Generation Seven Year Capacity Statement 2007 – 2013

December 2006

System Operator for Northern Ireland

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SONI Ltd

GENERATION SEVEN YEAR CAPACITY STATEMENT

For the years 2007 to 2013

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December 2006

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This 2006 Generation Seven Year 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 2007 to 2013.

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 new Single Electricity Market (SEM) is to be implemented in November 2007. This will create a wholesale electricity market on the basis of a gross mandatory pool. The new market arrangements are designed to create conditions that encourage investment in new generation capacity to meet the generation security standard.

As part of the process for producing a single all-island generation adequacy report the Regulators (NIAER and CER) approved, in August 2006, a joint paper from the two transmission system operators (SONI and Eirgrid) entitled ‘All Island Generation Adequacy Policy Proposal’.

The paper proposed a revised methodology to assess generation capacity adequacy. The proposal was based on the need for the adequacy of generation capacity to be assessed over a full year taking account of planned maintenance and potential forced outages of generating plant.

These revisions substituted the existing methodology which had hitherto been adopted in NI. The previous methodology confined analysis to 50 winter peak demand periods.

The new generation standard adopted is based upon a Loss of Load Expectation (LOLE). Comparison of the old methodology with the LOLE analysis demonstrated that the standard adopted by NI was equivalent to an LOLE of 4.9 hours per year. This LOLE was chosen as an appropriate generation security standard for NI. It was also agreed that the adequacy assessment would be undertaken on the basis of a No Load Loss Sharing (NLLS) policy. This obliges each of the two Island systems to help the other to the extent of any surplus it may have during a generation capacity shortfall but not to shed load. Hitherto, the generation adequacy assessments in NI and the RoI have assumed zero support is available on the N-S interconnector. The level of reliance on capacity support takes into account the fact that the N-S interconnector represents a transmission constraint. It was agreed that this new assessment of adequacy would include a formal reliance of 100MW of support from the RoI system. In the EirGrid adequacy assessment a formal reliance of 200MW of support from NI is included. The introduction of this more robust capacity assessment methodology required a high level of co-operation between Eirgrid and SONI to undertake the considerable joint analysis that was required to determine the level of generation adequacy in each jurisdiction.

The generation capacity assessment in NI is measured against three future demand scenarios - High, Medium and Low (i.e. increases in demand of 2.4%, 1.7% 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. NI has, in recent years, benefited from high levels of generator availability (circa 92%). 92% availability is, therefore, one scenario used in this Statement. A more pessimistic scenario predicated upon lower availability of 90% is also included in the Statement.

Previous Generation Seven Year Capacity Statements indicated surplus generation capacity in the region of 300MW based on winter analysis. In this Statement an additional 170MW unit at Ballylumford has been added to the capacity portfolio and there is also a formal reliance of 100MW placed on RoI. Despite these capacity additions, the new methodology results in surpluses which are comparable with previous stated levels in certain years. This is a result of a full year's analysis where the risk of capacity shortfalls are assessed at low margin periods inside and outside of winter peak periods. Capacity margins may be reduced outside the winter period as generators carry out planned maintenance. In 2007 with the Medium Demand and High Availability (MDHA) scenario there is circa. 280MW of surplus generation and the more pessimistic High Demand Low Availability (HDLA) reduces the surplus to 150MW. This situation would be further decremented if the additional 170MW unit at Ballylumford does not continue to generate beyond its contracted date of 31 October 2007. By 2013, the final year of this assessment, even the most likely scenario of Medium Demand Growth and High Availabilities (MDHA) indicates a surplus of less than 100MW. There is a deficit of over 100MW under the most pessimistic scenario. This scenario includes the potential withdrawal of the two generating units totalling 340MW of capacity at Ballylumford.

The Statement concludes that with the committed levels of generation capacity during the period from 2007 to 2012 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 clear requirement for additional generation capacity in NI by 2013.

Eirgrid carried out an all-island study for 2013 assuming that additional transmission interconnection would be in operation thus removing the existing technical constraint imposed by the present interconnector and network configuration. It identified a generation capacity deficit of 1,000MW on the island of Ireland. This underscores the fact that planning for the provision of additional generation capacity is required within the timescales covered by this report.

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 or through System Operator – System Operator (SO-SO) trades. Up to the introduction of SEM the cost of SO-SO trades is limited to the Maximum Energy Price as set out in the NIE Transmission and Public Electricity Supply Licence.

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. In normal operating conditions and the present market arrangements there is an export from NI to RoI that results from nominations on the N-S interconnector based on energy sourced from the Coolkeeragh CCGT and from GB via the Moyle Interconnector. To meet demand during generator outages it is often necessary to purchase energy from RoI or GB to offset the market flows. Ultimately, however, in a generation shortfall scenario the importing area sheds customers.

There is also an agreement between the two system operators that NI will carry in excess of 100MW of spinning reserve. This will continue in the SEM and the remainder is carried in RoI. Spinning reserve is required to enable the generators across the Island to automatically respond to the loss of generation capacity for period sufficient to allow fast start plant to meet the deficit.

Interconnector nomination, energy allocation processes and the provision of spinning reserve has increased the complexity of the SONI generation dispatch process. The new SEM arrangements will retain the technical constraint imposed by the present interconnector and a locational spinning reserve requirement but will lead to a more streamlined dispatch process in an all-island context.

TSO/TSO arrangements are increasingly important in securing inter-area rescue flows. Co-operation between the TSO's in GB, NI and RoI needs to be at a high level to ensure optimised security of supply.

1.0 Introduction

This is the third Seven Year Generation Capacity Statement published by SONI Ltd, the Northern Ireland Transmission System Operator, at the request of the Northern Ireland Authority for Utility Regulation (NIAUR). Under the Single Electricity Market (SEM) SONI Ltd will possess a separate SO Licence that is anticipated to include an obligation to publish an annual statement on generation capacity.

This statement covers the seven year period from 2007 to 2013. It assesses the margin 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 new methodology adopted, the input data requirements (demand and generation) and sets out the generation capacity adequacy results. The report 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 the NIAUR and DETI to put in place short and medium term arrangements to cover known capacity shortfalls.

2.0 Methodology of NI Generation Capacity Adequacy

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

2.1 Previous NI Generation Capacity Assessments

SONI used the following methodology in previous NI Generation Seven Year Capacity Statements.

The Cumulative Outage Probability Table (COPT) was derived from the 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 Generation Seven Year 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 report 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 (NIAER 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 year, taking account of scheduled maintenance.

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

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

This report covers the period from 2007 – 2013. It is anticipated that further interconnection will be commissioned by 2012. As a result an additional section has been included in the report 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 Newly adopted 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, in our case 4.9 hours per year. 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 of this report 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 is described in detail in Section 4. 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. NIE adopted a standard of 70 days per 100 years 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 to 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 LOLE's 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 – Expected Unserved Energy (EUE)

System	LOLE hrs/year	EUE per million
RoI	8.0	34
NI	4.9	43

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 the report that the existing interconnection 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 at a particular day and time System A has a surplus of 150 MW 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

From the early 1970s to 1995 the interconnector was out of service as a result of malicious damage. In this period the two systems clearly had no support from each other in meeting their adequacy targets. The interconnector was repaired and restored to service in 1995 and the previous policy of co-operation reintroduced. 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. This was dealt with commercially through the marginal trading arrangements.

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 interconnection removes this physical constraint. The existing Net Transfer capacity values are:

North – South 330MW Day
400MW Night

South – North 170MW Day and Night

The recommended values for the standards and the reliance values are described in Figure 2.2.

Figure 2.2 - Capacity Reliance and Generation Security Standards

	LOLE Standard Hours/year	Capacity reliance MW
RoI	8.0	200
NI	4.9	100

These reliance values should be reviewed annually. When the transfer capability reaches a level that does not pose a significant constraint on cross-border power flows, the case for adopting a single LOLE standard for the whole island becomes compelling.

2.7 Summary of Joint Methodology

The following are the principal features that have been agreed jointly by the two TSOs for this statement:

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 year. 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 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.

