System Operator for Northern Ireland

Seven Year Generation Capacity Statement 2009 – 2015

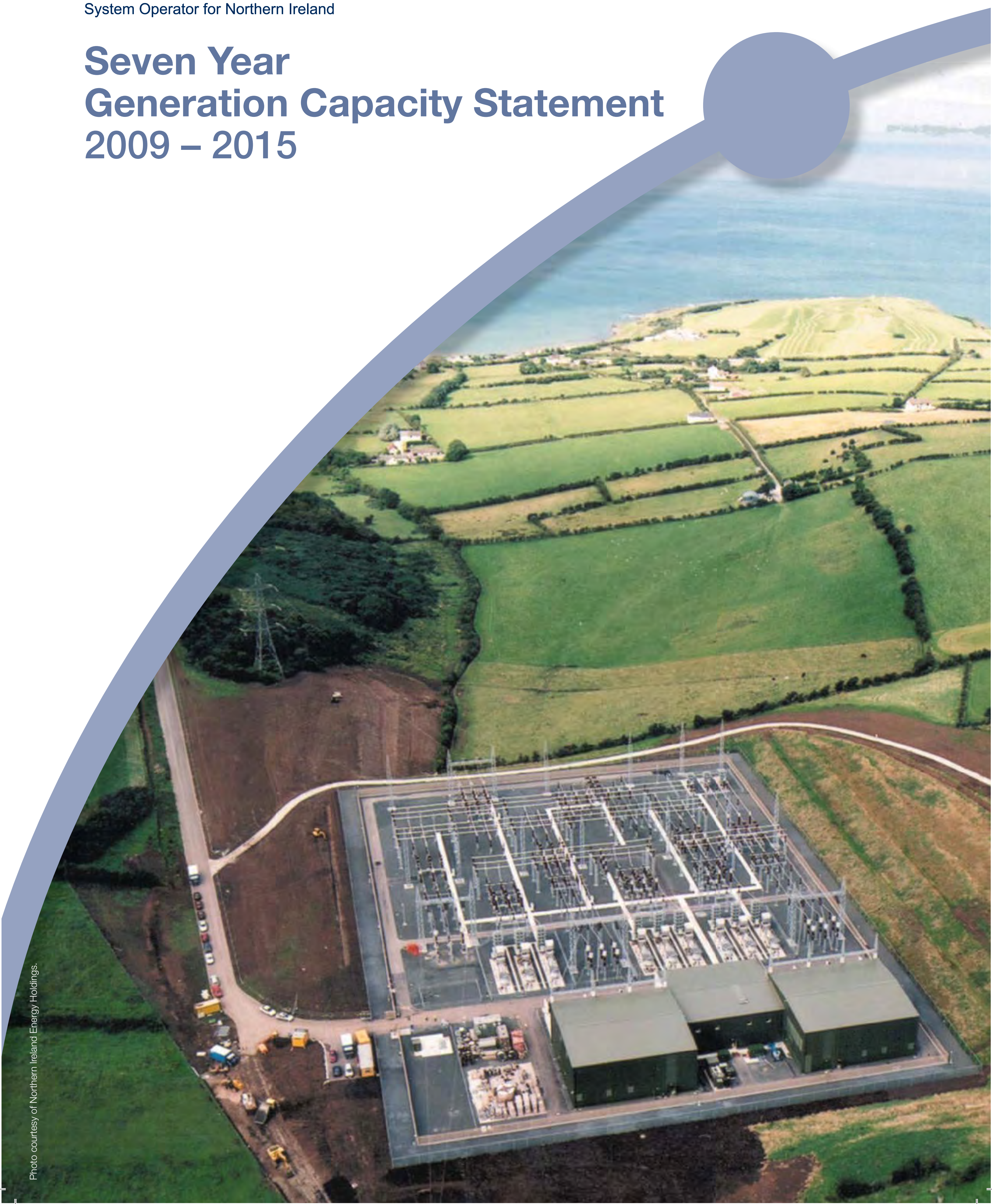

Photo courtesy of Northern Ireland Energy Holdings.

