCs to companies other than ESB is strengthened as other companies catch up to ESB in size, since the Model will reflect their effect on HHI or RSI as well.

Alternatively, the RAs could take a view that ESB's market position in several aspects of the power sector in Ireland and Northern Ireland, including in retail, make it unique among companies in its potential ability to influence markets.[65] As such, the RAs could decide that only ESB merits DCs.

On balance, we recommend allowing the Model to treat all companies equally in terms of potential to be assigned DCs (that is, allowing any company to be obliged by the RAs to make DCs available to subscribers).

4.4.2. Assignment of the incremental MW of DCs

A Model that assigns DCS to multiple companies needs to include rules to determine which company is assigned the next incremental MW of DCs, within the Model's iterative DC assignment process.

The HHI-based Model assigns the next incremental MW of DCs to the company whose net competitive supply is largest (i.e. competitive supply after removing any DCs already assigned). The RSI model takes a similar approach, assigning the next increment of DCs to the company with the lowest average RSI for the relevant quarter and type of hour (off-peak, mid-merit, or peak), after consideration of DCs already assigned.

When ESB is the only company receiving DCs, the precise approach to assign the next increment of DCs does not matter. However, in cases where material volumes of DCs are assigned to companies besides ESB, alternative approaches for assigning the next increment of DCs could lead the Model to assign a lower total volume of DCs overall.

We chose to assign the next increment of DCs to the company with the lowest average RSI in our proposed Model due to the simplicity, explainability, and intuitiveness of that approach.

Under current conditions and for the foreseeable future, we view it unlikely that a company beside ESB would receive material quantities of DCs. The proposed Model currently only assigns DCs to companies other the ESB when a high total volume of DCs is required to meet the RSI threshold.[66] We expect the make-up of supply in the market would need to shift for the Model to assign DCs to other companies. In particular, ESB's capacity relative to the second and third largest companies would need to shrink.

If the RAs select RSI parameter settings that lead the Model to assign material volumes of DCs to multiple companies, we recommend that the RAs more carefully consider the relative merits of different approaches to determining which company receives the next incremental MW of DCs.

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[65] However, we understand that the aim of DCs is to reduce the potential for market abuse in the DAM in particular. If the RAs are concerned about market abuse in other markets (e.g. the Balancing Market or locational market power), other tools may be more appropriate to alleviate these concerns than DCs.

[66] That is, when we set "strict" RSI parameters that lead the Model to assign a substantial volume of DCs.

4.4.3. Calculation of quarterly DC volumes

The current (HHI-based) Model calculates the number of DCs required by month and then takes the maximum across months to determine quarterly volumes. This is a conservative approach which errs on the side of assigning more DCs to help minimise the potential for market power abuse and ensure the Model reaches market concentration limits separately in every month.

With the switch to RSI, and the RSI's emphasis on percent of hours below a threshold, we recommend measuring the percentage on a quarterly basis as opposed to a monthly approach. This simplifies the Model.

If the RAs decide to retain the HHI model, they could consider deviating from the current max-of-months approach. We have not tested that option specifically in the HHI context, but it would tend to reduce DCs in the current Model.

4.5. Discussion of Results: The RSI Model Produces Non-Zero DCs for Many Parameter Settings

Table 4.1 reports the allocation of DCs across quarters produced by different settings of the four key parameters. The allocated DCs are the sum of DCs across the three products (off-peak, mid-merit, and peak). Some parametrisations allocate DCs to multiple companies if there are large volume of DCs. In particular, the parametrisations in the top two rows of the table below assign a small volume of DCs to EP as well as assigning DCs to ESB. The parameter settings shown do not represent a recommended set of parametrisations that the RAs should use; other parametrisations are possible.

This table also appears as Table 1 in the Executive Summary, and we provide more discussion of the results there. One overarching theme is that all but one of the parametrisations produces a non-zero allocation of DCs. This stands in contrast to the results of the current (HHI-based) Model for Round 31, which assigned no DCs. Indeed, the current Model has not assigned DCs for several quarters.

In this section, we discuss the factors contributing to this difference in results between the current (HHI-based) Model and the RSI-based model.

Table 4.1: The Volume of DCs Depends on the Settings Chosen for Four Parameters (Illustrative Example of Seven Parameter Settings and the Resulting DCs for Round 31)

Input: Parameter Settings				Output: Allocated DCs (MW)				
X-RSI	RSI threshold	Cost-competitive capacity threshold (CCCT)	Limit on hours	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Average
2-RSI	1.0	No CCCT	5%	750	1350	990	490	**895**
2-RSI	1.0	100%	15%	540	700	770	320	**583**
2-RSI	1.0	No CCCT	15%	360	610	570	90	**408**
1-RSI	1.1	50%	5%	90	540	540	0	**293**
1-RSI	1.1	50%	10%	0	150	310	0	**115**
1-RSI	1.1	100%	5%	40	360	110	0	**128**
1-RSI	1.0	50%	5%	0	0	0	0	**0**

Notes: (1) The allocated DCs are the sum of DCs allocated across all products (baseload, mid-merit, and peak) and all companies within each quarter. (2) The parameter settings shown do not represent a recommended set of parametrisations that the RAs should use; other parametrisations are possible.
Source: NERA Analysis

The current (HHI-based) Model assesses market concentration based on supply alone. While the current Model has in the past assigned non-zero DCs, more recently it has assigned zero DCs. This reflects changes to the supply side of the market which reduce market concentration on average, as measured by HHI. These changes include:

- The Greenlink Interconnector achieving commercial operation. This added 500 MW of supply to the Model. Supply from interconnectors is atomised, since interconnectors cannot control their operating schedule; and
- Moneypoint, historically a major ESB coal-fired resource, has been retired from active participation in the ex-ante markets. It now only provides emergency capacity and so is not counted in the Model. Prior to its retirement, Moneypoint experienced a longer-term trend of reduced availability and cost-competitiveness in the SEM, which likely led it to be excluded from cost-competitive capacity in some rounds.