A policy of No Load-Loss Sharing is to be continued on an interim basis.

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) to establish generation capacity adequacy. This section describes the methodology by which the demand profile information is created.

3.1.1 Demand Profile Creation

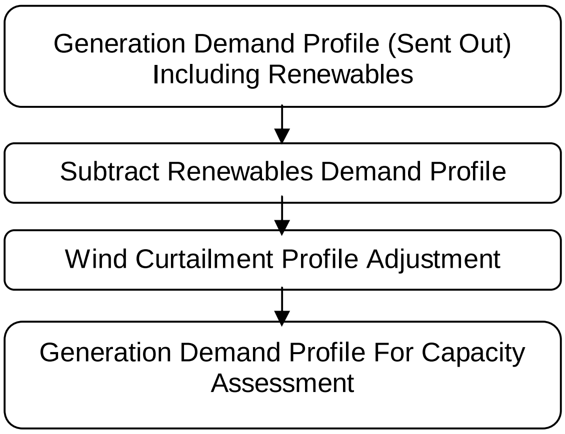
The demand profile data used is on a sent out basis or net of power station auxiliary load. It is the power directly injected onto the 275/110kV transmission network to meet the demand.

The demand profiles that are utilised over the last decade reflect customers running private embedded diesel generation (estimated to total circa. 132MW) 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 was 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 - **Profiling Process**



3.1.2 Future Demand Profiles

To create demand profiles for the years 2007 – 2013 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 2005. 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 2005 there was an installed wind capacity of 102 MW in NI. Individual wind farm generated demand (sent out MW) data was summated for 2005 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.

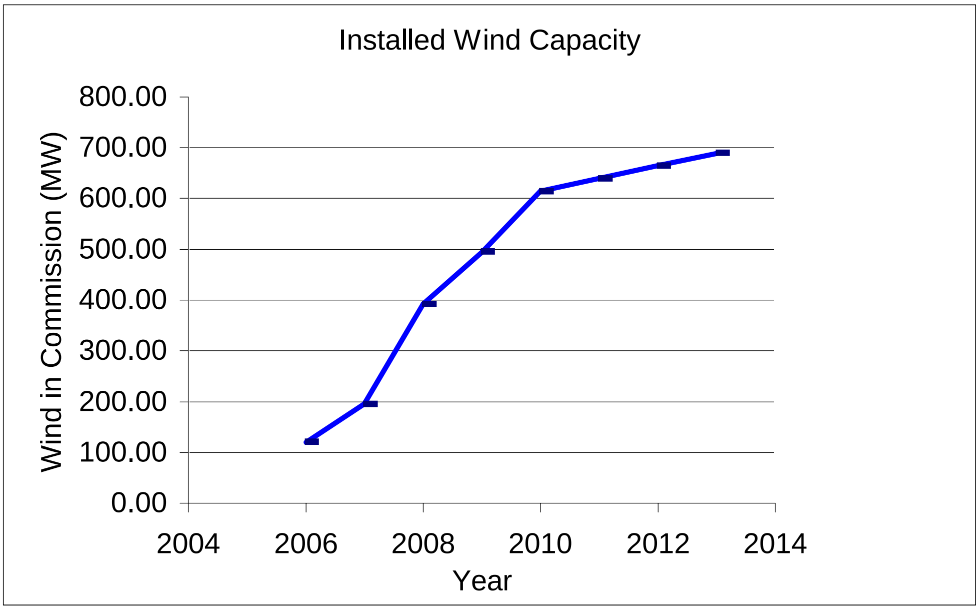
Figure 3.2 below indicates future estimates of generated wind capacity connected to the network and the scaling factors used to adjust base wind profile data to the appropriate level. The wind capacity information was derived from NIE T&D connection information and is based on programmed work with developers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

The wind generation capacities shown are the average figure for each year as wind farms become operational at different times throughout each year.

The scaling factor is calculated by dividing the average installed capacity for that year by that of the 2005 capacity (102 MW). The 2005 wind profile was scaled up to create profiles for each of the seven years of the statement.

Figure 3.2 – Future wind capacity

Year	Capacity	Scaling Factor
2007	195.63	1.92
2008	391.83	3.84
2009	495.09	4.85
2010	614.15	6.02
2011	639.15	6.27
2012	664.15	6.51
2013	689.15	6.76



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[1].

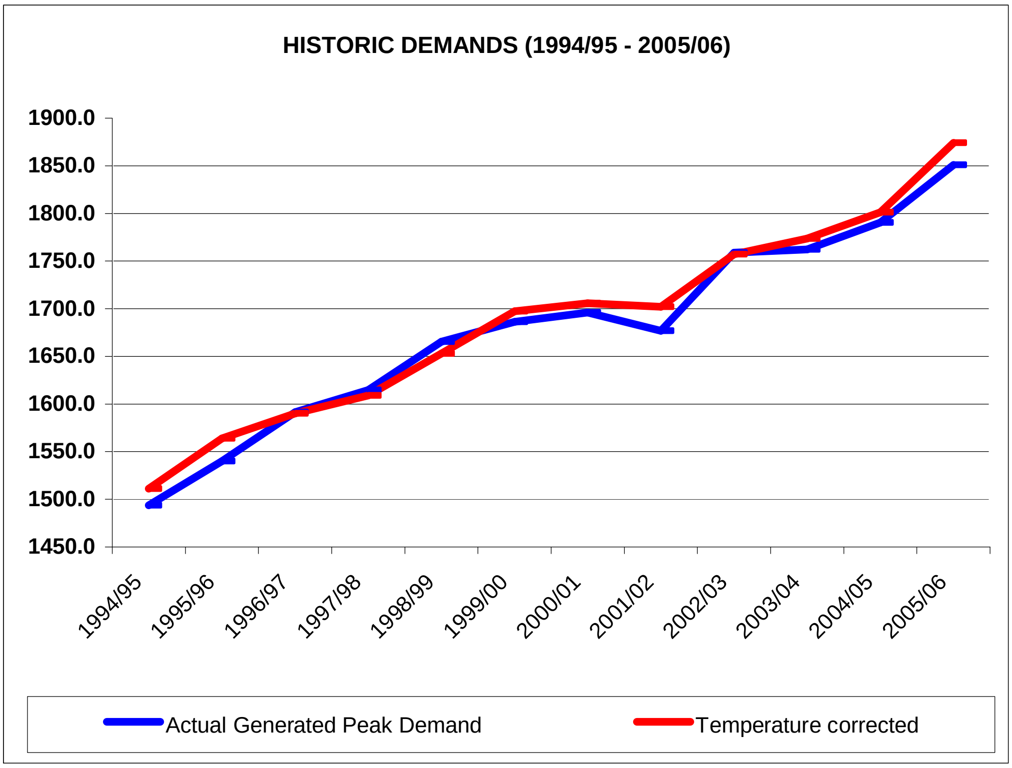
It has been previously identified that it is necessary to correct peak demands forecasts by temperature correction where an individual peak demand might be influenced greatly by the temperature at that time. Temperature has a lesser impact on annual energy consumption where the effect is found to generally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

3.2.2 Historic Generated Peak Demands

The historic generated peak demands, actual and temperature corrected are shown in Figure 3.3 below. These demands are peak generated and include customer private generation i.e. are greater than would have been observed if the private generation had not been running over the peak period.

Figure 3.3 – Historic Demands

[1] First Trust economic outlook



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

The generated sent out forecasts used in the analysis are not generated peak demands but are net of power station auxiliary load, and do not adjust for suppressed demands resulting from private customer generation.

3.2.3 Review of 2005/06 Winter Period

During winter period 2005/06, the NI maximum generation was 1719MW [1681MW centrally despatched, 38MW of other generation (including renewable generation)] and occurred on Tuesday 13 December 2005 at 17.20hrs. When adjusted to average cold spell (ACS) conditions, the peak demand was determined to be 1741MW – an upward adjustment of 22MW from measured.

The NI minimum demand occurs during the summer period, and was 580MW on Tuesday 12 July 2005 at 06.00hrs. No ACS adjustment is applied to demands during the months of March through to the beginning November.

