National Resource Adequacy Assessment Methodology for Ireland and Northern Ireland

Consultation

December 2023

Contents

Revision	Date	Comment
1.0	December 2023	Version for consultation.

1. Introduction

EirGrid and SONI, as the Transmission System Operators (TSO) for Ireland and Northern Ireland respectively, have a responsibility to operate the electricity transmission system every minute of every day, whilst also planning the future of the transmission grids in their relevant jurisdictions.

EirGrid, the TSO in Ireland, is required to publish forecast information about the power system, as set out in Section 38 of the Electricity Regulation Act 1999[1] and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations[2]. The forecast statement is a requirement of Condition 7 of EirGrid's Transmission System Operator licence, which also states that the methodologies on which the forecast statement is based shall be subject to the approval of the Commission for Regulation of Utilities in Ireland.

SONI, the TSO in Northern Ireland, is required to produce an annual Generation Capacity Statement (GCS), in accordance with Condition 35 of the Licence[3] to participate in the Transmission of Electricity granted to SONI by the Department for the Economy (DfE). Condition 35 also states that the statement shall be based on methodologies approved by the Utility Regulator for Northern Ireland.

Under these reporting requirements, EirGrid and SONI forecast the projected level of electricity demand and the expected resources available to supply this demand. The demand and generation forecasts for Ireland and Northern Ireland are modelled along with relevant operational requirements to evaluate power system reliability in reference to the relevant reliability standard. This process is referred to as a resource adequacy assessment where the reliability standard is specified on a jurisdictional basis for Ireland and Northern Ireland using Loss of Load Expectation (LOLE).

As European policy direction and regulations have evolved, the approach for assessing resource adequacy has also evolved to appropriately represent the transforming power system i.e. transitioning away from aging fossil fuelled conventional generation plant and towards a power system increasingly dependent on variable renewables, interconnection, demand side response, long duration energy storage and other renewable gas ready dispatch power plants. Through the Shaping Our Electricity Future Roadmap[4], EirGrid and SONI identify the need to enhance our reliability assessments to suitably dimension the possible risks to resource adequacy and align with European Union regulation.

The methodology proposed in this consultation will evolve the existing Generation Capacity Statement (GCS) methodology for EirGrid and SONI annual publications, to align with EU Regulation 2019/943 Article 24(1) and overall improve the approach to assessing the reliability of the evolving power system. This methodology is focussed on the modelling of resource adequacy for Ireland and Northern Ireland.

Assessments conducted using this methodology will support signalling future system outlook and requirements to the energy market as well as to policy makers, regulators, industry, TSOs, Distribution System Operators (DSOs), electricity consumers, and the general public.

1.1. European Regulatory Framework

The 'Clean Energy for all Europeans' package adopted in 2019 set out a new framework for the transition away from fossil fuels to cleaner sources of energy which included the Regulation on the internal market for electricity (EU/2019/943)[5] herein referred to as 'the Regulation'. Chapter IV (Articles 20-27) of the Regulation are focussed on resource adequacy.

[1] https://www.irishstatutebook.ie/eli/1999/act/23/section/38/enacted/en/html
[2] https://www.irishstatutebook.ie/eli/2005/si/60/made/en/print#partx-article28
[3] https://www.uregni.gov.uk/files/uregni/media-files/SONI%20TSO%20Consolidated%20Feb%202019.pdf
[4] https://www.eirgridgroup.com/site-files/library/EirGrid/Shaping-Our-Electricity-Future-Roadmap_Version-1.1_07.23.pdf
[5] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

Article 23 of the Regulation mandates the European Network for Transmission System Operators for Electricity (ENTSO-E) to conduct annual resource adequacy assessments based on projected supply and demand for electricity across the EU to identify resource adequacy concerns for Member States. ENTSO-E's obligations under Article 23 of the Regulation are fulfilled through the European Resource Adequacy Assessment[6] (ERAA), which was approved by the European Union Agency for Cooperation of Energy Regulators (ACER) on 2nd October 2020. ACER also has responsibility for approving the annual implementation of the ERAA methodology conducted by ENTSO-E.

Article 20(1) of the Regulation states that Member States may also carry out national adequacy assessments where necessary. Article 24 of the Regulation states that the national adequacy assessment should be based on the ERAA methodology, and capture market specific characteristics or risks that the European assessment may not capture in detail. Effectively, the national adequacy assessment provides the scope to run studies that are relevant on a national level but may not be relevant at a pan-EU level.

The development of an implementation plan for the NRAA methodology has been a component of the Security of Supply Programme in Ireland, led by the Commission for Regulation of Utilities (CRU); and the requirement for the NRAA framework to be applied in Northern Ireland has been acknowledged by the Utility Regulator. Engagements on the implementation of NRAA have been ongoing with the Regulatory Authorities from early 2023. Although Northern Ireland is no longer a member state of the EU, as the Single Electricity Market (SEM) operates on an All-Island basis and the Withdrawal Agreement has made provisions for the continued operation of the SEM. Article 9 and Annex 4 lists the legislation that continues to apply in respect of Northern Ireland including EC 714/2009. Article 6 of the Withdrawal Agreement ensures that any legislation that updates this will continue to apply automatically to Northern Ireland. This means that Regulation 2019/943 applies with respect to electricity generation and transmission in Northern Ireland.

As we enhance our resource adequacy assessments, we are analysing the interactions between EU regulations, ACER approval of the ERAA methodology, and the statute and licence requirements of EirGrid and SONI respectively to ensure that all relevant processes are followed, and that the legal hierarchy is respected. We are currently engaging with the Regulatory Authorities (RAs) to determine on what amendments are required to the local frameworks to ensure that they are aligned with the new obligations placed on Ireland and Northern Ireland by the Electricity Regulation.

1.2. Consultation

The purpose of this consultation paper is to set out the proposed National Resource Adequacy Assessment methodology of which the first iteration will be implemented and published in 2024. To maintain transparency, stakeholders will be consulted again in the future if further development of the methodology is required.

Questions are provided through the document, with a summary of all questions in section 8. We request any responses to these questions by the 12th January 2024.

[6] https://www.acer.europa.eu/Individual%20Decisions_annex/ACER%20Decision%2024-2020%20on%20ERAA%20-%20Annex%20I_1.pdf

1.3. Structure of the Consultation Paper

This consultation paper is structured as follows:

Section 2 provides an overview of the timeline for publishing the first National Resource Adequacy Assessment.

Section 3 provides context and background information on the scope of this methodology.

Section 4 describes the methodology for forecasting and modelling demand.

Section 5 gives information on the various resources considered to contribute to resource adequacy.

Section 6 describes the methodology for assessing power system reliability.

Section 7 gives a description of aspects which may be considered in future iterations of this methodology.

Section 8 provides an overview of next steps and details the consultation questions.

2. Consultation Plan

This consultation is the first of three opportunities for stakeholders to provide feedback into the National Resource Adequacy Assessment process.

This consultation is specifically related to the proposed methodology and does not provide details regarding certain data sources or input assumptions.

Stakeholders will have the opportunity to provide input through subsequent consultations on the proposed data sources or input assumptions, and feedback will be welcomed on the final results and report.

Consultation Stage	Date	Content
Methodology	December 2023	Covers the methodology for processing input data related to forecasting demand, resource availability, and modelling of adequacy. This will also cover the scope of the study and key output metrics. A stakeholder workshop will form a part of the consultation process. Information pertaining to specific input assumptions and data sources does not form part of the methodology.
Input Assumptions & Data Sources	Early 2024	Includes the key assumptions within the demand and generation portfolios, and the key data sources being used to inform these forecasts.
Results & Report	Autumn 2024	Reporting on the results from the implementation of the National Resource Adequacy Assessment methodology.

3. Study Content

3.1. Assessing Resource Adequacy

The purpose of this National Resource Adequacy Assessment (NRAA) methodology is to evolve the resource adequacy assessment from the existing Generation Capacity Statement (GCS) methodology and evaluate adequacy in line with reliability standards for Ireland and Northern Ireland.

Resource adequacy refers to having sufficient supply to meet the reliability standard. This includes providing for the capacity and energy needs of the system accounting for relevant operational requirements. To operate a reliable power system, reserve resources are required to ensure security of supply is maintained following a disturbance to the system. When planning the future power system, it is necessary to consider the provision of resources to ensure the system can be operated reliably according to the specified reliability standard.

A key consideration for conducting resource adequacy assessments is the availability of resources available to System Operators to operate a reliable system, accounting for various characteristics that can restrict the ability of a resource to contribute to resource adequacy. These characteristics can include:

- The dependency on weather dependent resources contributing to reliable operation of the evolving power system requires multi-year climate data to assess the availability of variable or energy limited resources such as wind, solar, hydro, and storage technologies.
- The contribution from interconnection needs to consider the availability of neighbouring regions to provide energy, accounting for climate variation and the availability of lines.
- Forced Outages, Scheduled Outages, Annual Run Hour Limitations (ARHL), and energy constraints that restrict power plant availability.

The existing GCS methodology and the NRAA methodology in this consultation both employ probabilistic methodologies to assess resource adequacy accounting for the characteristics mentioned above. The existing methodology, as published in the latest GCS[7], is convolution-based and assesses the Loss of Load Probability in each 30-minute interval to provide an average deterministic output for a given year. The NRAA methodology will be Monte Carlo based, solving a range of possible operating scenarios to converge on a deterministic output.

Figure 1 illustrates the resource adequacy balance, where the scales are balanced with reference to the defined reliability standard. Insufficient resources to operate a reliable system accounting for possible uncertainty and disturbances means the system could be operating outside the acceptable level of risk.

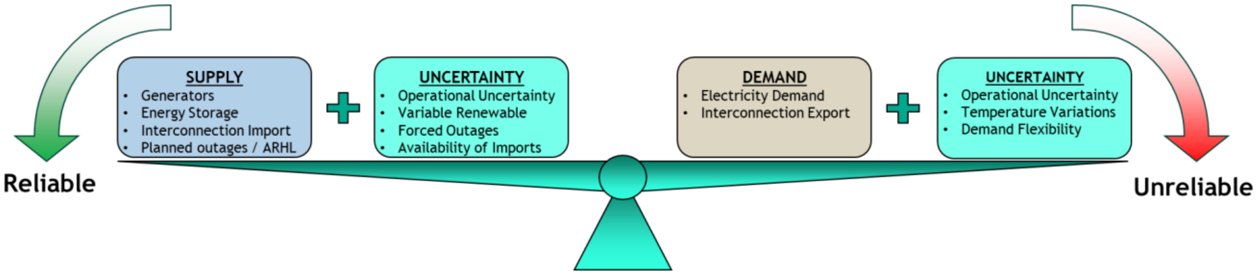

Figure 1 - The Resource Adequacy Balance

The NRAA methodology will use an industry standard techno-economic modelling package to perform, at a minimum, the Monte Carlo probabilistic calculation of regional LOLE and ENS. The surplus/deficit (MW) of the system will also be provided to provide insight on the amount of perfect plant that is required to balance the scales and return to standard.

