Gas Demand Forecasting Methodology

December 2007

National Grid

GAS DEMAND FORECASTING METHODOLOGY DISCLAIMER

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Introduction

This report describes the methodology utilised by National Grid to produce forecasts of peak day gas demand and load duration curves. Day-ahead and within-day gas demand forecasting utilises a separate methodology, which is not covered in this report.

The forecasting methodology evolves over time in response to changes in the market, new technology and changing requirements. This document describes the processes used to produce National Grid's 2007 demand forecasts. The original document was first published in November 2004.

Peak day and annual forecasts are published in the Ten Year Statement which can be downloaded from the National Grid website. Additional forecasting and supply/demand modelling information is published in the Winter Consultation Documents available from the National Grid and Ofgem websites.

The main changes from the November 2006 version of this report are

1) The power station model used in the 2007 forecasts utilised 3-monthly power station ranking orders derived from our "best view" forecast of fuel prices. For comparison, high and low power generation gas demand figures were also produced using different fuel price assumptions. These replace the restricted and unrestricted forecasts generated in 2006. Only one forecast is produced for the non-power market sectors.

2) The chapters have been reordered with key concepts moved to the beginning and the detailed calculations of the load duration curve relegated to an appendix.

Contents

1. Background

National Grid's planning process provides the gas demand information required for a wide range of uses on a consistent basis. Some of the uses are listed below

1. Safety
   Load duration curves are now used in the calculation of the GS(M)R Safety Monitors, which are used to ensure sufficient gas is held in storage to underpin the safe operation of the transportation system.

2. Ten Year Statement
   Peak day and annual demand forecasts and load duration curves are published in the Ten Year Statement.

3. Security of Supply
   Demand forecasts are a key element of any analysis of supply security such as that undertaken for the Winter Consultation Report. This report includes load duration curves with assumed supplies matched to them. It can be found at http://www.nationalgrid.com/uk/Gas/TYS/outlook/ .

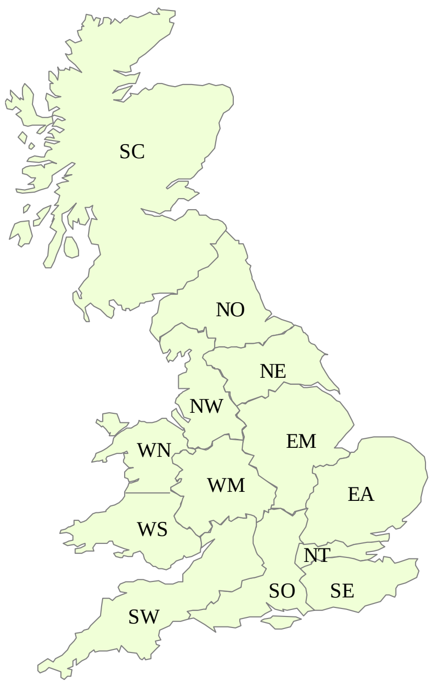
4. Investment Planning
   National Grid is required by its Gas Transporter Licence to develop the gas network so that it can transport the gas demand on a 1 in 20 peak day.

5. Operational Planning
   Demand and supply forecasts enable the efficient operation of the gas network to be planned in advance.

6. Pricing
   The demand forecasts assist the setting of prices that recover National Grid's allowable revenue.

Demand forecasts are produced for each Local Distribution Zone (LDZ).
These are

Scotland	SC
Northern	NO
North West	NW
North East	NE
East Midlands	EM
West Midlands	WM
Wales North	WN
Wales South	WS
Eastern	EA
North Thames	NT
South East	SE
Southern	SO
South West	SW



The demand in each LDZ is categorised by load band. Load bands are defined by the seasonal normal annual demand and whether the meter is read daily. These load bands were originally defined in therms.

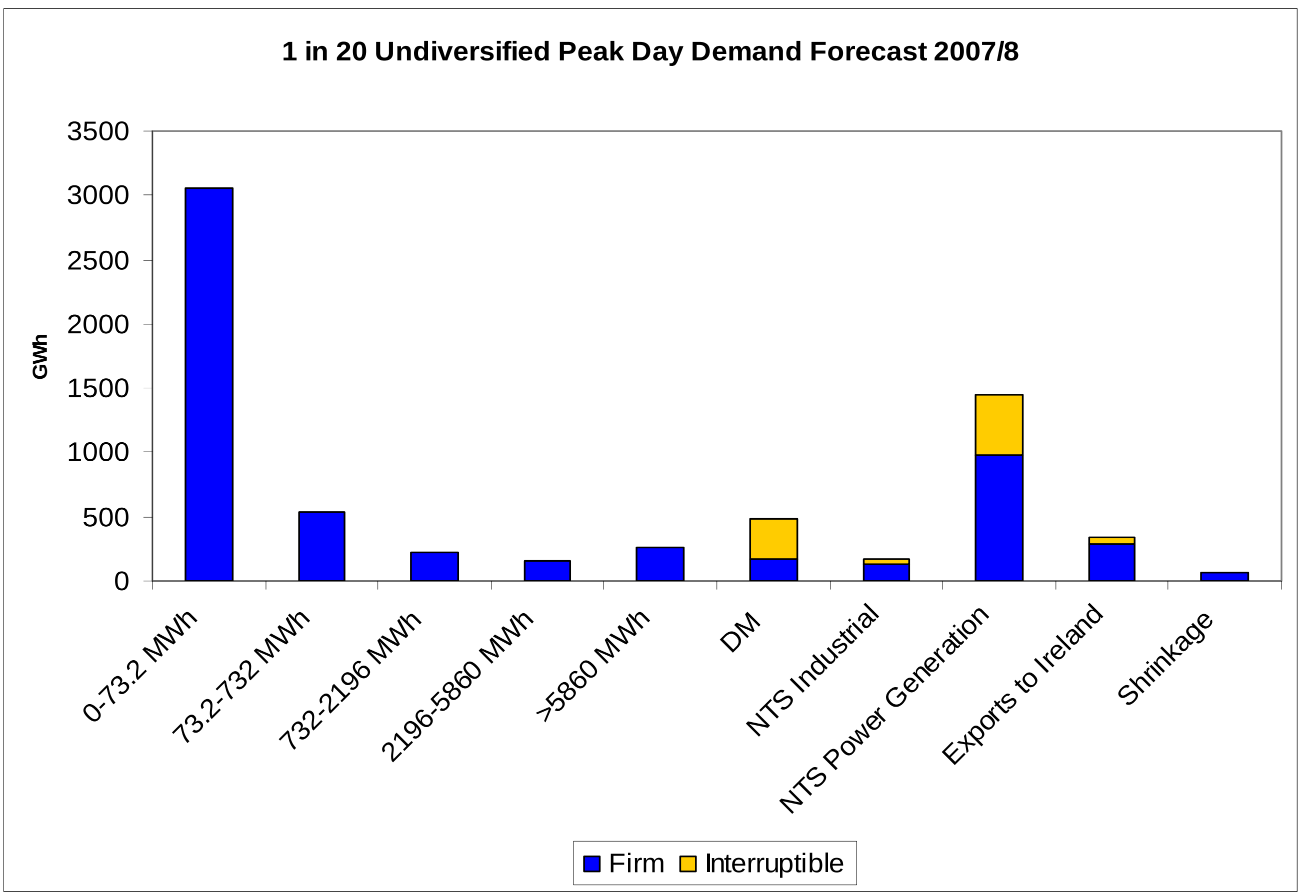
Load Band **Non daily metered (NDM)**	**Therms**	**Comment**
0-73 MWh	0-2500	Used as a proxy for domestic demand
73-732 MWh 732-2196 MWh	2500-25000 25000-75000	Small NDM. 75000 therms is the statutory threshold
2196-5860 MWh >5860 MWh	75000-200000 >200000	Large NDM. Sites below 200000 therms must be firm
Daily metered (DM) Firm Interruptible		

In addition to the LDZs there are loads connected directly to the National Transmission System (NTS). These are grouped into

1. Industrial
2. Power Generation
3. Exports to Ireland
4. Exports to Europe
5. Storage Injection

Figure 1 shows how each load band contributes to the demand on a peak day using data from the 2007 demand forecasts. It has traditionally been assumed that on a peak day all interruptible demand would be interrupted. The peak day figures for interruptible demand illustrate the extent of this interruption.

Figure 1

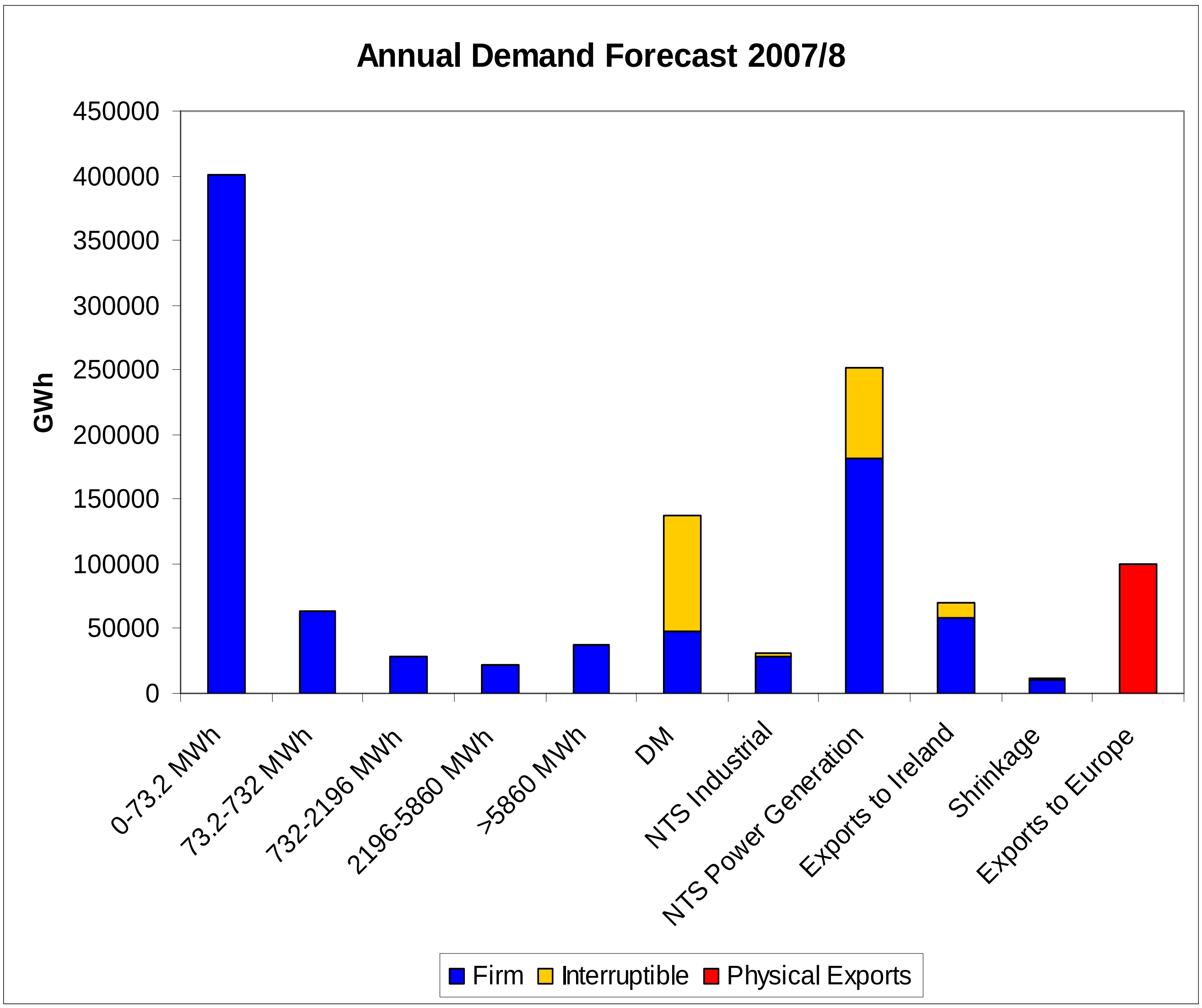


Exports through the Interconnector to Europe are modelled as part of the supply analysis because the Interconnector behaves in a similar way to a storage site, responding to the supply/demand position in the UK and the relative prices in the UK and Europe. They are assumed to be zero on a peak day. GB demand is forecast including and excluding European exports. Exports to Ireland behave more like an LDZ, with some weather sensitive gas demand.

Storage injection is not forecast as part of the standard demand forecasting process. Estimates of the average profile of storage injection are produced for adding to seasonal normal demand for comparisons with actual on the daily summary page (see section 2.13). These are calculated from a regression model of storage injection and withdrawal. This model is fitted to seasonal normal parameter values and then all negative values (storage withdrawals) set to zero.

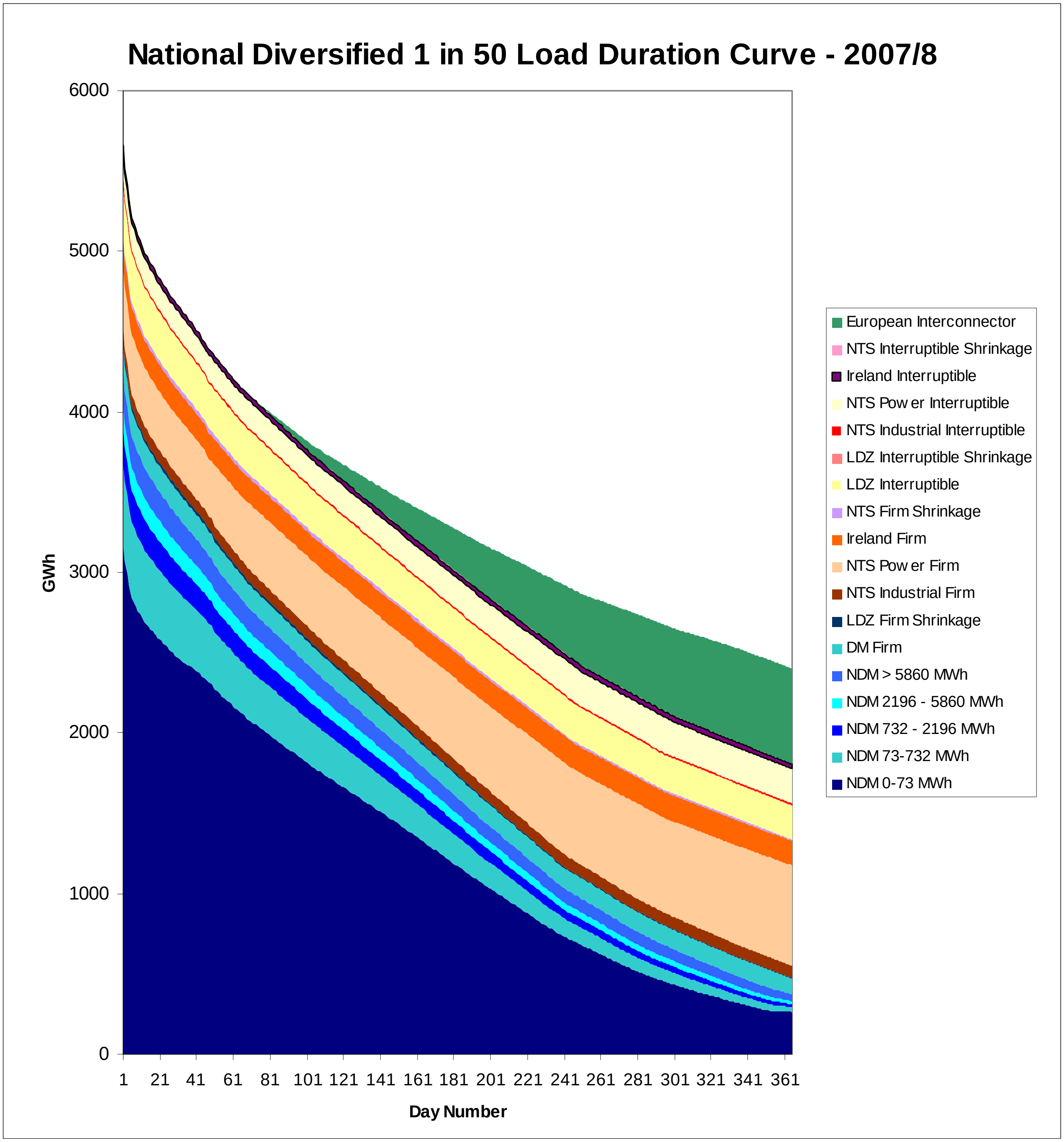
The annual demand forecasts in figure 2 are from the 2007 demand forecasts and assume average weather conditions, based on the weather from 1987/8 to 2003/4.

Figure 2



One way of presenting a demand forecast is a load duration curve (see section 2.1), which ranks daily demands from highest to lowest. An example is shown in figure 3. Most of the variation in demand is due to the weather. This load duration curve apportions total demand by load band. It shows that the smaller NDM customers are responsible for the majority of the weather sensitivity. NDM demand accounts for almost ¾ of total demand on a peak day but less than ¼ on a warm summer's day. The graph also shows an increase in the steepness of the load duration curve at the top end. The title of the graph is a detailed description of the data. These elements are discussed in detail as follows: national (section 6.7) diversified (2.9) 1 in 50 load duration curve (2.2, 7.3, appendix 1) 2007/8 gas supply year (2.17) load band (2.8, 6.1). It is important to understand these issues before using the data. For example the firm only proportion of a diversified load duration curve is likely to underestimate demand at times of full interruption because it does not include any substitution of firm gas for interruptible gas (2.9).

Figure 3



2. Key Concepts and Definitions

2.1 Load duration curve

A load duration curve is a curve of load or demand on the vertical axis against days' duration on the horizontal axis. The days' duration correspond to the days in a supply year (1st Oct. to 30th Sept.). The daily demands are ranked so that the day with the highest demand becomes day one and the day with the lowest demand for gas is day 365. Thus any point on the curve corresponds to a demand level and a number of days on which that demand is equalled or exceeded in the supply year.

Figure 4

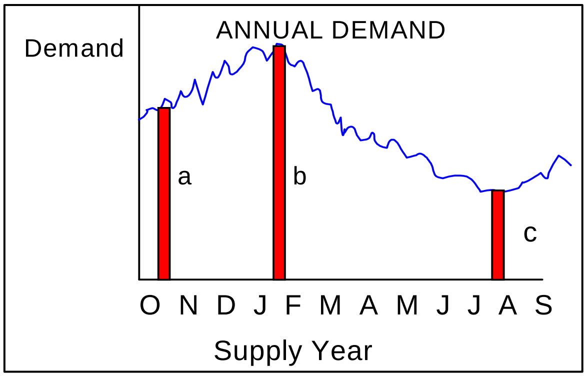
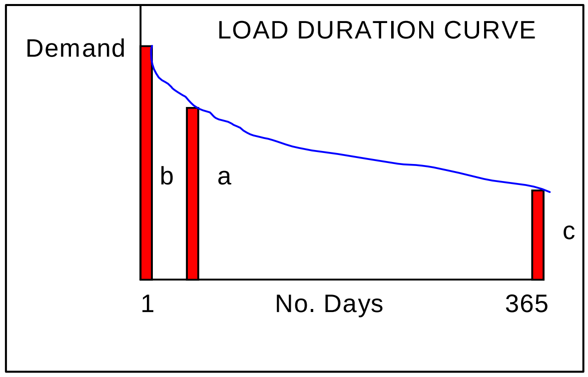


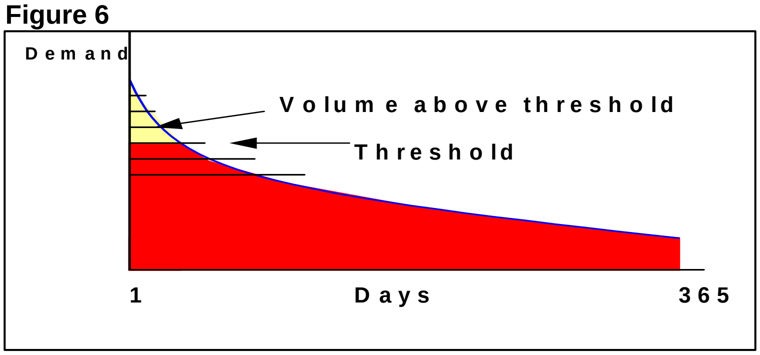
Figure 5



2.2 1 in 50 Load Duration Curve

The 1 in 50 load duration curve is that curve which, in a long series of years, with connected load held at the levels appropriate to the year in question, would be such that the volume of demand above any given demand threshold (represented by the area under the curve and above the threshold) would be exceeded in one out of 50 years. It is also called the severe year curve.

Figure 6



The day number shows the average number of days that would be expected to have volumes above a threshold in a 1 in 50 year. The same methodology can be used to produce load duration curves for other severities. However, because the methodology is designed to give a good estimate of an extreme event, the accuracy of the methodology is reduced for severities below 1 in 10 (except for the average load duration curve). Figure 7 shows that most of the variation is in the top half of the load duration curve. The average curve in these graphs has been calculated from the same data as the other severities and has not been adjusted for climate change.

Figure 8 shows the first 50 days of the same load duration curves. This shows that the highest days of the 1 in 5 curve are not in line with the other load duration curves.