NIE/SONI have historically quoted figures as being ‘peak generated’. To convert ‘peak generated’ to ‘sent out’ a factor of 94.2% is applied to the ‘generated peak’ demand. The sent out demand does not include power station auxiliary load.

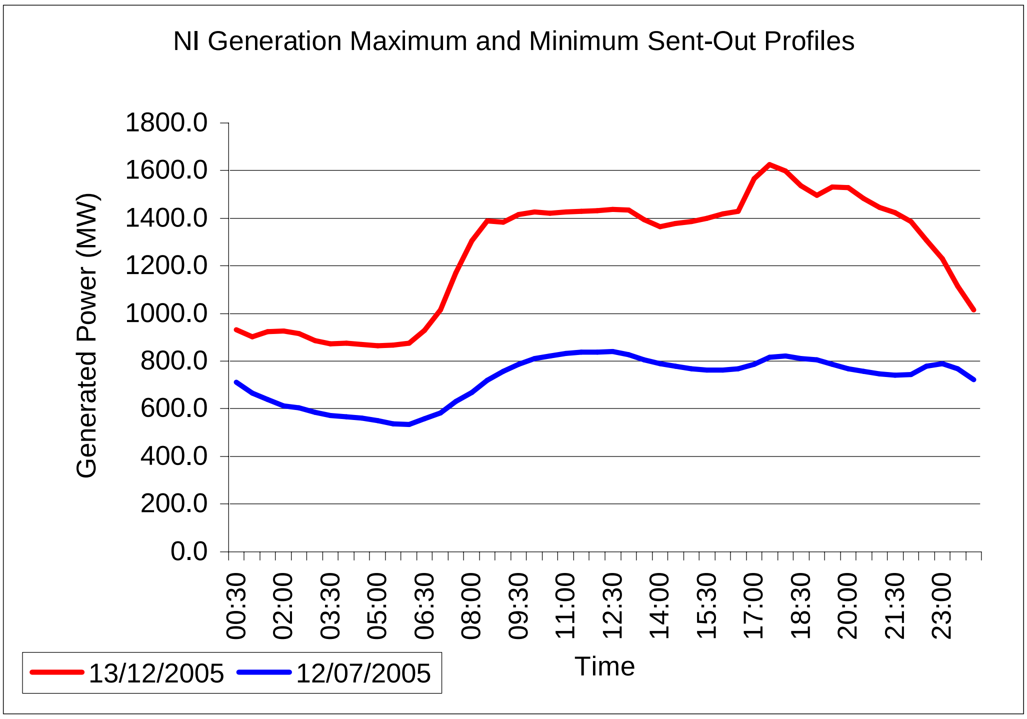
Figure 3.2.3 - NI Peak Generation

Measured	Maximum Measured	ACS Correction*	Minimum
Generated	1719 MW	1741 MW	580 MW
Sent-out	1625 MW	1647 MW	535 MW

**Applies to maximum measured only*

Figure 3.4 below plots the day profile on which the sent-out generation maximum and minimum values occurred.

Figure 3.4 – Sent Out Demand Profiles



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. The profiles in Figure 3.4 do not include the demand that was suppressed by customer private generation (approx. 132MW). At a network nodal level, 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.

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.

The numbers of jobs in the construction and service sectors in NI have continued to grow; whilst the manufacturing sector has continued to decline. Manufacturing productivity has shown an upward trend in recent years with manufacturing output remaining stable despite falling employment in the sector.

There is a possibility that next year's UK comprehensive spending review may result in some additional resources becoming available but the overall outlook to 2010 is for very modest growth. Higher energy bills, property revaluation, university top-up fees and phasing in of water charges early next year, will affect consumer spending. The outlook for industrial output remains somewhat mixed and is contingent upon an upturn in the national economy.

Figure 3.5

GDP growth Predictions (%)

	2006	2007	2008
NI	2.0%	2.2%	2.5%

(Sept 2006 – First Trust Economic Outlook)

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.

Medium 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 3.6 – Medium Forecast

Medium

YEAR	GEN Demand (MW)	GEN Energy (GWh)
2007	1667	9219
2008	1694	9368
2009	1721	9520
2010	1749	9675
2011	1777	9832
2012	1805	9991
2013	1836	10153

This forecast represents an underlying growth rate of circa 1.6 - 1.7%. The generation peak demand (MW) increases by an average of 28MW per annum and the generation energy forecast by 156GWh per annum.

Low forecast scenario

This forecast represents a lower growth rate for electricity demand based on an analysis of historic forecast trends (1993 - 2005). The lowest growth rate predictions over that period were circa 1.4% which is used in the forecast below.

Figure 3.7 – Low – Forecast

Low Forecast

YEAR	GEN Demand (MW)	GEN Energy (GWh)
2007	1652	9170
2008	1673	9300
2009	1694	9433
2010	1715	9566
2011	1737	9702
2012	1758	9840
2013	1781	9980

The generation peak demand (MW) increases by an average of 22MW per annum and the generation energy forecast by 135GWh per annum.

High forecast scenario

This forecast represents a higher rate of growth of electricity demand based on an analysis of historic forecast trends (1993 - 2005). The highest growth rate predictions over that period were circa 2.2 – 2.3% which is used in the forecast below.

Figure 3.8 – High Forecast

High Forecast

YEAR	GEN Demand (MW)	GEN Energy (GWh)
2007	1696	9364
2008	1735	9572
2009	1775	9783
2010	1815	9999
2011	1857	10220
2012	1900	10445
2013	1944	10675

The Generation Peak Demand (MW) increases by an average of 41MW per annum and the Generation energy forecast 218GWh per annum.