Even though there have been some changes to the market supply to reduce market concentration on average, other features of both supply and demand may still lead to concentration either on average or in certain periods:

- On the demand side, load has grown rapidly without comparable increase in supply of dispatchable plant. Where new dispatchable thermal capacity has been installed, it has been peakers that will not-necessarily be cost-competitive in the Model;
- On the supply side, while generation from renewables has grown rapidly, renewables are intermittent. In periods where renewables are low and demand is high supply conditions in the SEM can be tight.

The tighter the *net* supply (i.e., supply less demand) in a market the higher the potential for market power abuse, all things equal. The HHI approach does not consider how tight the market is overall, but the RSI approach does. It may therefore be reasonable to assign DCs to mitigate this potential risk of abuse of market power, even if the current Model does not assign DCs. Ultimately, it is up to the RAs to decide whether current conditions might merit DCs.

It is not *necessarily* true that an RSI model will produce more DCs than an HHI model. As Table 4.1 shows, the volume of DCs assigned by an RSI model is sensitive to the selection of values for the four key parameters used to calibrate the model. Indeed, one of the parameter settings shown in the table yields zero DCs.

Similarly, the volume of DCs assigned by an HHI model is sensitive to the selection of the HHI threshold that is the key parameter of the model. An HHI approach could also yield non-zero DCs for round 31, if the RAs were to reduce the HHI threshold.

A further difference between the RSI and HHI models as we have implemented them is that the RSI model may produce more variable DCs from quarter to quarter. This is because the RSI model focuses on market concentration in the most concerning hours and as such captures more instances of temporary market power than does the HHI model, which looks at average monthly HHI (as discussed in Section 4.1.2). For example, in Table 5.2 we see that DCs are much higher in Q2 than Q3 2026; this is partly due to planned outages in Q2 which temporarily increase market concentration.[67] From a theoretical perspective, this is a benefit of the RSI approach – to the extent that the ability of ESB or others to exercise market power does vary from quarter to quarter, the assignment of DCs should reflect that variability.[68] More generally, the volume of DCs produced by the Model are sensitive to other features of the Model design. We have recommended a suite of changes to the Model that would alter the DCs it produces, even if the RAs were to retain the HHI approach and leave the HHI threshold unchanged. Taken collectively, the changes we recommend for the Model have likely raised HHIs in the Model, which could in turn lead the HHI Model to produce non-zero DCs. Assigning wind and solar to generators besides ESB is the primary reason the HHIs (and thus DCs) would increase.

However, conceptually, we recommend the RSI approach, because it automatically adjusts DC volume commensurate with changes in the supply and demand balance. It therefore captures *net* supply conditions, which are in general a better indicator of potential for abuse of market power than the *gross* supply conditions captured by the HHI approach.

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67 Planned outages could also lead to quarterly variability in DCs in the HHI model, if they are of long duration (more than a few days). The HHI model is likely to be less responsive to short planned outages than the RSI model, because it allocates DCs based on the average value of the concentration index over the whole month. The RSI model allocates DCs to limit the percentage of hours within a quarter that fall below the RSI threshold to a relatively small percentage (e.g., 5 per cent) and so is more sensitive to concentration in the most concerning hours.

68 One might question whether DCs ought to reflect variability driven by planned outages, since planned outages are not a structural characteristic of the system and could be rescheduled. However, since DCs are allocated on a quarterly basis a rescheduling would only affect DCs if the outage moved to a different quarter; in practice, planned outages typically occur in either Q2 or Q3 and so there is limited potential for rescheduling from the perspective of DC assignment. Furthermore, since the RAs assign the DCs applicable to a quarter gradually (over four runs preceding the actual quarter) there is time for adjustment of DCs to reflect rescheduling of planned outages.

5. Sensitivity Testing: Estimated DCs from the RSI Model Under Different Scenarios

In this section we set out the results of scenario analysis we conduct to test how the volume of DCs the Model allocates varies according to different market conditions. We agreed with the CRU to test the following three scenarios:

1. **High Gas and CO2 Prices**: Gas prices are a key driver of SEM prices as the marginal unit in the DAM is typically gas fired. High gas prices and CO2 prices raise the generation costs for gas-fired units and thus raise SEM prices. We model a high gas and CO2 price scenario to assess the impact on DC volumes. Otherwise, this scenario mirrors the base case (DC R31);
2. **Low Gas and CO2 Prices**: We also model a low gas price and CO2 price scenario. Lower gas prices and CO2 prices reduce the generation costs for gas-fired units and lower SEM prices. Otherwise, this scenario mirrors the base case (DC R31); and
3. **Future Year (2029)**: We also model a future year (2029) to understand how DC volumes may evolve in the future. 2029 captures three important likely future changes in the SEM: a) the 700 MW Celtic interconnector between France and Ireland coming online; b) material growth in wind and solar generation; and c) load growth, including due to data centres. All three changes could affect the DC volumes in the Model. We maintain the same underlying gas and CO2 price assumptions as the base case for this scenario.

The CRU provided natural gas and CO2 prices for each of these scenarios. These are set out below in Table 5.1. The assumed prices for the high and low scenarios are based on historical price data, although these prices do not reach the peak of prices following the gas crisis (c. 2021-2023) nor the low point reached by prices during the Covid pandemic.