Figure 7

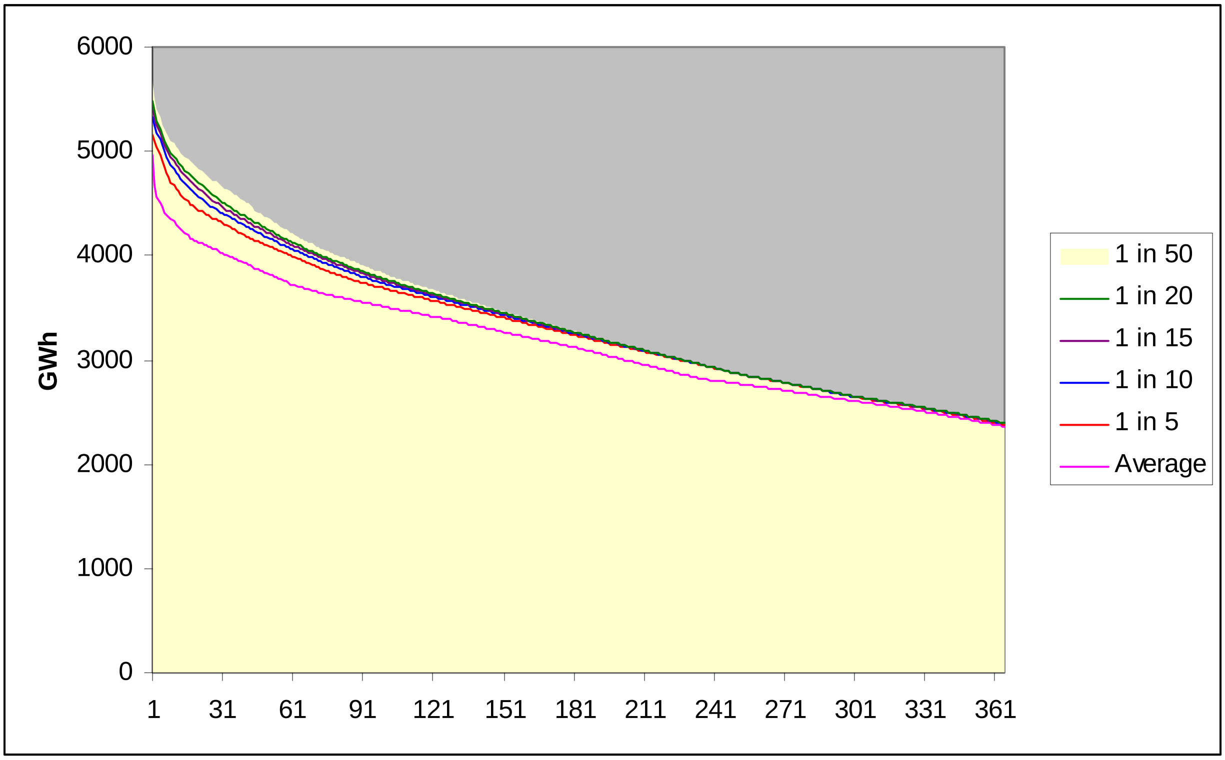
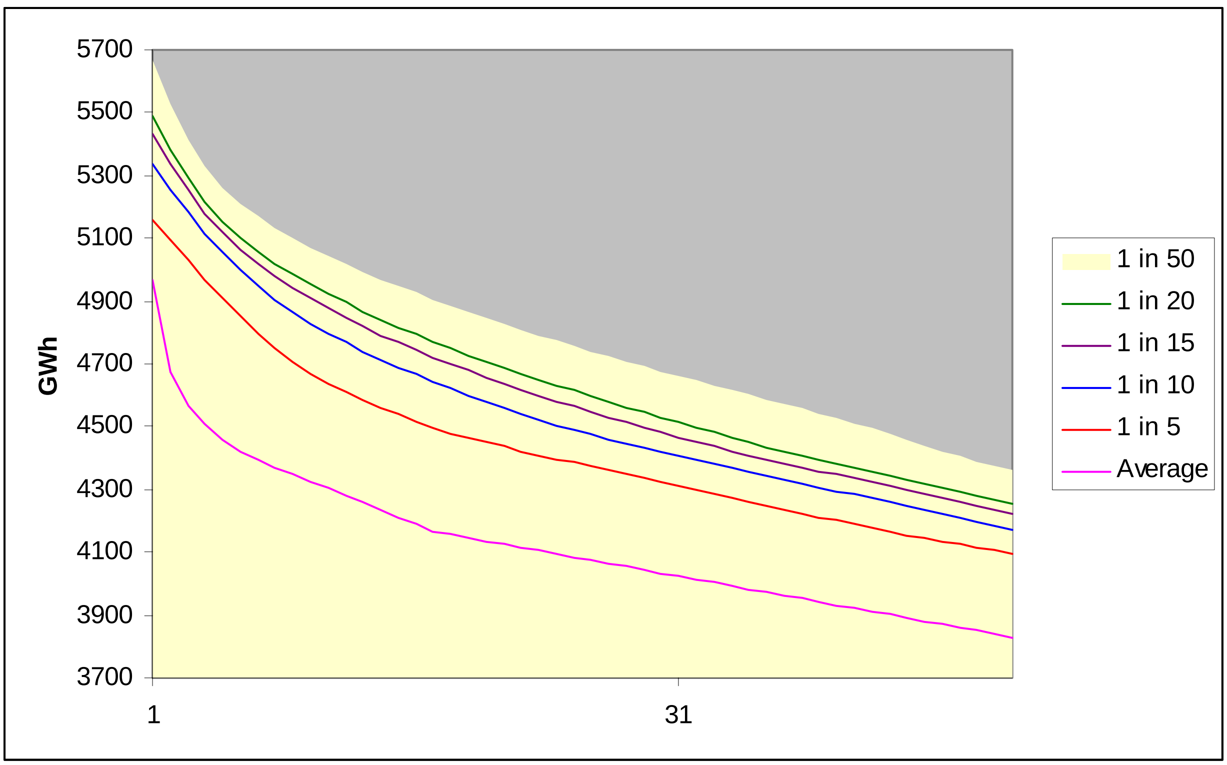


Figure 8



2.3 1 in 20 Peak Day

1 in 20 peak day demand is the level of daily demand that, in a long series of winters, with connected load held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once. This is the UNC definition of the 1 in 20 peak day. It can be found in section W2.6.4(c). Day 1 on the 1 in 50 load duration curve is the 1 in 50 peak day demand. A day 0 demand level is sometimes shown above the 1 in 50 load duration curve data. This day 0 demand is the 1 in 20 peak day demand and is shown for comparison purposes only, and does not form part of the load duration curve. The 1 in 20 peak day is calculated from a statistical distribution of simulated historical peak days. It is not the highest demand in the last 20 years, nor is it the demand that would be expected in the coldest weather experienced in the last 20 years.

2.4 LDCs by difference

Not all load duration curves are produced direct from simulation. Simulation works best for market sectors with significant weather sensitivity. Other market sector LDCs are calculated from the difference between two simulated load duration curves or from indicative load duration curves scaled to add up to a simulated load duration curve.

2.5 Indicative peaks and load duration curves

An indicative peak day demand is often calculated to obtain a quick estimate of the peak day demand without the need for simulation. An indicative peak day demand is calculated by inserting the 1 in 20 peak composite weather variable in the demand model. Alternatively an indicative peak day can be calculated from a seasonal normal annual demand and a load factor.

Indicative load duration curves can be calculated from a regression model and a composite weather duration curve. Composite weather duration curves are calculated in a similar way to load duration curves, but using historical composite weather instead of demand. An alternative method of producing an indicative load duration curve is to combine a seasonal normal annual demand with a standardised load duration curve. A standardised load duration curve is a load duration curve that contains daily values as a percentage of the seasonal normal annual demand.

2.6 Load Factors

A load factor shows the relationship between the peak day demand and the average daily demand. It has a value between 0 and 100. Weather sensitive demand models will have a low load factor. NDM load bands have load factors between 31% and 45%. Large sites with constant gas consumption can have load factors approaching 100%. The formula is

$$\text{Load Factor} = \frac{(\text{Annual Demand}/365) * 100}{\text{Peak Day Demand}} \%$$

2.7 Composite Weather Variable

The composite weather variable (CWV) is a function of actual temperature, wind speed, effective temperature and pseudo seasonal normal effective temperature, and is a single measure of weather in each LDZ. The pseudo seasonal normal effective temperature is the seasonal normal effective temperature adjusted to the profile of seasonal normal NDM demand. The composite weather variable includes summer cut-offs and provision for cold weather upturn during low temperature extremes, defined such that a linear relationship applies between daily demand in the LDZ and the composite weather variable. The composite weather variable is described in more detail in section 4.1.

2.8 Demand Data

Gas demand is categorised by load band and not by type of load. The load bands refer to the seasonal normal annual demand of each load. The consumption is metered as a volume and then converted to energy using calorific values. The demand forecasting methodology calculations use energy units. Typically these are GWh for annual forecasts and MWh for daily forecasts. Sometimes the forecasts are required as a volume. For a quick analysis a standard CV of 39 MJ/m3 is often used. To convert from GWh to MCM use the following formula

Volume (MCM) = Energy (GWh) * 3.6 / Calorific value (MJ/m3)
= Energy (GWh) / 10.833 using the standard CV of 39 MJ/m3

Forecasts are produced for LDZ (Local Distribution Zone) geographical areas and not by Network. Network forecasts can be produced from the sum of the relevant LDZ forecasts. National forecasts are described in appendix 1.9 Diversity. The main LDZ load band categories are

Non-daily metered 0-73 KWh
Non-daily metered 73-732 KWh
Non-daily metered 732-2196 KWh
Non-daily metered 2196-5860 KWh
Non-daily metered >5860 KWh
Daily-metered firm consumption
Daily-metered interruptible consumption
Shrinkage

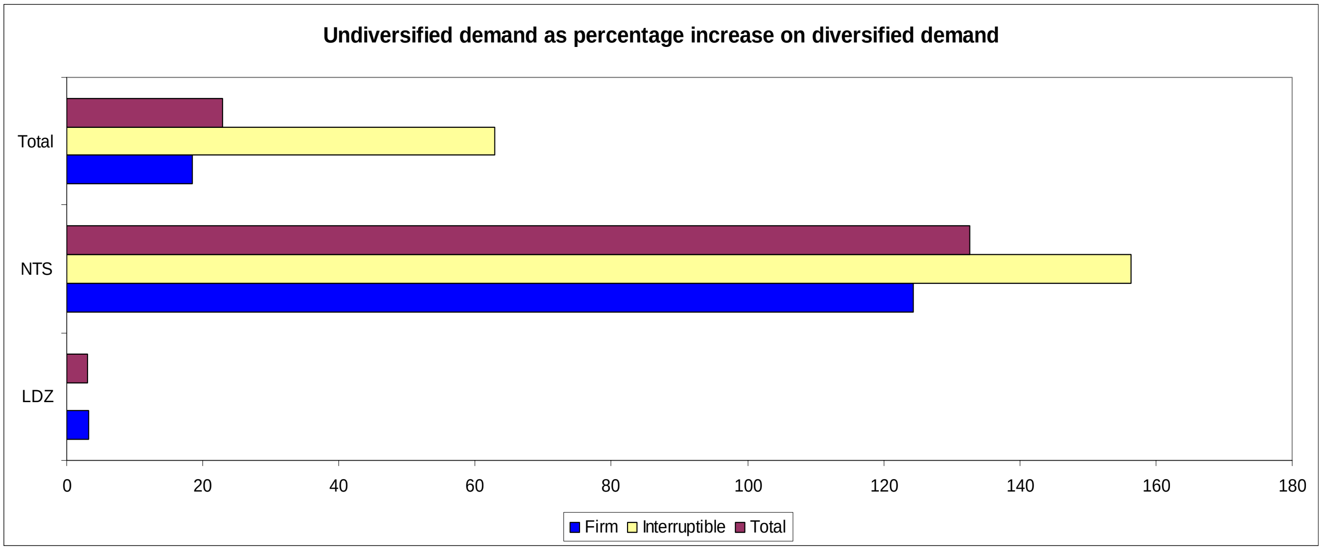
2.9 Diversity

Diversity in the context of gas demand refers to how the demands at different points of the network are added together. Undiversified demand is derived by forecasting peak demands and load duration curves for each location separately, and then summing these calculated figures. Diversified demand is calculated by adding together the daily demands for all the locations first and then calculating peak day and load duration curves from the aggregate number. Diversified demand is the aggregate demand for a group of consumers which allows for each consumer to be using gas at different times. Diversity factors can be calculated as the percentage difference between undiversified and diversified forecasts. They are an output from the process not an input.

Figure 9 shows the diversity for 2007/8 peak day forecasts. There is very little difference between diversified and undiversified LDZ demand. This is because any diversity due to individual end-users taking gas off the network at different times has already been included within the individual LDZ figures. Therefore the LDZ diversity represents the variation in weather across the country. The NTS diversity is partly due to the different patterns of gas usage between the NTS sites and partly due to the difference between the contract maximum demands and the actual maximum demands.

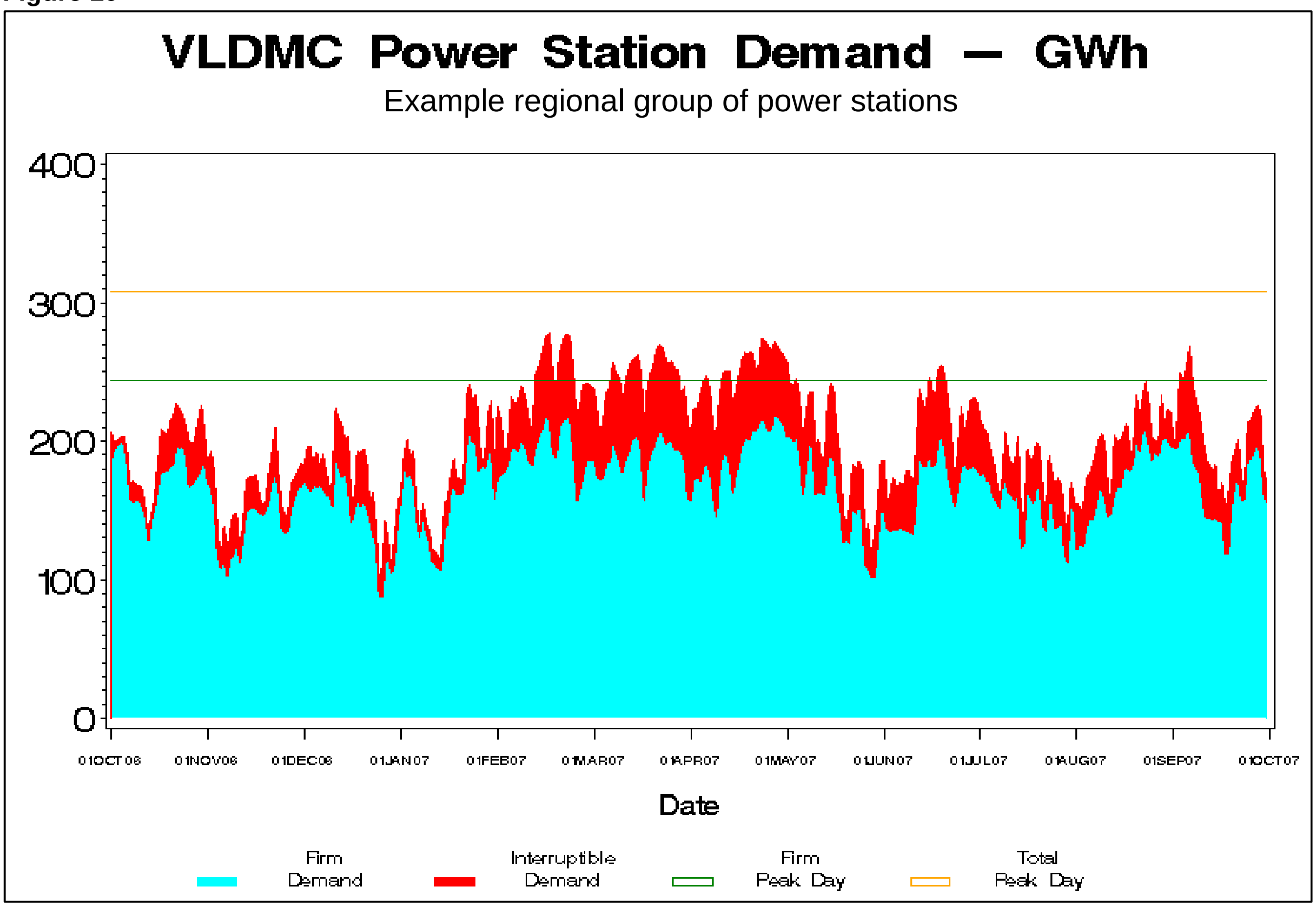
The forecast of undiversified peak day demand for each NTS site is its SOQ (Supply point Offtake Quantity). Diversified NTS peak day demand is the difference between total demand on a cold winter's day and LDZ demand on a cold winter's day. The 2007 demand forecasts expect coal to be the preferred fuel for generation on high demand days reducing gas consumption for power stations. This reduction in NTS demand greatly increases diversity. This diversity contributes to the plant margin in electricity generation. Plant margin is an essential component of the electricity generation market. It ensures there is enough generation available to cover technical problems in base load generation and to cope with the diurnal profile of electricity demand. At peak times of the day more power stations are operating at maximum capacity than would be implied by the average power station gas demand over the whole day. Planning the gas network to undiversified demand ensures capacity is available where and when it is required. For details of national diversified demand methodology see sections 6.6, 6.7 and 7.8.

Figure 9



The capacity of the gas network is designed to cope with 1 in 20 peak day firm demand. This ensures that local networks can deliver local high demand. The diversity factors above may seem to suggest that this demand level is too high. However, figure 10 illustrates that firm peak demand is an appropriate level. This graph shows gas consumption for a number of power stations in the same geographical location.

Figure 10

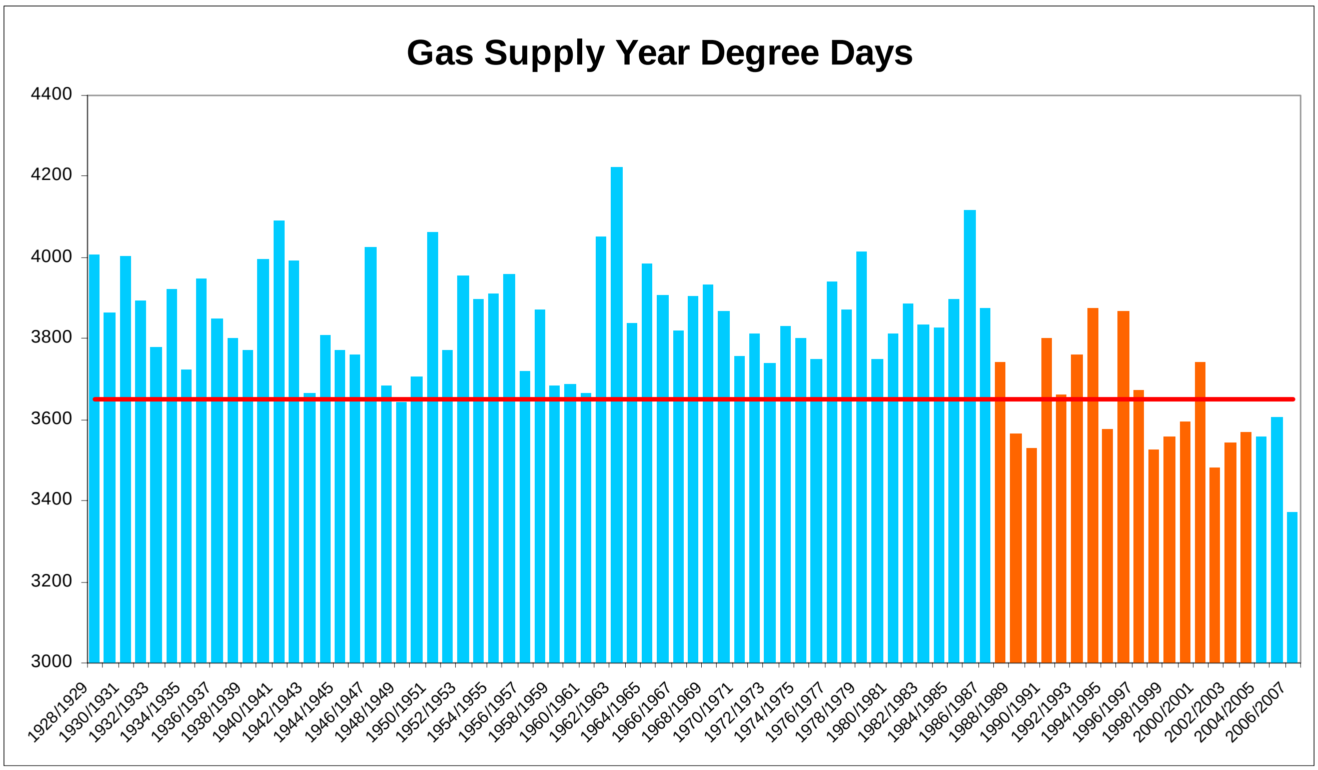


Total peak day demand is much higher than total demand on any day. If interruptible contracts were to be interrupted it would be reasonable to assume that the shortfall in generation would be made up by spare capacity in the firm contracts. The appropriate comparison is therefore between total demand and the firm peak day. The graph shows total demand to be above the firm peak day towards the end of the winter thus justifying the use of undiversified firm peak day demand for planning the capacity of the network.

2.10 Weather basis

The 2007 peak day and load duration curve demand forecasts were calculated using the 78 year weather history from October 1928 to September 2006. Seasonal normal demand forecasts are calculated on the basis of the average weather from the 17 years from October 1987 to September 2004. Figure 11 shows annual composite weather degree days with the 17-year seasonal normal period shaded. The red line shows the average degree days for the 17-year seasonal normal period.

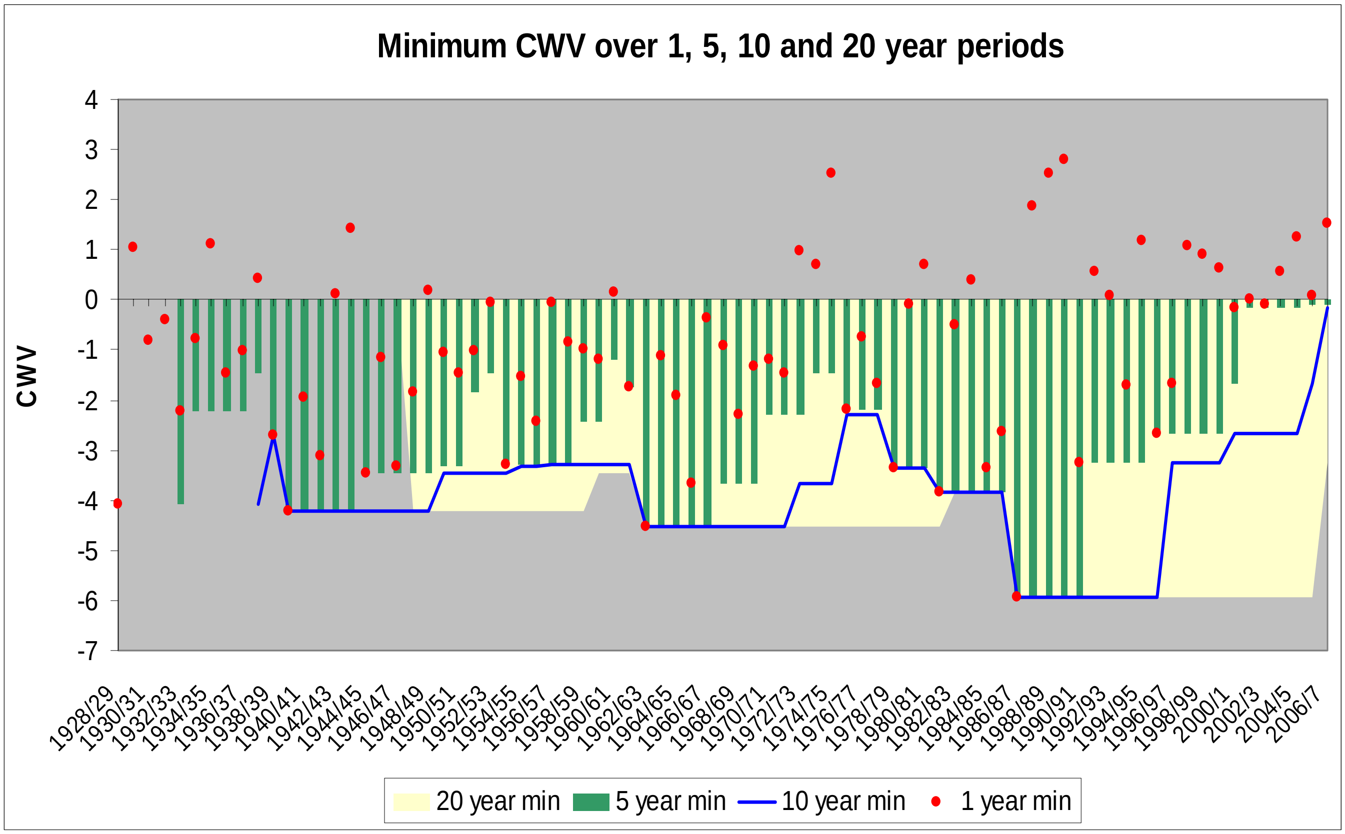
Figure 11



The coldest day nationally was only 20 years ago, on January 13th 1987, when every LDZ experienced weather colder than the 1 in 20 peak day. The coldest day in Scotland was even more recent, on December 29th 1995. However recent winters have been very mild suggesting that at some stage adjustments to peak day demands and severe load curves should be made. Figure 12 shows the coldest weather over 1, 5, 10 and 20 year periods.