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

Figure 3.9 – Forecast Comparisons – High/Medium/Low – Demand MW

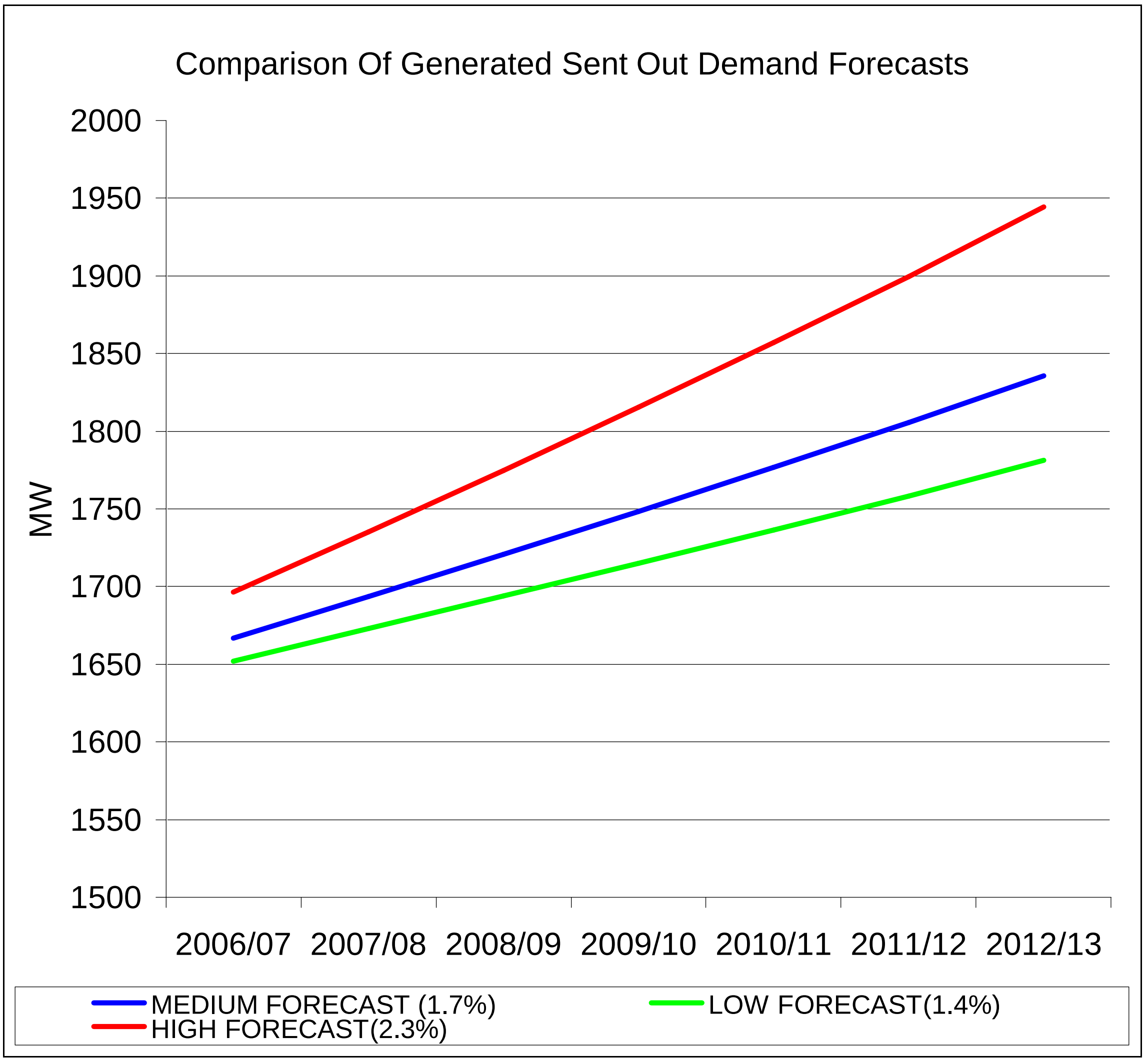
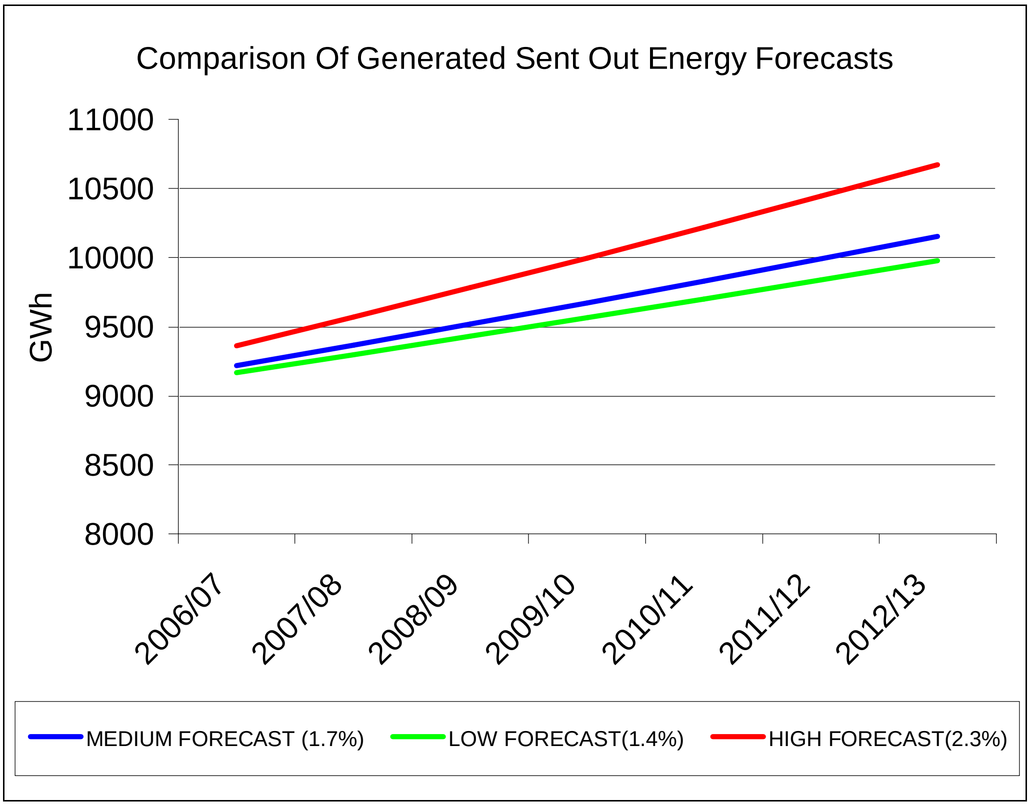


Figure 3.10 – Forecast Comparisons – High/Medium/Low – Energy (GWh)



4.0 Generation Input Data

This section of the report deals with the generation input data used to create the capacity outage probability table (COPT) described in Section 2.0.

Over the time period 2007 – 2013 generation capacity, forced outage probabilities (FOPs) and scheduled outage duration (SOD) information for each generator is used to assess the balance between power generation capacity and customer demand.

4.1 Generation Capacity Assumptions

In advance of the preparation of this statement SONI met with NIAUR to discuss the future retirement and cancellation option dates of generating plant under contract to NIE until 2013. 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 represents the best view of the capacity position up until 2013.

The new SEM arrangements including the capacity payment mechanisms appropriate are designed to create conditions where there will be economic signals for investment in new generation projects.

However it is only possible to make assumptions about the life of generation capacity and the future level of renewable generation.

Figure 4.1 – Generation Capacities 2007 - 2013

Cenrally Despatched Generating plant	Fuel type	Sent Out Generating Capacity (net - MW)						
		2007	2008	2009	2010	2011	2012	2013
Ballylumford ST 4	*Gas/HFO	170	170	170	170	170	170	
Ballylumford ST 6	*Gas/HFO	170	170	170	170	170	170	
Ballylumford CCGT 21	*Gas/Gasoil	159	159	159	159	159	159	159
Ballylumford CCGT 22	*Gas/Gasoil	159	159	159	159	159	159	159
Ballylumford CCGT 20		170	170	170	170	170	170	170
Ballylumford CCGT 10	*Gas/Gasoil	98	98	98	98	98	98	98
Ballylumford GT 7	Gasoil	58	58	58	58	58	58	58
Ballylumford GT 8	Gasoil	58	58	58	58	58	58	58
Kilroot ST 1	*Oil/coal	240	240	240	240	240	240	240
Kilroot ST 2	*Oil/coal	240	240	240	240	240	240	240
Kilroot GT 1	Gasoil	29	29	29	29	29	29	29
Kilroot GT 2	Gasoil	29	29	29	29	29	29	29
Coolkeeragh GT 8	Gasoil	58	58	58	58	58	58	58
Coolkeeragh CCGT	*Gas/Gasoil	400	400	400	400	400	400	400
Moyle Interconnector	DC Link - *note 1*	450	450	450	450	450	450	450
Total Generation Capacity		2488	2488	2488	2488	2488	2488	2148

* - 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 day rating of 450MW and 400MW summer day, this is due to network security considerations.

In Figure 4.1 the only units that are assumed to be decommissioned by 2013 are Ballylumford ST4 and ST6 which have opted out of the EU Large Combustion Plant Directive (LCPD). The individual generator capacities are expressed in sent out terms that is net of power station auxiliary load.

There is a total capacity of 2488MW in 2007. This does not include the 100MW of capacity that can be relied on from RoI. (See Section 2.0).

The generation capacities represented are for peak periods. For example the capacities at Kilroot ST1 & ST2 on coal fuel are reduced by 37MW to 203MW. The open cycle gas turbines at Ballylumford, GT 7&8, would normally operate at a maximum of 53MW at non-peak periods representing a reduction of 5MW from full output.

The large-scale generation is mainly connected to the east of the province, with the exception of Coolkeeragh Power Station that is connected in the North West. The connection points are shown on the 2007 Transmission and Generation map (see Appendix A).