SONI Ltd

SEVEN YEAR GENERATION CAPACITY STATEMENT

For the years 2009 to 2015

November 2008

12 Manse Rd, Belfast, BT6 9RT

Front cover image: Moyle HVDC interconnector. Photo courtesy of Northern Ireland Energy Holdings. Chapter page images: Lendrum's Bridge 13.2MW wind farm. Photo courtesy of RES. Rear cover image: Coolkeeragh Power Station. Photo courtesy of Coolkeeragh ESB

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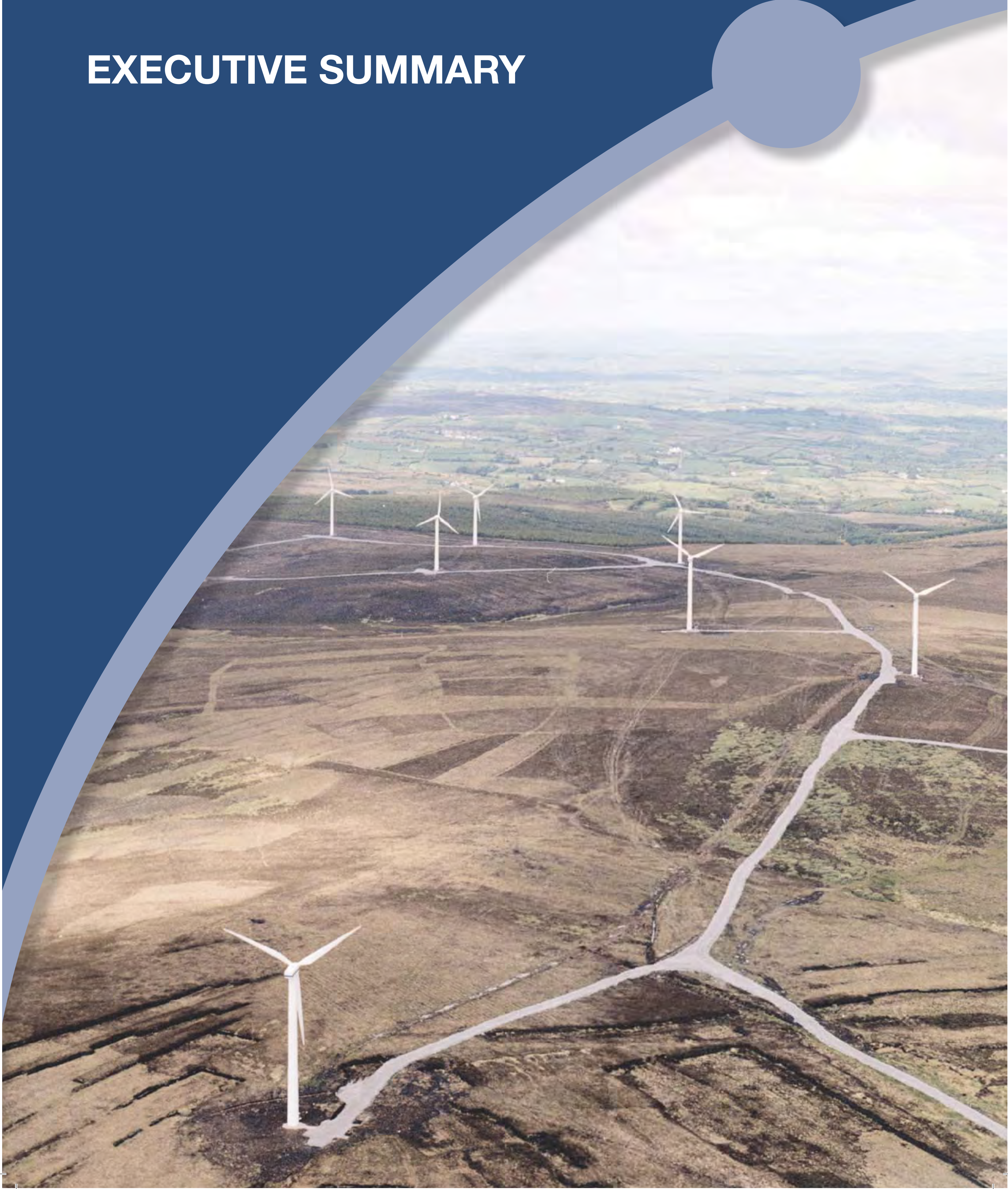