Table 5.1: Gas and CO2 Prices by Scenario

	Gas Price (pence per therm)				**CO2 Price (EUR per tonne)**			
Scenario	*Q1*	*Q2*	*Q3*	*Q4*	*Q1*	*Q2*	*Q3*	*Q4*
Base Case	95.63	82.04	79.98	92.44	74.28	74.28	74.28	72.33
High Price	282.44	194.78	173.83	283.35	93.01	90.46	90.46	90.46
Low Price	54.48	45.92	44.99	45.28	28.57	28.57	28.57	28.28
Future Year (2029)	95.63	82.04	79.98	92.44	74.28	74.28	74.28	72.33

Source: Provided by the CRU.

We did not consider changes in oil prices as part of these scenarios, even though the SEM has several gasoil-fired peaking plants. Gasoil peakers have relatively little effect on the DAM (compared to gas-fired resources) and correspondingly have relatively little effect on the Concentration Model. In addition, it is the relative relationship between oil and gas prices that matters for the merit order in the SEM (and so market concentration in the Model). Doubling both natural gas and oil prices would likely have minimal effect. Thus, a (relatively) high gas price scenario is comparable to a (relatively) low oil price scenario and vice versa.

The high and low gas and CO2 scenarios are identical to the base case in all other regards, aside from changing these prices. To generate the inputs for these scenarios, the CRU re-ran the base case (DC R31) of the SEM PLEXOS Model with the revised gas and CO2 prices.

For the future year scenario, we chose the year 2029. The CRU ran the SEM PLEXOS model for 2029, using the same gas and CO2 prices and same unit outage schedule as the R31 base case run. Therefore, the scenario isolates the effect of changes in supply capacity and demand. This primarily reflects adding the Celtic interconnector, new wind and solar capacity, and load growth as forecast in the RAs' SEM PLEXOS Model. The 2029 run also reflects new thermal capacity and battery capacity in the SEM, i.e., the new capacity with online dates through 2029 as determined through the validation process that produced the SEM PLEXOS Model.

The differences in allocated DCs between scenarios depend on the setting of RSI parameters. We present the results for an illustrative selection of seven parameter settings in Table 5.2 below.

Table 5.2: The Volume of DCs Various Across Modelling Scenarios as well as Parameter Settings

Parameter Settings				Average Allocated DCs per Quarter by Scenario (MW)			
X-RSI	RSI threshold	Cost-competitive capacity threshold (CCCT)	Limit on hours	Base Case	High Price	Low Price	Future Year (2029)
2-RSI	1.0	No CCCT	5%	**895**	868	883	0
2-RSI	1.0	100%	15%	**583**	415	723	0
2-RSI	1.0	No CCCT	15%	**408**	383	395	0
1-RSI	1.1	50%	5%	**293**	65	510	0
1-RSI	1.1	50%	10%	**115**	0	275	0
1-RSI	1.1	100%	5%	**128**	25	238	0
1-RSI	1.0	50%	5%	**0**	0	30	0

Note: The allocated DCs are the averages quarters of the sum of DCs allocated across all products (baseload, mid-merit, and peak) and all companies within each quarter.
Source: NERA Analysis

Looking first at the results for the high and low gas price scenarios, we observe that they produce a materially different level of DCs for RSI parametrisations that include a CCCT (50 per cent or 100 cent). The low price scenario has materially higher DC quantities and the high price scenario has materially lower DC quantities versus the base case.

SEM prices are higher in the high price scenario, so the cost-competitive thresholds in EUR per MWh are also higher. However, gasoil prices are unchanged. Therefore, gasoil peakers are relatively more competitive with gas-fired generation in the high price scenario than in the base case and so gasoil peakers are more commonly cost-competitive in the Model. All things equal, this increases cost-competitive supply, increases the RSI, and decreases DCs. The reverse is true in the low price scenario, where gasoil peakers are less commonly cost-competitive, decreasing the RSI and leading to fewer DCs.

In the RSI parametrisations with no CCCT, the results do not substantially differ between the two price scenarios and the base case. If there is no CCCT, all capacity counts as cost-competitive capacity, so the costs of generators or market prices do not affect the calculation of RSI. The small observed differences under "no CCCT" (in the region of c. 20 MW) reflect differences in patterns of generation of hydro, pumped storage, and batteries across the different scenarios, due to minor changes in the merit order as a result of the changed prices. These changes have a small effect on the calculation of RSI (and so the volume of DCs).

Under the future year scenario (2029), RSIs are higher and there no DCs for all seven parametrisations we consider. The additional supply from the Celtic interconnector, new wind and solar capacity, and additional thermal capacity not owned by ESB more than counteracts the higher load. Even under a relatively strict parametrisation of RSI that would assign a material volume of DCs in the base case, the Model does not allocate any DCs in 2029.

The finding that the RSI Model could yield zero DCs in a few years' time may be a relevant consideration for the RAs in deciding whether to adopt the RSI Model, as they must trade of the theoretical benefits of the updated Model against the implementation cost associated with the change. However, the scenario we have tested reflects only one possible set of system conditions in 2029. Under different system conditions – for example, if there is more market consolidation, slower rollout of new capacity, or higher-than-expected demand from data centres – the model could continue to produce non-zero DCs in 2029 and later years.

6. Conclusion: Recommendations for the Current Round of Updates and Considerations for Future Updates

Throughout this report, we have described our recommended updates to the Concentration Model that the RAs use to assess market power in the DAM and assign DCs to mitigate the risk of abuse of that market power.

Many of the updates we have recommended are relatively uncontroversial and arguably necessary to ensure that the Model accurately reflects the evolving characteristics of the SEM. These include, for example, the addition of solar and batteries to the model and updates to reflect changes to the ownership and control of other generating assets. We provide a summary table of all recommended updates, and their directional impact on DC assignment, in Appendix C.

