Seven Year Generation Capacity Statement 2008 – 2014

System Operator for Northern Ireland

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SONI Ltd

SEVEN YEAR GENERATION CAPACITY STATEMENT

For the years 2008 to 2014

The information used to compile this statement is derived from SONI's own data. Whilst all reasonable care has been taken in the preparation of this data, SONI is not responsible for any loss that may be attributed to the use of this information.

2008

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EXECUTIVE SUMMARY

This 2008 Seven Year Generation Capacity Statement has been produced by SONI Ltd, the Transmission System Operator (TSO) in Northern Ireland (NI), at the request of the Northern Ireland Authority for Utility Regulation (NIAUR). It is an assessment of the adequacy of the generation capacity in NI based on the NI Generation Security Standard; it covers the seven year period from 2008 to 2014. The key findings from the Statement are:

- *The NI Generation Security Standard is met until 2012 based on the central scenario*[1]*;*

- *NI and All Island generation adequacy*[2] *analysis for beyond 2013, based on assumptions regarding plant retirements, has identified scenarios where there is a requirement for additional generation capacity;*

- *The NI Generation Security Standard has been determined using a harmonised approach to all year analysis of generation capacity agreed between SONI and EirGrid, the Transmission System Operator in RoI;*

- *The analysis is based on an NI Generation Security Standard of 4.9 Loss of Load Expectation (LOLE) with 100MW reliance on RoI;*

- *The expected increase in penetration of wind in the NW and on the island as a whole will be a challenge to manage in the short to medium term.*

In June 2004, the Department for Enterprise Trade & Investment (DETI) in NI and the Department of Communications Marine & Natural Resources (DCMNR) in the Republic of Ireland (RoI) issued the All Island Energy Market Development Framework. It set out a series of policy objectives for the delivery of efficient energy provision in an all island context. This included the establishment of an all island wholesale electricity market and a future requirement for a single all island generation adequacy report.

The Single Electricity Market (SEM) was implemented in November 2007. This created a wholesale electricity market on the basis of a gross mandatory pool. The new market arrangements, specifically the capacity payment mechanism, rewards generation for being available and amongst other measures it encourages new generation capacity to enter the market.

As part of the process for producing a single all island generation adequacy report the Regulators (NIAUR and CER) approved, in August 2006, a joint

[1] High availability of generation capacity and medium demand growth
[2] This is based on the EirGrid 2007 Generation Adequacy Report

paper from the two transmission system operators (SONI and EirGrid) entitled "All Island Generation Adequacy Policy Proposal".

This paper proposed a revised methodology to assess generation capacity adequacy initially in N Ireland but moving towards an all-island basis. The proposal was based on the need for the adequacy of generation capacity in Ireland to be assessed over a full year taking account of planned maintenance and potential forced outages of generating plant.

The overall aim of this exercise was to progress to a single adequacy assessment against a single all island standard. However, in assessing the situation on the island of Ireland it was recognised that the two transmission systems have interconnection that results in a physical constraint in terms of export and import capability. As an assessment against a single standard was not feasible while this physical constraint existed it was determined that it was appropriate to maintain a separate adequacy assessment in NI and RoI against separate generation security standards. A harmonised methodology would be used and an agreed level of capacity reliance would be placed on each system.

This is now the second year that the new methodology has been adopted. Prior to 2006 the N Ireland methodology was confined to analysis over winter peak demand periods.

The generation capacity assessment in NI is measured against three future demand scenarios - High, Medium and Low (i.e. increases in demand of 2.2%, 1.6% and 1.4% respectively). The purpose of including these scenarios is to cover a realistic range of potential demand outcomes.

A further key variable is generator availability. This includes Planned and Forced Outages. NI has, in recent years, benefited from high levels of generator availability (circa 92%). This 92% availability level is, therefore, one scenario used in this statement. A more pessimistic scenario predicated upon lower availability of 90% is also included in the Statement.

In the 2006 Seven Year Generation Capacity Statement, the high availability medium demand, or most likely scenario, showed surpluses of between circa 300MW and 650MW for the years 2007 - 2012. This variation was, in part, due to scheduled outage uncertainty. In this statement and, since the introduction of SEM, generation outages involve SONI/EirGrid cooperation and scheduled outages are planned on an all island basis only to optimise the security of supply 7 years ahead. This has lead to more consistent surplus generation values of circa 550MW between 2008 and 2012.

By 2013, under certain circumstances and based on the assumption of certain plant retirements, the surplus has fallen to unacceptable levels, the high availability scenarios show only 100 and 229MW surplus, while by 2014 a further deterioration occurs with surpluses of 5MW and 123MW deficit.

This is mainly driven by the assumed withdrawal of two generating units totalling 340MW of capacity at Ballylumford.

This Statement concludes that during the period from 2008 to 2012 with the committed levels of generation capacity there is sufficient generation capacity to achieve compliance with the generation security standard in NI. This assumes that the generation capacity is operating at reasonable levels of availability and import capability from GB and RoI can be achieved. However, with increased generator unit sizes and the dependency on imports there is a higher risk of an operational scenario that could result in load shedding due to a generation capacity shortfall. There is a potential requirement for additional generation capacity in NI beyond 2013.

This statement is based on a NI assessment of generation. In addition, an all island study has been carried out for the final two years ie 2013 & 2014. This assumes that additional transmission N-S tie-line capacity would be in operation, thus removing the existing constraint imposed by the present N-S tie-line and network configuration. This study, using an all island LOLE of 8 hours as agreed with both Regulatory Authorities has identified deficits of -27MW and -291MW for the 2014 for the equivalent central scenario. This analysis also highlights the need for additional capacity beyond 2013.

This assessment of generation capacity assumes that under emergency conditions there is an import capacity available of 450MW from GB via the Moyle Interconnector. This depends on energy being available from the BETTA market via market flows or through System Operator - System Operator (SO-SO) trades that may be executed in accordance with SEM arrangements.

By placing a formal reliance on 100MW of capacity from RoI this again assumes that this capacity is available when required. The EirGrid Generation Adequacy Statement identifies that there is a deficit of generation capacity when availability levels are low.

There is also an agreement between the two System Operators that NI will carry a proportion of the island's spinning reserve. For example, under normal conditions, conventional generation in NI carries a minimum of 50 MW. Spinning reserve is required to enable the generators across the Island to automatically respond to the loss of generation capacity for a period sufficient to allow fast start plant to meet the deficit.

North-South and South-North transfer capability, energy allocation processes and the provision of spinning reserve has increased the complexity of the SONI generation despatch process. The new SEM arrangement retained the technical constraint imposed and a locational spinning reserve requirement has led to a more streamlined dispatch process on an all island basis.

1.0 INTRODUCTION

This Seven Year Generation Capacity Statement is produced in accordance with condition 35 of the Licence to Participate in the Transmission of Electricity granted to SONI Ltd by the Department of Enterprise Trade and Investment. This statement is produced in a form and based on methodologies approved by NIAUR in respect of each of the seven succeeding financial years. There is an obligation to produce this statement on an annual basis.

This statement covers the seven year period from 2008 to 2014. The freeze date for the input data that forms the basis of this statement was 1 December 2007. This statement assesses the balance between demand and generation capacity for those years. This analysis is carried out against a generation security standard and methodology agreed with NIAUR. It describes the methodology adopted, the input data requirements (demand and generation) and sets out the generation capacity adequacy results. The statement provides generators or potential generators considering investing in capacity with useful background information. It is also of interest to the wider electricity supply industry and more particularly the regulatory agencies, policy makers and electricity supply companies.

Previous Seven Year Generation Capacity Statements included a section setting out a centralised plan to address any capacity shortfalls. Under the Electricity (NI) Order 1992 as amended by the Energy (NI) Order 2003, DETI and NIAUR carry joint responsibility for security of supply. With the introduction of market liberalisation in July 1999 as a result of the IME Directive (part 10 of S.I. No. 60, 2005 European Communities Regulations) the electricity market is now expected to provide adequate generation capacity. This Statement is designed to identify and highlight risks to security of supply over the seven year period on the basis of known generation capacity connected to the system.

SONI monitors the generation capacity situation in operational timeframes and highlights security of supply risks to NIAUR. In the past NIE and SONI have worked with NIAUR and DETI to put in place short and medium term arrangements to cover known capacity shortfalls.

2.0 METHODOLOGY FOR DETERMINING NI GENERATION CAPACITY ADEQUACY

This section of the statement describes the methodology on which the analysis is based. It explains the difference between Pre 2006 NI generation capacity statements and the methodology adopted in this Statement.

2.1 Pre 2006 NI Generation Capacity Assessments

It is important to understand the change in methodology if generation adequacy results are to be analysed over a historic period straddling 2006. SONI used the following methodology in NI Seven Year Generation Capacity Statements pre 2006.

The Cumulative Outage Probability Table (COPT) was derived from he installed capacity of individual generators and forced outage probabilities/winter availability. From this it was possible to determine the risk of failure to meet a range of demand levels on the basis of known generation capacity and estimates of renewable generators connected to the system over the seven year period.

Historic winter demand data was then analysed to obtain the ratio of the top 50 peaks relative to the temperature corrected average cold spell (ACS) peak demand. These ratios were applied to the forecast ACS peak demand values to obtain an estimate of the 50 peaks to be analysed in the generation adequacy assessment for each year.

The COPT was applied to each of the estimated 50 peaks to calculate the probability of failure for each generating unit. A single probability of failure figure was derived for the winter by summating the probabilities across the 50 peaks. The winter probability of failure was compared with a generation security standard to determine the adequacy of generation capacity. The generation security standard utilised by SONI in previous statements allowed for a disconnection rate of not more than 70 days in 100 years the equivalent of one failure every 1.4 years.

The 50 peaks were then progressively scaled up until the winter probability of failure matched the generation security standard. At this point the demand value was defined as the peak which can be met (PWCBM). The PWCBM value was compared on an annual basis with the ACS corrected peak demand forecast to establish if surplus or deficit generation capacity conditions occurred.

