Short-Term Demand Forecasting Methodology for Scheduling and Dispatch

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EIRGRID SONI

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1 INTRODUCTION

This methodology document expands on the information provided in SONI and EirGrid's Balancing Market Principles Statement.

We are required under OC1 of both Grid Codes to produce demand forecasts ranging from the operational planning phase through to real time operation i.e. scheduling and dispatch. A number of factors are considered when producing a demand forecast in the scheduling and dispatch timeframe. These factors include historical demand curves, the impact of public holidays and weather forecasts - both current and historic.

We calculate the forecasts for each jurisdiction separately due to the different demand profiles in Ireland and Northern Ireland and to reflect the differences in public/bank holidays. There is also a difference in the two demand profiles throughout the course of any given day as a result of different usage patterns including the presence of larger industrial customers in Ireland. Therefore, it is not practicable to produce a single demand forecast for the Single Electricity Market. The need for jurisdictional forecasts is also driven by the physical limitation on the circuits that connect Ireland and Northern Ireland (the tie lines) which results in a requirement to have a minimum number of generators in either jurisdiction at any given time for system security reasons.

2 HISTORICAL JURISDICTIONAL DEMAND DATA

The starting point for a demand forecast is the historical jurisdictional data for total generation which includes conventional generation, renewable generation, aggregated generator units (AGU) and demand side units (DSU).

The next step is to make adjustments to account for flows on interconnectors and the circuits connecting Ireland and Northern Ireland (the 'tie lines'). If there is a net import on the interconnector and tie-lines in a jurisdiction this is added to the generation to derive the demand figure (Figure 1). Conversely if there is a net export on the interconnector and tie-lines in a jurisdiction this is subtracted from the generation to derive the demand figure (Figure 2).

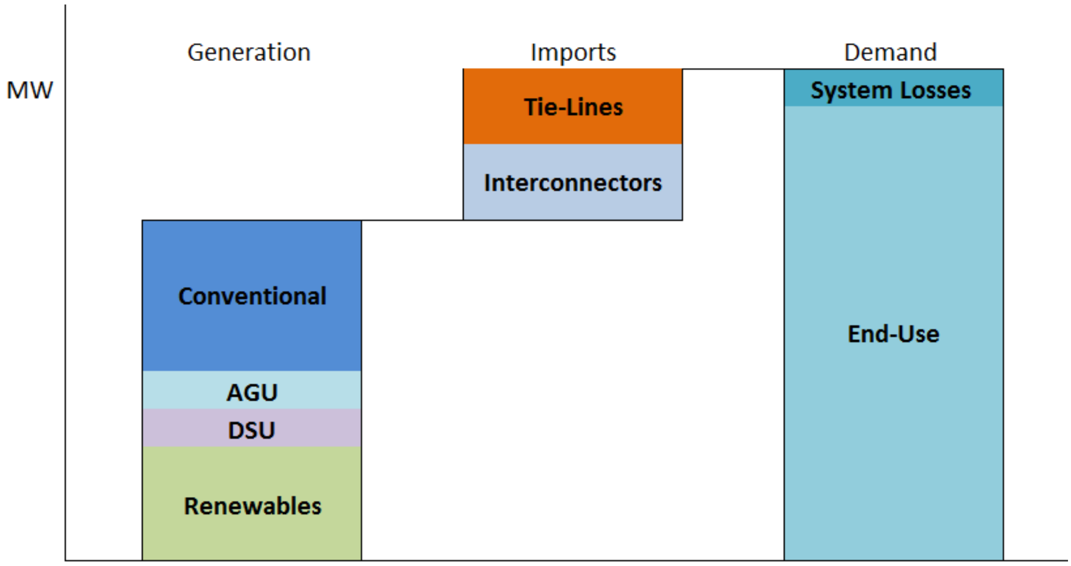

Figure 1: Total generation equating to demand with imports on tie-lines and interconnectors.