Three of the updates that we have recommended are more material. We have worked closely with CRU over the course of the project to develop our recommendations in relation to these updates. We recommend:

1. **Changing the measure of market concentration from HHI to RSI.** The Model currently uses HHI, which measures market concentration based on ownership of supply only. We recommend switching to RSI, which evaluates how much residual supply there is to meet demand without the capacity of the largest supplier or suppliers. Because it accounts for demand, the RSI approach provides a more contextualised estimate of the potential for abuse of market power than HHI.
2. **Differentiated treatment of wind and solar capacity by support scheme.** The Model currently treats all variable renewable capacity as supply for both the whole market and individual companies. Different financial support schemes create different incentives for wind and solar units to participate in market power schemes. RESS is a two-way CfD, so RESS-supported units are insulated from market prices and do not benefit from market power schemes. We therefore include them in market capacity but exclude them from the capacity of individual companies for the RSI calculation (we refer to this treatment as *atomisation*). Units supported by REFIT (a one-way CfD) and NIRO can benefit from higher market prices and so we include them in both market capacity and the capacity of individual companies.
3. **Allowing the model to allocate DCs to companies other than ESB.** The Model currently allows for DCs to be allocated to up to two named companies (typically ESB and one other company). We recommend updating the Model to allocate DCs incrementally to the company with the lowest RSI, which means the Model can allocate DCs to multiple companies and that there is no need to specify at the outset which companies are eligible for DCs.

To use the updated RSI-based model, the RAs will need to set values for four key RSI parameters. These are: X-RSI (where X is the number of companies excluded from the calculation of RSI), the RSI threshold, the cost-competitive capacity threshold (CCCT), the limit on hours allowed to be below the RSI threshold. For each, there is a range of values the RAs could reasonably consider.

We recommend that the RAs pick a suite of RSI parameter settings that *collectively* reflects the RAs' tolerance for risk arising from market concentration in the SEM, with due consideration that (i) DCs are not the only tool the RAs have to mitigate market power[69] and (ii) higher volumes of DCs can be detrimental to free price formation in the SEM. Each parameter has stricter or laxer options, with stricter options leading to higher volumes of DCs, all things equal.

We provide more detailed guidance on how the RAs might approach the setting of RSI parameter values in Sections 4.2 and 4.3 of this report. We also provide illustrative examples of the impact of different RSI parameter settings on the allocation of DCs in Appendix B.

One could consider the 1-RSI model with a 1.1 threshold, 50 per cent CCCT, and limit on hours of 5 per cent as a baseline (as explained in Section 4.2.4). However, the commentary from which this baseline is derived also explicitly advises that the setting of parameters should be tailored to the market in question. For example, the RAs could consider a 2-RSI model for the SEM if they are particularly concerned about simultaneous withdrawal of capacity by the two largest suppliers. The RAs could then adjust the remaining three parameters accordingly to ensure the final parametrisation reflects their overall risk preferences.

Ultimately, the setting of RSI parameters is a matter for regulatory judgement.

We have recommended updates to the Concentration Model with the aim of achieving a reasonable representation of the DAM *given the current characteristics of supply and demand in that market*. Our recommended updates include simplifying assumptions which the RAs may need to review if the characteristics of supply and demand in the DAM change (e.g., if participation of batteries and DSUs increases materially). We set out considerations for future updates to the Concentration Model in Table 6.1.

The RAs could also consider extending their analysis of market concentration to markets other than the DAM. For example, the RAs could consider developing a model of market concentration that accounts for network and system constraints. Such a model would more closely proxy real-time dispatch and therefore would offer a better representation of the Balancing Market.

Table 6.1: Key Consideration for Future Updates to the Concentration Model

Item	Consideration for Future Updates
Potential market power in constrained dispatch	The Model aims to assess market concentration in the DAM, which is an unconstrained market. It may be beneficial to develop a separate model to assess the potential for market power after accounting for system constraints, that is, taking into account system operation decisions (e.g. must-run units providing inertia to the grid or thermal constraints) and transmission constraints. This would be useful to understand the potential for exercise of market power in the Balancing Market.
Wind and solar ownership (update annually)	We have updated the Model to reflect current wind and solar ownership shares. We recommend the RAs continue to update ownership shares regularly, e.g. annually or even more frequently, particularly while new solar deployment continues at pace.
Batteries	We have recommended that the Model treat batteries in the same manner as hydro and pumped storage by only counting generation scheduled in the SEM PLEXOS Model towards cost-competitive capacity. As the share of batteries in the SEM grows, we recommend the RAs consider whether more sophisticated treatment of batteries is required to better capture the potential to contribute to or mitigate market abuse.

69 For example, the MMU monitors all markets and can recommend enforcement action.

Item	Consideration for Future Updates
Hydro and pumped storage	We recommend the Model continue to only count actual generation towards cost-competitive capacity. We recommend the RAs consider if more sophisticated treatment is required to better capture these units' potential to contribute to or mitigate market abuse as and when they conduct a similar assessment for batteries.
Demand Side Units (DSUs)	The Model does not currently include DSU capacity. The RAs may wish to reevaluate the treatment of DSUs in the Model if the DSU capacity grows or their usage or market bidding behaviour changes – particularly if such changes lead to changes in the SEM PLEXOS Model, which could be mirrored in the Concentration Model.
Bid mark-ups	The Model does not currently include bid markups as part of generator bids due to the complexity of using PLEXOS outputs to incorporate their effect on average generator costs into the Concentration Model. The RAs may wish to include bid markups in the future.
Method for assigning incremental DCs to multiple companies	Our proposed Model assigns each incremental MW of DC to the company with the lowest average RSI for each quarter and hour type combination. If the Model assigns DCs to multiple companies in material volumes (rather than just ESB), we recommend the RAs consider whether to adopt a more sophisticated approach to assigning incremental DCs.
Atomisation of wind and solar capacity in receipt of financial support	We have recommended that the Model atomises wind and solar capacity supported by RESS due to the 2-way CfD, but does not atomise capacity supported by REFIT or NIRO. Our recommendation for REFIT reflects that current market prices are around or above REFIT contract prices, increasing the potential for REFIT supported resources to benefit from higher market prices. If market prices fall below REFIT contract prices, the RAs could consider atomising REFIT-supported capacity. In general, we recommend caution in choosing to apply atomisation, which is tantamount to assuming that the capacity provides no benefit in potential market power schemes.
Offshore wind	Offshore wind is not currently in the Model, but we recommend RAs include offshore wind once it comes online. RAs should consider atomising offshore wind depending on the design of its support schemes (e.g. 2-way CfDs). Given the forecasted capacity of offshore, we also recommend the RAs give consideration of how offshore wind could contribute to market power even if supported by a 2-way CfD.
Pricing of units that do not generate in PLEXOS	The Model currently assigns a cost of 10,000 EUR per MWh to units that do not generate in PLEXOS. This value is higher than these unit's actual costs. If the number of units which do not generate in PLEXOS increases, the RAs could adjust the Model so these units are priced in line with their average costs of generation.
Treatment of split ownership	Some generation assets may have split ownership (e.g. Tynagh is split 80-20 between EP and Mountside Partners). We currently recommend treating the party with operational control of the unit as the owner for measuring market concentration. The RAs could consider allowing for partial ownership in the future if partial ownership becomes more common.