[7] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid_SONI_Ireland_Capacity_Outlook_2022-2031.pdf.

3.2. Geographical Scope

This methodology is focussed on the modelling of resource adequacy for Ireland and Northern Ireland. France and Great Britain (GB) will be modelled explicitly and interconnection between these regions will be included. Ireland, Northern Ireland, Great Britain and France will be modelled as market nodes effectively a 'copper plate model', therefore not explicitly modelling localised network constraints within the regions themselves.

To account for exchanges between non-explicitly modelled market regions such as interconnected regions beyond GB and France, the full ERAA model will be used to create typical market exchanges between these regions which will be fixed for the purpose of studies for this methodology. Further details on the configuration of interconnection in the model is presented as described in Section 5.2.

3.3. Time Horizon & Resolution

This methodology aims to assess resource adequacy over a 10-year horizon such that for a given Publication Year (PY) resource adequacy will be assessed for years PY+1 to PY+10. For example, the first statement utilising this National Resource Adequacy Assessment methodology will be published in 2024 for the study period 2025 – 2034. This is consistent with the approach used in the ERAA methodology Article 4(1)(b).

The forecast years will be modelled at an hourly resolution for the purpose of the adequacy assessments, consistent with the ERAA methodology Article 4(1)(h).

3.4. Modelling Considerations

This methodology provides a framework for assessing resource adequacy in the Ireland and Northern Ireland however, due consideration is required for the following:

- Economic decision making: The model will consider the optimal solution to match supply and demand taking into account availability of resources. The solution is optimised on an unconstrained basis and therefore may not reflect actual unit dispatch.
- Perfect foresight: System stress in real time can be driven by uncertainty, however the modelling employed under this methodology will utilise perfect foresight such that the availability of variable generation and unit availability will be known by the model and optimised accordingly. The uncertainty of operating the system
- Simplified modelling of resources: In the interest of reducing computational complexity, the modelling of units has been simplified by removing factors that are unlikely to impact on adequacy due to the perfect foresight in the model e.g. start times, ramp rates, min stable levels.
- Simplified operational security: Reserves are accounted for and transmission system limitations will be modelled in a simplified manner. Voltage and frequency stability limits are not considered within the scope of this methodology.
- Climate years: Where necessary, particular climate years may be selected to represent the credible range of operating conditions.

4. Demand Modelling

4.1. Total Electricity Requirement

The forecasted level of demand is estimated from four sectors, each with different driving factors and underlying trends.

1. Residential, commercial, and industrial demand
2. Electric Vehicle Demand
3. Heat Pump Demand
4. Data Centre and New Technology Demand

The forecast level of demand for each of these sectors are combined to give the estimated Total Electricity Requirement (TER) on an annual basis. The impact of transmission and distribution losses, as well as self-consumption are factored into the final TER forecast.

Three different demand levels will be forecast to represent a low, median, and high demand level. The exact assumptions that change between these demand levels will be covered in the assumption consultation referenced in section 2.

4.1.1. Residential, Commercial and Industrial Annual Demand

Residential, Commercial and Industrial demand is forecast on the basis of correlation between historic temperature corrected demand (including self-consumption) and economic performance. Historic periods of economic turbulence are excluded from this correlation. The correlation is extrapolated across the study horizon on the basis of an economic forecast. The predicted demand is adjusted to take into account external factors and policies such as efficiency improvements, smart meters effects and the electrification of industry.

The effect of temperature on demand in these sectors affects the demand shape significantly more than the annual demand.

Whilst the electrification of heat and transport as well as growth from data centres and new technology loads will affect these sectors demand, the impact of these factors are captured separately, to enable the underlying trends of this conventional load to be appropriately assessed and forecasted.

4.1.2. Electric Vehicle Annual Demand

Electric vehicle demand incorporates passenger vehicles, light goods vehicles, and public service vehicles. Within these categories, both Battery Electric Vehicles and Plug-In Hybrid Electric Vehicles are included. The total demand from this sector considers:

- Number of vehicles.
- Vehicle efficiency.
- Average annual distance travelled.

These metrics are assessed for each class of vehicle and combined for the total electric vehicle demand for an average climate year.

4.1.3. Heat Pump Annual Demand for Space and Water Heating

Heat pump demand incorporates the space and water heating through heat pumps for both commercial and residential properties (including new builds and retrofits). The total electricity demand for this sector considers:

- Number of installations.

- Space and hot water heating demand (climate dependent).
- Type and efficiency of heat pumps installed.

These metrics are assessed for residential new builds, retrofits and commercial properties and combined together for the total heat pump demand.

This sector focuses on the use of heat pumps to provide space and hot water heating. It does not include the use of heat pumps manufacturing and industry; this will be captured in the adjustment to Industrial demand under electrification of industry. It also does not include the use of heat pumps for cooling, this sector is assumed to be captured already in the residential, commercial and industrial demand.

4.1.4. Data Centre & New Technology Annual Demand

Data Centre and New Technology Load demand incorporates connections at both the transmission and distribution system for these users that typically use large amounts of energy. A range of factors that will drive growth is considered for each site; these include historical demand growth rates from existing sites, contracted positions from companies and their growth potential, financial close, planning permission, and any relevant direction from regulatory authorities etc. This process creates three credible scenarios that drive demand across the low, median, and high forecast scenarios.

4.1.5. Annual Losses

Losses within the electricity system are forecast based on the historic trends of losses (differences between metered generation and metered demand and interconnection flows). Different levels of losses are assumed for demand connected at the transmission and the distribution level. The forecast level of self-consumption is taken away from the forecasted level of demand, and losses are calculated on the basis of the remaining demand.

4.2. Demand Profile & Flexibility Modelling

The demand profile refers to the changing demand in each hour of the year. There are a multitude of factors that influence when consumers will use electricity, and these factors may change into the future. For the purpose of this forecast, the demand is again broken down into different sectors that each have distinctive usage patterns and influencing factors.

The intent is to align with the European Resource Adequacy Assessment (ERAA) methodology and utilise the ENTSO-E Demand Forecasting Tool (DFT) to forecast the demand profile. This tool utilises historic demand trends, correlated to temperature and economic factors and includes forecasted heating profiles and EV charging profiles. Whilst this tool is being proposed for use within ENTSO-E studies and is being quickly developed, the feasibility of the tool is currently being assessed for this NRAA methodology. As such, the current intent is to develop demand profiles in tandem utilising EirGrid and SONI's existing toolset. The output of this tandem study will be used to validate, supplement or replace the output from the DFT where applicable.

4.2.1. ENTSO-E Demand Forecasting Tool

Within this tool (which has been built as an evolution of the TRAPUNTA tool used previously[8]), historic demand, economic and climatic factors are evaluated in relation to the assumptions around the key demand sectors (base load, electric vehicles, heat pumps and data centres and new technology loads). Modelling parameters can be adjusted to ensure a strong correlation between expected levels of demand and real historic data to ensure the model is representing the demand appropriately.

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[8] https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/MAF/2020/Demand_forecasting_methodology_V1_1.pdf

Forecasted levels of annual demand by sector, economic forecasts, behavioural patterns, electrification uptake and efficiency and demand profiles are input tool to forecast the future demand shape.

This model utilises historic climatic data covering irradiance, wind speed and population weighted temperature to forecast a range of climate dependent forecasted demand shapes.

4.2.2. Residential, Commercial and Industrial Demand Shape & Flexibility

The projected demand shape for this sector is based on historical demand shape, projected trends and the impact of temperature. An average load factor is used to assess the ratio of temperature corrected peak demand to total energy demand for these sectors in historic years. The trend of this average load factor changing over time is projected into the future to assess the forecasted peak demand.

Historic demand profiles are scaled and translated to align with both the forecasted peak demand and forecasted total energy demand from these sectors. The shape of this temperature corrected demand is then adjusted to factor in weather patterns based on historic climatic data.

Demand flexibility in this sector is accounted for through reducing the peak demand, the scaling and translation process will result in the energy that is removed from peak times being distributed across the day.

4.2.3. Electric Vehicle Demand Shape & Flexibility

The forecasted electric vehicle demand shape is based on forecast vehicle usage patterns, temperature dependent efficiency and charging behaviour.

Vehicle usage patterns incorporates both day of the week and time of year impacts.

Temperature dependent efficiency includes the impact of temperature on battery performance and vehicle cabin heating demand.

Charging behaviour factors in when people choose to charge their electric vehicle. Multiple profiles will be utilised to reflect different consumer behaviour, with the number of people attributed to different profiles expected to change across the study horizon. The different categories of vehicles (private, commercial, and public service), as well as differentiation between PHEV and BEV, may also be assigned different charging patterns.

Demand flexibility in this sector will be modelled on the basis of uptake of charging profiles that avoid peak times.

4.2.4. Heat Pump Demand Shape & Flexibility

The shape of demand from heat pumps is heavily dependent on climatic temperature, and also factors in consumer behaviour.

Whilst the average space and hot water heating demand is utilised in calculating the annual demand, the daily heating demand will fluctuate on the basis of temperature. In addition to this, the coefficient of performance (COP) of heat pumps (which indicate their efficiency) is affected by climatic temperature with heat pumps becoming less efficient at lower temperatures. This compounds the impact of low temperatures with heating demand increasing and heat pumps becoming less effective. The differing COP impact of temperature on different technologies of heat pumps is factored into this assessment.

The behavioural use of heating with a heat pump is different to conventional boiler as heat pumps operate most efficiently when they are run for a higher number of hours each day at a lower heat output[9]. A behavioural usage profile is incorporated to reflect how consumers will utilise their heat pump in each hour of the day to ensure space and water heating is sufficient to reach desired comfort level.

[9] https://www.seai.ie/publications/Low-Carbon-Heating-and-Cooling-Technologies.pdf

The hourly profile based on behavioural use has the opportunity to be altered to provide demand flexibility. Whilst evidence of this service is currently scarce, the methodology will provide a provision to shift some demand earlier, avoiding peak times.

4.2.5. Data Centre and New Technology Load Demand Shape

Historic trends show the shape of demand observed from data centres and new technology loads is relatively flat across the day. Previously the daily demand has, on average, gradually increased across the year to the forecasted peak based on the individual sites building out towards their contracted ramp. This will be reflected by the daily demand gradually increasing throughout the year from the previous year's peak demand to the forecast peak demand.

For the purposes of modelling the demand profile, it can include a portion of flexibility that is represented through reduced demand during time of high tariffs. Historical data and policies can be used to assess the scale of the current and future flexibility.

For emergency situations, some sites will be required to curtail their demand requirements, altering their demand shape. These measures are assumed to be operational measures during a system Emergency State rather than contributing to system adequacy. As such these are not factored into the forecasted demand shape.

4.2.6. Demand Side Units / Demand Side Response

Demand Side Response (DSR) is an energy product that aims to reduce or shift demand on the transmission system. This can be achieved either through a reduction of demand at a particular site or using on-site generation to meet the demand. Further details on modelling DSR is described in Section 5.