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

Figure 4.2 – Contact Details

Centrally Despatched Generating plant	Fuel type	Generation Contract details
Ballylumford ST 4	*Gas/HFO	Contracted until 31 March 2012, can be cancelled earlier. Assumption - Opted out of the LCPD (20,000 hrs limit to generate) from 2008
Ballylumford ST 6	*Gas/HFO	Contracted until 31 October 2007, with an option to extend. Assumption - Opted out of the LCPD (20,000 hrs limit to generate) from 2008
Ballylumford CCGT 21	*Gas/Gasoil	Contracted until 31 March 2012
Ballylumford CCGT 22	*Gas/Gasoil	Contracted until 31 March 2012
Ballylumford CCGT 20		Contracted until 31 March 2012
Ballylumford CCGT 10	*Gas/Gasoil	Contracted until 31 March 2012
Ballylumford GT 7	Gasoil	Contracted until 2020, can be cancelled earlier by NIAUR
Ballylumford GT 8	Gasoil	Contracted until 2020, can be cancelled earlier by NIAUR
Kilroot ST 1	*Oil/coal	Contracted until 2024, can be cancelled earlier by NIAUR
Kilroot ST 2	*Oil/coal	Contracted until 2024, can be cancelled earlier by NIAUR
Kilroot GT 1	Gasoil	Contracted until 2024, can be cancelled earlier by NIAUR
Kilroot GT 2	Gasoil	Contracted until 2024, can be cancelled earlier by NIAUR
Coolkeeragh GT 8	Gasoil	Contracted until 2020, can be cancelled earlier by NIAUR
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.

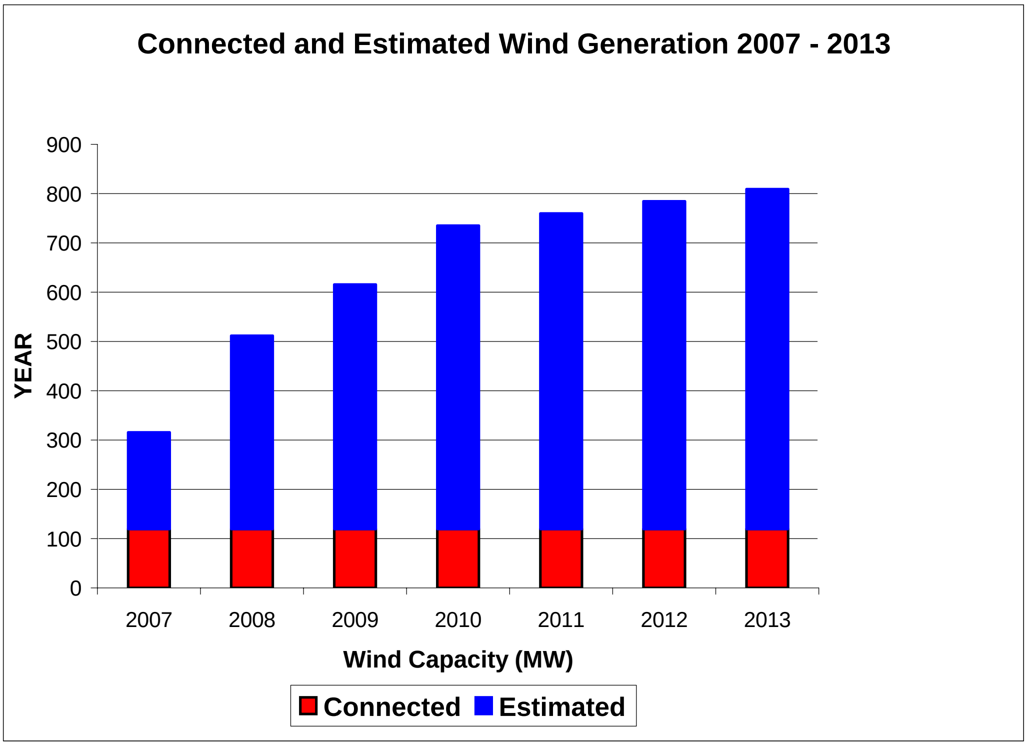
4.2 Renewable Generation

The increase in generation capacity due to the connection of wind farms to the NI distribution network represents a necessary increase in generation capacity available to meet demand. Higher penetration of wind generation leads to the system operator having to manage the variability and system security issues in real time. Into the future it is important that the centrally despatched plant is of the appropriate plant type mix to enable the system to be operated in a stable manner.

Section 3.0 explains how the future wind profiles are created. The methodology agreed with NIAUR is to subtract the wind profile from the total NI generation demand profile. The resulting profile is used to assess the capacity adequacy of the centrally despatched generation capacities (including the Moyle Interconnector) listed in Figure 4.1.

Figure 4.3 below shows the expected installed capacity from 2007 to 2013. The capacity levels increase greatly in the early years with a total capacity in excess of 600MW expected by 2010. At this level of wind penetration it may be necessary to curtail wind at low load times for system security and stability reasons. The annual capacity values are the estimated average value for each year as additional wind generation is connected progressively throughout the year.

Figure 4.3 – Wind Capacity



The estimated wind capacity is derived from information provided by wind developers of their plans over future years. It is therefore not appropriate to publish full details of each of the wind generators that make up the totals in the graph. 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).

Figure 4.4 – Committed Renewable Generators

Wind Farm Name	2006	2007				2008
		Q1	Q2	Q3	Q4	
Corkey	5.0					
Slievenahanghan	1.0					
Rigged Hill	5.0					
Snugborough	13.5					
Slieve Rushen Ph1	5.0					
Elliot's Hill	5.0					
Altahullion	26.0					
Tappaghan	19.5					
Lendrum's Bridge	13.2					
Bessy Bell	5.0					
Owenreagh	5.0					
Callagheen	16.9					
Bin Mountain		9.0				
Slieve Rushen Ph2			54.0			
Owenreagh Ext.			5.1			
Lough Hill			7.8			
Garves				15.0		
Wolfe Bog				11.5		
Altahullion Ext.				12.0		
Bessy Bell 2						9.0
Quarterly Total	120.1	9.0	66.9	38.5	0.0	9.0
Total (MW)	120.1	129.1	196.0	234.5	234.5	243.5

The network connection points of these wind farms are shown in Appendix A. It can be seen that the majority of sites are located to the west of the province. This map shows the generation sites in relation to the NI transmission network.

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

A number of possible solutions are being considered by NIE, in conjunction with the work of the All-island Wind Studies Group. This

Group has been established at the request of the RoI and NI governments (DCMNR and DETI respectively). There are four separate work streams with work stream 2 broadly considering the variability issues and work stream 3 the network development requirements. The Group is expected to report in the first quarter of 2007.

Non Fossil Fuel Obligation (NFFO) Capacity

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 report it is assumed that they will continue to generate as renewable IPP plant.

Figure 4.5 – NFFO

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
NFFO2		
Lendrum's Bridge	Wind	5000
Slievenahanaghan	Wind	1000
Blackwater Museum	Biomass	204
Brook Hall Estate	Biomass	100
Benburb Small Hydro	Hydro	75
Total NFFO		38753

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 this situation may change.

4.3 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 132MW. The largest proportion of this power is provided by industrial and commercial customers utilising diesel generators which tend to operate over peak periods (16.00-20.00hrs) with some CHP 24 hour generation (circa 15% of total private generation). Our analysis assumes that tariffs will continue to incentivise this generation to operate and as a result suppress the NI generated demand profile into the future.

4.4 Interconnection

Moyle

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 two co-axial under sea cables from Ballycronanmore (Islandmagee NI) to Auchencrosh (Ayrshire, Scotland). The physical capacity of the link is 500MW but the transfer capability is curtailed by certain network limitations in both NI and Scotland. The available net transfer capacity (NTC) for import into NI is therefore 400MW, except in emergency conditions, when it can be increased to 450MW. The NTC figure of 400MW is further reduced to 300MW during summer nights to take account of network load changes or outages. NIE PPB has retained priority access to 125MW of capacity until late 2007. The remaining interconnector capacity is auctioned by SONI on behalf of Moyle Interconnector Ltd. Some of this capacity is purchased by market participants to facilitate transit energy flows to supply the RoI market. 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 NGET facilitates energy purchases including emergency assistance up to the emergency 450MW capacity of the interconnector. This capacity and availability level attributed to the Moyle interconnector is based on an assumption that there would be energy available in a GB system with circa 70TW of installed generation capacity to meet a generation shortfall situation. 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. A 450MW import capability on Moyle tends to project a healthy position with respect to capacity adequacy in NI. In practice the current achievement of a high level of security of supply in NI comes with operational complexity and uncertainty as a result there is a need for SONI to engage to SO-SO trades with NGET and maintain operational security standard. In operational timeframes margins are frequently tight and complex to manage.