This analysis was carried out on future demand predictions for each of the seven years to establish the generation adequacy position and the results were published in the SONI Seven Year Generation Capacity Statement. A sensitivity analysis was provided by considering the impact of high and low generator availability figures. The principal limitation of this methodology is that the assessment is only carried out over the winter period. It does not assess capacity requirements during the spring/summer/autumn periods when the peak demand is reduced and plant outages tend to be scheduled.

2.2 Drivers for the Assessment of Generation Capacity on an All Island Basis

The All Island Energy Market Development Framework was published by DCMNR and DETI in November 2004. It set out the strategic energy objectives for the island of Ireland and identified specific actions to achieve those objectives. One key deliverable was the establishment of an all island wholesale market for electricity and also a future requirement for a single all island generation adequacy report.

As a result of this statement and the subsequent planned implementation of a single electricity market, both TSOs (SONI and EirGrid) put forward a joint paper for approval by both Regulators (NIAUR and CER) entitled All Island Generation Adequacy: Policy Proposal. This paper was approved by the Regulatory Authorities in August 2006.

The paper dealt with defining an appropriate generation security standard and the methodology adopted to assess the generation capacity/demand margin.

The overall aim of this exercise was to progress to a single adequacy assessment against a single all island standard. However, in assessing the situation on the island of Ireland it was recognised that the two transmission systems have interconnection that results in a physical constraint in terms of export and import capability. As an assessment against a single standard was not feasible while this physical constraint existed it was determined that it was appropriate to maintain a separate adequacy assessment in NI and RoI against separate generation security standards. A harmonised methodology would be used and an agreed level of capacity reliance would be placed on each system.

Proposals were put forward to adopt a common methodology to assess generation adequacy, the key features being:

a) the adequacy standard should be expressed in terms of loss of load expectation (LOLE).

b) it should be assessed over a full calendar year, taking account of scheduled maintenance.

c) both TSOs would adopt a No Load Loss Sharing (NLLS) policy ie each system is obliged to help the other only to the extent of any surplus it may have at the time.

By adopting a common methodology the impact is either an improved delivered LOLE and/or a saving in plant capacity.

This statement covers the period from 2008-2014. It is based on an NI generation assessment. It is anticipated that further interconnection will be commissioned by 2012. As a result an additional section has been included in the statement to consider an all island capacity assessment based on an inclusive all island plant portfolio and measured against a single all island standard. The results are included in Section 5.0.

2.3 Post 2006 NI Generation Security Standard and Methodology

The new method adopted is based on a similar statistical analysis technique used in the previous methodology to determine the probability that there is insufficient plant available to meet forecasted demand.

The COPT is derived from installed capacity for each generator and forced outage probabilities (FOP). The main difference is that the analysis is carried out for a complete year and so it is necessary to include Planned outages (named SODs, Scheduled Outage Durations), which normally occur at times of reduced demand during March to October. From the COPT it is possible to determine the risk of failure to meet a range of demand levels. The calculation of failure probabilities is carried out for each half-hour period in the year (17520 periods).

The summation of the half hourly probabilities provides an annual expectation of the number of hours in the year that there may be generation shortfalls. This annual expectation is known as the Loss of Load Expectation (LOLE). The measured LOLE is compared against the accepted generation security standard, 4.9 hours per year for NI. The method of determining this standard is described in Section 2.4.

The expected demand profile is then progressively scaled up or down. The LOLE is calculated for each case and compared with the standard. If the initial calculated LOLE is greater than the LOLE standard of 4.9 hours the system is in generation capacity deficit and the reverse is true when the LOLE falls below standard and the system is in surplus. This iterative process is followed until the resulting scaled annual profile results in the standard being met. The peak demand on this profile is known as the Peak Carrying Capability (PCC).

This PCC is an estimation of the peak demand that a given portfolio of plant can meet in order to achieve the LOLE generation standard. The PCC is always less than the actual installed plant capacity due to the influence of forced and planned outages.

Higher forced outages and planned outages result in lower availability and reduce the PCC. To provide a sensitivity analysis two scenarios of forced outages are examined and this is explained in more detail in Section 3.0.

Section 5.0 of this statement sets out the results of the analysis and focuses on the surplus/deficit for a number of demand and availability scenarios.

To ensure consistency the plant capacities and the demand forecasts are expressed net of Power Station auxiliary demand i.e. sent-out. The expected wind generation is removed from the demand profile and this process is described in detail in Section 4.0. Generation surplus or deficits are determined based on the ability of conventional centrally despatched generation plant to meet the resulting demand profile.

2.4 NI Generation Security Standard

SONI and EirGrid jointly commissioned a report to compare generation capacity adequacy methodologies in NI and RoI. It was difficult to make a direct comparison between the adequacy standards in place in NI and RoI due to the different methodologies employed. SONI adopted a standard of 70 days per 100 years, pre 2006 and investigated only the winter period. RoI historically made their adequacy assessment by analysing each half hour period throughout the year and adopting a LOLE standard of 8 hours.

The input modelling assumptions for both NI and RoI approaches were kept constant. The conclusion reached was that in order to maintain the standard on the NI system as given by the previous NI methodology, the whole year equivalent standard LOLE was 4.9 hours/year. This compares with the RoI standard LOLE of 8 hours/year.

Although the ratio of the LOLEs would indicate that the NI standard is considerably more rigorous than the RoI standard, it is important to make a further comparison of the proportional Expected Unserved Energy (EUE). LOLE is concerned only with the likely number of hours of shortage; EUE goes further and takes account also of the extent of shortages.

Figure 2.1 – LOLE & Expected Unserved Energy (EUE)

System	LOLE hrs/year	EUE per million
RoI	8.0	34.5
NI	4.9	33.8

The comparison of NI and RoI standards in terms of EUE suggests that the apparently more rigorous adequacy standard in NI when expressed in LOLE terms is appropriate for NI separate system conditions, that is, for a relatively small system with relatively large unit sizes. The more rigorous LOLE standard in NI taken in conjunction with the larger proportional failures results in a higher EUE compared to RoI.

2.5 Load Loss-Sharing Policy

It was noted earlier in this statement that the existing tie-line arrangement between NI and RoI creates a physical constraint that needs to be taken into account when considering the application of generation security standards. It was agreed that, in the interim period before additional interconnection is commissioned a separate LOLE would apply in NI and RoI. There is a need to define the impact of the physical constraint to determine the level of support that can be provided by each system to the other.

The agreed methodology developed jointly by the TSOs is for each TSO to carry out an annual adequacy assessment and to apply a No Load Loss Sharing (NLLS) policy.

With a NLLS policy each system is obliged to help the other only to the extent of any surplus it may have at the time. For example, suppose that on a particular day and time System A has a surplus of 150MW while System B has a deficit of 300 MW. System A would be required to export 150 MW, leaving its own position still in balance, while System B would then have a deficit of 150 MW to deal with.

2.6 Inter System Reliance Values

Since the re-introduction of the N-S interconnector in 1995 and as capacity margins have reduced the TSOs have developed a joint operational approach to capacity shortfalls. It was agreed that the level of spinning reserve would be maintained by modifying the interconnector flow. Further reductions in reserve carried, to achieve a minimum level of operating reserve was then followed by load shedding by the importing party as a final step to maintain system integrity.

To translate this operational procedure into the methodology of a generation capacity adequacy assessment requires that each TSO undertakes annual adequacy assessments in each system with a formal degree of capacity interdependence and appropriate LOLE standard. This will lead to capacity benefits on the island. This is an interim arrangement until the additional tie-line removes this physical constraint. The Total Transfer capacity values on the existing tie-line are:

North-South 450MW

South-North 400MW

The recommended values for the standards and the reliance values are as follows:

Figure 2.2 - LOLE & Capacity Reliance

	LOLE Standard Hours/year	**Capacity reliance MW of perfect plant**
RoI	8.0	200
NI	4.9	100

2.7 Summary of Joint Methodology

The principal features of the methodology that has been agreed jointly by the two TSOs for this statement are as follows:

- Adequacy will be assessed on a whole-year basis. Analysis will capture high periods of risk when the winter demand is high and periods of relatively low demand when scheduled maintenance generally occurs in the summer months.

- The principal index of generation plant adequacy will be a Loss of Load Expectation (LOLE), expressed in hours/year.

- Demand for future years will be estimated as half-hourly values for a 52-week year. The future demand will be projected from the shape of an actual previous year so as to forecast the peak demand and energy for future years.

- Wind generation will be modelled by estimating the profile of total half-hourly wind output for the future years. This will then be subtracted from the total demand to give the demand that has to be met by the remaining plant.

Interim Measures

In the medium term, because of the difficulties of implementing a single LOLE standard described previously above, a suitable compromise is to use separate LOLE standards, with each jurisdiction placing formal reliance on the other as described in Figure 2.2.

An interim policy of No Load Loss Sharing should be adopted.

3.0 DEMAND INPUT DATA

3.1 Demand Profiles

The probabilistic analysis used to determine LOLE is calculated on a half-hourly basis over each of the seven years of the statement. As a result there is a need to compare predicted demand profiles with generation input data (see Section 5.0) to establish generation capacity adequacy. This section describes the methodology by which the demand profile information is created.

3.1.1 Demand Profile Creation

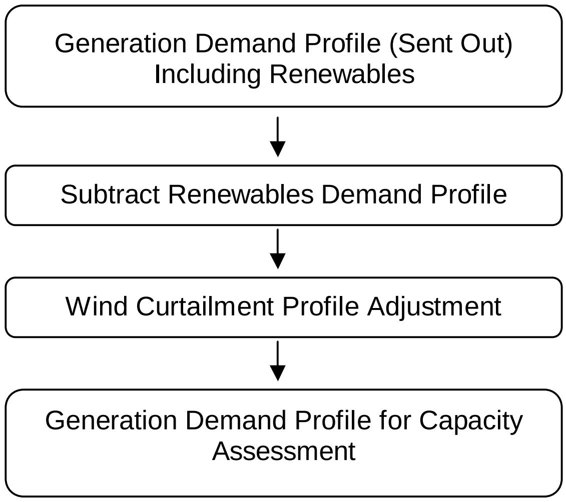
The demand profile data used is on a sent out basis or net of power station auxiliary load. It is the power directly injected onto the 275/110kV transmission network to meet the demand.

