

### 3 DEMAND

The flow of power on the grid is determined largely by the generation feeding into it and the demand that is drawn from it. This chapter deals with forecasts of the total peak demand on the transmission network, and of demand at individual transmission-connected stations.

The *Generation Adequacy Report 2007-2013* (GAR), published by the Transmission System Operator (TSO) in November 2006, contains forecasts of future energy consumption and demand for the seven-year period to 2013. Section 3.1 describes how the GAR's median peak demand forecast is adjusted to determine the transmission peak forecasts used in this Transmission Forecast Statement (TFS).

#### 3.1 BASIS OF DEMAND FORECASTS

The peak demand forecasts in the GAR relate to total electricity demand in the Republic of Ireland. This TFS is concerned with the power that is transported on the grid from generation stations to the transmission stations interfacing with the distribution system and grid-connected demand customers.

Embedded generation<sup>7</sup> may reduce the net demand supplied through the transmission interface stations to which they are connected, as illustrated in Figure 3-1. There are a number of types of embedded generation: combined heat and power (CHP) schemes, wind, land-fill gas (LFG), biomass, and small hydro and thermal plants.

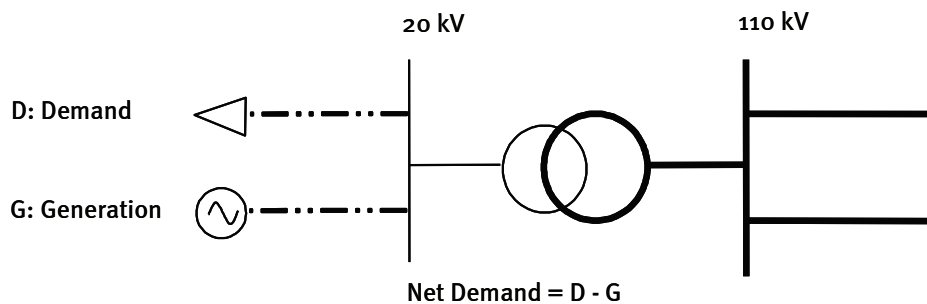


Figure 3-1 Net Demand Reduction due to Embedded Generation

Embedded non-wind generators are not modelled explicitly in the analyses carried out for this TFS. In determining forecast transmission peak flow, an estimate of the demand met by non-wind embedded generation is deducted from the GAR peak projections. This deduction explains why the demand forecasts in Table 3-1 differ from those published in the GAR. All embedded wind generators, both existing and those with signed connection offers, are modelled explicitly. This is because wind generation, having a variable energy source, may at some times reduce local demand but at other times may not.

<sup>7</sup> Generation connected to the distribution system or at a directly-connected customer's site.

### 3.2 FORECASTS OF TRANSMISSION PEAKS

Table 3-1 presents the forecasts of transmission demand for the seven years 2007 to 2013, as published in the GAR. While it is difficult to accurately predict a peak demand figure for a particular year, the forecasts in Table 3-1 may be taken as indicative of a general trend in demand growth. Three demand values are presented for each year: the winter peak, the summer peak and the summer valley.

Table 3-1 Transmission Demand Forecast, MW

Year	Summer Peak	Summer Valley	Winter Peak
2007	4,006	1,803	5,008
2008	4,172	1,877	5,215
2009	4,335	1,951	5,419
2010	4,518	2,033	5,647
2011	4,682	2,107	5,853
2012	4,838	2,177	6,048
2013	4,984	2,243	6,230

The winter peak figures represent the expected annual peak demands that are forecast to occur in the October to February winter period of each year e.g., the 2007 forecast of 5,008 MW is the maximum demand projected to occur in winter 2007/08. These peak forecasts take account of the influence of demand-side management (DSM) schemes, such as the TSO's winter peak demand reduction scheme (WPDRS). In winter 2006/07, DSM accounted for approximately 120 MW of a reduction to the peak demand. This amount of DSM is assumed to continue over the next seven years.