Work is still in progress to develop a methodology to create severe load duration curves that reflect climate change. Discussions are taking place with the Hadley Centre to investigate whether their climate change modelling can be of assistance. Any changes must be carefully considered and agreement reached with the HSE, Ofgem, BERR and the energy industry before changes to the peak day methodology are implemented.

Figure 12



2.11 Connected Load

Connected load refers to the demand that a site, or group of sites, connected to the gas network would be expected to consume in a seasonal normal year. This is best explained with the aid of an example. Consider a large flat load that started to operate, at full capacity, on September 1st 2007. The seasonal normal demand for the load is 3650 GWh. The seasonal normal annual demand forecast for the 2007 calendar year would be 3650GWh*122days/365days=1220. However, the connected load for all the days from January 2007 to August 31st would be zero GWh. The connected load for September 1st 2007 onwards would be 3650 GWh. Demand models are scaled to connected load forecasts, not annual demand.

2.12 Degree Days

Degree-days show the number of degrees that the daily temperature is below a specified threshold.

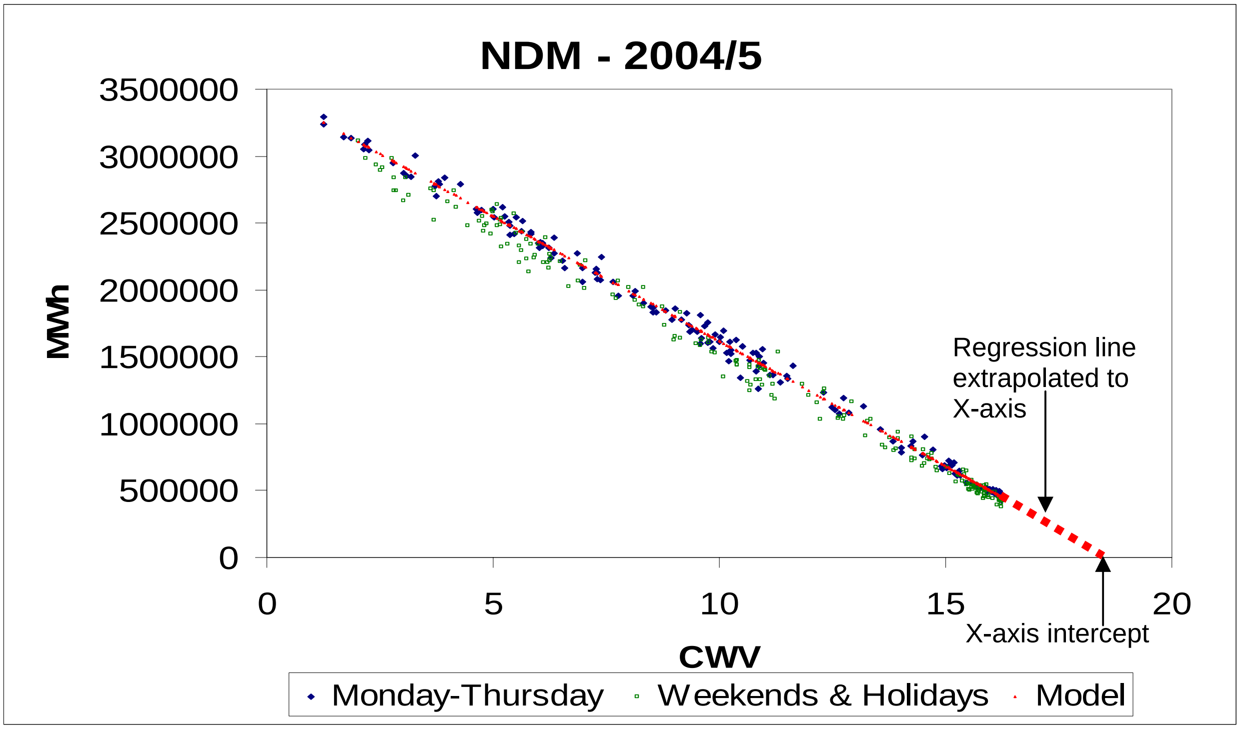
Degree-days = maximum (threshold temperature – daily temperature, 0)

Composite weather degree-days are calculated in the same way.

Composite weather degree-days = maximum (threshold CWV – daily CWV, 0)

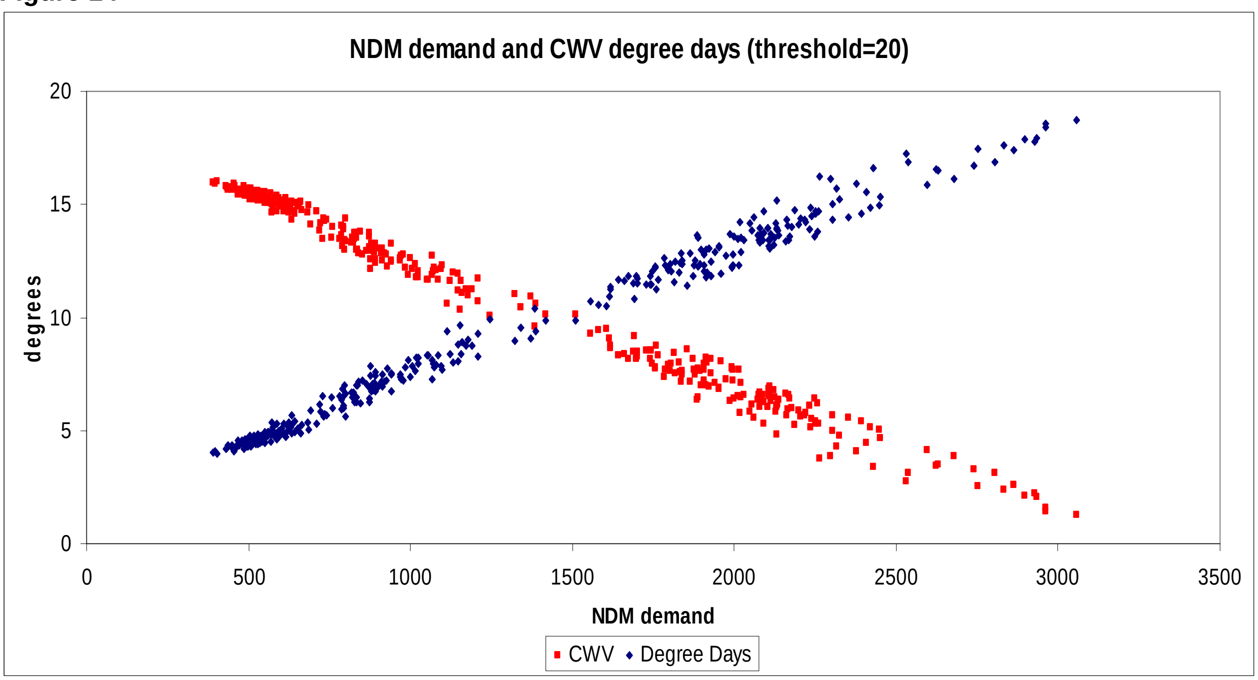
The threshold is set depending on the analysis required. A typical threshold for analysis of trends in weather is 20 degrees (see Figure 11). For severe weather analysis a threshold of zero degrees is often used. Alternatively the threshold can be set to the point at which a weather demand regression line crosses the weather axis, the X-axis intercept. This is illustrated by figure 13.

Figure 13



Degree-days are positively correlated with gas demand. This is illustrated in figure 14.

Figure 14



2.13 Seasonal normal, cold & warm weather and demand

Figures 15 and 16 show the seasonal normal cold and warm demand and CWV from the National Grid website at http://www.nationalgrid.com/uk/Gas/Data/dsr/

Figure 15

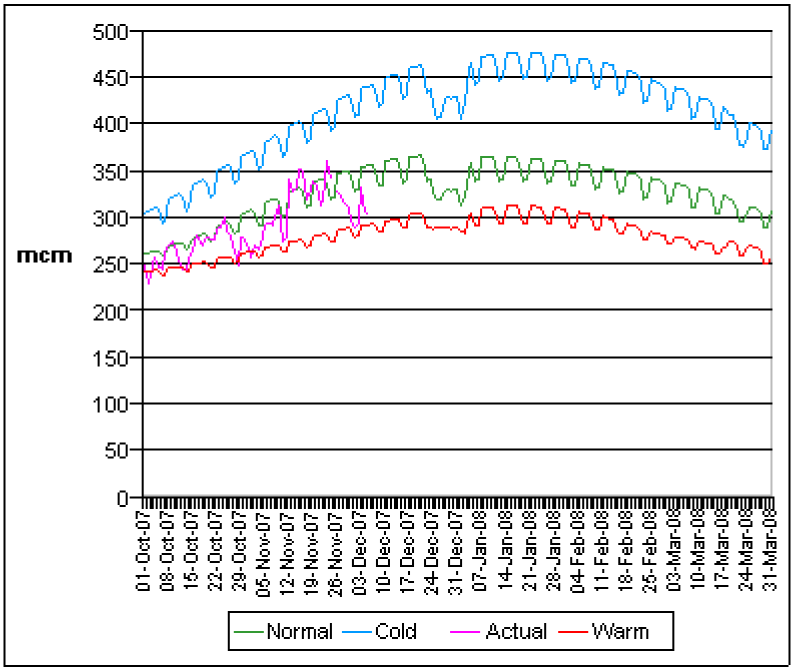
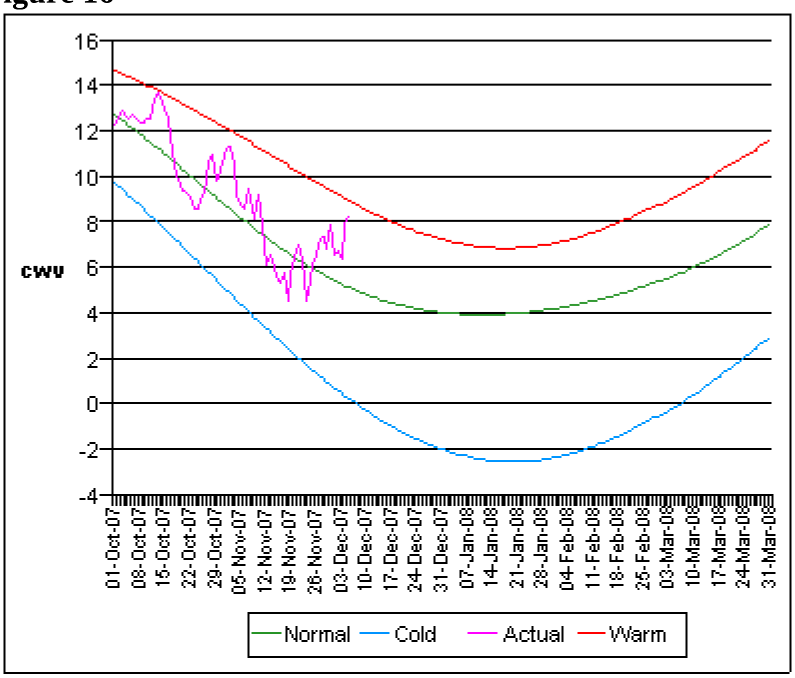


Figure 16

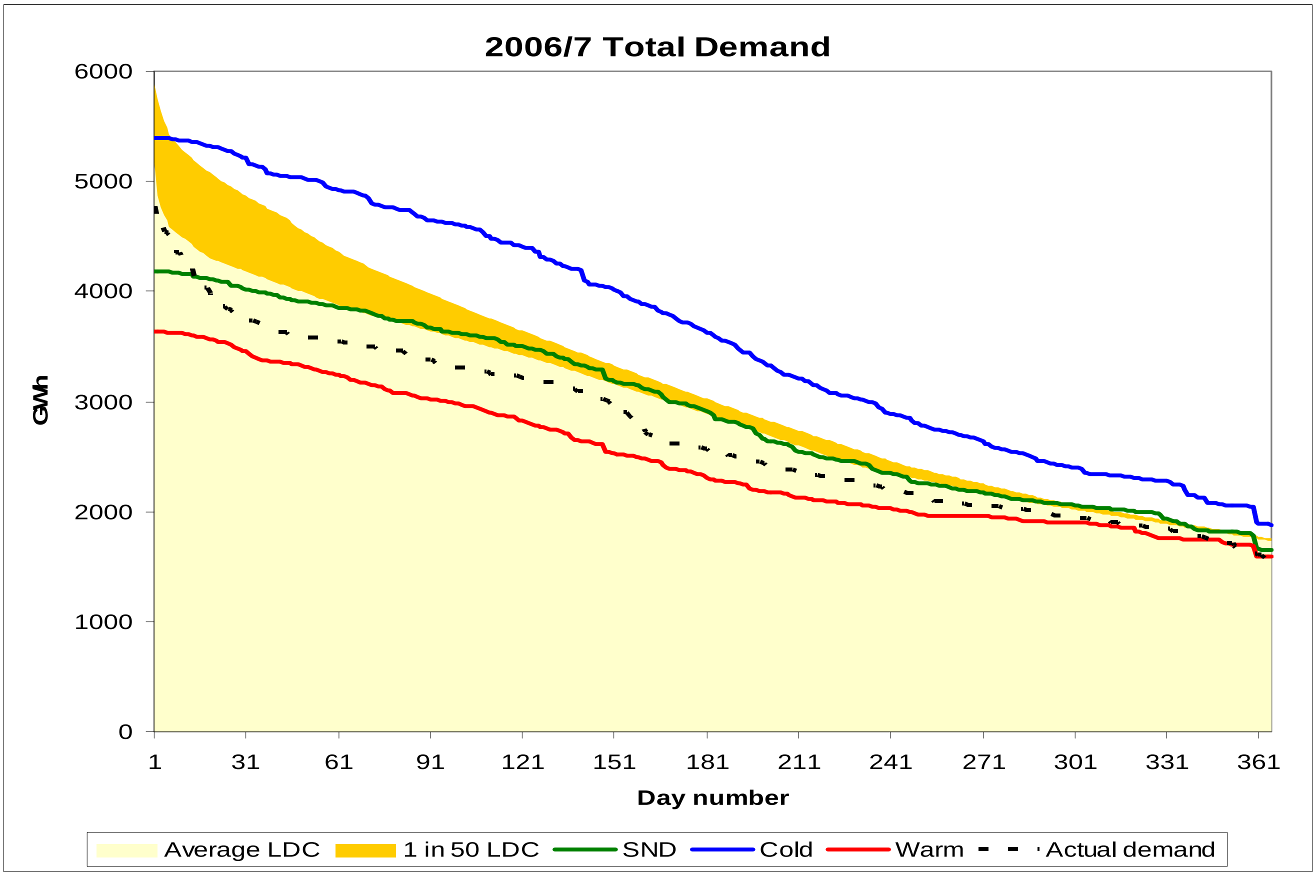


The seasonal normal demands are calculated as energy values and then converted to volumes using a standard calorific value of 39 MJ/m3. LDZ demand is linearly related to composite weather so for the most part these two graphs should be a mirror image of each other. However, the NTS loads are generally not weather sensitive and there are differences in the demand definitions between the actual and seasonal normal data. The cold, warm and seasonal normal figures now include exports to Europe and storage injection. The assumptions for power station gas demand change every 3 months. Gas power stations are assumed to be marginal generation during January to March 2008 and base load generation during the summer. However electricity companies make decisions on which stations to operate on a daily basis so the actual demand will reflect these decisions as well as the impact of weather.

2.14 Seasonal profile of demand compared to load duration curves

Figure 17 shows the seasonal normal, warm and cold profile demands reordered into load curves and compared with the average and 1 in 50 load duration curves and actual demand. The average load duration curve has higher demands than the highest average profile demand. This is because the load duration curve represents an average winter and in any winter there will always be some days colder than normal and some warmer. 2006/7 was a very mild year but the actual demand line shows that some days experienced demands much higher than seasonal normal. The volumes under both the average load duration curve and average demand profile should be very similar with those days on the load duration curve higher than the average profile cancelled out by corresponding days lower than the average profile.

Figure 17



The cold and warm values are 1 in 20 ranges for each calendar day. They should not be added together to get a range of demands for longer periods than a day. This is illustrated by comparing the 1 in 20 cold line with the 1 in 50 load duration curve. The top few days on the load duration curve are higher than the cold curve. This reflects the difference between a 1 in 50 probability over a year and a 1 in 20 probability over a 7 day period. However, for most of the year the cold curve greatly exceeds the 1 in 50 load duration curve. This is because even in a severe cold year there are many days at average or warmer than average temperatures.

2.15 Demand response

Demand response refers to the reduction in demand, in the short term, due to high prices. The econometric models include the impact of gas prices on an annual basis. However, in the 2005/6 winter there were prolonged periods of tight gas supply which drove up prices. This resulted in some customers switching to alternative fuels or reducing consumption. The main market sector where demand response occurs is power generation. This is because electricity generators are often able to switch between power stations that use different fuels. When gas prices are high gas power stations become marginal generators with coal power stations producing base load generation. Demand response, particularly with regard to interaction with the electricity sector, forms part of the winter consultation process.

2.16 Data definitions

Daily gas demand can be defined in a number of different ways which all give different values. The main variations are

1) Storage injection

2) Interconnector exports. The interconnector acts in a similar way to a storage site exporting when supplies are plentiful and importing when supplies are low.

3) Line pack. Line pack is gas stored in gas pipelines. Changes in line pack are accommodated through changes in pressure.

4) Calorific value. Gas demand forecasts are produced in energy units. They are often converted to volumes using a standard calorific value of 39 MJ/m3.

5) Timing. Errors in individual meters can affect how the gas demand is assigned to different load bands. For example, a meter error at a large factory will not only affect the gas demand reported for that factory but also total DM demand and NDM demand. Over time these errors are spotted and rectified. D+5 demand refers to the demand figure 5 days after the event. This data is assumed not to change.

6) CHP. Combined heat and power systems provide heat to large industrial users and also generate electricity. These sites can sometimes be categorised as industrial and sometimes as power generation.

7) Grid connection. Power stations connected to the electricity distribution networks are not always the same power stations that consume gas from the LDZs. Therefore power station demand can sometimes be on a gas connection basis or an electricity connection basis.

8) Shrinkage. Shrinkage refers to the difference between gas consumed and gas supplied. Reasons for shrinkage include leakage, theft of gas and CV issues. Demand forecasts do not contain detailed forecasts of shrinkage. Shrinkage is forecast as an annual shrinkage factor which is applied to total demand and apportioned between firm and interruptible load bands. Load bands that do not include shrinkage are typically labelled consumption and those that include shrinkage are labelled demand.

9) Directs. This refers to gas consumers, typically large industry or power stations, which obtain gas directly from an import terminal without that gas travelling through the national transmission system. National Grid figures normally only include the NTS portion of gas consumption. BERR figures often include direct gas.

10) Origin of forecasts. This document describes the methodology that National Grid Transmission employs. The Distribution Networks are given a copy of the forecast for their Network which they can use. Alternatively they can choose to produce their own forecasts or obtain forecasts from other service providers. National Grid design the Network based on the 1 in 20 peak day demand forecasts submitted by each Distribution Network combined with National Grid Transmission's NTS forecasts. This will be different from National Grid Transmission's undiversified 1 in 20 peak day forecast.

2.17 Time Periods

The standard time period for gas demand is a gas day. This is because gas travels at 25mph through the National Transmission System (NTS). Gas landed in Scotland would take 23 hours to travel to the furthest point on the network in Cornwall. The gas day starts and ends at 6am when gas demand tends to be lowest.

Annual figures are produced for three different time periods:

Gas supply year – This runs from October 1^{st} to September 30^{th} and has the benefit of containing a whole winter. Load duration curves, peak day demands and load factors are produced on a gas supply year basis.

Calendar year – This runs from January 1^{st} to December 31^{st}. The main advantage is that it coincides with the time period for a lot of the econometric variables used in the annual demand forecasting process. The main disadvantage is that the winter is split between two years.

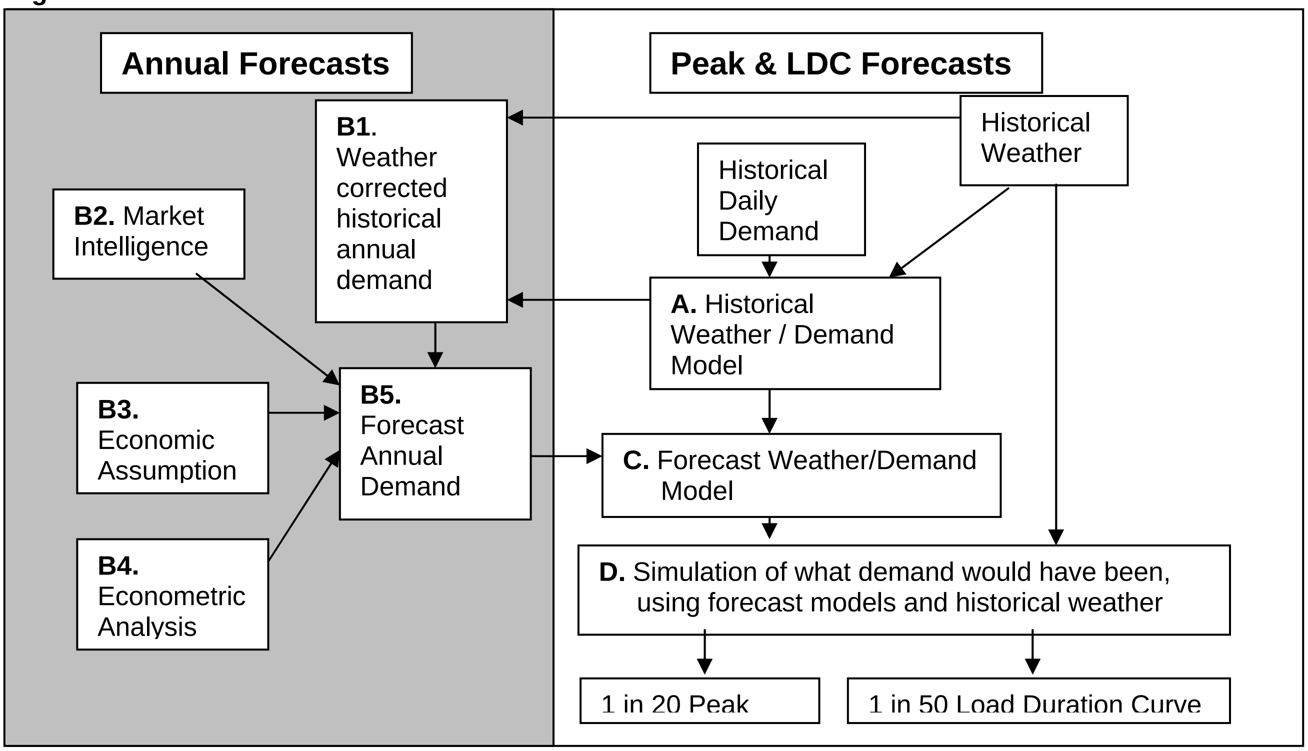
Formula year – This runs from April 1^{st} to March 31^{st}. It is used for financial purposes.

3. Summary of Process

3.1 Process Diagram

Figure 18 illustrates the main stages of the peak and annual gas demand forecasting process. These are then described in more detail in the remaining chapters of this note.