The demand profiles that are utilised over the last decade reflect customers running private embedded diesel generation (estimated to total circa 136MW) to avoid the higher winter peak tariff charges. This has the effect of suppressing demand and is assumed to continue over the seven years of the statement.

The methodology subtracts the estimated wind generation profile from the total demand profile and then the generation capacity adequacy is determined based on the ability of conventional centrally despatched generation plant to meet the resulting demand profile.

During the summer when the system can face both low demand and high wind output it was found necessary to curtail the wind output at minimum load conditions to ensure sufficient levels of conventional generation plant is connected to the network. It is necessary to have this level of conventional generation to respond to wind variability and to provide sufficient system inertia to maintain system stability. Wind was curtailed when conventional generation levels were below 350MW. This is an issue from 2008 onwards when a significant level of wind generation is expected on the NI network. The process of estimating future wind profiles is detailed in Section 3.1.3. Figure 3.1 below describes the demand profile creation process.

Figure 3.1 – Demand Profile Creation Process



3.1.2 Future Demand Profiles

To create demand profiles for the years 2008-2014 it is necessary to use an appropriate base year profile which provides a representative demand profile of the NI system. This profile is then progressively scaled up using forecasts of generated demand (sent out MW), generated energy (sent out MWh) and a corresponding load factor adjustment. The base year chosen for the profile creation was 2006. A similar process is used to create generated wind demand profiles and is described in Section 3.1.3.

3.1.3 Generated Wind Demand Profiles

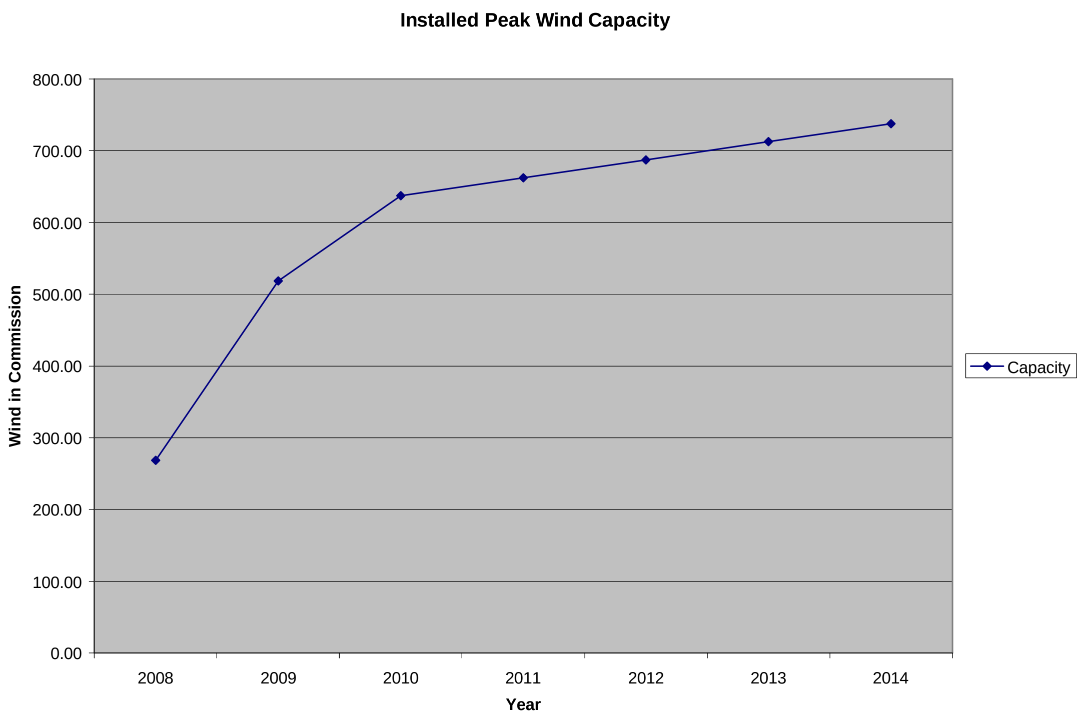
In 2006 there was a peak installed wind capacity of 120.1MW in NI Individual wind farm generated demand (sent out MW) data was summated for 2006 to provide a base year aggregated profile total. The characteristics of the profile were validated to ensure it was a satisfactory demand representation that could be used to create wind profiles for future years. Wind farms that were commissioned part way through the year were removed from the base 2006 wind profile to ensure a consistent wind shape throughout the year. When this adjustment was made the remaining peak installed capacity equated to 104MW. This figure was used for scaling factors for future years.

Figure 3.2 below indicates future estimates of generated peak wind and average annual wind capacity connected to the network and the scaling factors used to adjust base wind profile data to the appropriate level. The wind capacity information was derived from NIE T&D connection information and is based on programmed work with developers to secure connections to the network.

The scaling factor is calculated by dividing the average installed capacity for that year by that of the 2006 base year capacity (104 MW). The 2006 wind profile was scaled up to create profiles for each of the seven years of the statement.

Figure 3.2 - Future Wind Capacity Scaling Factor

Year	Capacity	Average Capacity	Scaling Factor
2008	268.7	221.68	2.13
2009	518.7	383.18	3.68
2010	637.45	604.76	5.82
2011	662.45	643.7	6.19
2012	687.45	668.7	6.43
2013	712.45	693.7	6.67
2014	737.45	718.7	6.91



3.2 Demand Forecasts

3.2.1 Forecast Methodologies

The accuracy of demand forecasts depends upon the data used in the analysis being comparable and consistent year-on-year. Of all the meteorological elements it has been found that temperature has the greatest effect on the demand for electricity. For this reason the demand data is adjusted to a temperature standard known as Average Cold Spell (ACS). ACS analysis produces a peak demand which would have occurred had conditions been averagely cold for the time of year.

The forecast procedures are deterministic and use regression analysis to establish the relationship between demand and other factors which influence demand. Regression analysis is carried out over different time periods to establish the highest degree of correlation and reduce standard errors to a minimum. Demand growth rates are established and applied to base year demands to establish future forecasts.

Although the forecasts are based primarily on the extrapolation of historic demand data, it is validated against a consideration of the economic outlook in NI. See section 3.3.

It has been previously identified that it is necessary to correct peak demands forecasts by temperature correction where an individual peak demand might be influenced greatly by the temperature at that time. Temperature has a lesser impact on annual energy consumption where the effect is found to generally balance over the course of a year. Energy forecasts are therefore based primarily on regression analysis techniques.

3.2.2 Review of 2006/2007 Winter Period

The generation peak demand forecasts represent the total NI generated demand. They include private customer generation (136MW), renewable generation, interconnector contributions and NI centrally despatched generation units (CDGU).

The peak demand for 2006 occurred on 19th December @ 17:20pm. The total generation peak demand was follows:

Figure 3.3 – Generation Demand Figures

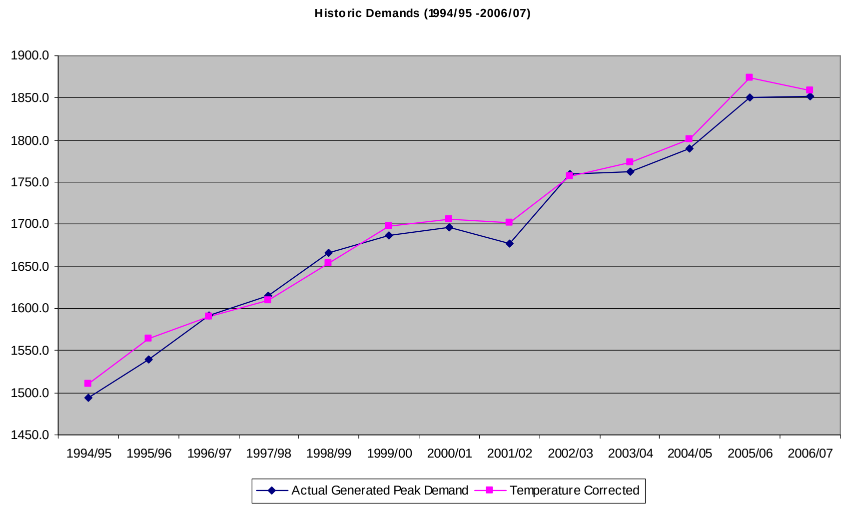
Generation type	**MW's**
CDGU + Interconnections	1710
Renewables	5.8
Customer Private Generation	136
Total NI Generated Peak Demand	1851.8

When average cold spell temperature correction (ACS) is applied this figure is corrected up by 7.2MW, providing a figure of 1859MW for the 2006/07 winter period.

3.2.3 Historic Generation Peak Demand

The historic actual ACS NI generation peak demand is represented in Figure 3.4 below.

Figure 3.4 – Historic Demands



	Generated Peak Demand	
	Actual	**ACS Corrected**
1994/95	1494	1511
1995/96	1540	1564
1996/97	1591	1590
1997/98	1615	1609
1998/99	1665	1653
1999/00	1686	1697
2000/01	1696	1706
2001/02	1677	1702
2002/03	1759	1757
2003/04	1762	1774
2004/05	1791	1801
2005/06	1851	1874
2006/07	1852	1859

There has been steady incremental demand growth over the last 12 years.

The historic data is subjected to regression analysis as described in Section 3.2.1. The forecasted demands for high, medium and low scenarios are shown in Section 3.4.

3.2.4 NI Generation Sent-Out profiles for 2006

It should be noted that the generation adequacy assessment is based on generation sent out or in net terms. To express the forecasts in Section 3.4 in sent out terms it has been necessary to remove private generation and power station works units. A conversion factor of 0.942 is applied to the NI generated peak demand forecasts to convert them to NI generated in sent out terms.

We can see a comparison of the "peaky" winter demand profile as compared with the "flatter" summer profile.