4.3. Demand in Great Britain and France

Forecasted demand levels and profiles for both Great Britain and France are required to enable representative interconnection modelling. This will utilise the output from the latest published European Resource Adequacy Assessment (ERAA) with interpolation used to calculate the intermediate years not currently covered by the ERAA study.

Question 1 - Do you have any comments on the factors considered in forecasting the Total Electricity Requirement (TER)?

Question 2 - Do you have any comments on the approach to modelling demand and flexibility?

5. Adequacy Resources

This section provides details on the various types of resources that will be included in this methodology as contributing to the operation of a reliable power system. The detail provided in this section is specific to modelling resources in the SEM region with the exception of the section on interconnection. The resources associated with the France and Great Britain will be fully aligned with and modelled according to the latest ERAA methodology approach.

5.1. Conventional Generation

This methodology will include existing and new conventional units on a unit-by-unit basis and apply capacity weighted class average forced and scheduled outage statistics.

5.1.1. Technology Summary

Conventional generation units such as gas turbines and some steam turbines are necessary to provide inertia, fault current, voltage support, ramping needs and are still the primary source of reliability for the All-Island power system. The transition to increased supply from renewable generation will mean that these conventional units may be required less of the time, and many of the services they provide will be sourced from alternative low carbon sources including renewable generators, storage, synchronous compensators and more. However, replacing the value these units can bring to reliability of operating the power system remains challenging and so it is expected these units will be required to support delivery of climate ambitions providing back up supply when other lower emissions generation is unavailable. EirGrid and SONI have seen through the Tomorrow's Energy Scenarios[10] (TES) work that renewable fuel-ready conventional generation capacity will be required to support the needs of a net-zero power system.

5.1.2. Conventional Generation Information

Availability of current conventional generation capacity will consider existing and new generation capacity on a unit-by-unit basis. Availability across the study horizon will consider delivery of new capacity and exit dates for existing capacity, adjusted for risk, and based on the latest information available.

5.1.3. Conventional Generation Modelling Parameters

Conventional generation will be implemented in the model using the parameters in Table 1.

Modelling Parameter	Description
Forced Outage Rate (%)	Annual % the unit is on an unplanned outage
Forced outage Mean Time To Repair (hours)	No. of hours a unit resolves an unplanned outage
Maintenance Frequency	No. of times per year a unit has a planned outage
Scheduled Outage Duration (hours)	No. of hours a unit is on planned outage
Installed Capacity (MW)	Installed capacity of a unit
Rating Factor (%)	Scaling factor applied to reflect ambient availability across the year
Heat Rate (GJ/MWh)	Amount of energy required to generate one MW of electrical output for one hour
Fuel Type	Primary (and possibly secondary) fuel type(s) used by the unit

[10] https://www.eirgridgroup.com/site-files/library/EirGrid/Tomorrows-Energy-Scenarios-2023-Consultation-Report.pdf

Annual Run Hour Limitations (hours)	Annual limit on the number of hours a unit or stack (exhaust shared by multiple units) can be on load.

Table 1 - Conventional Generation Modelling Parameters

* Technical parameters such as start-up times, ramp rates and min stable levels are excluded from this adequacy model. These parameters need to be considered in the context of real-world operation of the power system but have a negligible impact on adequacy modelling due to the perfect foresight in the optimisation.

5.1.4. Conventional Generation Availability

EirGrid and SONI report on conventional unit availability on a monthly basis using the following metrics to reflect unavailability of units:

- Scheduled: Scheduled generator outage approved by the relevant TSO Generation Outage Planning Team.
- Forced: Any reduction in availability not approved in advance with the relevant TSO Generation Outage Planning Team (including trips, outage overruns, urgent repairs, partial outages etc.).
- Ambient: Reduction in generator availability due to ambient temperature conditions.

Monthly availability data is used to generate a capacity weighted class average probability of the technology class being on either forced or scheduled outage. Further details on the specific modelling approach for the types of outages in contained in Section 6.

The average is calculated using a number of years of data aimed at incorporating the latest trends and create a reasonable estimate for future plant performance. Applying the class average socialises the risk of poor unit performance outages across the class, as it cannot be predicted which specific unit might perform poorly in future.

The capacity weighted class average forced outage rate is calculated for each class using:

$$\frac{\sum_{unit}\sum_{year}(Capacity)_{Unit} \times (Average\ Forced\ Outage\ Rate)_{unit}}{\sum_{unit}\sum_{year}(Capacity)_{Unit}}$$

The process above is repeated for the derivation of scheduled outage statistics with one additional step in converting from a scheduled outage rate to scheduled outage duration:

$$SOD = SOR \times 8760$$

With regards to the capacity weighted class average statistics there are two additional considerations:

1. Future performance of plant will be based on historical trends.
2. The outage statistics will be applied to both existing and new plant in the same way.

5.2. Interconnection

This methodology will explicitly model Ireland, Northern Ireland, Great Britain, and France acknowledging transfer capacity limits between regions. Interconnection beyond GB and France will be fixed based on ERAA modelling outputs.

5.2.1. Interconnection Summary

Increased interconnection provides the opportunity for power sharing between regions is seen as a key enabler to increasing renewable integration and potential to support security of supply during periods of system stress. The availability of interconnection to support security of supply for a given region depends on the availability of surplus energy from the neighbouring region in addition to the operational availability of the interconnector.

The ERAA methodology for modelling cross border exchanges across interconnectors includes flow-based constraints within the core region, with Advanced Hybrid Coupling (AHC) for non-core countries connected to the core region and Net Transfer Capacities (NTC) for countries not connected to the core region. The NTC approach refers to a maximum possible transfer between two boundaries and will be utilised for the purpose of this methodology, further information on Flow Based Market Coupling (FBMC) is covered in section 7.5.

5.2.2. Interconnection Internal to the SEM

The tie line between Ireland and Northern Ireland will be modelled using the NTC approach enabling power exchanges between the jurisdictions. The NTC will account for future development of the link such as the introduction of the new North South interconnector.

5.2.3. Interconnection External to the SEM

The NRAA methodology is aimed at complementing the ERAA methodology; where the National assessment has the provision to assess local risk analysis through modelling scenarios and sensitivities. The chosen approach to enable this and reduce the computational time required to run simulations is to model the SEM and neighbouring regions which the SEM will be directly interconnected to within the study horizon.

1. **Explicitly modelled regions**

It has been observed that due to the close geographical proximity of the SEM to GB, that similar weather conditions may prevail across each of the regions such that a cold spell in the SEM could also be a cold spell in GB. The impact and risks associated with simultaneously occurring weather conditions needs to be appropriately understood and therefore Great Britain is explicitly modelled in this methodology.

Re-integration with Europe is anticipated to enhance security of supply for the SEM, considering that the weather correlation is less prevalent between the SEM and FR regions but also that it will bring support from the wider EU electricity system. On this basis, France is explicitly modelled in this methodology.

The approach for modelling the interconnection between explicitly modelled regions will be based on the NTC limits. This will account for future roll out of additional interconnection and reflect power transfer limits between the regions. Where necessary, this methodology will consider market developments that could influence on the availability of a region to provide interconnection support to the SEM.

2. **Non-explicitly modelled regions**

To appropriately represent the availability of interconnector support from GB and FR, it is important to also consider onward interconnection from GB and FR to other countries. Table 2 below provides a list of regions which have direct links to GB and FR. Interconnection to these countries will be represented through the use of fixed flows derived from a pan-EU model.

Region	Interconnection to Great Britain	Interconnection to France
Belgium	✓	✓
Denmark	✓	✓
Germany		✓
Italy		✓
Netherlands	✓	
Norway	✓	

Spain		✓
Switzerland		✓

Table 2 - Implicitly modelled regions

For this methodology, fixed flows will be derived using the NTC approach, whereby market coupling limits are defined by transfer capacity limits. The ERAA model will used to derive imports into and exports out of GB and FR from the countries in the table above, which will then be fixed for the purpose of conducting national adequacy assessments for Ireland and Northern Ireland. This approach implicitly captures an average representation for how interdependencies across Europe may affect security of supply in the SEM.

This approach will account for changes to interconnection capacity across the study horizon through developing fixed flows for each target year and will capture the effect of climatic variations on interconnection at a pan-European level through modelling multiple climate years.

The boundaries discussed above are shown in Figure 2.

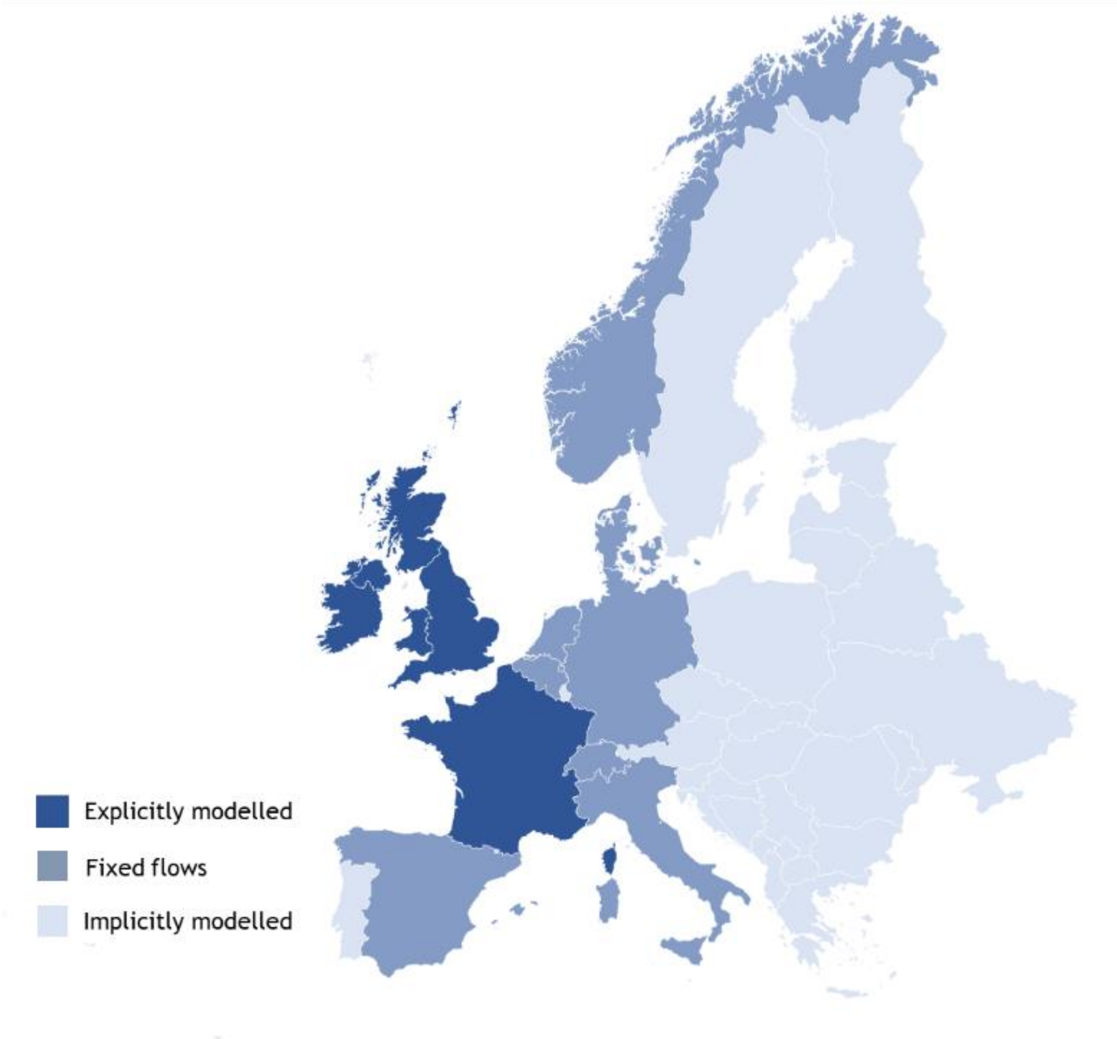

Figure 2 - NRAA Modelling Regions

5.2.4. Interconnection Modelling Parameters

Interconnection will be implemented in the model using the parameters in Table 1.