Figure 18



A. Weather/Demand regression models calculate the weather sensitivity of each load band.

B1. Historical annual demands are weather corrected so that each year is on the same weather basis. Growth in annual demand can then be calculated from these values.

B2. Market intelligence provides information on new large loads that are expected to connect to the gas network and changes to existing large loads. The main sources of this information are through the consultations with distribution networks (DNs) and the Transporting Britain's Energy (TBE) consultation. The TBE process includes meetings with producers, shippers and consumer groups.

B3. Economic assumptions are commissioned from an economic consultancy. These break down government statistics and other information into LDZ specific forecasts. A number of economic reports on key information, such as inflation rates and the price of oil, are purchased. This enables us to validate our economic forecasts.

B4 Econometric models are produced that link changes in gas demand to economic variables.

B5 Trends in growth and economic factors are combined to produce annual forecasts. These are adjusted for known changes in large loads.

C The weather demand models calculated in step A are converted to daily demand models and scaled to produce the annual demand forecast in average weather.

D Forecast gas demand is simulated under historical weather conditions. Statistical distributions are calculated from the simulated demands and 1 in 20 peak days and 1 in 50 load duration curves calculated from these distributions.

3.2 Timeline

	October	November	December	January	February	March	April	May	June	July	August	September	October	November	December
Historical weather & demand data	X			X											
Planning assumptions				X	X	X									
Distribution Network consultations				X	X				X						
TBE consultation				X	X	X									
Internal challenge and review							X								
Update methodology and programs	X	X	X	X	X	X									
Produce annual forecasts					X	X	X								
Produce peak and load duration curve forecasts								X							
Internal publication of demand forecasts								X							
Winter consultation document analysis							X	X	X	X	X	X			
TBE summer event (External summary of forecasts)										X					
Publication of Ten Year Statement															X

The publication of the Ten Year Statement is in December to enable the results and impact of the autumn entry auctions to be included.

The Transporting Britain's Energy (TBE) consultation consists of meetings with shippers, suppliers and other industry stakeholders. These meetings provide feedback on the previous forecasts and information for the next forecasts from tailored questionnaires.

3.3 External Audits

The forecasting process has been audited regularly. For the 2001 Price Control Review (PCR) Mott Macdonald conducted an audit of demand & supply forecasting plus the network design process. They said

- "National Grid has a comprehensive and soundly based demand forecasting process"
- "We have not identified any changes that would make a material improvement to forecasting performance"

In late 2002 Deloitte & Touche audited the split of the LDZ price control into networks and found no issues with the demand forecasting process.

Ofgem asked Frontier Economics to review the methodology underpinning the gas demand forecasts following the demand response that occurred in the 2005/6 winter. In their April 2006 report they wrote that "the demand forecasting process appears to have worked satisfactorily in the past, and continues to do so for non-price sensitive customers". They recommended incorporating demand response in the process for price sensitive customers. This recommendation has been addressed in the 2006 demand forecasts with the production of restricted and unrestricted demand forecasts (see appendix A1.16).

TPA Solutions were appointed by Ofgem to provide technical support in relation to the 2007-2011 Price Control Review. In their July 2006 report they wrote "TPA supports the approach and methodology".

4. Weather

The weather explains most of the variation in LDZ demand. Actual demands have to be adjusted for the weather before underlying growth can be calculated. The weather conditions applied when calculating forecast demand have to be identified. These calculations are simplified through the use of a composite weather variable.

4.1 Composite Weather Variable

The Composite Weather Variable (CWV) is a weather variable created from 2-hourly temperatures and 4-hourly wind speeds transformed to produce a linear relationship with LDZ demand. The benefits of a composite weather variable are

1. Improves the fit of weather/demand models.
2. Historical weather can be used to estimate what demand would have been at current levels of connected load.
3. Linear relationship with LDZ demand greatly simplifies demand models.

A separate composite weather variable is produced for each LDZ although the same weather station is sometimes used for more than one CWV. The national composite weather variable is a weighted average of the LDZ CWVs. The CWV is for a gas day, 6am to 6am. The components of the composite weather variable are

1. Effective temperature (0.5 * today's temperature + 0.5 * yesterday's effective)
2. Pseudo seasonal normal effective temperature
3. Wind chill
4. Cold weather upturn
5. Summer cut-off

The pseudo seasonal normal effective temperature is the seasonal normal effective temperature adjusted to the profile of seasonal normal NDM demand.

The composite weather variable parameters are calculated from historical weather and demand data from October 1981. The parameters are recalculated every 5 years or when a weather station changes. The parameters are calculated in a number of steps, which ensure that changes to one parameter do not have an adverse effect on the fit of the whole model. It also enables different data to be used in different stages.

The concept of the composite weather variable is also included in Section H of the Uniform Network Code. It is a Network Code requirement that the CWV parameters are reviewed every 5 years. Keeping the parameters unchanged for 5 years helps to maintain stability in the demand forecasts from one year to the next. More frequent revisions are sometimes required due to the closure of weather stations. There is no requirement for the same CWV to be used for NDM profiling and demand forecasting. It may be that as the methodologies develop in the future different CWVs will be used for each task. However, at present it is more efficient to use the same composite weather definition.

Most of the CWV parameters are calculated using NDM demand. This removes any adverse impact of step changes to non-weather sensitive DM demand. However, NDM demand data is only available from the 1996/97 gas supply year. Very little extreme cold weather has occurred in that period, so the cold weather upturn parameter is calculated using a longer history and total LDZ demand.

The following graphs illustrate how well the CWV improves the fit of the demand model.

Figure 19: Monday-Thursday demand against effective temperature

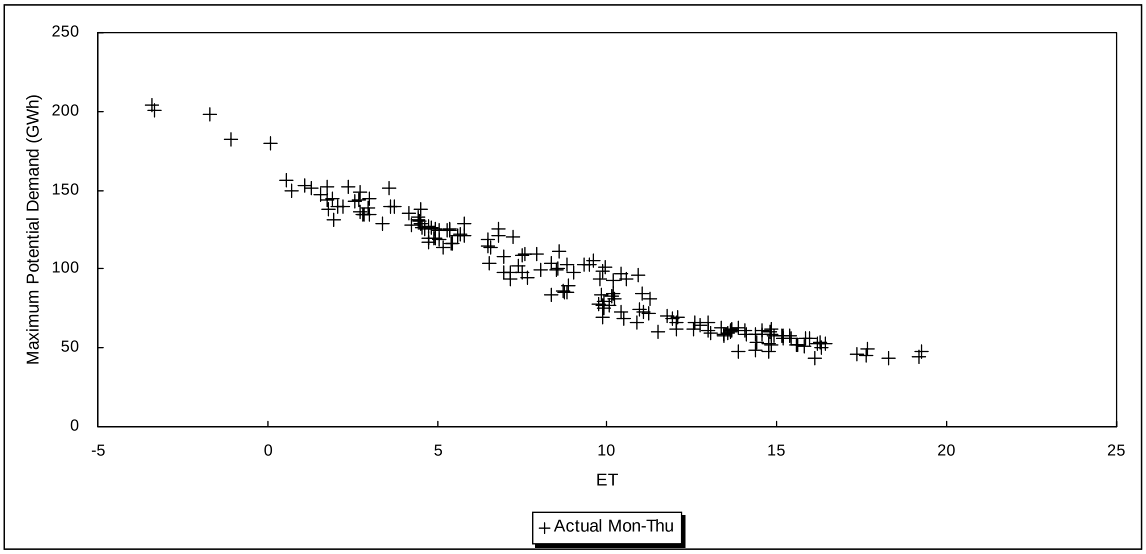
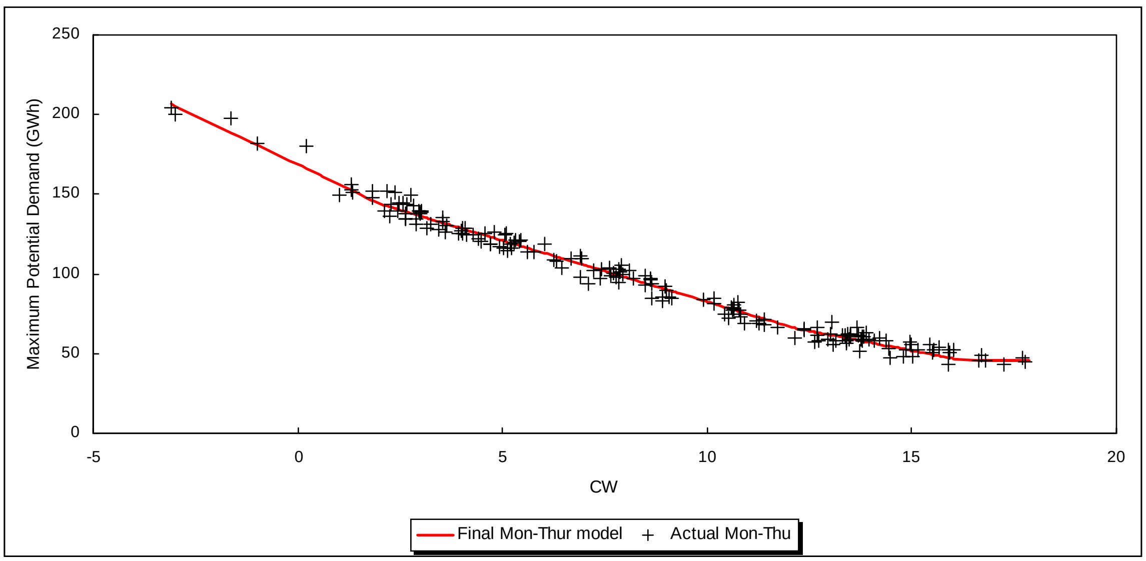
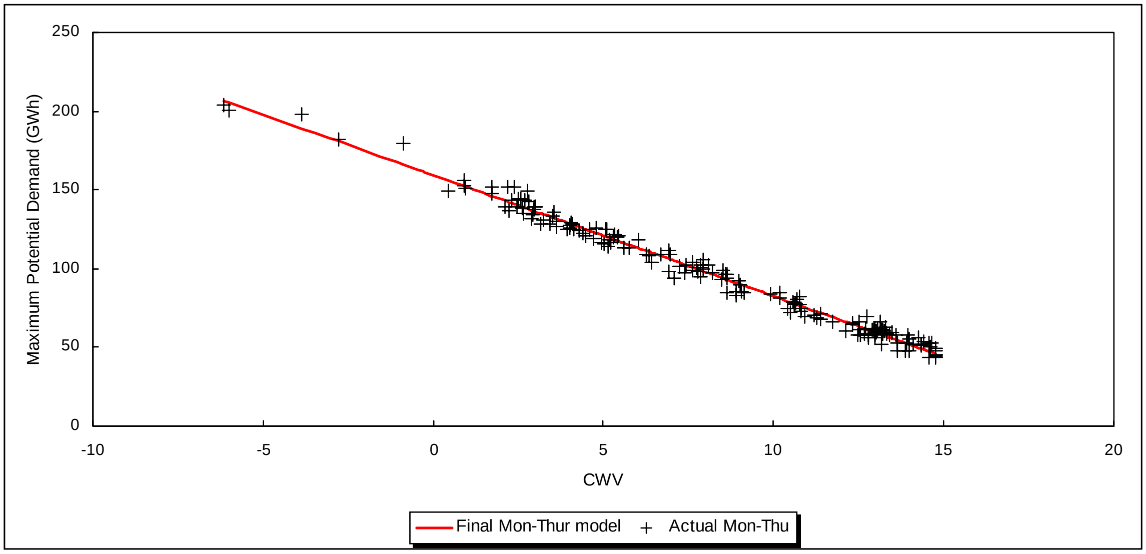


Figure 20: Monday-Thursday demand against CW



At this stage (figure 20) combining temperatures, wind speeds and a seasonal normal profile has reduced the scatter in the demand/weather relationship but cold weather upturn and warm weather cut offs have not yet been applied. The weather station used in this example is on top of an office building and is affected by the heat from the building in very cold weather. The cold weather upturn parameter compensates for this effect by multiplying the composite weather below a threshold by a constant value. This has the effect of stretching the weather demand relationship below the threshold value so that the change in demand for a one-degree change in the composite weather variable is the same above and below the threshold. Similarly, the composite weather above a threshold is adjusted to compensate for reduced weather sensitivity in warm weather. A warm weather cut off is applied at the point where there is no further weather sensitivity.

Figure 21: Monday-Thursday demand against CWV



This graph shows that with cold weather upturn and warm weather cut offs applied the CWV gives a very good linear relationship with LDZ gas demand.

4.2 Weather Data used in Simulations

National Grid has a database of daily composite weather variable values going back to 1st October 1928, for each LDZ. These are used in a simulation to derive 1 in 50 load duration curves and the 1 in 20 peak day. For analysis carried out in 2007, 78 gas years of daily weather data were used in the simulation (i.e. from 1st October 1928 to 30th September 2006). The number of years used in the simulation is advanced by one each year. Consequently, the analysis undertaken in 2006 used 77 years of data and the analysis undertaken in 2005 used 76 years of data. For average conditions the simulations now use a fixed 17-year period from October 1987 to September 2004.

4.3 National CWV

CWV parameters are optimised for each LDZ. A national CWV is calculated as a weighted average of the LDZ CWVs. The weights are updated every 5 years to coincide with the review of seasonal normal weather. The weights reflect the level of gas demand in each LDZ.

5. Annual Demand Forecasting

5.1 Annual Demand Forecasts

Annual demand forecasts, for the next ten years, are required by Standard Condition 25 of National Grid's Gas Transporter Licence, and Section O of the UNC. These forecasts are published annually in the Ten Year Statement, available from http://www.nationalgrid.com/uk/Gas/TYS/ .

5.2 Data Sources

A number of different sources of information provide the data used to calculate the annual demand forecasts. These include

1 Weather corrected demand, historical gas demand adjusted to the demand that would be expected in seasonal normal conditions.

2 Feedback on the previous year's forecasts from Shippers, Suppliers and consumers through the Transporting Britain's Energy (TBE) consultation.

3 BERR (Digest of UK Energy Statistics (DUKES) and Quarterly Energy Prices publications):
Annual gas demand by load type
Indices of retail gas prices relative to GDP deflator
Indices of real price of gas (industry) excluding climate change levy

4 Commercial sources for economic indicators:
Household numbers
Household disposable income
Gross Value Added in the industrial and commercial sectors
Fuel price forecasts
Energy forecasts
Forward markets

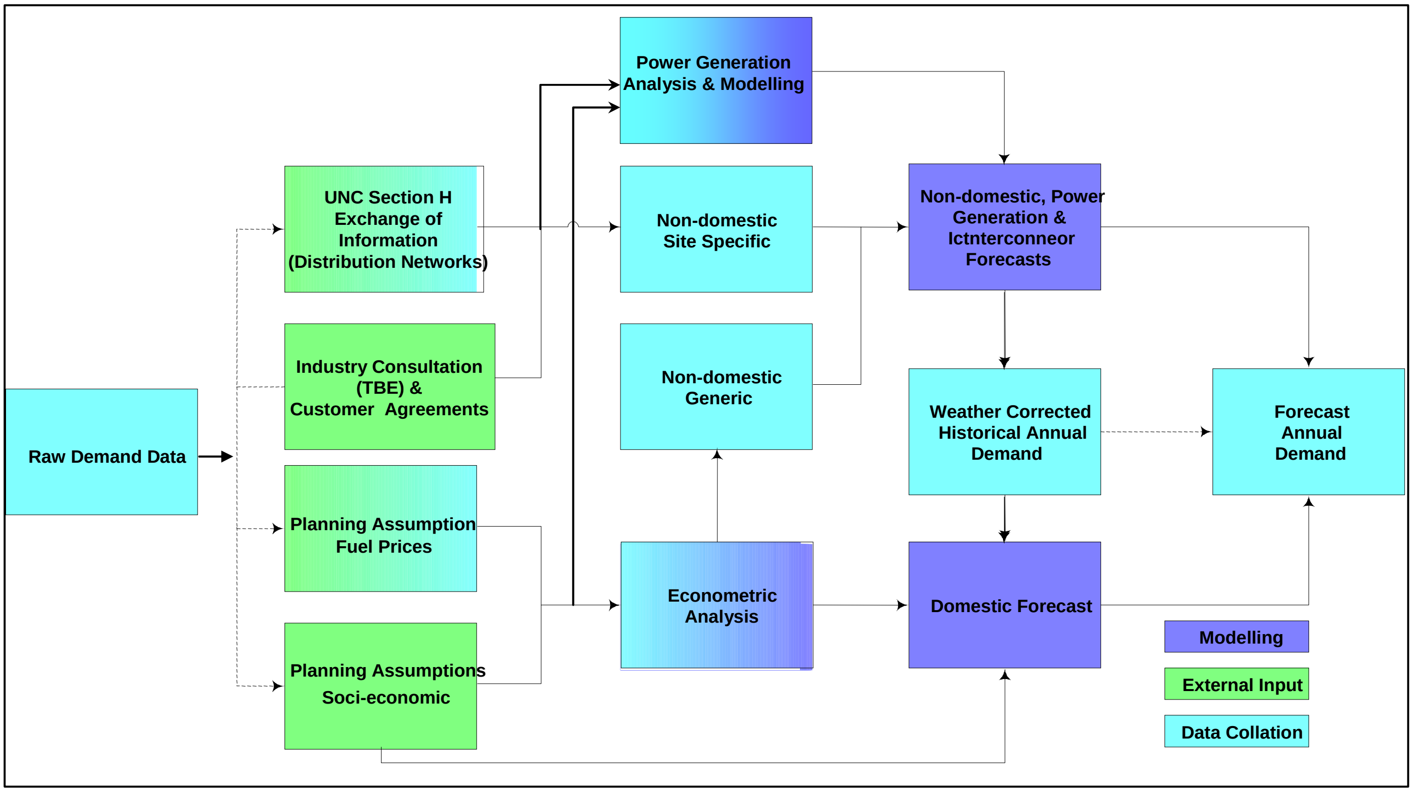
5 Distribution Networks provide useful information on changes expected within the LDZs such as new load enquiries and changes to existing large loads

6 Publicly available information from DEFRA on future plans for energy conservation in the domestic sector.

5.3 Methodology

The development of annual gas demand forecasts utilises a number of techniques, from econometric modelling to an assessment of individual load enquiries. Our forecasts are also benchmarked against the work of a number of recognised external sources, such as BERR. Figure 22 illustrates the annual demand forecasting process.

Figure 22: Annual demand forecasting process



To gain a better understanding of how these assumptions are utilised and the modelling approach adopted it is necessary to consider the LDZ and NTS processes separately.

5.3.1 LDZ Modelling

LDZ demand is split into four market sectors according to load size and supply type (i.e. firm or interruptible). For each sector, models have been developed that make allowance for economic conditions, local demand intelligence, new large load enquiries, relative fuel prices, potential new markets and other factors, such as the Climate Change Levy, that could affect future growth in demand. By adopting this approach we are able to take account of varying economic conditions and specific large loads within different LDZs. Economic indicators vary by load type category but gas demand is modelled in load size categories. For the purposes of econometric modelling the load categories are mapped to the load bands as follows:

	Domestic	Commercial	Industrial
NDM 0-73 MWh pa	100%	0%	0%
NDM 73-732 MWh pa	15%	85%	0%
>732 MWh pa Firm	0%	49%	51%
Interruptible	0%	0%	100%

A number of criteria are used to select the most appropriate econometric model for each load band. These are

1. Statistical criteria – quantitative
   Fit of model: Adjusted R square statistic and root mean square percentage residual error for 1987-2005
   Forecast error: Root mean square percentage residual error for 2001-2005 using a forecast model derived from data to 2000
   Stability of model: Parameters for last 5 years compared to parameters fitted to first 14 years and similarly for the first 5 years to last 14 years using the two-tailed statistical significance test.
   Significance of parameters: The appropriate p-value is used for this test.

2. Economic and other criteria – qualitative
   Economic plausibility: Models are rejected irrespective of the statistical fit if the resulting model is seen to be economically implausible.

In the case of the >732 MWh pa Firm and Interruptible load bands, historic demands for specific large loads are excluded from the econometric modelling and dealt with separately using information from the Distribution Networks.

For each load band, a baseline forecast is produced using the econometric model and is adjusted using the intelligence about large LDZ loads and, for the 0-73.2 MWh pa band, projected domestic energy conservation improvements beyond historic levels, based on a judgement balanced between government projections and historic evidence from the econometric models of domestic energy efficiency improvements not leading in the long run to reductions in household gas consumption.

5.3.2 NTS Modelling

Historically, NTS demand (i.e. loads with their own connection to the NTS) was limited to a small number of large industrial sites and chemical works. However, with the advent of gas-fired power generation and interconnectors to Ireland and Continental Europe, a new methodology had to be developed. This methodology can best be described by looking at each sector in turn.

5.3.3 Power Generation

The power generation forecast consist of two main elements: firstly, the capacity available to generate; and, secondly, how frequently this capacity is used.

The first element is developed by combining information from connections requests and load enquiries with feedback received from the Transporting Britain's Energy (TBE) consultation process and a range of commercial sources. In addition, the influence of commercial arrangements, Government policies and legislation are taken into account when forecasting which power stations will be built or closed.

To complete the second element, a model has been developed to forecast electricity generation by fuel type and individual station over the forecast period. The modelling process takes account of station specific operating assumptions, constraints, availability and costs. Different ranking orders are applied for each 3 month period of the forecast to reflect our best view of the ranking order most likely to predominate during the period. The relative positions of most fossil fuel stations in each 3-month ranking order are based on our best view of the relative fuel-related costs per net unit of electricity generated. High and low power generation gas demand forecasts are also produced using different fuel price assumptions. The high forecast is calculated using ranking orders where gas is mainly base load generation (low gas price relative to coal), the low where gas is mainly marginal generation (high gas price relative to coal).

The resultant power generation forecast, encompassing all fuel types is then used to derive a split between gas-fired stations supplied by the NTS (or embedded within the DNs) and those with their own dedicated pipeline delivering supplies direct from the beach.

5.3.4 Exports

Forecast flow rates to and from Europe via the Interconnector are based on an assessment of relative gas prices between Europe and the UK, allowing for the seasonal variation of gas prices and resultant price differentials.

Exports to Ireland are derived from a sector-based analysis of energy markets in Northern Ireland and the Republic of Ireland, including allowances for the depletion and development of indigenous gas-supplies, feedback from the TBE process, commercial sources and regulatory publications.

5.3.5 Industrials

The production of forecasts within this sector is dependent on forecasts of individual new and existing loads based on recent demand trends, TBE feedback, load enquiries and commercial sources.

6. Daily Demand Modelling

The composite weather variable greatly simplifies the structure of the weather/demand model. The consistency of CWV parameters for up to 5 years helps to reduce volatility in demand models from year to year. The simplicity of the demand models makes it easier to combine models for different load bands and to scale the models to annual demands.

6.1 Load Bands

Gas consumers are grouped by load band and whether they are firm or interruptible. Load bands are categorised by the expected consumption of each gas consumer in a seasonal normal year. They are not categorised by type of customer. The only exceptions to this are the models for the 0-73.2 load band, which are created from domestic consumers only. Regression models are calculated for the following load bands. The NDM load band models are calculated by aggregating the NDM profile models produced annually, as shown in the following table.