EXECUTIVE SUMMARY

- *The Generation Security Standard is met until 2015 for the central demand and generator capacity availability scenario. The central or most likely scenario (Medium Demand High Availability) assumes further North-South tie line capacity and increased generation capacity at Kilroot by 2013.*

- *The expected significant increase in penetration of wind generation in the NW and on the island as a whole has been included in the analysis. Studies are underway to understand the operational and technical challenges that the renewable targets present.*

- *The harmonised (SONI-EirGrid) approach to all year analysis of generation capacity established in 2006 has been adopted.*

- *The analysis is based on an NI Generation Security Standard of 4.9 hours Loss of Load Expectation (LOLE) with 100MW reliance on RoI for the period 2009- 2012. For the period 2013-2015 an All Island Generation security standard of 8 hours is used.*

This 2008 Generation Seven Year Capacity Statement has been produced by SONI Ltd, the Transmission System Operator (TSO) in Northern Ireland (NI), in accordance with condition 35 of its Transmission System Operator Licence). It is an assessment of the adequacy of the generation capacity in NI over the seven year period from 2009 to 2015 based on an agreed Generation Security Standard.

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) has operated since November 2007. It is a wholesale electricity market based on a gross mandatory pool supported by a capacity payment mechanism. This is designed to reward generation for being available and to create an environment that attracts new generation to enter the market to meet the generation security standard

As part of the process to produce a single all island generation adequacy report the Regulators (NIAUR 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”.

This paper proposed a revised methodology to assess generation capacity adequacy initially in NI and ROI separately but moving towards an all-island approach when additional tie-line capacity is available between NI and ROI in 2012/2013. 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. Prior to 2006 the Northern Ireland methodology was confined to analysis over winter peak demand periods only.

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 transmission system N-S tie line remains a physical constraint. As an assessment against a single standard was not feasible while this physical constraint existed it was determined that it was appropriate to maintain for an interim period a separate adequacy assessment in NI and RoI against separate generation security standards. The agreed harmonised methodology would be used and an agreed level of capacity reliance would be placed on each on NI and RoI respectively.

This is now the third year that the new methodology has been adopted and details are included in section 2.1 of this report.

The generation capacity assessment in NI is made against three future forecast demand scenarios - High, Medium and Low (i.e. increases in demand of 2.3%, 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 takes into account assumed levels of planned and forced outages. NI has benefited from high levels of generator availability (circa 92%). This 92% availability level is therefore the high level scenario used in this statement. A more pessimistic low level scenario based on an availability of 90% is also used.

In the last Generation Seven Year Capacity Statement, the high availability medium demand, the central or most likely scenario, showed surpluses of between circa 540MW and 620MW for the years 2007-2012. In the 2008 Generation Seven Year Capacity Statement, the same scenario shows surpluses of circa 446MW and 924MW for the years 2009-2015

The 2008 Statement has revisited the generation capacity assumptions made in the previous statement and included the following revisions;

Revised assumptions regarding planned outages. The assumptions used in the 2007 Statement are deemed to be optimistic i.e. more outages are now required to meet the statutory requirements of generating plant and the operating regimes experienced to date in SEM.

There is also an additional 690MW of generation capacity (520MW at Kilroot and 170MW at Ballylumford) that has received connection offers since the last 2007 Statement was published.

A revised decommissioning plan has been received from Ballylumford. The 2007 Statement had assumed that the two steam units at Ballylumford (G4 & G6) would be decommissioned by 2013 due to environmental constraints. During the last year the running hours of these machines have been less than expected. New estimates of running hours for the next seven years have led to the assumption that G5 and G6 will be decommissioned by 2014 and G4 will be available until 2015.

This Statement concludes that during the period from 2009 to 2015 there is sufficient generation capacity to achieve compliance with the generation security standard.

This is based on the assumption that forecasts of demand, generation capacity and availability are achieved. It also relies on imports from GB a reliance on generation in RoI. There remains however a risk of an operational scenario that could result in load shedding due to a generation capacity shortfall as generator unit sizes are large and there is a dependency on imports.