Modelling Parameter	Description
Max Flow (MW)	Maximum allowable flow on the line in the reference direction
Min Flow (MW)	Minimum available flow on the line in the counter reference direction (-ve value for bi-directional lines)
Forced Outage Rate (%)	Annual % the line is on an unplanned outage
Forced outage Mean Time To Repair (hours)	No. of hours for a line to resolve an unplanned outage
Maintenance Frequency	No. of times per year a line has a planned outage
Scheduled Outage Duration (hours)	No. of hours a line is on planned outage

Table 3 - Interconnection Modelling Parameters

5.2.5. Interconnection Availability

The availability of High Voltage Direct Current (HVDC) interconnectors between the SEM and neighbouring regions is considered by using a combination of forced and scheduled outage statistics for the HVDC line. HVDC Interconnectors between GB and FR will be assigned outage statistics and repair times in accordance with the latest ERAA modelling methodology. High Voltage Alternating Current (HVAC) interconnectors will not be assigned outage statistics in line with the ERAA methodology.

Outage statistics for interconnection between explicitly and non-explicitly modelled regions will be implicitly captured in the fixed flows used to represent these interconnections.

5.3. Variable Generation (Wind / Solar / Hydro)

This methodology will model variable renewable energy availability aggregated by technology type on a jurisdictional basis using correlated climate availability profiles.

5.3.1. Technology Summary

The transition to a power system predominantly supplied from variable renewable energy sources means the risks associated with periods of low renewable availability need to be dimensioned appropriately. It has been observed that risks to security of supply can result from correlation between weather patterns. On this basis, NRAA will model variable energy generation using multiple climate years to examine the impact of correlated weather events across the SEM, FR and GB on security of supply in the SEM region.

5.3.2. Variable Generation Information

Variable generation will be aggregated to a single installed capacity on a jurisdictional basis according to the following technology types:

- Offshore Wind
- Onshore Wind
- Solar PV – Large Scale
- Solar PV – Rooftop
- Run of River Hydro

Solar PV has been categorised into two capacity types differentiating capacity associated with small-scale behind the meter capacity (e.g. domestic rooftop PV) from large-scale distribution and transmission connected capacity. Wind capacity has been categorised into offshore and onshore capacity to reflect a possible increased contribution from offshore wind resulting from expected higher capacity factors.

5.3.3. Variable Generation Modelling Parameters

Variable renewable capacity will be modelled using the parameters in Table 4.

Modelling Parameter	Description
Installed Capacity (MW)	Installed capacity of a unit
Rating Factor (%)	Availability profile of the resource at the model resolution e.g. hourly

Table 4 - Variable RES Modelling Parameters

5.3.4. Variable Generation Availability

Availability of variable generation will be modelled using multi-year climatic data, reflecting correlated availability of these resources across possible climatic conditions. The profiles used will implicitly capture the effect of plant outages on availability.

5.4. Battery Storage

This methodology will model Battery Storage on an individual unit basis and apply an availability scalar to the storage capacity of the units.

5.4.1. Technology Summary

Battery Energy Storage System (BESS) units provide a range of services including renewable energy balancing, congestion management and voltage and frequency support. Storage units can also contribute to system adequacy needs and typically through storing energy during periods of generation surplus and discharging during periods of tight margins to alleviate stress on the system.

5.4.2. Battery Storage Information

Availability of battery storage capacity will consider existing and new storage capacity on a unit-by-unit basis. Availability across the study horizon will consider delivery of new capacity based on the latest information available.

5.4.3. Battery Storage Modelling Parameters

BESS units will be modelled considering the factors set as per Table 5 below.

Model Parameter	Description
Installed Capacity (MW)	Installed MW capacity of a unit
Installed Energy Capacity (MWh)	Installed MWh energy capacity of a unit
Initial State of Charge (%)	State of Charge in the initial period of the Horizon
Charge Efficiency (%)	Efficiency applicable to charging the unit
Maximum State of Charge (%)	The maximum state of charge a unit can achieve
Minimum State of Charge (%)	The minimum state of charge a unit can achieve

Maximum Cycles Per Day	The maximum number of cycles (charge and discharge) a unit can complete in a day
Pump Load (MW)	The maximum capacity the unit can import
Forced Outage Rate (%)	Annual % the line is on an unplanned outage
Forced outage Mean Time To Repair (hours)	No. of hours for a line to resolve an unplanned outage
Maintenance Frequency	No. of times per year a line has a planned outage
Scheduled Outage Duration (hours)	No. of hours a line is on planned outage

Table 5 - Battery Storage Modelling Parameters

5.4.4. Battery Storage Availability

This methodology will use the latest information available in relation to the performance and availability of battery storage units, to appropriately reflect the contribution to adequacy from this technology. As data becomes available in respect of outage statistics for battery storage units, this will be considered as part of the modelling input assumptions.

5.5. Demand Side Units

This methodology will model the Demand Side Units as an aggregated capacity, accounting for availability through applying an availability adjustment to the rated capacity and accounting for run hour restrictions where applicable.

5.5.1. Technology Summary

The capacity of DSUs has grown significantly in recent years, with a range of units supporting demand side management across a range of horizons. In terms of adequacy, units are dispatched before and during system alerts to provide demand reduction and alleviate stress on the system.

5.5.2. DSU Resource Information

Availability of DSU capacity will consider existing and new storage capacity on a unit-by-unit basis. Availability across the study horizon will consider delivery of new capacity based on the latest information available.

5.5.3. DSU Modelling Parameters

DSU resources will be implemented in the model using the parameters in Table 4.

Modelling Parameter	Description
Installed Capacity (MW)	Installed capacity of a unit
Rating Factor (%)	Availability of the resource
Max Capacity Factor Day (%)	Daily energy constraint applicable to DSUs with run hour limits
Offer Quantity (MW)	Quantity of generation offered
Offer Price (€/MWh)	Price of generation quantity offered

5.5.4. DSU Availability

DSUs may be subject to run hour or energy limits due to individual demand sites being subject to energy or run hour limits or possibly only being available to reduce load at certain times of the day depending on the type of demand available at a particular site.

Due to the various configurations comprising DSUs, it is difficult to specify exact times when a DSU has reduced availability for maintenance reasons or is forced unavailable. As such, the monthly availability reporting conducted by EirGrid and SONI provides DSU availability as a percentage of capacity available on average across the month.

This methodology will use DSU availability data from the EirGrid and SONI monthly availability reports to construct a capacity weighted average availability for the resource. The average DSU availability value will be applied to both run hour limited and non-run hour limited DSU resources, with an additional constraint implemented to restrict the energy that can be delivered from the run hour units on a daily basis.

5.6. Pumped Storage

This methodology will model pumped storage on a unit-by-unit basis. Availability to support adequacy will include outages based on historical availability and account for black start requirements.

5.6.1. Technology Summary

The pumped storage facility provides a range of system support functions, including reserve provisions and black start capability which will be reflected in the modelling for this resource.

5.6.2. Pumped Storage Information

Pumped storage resources will consider existing capacity connected to the system. Additional projects will be considered where there are contractual obligations in place such as connection agreements or capacity market contracts etc.

5.6.3. Pumped Storage Modelling Parameters

Hydro resources will be implemented in the model using the parameters in Table 6.

Modelling Parameter	Description
Installed Capacity (MW)	Installed capacity of a unit
Max Volume (GWh)	Upper volume bound for a storage reservoir
Min Volume (GWh)	Lower volume bound for a storage reservoir
Forced Outage Rate (%)	Annual % the unit is on an unplanned outage
Forced outage Mean Time To Repair (hours)	No. of hours a unit resolves an unplanned outage
Maintenance Frequency	No. of times per year a unit has a planned outage
Scheduled Outage Duration (hours)	No. of hours a unit is on planned outage
Initial State of Charge (%)	State of Charge in the initial period of the Horizon
Pump Efficiency (%)	Efficiency applicable when in pump mode
Pump Load (MW)	The maximum load drawn when in pump mode

Table 6 - Pumped Storage Modelling Parameters

5.6.4. Pumped Storage Availability

Pumped storage will be free to optimise it’s charging and discharging cycles within the bounds of the optimisation. Forced and scheduled outage statistics will be applied to individual pumped storage generator units based on class average statistics.

5.7. Other RES / Other Non-RES

The Other RES category contains units such as small-scale biomass units and small-scale hydro units for which inflows are unavailable. The Other Non-RES category consists of some smaller CHP units which will be aggregated together. The contribution from these categories to the overall reliability of the system is minimal due to the smaller nature of these capacities, however, will be included based on the latest estimates of available capacity.

These categories will be simplified in terms of modelled attributes and the availability of energy from each will be assumed using an availability profile consistent with the ERAA methodology.

Question 3 - Can you identify any resources that could be considered under this methodology which are not listed above?

Question 4 - Do you agree with the proposed approach to modelling the resources listed above?

6. Adequacy Modelling

6.1. Monte-Carlo Simulation

The objective of the stochastic Monte Carlo simulations is to create a range of possible scenarios and conduct a probabilistic assessment on the likelihood of operating the system within the defined reliability standard.

In real world operation of the power system, there are many factors which the system operators have little or no control over including weather, demand, and unplanned unit outages. Even planned outages may occur during undesired times of the year, either due to availability of maintenance personnel or late notice of requirements to carry out maintenance.

The intention of conducting a Monte Carlo type analysis, means a large number of possible scenarios can be constructed to vary each of the unknowns above, producing a range of credible operational scenarios. Figure 3 below illustrates the high-level building blocks used in the adequacy modelling, and further detail on these is provided thereafter.