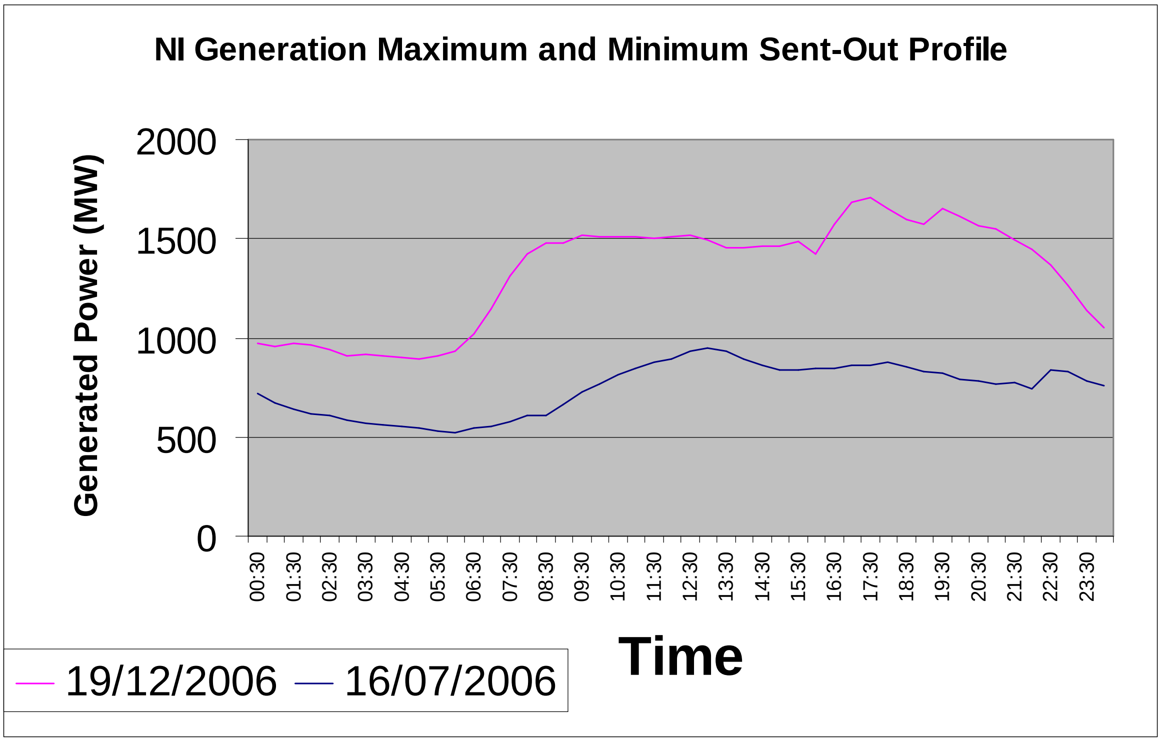
The summer minimum demand value of 526MW occurred on 16/07/2006 at 06:00am.

The winter maximum demand value of 1716MW occurred on 19/12/2006 at 17:20pm.

The winter maximum demand normally occurs at circa 17.20hrs and is as a result of coincidental usage patterns, for example, domestic cooking load and lighting load. At a network nodal level, 110/33kV BSP, no consistent and simple relationship between winter and summer daily load patterns can be identified. At some nodes, the summer peaks appear early in the day whereas others occur around the evening mealtime. This variance is the result of the mix of commercial, industrial, and domestic load at a particular node.

Figure 3.5 below plots the daily profile on which the 2006 sent-out generation maximum and minimum values occurred.

Figure 3.5 – Maximum and Minimum Sent Out Profile



3.3 Economic Outlook

While regression analysis is deployed to forecast future demand it is also necessary to assess if there are economic factors that may lead to specific changes in the demand for electricity. Despite the signs of a slowing growth in the national economy, the outlook for NI remains relatively positive for the next 12 months. Following the political developments in NI, confidence in the economy has risen. The massive capital investment programme in NI, (ISNI 2), has now commenced and this will help to sustain growth in the construction sector. The economic fundamentals are strong – employment, incomes, wealth, business and consumer confidence are buoyant. NI is well placed for continued growth in 2008.

Figure 3.6 - GDP Growth Predictions (%)

	2006	**2007**	**2008**
NI	2.5%	3.0%	3.0%

3.4 Forecast Scenarios

The generation capacity assessment is measured against three scenarios of future demand predictions medium, low and high. This is intended to provide a realistic range of demand profiles.

3.4.1 Medium Demand Forecast Scenario

Statistical measures indicate that this scenario is the most likely future trend for electricity peak demand and energy consumption in the medium term (8 years ahead).

Figure 3.7 – Medium Forecast Scenario

Year	**Gen Demand (MW)**	**Gen Energy (GWh)**
2008	**1678**	**9368**
2009	**1702**	**9520**
2010	**1727**	**9674**
2011	**1752**	**9831**
2012	**1778**	**9991**
2013	**1804**	**10153**
2014	**1830**	**10318**

This forecast represents an underlying growth rate of circa 1.6%. The generation peak demand (MW) increases by an average of 25MW per annum and the generation energy forecast by 158GWh per annum.

3.4.2 Low Demand Forecast Scenario

This forecast represents a lower growth rate for electricity demand based on an analysis of historic forecast trends (1993 - 2006). The lowest growth rate predictions over that period were circa 1.4% which is used in the forecast below.

Figure 3.8 – Low Forecast Scenario

Year	Gen Demand (MW)	Gen Energy (GWh)
2008	1668	9300
2009	1690	9433
2010	1711	9566
2011	1733	9702
2012	1756	9839
2013	1778	9979
2014	1801	10121

The generation peak demand (MW) increases by an average of 22MW per annum and the generation energy forecast by 137GWh per annum.

3.4.3 High Demand Forecast Scenario

This forecast represents a higher rate of growth of electricity demand based on an analysis of historic forecast trends (1993 - 2006). The highest growth rate predictions over that period were circa 2.2% which is used in the forecast below.

Figure 3.9 – High Forecast Scenario

	Gen Demand (MW)	Gen Energy (GWh)
2008	1741	9572
2009	1784	9783
2010	1828	9999
2011	1873	10219
2012	1919	10445
2013	1966	10675
2014	2015	10909

These forecasts represent underlying growth rates of circa 2.2 %. The generation peak demand (MW) increases by an average of 46MW per annum and the generation energy forecast by 223GWh per annum.

The following two graphs sets out the generation demand forecast scenarios and the energy demand forecast scenarios:

Figure 3.10 – Generated Sent Out Demand Forecast

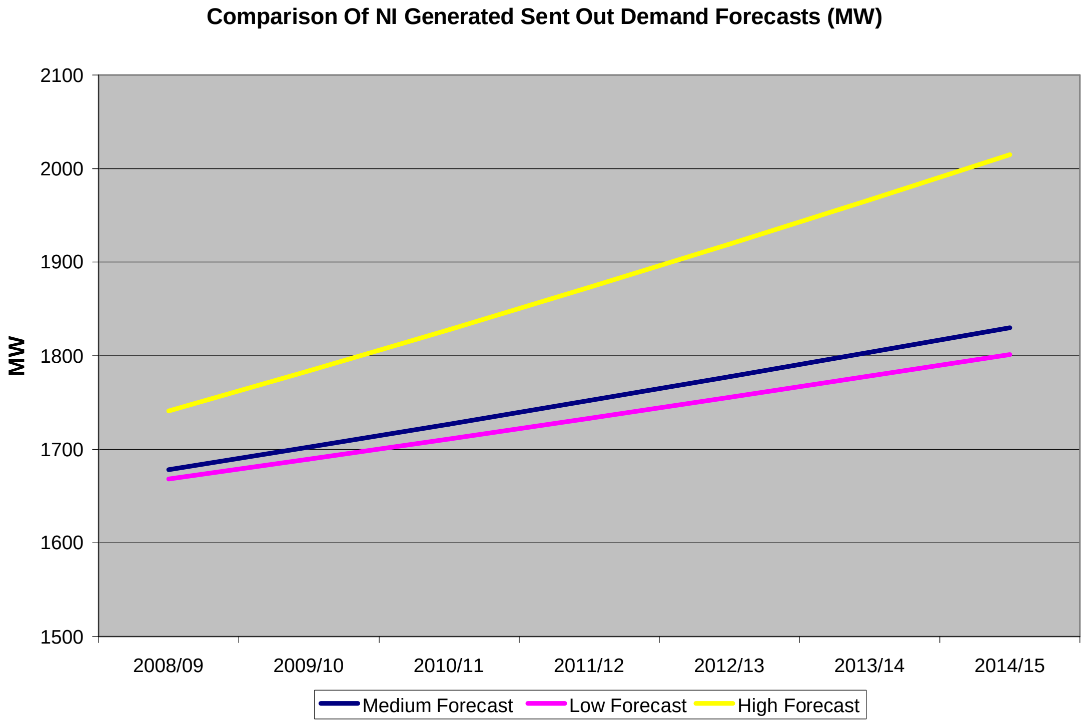
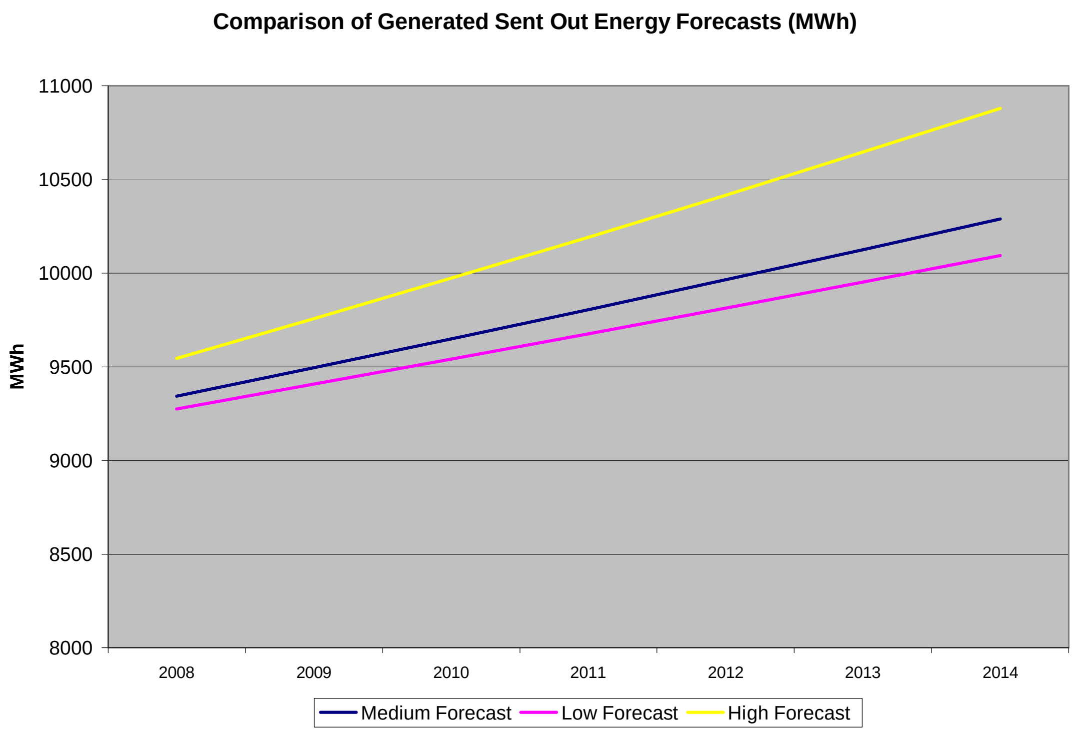