For example, 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. For future statements additional analysis will be required to assess likely power flows and the capability of importing energy from the GB system.

By placing a formal reliance on 100MW of capacity from RoI this again assumes that this capacity is available when required.

1.0 INTRODUCTION

1.0 INTRODUCTION

This generation seven year 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 a Licence obligation to produce this statement on an annual basis.

This statement covers the seven year period from 2009 to 2015. The freeze date for the input data that forms the basis of this statement was 15 September 2008. This statement assesses the adequacy of the balance between demand and generation capacity for those years. This analysis is carried out against a generation security standard and to a 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 encourage investment in generation capacity to maintain the generation security standard. This Statement is designed to identify and highlight risks to security of supply over the seven year period on the basis of existing and planned generation capacity.

SONI also monitors the generation capacity situation in operational timeframes and highlights security of supply risks to NIAUR.

2.0 METHODOLOGY FOR DETERMINING NI GENERATION CAPACITY

2.0 METHODOLOGY FOR DETERMINING NI GENERATION CAPACITY ADEQUACY

This section of the statement describes the methodology on which the analysis is based. Appendix A explains the methodology used to determine the generation capacity adequacy pre 2006.

2.1 NI Generation Security Standard and Methodology

The 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 calculation of failure probabilities is carried out for each half-hour period in the year (17,520 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 Appendix A2.

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 dealt with by subtracting it 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.

2.2 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.
- When modelling the all island generation adequacy, the contribution of wind power to generation adequacy is known as the wind capacity credit. This capacity credit has been determined by subtracting the wind forecast from the demand curve. The modified demand curve, (net of wind), results in an improved adequacy position. The amount of conventional plant which leaves the system with the same improvement in adequacy as the net load curve is taken to be the capacity credit of wind.

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 A2.

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

3.0 DEMAND INPUT DATA

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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. It is necessary 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

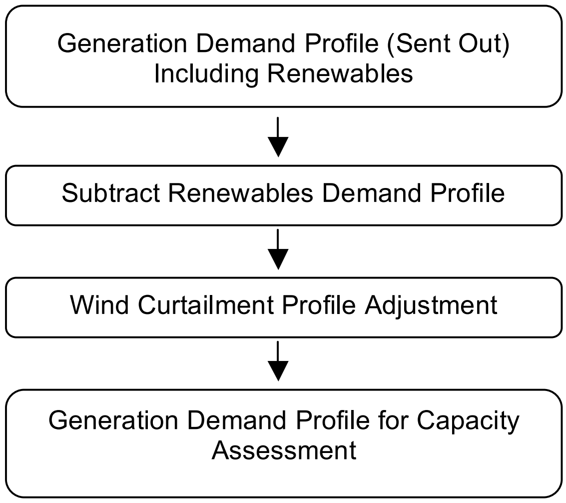
The demand profile data used is on a sent out basis or net of power station auxiliary load. It is the power directly injected onto the 275/110kV transmission network to meet the demand by centrally dispatched generating plant.

The demand profiles that are utilised over the last decade reflect customers running private embedded diesel generation (estimated to total circa 140MW and connected to the distribution system) to avoid the higher winter peak use of system 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 the generation capacity adequacy is then 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 a sufficient level 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 380MW. During the years 2009-15 it has been forecasted that wind curtailment will occur each year. It is more common towards the end of the study as 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



3.1.2 Future Demand Profiles

To create demand profiles for the years 2009-2015 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 2007. There is a similar process used to create generated wind demand profiles and is described in Section 3.1.3.