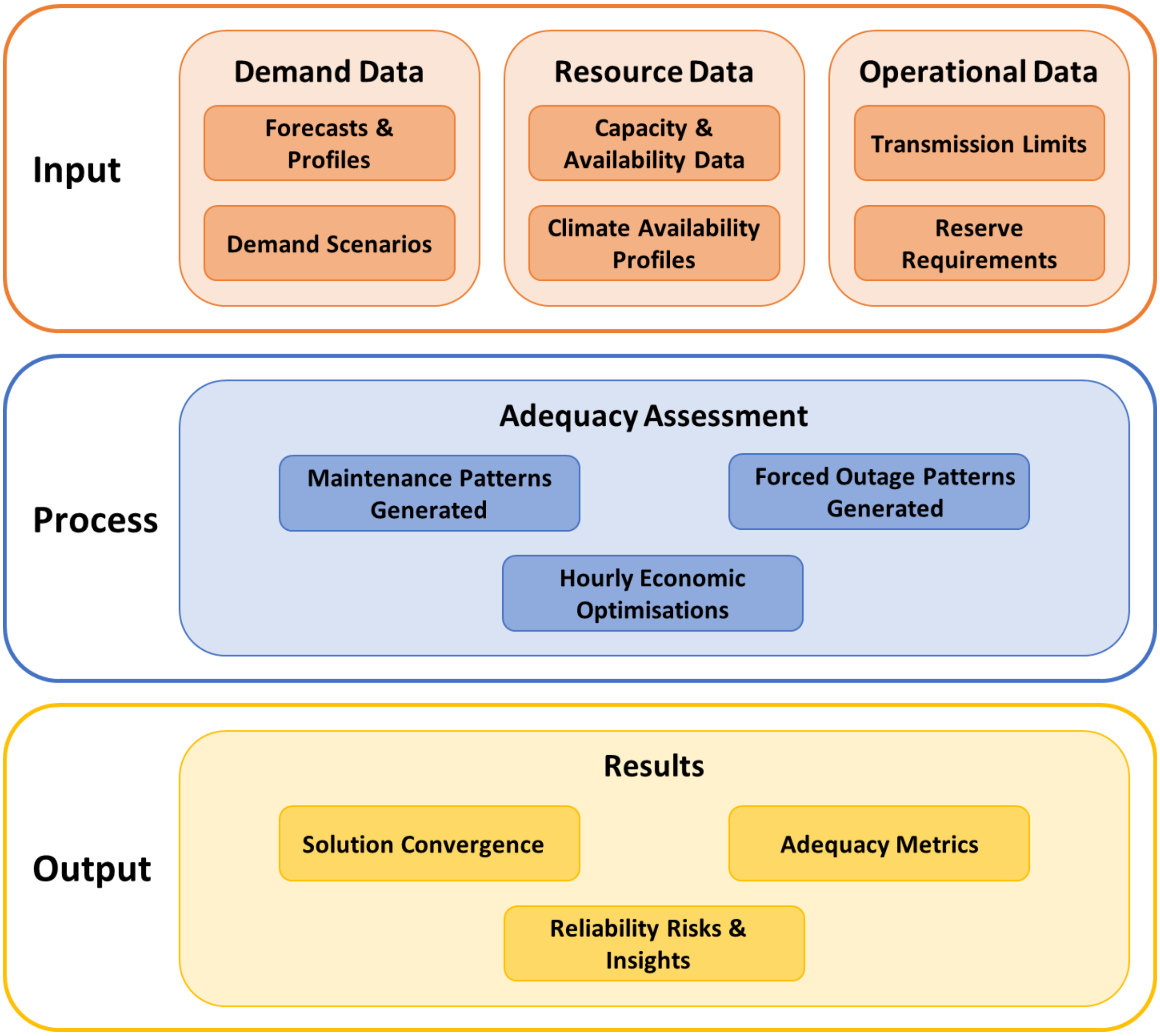

Figure 3 - Overview of Monte Carlo Methodology

6.1.1. Input Data

The input data has been prescribed in detail throughout the earlier sections of this methodology document. In summary:

- A range of input demand forecasts are developed for each year of the study horizon, where the range consists of a minimum high, low, and median forecast levels. The demand forecasts are combined with historical climatic data to produce a range of demand scenarios which include the effects of temperature dependency. This is illustrated in Figure 4 below.
- An input portfolio specifies all of the resources to be considered as contributing to adequacy, along with relevant outage statistics and operational requirements.
- Climatic profiles for variable generation sources such as wind, solar and hydro are correlated to the climatic year used in the demand scenario.

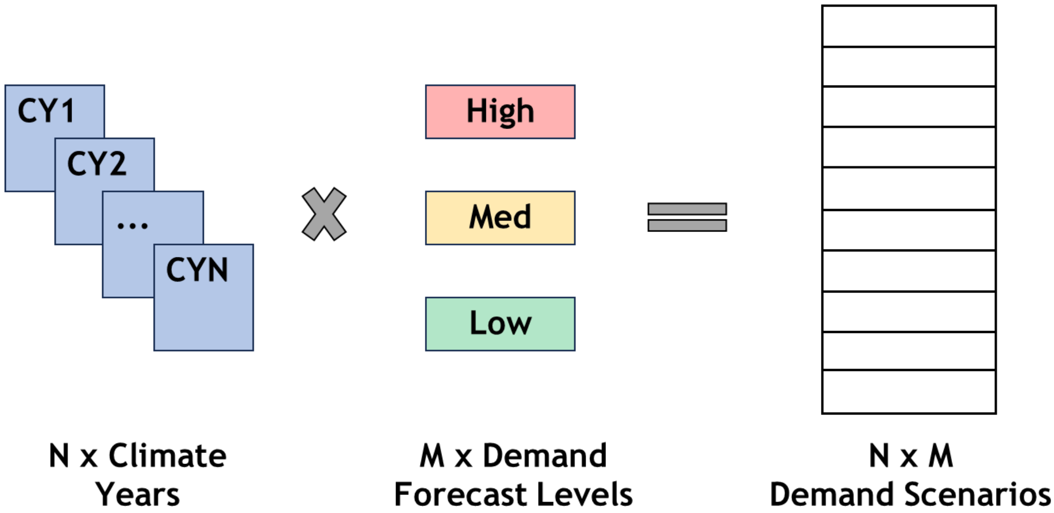

Figure 4 - Construction of Demand Scenarios

6.1.2. Adequacy Analysis

The Monte Carlo simulation is set to generate a number of different 'samples', with each sample having a different independent forced (unplanned) and scheduled (planned) outage pattern. The scheduled outage patterns are generated first, and forced outage patterns are randomly generated based on the available capacity remaining after scheduled outages are considered.

Each sample is simulated is solved to produce a least cost optimisation, respecting any additional bounds or constraints specified e.g. availability restrictions due to run hour or energy limits associated with a technology .

6.1.3. Output Data

The output from the Monte Carlo simulation is a set of independent samples with unique optimisations. The relevant metrics can be observed at a sample level, or an average can be taken. A post optimisation processing step as part of the output process is to assess the convergence of the solution and the adequacy analysis will be rerun if the problem has not converged to within the tolerance. More information on convergence is provided below.

Figure 5 provides illustrates the optimisation process for a single demand scenario, where S is the number of Samples.

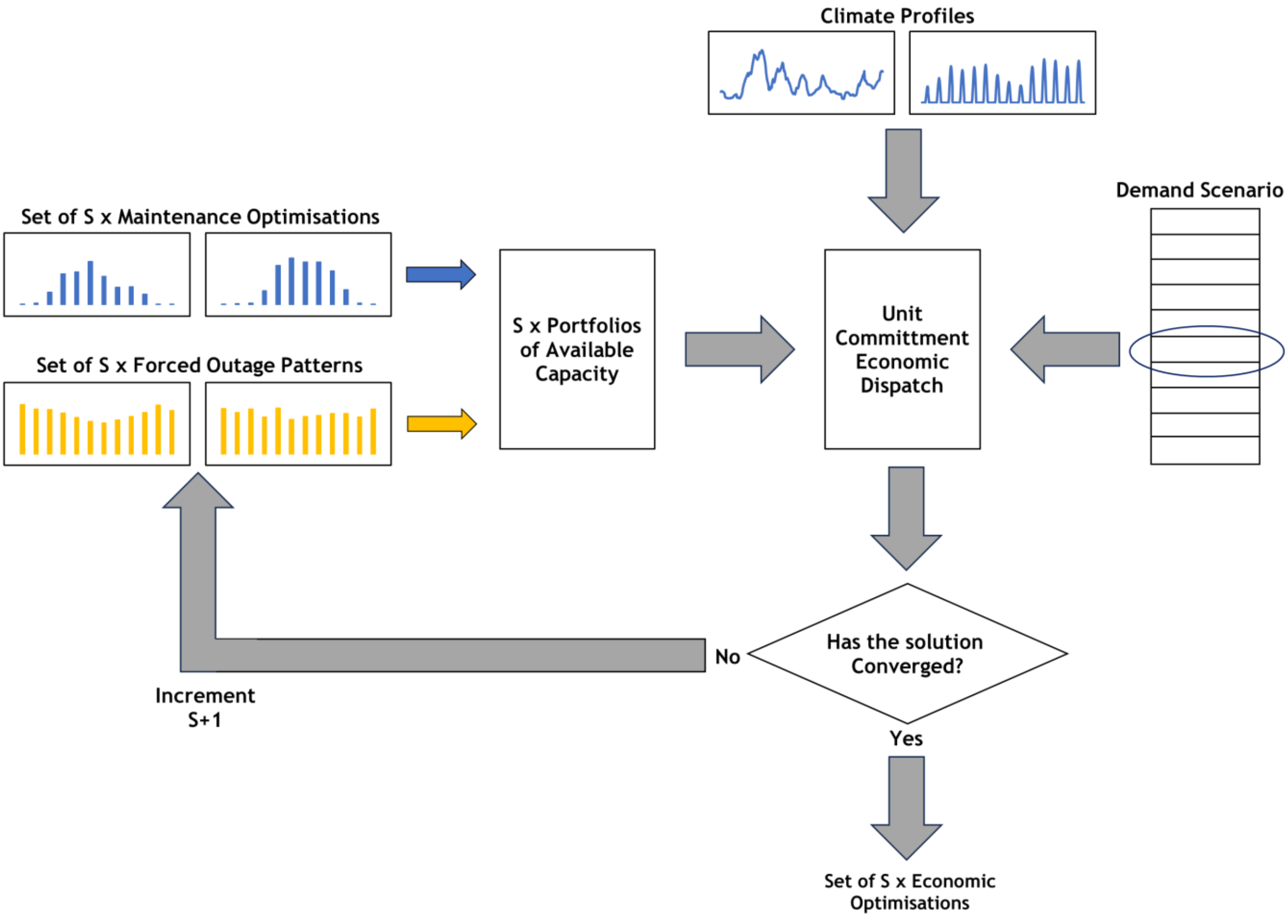

Figure 5 - Monte Carlo process for a single demand scenario

6.2. Adequacy Indicators

This methodology will report on the adequacy of Ireland, Northern Ireland and the All-Island SEM using appropriate indicators to examine the risks to the evolving power system.