Figure 3.11 – Generated Sent Out Energy Forecast


Comparison of Generated Sent Out Energy Forecasts (MWh)
MWh
11000
10500
10000
9500
9000
8500
8000
2008
2009
2010
2011
2012
2013
2014
Medium Forecast
Low Forecast
High Forecast

4.0 GENERATION INPUT DATA

This section of the statement deals with the generation input data that facilitates the creation of the capacity outage probability table (COPT) described in Section 2.0. Over the time period 2008-2014, generation capacity, forced outage probabilities (FOPS) and scheduled outage duration (SOD) information is required for each generator, to assess the balance between power generation capacity and NI generated demand.

4.1 Generation Capacity Assumptions

With the introduction of the Single Electricity Market (SEM) in Nov 2007 during the transitional period it is expected to bring with it uncertainties about future generation capacity connected to the network. The new capacity payment mechanisms may take time to encourage new participants to invest capital in new generation projects.

Where contract decisions are required to be taken, a view is necessary of whether the capacity will remain connected. If the capacity is to remain connected it may be as a result of contract extensions or the assumption that the generator will opt to become a participant in the new SEM.

Figure 4.1 – Generation Capacity

Centrally Dispatched Generating Plant	Fuel Type	Sent-Out Generating Capacity (net - MW)						
		2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Ballylumford ST 4	*Gas/HFO	170	170	170	170	170		
Ballylumford ST 6	*Gas/HFO	170	170	170	170	170		
Ballylumford CCGT 21	*Gas/Gas oil	160	160	160	160	160	160	160
Ballylumford CCGT 22	*Gas/Gas oil	160	160	160	160	160	160	160
Ballylumford CCGT 20		170	170	170	170	170	170	170
Ballylumford CCGT 10	*Gas/Gas oil	97	97	97	97	97	97	97
Ballylumford GT 7	Gas oil	58	58	58	58	58	58	58
Ballylumford GT 8	Gas oil	58	58	58	58	58	58	58
Kilroot ST 1	*Oil/coal	238	238	238	238	238	238	238
Kilroot ST 2	*Oil/coal	238	238	238	238	238	238	238
Kilroot GT 1	Gas oil	29	29	29	29	29	29	29
Kilroot GT 2	Gas oil	29	29	29	29	29	29	29
Coolkeeragh GT 8	Gas oil	53	53	53	53	53	53	53
Coolkeeragh CCGT	*Gas/Gas oil	402	402	402	402	402	402	402
Scottish Interconnector	DC Link - note 1	450	450	450	450	450	450	450
Total Generation Capacity		2482	2482	2482	2482	2482	2142	2142

- *Where dual fuel capability exists this indicates the fuel type assumed to be utilised to meet peak demand
- Note 1 - The Moyle Interconnector has a winter rating of 450MW and 400MW summer. This is due to network security considerations

In Figure 4.1 the only units that SONI have assumed to be decommissioned by 2013 are Ballylumford G4 and G6 and this is due to environmental constraints introduced by EU legislation. From 2008 to 2015 the units are limited to a total of 20,000 running hours each. For this adequacy statement we have assumed that these running hours will be used by 2012 and the plant decommissioned thereafter. This would assume that Unit 6 continues to operate in SEM beyond its 2008 contract date. The running hours will depend on a number of factors such as market conditions and plant availabilities in the all island generation portfolio. SONI will monitor actual despatches and market conditions as the SEM develops and modify assumptions as required.

The individual generator capacities are expressed in sent out terms that is net of Power Station auxiliary load.

There is a total capacity of 2482MW in 2008. This does not include the 100MW of perfect plant available from RoI (See Section 2.0).

The generation capacities represented are for peak periods. For example the capacities at Kilroot G1 and G2 on coal fuel are reduced by 37MW to 203MW. The gas turbines at Ballylumford GT7 and GT8 would normally operate at a maximum of 53MW at non-peak periods a reduction of 7MW.

The large-scale generation is mainly connected to the east of the province, with the exception of Coolkeeragh Power Station which is connected in the North West. The connection points are shown on the 2009 Transmission and Generation map (See Appendix A).

Figure 4.2 describes the contract dates of centrally despatched generation connected to the transmission network.

Figure 4.2 – Generation Contract Details

Centrally Despatched Generating pPplant	Fuel type	Generation Contract Details
Ballylumford ST 4	*Gas/HFO	Contracted until 31 March 2012, can be cancelled earlier. Assumption - EU legislation on emissions will limit generation beyond 2012
Ballylumford ST 6	*Gas/HFO	Contracted until 31 March 2008. Assumption - EU legislation on emissions will limit generation beyond 2012
Ballylumford CCGT 21	*Gas/Gasoil	Contracted until 31 March 2012, with an option to extend.
Ballylumford CCGT 22	*Gas/Gasoil	Contracted until 31 March 2012, with an option to extend.
Ballylumford CCGT 20		Contracted until 31 March 2012, with an option to extend.
Ballylumford CCGT 10	*Gas/Gasoil	Contracted until 31 March 2012, with an option to extend.
Ballylumford GT 7	Gasoil	Contracted until 2020, can be cancelled earlier
Ballylumford GT 8	Gasoil	Contracted until 2020, can be cancelled earlier
Kilroot ST 1	*Oil/coal	Contracted until 2024, can be cancelled earlier
Kilroot ST 2	*Oil/coal	Contracted until 2024, can be cancelled earlier
Kilroot GT 1	Gasoil	Contracted until 2024, can be cancelled earlier
Kilroot GT 2	Gasoil	Contracted until 2024, can be cancelled earlier
Coolkeeragh GT 8	Gasoil	Contracted until 2018
Coolkeeragh CCGT	*Gas/Gasoil	This is an Independent Power Producer, commercial operation commenced 1 April 2005.
Scottish Interconnector	DC Link - *note 1*	Capacity is auctioned regularly (monthly and annually) to market participants.

This plant portfolio over the next seven years has considerable reliance on gas-fired generation. This is in part due to the emergence of new technologies and higher efficiency generation Combined Cycle Gas Turbine (CCGT) plants. These cleaner technologies assist in cutting greenhouse gas emissions. In NI over 1000MW of this plant type has been commissioned since 2002.

Gas dependency at present is manageable though this will need careful monitoring over the next seven year period as the supply and demand relationship unfolds.

4.2 Renewable Generation

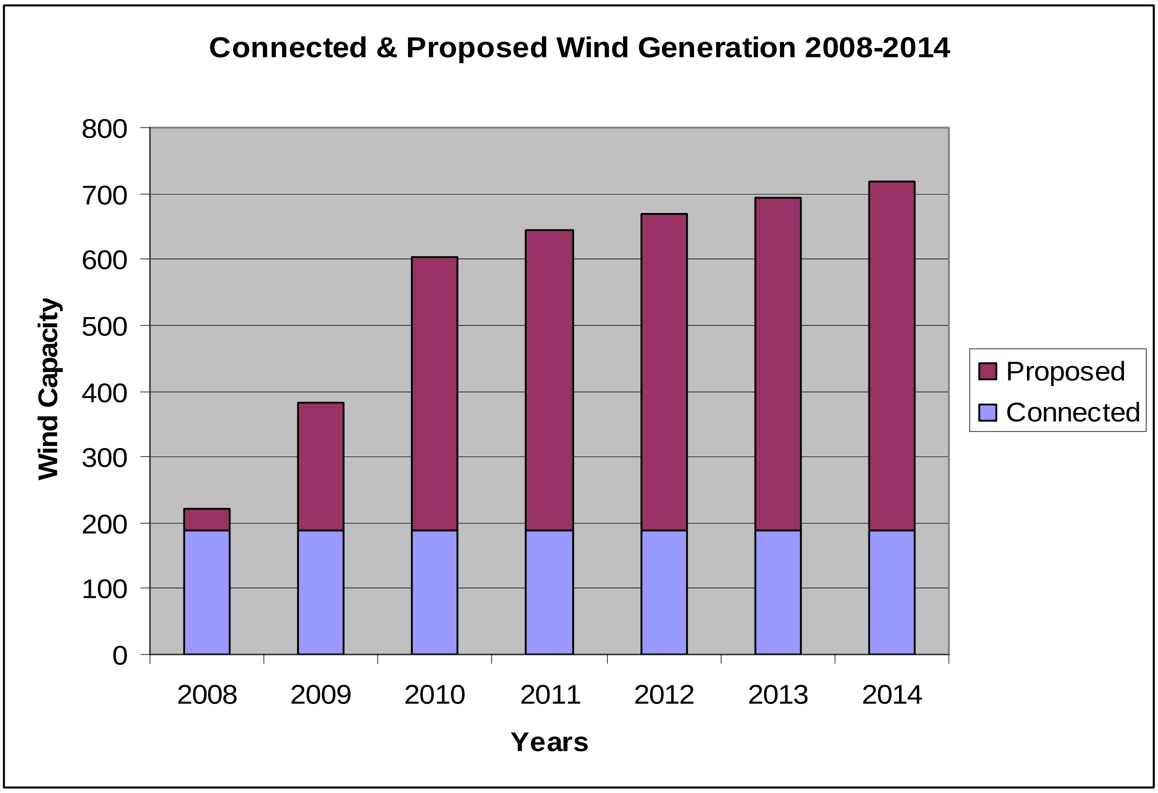
One of the areas of considerable change is the connection of wind farms to the NI transmission and distribution network. This has in part been driven by EU Policy. European Union leaders agreed to adopt a binding target on the use of renewable energy, such as wind and solar power. By 2020, 20% of the EU's energy supply must come from renewable sources. As a result of this, the British government has set a UK target of 10% by 2010, and a 20% target by 2020. In RoI the government's white paper produced in March 2007 set a target of 33% of renewable production by 2020. In addition, the 27 Members States that make up the EU set a firm target of cutting 20% of the EU's greenhouse gas emissions by 2020 as part of the post-Kyoto arrangements.