3.1.3 Generated Wind Demand Profiles

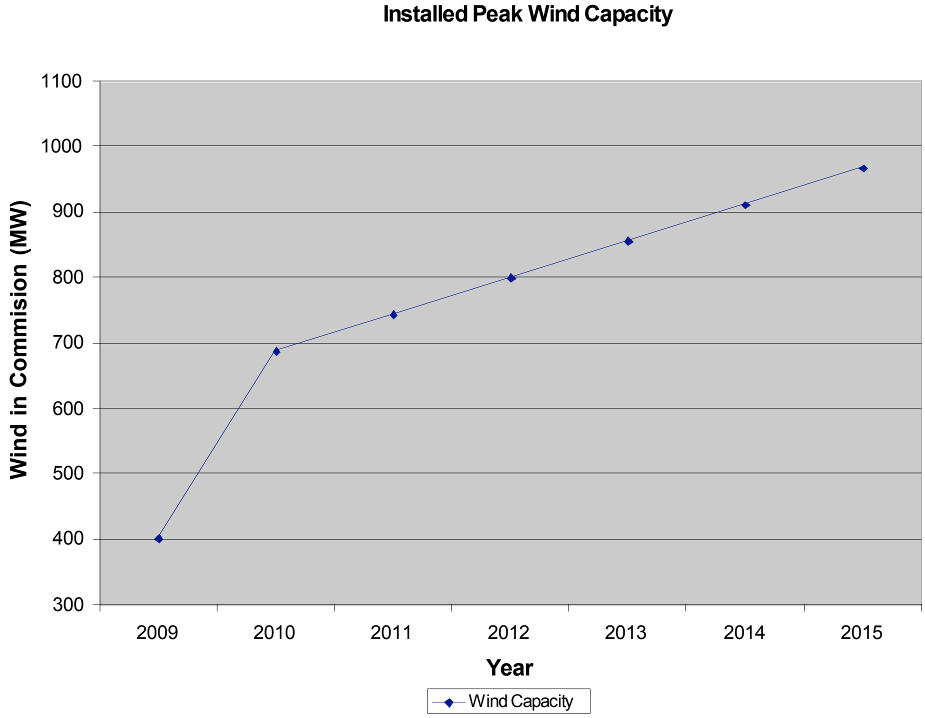
In 2007 there was a peak installed wind capacity of 188.6MW in NI. Individual wind farm generated demand (sent out MW) data was summated for 2007 to provide a base year aggregated profile total. The characteristics of the profile were validated against previous years to ensure it was a satisfactory demand 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 2007 wind profile to ensure a consistent wind shape throughout the year. When this adjustment was made the remaining peak installed capacity equated to 120.1MW. 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 a programme work provided by 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 2007 base year capacity (120.1 MW). The 2007 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	Average Capacity	Scaling Factor
2009	401.4	332.38	2.77
2010	687.95	608.81	5.07
2011	743.95	701.95	5.84
2012	799.95	757.95	6.31
2013	855.95	813.95	6.78
2014	911.95	869.95	7.24
2015	967.95	925.95	7.71



3.2 Demand Forecasts

3.2.1 Forecast Methodologies

The accuracy of demand forecasts depends upon the quality of the data used in the analysis and it 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 2007/2008 Winter Period

The generation peak demand forecasts represent the total NI generated demand. They include private customer generation (140MW), renewable generation, interconnector contributions and NI centrally despatched generation units (CDGU).

The peak demand for 2007/08 occurred on 9th January 2008 @ 17:30pm. The total generation peak demand was as follows:

Figure 3.3 – Review of 2007/08 Winter Period

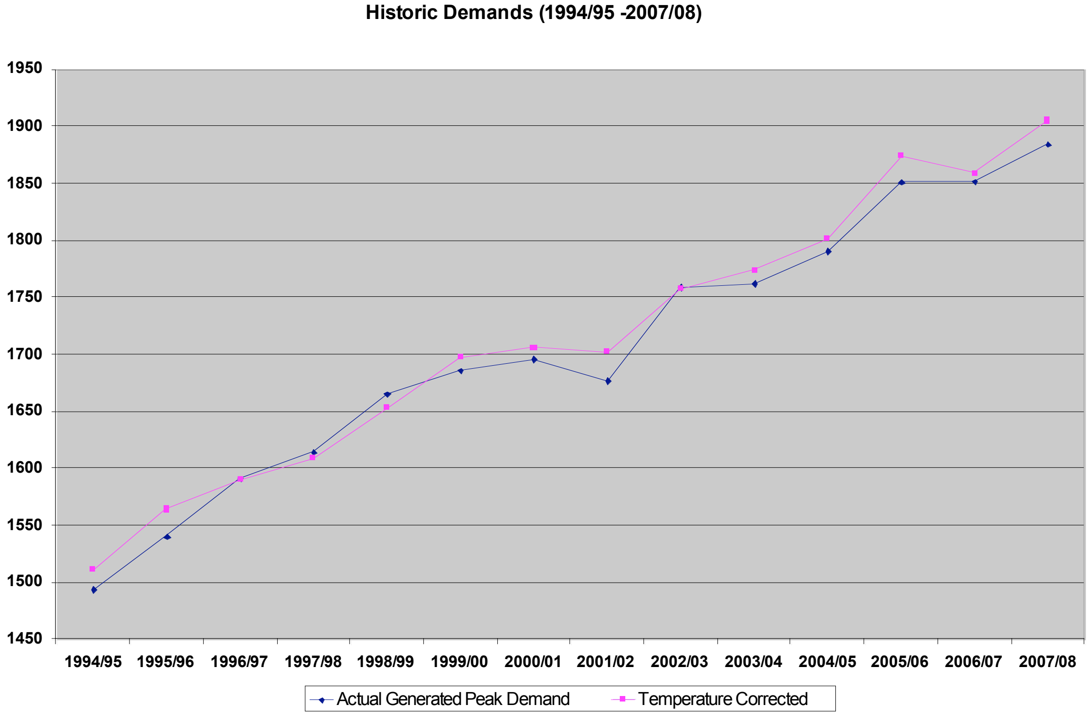
Generation type	**MW's**
CDGU + Interconnections	1704.7
Renewables	39.4
Customer Private Generation	140.0
Total NI Generated Peak Demand	1884.1

When average cold spell temperature correction (ACS) is applied this figure is corrected up by 20.9MW, providing a figure of 1905MW for the 2007/08 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
2007/08	1884	1905

There has been steady incremental demand growth over the last 14 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 2007

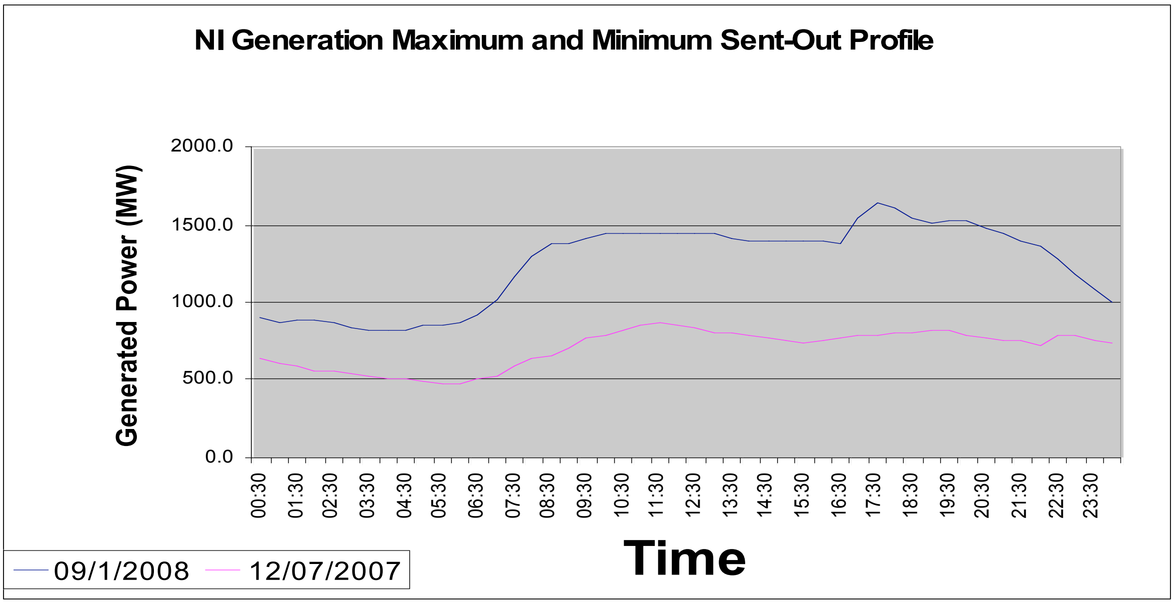
It should be noted that the generation adequacy assessment is based on generation sent out or in net terms. To express the forecasts in Section 3.4 in sent out terms it has been necessary to remove private generation and power station works units. A conversion factor of 0.942 is applied to the NI generated 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 474MW occurred on 12/07/2007 at 06:00am.