The summer peak refers to the average peak value between March and September. This is typically 20% lower than the winter peak. While the overall grid power flow may be lower in summer than in winter, this may not be the case for flows on all circuits. In addition, the capacity of overhead lines is lower because of higher ambient temperatures, while network maintenance, normally carried out in the March to September period, can weaken the network, further reducing its capability to transport power.

The annual minimum is referred to as the summer valley in this TFS. Summer valley cases examine the impact of less demand and less generation dispatched. This minimum condition is of particular interest when assessing the capability to connect new generation. With local demand at a minimum, the connecting generator must export more of its power across the grid than at peak times. The forecasts of summer valley demands in Table 3-1 assume a figure of 36% of the annual maximum demand, which is consistent with historical summer valley demand data.

### 3.2.1 Peak Out-turn for Winter 2006/07

The peak exported demand in winter 2006/07 was 4,854 MW. This figure is 100 MW higher than the transmission peak forecast for winter 2006/07 of 4,754 MW presented in *Transmission Forecast Statement 2006-2012*. At the time of peak the production from wind generation was 4 MW. However, the energy growth for 2006 was in line with forecasts. The high peak figure indicates the difficulty in accurately predicting the maximum demand in a particular year. Peak demands may be higher or lower than forecast depending on factors such as weather conditions and customer behaviour. The TSO will continue to monitor future peaks and adjust its forecasts accordingly.

### 3.3 COMPARISON WITH PREVIOUS DEMAND FORECAST

Table 3-2 compares the winter peak transmission demand forecasts in this TFS with those given in *Transmission Forecast Statement 2006-2012*. The current demand forecasts reflect an average increase in winter peak demand of 3.8% over the period 2007 to 2013. This is slightly higher than last year's forecast average annual increase to 2012. Table 3-2 presents the differences between the peaks forecast in the previous TFS and the current forecasts. The new peaks forecast are slightly higher than last year's forecasts as a consequence of the increase in the expected rate of demand growth.

Table 3-2 Comparison of Peak Demand Forecast with Previous TFS, MW

	2007	2008	2009	2010	2011	2012	2013
TFS 2007-2013	5,008	5,215	5,419	5,647	5,853	6,048	6,230
TFS 2006-2012	4,951	5,158	5,365	5,566	5,732	5,895	N/A
Difference	57	57	54	81	121	153	N/A

### 3.4 FORECAST DEMAND AT TRANSMISSION INTERFACE STATIONS

Transmission interface stations are the points of connection between the transmission system and the distribution system, or directly-connected customers. These are mostly 110 kV stations. In Dublin city, where the Distribution System Operator (DSO) operates the 110 kV network, the interface is usually at 220 kV stations.

Appendix C lists the forecast demands at each transmission interface station at time of winter peak, summer peak and summer valley for all years from 2007 to 2013. Demand projections at individual transmission stations are developed from the system demand forecasts on a top-down basis. The forecasting process includes regular monitoring and review of trends in consumption in all parts of the country. The allocation of the system demand forecast to each station is based pro-rata on an up-to-date measurement of actual peak demand at each station. Account is taken of planned transfers of demand between stations as agreed with the DSO. In this way, changes in the geo-diversity of electricity

consumption are captured. This process provides a station demand forecast and by extension a regional demand forecast for the short to medium term.

The system-wide demand forecasts, presented in Table 3-1, include transmission losses whereas the individual station demand forecasts do not. Transmission losses therefore account for the difference between the system-wide demand forecasts and the sum of the forecasts at each interface station in Appendix C.

Demand forecasts for the small number of directly-connected customers are the current best estimates of requirements. In some cases, the estimates may be less than contracted Maximum Import Capacity (MIC) values, but are chosen to give a better projection of expected demand on a system-wide basis. However, when analysing the capacity for new demand in a particular area, the MIC values of local directly-connected customers are assumed to ensure that the contracted MIC is reserved.