The system operator will have to manage the variability and system security issues at a system level. To achieve this it is important that the centrally despatched plant is of the correct plant type mix to meet the future needs of the network.

The Demand Section 3.0 explains how future wind profiles are created. The methodology agreed with the Regulatory Authorities, for the production of the NI GAR, is to subtract the future wind profiles from the total NI generation demand profile. The resulting profile is used to assess the capacity adequacy of the centrally despatched generation capacities listed in Figure 4.1

Figure 4.3 below shows the expected installed wind generation capacity from 2008-2014. The capacity levels increase greatly in the early years with in excess of 600MW expected by 2010. With this level of wind penetration it may be necessary to curtail wind at low load times for system security and stability reasons. The annual values are estimated average values for the year as generation is connected progressively throughout the year.

Figure 4.3 – Connected and Estimated Levels of Expected Installed Wind Generation Capacity



Due to confidentiality reasons it is not possible to publish full details of all wind generators that make up the totals in the graph, especially in later years. The following Figure 4.4 lists projects, which have already been commissioned or are committed. A wind generator is classified as committed when it has received planning permission from the relevant statutory authority and has officially agreed terms with NIE for connection to the network. The wind capacities in Figure 4.4 are expressed in power output MW as at 1 December 2007.

Figure 4.4 – Wind Farm Projects

Wind Farm Name	2007	2008				2009
		Q1	Q2	Q3	Q4	
Corkey	5					
Rigged Hill	5					
Elliott's Hill	5					
Bessy Bell	5					
Slieve Rushen	5					
Owenreagh	5					
Lendrum's Bridge	5.94					
Lendrum's Bridge2	7.26					
Altahullion	26					
Tappaghan	19.5					
Snugborough	13.5					
Slievenahanaghan	1					
Callagheen	16.9					
Lough Hill	7.8					
Bin Mountain	9					
Wolf Bog	10					
Sl Rushen	30					
Altahullion Ext	11.7					
Owenreagh Ext			5.1			
Garves				15		
Bessy Bell 2		9				
Gruig						25
Curryfree						11.7
Crighshane						21
Church Hill						10
Tievenameenta						30
Drumadarragh						20
Screggagh						19.5
Hunters Hill						13.8
Crockagarron					18	
Sl Kirk						75
Sl Rushen 2						24
Sl Divena					30	
Glenbuck					3	
Quarterly Total	188.6	9	5.1	15	51	250
Total (MW)	188.6	197.6	202.7	217.7	268.7	518.7

The network connection points of these wind farms are shown in Appendix A. Appendix A is a geographical representation of the NI transmission network in 2009 and shows the location of generation. It can be seen that the majority of wind generation sites are located to the west of the province.

The western location of the wind sites in NI in itself causes local transmission network difficulties. As wind levels grow under certain outage contingencies and generation despatch scenarios it is possible to exceed the thermal ratings of certain 110kV overhead line circuits.

Following a meeting of Ministers Noel Dempsey and Angela Smith on 21 June 2005, an all island grid study was initiated to address and report on the technical and economic issues associated with the development of renewable energy with a vision for 2020 and beyond. The results of this study are now available. The report concludes that Portfolio 5, (6000MW of wind on the All Island network), accommodates up to 42% of renewables. However a relatively large amount of high voltage transmission reinforcement is required. The cost of reinforcement on the NI network would be €300-400m. Specifically major reinforcement was identified in Donegal and NI with extensive reactive compensation required. NIE, SONI and EirGrid have commenced a joint study in this geographical area to consider the options. The TSO's also plan to carry out joint studies to consider the practicality and technical issues associated with managing large quantities of wind on the All Island transmission network.

4.3 Non Fossil Fuel Obligation (NFFO) Capacity

A number of wind farms in Figure 4.4 have signed contracts under the Non Fossil Fuel Obligation (NFFO). NIE signed contracts for Non Fossil Fuel Plant in 1994 and 1996 as described in Figure 4.5 below. Contracts for NFFO1 expire in March 2009 (32MW) and NFFO2 expire between April 2012 and August 2013 (7MW). It is not clear how these will develop thereafter. For the purposes of this statement it is assumed that they will continue to generate as a renewable IPP plant.

Figure 4.5 – Non-Fossil Fuel Obligation (NFFO) Site List

Scheme Name	Technology	Gen Kw
NFFO1		
Rigged Hill	Wind	5000
Corkey	Wind	5000
Slieve Rushen	Wind	5000
Elliott's Hill	Wind	5000
Bessy Bell	Wind	5000
Owenreagh	Wind	5000
Harperstown	Hydro	250
Benburb	Hydro	75
Carrickness	Hydro	155
Park Mills	Hydro	30
Randalstown	Hydro	500
Blackwater	Hydro	100
Sion Mills	Hydro	780
Oakland's WTW	Hydro	49
Silent Valley	Hydro	435
Total NFFO1		32374
NFFO2		
Lendrum's Bridge	Wind	5000
Slievenahanaghan	Wind	1000
Blackwater Museum	Biomass	204
Brook Hall Estate	Biomass	100
Benburb Small Hydro	Hydro	75
Total NFFO2		6379

Wind energy dominates the total power generated by renewables. Biomass and Hydro continue to make a very small contribution though in the long term, as technologies develop, the situation may change.

4.4 Customer Private Generation

A number of customers have been reducing their energy consumption by load shifting or by running private generation. The private generation has steadily grown from a figure of 38MW in 1994 to the present estimated total of 136MW. This figure (136MW) has been produced from the extrapolation of accurate historic assessments. There is a requirement to carry out a detailed study over the 2007/08 winter to establish the impact of SEM on current customer usage patterns. It is important to understand this private generation figure as it influences the accuracy of the NI demand profile forecast. The largest proportion of this power is provided by industrial and commercial diesel generators which tend to operate over peak periods, (4-8PM), with some CHP 24 hour generation (circa 15% of total private generation). This analysis assumes that this generation will continue to operate and suppress the NI generated demand profile into the future.

4.5 Moyle Interconnection

In 2002 a high voltage direct current (HVDC) link between Scotland and NI was commissioned. It was constructed as a dual monopole HVDC link with 2 co axial under sea cables from Ballycronanmore (Islandmagee) to Auchencrosh (Ayrshire). The installed capacity of the link is 500MW but the transfer capability is curtailed by certain network limitations on both sides. The available net transfer capacity (NTC) is therefore 400MW, except in emergency conditions when it can be increased to 450MW. The NTC figure of 450MW is further reduced to 400MW during summer nights to take account of network load changes or outages. All interconnector capacity is auctioned by the Transmission System Operator (TSO) in NI on behalf of Moyle Interconnector Ltd (MIL). This capacity is purchased by market participants. In the SEM the capacity can, in emergency situations, be used solely to meet the NI peak demand. It is for this reason that this capacity assessment assumes the capacity of the Moyle Interconnector as a maximum of 450MW.

The Balancing & Services Agreement between SONI and NGT facilitates energy purchases including emergency assistance up to the 450MW capacity of the interconnector. The availability level attributed to the Moyle Interconnector includes an assumption that there would be capacity available in a GB system with circa 70MW of installed generation capacity. It should also be noted that there have been occasions when energy has not been available during a capacity shortfall either for balancing trades or emergency assistance. On the face of it a 450MW import capability on Moyle tends to project a healthy position with respect to capacity adequacy in NI. The achievement of high levels of generation capacity security in NI in practice comes with a large degree of operational complexity and uncertainty in the commercial markets SONI now operate in. As flows are difficult to predict margins are frequently tight and complex to manage in operational timescales.

4.6 Louth-Tandragee 275kV Transmission Tie Line

The Louth-Tandragee 275kV circuit is now a tie-line rather that an interconnector operating in the SEM. The circuit will carry varying amounts of reserve and the concept of Net Transfer Capacity (NTC) is no longer tenable. The term now used is Total Transfer Capacity (TTC). This is the maximum that can flow in any period and is determined by the TSO’s. The market flow that is determined from the commercial data is calculated such that it cannot be greater than TTC less the reserve.

4.7 Future Transmission Tie Line Proposals

EirGrid and NIE are committed to establishing a new tie line between RoI and Tyrone. In addition, EirGrid plan to reinforce the infrastructure between Dublin and the new line. Present plans indicate the circuit will be a single 400kV overhead line tower circuit with initial capacity of circa 1000MW. With additional transformation capacity it may be possible to increase this to 1500MW.

4.8 Generator Availability Data

The Methodology Section 2.0 describes the process of determining the Peak Carrying Capability (PCC) of a given portfolio of plant in order to deliver a particular LOLE generation standard.

The size of the PCC is influenced by a number of factors one of which is generator availabilities. The availabilities can be separated into two areas, forced outage probabilities (FOPs) and scheduled outage durations (SODs).

The PCC is always less than the actual installed generation capacity on the network due to Scheduled Outages and Forced Outages. The likelihood of all generating plant being available on a given day is low. Forced outages have a much greater impact than scheduled outages due to their unpredictability in operational time frames.

4.8.1 Scheduled Outage Durations (SODs)

Generators are obligated to provide SONI with planned outage information in accordance with Grid Code (OC2). Each power station provides this information for individual generating units indicating the expected start and finish dates of required maintenance outages; they are normally expressed in days. The time periods are normally well defined for the first 3 years, and beyond this the SODs are allocated to optimise security of supply. The future SODs represented in this statement are based on past and present performance requirements. SONI do have a concern that these patterns may change as a result of increased two shifting. Two shifting is where a Generator is taken off overnight or at min load times. This will occur more frequently with increased penetration of wind generation. The continual running up and down of plant results in the requirement for additional maintenance and increased SODs.