The winter maximum demand value of 1645MW occurred on 9/1/2008 at 17:30pm.

The winter maximum demand normally occurs at circa 17.30hrs 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 plots the daily profile on which the 2007/08 sent-out generation maximum and minimum values occurred.

Figure 3.5 – NI Maximum and Minimum Sent-Out Profile



3.3 Economic Outlook

The performance of the NI economy weakened towards the end of 2007 in line with the general slowdown in the UK economy. Increased levels of uncertainty coming from the global economic crisis and the rapidly cooling housing market in NI are starting to affect activity in 2008. However negative growth in the NI economy is not expected.

The outlook for the rest of 2008 and 2009 is for economic growth to continue but at some way below what has been experienced in recent years. GDP levels for 2008 are expected to be 1%. This is 2% lower than what was forecasted in the First Trust economic review, volume 22.2, June 2007.

It is not expected however, that the downturn in GDP levels will have a severe impact on the demand for electricity. Despite the rise in employment figures the significant public service dependence should see the NI economy continue to grow.

Figure 3.6 – DP Growth Predictions (%)

	2007	2008	2009
NI	3.0%	1.0%	1.0%

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 (7 years ahead).

Figure 3.7 – Medium Demand Forecast Scenario

Year	Gen Demand (MW)	Gen Energy (GWh)
2009	1721	9466
2010	1749	9616
2011	1777	9768
2012	1806	9923
2013	1836	10080
2014	1866	10239
2015	1897	10402

This forecast represents an underlying growth rate of circa 1.6%. The generation peak demand (MW) increases by an average of 29MW per annum and the generation energy forecast by 156GWh 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 - 2007). The lowest growth rate predictions over that period were circa 1.4% which is used in the forecast below.

Figure 3.8 – Low Demand Forecast Scenario

Year	Gen Demand (MW)	Gen Energy (GWh)
2009	1705	9400
2010	1729	9530
2011	1753	9663
2012	1778	9797
2013	1803	9933
2014	1828	10071
2015	1854	10210

The generation peak demand (MW) increases by an average of 25MW per annum and the generation energy forecast by 135GWh 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 - 2007). The highest growth rate predictions over that period were circa 2.3% which is used in the forecast below.

Figure 3.9 – High Demand Forecast Scenario

Year	Gen Demand (MW)	Gen Energy (GWh)
2009	1775	9697
2010	1818	9914
2011	1862	10136
2012	1906	10363
2013	1952	10594
2014	1999	10830
2015	2048	11073

These forecasts represent underlying growth rates of circa 2.3%. The generation peak demand (MW) increases by an average of 45MW per annum and the generation energy forecast by 229GWh per annum.

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

Figure 3.10 – Comparison of Generation Demand Forecasts (MW)