AQ Range Modelled	**Load Band Name**	**Calculation**
0-73.2	NDM1: Firm 0-73.2	0-73.2 model
73.2-293	NDM2: Firm 73.2-732	Weighted average of 73.2-293 model and 293-732 model
293-732		
732-2196	NDM3: Firm 732-2196	732-2196 model
2196-5860	NDM4: Firm 2196-5860	2196-5860 model
5860-14650	NDM5: Firm >5860	Weighted average of models for 5860-14650, 14650-29300, 29300-58600 and >58600 load bands
14650-29300		
29300-58600		
>58600		
	Total NDM	Total NDM daily demand in LDZ
	DM Firm >732	Total DM firm daily demand in LDZ less selected large loads
	Total Firm	Total firm daily demand in LDZ less selected large loads
	DM Interruptible	Total interruptible daily demand in LDZ less selected large loads
	Total LDZ	Total daily demand in LDZ less selected large loads

NDM profile models are calculated from daily demands for a fixed sample of customers. The LDZ models are calculated using the total daily demand within the LDZ, but selected large loads are removed where there is a step change in demand within the year, or where a specific model has been generated for that load. Historical DM data is also adjusted for known changes to the firm/interruptible split in demand. Some of the larger DM sites have demand patterns that have predictable step changes throughout the year. These sites are given individual models and demand profiles.

National demand models are calculated and processed into peak days and load duration curves, in a similar way to LDZ demand models. These produce diversified peak day demands and load duration curves. The national demand model load bands are NDM, DM Firm, LDZ firm, NTS firm, LDZ Interruptible, NTS Interruptible, total firm, total interruptible, total demand. The NTS load bands include power generation, industrials and exports to Ireland but exclude exports to Europe. Section 2.9 describes diversity in more detail.

6.2 Generic weather/daily demand regression model

The relationship between demand and the composite weather variable on a non-holiday weekday (i) is

$Demand_i = A + B * CWV_i + u_i$

where A and B are constants and u_i is an error term.

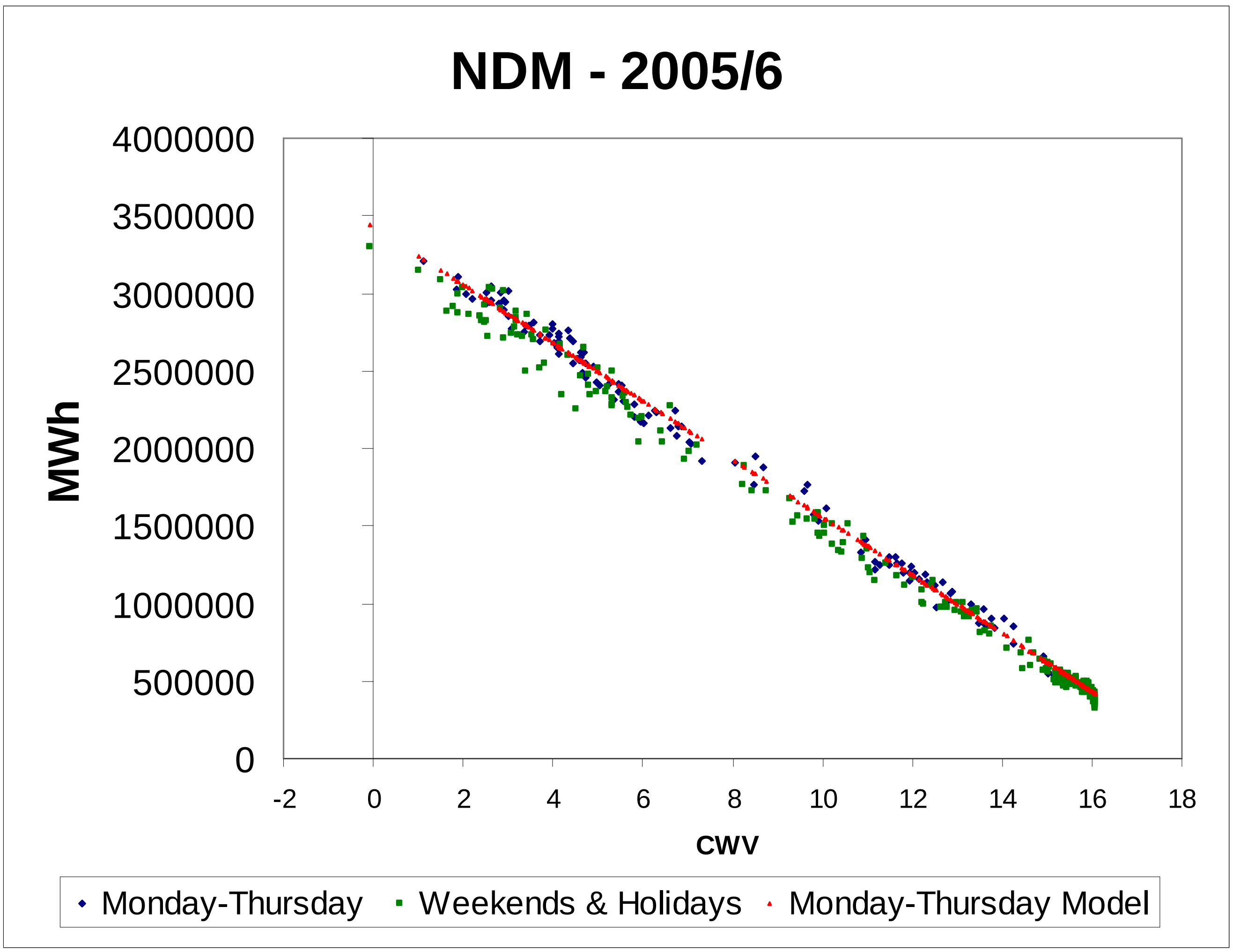
The error stream has the structure:

$u_i = p\ u_{i-1} + e_i$

where e_i is a random sample from the normal distribution with mean zero and standard deviation s.

The parameters p and s are estimated from the demand/weather data. The autocorrelation coefficient p measures the extent to which the error on a day is correlated with the error on the previous day. The standard deviation s measures the "noise" in the model.

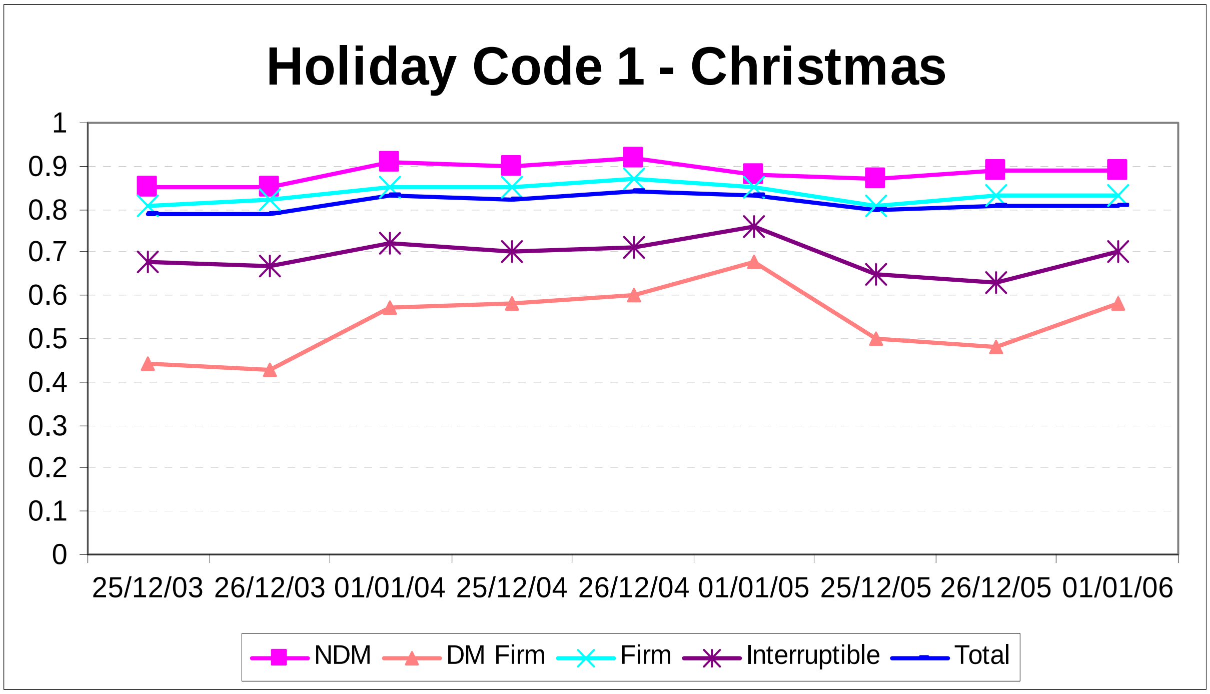
Figure 23



The NDM regression graph above shows that there is a very good fit between weather sensitive demand (such as total NDM demand) and CWV. Separate models are calculated for each of the last 3 gas supply years. These models are adjusted to give the same annual demand. The average value for each parameter is calculated. This is to minimise any volatility in model parameters that may be caused by different economic conditions or weather patterns in each year. Increasing the number of years from 3 may reduce the volatility but it increases the risk of the models becoming out of date and not representing changes in demand patterns due to changing consumer behaviour. Three years is therefore considered an acceptable compromise between these conflicting aims.

Friday, Saturday, Sunday and holiday factors are calculated as a percentage of the expected non-holiday, weekly demand as illustrated in this chart:

Figure 24



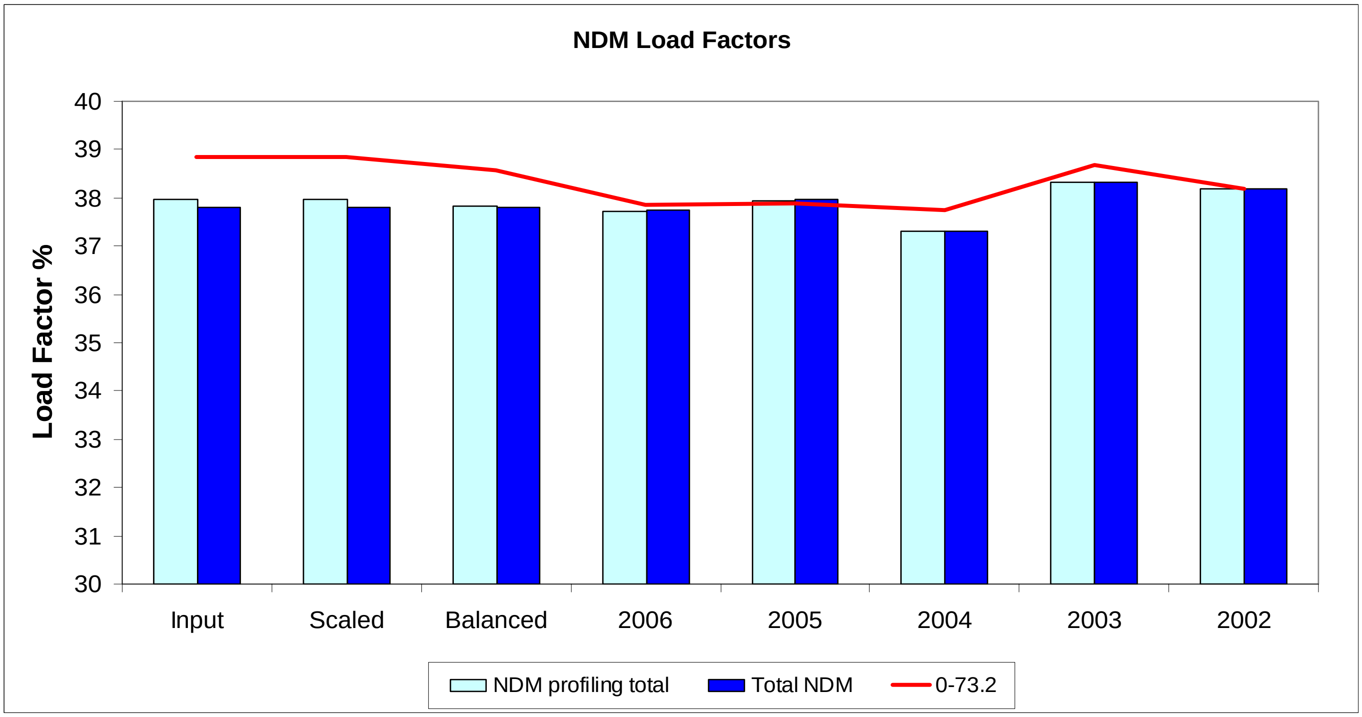
6.3 Derivation of load band models and validation

The NDM profile models are scaled up to represent the total population. The sum of these models is then compared with the NDM model. In many cases there is a good match between the parameters and so no adjustments to balance the models are required. Otherwise, the NDM profile models are scaled to add up to the total NDM model.

Finally, checks are made to ensure that holiday and weekend factors are consistent. For example, the reduction for holiday code 1, which represents Christmas Day and New Year's Day, should be greater than the reduction for holiday code 3, which represents the working days between Christmas and New Year.

The following graph shows load factors for the sum of the NDM profile models in light blue and the total NDM model in dark blue. The load factors are very similar, validating the quality of both the NDM profile and total NDM models for this LDZ.

Figure 25



6.4 Conversion to daily models

The regression models are converted to daily models before adjusting for growth in demand and changes to connected load. The regression model is

$Demand_i = A + B * CWV_i + u_i$

This is rearranged as:

$Demand_i = SND_i + B * (CWV_i - SNCWV_i) + u_i$

where SND_i is the seasonal normal demand for day i, given by:

$SND_i = A + B * SNCWV_i$

and $SNCWV_i$ is the seasonal normal value of the CWV for day i.

The non-holiday weekday model is generalised by incorporating weekend, holiday and forecast growth effects into the SND and weather sensitivity (B) terms to produce a separate model for each day of the year:

$Demand_i = SND_i + Weather\ Sensitivity_i * (CWV_i - SNCWV_i) + u_i$

6.5 Production of forward-looking LDZ daily demand models

Each LDZ load band model is scaled separately. The first stage is to calculate the connected load (see 2.11) for each day of the forecast. The connected load at the midpoint of each year is set consistent with the forecast annual demand. Linear interpolation is then used to calculate the connected load on all the other days of the year.

A profile of demand is calculated from the regression model and the seasonal normal composite weather divided by the average daily demand. Combining the profile with the forecast connected load produces the seasonal normal demand part of the daily forecast model.

The weather sensitivity term is scaled by connected load forecast divided by regression model average daily demand.

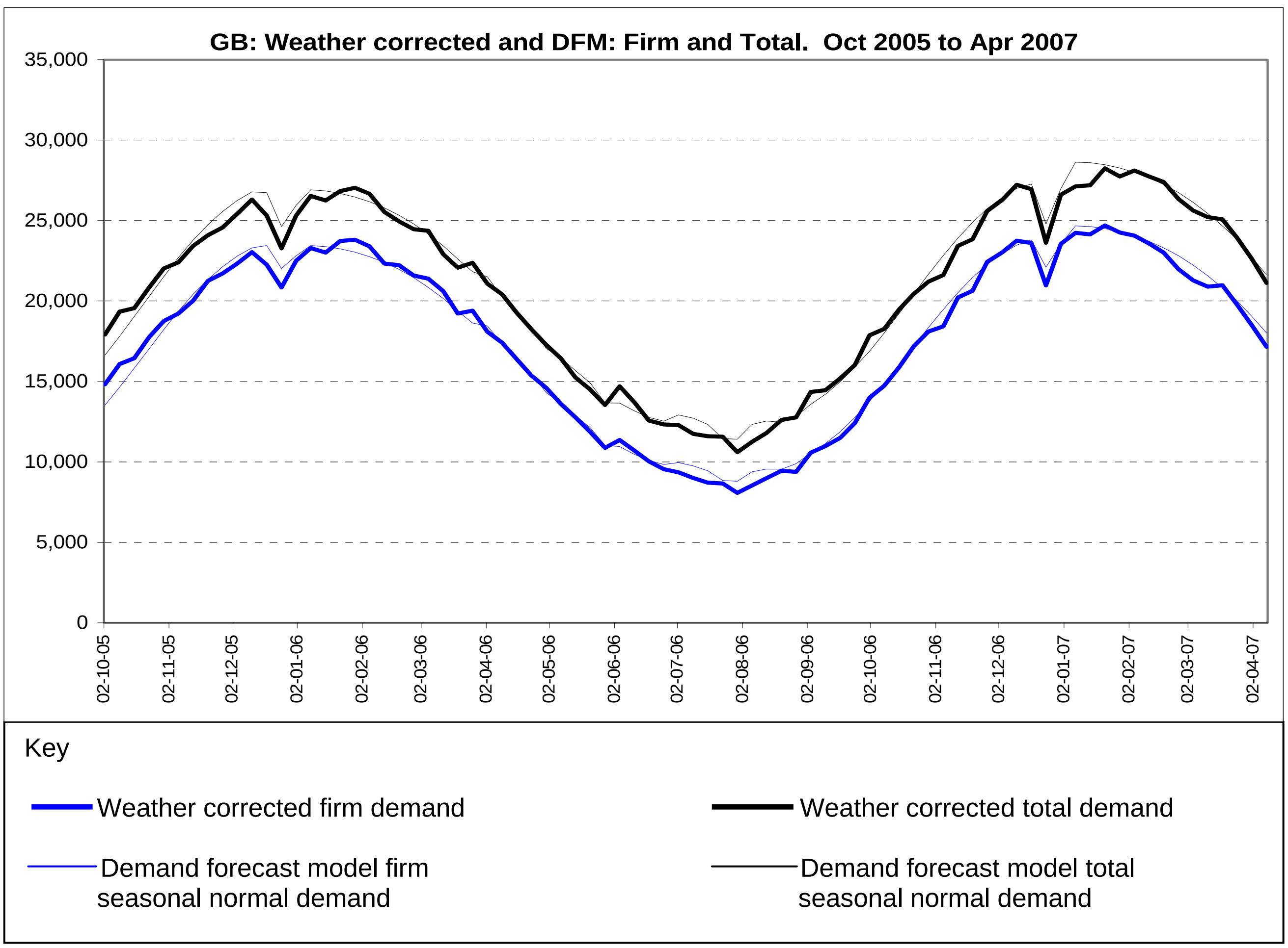
Changes in connected load, due to step changes in large load demand, are excluded from the generic DM load bands. These large loads are treated as separate individual load bands. Total DM Firm and DM interruptible load band models are created by adding the generic DM load band models to the individual large load models.

A total NDM model is created from the sum of the NDM load band models, total firm from the sum of total NDM and firm DM models, and total LDZ from the sum of total firm and DM interruptible models.

The annual demand forecasts produced by the model are compared to those input into the model and, if necessary, the interpolated connected load forecasts adjusted to obtain a better match. An historical 18-month period is used to validate the fit of the models.

This example compares weather corrected (WC) demand in bold, with the seasonal normal profile from the demand forecast model (DFM) for a single LDZ. Firm demand is in blue and total demand in black.

Figure 26



6.6 NTS site daily demand models

Demand models are created for every load connected to the NTS and for a small number of LDZ large loads. These models consist of a regression model with the same parameters and calculated in the same way as the LDZ models plus a profile adjustment. The profile adjustment consists of a date from which the profile changes and a multiplier to adjust the profile. This enables unique site profiles, for example sugar beet factories, and demand response reductions to be accommodated. Generic models are created for new sites. These models are scaled to the forecast connected load and then converted to daily models with a seasonal normal and weather sensitivity term using similar methodology to the LDZ forecasts.

Profile adjustments are manual estimates based on historical observations. An initial estimate is made. Forecasts are produced for the base year and compared with actual demand. This ensures that when annual, regression and profile elements of the forecast are combined the desired results are achieved. If necessary adjustments are made to the profiles and the process repeated.

6.7 National demand models

The LDZ modelling process is repeated to produce a national LDZ demand model calculated from the total LDZ demand and the national CWV. The forecast daily demand models derived from this process are added to the NTS site daily demand models to produce a National daily demand model. The peaks and load duration curves derived directly from the national models are different from those calculated by adding up the individual LDZ and NTS peak and load duration curve forecasts. This difference is called diversity and is discussed in section 2.9. These two different ways of producing national forecasts are summarised in appendix 3.2.

7 Load Duration Curve Production

7.1 Process of demand simulation

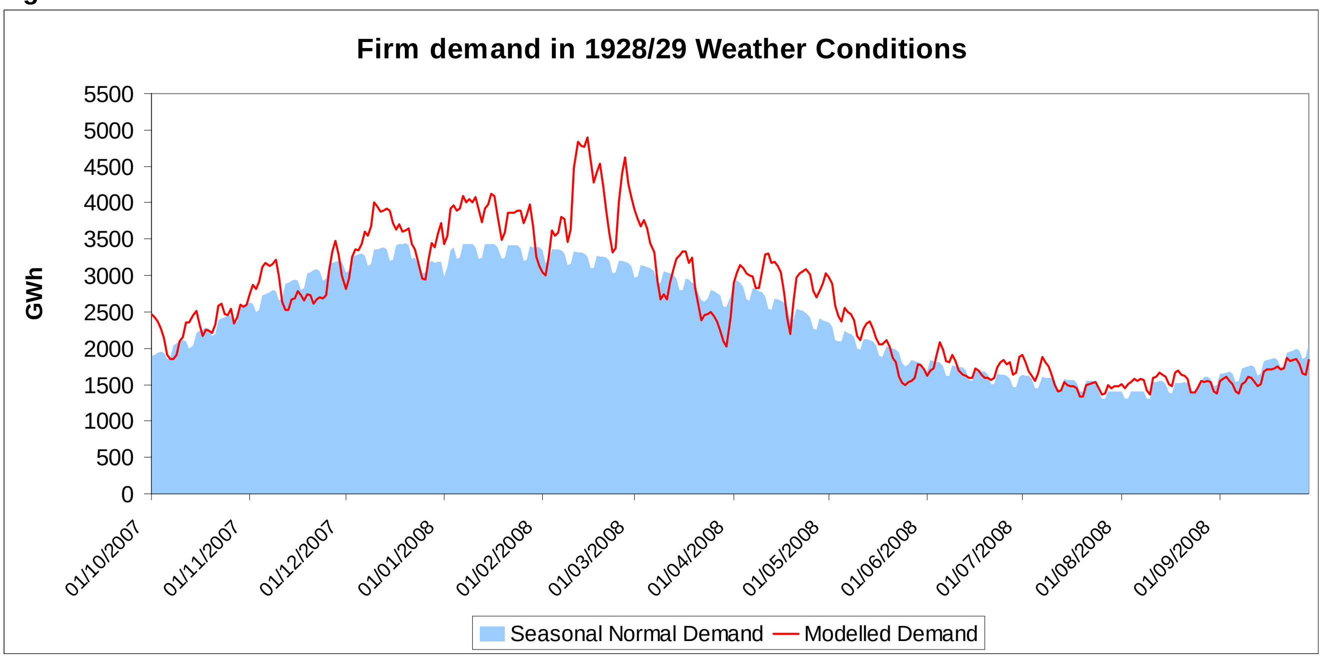
The simulation program creates an estimate of what demand would be in a particular gas year if historical weather was to be repeated in exactly the same order it originally occurred.

Simulated Demand $_{yi}$ = SND $_i$ + (CWV $_{yi}$ – SNCW $_i$) + u $_i$

where y is the supply year and i is the day of the year.

The daily demand models are for a single load band and supply year. They are combined with daily composite weather for a single supply year in exactly the same order as the weather occurred in history. This ensures that the length and severity of weather patterns are accurately reflected in the simulation.