4.8.2 Forced Outage Probabilities (FOPs)

Individual forced outages are derived from the SONI Commercial Management System and FOPs are calculated by SONI for individual generators on an annual basis. Future FOP predictions are based on the historic performance of generators and where data is unavailable, for example newly commissioned plants, by making comparisons with similar units. The FOP may be defined as the probability that a generator will be out of service for non-scheduled or unplanned reasons. This will be as a result of plant failures or mal operations that cause the generator to trip. Historic performance is used to determine future FOPs for Moyle HVDC link.

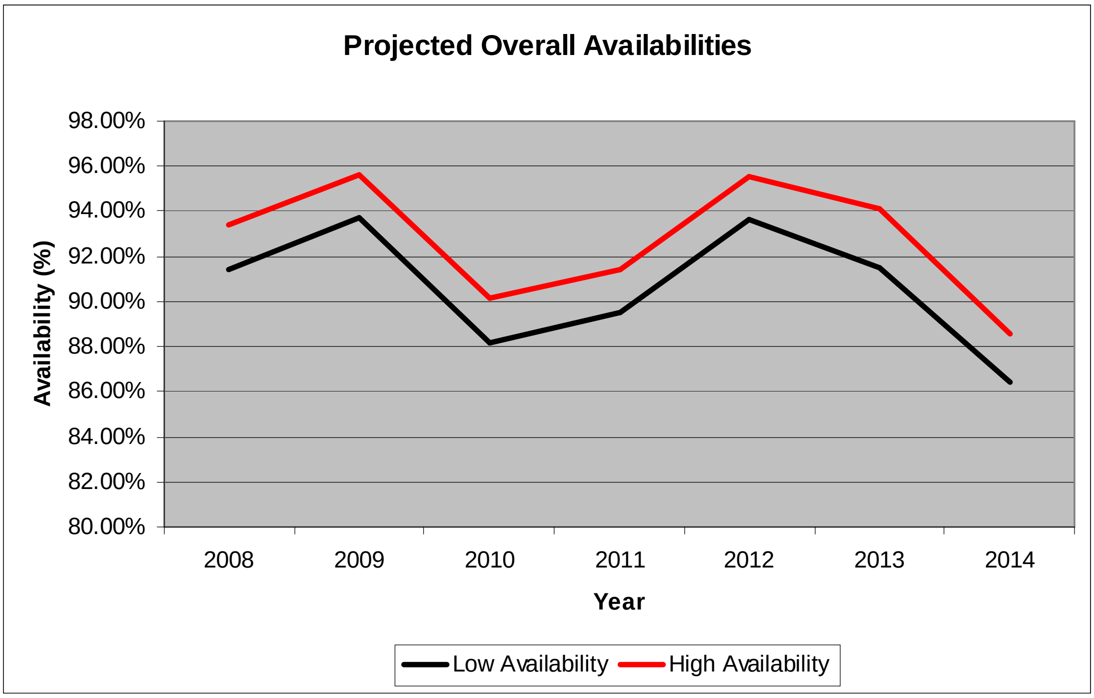
4.8.3 Generator Availability Scenarios on a Network Basis

It is possible to derive availability figures on an overall network basis. This is achieved by calculating the generation capacity in total, which is lost on an annual basis as a result of FOPs and SODs. The actual availability is the remaining generation capacity, which is then available to meet network operational requirements and customer demand.

In the capacity assessment, Section 5.0 of the statement it is necessary present a range of scenarios for the future. In the case of availabilities high and low availability scenarios have been considered. The high availability scenario is based on the actual historic performance of generators in NI, which are considered good. The low availability has been calculated with a pessimistic view of FOPs, where the performance of all generators drops to a level corresponding to the worst performing unit on the system.

Figure 4.6 below shows the projected overall availabilities projected for the seven year period covered by this statement are displayed.

Figure 4.6 – Projected Generation Availability



Year	2008	2009	2010	2011	2012	2013	2014
High Availability	93.36%	95.62%	90.13%	91.43%	95.57%	94.09%	88.59%
Low Availability	91.43%	93.69%	88.14%	89.55%	93.65%	91.47%	86.43%

The average high availability over the seven-year period is 92.68% and the low availability figure is 90.62%.

This analysis is focused on conventional generation plant and does not include Moyle. The availability of Moyle has been much higher than conventional generation as one would expect from a modern HVDC link commissioned in 2002.

5.0 ASSESSMENT OF GENERATION CAPACITY REQUIREMENTS

The results in this section of the statement are a series of graphs representing surplus or deficit generation capacity from 2008 to 2014. This follows the methodology described in Section 2.0. The surplus or deficit is expressed in demand terms and does not attempt to identify the installed generation capacity requirement, unit sizes or plant type necessary to reduce deficits.

The surplus or deficit is calculated by subtracting the Peak Carrying Capability of the plant portfolio from the forecasted NI generated demand forecast. A number of scenarios are considered in the results. Here is a brief summary:

Demand Scenarios

High Demand (HD)	-	Optimistic
Medium Demand (MD)	-	Most likely
Low Demand (LD)	-	Pessimistic

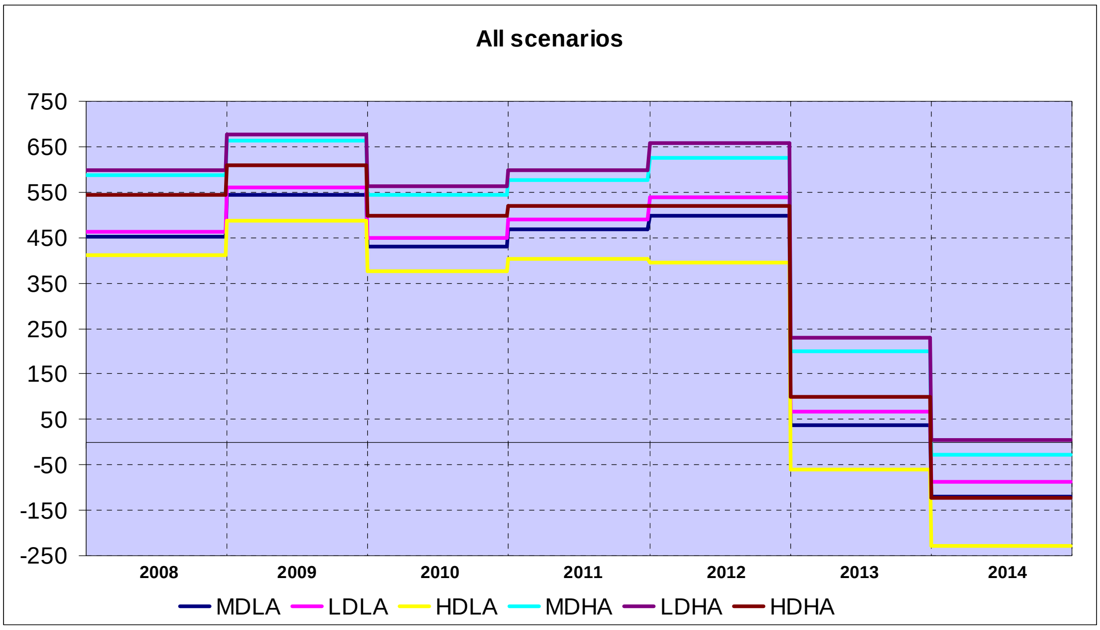
Each of these demand forecast predictions are analysed for both high and low generator availability performance. The scenarios and codes then become:

Description	***Codes***
High Demand & High Availability	HDHA
High Demand & Low Availability	HDLA
Medium Demand & High Availability	MDHA
Medium Demand & Low Availability	MDLA
Low Demand & High Availability	LDHA
Low Demand & Low Availability	LDLA

5.1 Results

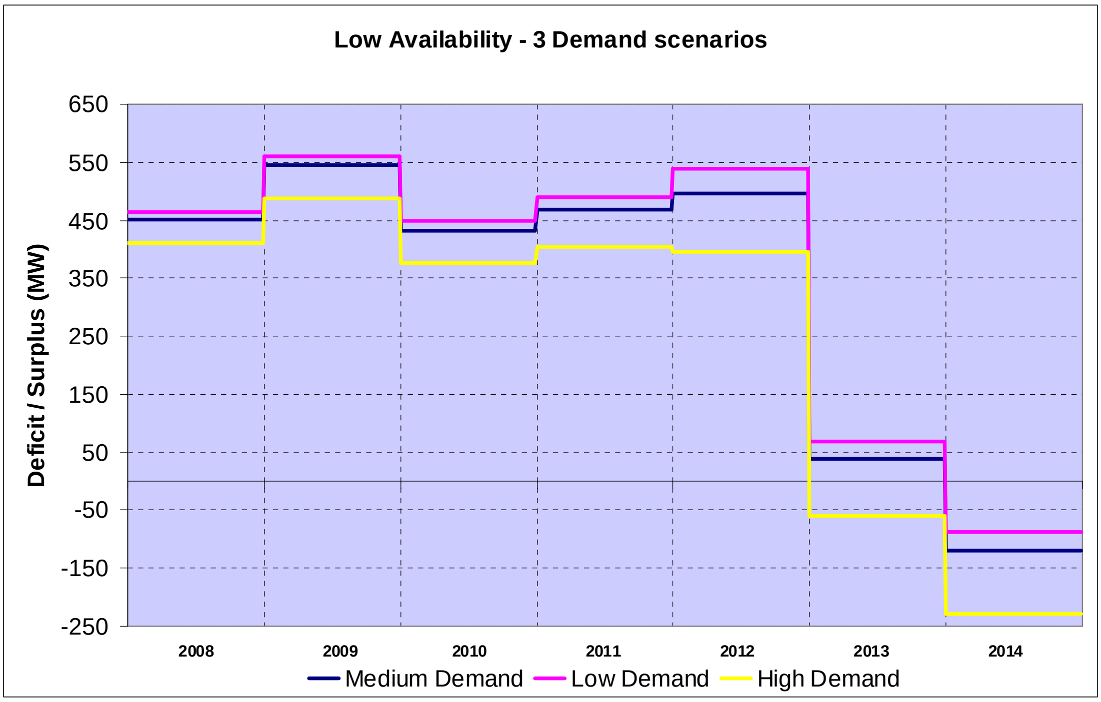
The first graph, Figure 5.1 describes all of the above scenarios on a single graph from 2008-2014. This is particularly useful as it is possible to assess the full extent of the Surplus/Deficit for each scenario.