Source: NERA analysis

Appendix A. Glossary

Term	Definition
Atomisation	The splitting of ownership of generation capacity across many small owners, such that each owns a tiny fraction (an "atom's worth"). In the Model, atomised capacity counts towards total market supply but not attributed to any individual owner. The Model applies this to certain wind or solar capacities depending on the support scheme used.
Concentration Model (the "Model")	The Concentration Model is the model used by the RAs to measure market concentration and calculate the volume of DCs that RAs impose on generation companies in the SEM.
Cost-Competitive Capacity Threshold (CCCT)	The threshold for determining which supply capacity the Model includes in the RSI calculation. For example, the Model could use 50 per cent CCCT whereby any capacity that costs less than 1.5 times the SEM price is deemed "cost-competitive".
Curtailment	Reduction of generation (primarily due to wind or solar) output when supply exceeds demand or due to system constraints. The Model only includes curtailment when supply exceeds demand or for economic reasons (e.g., thermal generator start-up or shut-down costs). It does not consider curtailment due to system constraints because it represents the Day-Ahead Market (DAM), which is unconstrained.
Demand Side Units (DSUs)	Consumer or customer-side resources that can reduce demand or provide generation-like services.
Directed Contracts (DCs)	Directed contracts are obligations imposed by the RAs which require certain companies (notably ESB) to make available specified volumes of generation capacity to the market at regulated prices to mitigate market power concerns.
Herfindahl-Hirschman Index (HHI)	HHI is a market concentration measure calculated as the sum of the squares of each company's market share. Values range from 0 to 10,000, with higher values indicating higher concentration (monopoly = 10,000). The Model currently uses HHI to measure concentration.
HHI Threshold	The level of HHI above which the Model deems an hour at potential risk of market abuse.
Limit on Hours	The limit on the percentage of hours allowed to be below the RSI threshold. The model assigns DCs until this limit is met.
Pivotality	Pivotality means a single supplier has a sufficient share of capacity that they could withdraw their capacity so that the remaining generation could not meet demand (i.e., the RSI is less than one).
PLEXOS	A detailed electricity market simulation tool used to provide hourly generation, prices, availability, and other data as inputs for the Concentration Model.
Renewable Electricity Support Scheme (RESS)	A 2-way CfD support mechanism for renewables where the supported generator receives a top-up equal to the difference between the market price and the strike price if an hourly price is below the strike price and pays back the difference between the market price and the strike price if an hourly price is above the strike price.
Renewable Energy Feed-in Tariff (REFIT)	A 1-way CfD support mechanism that tops-up renewable generators if the average market price is below the unit's REFIT contract price. If the average price is above the contract price, the scheme has no effect so the generator benefits from price increases but is protected if prices are lower.

Term	Definition
Renewable Obligation (RO) Scheme	Renewable Obligation Scheme in Northern Ireland, which allows generators to obtain additional revenue for each MWh of electricity generated by selling Renewable Obligation Certificates (ROCs).
Residual Supplier Index (RSI)	RSI is an alternative market concentration measure as a replacement for HHI. It measures the supply available from all suppliers except the largest (or a number X of largest) relative to demand. Lower RSI values indicate a higher risk of market power. RSI of less than one indicates *pivotality*.
RSI Threshold	The level of RSI below which the Model deems an hour at potential risk of market abuse.
X (from X-RSI)	The X largest companies excluded from the RSI calculation (e.g., 1-RSI excludes the largest in each hour, 2-RSI excludes the two largest in each hour).

Appendix B. Detailed Directed Contracts Results

In this appendix, we present the detailed breakdown of the DC allocations for different parametrisations of the RSI model. We break down the volume of DCs across product types (baseload, mid-merit, and peak), quarters within the modelled round, the company to which the DCs are allocated, and the different scenarios we consider.

Table B.1: Detailed DC Allocation in Base Case (R31) for 1-RSI Parametrisations

Parameter Settings				Allocated DCs (MW)										
					Baseload				Mid-Merit				Peak	
X-RSI	RSI threshold	Cost-competitive capacity threshold (CCCT)	Limit on hours	Company	*Q4-25*	*Q1-26*	*Q2-26*	*Q3-26*	*Q4-25*	*Q1-26*	*Q2-26*	*Q3-26*	*Q4-25*	*Q1-26*
1-RSI	1.1	50%	5%	*ESBPG*	-	-	320	-	90	370	220	-	-	170
1-RSI	1.1	50%	10%	*ESBPG*	-	-	170	-	-	150	140	-	-	-
1-RSI	1.1	100%	5%	*ESBPG*	-	-	-	-	-	-	110	-	40	360
1-RSI	1.0	50%	5%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
1-RSI	1.1	No CCCT	5%	*ESBPG*	-	-	-	-	-	-	-	-	-	80
1-RSI	1.1	50%	15%	*ESBPG*	-	-	50	-	-	-	140	-	-	-
1-RSI	1.0	No CCCT	15%	*ESBPG*	-	-	-	-	-	-	-	-	-	-

Source: NERA analysis.