Figure 27



This process is then repeated for each of the x years in the weather history. Rather than generating just one series of x years of simulated daily demands for the gas year, the simulation generates 28 such series. These series are constructed by varying the error terms and the historic CWV values as follows:

Seven different simulations are generated, by shifting the historic CWV values forwards by one, two and three days, and similarly backwards, in addition to the base run. This ensures that the extreme CWV values occur on every individual day of the week in the overall simulation.

For each positioning of the historic CWV values two independent sets of random error terms are generated, and for each of these sets a corresponding antithetic error stream is generated as follows:

random error, $u_i = p\, u_{i-1} + e_i$

antithetic random error, $u^*_i = p * u^*_{i-1} - e_i$

The use of antithetic random error terms is a variance reduction technique, which minimises the chance of bias in the overall set of results.

This approach therefore yields 7*2*2 = 28 sets of simulated demands, each comprising x gas years.

7.2 Calculation of the 1 in 20 peak day

For each of the 28 simulations there are x maximum daily, simulated demands (one for each gas year in the historic weather database). A Gumbel-Jenkinson distribution is fitted to these x values. This distribution is designed for fitting to extreme events and is often used in analysis of extreme weather. Similar results can be obtained by using a Weibull distribution.

A 1 in 20 peak day value is calculated for each of the 28 sets of simulations from the 95 percent value from the distribution. The 28 1 in 20 peak day estimates are averaged to give the 1 in 20 peak day. Note that only the maximum daily demand in each simulated year is considered. Thus in a very cold winter when the 1 in 20 peak demand is exceeded, there may be more than one day when demand exceeds the 1 in 20 value.

The following two graphs are derived from all the years in one set of simulations of firm demand. Figure 28 shows the shape of the distribution of the maximum demands for each year. Figure 29 shows the cumulative distribution for this data (blue) compared with the fitted Gumbel-Jenkinson distribution (red). The Y-axis shows the probability of maximum demand exceeding the value on the X-axis. The horizontal lines are the 1 in 20 peak day and the 1 in 50 level, which becomes day 1 on the 1 in 50 load duration curve.

Figure 28

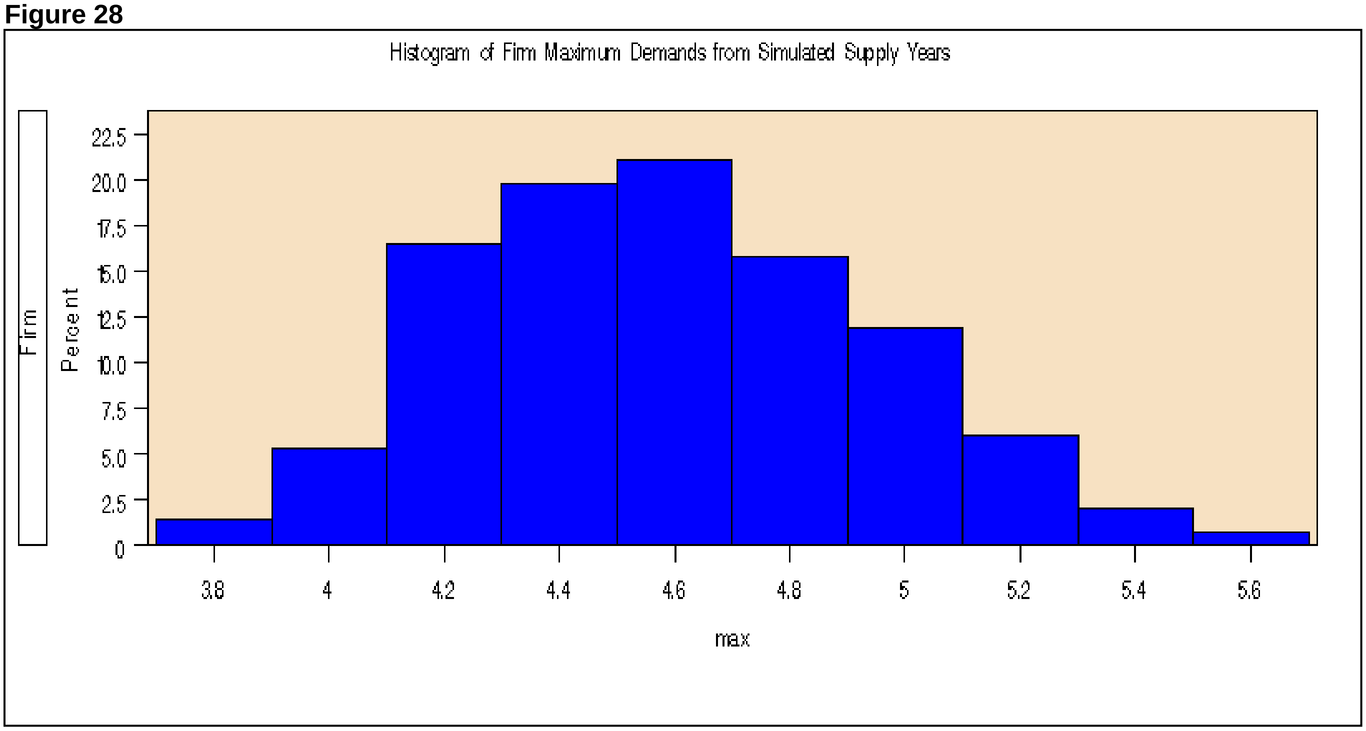
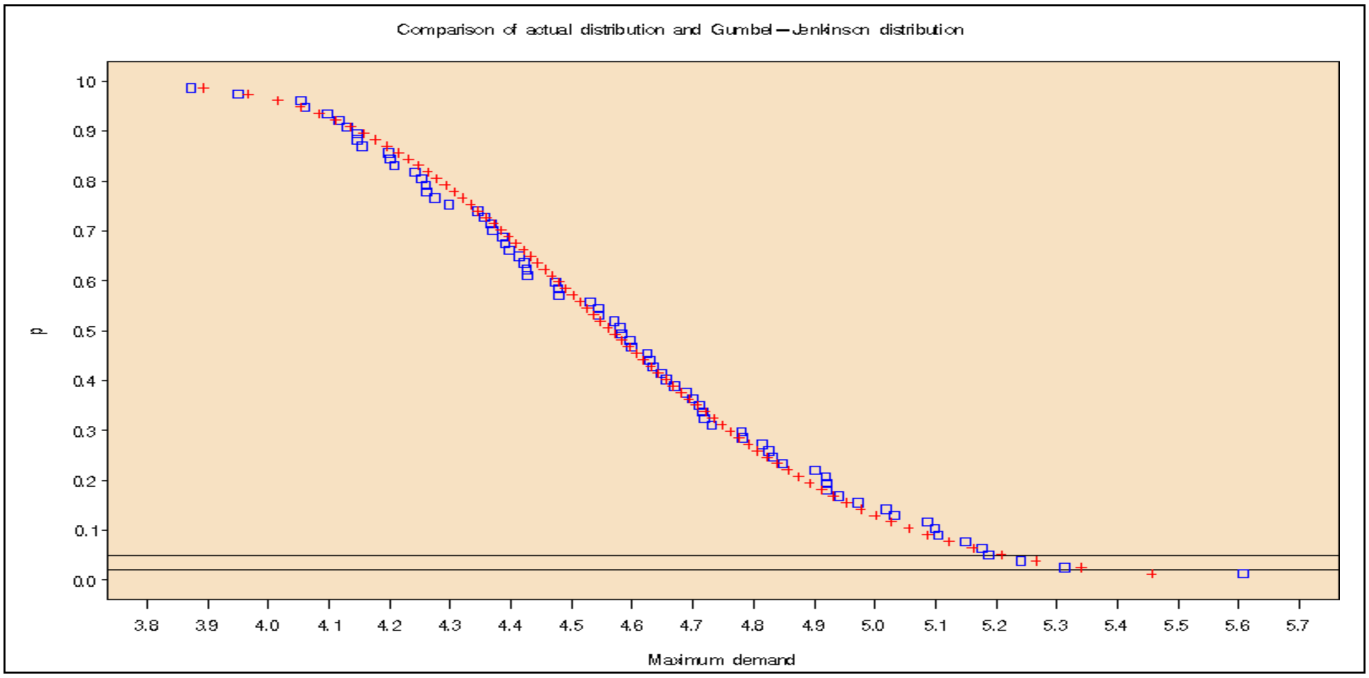


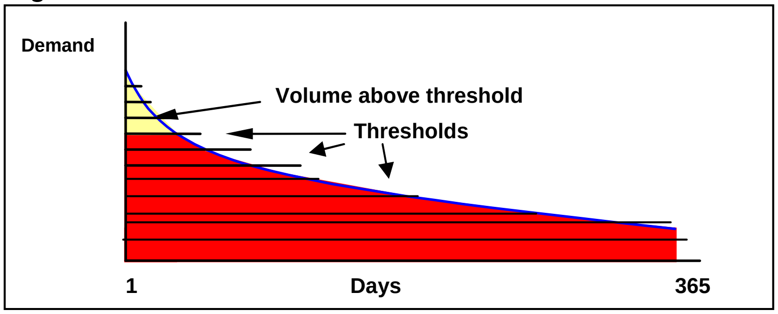
Figure 29



7.3 Calculation of the 1 in 50 Load Duration Curve

A load duration curve is designed to provide an estimate of the total demand in a gas year above any specific demand threshold. A number of thresholds covering the full demand range are required for the construction of the 1 in 50 load duration curve.

Figure 30



1 in 50 values of volumes above thresholds are calculated separately for each threshold by fitting a cube-root normal distribution to the volumes above each threshold from the simulations described in 7.1. Day 1 of the 1 in 50 load duration curve is the 1 in 50 peak day demand calculated from the same distribution that produces the 1 in 20 peak day (see section 7.2). The load duration curve is then produced by joining these values. A detailed description of the methodology is described in appendix 1.

7.4 Calculation of the Average Peak Day

The average peak day demand is the mean of the maximum daily demands in each simulated year, described in section 7.1. It is the average highest demand day in a year.

7.5 Calculation of the Average Load Duration Curve

The average load duration curve is calculated from the average volume above the threshold. This is more severe than the 1 in 2 load duration curve because the volume above a threshold has a skew distribution. The simple average of the volumes is larger than the middle ranking or median volume. Thus the average load duration curve represents a more severe winter than does the 1 in 2 duration curve and day 1 on the average load duration curve is a more severe day than the average peak day.

7.6 Use of simulated load duration curves to calculate load duration curves for different load categories

This section describes how the simulated load curves are adjusted to create the final load duration curves. Simulation works best for market sectors with a high level of weather sensitivity. The NDM, firm and total market sectors all have significant weather sensitivity. Other market sectors, such as DM Firm and interruptible, can be calculated by difference. However, calculating a small, flat LDC from the difference between two large weather-sensitive LDCs can result in a load curve that is non-monotonic i.e. where demand does not decrease down the load curve.

The other main reason for adjusting LDCs is to ensure that the daily values on the average curve do not exceed the daily values on the severe curve. This can happen when the slope between the last two thresholds of the severe curve is steeper than the slope between the last two thresholds of the average curve. Extrapolating the curve to day 365 can result in the two curves crossing over.

These adjustments are developed over time in response to any issues that are raised each year. Therefore these notes represent a snapshot of the methodology used for the 2007 forecasts and may be slightly different from the methodology in other years. Appendix 3 describes the calculations in more detail.

7.7 Information produced

Appendix 3 summarises the typical load bands for which peak day demands and load duration curves are calculated. It also identifies which information is produced directly from the methodology described above and which information is calculated by difference. This reflects the priorities of the main users of the forecasts.

The 2005 forecasts did not include demand response. This was modelled separately, and reasonably accurately, for the 2005/6 Winter Outlook Report. However, feedback from operational users and from Ofgem’s consultants Frontier Economics, requested a full set of demand forecasts with demand response incorporated. Demand response is a function of the supply demand balance. With so many uncertainties affecting the balance between supply and demand it is not possible to predict on a daily basis what the demand response will be. The 2006 forecasts contained a restricted and unrestricted set of forecasts with the restricted set incorporating an element of demand response. For 2007 this approach has been developed further due to the observation that during 2006/7 actual demand fluctuated between restricted and unrestricted levels. Most demand response has been in the power sector with minimal impact in the industrial and commercial sectors. Therefore a single set of forecasts has been produced for the non-power market sectors. For power generation 3 sets of forecasts have been produced. High and low power generation forecasts have been produced for comparison with our standard forecasts. This standard forecast is not a central case but a best view of the likely generation ranking order that will prevail over each 3-month period of the forecasts. The high forecast is calculated from a ranking order where gas is mainly base load generation, the low where gas is mainly marginal generation.

7.8 National diversified

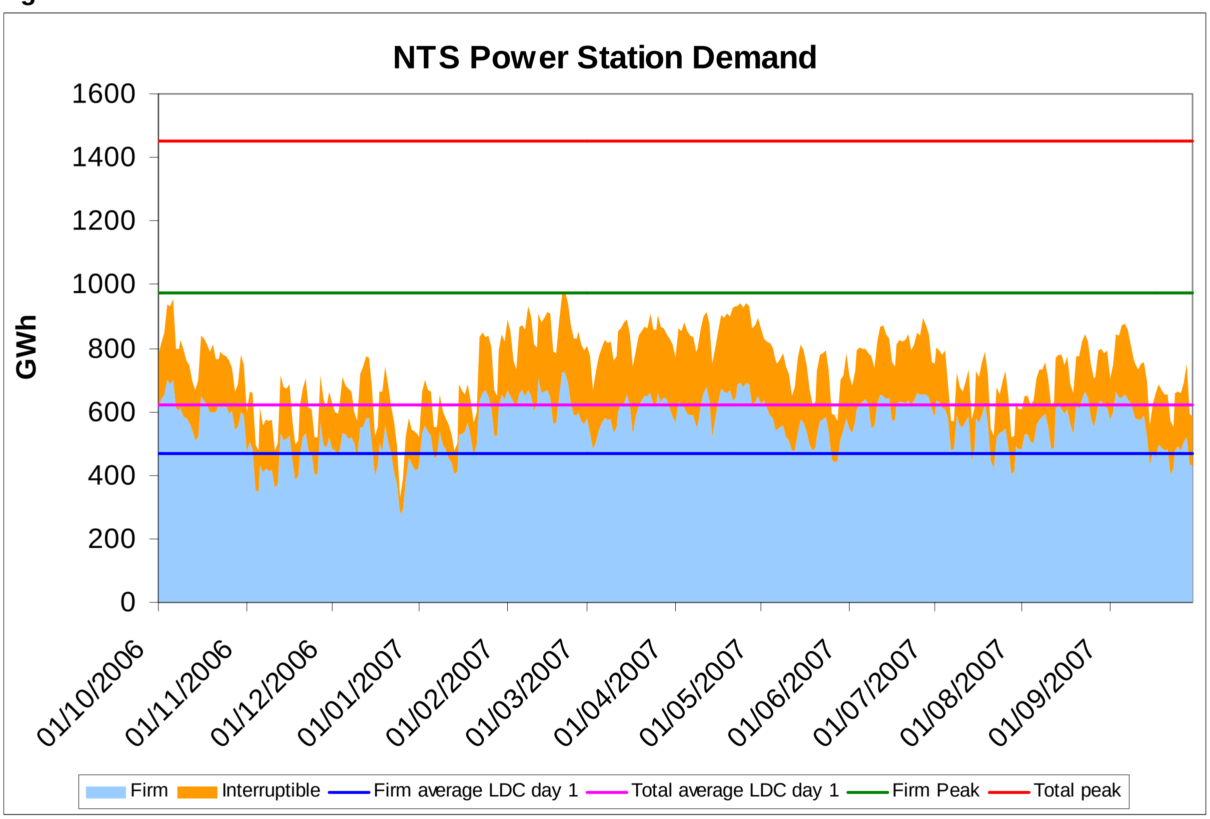
Peaks and load duration curves are simulated for firm LDZ, total LDZ, national firm and national total load bands. Interruptible demands are calculated by difference. The NDM load band split is calculated by scaling the sum of the undiversified LDZ values by the weather sensitivity of each load band. Forecasts for individual NTS sites are obtained as follows:

1) Sort National seasonal normal demand in descending order.
2) Reorder the NTS site models in the same order as the National seasonal normal demands.
3) Combine the national CWV average and severe duration curves with the sorted daily demand models.
4) Calculate the demand for each site at average and severe weather conditions.
5) Set the peak value to be the same as day 1 on the severe curve.
6) Smooth the curves.
7) Add the industrial site demands to obtain the diversified industrial firm and total peak day forecasts and load duration curves.
8) Calculate NTS shrinkage using the undiversified shrinkage factor.
9) Calculate diversified power generation demand as total minus shrinkage, industrial sites and exports to Ireland.

7.9 Choosing the most appropriate forecast

If the information is required for a specific purpose then an alternative methodology may be required that focuses on the specific needs of that project. For example, the contribution of the power generation sector to total gas demand can be estimated by taking a proportion of the diversified NTS load duration curve, but this would not be appropriate for an analysis of the behaviour of the power station market. The different values are illustrated by figure 31. The blue shaded area shows firm power station demand connected to the NTS. The orange shaded area is interruptible demand. The green line is the sum of the contracted firm peaks. This value is used in the undiversified 1 in 20 peak day. The red line is the sum of the firm and interruptible peak demands. The difference between the red and green lines is the amount of potential demand that would be interrupted on a peak day, not the actual demand. The blue and pink lines are the diversified firm and total average peak day demands. These give a reasonable indication of the average level of power generation demand in the winter but do not reflect maximum NTS power station demand to be expected in an average year.

Figure 31



8. Forecasting Accuracy

It is not possible to calculate the accuracy of peak demand forecasts directly because a 1 in 20 peak day demand should only occur 1 year in twenty. Even in that very cold year the severity is unlikely to be exactly 1 in 20. The nearest to an actual peak day is the base year forecast peak day. A base year forecast is a forecast for the most recent winter. The forecasts produced in May 2007 included a peak day forecast for the 2006/7 winter. This is the base year forecast for 2006/7 against which all previous forecasts can be compared. Annual demand forecasts can be compared against weather-corrected actual demand.

For these to be reasonable comparisons the underlying demand models have to be validated. This is done at several stages of the process.

1. Figure 25, on page 34, shows a comparison of the NDM profiling models with the NDM models. These are developed independently, from different demand data, and therefore provide a good comparison.

2. Figure 26, on page 35, is an example of the validation of the daily demand models. The seasonal normal element of the demand model is compared to actual demand weather corrected by the weather sensitivity element of the demand model. Comparisons between seasonal normal demand forecasts and weather-corrected demand are also made throughout the year.

3. A forecasting accuracy report is provided annually to Ofgem. The following table shows 1-year ahead and 3-year ahead forecasting accuracy since 1993. Over this time total throughput has grown by over 70%. The error over period figures show over forecasts as positive numbers and under forecasts as negative numbers.

	LDZ Annual	LDZ Peak	Throughput Annual	Throughput Peak
1-year average absolute error	1.19%	1.33%	1.72%	1.43%
1-year error over period	0.07%	0.60%	-0.04%	0.39%
3-year average absolute error	5.18%	3.22%	5.16%	4.01%
3-year error over period	2.11%	1.50%	-0.52%	-0.03%

9. Contact

If you have any questions please contact, via email,

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Appendix 1: Calculation of the 1 in 50 Load Duration Curve

A load duration curve is designed to provide an estimate of the total demand in a gas year above any specific demand threshold. A number of thresholds covering the full demand range are required for the construction of the 1 in 50 load duration curve.