Figure 5.1 - All Demand Scenario



The second graph, Figure 5.2 considers only the Low Availability scenarios on a single graph.

Figure 5.2 – Low Availability Scenario



The third graph Figure 5.3 considers only the High Availability scenarios on a single graph.

Figure 5.3 – High Availability Scenario

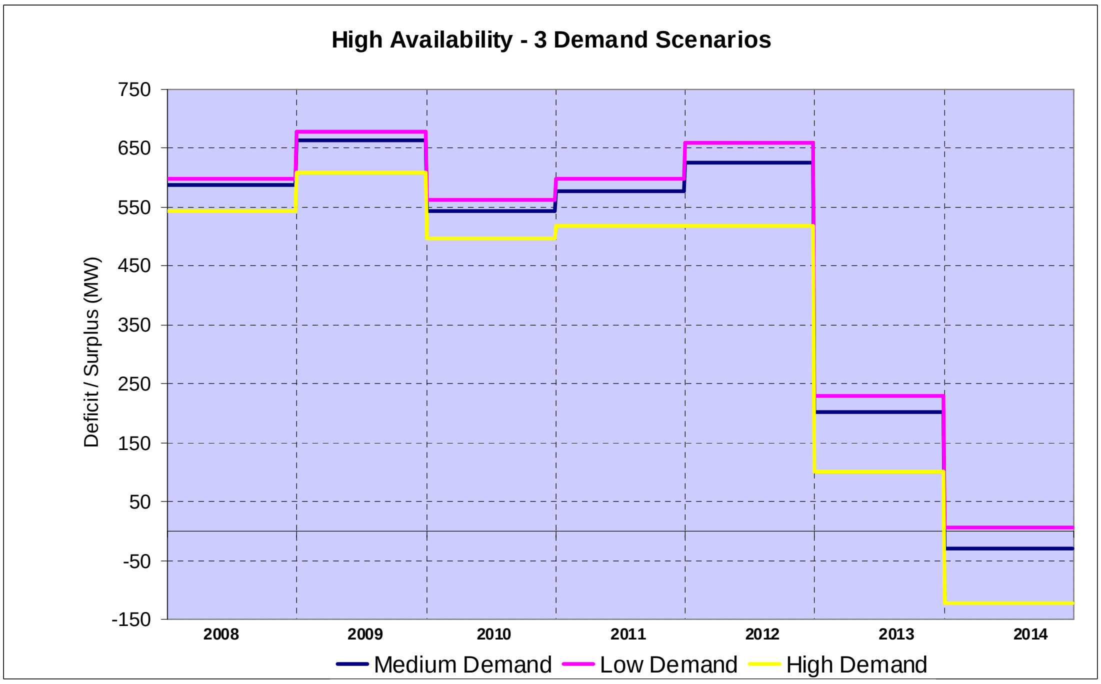


Figure 5.4 provides a tabular summary of the above analysis with red values representing deficits.

Figure 5.4 – All Demand Scenario

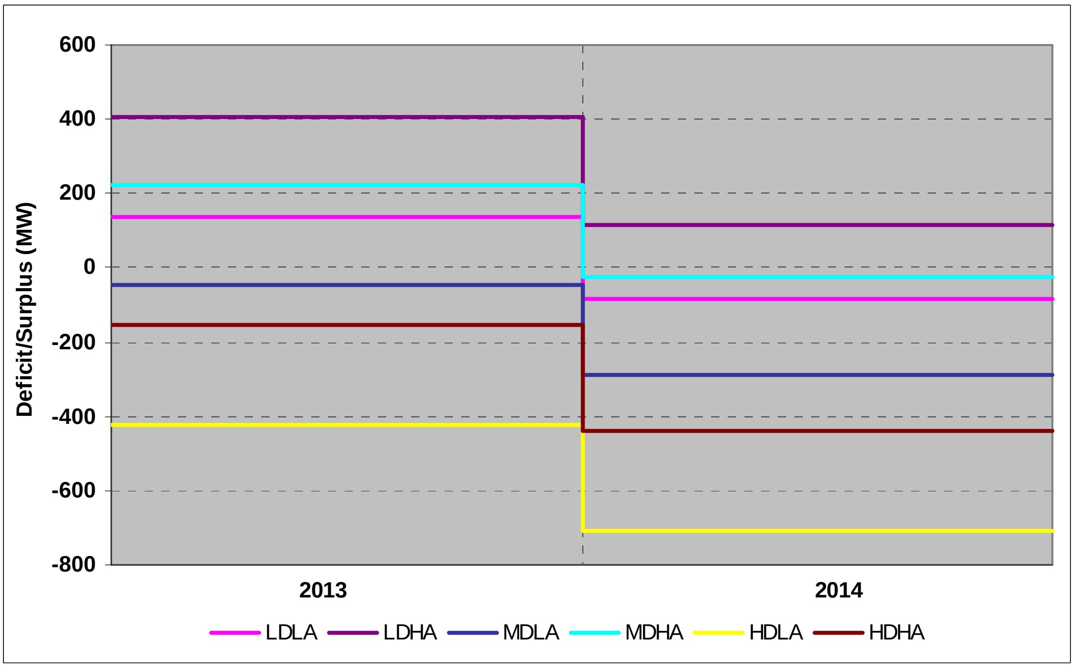
Demand	Availability	2008	2009	2010	2011	2012	2013	2014
High	Low	411	488	377	404	395	-60	-228
	High	543	609	497	519	519	100	-123
Medium	Low	452	545	431	468	497	38	-120
	High	587	664	544	577	625	201	-29
Low	Low	463	560	450	490	539	68	-87
	High	598	678	562	599	659	229	5

5.2 All Island Generation Capacity Assessment for 2013 & 2014

In 2013 it is anticipated that the N-S tie-line constraint will be removed with the introduction of additional interconnection capacity. This will remove the transmission constraint between NI and RoI. A series of adequacy studies were carried out by EirGrid with a single all island security standard and portfolio of generation plant for 2013 & 2014. An all Island generation adequacy standard of 8 hours LOLE was chosen for the studies and the scenarios studied were based on credible high and low availability and for three demand growth scenarios, low, medium and high. The results of these studies are shown in the following table and graph, Figure 5.5.

Figure 5.5 – All Island Generation Capacity Assessment 2013-2014

Demand	Availability	2013	2014
High	Low	-423	-708
	High	-154	-437
Medium	Low	-45	-291
	High	225	-27
Low	Low	137	-83
	High	407	118



When the generation portfolio on the island is analysed as a single capacity pot, there is a capacity benefit achieved. Even with the capacity benefit the results, for example, of the medium demand scenario points to a requirement for additional plant by 2013. In these all island studies, plant openings and closures, and further E-W interconnection etc are modelled.

5.3 NI Generation Capacity Requirements 2008-2014

Considering Figure 5.1 which shows all 6 scenarios over the seven year period, from 2008 to 2013 the results are reasonably consistent indicating a surplus of circa 500MW year on year. The small variations that occur are due to small changes in the load demand profile forecast and scheduled outages each year.

In years 2013 and 2014 the surpluses drop to unacceptable values, for example, the medium demand high availability in 2014 shows a deficit of 29MW. There is a requirement to install additional generation capacity in advance of 2013. It can take a considerable period of time for new generation plants equipped with modern technologies to settle down with acceptable levels of reliability. These plant deficits are validated by the all island studies in Section 5.2.

With the introduction of SEM in November 2007 the capacity payments are designed to incentivise new entrants into the market and reduce deficits. The TSO's generation adequacy assessments will be used to monitor progress in this regard.

The results indicate a healthy position in the short term however in practice SONI is left with tight margins to manage in operational time frames. A capacity of 450MW on Moyle can only be utilised if generation capacity is available in the UK market and it is cost effective to purchase the energy. In normal operation a proportion of the power generated by the Coolkeeragh CCGT will flow to customers in RoI and SONI is required to maintain a spinning reserve capacity in excess of 100MW. As a result it is proving to be more and more difficult to release plant for short term planned maintenance even at times of low load. The financially driven electricity markets add an additional layer of complexity in maintaining satisfactory generation security standards.

5.4 Comparison with Previous Capacity Assessments

The methodology used in this statement is similar to previous statements in that it is based on probabilistic statistical techniques. The main difference is that Post 2006 an all year assessment is carried out as compared to the Pre 2006 statements which were based on an analysis of the winter period.

When we compare the results of this statement with the 2006 statement, we find that the surplus/deficit in the 2006 statement showed considerably more variation (between 650 & 200MW's), whereas in this statement up to 2012, the surpluses are fairly consistent at around 500MW. When we investigated the difference we found that following the introduction of SEM, the SONI SOD's had been planned in an optimum manor that resulted in higher consistent surpluses. This statement shows a drop in surplus generation by 2013 as a result of plant retirements. This is consistent with the 2006 statement.

Glossary of Terms

COPT	Capacity Outage Probability Table
PWCBM	Peak Which Can Be Met
ACS	Average Cold Spell
DCMNR	Depart of Communications, Marine & Natural resources
DETI	Department of Enterprise, Trade & Investment
LOLE	Loss of Load Expectation
NLLS	No Load Loss Sharing
FOP	Forced Outage Probability
SOD	Scheduled Outage Duration
PCC	Peak Carrying Capability
EUE	Expected Unreserved Energy
TSO	Transmission System Operator
CDGU	Centrally Despatched Generating Units
CHP	Combined Heat & Power
GAR	Generation Adequacy Report
SEM	Single Electricity Market
CCGT	Combined Cycle Gas Turbine

Appendix A