To understand and represent power system reliability, various indicators have been developed as presented below. Each indicator may be expressed as an average, range, or as a percentile function (the 95th percentile is commonly used across industry) depending on the particular insights being communicated.

Adequacy indicators required under Article 24 of Regulation(EU) 2019/943:

- **Loss of Load Expectation (LOLE) [hrs/year]:** For a given number of samples S, LOLE represents the average number of hours in which there will be insufficient resource capacity to supply the required demand in which the LOLE for a single sample is a summation of the Loss of Load Duration (LOLD) periods.

$$LOLE = \frac{1}{S}\sum_{S=1}^{S} LLOD_S$$

- **Expected Energy Not Served (EENS) [GWh/year]:** The EENS is an average of the Energy Not Served over the total number of Monte-Carlo simulations. For each demand scenario, the optimisation solves for each Monte-Carlo sample (S).

$$EENS = \frac{1}{S}\sum_{S=1}^{S} EENS_S$$

Additional adequacy indicators which may be reported on as part of this methodology:

- **Loss of Load Duration (LOLD) [hrs]:** A period in which there is insufficient resource capacity to supply the required level of demand. It should be noted that 1hr LOLE does not mean there is ENS for the whole hour, but instead, as the solution is optimised to an hourly interval there is a probability that generation capacity will not meet demand for the hour. LLOD does not provide an indication as to the extent of energy unserved for the hour.
- **Loss of Load Probability (LOLP) [%]:** The probability in a given hour there will be insufficient generation capacity to meet the required level of demand.
- **Capacity Surplus (+ve) / Deficit (-ve) (MW):** An indication of the MW position relative to the specified adequacy standard for a jurisdiction. This value is the amount of perfect (100% reliable) plant that is required to bring the system back to standard. Where the MW value is:
    - Equal to 0 – This implies there is enough capacity to manage the power system with an acceptable level of risk.
    - Greater than 0 - This implies the system could be operating with a reduced level of risk and operationally there is low possibility of losing supply to some customers or part of the power system.
    - Less than 0 – This implies the system could be operating outside of the acceptable level of risk and operationally there is an increased possibility of losing supply to some customers or part of the power system.

Question 5 - Can you identify any additional indicators that may support communicating resource adequacy results?

6.3. Maintenance Profiles

This methodology will include a probabilistic assessment when planned outages are most likely to occur when considering historical outages and forecast outage plans.

A three-step process will be used to produce and verify maintenance profiles as shown in Figure 6 and further described below.

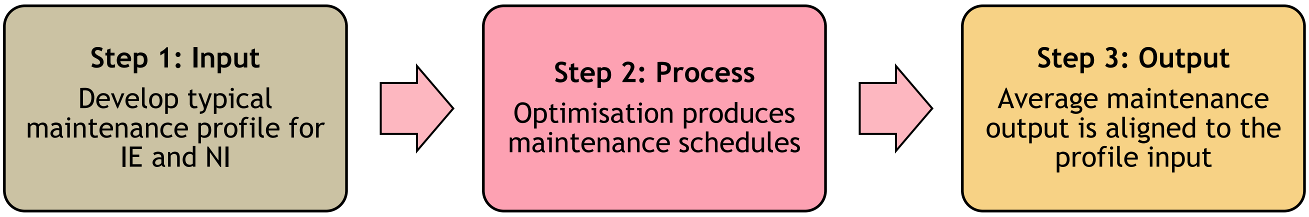

Figure 6 - Maintenance Scheduling Process

Step 1 of the process involves using historical and forecast scheduled outage patterns, to construct a representative maintenance profile.

Step 2 of the process involves generating multiple maintenance schedules creating a distribution of possible maintenance events.

Step 3 of the process validates that the average of the maintenance schedules generated in Step 2, is aligned with the representative input profile generated in Step 1.

Following Step 3 the profiles are ready to be used for the adequacy analysis as described in section 6.1.2.

This process approach aims to account for the possible distributions of maintenance events occurring from time to time, whilst overall representing the average planned outage patterns realised in Ireland and Northern Ireland. Repeating the process across multiple samples captures the risk of correlated maintenance events reducing availability of capacity to support security of supply.

FR and GB actual maintenance schedules will be developed based on the capacity reserve margin in each region considering firm resources only i.e. not considering interconnection support, variable generation, or storage.

Where available, the maintenance schedules from the ERAA modelling outputs may be assessed in validating the maintenance schedules produced using this methodology.

6.4. Forced Outage Profiles

This methodology will include a probabilistic assessment on unit availability accounting for forced unavailability of resources using randomly generated forced outage patterns.

Forced outages are included in this methodology as part of the probabilistic assessment of resource availability. Section 5 includes information related to the outage statistics which are inputs to the Monte Carlo optimisation. A forced outage profile is produced for each individual unit that has a forced outage rate applied to it. The forced outage profiles for units are produced independently of other resource availability and system conditions. Through generating a large number of random forced outage profiles, the risk to system adequacy of simultaneous outages at various times during the year can be captured i.e. the uncertainty associated with forced plant unavailability.

When a unit is forced offline, the time before it becomes available for dispatch again can vary significantly from hours to days and in some cases months at a time. This methodology will use an average repair time.

6.5. Economic Dispatch

This methodology will include unit commitment economic dispatch model to reflect operational and economic dispatch of units on the system.

This methodology will implement economic dispatch to simulate the electricity market, whereby the solver will optimise to reduce the overall system costs across the study horizon. This includes making unit commitment decisions for modelled regions at the resolution of the study horizon. This methodology will make simplifications for some parameters relating to economic dispatch for units, within the interest of improving process efficiency and reducing computational complexity.

The cost associated with conventional generation considers the following marginal cost:

$$SRMC = VO\&M\ Cost + \frac{Fuel\ Price\ \times 3.6}{Unit\ Efficiency} + \frac{CO_2\ Intensity\ \times 3.6}{Unit\ Efficiency} \times CO_2\ Price$$

Where:

- Short-Run Marginal Cost (SRMC) (€/MWh) is the marginal cost of producing the next MW of generation.
- Fuel Price (€/MWh) is specific to each type of fuel, and the fuel types considered in this methodology include Nuclear, Coal, Gas and Oil (differentiated between heavy oil and light oil).
- Unit Efficiency (%) will be based on the standard efficiency of the technology group in Net Calorific Value (NCV) terms.
- CO_2 Intensity (tCO_2/GJ) will be specific to the fuel type and reflect the technology being utilised e.g. gas with CCS will have a lower intensity than gas alone.

- CO_2 Price (€/tCO_2) is specific to the price associated with carbon emissions.
- VO&M (€/MWh) is a component used to reflect the operations and maintenance costs resulting the unit generating power.

Renewable energy sources including variable renewable generation and hydro units are assumed to have 0 SRMC and therefore will utilise renewables before dispatching thermal generation. Within the economic dispatch, battery storage units are free to optimise within the bounds of the optimisation. Hydro and Pumped Storage are free to optimise, however are in some cases subject to constraints such as weekly reservoir limits and annual targets. As such, storage units typically optimise to charge / pump / minimise output during periods of low energy prices and discharge / generate / maximise output during periods of high energy prices. Overall this has a net impact of placing downwards pressure on system costs as storage can displace the need to bring on more costly generation whilst maximising net revenue for the storage assets. Conventional generation will supply the remaining net demand once renewable and storage resources have been optimised.

Unserved energy is priced at the Value of Lost Load (VoLL) in the model, which is effectively set such that the economic optimisation will only result in there being energy unserved as a last possible option (whilst adhering to hard constraints in the model).

The economic dispatch consists of two stages. The first stage will optimise constraints which are applied outside of the short-term horizon resolution. For example annual run hour limits, storage energy limits and annual hydro constraints and targets which are required to be optimised on an annual basis rather than over a day(s). This first stage will consist of grouping a number of periods into a number of blocks, over which the medium-term constraints can be optimised in a more computationally efficient way. The output from this first stage is a decomposition of the medium-term constraints into constraints which can be realised in the short-term optimisation i.e. a set of daily constraints or targets which are typically applied as soft constraints within the short-term optimisation.

The second stage of the economic dispatch optimisation looks at a more granular level such as a daily or multi day basis and produces a least cost optimised unit commitment schedule adhering to constraints active in the timeframe and constraints passed down from the first stage as mentioned above. The output from this stage is an hourly dispatch of units. This methodology will assess the full chronology for each Monte Carlo sample i.e. at the specified resolution instead of selecting representative weeks to model which could reduce computational time.

6.6. Monte Carlo Convergence

This methodology will assess optimisation solutions to evaluate convergence of the solution in accordance with the approved ERAA methodology approach.

The Monte Carlo samples will be assessed in terms of solution convergence for a given target year and scenario. As stipulated in Article 4 (2) (e) of the ERAA methodology[11], the coefficient of variation will be assessed using the following equation:

$$a_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

Where $EENS_N$ is the expectation estimate of ENS over the number of Monte Carlo simulations i.e. $EENS_N = \frac{\sum_{i-1}^{N} ENS_i}{N}$, $i = 1 \dots N$ and $Var[EENS_N]$ is the variance of the expectation estimate, $Var[EENS_N] = \frac{Var[ENS_N]}{N}$.

[11] https://www.acer.europa.eu/Individual%20Decisions_annex/ACER%20Decision%2024-2020%20on%20ERAA%20-%20Annex%20I_1.pdf

As N increases, the incremental coefficient of variation a_N is compared against a specified threshold θ as per the following:

$$\frac{|a_N - a_{N-1}|}{a_{N-1}} < \theta$$

Where the solution is considered to have converged when further incrementing N will not improve the accuracy of the simulation and as such no further increments are required.

Setting the threshold θ will consider the computational time associated with increasing number of Monte Carlo simulations as part of the convergence assessment, and sensitivity analysis may seek to implement a different value for θ where the benefit of providing insights outweighs the need for accuracy.

Figure 7 shows the impact of increasing samples on the coefficient of variation and relative change of coefficient.