Figure A1

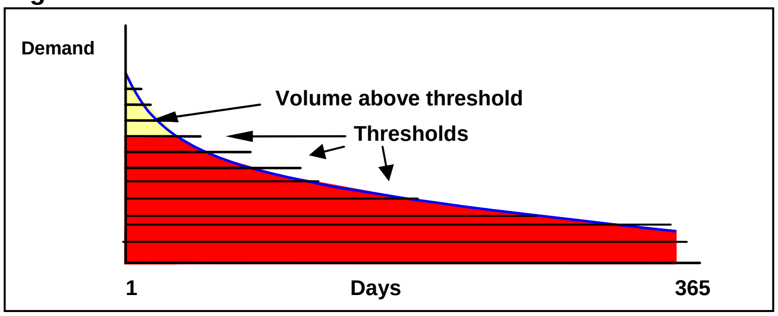


Figure A2: Load Duration Curve Methodology Process Diagram

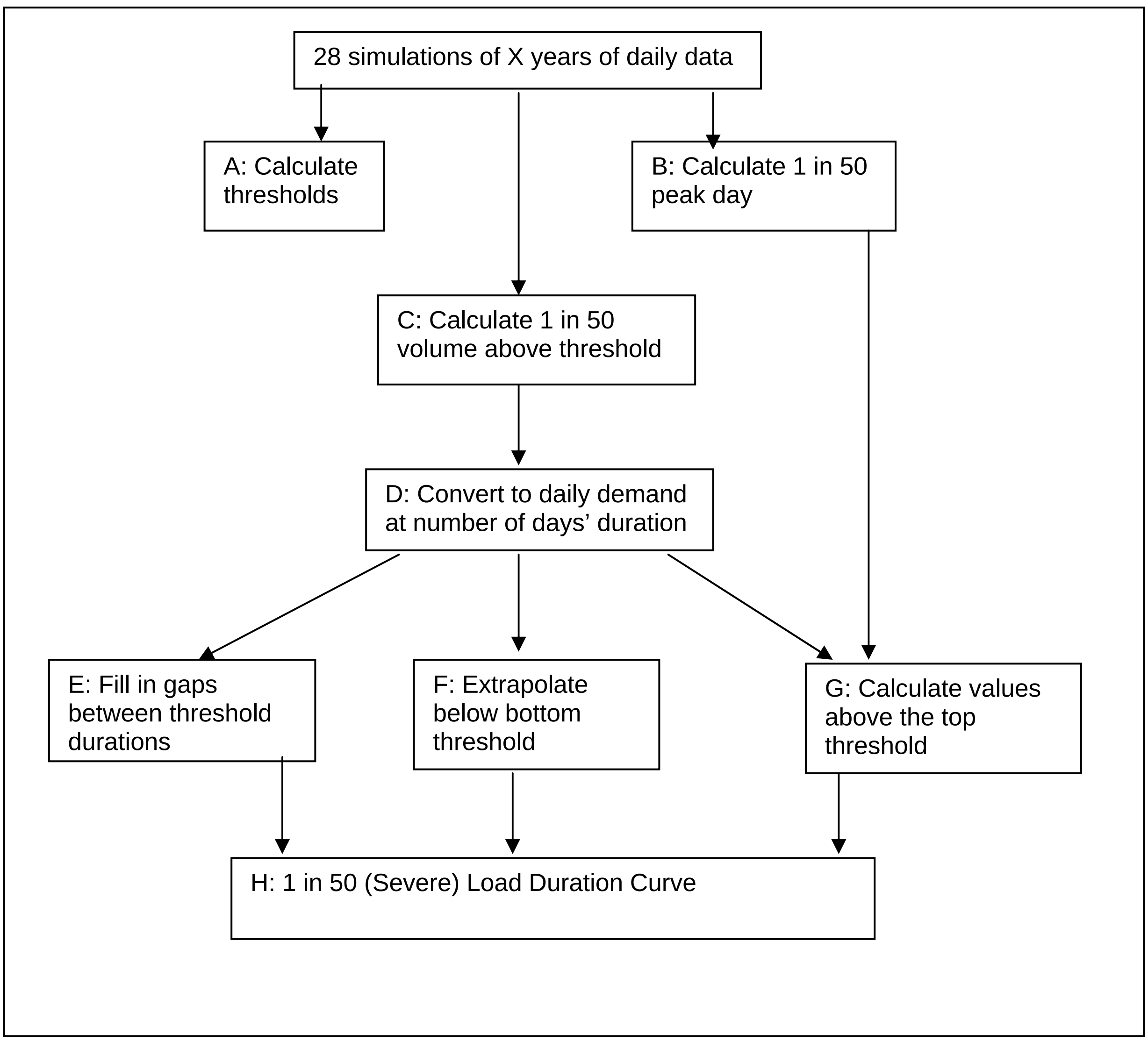
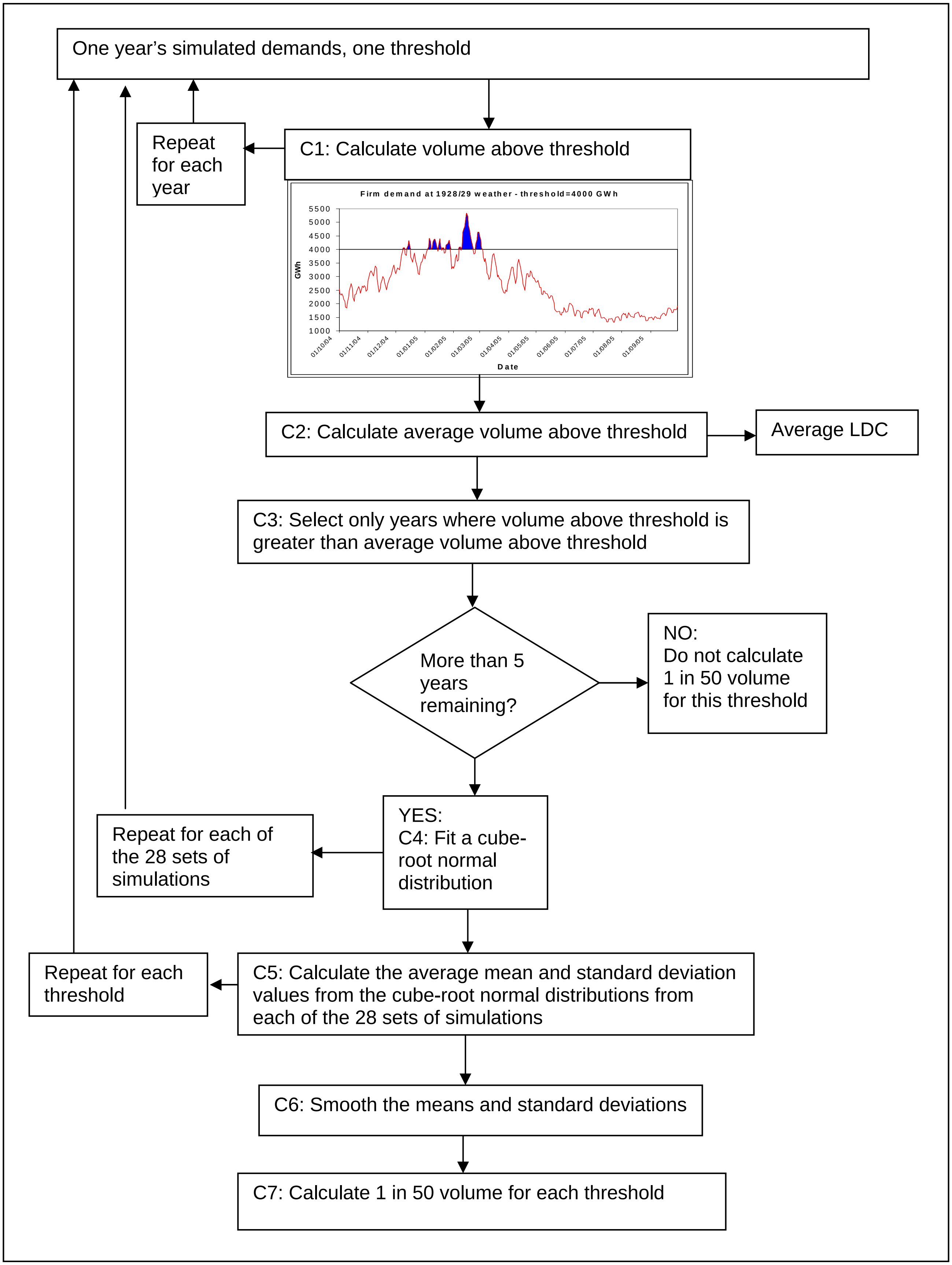


Figure A3: Volume above threshold process diagram



Step A: Calculate thresholds

Thresholds are required that cover the whole range of demands. The top threshold is set to demand expected on a cold winter weekday and the bottom threshold to demand expected on a warm summer weekend. The remaining thresholds are spaced between the top and bottom thresholds. The high demand thresholds are closer together than those lower down the curve. For example the top threshold can be set to the demand expected on a mid January weekday under 1 in 20 CWV conditions. If the demand model was

Demand = 4456 – 213 * (CWV – 3.34) and the 1 in 20 CWV was –3.51 then the top threshold would be
4456 – 213 * (-3.51 – 3.34) = 5915 GWh

Similarly, the bottom threshold could be calculated from the demand model for an August Saturday under maximum SNCWV conditions.

Demand = 1701 – 185 * (CWV – 15.38) at a maximum CWV value of 15.61 gives a bottom threshold of
1701 – 185 * (15.61 – 15.38) = 1658 GWh

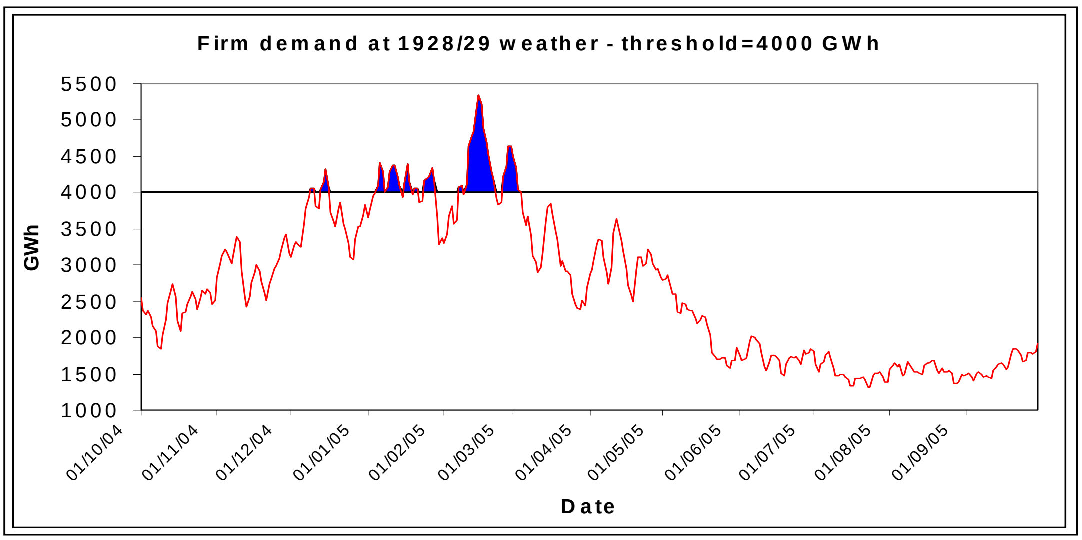
Step B: Calculate 1 in 50 peak day

The 1 in 50 peak day calculation is described in section 6.2.

Step C1: Calculate volume above threshold

For each year for a single threshold the demand above the threshold is calculated. This produces one volume figure for each of the X years simulated. In figure A4 the volume above the threshold of 4000 GWh is the area shaded in blue.

Figure A4



Step C2: Calculate average volume above threshold

The mean volume above the threshold is calculated. This value is used to fit the average load duration curve and to censor the data used to generate the severe load duration curve. In this example the following 6 years had volumes above the threshold. The remaining 69 years had no days that exceeded the threshold. Note that the sum is divided by the number of simulated years not the number of years with volumes above the threshold.

Year	1928/9	1939/0	1944/5	1962/3	1981/2	1986/7	Total
Volume (GWh)	130	85.7	8.6	207.1	28.6	794.3	1254.3

The average volume above the threshold = Total volume above threshold / Number of years simulated
= 1254.3 / 75 = 16.724 GWh

Step C3: Select volumes greater than average

Only volumes greater than the average are retained because this improves the fit of the distribution at extreme severities at the expense of milder weather. If there are less than 5 values remaining then the threshold is not used to calculate the load duration curve. Using the example from step C2, the volume above threshold for 1944/5 is less than the average volume and is therefore discarded. This leaves 5 years with volumes above the threshold greater than the average, the minimum amount for fitting a cube-root normal distribution for the threshold.

Step C4: Fit a cube-root normal

The cube root of each of the remaining volumes is calculated. A normal distribution is fitted to the cube-root volumes.

Year	1928/9	1939/0	1962/3	1981/2	1986/7
Volume (GWh)	130	85.7	207.1	28.6	794.3
Cube-root volume (GWh)	5.07	4.41	5.92	3.06	9.26

The mean and standard deviation of the cube-root normal distribution are calculated from a linear regression of the cube-root volumes against normal order statistics. Normal order statistics relate to a random sample of n values from the standardised normal distribution, the rth normal order statistic being the expected value of the rth smallest value in the sample, where n is the number of years being simulated. Figure A5 illustrates the normal order statistics for 75 years. Figure A6 shows the 5 cube-root normal values from the above example against the highest 5 normal order statistics.

Figure A5

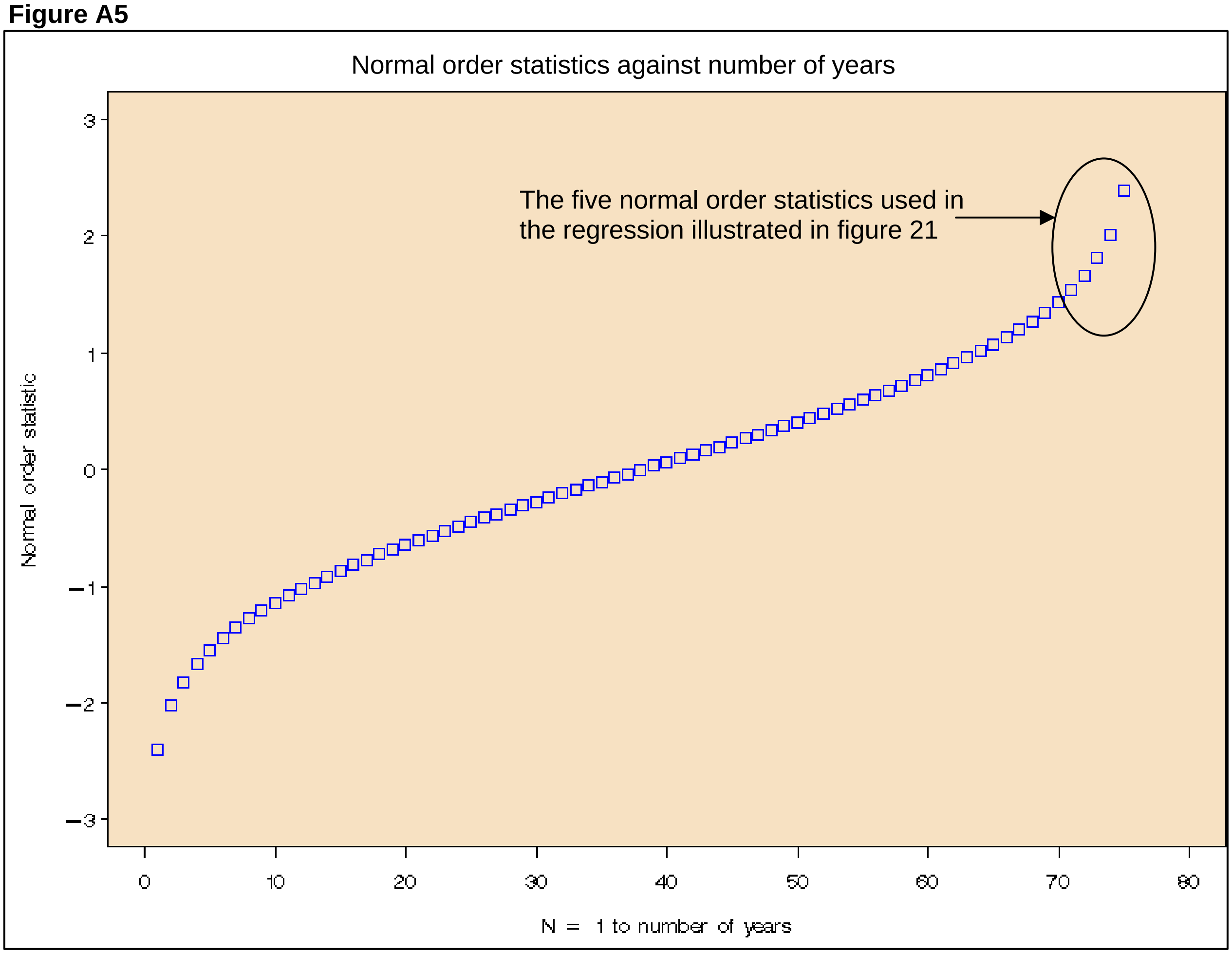
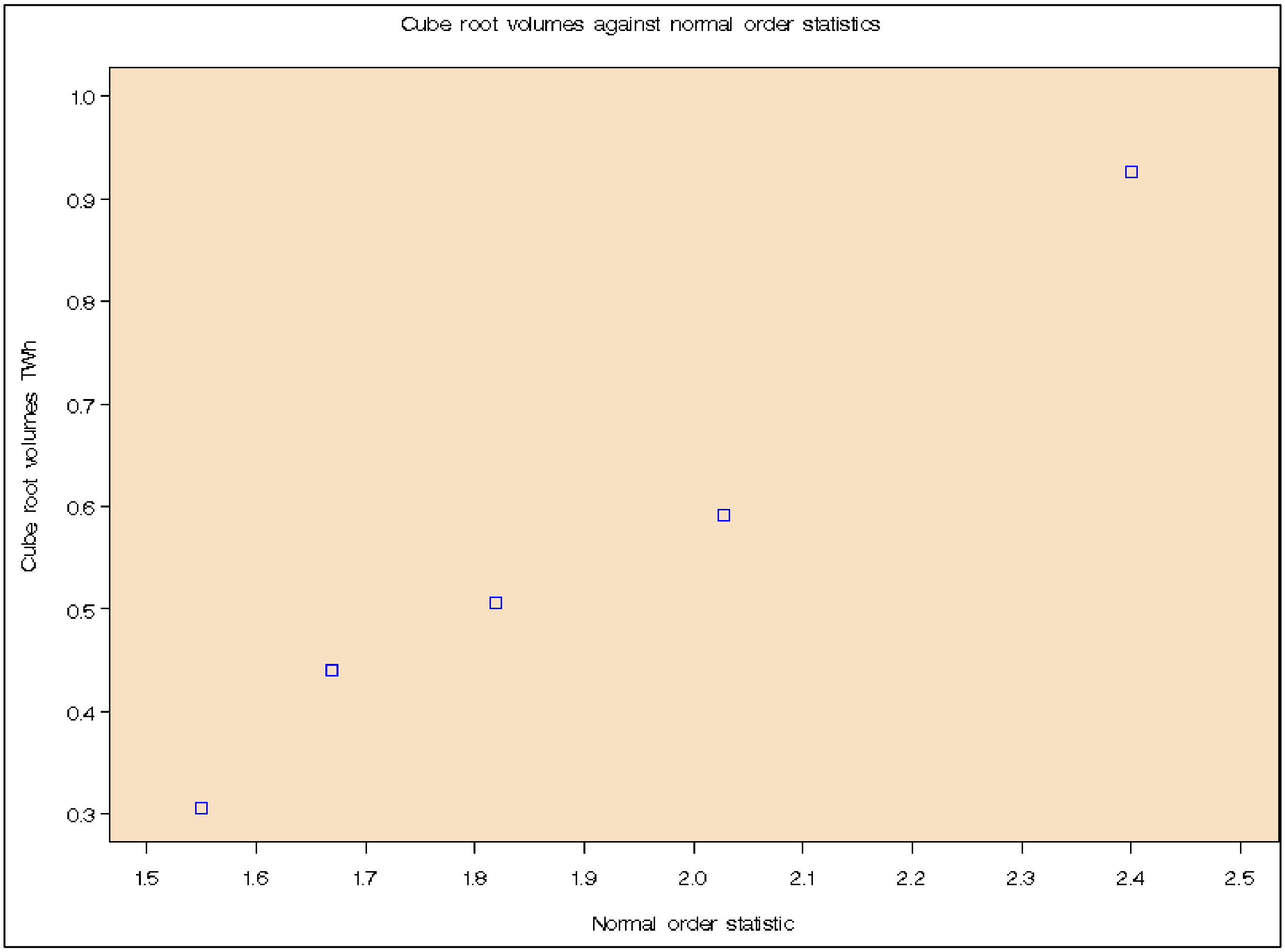


Figure A6



Step C5: Calculate the average mean and standard deviation for each threshold

A mean and standard deviation of the cube-root normal distribution is calculated for each of the 28 sets of simulations for each threshold. An average cube-root normal mean and standard deviation is calculated, from the 28 sets of simulations, for each threshold.

Step C6: Smooth the means and standard deviations

A smoothing procedure is applied to the values to ensure a decreasing load duration curve. The blue squares, in figures A7 and A8, show the mean and standard deviation before smoothing, the red crosses show the values after smoothing.

Figure A7

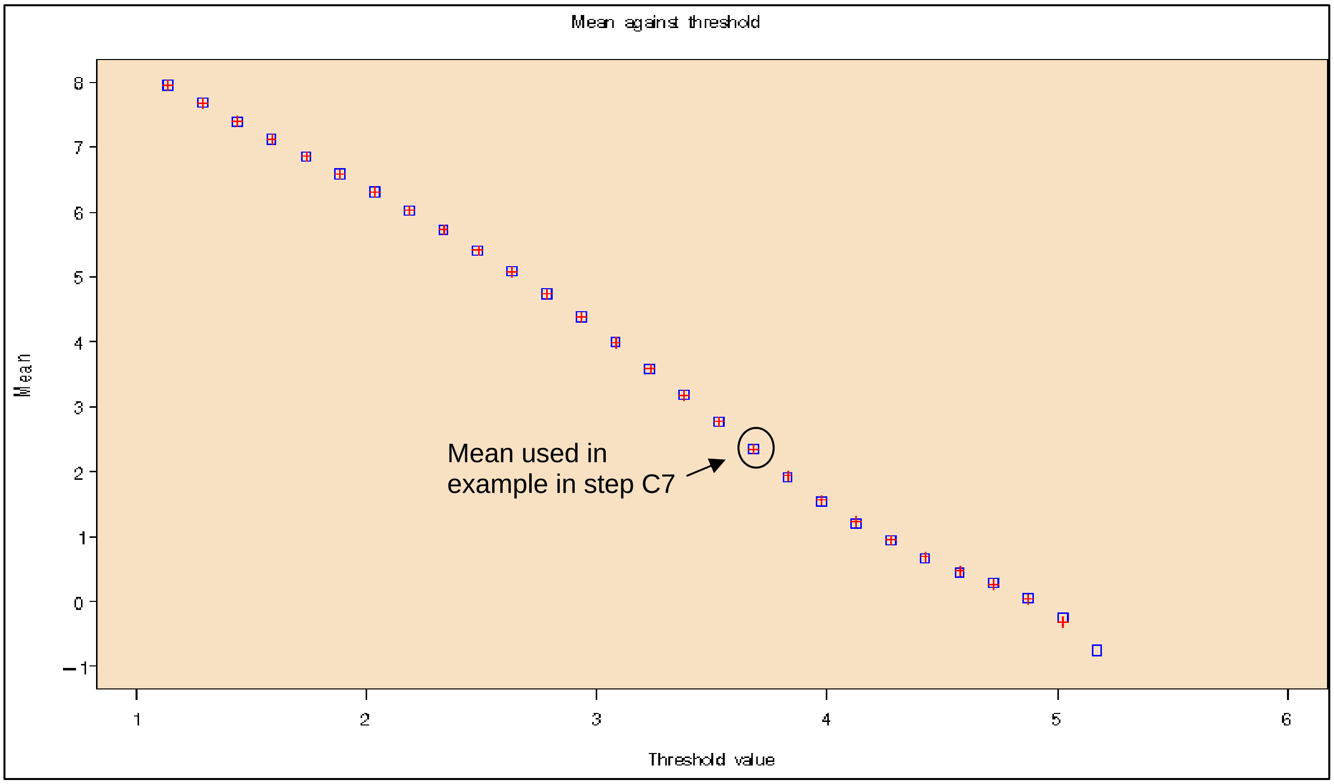
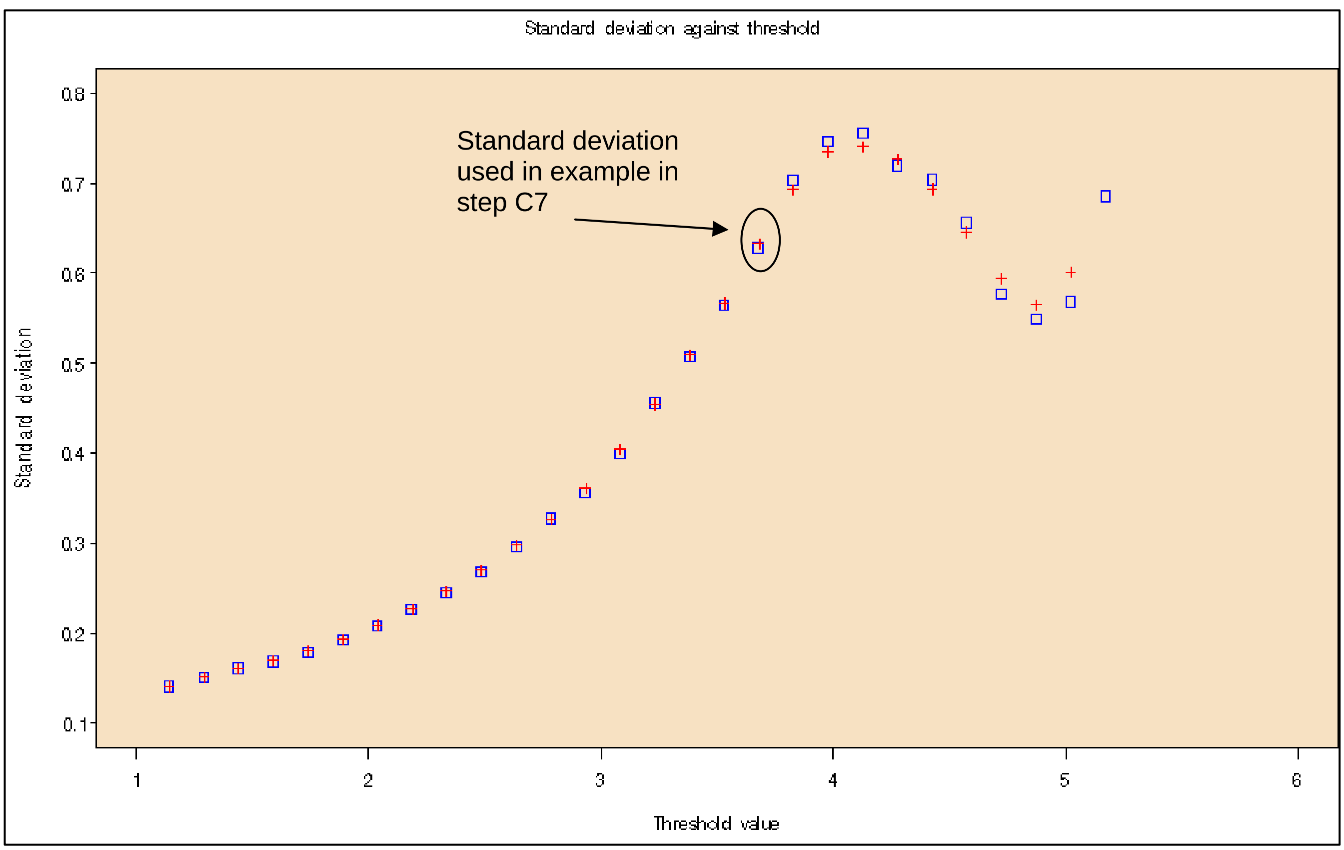