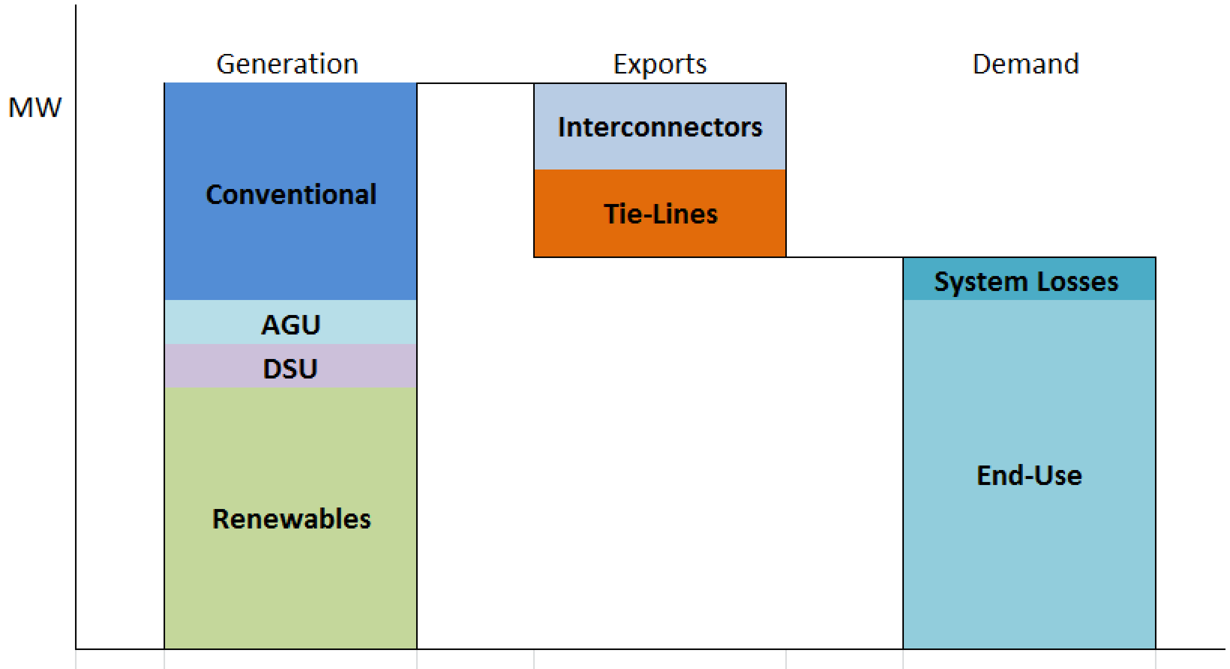

Figure 2: Total generation equating to demand with exports on tie-lines and interconnectors.

The total generation adjusted for interconnector and tie-line flows is used as a proxy for the total jurisdictional demand as we do not have access to actual demand data in a timely enough manner to meet the requirements of the scheduling and dispatch process.

Demand forecasts are produced representing the predicted electricity production required to meet the demand including system losses but net of generator unit demand requirements ('house-load') i.e. what the generator exports to the transmission or distribution system.

The historical generation data used to produce the demand forecast only reflects the generation visible to us in our Energy Management System (EMS) via our Supervisory Control and Data Acquisition (SCADA) system. Smaller distribution-connected generation is not included in this historical generation data and it therefore offsets a portion of demand on the system. As the amount of this type of generation increases the task of producing an accurate demand forecast becomes more difficult. We will estimate the impact of this smaller-scale generation on demand based on information available to us at that time. We are investigating options for better forecasting of the output of small-scale generation on the system as a whole.

Every half hour the EMS demand forecast tool uses the historical demand data, (predominately the last two weeks - commonly referred to as the 'hot history') to produce the demand forecast.

3 EMS DEMAND FORECAST

The EMS demand forecasts themselves are produced using proprietary software built in to our EMS system. Every half hour the tool uses the historical demand data as well as historical and forecast weather data combined with a user defined Load Forecast model to produce the demand forecast.