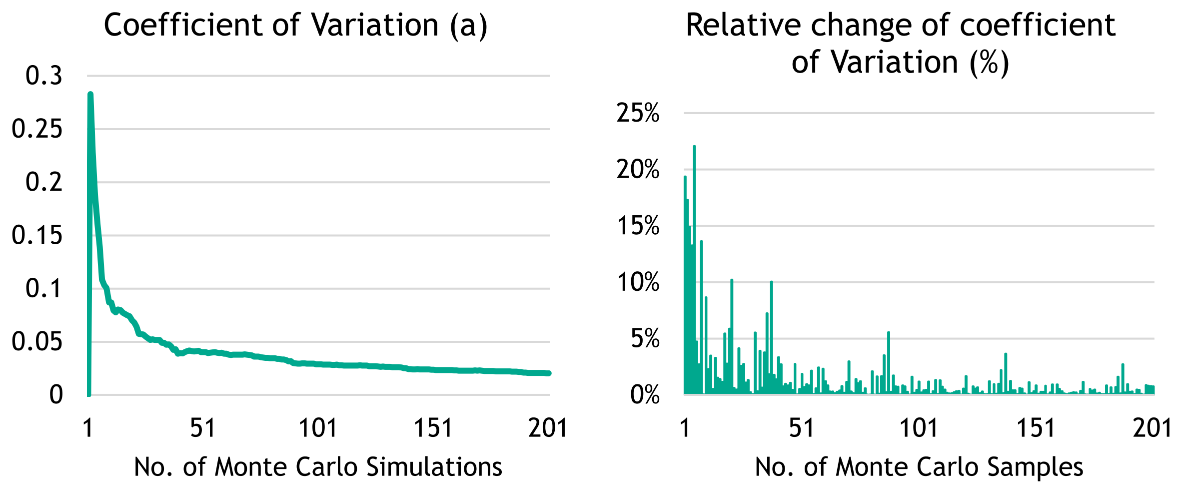

Figure 7 - Convergence variation with increasing samples

6.7. Operational Requirements

In the context of the SEM, to operate the power system in a safe, secure and reliable manner, a range of operational requirements are put in place as referred to in the Operational Security Standards[12] and Transmission System Security and Planning Standards[13] (TSSPS). Operational requirements include but are not limited to:

1. Reserves
2. Ramping
3. Network Constraints
4. Dynamic Stability

Furthermore, some of the above constraints are applied on a jurisdictional basis (specific to Ireland or Northern Ireland) and some constraints are relevant on an All-Island basis.

Consideration has been given to each of the above areas and the impact each could have on operating an adequate system and therefore the relevance to be included under this methodology. Securing the power system of the future is not just limited to the supply of energy, but a range of services and policies will be

[12] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid_Operating-Security-Standards_2021.pdf
[13] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Transmission-System-Security-and-Planning-Standards-TSSPS-Final-May-2016-APPROVED.pdf

required. Many of these have been highlighted in EirGrid and SONI's Shaping Our Electricity Future Roadmap[14]. The evolution of EirGrid and SONI's operational policy roadmap[15] will also be considered on an ongoing basis.

6.7.1. Reserves

This methodology will consider the provision of operational reserves and replacement reserves in accordance with the latest operational policy and relevant Grid Code requirements.

Reserves are required to balance the frequency across the power system. Reserves are specified across various timeframes depending on the service required to contain, restore, and maintain system frequency. Reserves requirements are shown in the operational constraints update[16] and as defined in the EirGrid and SONI Grid Codes.

Reserves are classified as per the following:

- Frequency Containment Reserves (FCR) – refers to the reserves available within the seconds following a trip which can act to contain the system frequency and mitigate against the potential magnitude of the under-frequency event.
- Frequency Restoration Reserves (FRR) – refers to the reserves available within the minutes following the trip which can act to restore the frequency to nominal levels.
- Replacement Reserves (RR) – refers to the additional reserves available to support the level of FRR and prepare for any additional disturbances.

The FCR and FRR act within seconds to minutes following a frequency event, which is a significantly shorter timeframe than the hourly granularity implemented in this methodology for the reliability assessments. This methodology will account for the provision of FCR and FRR through excluding capacity from the portfolio input to the economic dispatch.

The RR are required for up to 4 hours, which is multiples of the hourly granularity implemented in this methodology. This methodology will account for the provision of RR through including a reserve constraint in the model that must be satisfied in each hour of the economic dispatch.

The provision for FCR, FRR and RR as described above is consistent with Article 4 (1) (g) of the ACER approved ERAA methodology. Additionally, to maintain consistency with the ERAA methodology, the requirements for the provision of each reserve type will be specified for each Target Year, therefore implementing a static requirement in each hour of the economic dispatch.

Where necessary, this methodology will consider the evolution of reserve requirements across the study horizon based on the operational policy roadmap.

6.7.2. Network Constraints

This methodology will not seek to introduce jurisdictional network constraints directly within the model. However, an adjustment to account for transmission outage restrictions may be modelled as an additional load to represent the system network needs from an adequacy perspective.

In both Ireland and Northern Ireland there are conditions in which parts of the network may reach their limits in terms of thermal, voltage and short circuit limits. It is possible to model network elements in techno economic modelling applications to an extent, however detailed modelling of network components using techno-economic modelling applications has a significant impact on the time taken to construct the model and solve the optimisation. To account for network constraints, transfer limits, and facilitation of

[14] https://www.eirgridgroup.com/site-files/library/EirGrid/Shaping-Our-Electricity-Future-Roadmap_Version-1.1_07.23.pdf
[15] https://www.eirgridgroup.com/site-files/library/EirGrid/Operational-Policy-Roadmap-2023-to-2030.pdf
[16] Wk40_2023_Weekly_Operational_Constraints_Update.pdf (sem-o.com)

transmission outage plannings in a simplified manner, this methodology may include relevant adjustment(s) as a load adjustment for the purpose of adequacy studies.

It is possible that future iterations of the NRAA methodology may seek to implement targeted constraints to reflect real-world limitations experienced by the System Operators. This methodology evolution would be required to account for the future evolution of the network that may be in place to manage the limits across the network.

6.7.3. Ramping

This methodology iteration will not explicitly model ramping constraints or requirements.

Ramping requirement are driven by the need to account for uncertainty in renewable forecasts. For example, if renewable generation ramps down earlier than expected, generation from alternative resources is required. Moving to a system increasingly dependent on variable renewables, managing the possible impact of forecast errors becomes increasingly challenging as the possible forecast uncertainty increases. The model implemented for this methodology has perfect foresight of renewable availability and does not explicitly capture the possible impacts of forecast uncertainty.

6.7.4. Dynamic Stability

This methodology iteration will not include dynamic stability constraints.

System Non-Synchronous Penetration (SNSP) was introduced to manage the facilitation of non-synchronous technologies onto the Irish power system such as variable renewable generation and interconnector imports. SNSP is an upper boundary (%) to limit the amount of generation from these sources in respect of the system demand at the time, and when the limit is reached imports may need to be reduced or renewable energy may need to be curtailed depending on system conditions. The SNSP limit tends to come into effect during periods of high renewable generation, when system margins are in a healthy state of surplus. As a result, modelling the SNSP constraint is not expected to have a material impact on system adequacy. Other real-world constraints such as minimum number of conventional units online, short circuit strength, inertia and RoCoF constraints require complex modelling outside of the scope of this methodology.

6.8. Out of Market Adequacy Measures

As per ACER recommendation this methodology will not consider out of market measures contribution to system adequacy in the core scenarios but may assess approved out of market measures in a qualitative way for each jurisdiction in the SEM region.

The core NRAA scenarios will reflect in-market options. The contribution to operating a reliable system from out of market measures will be considered in a post-processing step by evaluating the impact on system reliability from approved out of market measures. This post processing step will assess relevant Monte Carlo samples to assess possible reductions in ENS and corresponding possible reductions in LOLE i.e. where ENS in a sample can be removed in an hour this will result in a decrease in LOLE.

Question 6 - Do you agree with the approach to modelling resource adequacy implementing stochastic assessments using a techno-economic model?

7. Future Considerations

The implementation of a new methodology fully compliant with requirements contained in the Regulation is a complex task, and therefore will be implemented as a phased approach. This section outlines work which will be considered through future developments of this methodology.

7.1. Economic Viability Assessment

Point (b) of Article 23 (5) of the Regulation requires that this methodology considers supply projections including an assessment of the likelihood of a resource being economically viable in future. The viability of resources will be assessed using a long-term planning model, optimised to reduce total system costs i.e. identify the least cost solution for ensuring system adequacy over the study horizon. The output of this assessment will identify the likelihood of:

i) Existing resources retiring

ii) Investment in new resources

iii) Existing resources being mothballed (or de-mothballed)

iv) Lifetime extensions for resources

The Economic Viability Assessment (EVA) implementation will initially identify a range of credible resources to be considered within the assessment, recognising there will be a range of emerging technologies which might be present in the future system, but which are not part of the system today. As such, the range of resources could consider storage resources, renewable resources as well as conventional fossil fuel resources (which may also apply certain emissions abatement technologies), etc.

Consideration for resources will also recognise the evolving electricity system needs in terms of flexibility and reliability requirements supporting the overall goal of decarbonising the power system. The intention is not to recreate a fully detailed financial study for each individual resource, but instead provide insights as to the viability of the range of resources considered.

It is likely that full implementation of the EVA may need to consider:

- Possible market specific changes or arrangements which may influence opportunities for resources.
- The time granularity assessed given the computational extensiveness required for modelling activities associated with long-term planning.
- A process for selecting appropriate climatic and/or target years for conducting the assessment.
- Simplification of modelling options including how outages are accounted for (explicitly or de-rated), how capacities are included in the model (aggregated or unit based) possibly relaxing constraints applicable to short-term operational restrictions on operating units.
- An approach for assessing viability of units on a regional basis. For example, as this methodology is a national assessment it is primarily focussed on arrangements in the Ireland and Northern Ireland regions. However, due to interconnection with neighbouring regions it will also be important to consider possible economic-based projects of supply in these regions.
- Expected economic lifetime of units and whether current capacity market arrangements will sustainably support projects. The primary focus may consider units which may not have the certainty of a capacity contract in the SEM.
- Evolution of additional aspects such as price caps, investor confidence, consumer behavioural changes, operational policies, market incentives, reliability standards and/or Value of Lost Load (VOLL) and Cost of New Entrant (CONE) studies.