Figure A8



Step C7: Calculate 1 in 50 volume for each threshold

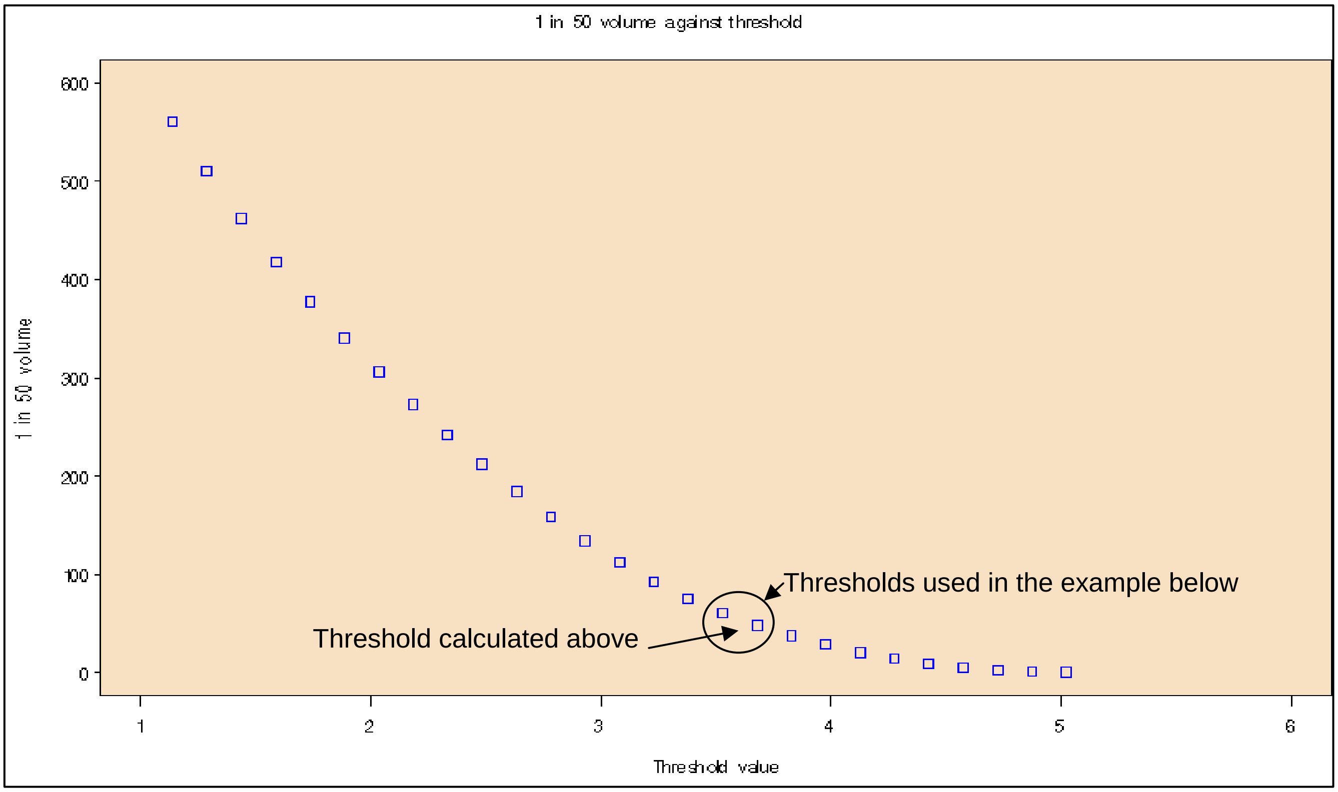
The 1 in 50 volumes above each threshold are calculated as

1 in 50 volume = $(\text{mean} + 2.054 * \text{standard deviation})^3$

For example if the mean is 2.35112 TWh and the standard deviation is 0.63239 TWh the threshold 1 in 50 volume is

$(2.35112 + 2.054 * 0.63239)^3 = 3.650049^3 = 48.62908$ TWh

Figure A9



Step D: Convert threshold volumes to daily demand and number of days' duration

The next step is to convert 1 in 50 volumes above thresholds to points on the load duration curve. Durations are calculated at the mid-point between two consecutive thresholds.

$$\text{Day number} = \frac{V_{i+1} - V_i}{D_i - D_{i+1}}$$

$$\text{Daily demand} = (D_i + D_{i+1})/2$$

where D_i is the threshold value of the ith threshold, V_i is the volume above that threshold.

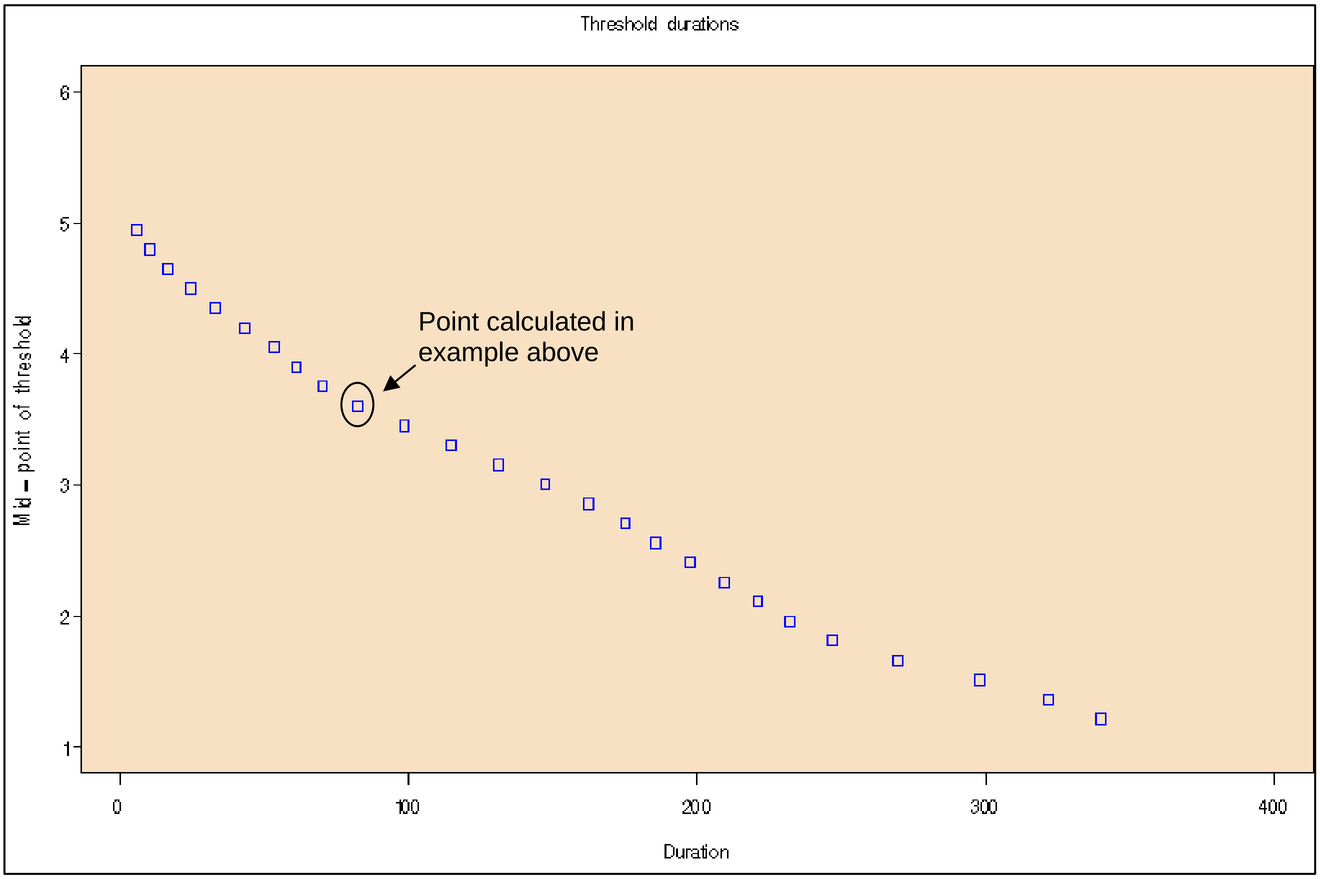
For example if the values of two consecutive thresholds are 3.68 and 3.53 TWh with corresponding 1 in 50 volumes of 48.63 and 60.96 TWh

Day number = (60.96-48.63)/(3.68-3.53) = 12.33/0.15 = 82.2

Daily demand = (3.68+3.53)/2 = 3.605 TWh

This forms the main part of the final load duration curve as illustrated in figure A10

Figure A10



Step E: Fill in gaps between threshold durations

The gaps between the threshold durations are filled using interpolation.

Step F: Extrapolate below bottom threshold

The values at the bottom of the curve are created by extrapolating the slope of the curve between the bottom two threshold durations.

Step G: Calculate values above the top threshold

The gap between day 1 and the highest threshold is filled by fitting a cubic equation that satisfies the following constraints:

i) Day 1 is set to the 1 in 50 peak day demand.

ii) The demand from the cubic equation must equal the demand from the volume analysis where the two curves meet.

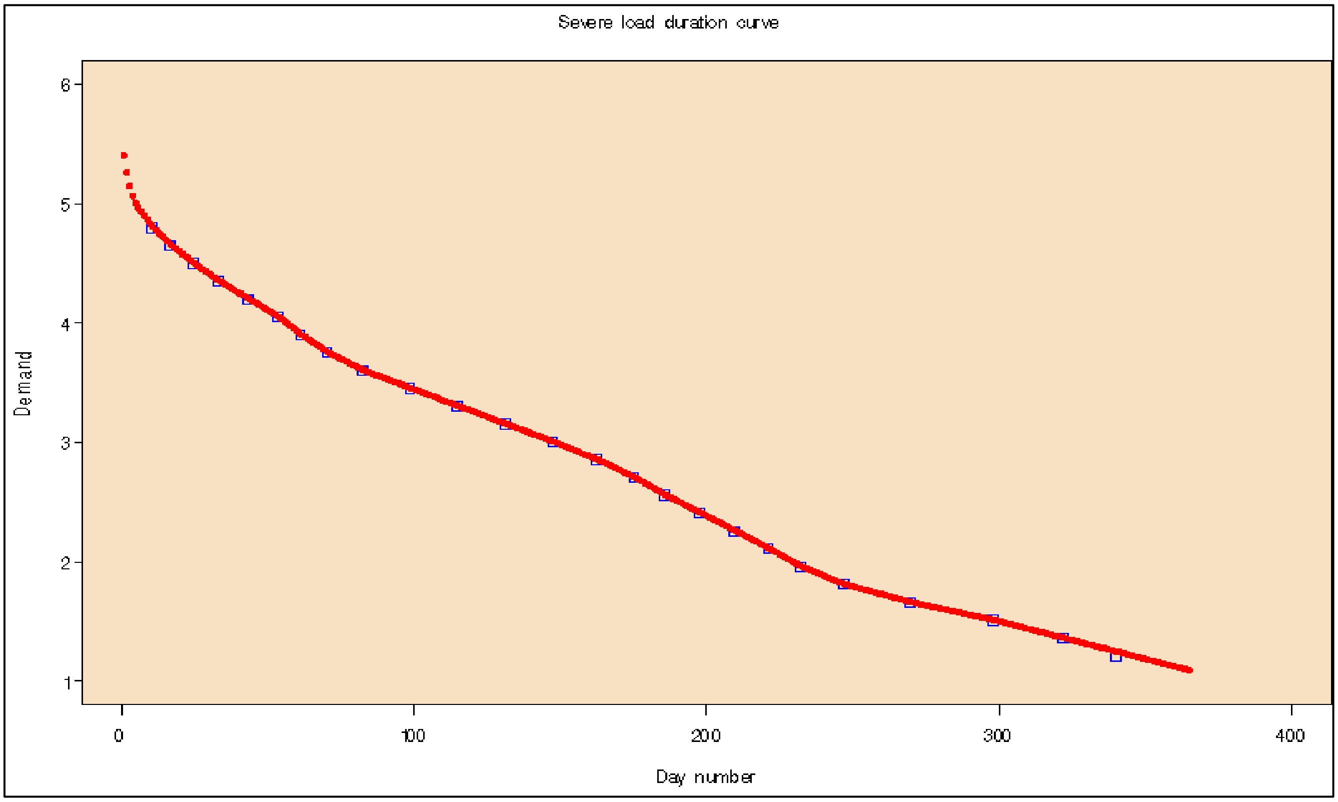
iii) The area under the fitted curve and above the demand threshold corresponding to the point where the two curves meet must be equal to the 1 in 50 volume derived from the volume analysis for this threshold.

iv) The slopes of the two curves should be the same where the two curves meet.

Step H: Combine to produce the 1 in 50 load duration curve

Figure A11 shows the final 1 in 50 load duration curve in red with blue squares showing the cube-root normal values.

Figure A11



Appendix 2: Extracts from the Gas Transporters Licence

Standard Special Condition A9. Pipe-Line System Security Standards

1. The licensee shall, subject to section 9 of the Act, plan and develop its pipe-line system so as to enable it to meet, having regard to its expectations as to –

(a) the number of premises to which gas conveyed by it will be supplied;
(c) the consumption of gas at those premises; and
(c) the extent to which the supply of gas to those premises might be interrupted or reduced (otherwise than in pursuance of such a term as is mentioned in paragraph 3 of standard condition 14 (Security and emergency arrangements) of the standard conditions of gas suppliers' licences or of directions given under section 2(1)(b) of the Energy Act 1976) in pursuance of contracts between any of the following persons, namely, a gas transporter, a gas shipper, a gas supplier and a customer of a gas supplier, the gas security standard mentioned in paragraph 2.

2. The gas security standard referred to in paragraph 1 is that the pipe-line system to which this licence relates (taking account of such operational measures as are available to the licensee including, in particular, the making available of stored gas) meets the peak aggregate daily demand, including, but not limited to, within day gas flow variations on that day, for the conveyance of gas for supply to premises which the licensee expects to be supplied with gas conveyed by it –

(a) which might reasonably be expected if the supply of gas to such premises were interrupted or reduced as mentioned in paragraph 1(c); and
(b) which, (subject as hereinafter provided) having regard to historical weather data derived from at least the previous 50 years and other relevant factors, is likely to be exceeded (whether on one or more days) only in 1 year out of 20 years, so, however, that if, after consultation with all gas suppliers, gas shippers and gas transporters, with the Health and Safety Executive and with the Consumer Council, the Authority is satisfied that security standards would be adequate if sub-paragraph (b) were modified by the substitution of a reference to data derived from a period of less than the previous 50 years or by the substitution of some higher probability for the probability of 1 year in 20 years, the Authority may, subject to paragraph 3, make such modifications by a notice which –
(i) is given and published by the Authority for the purposes of this condition generally; and
(ii) specifies the modifications and the date on which they are to take effect.

3. Paragraph 2(b) shall only be modified if, at the same time, the Authority makes similar modifications to (a) paragraph 6(b) of standard condition 14 (Security and Emergency Arrangements) and paragraph 5(a) of standard condition 32A (Security of Supply – Domestic Customers) of the standard conditions of gas suppliers' licences; and (b) sub-paragraph (b) of the definition of "security standards" in standard condition 1 (Definitions and Interpretation) of the standard conditions of gas shippers' licences.

4. For the purposes of paragraph 1, the licensee may have regard to information received from the operator of a pipe-line or pipe-line system to which it conveys gas as respects the quantity of gas which it expects to require.

Appendix 3: Methodology used to apportion simulated load duration curves to load bands in the 2007 demand forecasts

A3.1 Matrix of LDZ Peaks and Load Duration Curves

Load Band	Daily Model	Simulated	Peaks	LDCs
NDM 0 - 73.2 MWh	x		Initial peak calculated as (Annual*100/365)/load factor from regression model then scaled to add up to simulated NDM consumption	Initial LDCs created from demand model and CWV duration curve. These are sorted and scaled to add up to simulated NDM consumption
NDM 73.2-732 MWh	x			
NDM 732 - 2196 MWh	x			
NDM 2196-5860 MWh	x			
NDM >5860 MWh	x			
NDM Consumption	x	x	As simulated	As simulated
DM Firm - selected large sites	x		Created from demand model on day of highest SND and peak CWV	Not calculated
DM Firm - remaining consumption	x		DM firm consumption - DM firm selected large sites	Not calculated
Total DM Firm Consumption	x		Firm consumption - NDM consumption	Firm consumption - NDM consumption
LDZ Firm Consumption	x		Firm demand - firm shrinkage	Firm demand - firm shrinkage
LDZ Firm Shrinkage	x		Firm demand * shrinkage factor	Firm demand * shrinkage factor
Firm LDZ Demand	x	x	As simulated	As simulated
DM Interruptible - selected large sites	x		Created from demand model on day of highest SND and peak CWV	Not calculated
DM Interruptible - remaining consumption	x		DM interruptible consumption - DM interruptible selected large sites	Not calculated
Total DM Interruptible Consumption	x		Interruptible demand - interruptible shrinkage	Interruptible demand - interruptible shrinkage
LDZ Interruptible Shrinkage	x		Interruptible demand * shrinkage factor	Interruptible demand * shrinkage factor
LDZ Interruptible Demand	x		Total demand - firm demand	Total demand - firm demand
LDZ Total Demand	x	x	As simulated	As simulated

A3.2 Matrix of National Diversified Peak and Load Duration Curves

Load Band	Daily Model	Simulated	Undiversified Peaks	Undiversified LDCs	Diversified Peaks & LDCs
NDM 0 - 73.2 MWh			Sum of LDZ values	Sum of LDZ values	Sum of LDZ load band consumption adjusted to add up to LDZ firm diversified consumption in proportion to each load band's weather sensitivity
NDM 73.2-732 MWh					
NDM 732 - 2196 MWh					
NDM 2196-5860 MWh					
NDM >5860 MWh					
NDM Consumption	x				
DM Firm Consumption	x				
LDZ Firm Consumption					LDZ firm demand - LDZ firm shrinkage
LDZ Firm Shrinkage					LDZ firm demand * LDZ shrinkage factor
Firm LDZ Demand	x	x			As simulated
Individual NTS Site Firm Consumption	x		SOQs	Created from demand models and CWV duration curves	Not calculated
NTS Firm Industrial			Sum of relevant sites	Sum of relevant sites	Sum of model values at CWV duration curve weather selected by the date from GBSND sorted in descending order. Smoothing applied and peak day set to 1 in 50 LDC day 1 value.
NTS Firm Power Generation					NTS firm consumption - NTS firm industrial - Firm exports to Ireland
Firm Exports to Ireland					Same calculation as NTS Firm Industrial
NTS Firm Consumption	x				National firm demand - National firm shrinkage
NTS Firm Shrinkage	x		National diversified firm demand * NTS shrinkage factor	National diversified firm demand * NTS shrinkage factor	National firm demand * NTS shrinkage factor
National Firm Demand	x	x	Sum of firm load bands	Sum of firm load bands	As simulated
LDZ Interruptible Consumption	x		Sum of LDZ values	Sum of LDZ values	LDZ interruptible demand - LDZ interruptible shrinkage
LDZ Interruptible Shrinkage					LDZ interruptible demand * LDZ shrinkage factor
LDZ Interruptible Demand					LDZ total demand - LDZ firm demand
Individual NTS Site Interruptible Consumption	x		SOQs	Created from demand models and CWV duration curves	not calculated
NTS Interruptible Industrials			Sum of relevant sites	Sum of relevant sites	Same calculation as NTS Firm Industrial
NTS Interruptible Power Generation					NTS interruptible consumption - NTS interruptible industrial - Interruptible exports to Ireland
Interruptible Exports to Ireland					Same calculation as NTS Firm Industrial
NTS Interruptible Consumption	x				National interruptible demand - National interruptible shrinkage
NTS Interruptible Shrinkage	x		National diversified interruptible demand * NTS shrinkage factor	National diversified interruptible demand * NTS shrinkage factor	National interruptible demand * NTS shrinkage factor
National Interruptible Demand	x		Sum of interruptible load bands	Sum of interruptible load bands	National total demand - National firm demand
National Total Demand	x	x	Sum of all load bands	Sum of all load bands	As simulated
LDZ Total Demand	x	x	Sum of LDZ values	Sum of LDZ values	As simulated
NTS Total Consumption			Sum of NTS values	Sum of NTS values	National total demand - LDZ total demand - NTS total shrinkage

Appendix 4: References

A copy of Jenkinson's revisions to the Gumbel distribution is held at the Modern Records Centre at the University of Warwick reference MSS.335/GA/4/14/15. The title of the paper is "The frequency distribution of the annual maximum (or minimum) values of meteorological elements" by A.F.Jenkinson, Meteorological Office, London.

The Frontier Economics report is available from the OFGEM website.

http://www.ofgem.gov.uk/Markets/WhlMkts/CustandIndustry/WinterOutlook/Documents1/14619-117e.pdf

The offtake arrangements document section H – NTS long term demand forecasting is available of the Joint Office of Gas Transporters website.

http://www.gasgovernance.com/NR/rdonlyres/65BADE1A-277C-4A05-AB8B-1104DC53F090/16500/03_09_OADH1.pdf

The British Gas document TD76 is available from the Joint Office of Gas Transporters website.

http://www.gasgovernance.com/NR/rdonlyres/60BBF33E-C4D2-4FEE-827A-8F2A2F3BEDCE/9071/BGdocumentTD7620050518v01.pdf

Government energy statistics can be obtained from

http://www.berr.gov.uk/energy/statistics/index.html

Appendix 5: Data in the public domain

Selected figures from the demand forecasts can be obtained from the National Grid website.

Ten Year Statement

The ten year statement is the main document containing demand and supply forecasts. It is published every December. As well as the TYS document a spreadsheet is provided with the data behind the charts and tables. Annual and peak day forecasts and selected load duration curves are available. Winter Consultation and Transporting Britain's Energy (TBE) documents can also be accessed from the following web address.

http://www.nationalgrid.com/uk/Gas/TYS/

Demand and weather profiles

Seasonal normal cold and warm composite weather and daily demand at seasonal normal cold and warm weather conditions; see section 2.13.

http://www.nationalgrid.com/uk/Gas/Data/misc/

The seasonal normal demands for the previous, current and next day are also shown on the daily summary page.

http://www.nationalgrid.com/uk/Gas/Data/dsr/