Although demand-side management schemes are expected to reduce some industries' demands over winter peak hours, their normal demand levels are included in the winter peak demand forecasts shown in Table C-1 in Appendix C and are used in the power flow diagrams in Appendix J, as they are more indicative of general power flows.

### 3.5 DEMAND PROFILES

Electricity usage follows some generally accepted patterns. For example, annual peak demand occurs between 17.00 and 19.00 on winter weekday evenings, while minimum usage occurs during summer weekend night-time hours. Figure 3-2 shows the profile for the weekly peaks across the year for 2006. The profiles indicate that the average daily peak in summer is about 80% of the winter peak demand.

Figure 3-3 presents four daily demand profiles that indicate how electricity usage varies throughout the day. The demand profiles are for the day on which the annual peak occurred in 2006 as well as profiles for typical summer and winter weekdays and for the minimum demand day. The profiles, with demand levels ranging from approximately 1,740 MW to 4,854 MW, indicate that the power system deals with a wide variation in demand throughout the year. Even within the day demand variations are substantial.

Figure 3-3 illustrates that on the winter peak day the peak demand is almost twice the minimum demand on that day, a variation of over 2,200 MW. A number of points on this diagram, the winter peak (WP), typical summer peak (SP) and summer valley (SV) demands, are examined in the analyses undertaken for this TFS.



Figure 3-2 Weekly Peak Values for Year 2006

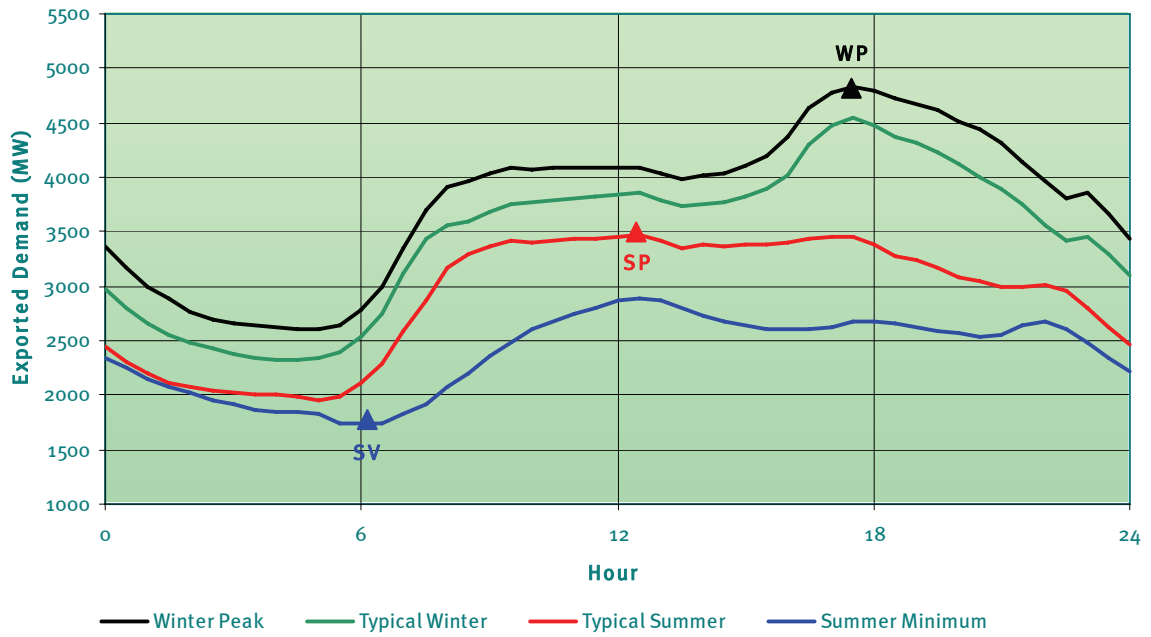


Figure 3-3 Daily Demand Profiles for Year 2006