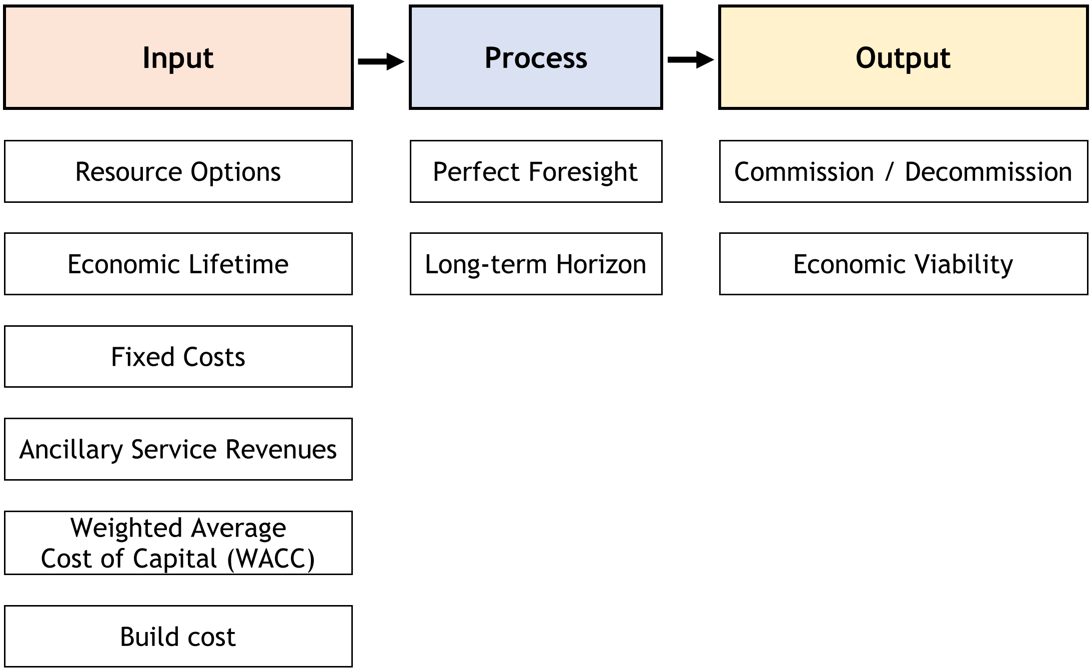

Figure 8 - Economic Viability Assessment process

7.2. Geographical Scope

The initial implementation of this methodology does not explicitly consider local network constraints within Ireland or Northern Ireland. A straightforward market NTC approach is used to simulate power flow between Ireland and Northern Ireland, and between the SEM region and interconnected regions. However, locational aspects related to network limitations and deployment of capacity resources could have a significant impact on the ability of EirGrid and SONI to operate the power system reliably.

It may be considered under future iterations of this methodology to break down the Ireland and Northern Ireland regions into more detailed nodes to reflect the internal limitations of transferring power within a region. This would require a new methodology to be developed for assessing transfer limits between nodes within each region. Simulating additional nodes increases the complexity of the optimisation process and therefore the impact on overall time required for modelling activities would need to be considered.

An alternative option may be to place constraints on groups of generators depending on their location in the network, effectively limiting their combined output to reflect constraints associated with the area. This would also require additional work to align with the monthly published operational constraints updates in the immediate term, as well as considerations for how these constraints may change as the power system evolves in the medium to long term.

7.3. Sector Coupling - Power-to-X (P2X)

The decarbonisation transition across industries including the sector is likely to create overlap between requirements and introduce the need for coupling between sectors. For example, hydrogen has been identified as a possible sustainable fuel for various applications including industrial manufacturing processes (replacing non-green hydrogen used today), long distance road and transportation, aviation and in the power sector to burn in gas turbines or fuel cells. Hydrogen can be stored in large quantities, and various forms which makes it a diverse option for an energy carrier.

It is widely discussed that hydrogen can be produced during periods of renewable energy surplus and used as a green fuel for the applications mentioned above, in the context of the power system providing a green fuel used in replace of emissions intense fossil fuels. The process for converting renewable energy to hydrogen through electrolysis consumes power, and therefore the additional load needs to be considered in the context of operating the power system reliably.

Currently, there are no large-scale electrolysis plants on the island of Ireland, but if these plants develop, they will be accounted for under this methodology. The implementation may include price responsive behaviour to load patterns of the units which may result in a negligible impact on adequacy. The possible loads may consider actual projects as well as future policy in both Ireland and Northern Ireland.

7.4. Enhanced Demand Flexibility

Currently, demand flexibility is accounted for in the demand modelling as described in section 4.2.

Future iterations of this methodology may consider implementing price responsive demand flexibility directly within the adequacy model as a proportion of the demand that will optimise on a daily basis shifting from periods of high energy prices to periods of lower energy prices emulating how demand could be shifted in response to market price signals.

7.5. Flow Based Market Coupling (FBMC)

In the European Day Ahead Market (DAM), electricity is traded within and across bidding zones. As proposed earlier in this methodology, a simplistic perspective on cross border trading is proposed through using NTC's to represent power transfer limits between zones.

Flow Based Market Coupling (FBMC) is implemented for the Core Capacity Calculation Region (CCR) in the European DAM. FBMC accounts for contingencies on specific network elements and therefore representing a more realistic representation of network constraints and therefore power transfer potential between Bidding Zones.

FBMC is implemented in in the ERAA methodology for the Core CCR, which is relevant due to the geographical scope modelled in ERAA. Implementation of FBMC introduces additional complexity and computational effort and as the explicitly modelled geographical scope proposed for this methodology does not include all of the Core CCR it is proposed to exclude FBMC from this methodology.

At the present time, the SEM is not part of the Core CCR however if this changes in future and the resultant implications need to be considered in terms of the impact on resource adequacy in Ireland and Northern Ireland this methodology will be reviewed and updated as required.

Question 7 - Are there any considerations beyond those listed above that you would like to see considered in future adequacy assessments?

8. Next Steps

8.1. Consultation Questions

Table 7 provides a list of questions included in this consultation.

Section	Question No.	Question
4	1	Do you have any comments on the factors considered in forecasting the Total Electricity Requirement (TER)?
4	2	Do you have any comments on the approach to modelling demand and flexibility?
5	3	Can you identify any resources that could be considered under this methodology which are not listed above?
5	4	Do you agree with the proposed approach to modelling the resources listed above?
6	5	Can you identify any additional indicators that may support communicating resource adequacy results?
6	6	Do you agree with the approach to modelling resource adequacy implementing stochastic assessments using a techno-economic model?
7	7	Are there any considerations beyond those listed above that you would like to see considered in future adequacy assessments?

Table 7 - Consultation Questions

8.2. Consultation Responses

EirGrid and SONI welcome feedback on the questions proposed in this methodology consultation.

Responses should be submitted through either our EirGrid or SONI consultation portals before 12th January 2024.

It would be helpful if answers to the questions include justification and explanation where possible. If there are pertinent issues that are not addressed in this consultation, these can be addressed at the end of the response.

If you require your response to remain confidential, you should clearly state this on the coversheet of the response. We intend to publish all non-confidential responses to provide transparency throughout this consultation process.

9. Appendices

9.1. Article 24 of Regulation 2019/943

National resource adequacy assessments under Article 24 of Regulation 2019/943.

1. National resource adequacy assessments shall have a regional scope and shall be based on the methodology referred in Article 23(3) in particular in points (b) to (m) of Article 23(5).

   National resource adequacy assessments shall contain the reference central scenarios as referred to in point (b) of Article 23(5).

   National resource adequacy assessments may take into account additional sensitivities to those referred in point (b) of Article 23(5). In such cases, national resource adequacy assessments may:

   (a) make assumptions taking into account the particularities of national electricity demand and supply;

   (b) use tools and consistent recent data that are complementary to those used by the ENTSO for Electricity for the European resource adequacy assessment.

   In addition, the national resource adequacy assessments, in assessing the contribution of capacity providers located in another Member State to the security of supply of the bidding zones that they cover, shall use the methodology as provided for in point (a) of Article 26(11).

2. National resource adequacy assessments and, where applicable, the European resource adequacy assessment and the opinion of ACER pursuant to paragraph 3 shall be made publicly available.

3. Where the national resource adequacy assessment identifies an adequacy concern with regard to a bidding zone that was not identified in the European resource adequacy assessment, the national resource adequacy assessment shall include the reasons for the divergence between the two resource adequacy assessments, including details of the sensitivities used and the underlying assumptions. Member States shall publish that assessment and submit it to ACER.

Within two months of the date of the receipt of the report, ACER shall provide an opinion on whether the differences between the national resource adequacy assessment and the European resource adequacy assessment are justified.

The body that is responsible for the national resource adequacy assessment shall take due account of ACER's opinion, and where necessary shall amend its assessment. Where it decides not to take ACER's opinion fully into account, the body that is responsible for the national resource adequacy assessment shall publish a report with detailed reasons.

9.2. Article 23 of Regulation 2019/943

European resource adequacy assessments under Article 23 (5) points (b) to (m) of Regulation 2019/943.

5. The European resource adequacy assessment shall be based on a transparent methodology which shall ensure that the assessment:

… …

(b) is based on appropriate central reference scenarios of projected demand and supply including an economic assessment of the likelihood of retirement, mothballing, new-build of generation assets and measures to reach energy efficiency and electricity interconnection targets and appropriate sensitivities on extreme weather events, hydrological conditions, wholesale prices and carbon price developments;

(c) contains separate scenarios reflecting the differing likelihoods of the occurrence of resource adequacy concerns which the different types of capacity mechanisms are designed to address;

(d) appropriately takes account of the contribution of all resources including existing and future possibilities for generation, energy storage, sectoral integration, demand response, and import and export and their contribution to flexible system operation;

(e) anticipates the likely impact of the measures referred in Article 20(3);

(f) includes variants without existing or planned capacity mechanisms and, where applicable, variants with such mechanisms;

(g) is based on a market model using the flow-based approach, where applicable;

(h) applies probabilistic calculations;

(i) applies a single modelling tool;

(j) includes at least the following indicators referred to in Article 25:

— ‘expected energy not served’, and

— ‘loss of load expectation’;

(k) identifies the sources of possible resource adequacy concerns, in particular whether it is a network constraint, a resource constraint, or both;

(l) takes into account real network development;

(m) ensures that the national characteristics of generation, demand flexibility and energy storage, the availability of primary resources and the level of interconnection are properly taken into consideration.

10. Glossary

ACER	The European Union Agency for Cooperation of Energy Regulators
AHC	Advanced Hybrid Coupling
ATC	Available Transmission Capacity
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicles
CCS	Carbon Capture & Storage
CHP	Combined Heat & Power
CO2	Carbon Dioxide
CONE	Cost Of New Entry
COP	Coefficient Of Performance
DFT	Demand Forecasting Tool
DSU	Demand Side Units
EENS	Expected Energy Not Served
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
EU	European Union
EV	Electric Vehicles
EVA	Economic Viability Assessment
FBMC	Flow Based Market Coupling
FCR	Frequency Containment Reserve
FOR	Forced Outage Rate
FR	France
FRR	Frequency Restoration Reserves
GB	Great Britain
GCS	Generation Capacity Statement
GJ	Gigajoules
GW	Gigawatts
LOLD	Loss Of Load Duration
LOLE	Loss Of Load Expectation
LOLP	Loss Of Load Probability
LSI	Largest Single Infeed
MW	Megawatt
NCV	Net Calorific Value
NRAA	National Resource Adequacy Assessment
NTC	Net Transfer Capacities
P2X	Power-to-X
PEMMDB	Pan-European Market Database
PHEV	Plug-in Hybrid Electric Vehicles
PTDF	Power Transfer Distribution Factor
PV	Photovoltaics
RES	Renewable Energy Sources
ROCOF	Rate-of-Change-of-Frequency
RR	Replacement Reserves
SEM	Single Electricity Market
SNSP	System Non-Synchronous Penetration
SONI	System Operator for Northern Ireland
SRMC	Short-Run Marginal Cost
SY	Submission Year
TSO	Transmission System Operator
VO&M	Variable Operations & Maintenance
VOLL	Value of Lost Load
WACC	Weighted Average Cost of Capital