North-South

The maximum available export transfer capacity that was on the North-South interconnector auctioned in 2006/07 was 330MW by synchronous interconnection. Some trades from Scotland on the Moyle Interconnector pass through the NI transmission system to RoI and in addition a percentage of the output of the Coolkeeragh CCGT is exported to RoI. In the event of a major loss of NI generation the energy flows on the interconnector to the RoI may be pulled back to zero (by purchasing at the marginal trading price), such that if load shedding is required the importing utility must take appropriate action to reduce demand. This methodology is adopted consistently by both SONI and Eirgrid. The maximum S-N import NTC was set at 170MW due to network limitations on the ESB network and separation constraints.

4.5 Generator Availability Data

Section 2.0 describes the methodology and 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 magnitude 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 the loss of availability as a result of 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 operational impact than scheduled outages due to their unpredictability in operational time frames.

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 each generating unit indicating the expected start and finish dates of required maintenance outage periods. As the individual generator scheduled outages are confidential and commercially sensitive they are not listed.

Forced Outage Probabilities (FOPs)

Individual Forced outages are derived from the generators' indicative availability declarations and 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 in, for example, newly commissioned plants comparisons are made with similar units.

The FOP is 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 be unavailable. Historic performance is used to determine future FOPs for Moyle HVDC link.

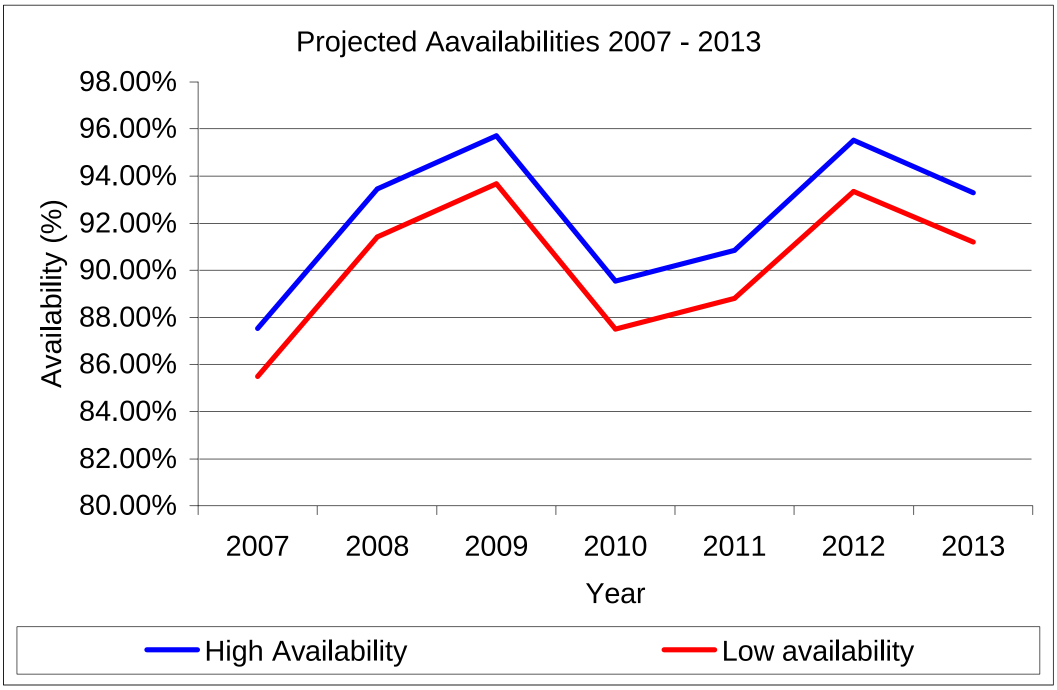
Generator Availability scenarios on a network basis

It is possible to derive a single availability figure for all generators. 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 system operational requirements and customer demand.

In Section 5.0, the Capacity assessment of the report, it is necessary to present a range of scenarios for the future. High and low availability scenarios are used. The high availability scenario is based on the actual historic performance of generators in NI, which is considered to be good to optimistic. The low availability scenarios 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.

In Figure 4.5 below the availabilities projected for the 7-year period covered by this report are displayed.

Figure 4.6 – Future Availabilities



Year	2007	2008	2009	2010	2011	2012	2013
High Availability	87.54%	93.46%	95.72%	89.54%	90.86%	95.52%	93.30%
Low availability	85.49%	91.42%	93.67%	87.50%	88.81%	93.34%	91.20%

The average high availability over the seven year period is 92.3% and the low availability figure is 90.2%.

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.

5.0 Assessment of Generation Capacity Requirements

The results in this section of the report are a series of graphs representing surplus or deficit generation capacity from 2007 to 2013. This follows the methodology described in Section 2.0. The surplus or deficit is expressed in demand terms (MW) 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 (PCC) 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)	(2.2 – 2.3)%	Optimistic
MediumDemand (MD)	(1.6 – 1.7)%	Most likely
Low Demand (LD)	1.4%	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

Figure 5.1 describes all of the above scenarios on a single graph from 2007 – 2013. This is particularly useful as it is possible to assess the full extent of the surplus/deficit for each scenario.