The algorithm learns the relationship between the system demand and a set of predictor variables (day of week, time of day, week of year, special days, average hourly temperature) based on the historical data.

It then creates a prediction for each half hour of jurisdictional system demand including system losses for the next fourteen days ahead. A full fourteen-day forecast is automatically performed at the start of each day (00:05) and every half hour afterwards. The actual SCADA data is used to amend the forecast for that day as the data becomes available, so the forecast is constantly refining itself as it 'learns' what is actually happening throughout the day.

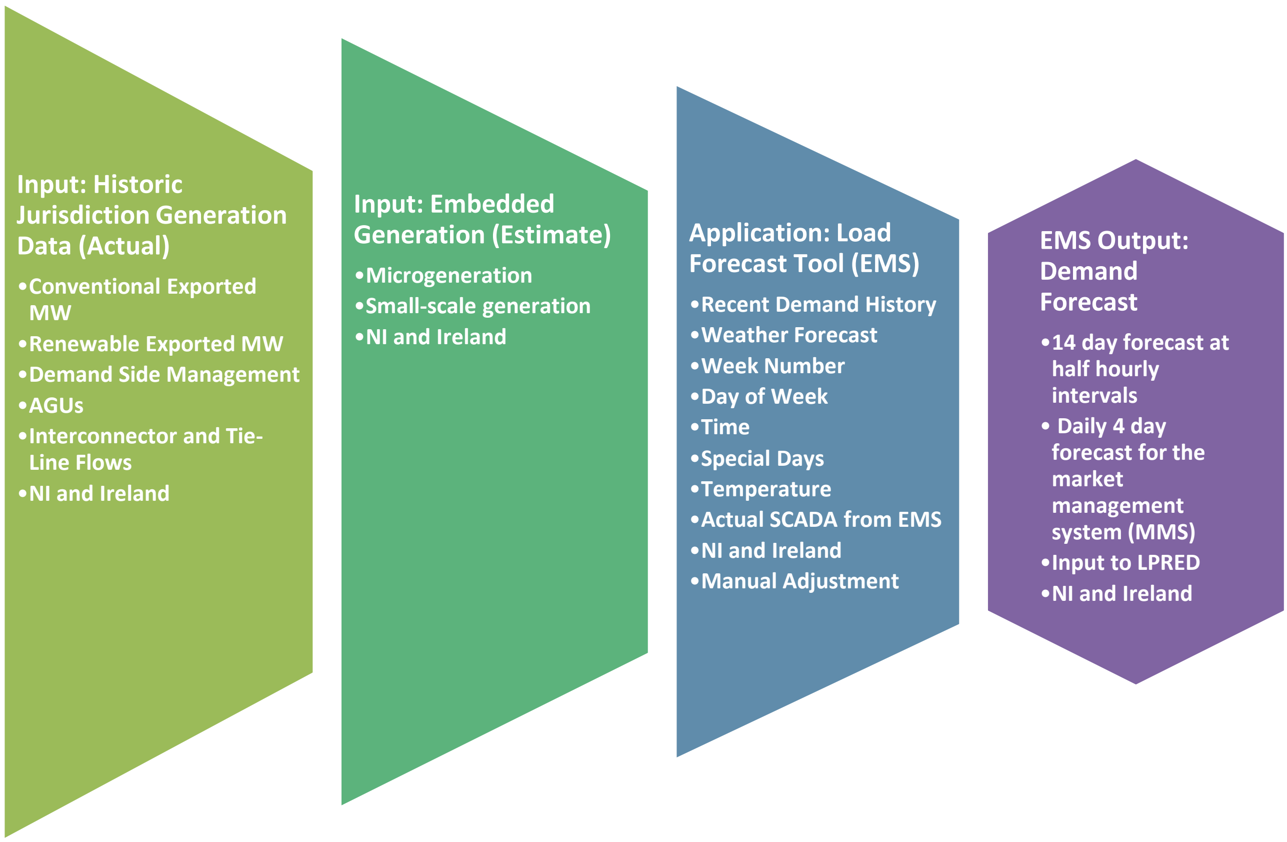

Figure 3: Summary of EMS Demand Forecast Process

3.1 MANUAL ADJUSTMENTS

The tool also has a number of alternative manual methods to assist the operator.