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Table B.2: Detailed DC Allocation in Base Case (R31) for 2-RSI Parametrisations

Parameter Settings				**Allocated DCs (MW)**										
					Baseload				*Mid-merit*				*Peak*	
X-RSI	RSI threshold	Cost-competitive capacity threshold (CCCT)	Limit on hours	Company	*Q4-25*	*Q1-26*	*Q2-26*	*Q3-26*	*Q4-25*	*Q1-26*	*Q2-26*	*Q3-26*	*Q4-25*	*Q1-26*
2-RSI	1.0	No CCCT	5%	*ESBPG*	-	-	230	-	140	290	580	340	610	870
				EP	-	-	-	-	-	-	180	150	-	190
2-RSI	1.0	100%	15%	*ESBPG*	-	-	130	-	-	-	560	320	540	700
				EP	-	-	-	-	-	-	80	-	-	-
2-RSI	1.0	No CCCT	15%	*ESBPG*	-	-	-	-	-	-	570	90	360	610
2-RSI	1.0	50%	15%	*ESBPG*	-	200	490	-	280	340	360	420	300	310
				EP	-	-	-	-	-	-	30	20	-	-
2-RSI	1.0	No CCCT	10%	*ESBPG*	-	-	30	-	-	10	660	220	530	900
				EP	-	-	-	-	-	-	50	20	-	-
2-RSI	1.1	No CCCT	15%	*ESBPG*	-	-	310	-	330	410	580	430	680	720
				EP	-	-	-	-	-	-	260	240	-	150
2-RSI	1.1	50%	5%	*ESBPG*	660	760	1130	540	570	470	300	400	60	310
				EP	-	-	260	150	240	370	400	430	120	280
				SSE	70	-	20	-	-	190	60	10	-	-
				Energia	220	220	110	120	-	110	40	60	-	-
				Bord Gáis Energy	-	-	-	-	-	-	80	-	-	-

Source: NERA analysis.

Table B.3: Detailed DC Allocation in High Gas and Carbon Price Scenario

Parameter Settings				Allocated DCs (MW)										
					Baseload				Mid-Merit				Peak	
X-RSI	RSI threshold	Cost-competitive capacity threshold (CCCT)	Limit on hours	Company	*Q4-25*	*Q1-26*	*Q2-26*	*Q3-26*	*Q4-25*	*Q1-26*	*Q2-26*	*Q3-26*	*Q4-25*	*Q1-26*
1-RSI	1.1	50%	5%	*ESBPG*	-	-	-	-	-	-	160	-	-	100
1-RSI	1.1	50%	10%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
1-RSI	1.1	100%	5%	*ESBPG*	-	-	-	-	-	-	-	-	-	100
1-RSI	1.0	50%	5%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
2-RSI	1.0	No CCCT	5%	*ESBPG*	-	-	200	-	110	260	600	330	620	880
				EP	-	-	-	-	-	-	170	140	-	160
2-RSI	1.0	100%	15%	*ESBPG*	-	-	-	-	-	-	550	180	340	590
2-RSI	1.0	No CCCT	15%	*ESBPG*	-	-	-	-	-	-	540	60	340	590

Source: NERA analysis.

Table B.4: Detailed DC Allocation in Low Gas and Carbon Price Scenario

Parameter Settings				Allocated DCs (MW)										
					Baseload				Mid-Merit				Peak	
X-RSI	RSI threshold	Cost-competitive capacity threshold (CCCT)	Limit on hours	Company	*Q4-25*	*Q1-26*	*Q2-26*	*Q3-26*	*Q4-25*	*Q1-26*	*Q2-26*	*Q3-26*	*Q4-25*	*Q1-26*
1-RSI	1.1	50%	5%	*ESBPG*	80	230	520	-	370	480	230	130	-	-
1-RSI	1.1	50%	10%	*ESBPG*	-	-	310	-	170	380	210	-	30	-
1-RSI	1.1	100%	5%	*ESBPG*	-	-	-	-	-	-	240	-	310	400
1-RSI	1.0	50%	5%	*ESBPG*	-	-	100	-	-	-	20	-	-	-
2-RSI	1.0	No CCCT	5%	*ESBPG*	-	-	240	-	120	300	570	340	610	850
				EP	-	-	-	-	-	-	180	140	-	180
2-RSI	1.0	100%	15%	*ESBPG*	-	-	160	-	240	300	650	370	560	550
				EP	-	-	-	-	-	-	30	30	-	-
2-RSI	1.0	No CCCT	15%	*ESBPG*	-	-	-	-	-	-	560	80	350	590

Source: NERA analysis.

Table B.5: Detailed DC Allocation in Future Year (2029) Scenario

Parameter Settings				Allocated DCs (MW)										
					Baseload				Mid-Merit				Peak	
X-RSI	RSI threshold	Cost-competitive capacity threshold (CCCT)	Limit on hours	Company	*Q1-29*	*Q2-29*	*Q3-29*	*Q4-29*	*Q1-29*	*Q2-29*	*Q3-29*	*Q4-29*	*Q1-29*	*Q4-29*
1-RSI	1.1	50%	5%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
1-RSI	1.1	50%	10%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
1-RSI	1.1	100%	5%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
1-RSI	1.0	50%	5%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
2-RSI	1.0	No CCCT	5%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
2-RSI	1.0	100%	15%	*ESBPG*	-	-	-	-	-	-	-	-	-	-
2-RSI	1.0	No CCCT	15%	*ESBPG*	-	-	-	-	-	-	-	-	-	-

Source: NERA analysis.