Figure 5.1 - Surplus/Deficit All Scenarios

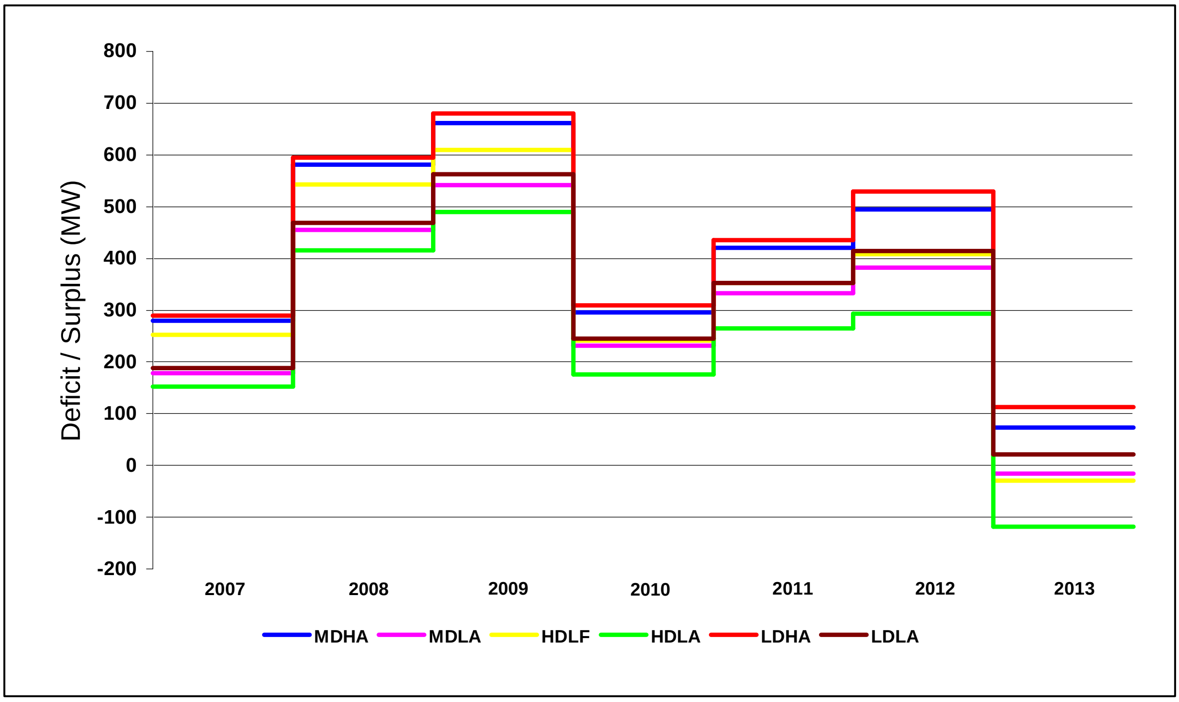


Figure 5.2 – Surplus/Deficit – High Availability

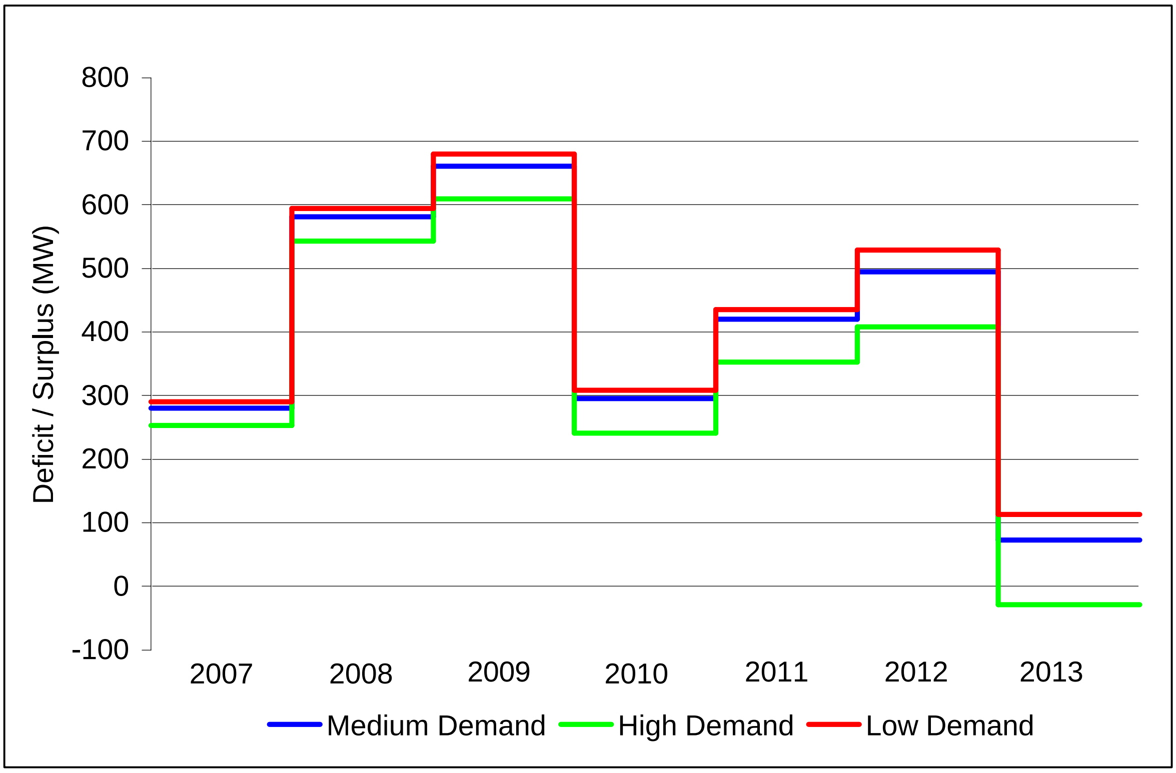


Figure 5.3 – Surplus/Deficit – Low Availability

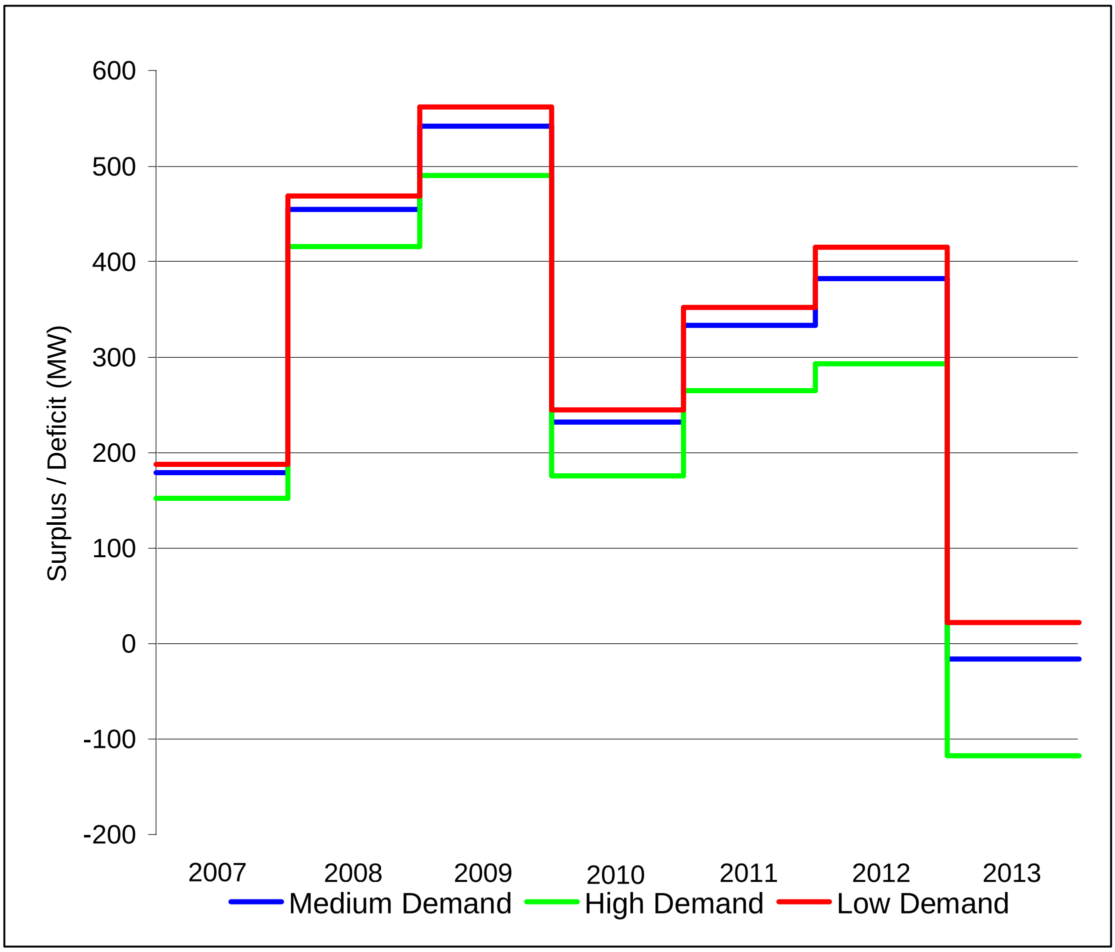


Figure 5.4 provides a tabular summary of the above analysis with red values representing deficits.

Figure 5.4 – Surplus/Deficits All Scenarios

Demand	Availability	2007	2008	2009	2010	2011	2012	2013
Low	High Low	290 188	595 469	680 562	309 245	435 352	529 415	113 22
Medium	High Low	280 179	581 455	661 542	296 232	420 333	495 382	73 -16
High	High Low	253 152	543 416	610 490	241 176	353 265	408 293	-29 -118

5.2 All island Generation Capacity Assessment for 2013

In 2013 it is anticipated that constraint costs in SEM resulting from the present N-S interconnector and associated transmission system limitations will be reduced with the introduction of additional interconnection capacity. NIE and Eirgrid are planning to build a 400kV interconnector between Cavan and Tyrone and it is expected to be completed during 2012 which is approximately 85km in length. This will reduce the constraint costs and increase the transfer capacity between NI and RoI. A series of adequacy studies were carried out by Eirgrid with a single security standard and single all island portfolio of generation for 2013. The results of these studies found a capacity deficit of circa 1000MW on the island of Ireland. An all-island generation adequacy standard of 8 hours LOLE was chosen for the studies and the scenario studied was based on credible generator availability figures and demand growth in RoI and NI.

5.3 Capacity Requirements 2007 – 2013

Each of the surplus/deficit graphs has similar characteristics. Figure 5.1 summarises a broad analysis of each year of the statement with all scenarios represented. There is approximately 200MW of variation between the LDHA and HDLA each year.