- The load shapes method is particularly useful for special days e.g. Christmas day has a unique curve shape.
- The abnormal dates method can be used to assign a different day type shape to a specific day. For example a bank holiday could be assigned a Sunday type rather than a weekday type. Abnormal days must be manually excluded from the model to avoid distorting forecasts for 'normal' days.
- A scaling feature is available, which can be used to apply different maximum and minimum to a forecast which is reasonable in shape but whose values are either too high or too low.

From the EMS demand forecast tool we prepare and publish a four-day demand forecast at half-hour resolution on a daily basis for use in the market systems.

4 MARKET MANAGEMENT SYSTEM LOAD PREDICTOR

The output of the EMS Demand Forecast tool will be used as the starting point for the Load Predictor tool which is part of the Market Management System (MMS).

The MMS Load Predictor retrieves long-term load forecasts for each jurisdiction from the EMS Demand Forecast for use in Long-Term Scheduling (LTS). The Load Predictor tool is also used to provide short-term system load forecasts at one-minute resolution from the current time (real time rounded to next one-minute boundary) to four hours ahead for each jurisdiction and total system. The short-term load forecasts are used by Real-Time Commitment (RTC) and Real-Time Dispatch (RTD) scheduling applications.

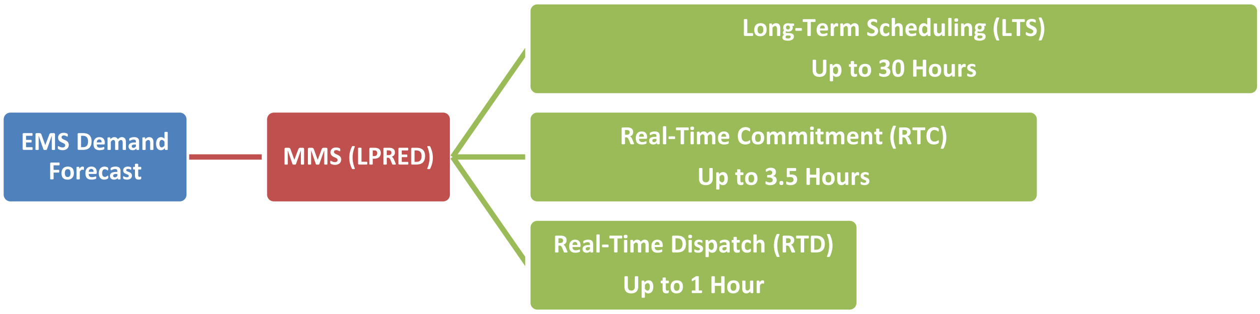

Figure 4: Outputs of EMS and MMS Forecasting Tools

LPRED has several functional components which will be used in the RTC and RTD timeframes including;

- Load Shape Management, which will allow the user to build a continuous jurisdictional load shape (1-minute spot values) from one or more historical daily load profiles. The selected historical load profiles will be able to be adjusted by a scaling factors or adjustments e.g. to account for small-scale, embedded generation.
- Frequency Deviation Load Adjustment, which creates a load normalised to target frequency based on the frequency deviation and frequency bias factor.
- Load Prediction, which will produce jurisdictional load forecasts at one-minute resolution from the current time (real time round to next one minute boundary) to four hours ahead by using actual load or normalized load and the constructed load shapes using filtering techniques.
- Load Blending, which will produce blended jurisdictional load forecasts at one-minute resolution from the border point in time to four hours ahead by using the load predictions calculated in the previous step and the long-term load forecasts received from SCADA demand forecast.

The ultimate aim of the TSOs' demand forecasting process is to ensure that we have as accurate a demand forecast as possible.

Further detail on the demand forecasting process and LPRED is available in Business Process BP_SO_4.2_Demand Forecasting for Scheduling and Dispatch.