Appendix C. Summary of Recommended Updates

Table C.1 summarises the updates to the Concentration Model that we considered as part of this assignment, and our recommended approach in relation to each update. In some cases, we recommend implementing the update. In others we recommend no change, usually because the expected impact of the change does not justify the effort involved in making the change.

The table also explains the directional impact of the update on DCs, relative to a model without the update. Where the directional impact depends on whether the baseline model is an HHI-based model or an RSI-based model, we describe the difference in effect.

For some updates, we have adopted simplifying assumptions to make the update feasible to implement. Where there is a known directional effect of the simplification, the table also reports this.

All updates are discussed in more detail in the body of the report; we provide references in the table to the sections of the body of the report where this additional detail can be found.

Table C.1: Summary of Updates to the Concentration Model Considered in this Report

Update	Existing Model Approach	Recommended Update	Directional Impact on DCs Relative to Model Without this Update (Considers Both HHI and RSI Models)	Directional Impact of Simplification (If Applicable)
Changes in Ownership of Assets (cf. Report Section 3.1)				
EP acquired an 80% stake in Tynagh in 2019		Treat Tynagh as 100% owned by EP in the Model.	Increase due to greater market concentration from EP acquisition (likely more effect on HHI than RSI since ESB remains largest).	May be slight overstatement as EP only receives 80% of the benefit from Tynagh; however, the fact that EP has full operational control supports 100% allocation.
EP acquired a 100% stake in		Treat Ballylumford as 100% owned by EP in the Model.	Increase due to greater market concentration from EP acquisition (likely more	N/A

Update	Existing Model Approach	Recommended Update	Directional Impact on DCs Relative to Model Without this Update (Considers Both HHI and RSI Models)	Directional Impact of Simplification (If Applicable)
Ballylumford in 2019			effect on HHI than RSI since ESB remains largest).	
Transfer of all EP assets to EP-TotalEnergies joint venture in 2025		No change to the Model, because TotalEnergies has no other assets in the SEM, so the joint venture has the same market power as EP previously had.	N/A	N/A
Wind and Solar (cf. Report Section 3.2)				
Inclusion of solar	Does not include solar capacity.	Include solar capacity in the Model and treat it in the same manner as wind.	Decrease as solar ownership is less concentrated / has a different set of owners than dispatchable generation.	N/A
Specify wind and solar ownership for all units	Specifies wind ownership for ESB and does not specify the ownership of wind for any other companies in the SEM.	Update the Model to reflect the current wind and solar market shares for the named companies in the Model based on ownership of units registered with GU_ numbers.	In HHI model, increases DCs since increases market share of larger, non-ESB companies. Potentially minimal increase to DCs in RSI model (since ESB remains largest).	Lack of data on small-scale (distributed) generation means we may slightly understate DCs, if large companies own or control wind or solar capacity without GU_ numbers.
Atomisation of wind and solar under financial support schemes	Does not atomise any wind or solar capacity.	We recommend atomising wind and solar supported by RESS 2-way CfDs. We do not recommend atomising wind and solar supported by REFIT (1-way CfD) or NIRO schemes.	Decrease as RESS supported wind no longer counts towards market concentration.	Treating all RESS supported wind and solar as atomised may understate market concentration if the capacity could be used in a market power scheme. Not atomising REFIT and NIRO-

Update	Existing Model Approach	Recommended Update	Directional Impact on DCs Relative to Model Without this Update (Considers Both HHI and RSI Models)	Directional Impact of Simplification (If Applicable)
				supported wind could overstate market concentration if suppliers would not use these units in a market power scheme (e.g., if market prices are consistently below the REFIT strike price).
Treatment of wind and solar curtailed in PLEXOS (for economic reasons, not constraints)	Does not include curtailed wind and solar volumes.	Include curtailed wind and solar as part of supply.	Could decrease as more available capacity reduces market concentration; in practice there is currently limited impact due to low levels of curtailment in PLEXOS.	N/A
Offshore wind	Does not include any offshore wind capacity (26 MW Arklow Bank Phase 1 counted as onshore).	No change, since planned and new offshore projects are not expected to be online in next few years.	N/A	N/A
Other Supply Resources and Cost of Generation (cf. Report Sections 3.3 to 3.8)				
Treatment of hydro and pumped storage	Includes hydro and pumped storage assets, counting *scheduled* generation in PLEXOS and ignoring *potential* generation (and	No change: continue to model hydro and pumped storage using scheduled generation per the SEM PLEXOS Model only, due to complexity of modelling potential energy output.	N/A	May overstate market concentration as hydro and pumped storage may increase generation in response to higher prices, but effect mitigated given energy limitations of those resources.

Update	Existing Model Approach	Recommended Update	Directional Impact on DCs Relative to Model Without this Update (Considers Both HHI and RSI Models)	Directional Impact of Simplification (If Applicable)
	charging for pumped storage).			
Inclusion of batteries	Does not include battery capacity.	Include batteries in the Model and treat them in the same manner as pumped hydro (i.e. only count scheduled generation from PLEXOS and ignore charging).	Could either increase or decrease estimated market concentration, depending on which companies own the batteries and where they place in the merit order.	May overstate market concentration as batteries may increase generation in response to higher prices, although their ability to do so may be limited by cycling or other practical constraints.
Exclusion of Demand Side Units (DSUs)	Does not include DSUs.	No change due to limited DSU capacity in PLEXOS model of SEM.	N/A	May overstate concentration as DSUs could supply power in response to high prices, but impact likely to be minimal due to low DSU capacity in PLEXOS and high average costs to dispatch most DSUs.
Using scheduled generation as a floor on cost-competitive capacity	Only considers a generation unit's average costs. Therefore, when a unit generates in PLEXOS even if costs are greater than the SEM price (to avoid start-up and shut-down costs), the Model will not include its capacity in market	Include actual generation as a floor on cost-competitive capacity, meaning a unit that generates despite having costs greater than the cost-competitive capacity threshold is included in cost-competitive capacity.	Decrease if there is a cost-competitive capacity threshold, as means there is more capacity available in the Model. Without this change, the Model would overstate concentration.	N/A