There is considerable variation from year to year and this is primarily caused by changing generator Scheduled Outage Duration requirements (SODs). The variations are particularly pronounced due to the relatively small generation pool and the relatively large unit sizes.

Surpluses reduce considerably in years 2007 and 2010. As a result the operation of the system will require careful planning at times when margins are low. In 2007 with the HDLA scenario there is only circa. 150MW of surplus generation.

By 2013 the final year of this assessment even the most likely scenario of MDHA indicates a surplus of less than 100MW with the pessimistic scenario showing a deficit of 100MW. This situation is a result of the withdrawal of the two Ballylumford phase 2 machines (a total of 340MW capacity). There is a clear requirement for generation plant in advance of 2013 to ensure security of supply is maintained in NI. It should be noted that similar analysis in RoI also shows a generation capacity deficit.

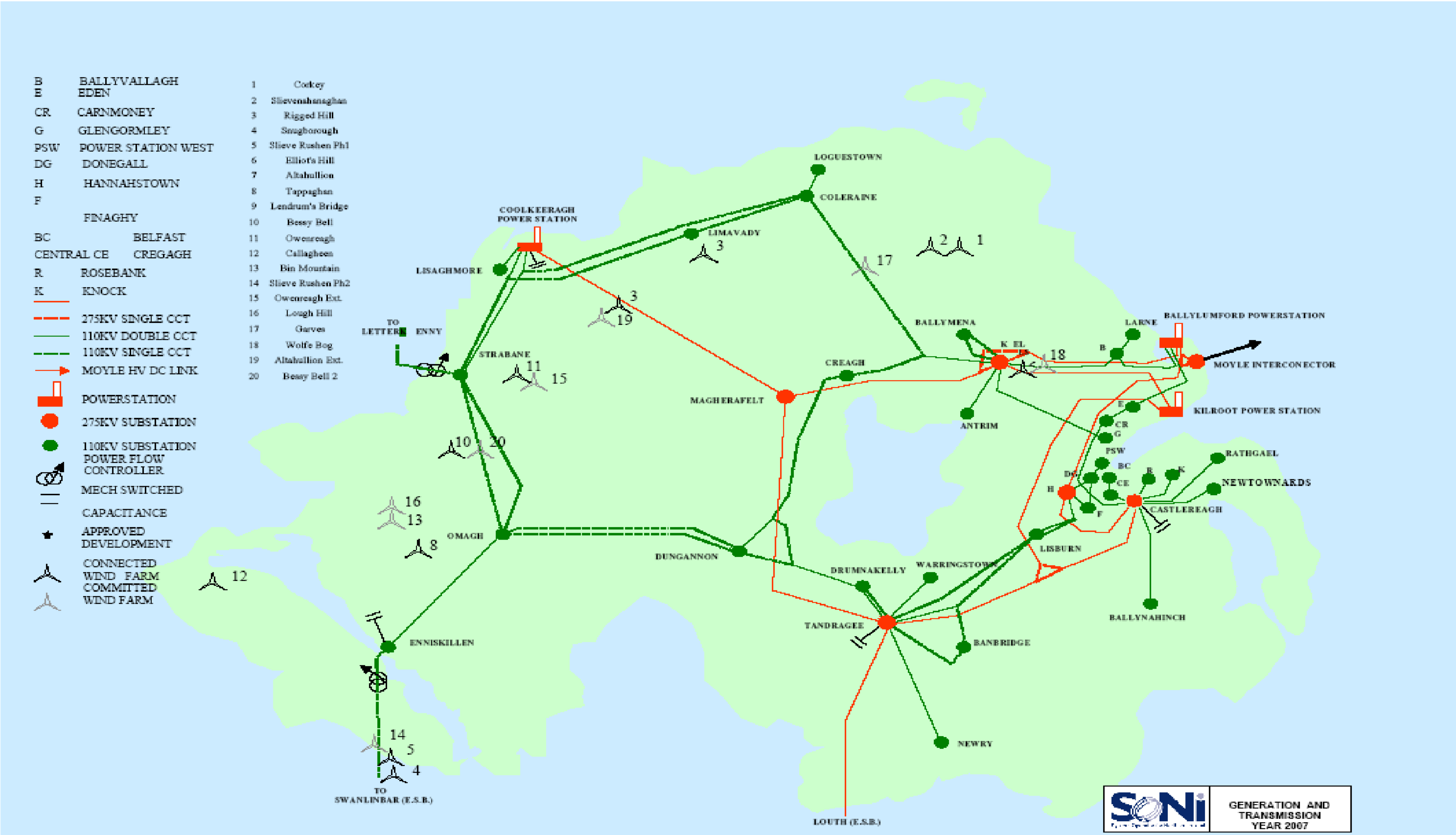
In the short term there are capacity surpluses however in practice SONI is left with tight margins to manage in operational time frames. A capacity of 450MW on Moyle can only be utilised if generation capacity is available in the UK market. In normal operation pre SEM a proportion of the power generated by the Coolkeeragh CCGT will flow to customers in RoI, and SONI is also required to maintain spinning reserve capacity as a system security measure. As a result it is proving to be more and more difficult to plan the release of plant in an economically optimal manner for short term planned maintenance even at times of low load. The financially driven electricity markets create a level of complexity in maintaining satisfactory operating security standards.

5.4 Comparison with Previous Capacity Assessments

The methodology used in this report is broadly similar to previous Generation Seven Year Capacity Statements in that it is based on probabilistic statistical techniques. The main difference is that now an all year assessment is carried out as compared to the previous analysis that focussed specifically on the winter period.

Previous Generation Seven Year Statements indicated surplus generation capacity levels in the region of 300MW. In this statement an additional 170MW unit at Ballylumford has been added to the portfolio and there is a formal reliance of 100MW placed on RoI, yet even with these additions, the new methodology is only highlighting surpluses comparable with previous stated levels in certain years. This is a result of the all year approach now taken, where generation maintenance requirements can result in low capacity margins and increased risk during periods of light load in summer.

Appendix A


B BALLYVALLAGH
E EDEN
CR CARNMONEY
G GLENGORMLEY
PSW POWER STATION WEST
DG DONEGALL
H HANNAHSTOWN
F FINAGHY
BC BELFAST
CENTRAL CE CREAGAGH
R ROSEBANK
K KNOCK
275KV SINGLE CCT
110KV DOUBLE CCT
110KV SINGLE CCT
MOYLE HV DC LINK
POWERSTATION
275KV SUBSTATION
110KV SUBSTATION
POWER FLOW CONTROLLER
MECH SWITCHED CAPACITANCE
APPROVED DEVELOPMENT
CONNECTED WIND FARM
COMMITTED WIND FARM
1 Corkey
2 Slievenahanaghan
3 Rigged Hill
4 Snugborough
5 Slieve Rushen Ph1
6 Elliot's Hill
7 Altahullion
8 Tappaghan
9 Lendrum's Bridge
10 Bessy Bell
11 Owenreagh
12 Callagheen
13 Bin Mountain
14 Slieve Rushen Ph2
15 Owenreagh Ext.
16 Lough Hill
17 Garves
18 Wolfe Bog
19 Altahullion Ext.
20 Bessy Bell 2
LOGUESTOWN
COLERAINE
COOLKEERAGH POWER STATION
LIMAVADY
LISAGHMORE
TO LETTERKENNY
STRABANE
MAGHERAFELT
CREAGH
BALLYMENA
ANTRIM
LARNE
BALLYLUMFORD POWERSTATION
MOYLE INTERCONNECTOR
KILROOT POWER STATION
RATHGAEL
NEWTOWNARDS
CASTLEREAGH
LISBURN
BALLYNAHINCH
OMAGH
DUNGANNON
DRUMNAKELLY
WARRINGSTOWN
TANDRAGEE
BANBRIDGE
ENNISKILLEN
NEWRY
TO SWANLINBAR (E.S.B.)
LOUTH (E.S.B.)
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