Update	Existing Model Approach	Recommended Update	Directional Impact on DCs Relative to Model Without this Update (Considers Both HHI and RSI Models)	Directional Impact of Simplification (If Applicable)
	concentration measures if its generation costs are greater than the cost-competitive capacity threshold.			
Pricing of units that do not generate in PLEXOS	Units that do not generate are priced at 10,000 EUR per MWh.	No change, due to complexity and limited impact of pricing closer to actual average costs.	N/A	May overstate concentration in models with a cost-competitive capacity threshold, as units are likely to be excluded from cost-competitive capacity; but limited as typically only applies to the few most expensive peakers (which may be excluded by the threshold even at a lower price). No impact if no cost-competitive capacity threshold.
Inclusion of bid markups	Does not include bid markups (adders generators may apply to their costs when bidding, e.g. opportunity costs) when measuring costs.	No change: continue to exclude bid markups from the Model due to the complexity of blending bid markups with costs from PLEXOS.	N/A	Theoretically could either over- or under-state concentration, depending on overall effect on merit order and SEM clearing price.
Treatment of Edenderry	Atomises 30% of Edenderry's capacity	No longer atomise 30% of Edenderry's capacity.	Minimal change in HHI approach (and likely no	In HHI approach, may minimally overstate concentration.

Update	Existing Model Approach	Recommended Update	Directional Impact on DCs Relative to Model Without this Update (Considers Both HHI and RSI Models)	Directional Impact of Simplification (If Applicable)
	to reflect a subsidy program for its peat-fired capacity.		change in RSI approach) as Edenderry's owner has low market share.	
Measure of Market Concentration and Allocation of DCs (cf. Report Section 4)				
Using RSI as the measure of market concentration	Uses HHI to measure market concentration in each hour.	Use RSI rather than HHI to measure market concentration as RSI considers supply relative to demand (rather than just supply), thresholds have natural interpretation, and there is some precedent from other power markets.	Directional impact depends on specific settings of RSI parameters (see Section 4.3 for details).	N/A
Floor on cost-competitive capacity threshold	Calculates the cost-competitive capacity threshold as a set percentage above the hourly SEM PLEXOS price. There is no floor on this threshold, even if market prices are very low (or even negative).	Include a floor on the cost-competitive capacity threshold based on gas and CO2 prices (as used in the SEM PLEXOS Model), parametrised to mimic the average costs of a typical CCGT in the SEM. This ensures the calculation includes some thermal generation as cost-competitive capacity even when high renewable generation results in low prices.	For HHI model, adding capacity could increase or decrease DCs depending on ownership. For RSI model, DCs decrease as more capacity is available if a floor on cost-competitive capacity is used.	N/A
Allocation of DCs to companies other than ESB	Only assigns DCs to ESB.	Allow Model to assign DCs to companies other than ESB. Treat all companies equally in terms of potential to be assigned DCs: incrementally assign DCs to the company with the lowest average RSI in the relevant quarter and type of hours.	Decrease in instances where the revised Model assigns another company DCs (because the Model would need to assign more DCs to ESB to achieve the same result). No change if only	In the case of high levels of DCs to more than one company, a more complex/precise algorithm to incrementally assign DCs may slightly reduce total volumes of DCs assigned.

Update	Existing Model Approach	Recommended Update	Directional Impact on DCs Relative to Model Without this Update (Considers Both HHI and RSI Models)	Directional Impact of Simplification (If Applicable)
			ESB receives DCs under the revised model.	
Calculation of quarterly DC volumes	Calculates DCs required in each month and takes the maximum to determine quarterly volumes.	Calculate DCs on a quarterly basis directly, particularly if switching to RSI.	Decrease in DCs as no longer take the maximum across months.	N/A

Source: NERA analysis

Appendix D. Use of Company-Specific RSI

As discussed in Section 4.1, we recommend calculating a market-wide RSI. Under this approach, we calculate RSI by subtracting the capacity of the largest supplier in each hour (or suppliers if a 2-RSI or 3-RSI approach), regardless of company size or market share outside of that specific hour. We recommend this approach, since it leads to the assignment of DCs in an efficient manner to minimise hours at risk of abuse of market power, regardless of which company has the largest quantity of supply resources in that hour. This approach also mirrors the HHI approach, where the HHI formula is necessarily market-wide.

An alternative approach could be to calculate company-specific RSIs and require each company to separately have its RSI statistics meet a required threshold, e.g., the Model might require each company have no more than a certain percentage of hours where the company's RSI is below some threshold. A company c's RSI in hour h is simply:

$$RSI_{h,c} = \frac{Total\ Cost\ Competitive\ Supply_h - \ Cost\ Competitive\ Company\ Supply_{h,c}}{Load_h}$$

We do not recommend the company-specific approach. This approach may fail to identify the overall risk of exercise of market power where there are multiple large players. For example, imagine a market with three similarly sized large players. Each company may have a company RSI with no more than 5 per cent of hours with an RSI below 1.1 (as the hypothetical criteria). Yet, the entire market could have more than 5 per cent of hours with an RSI below 1.1, assuming there is diversity when the three companies have RSIs below the RSI threshold. A company specific limit on hours could miss such cases of potential market power.

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