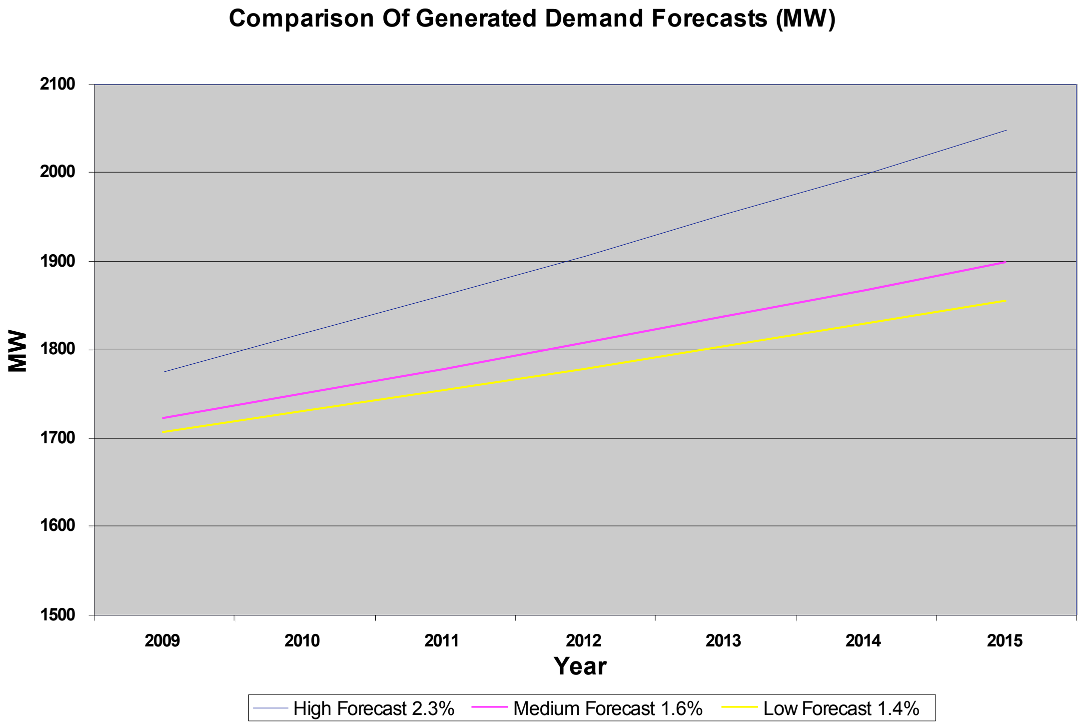
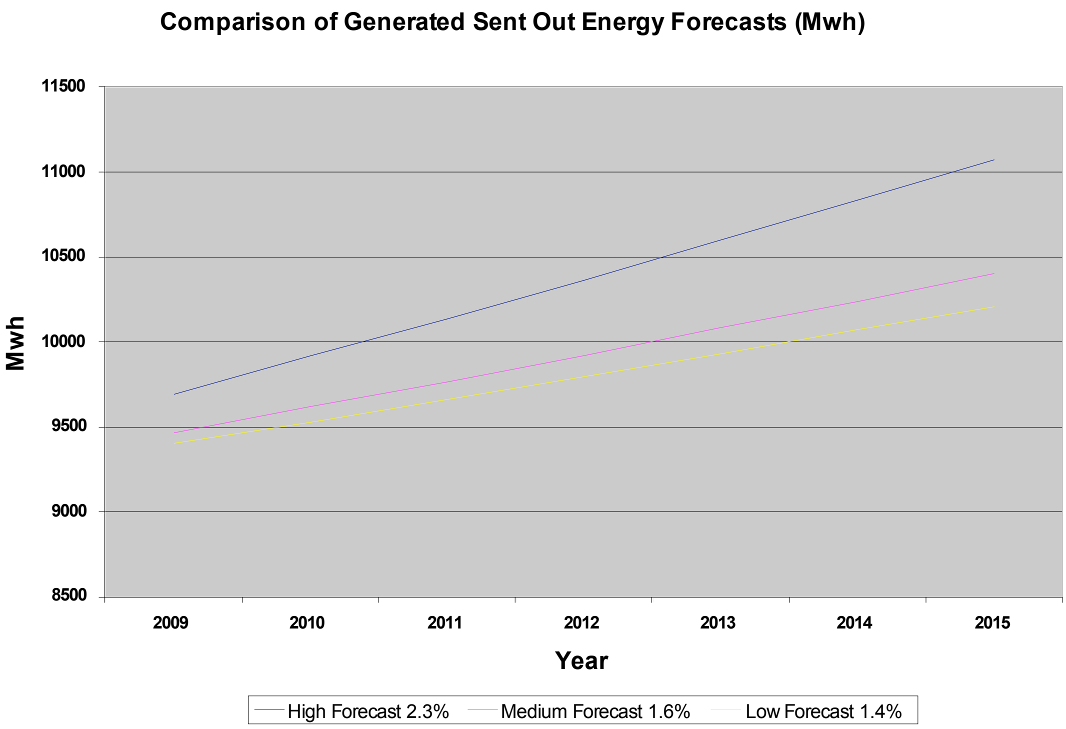
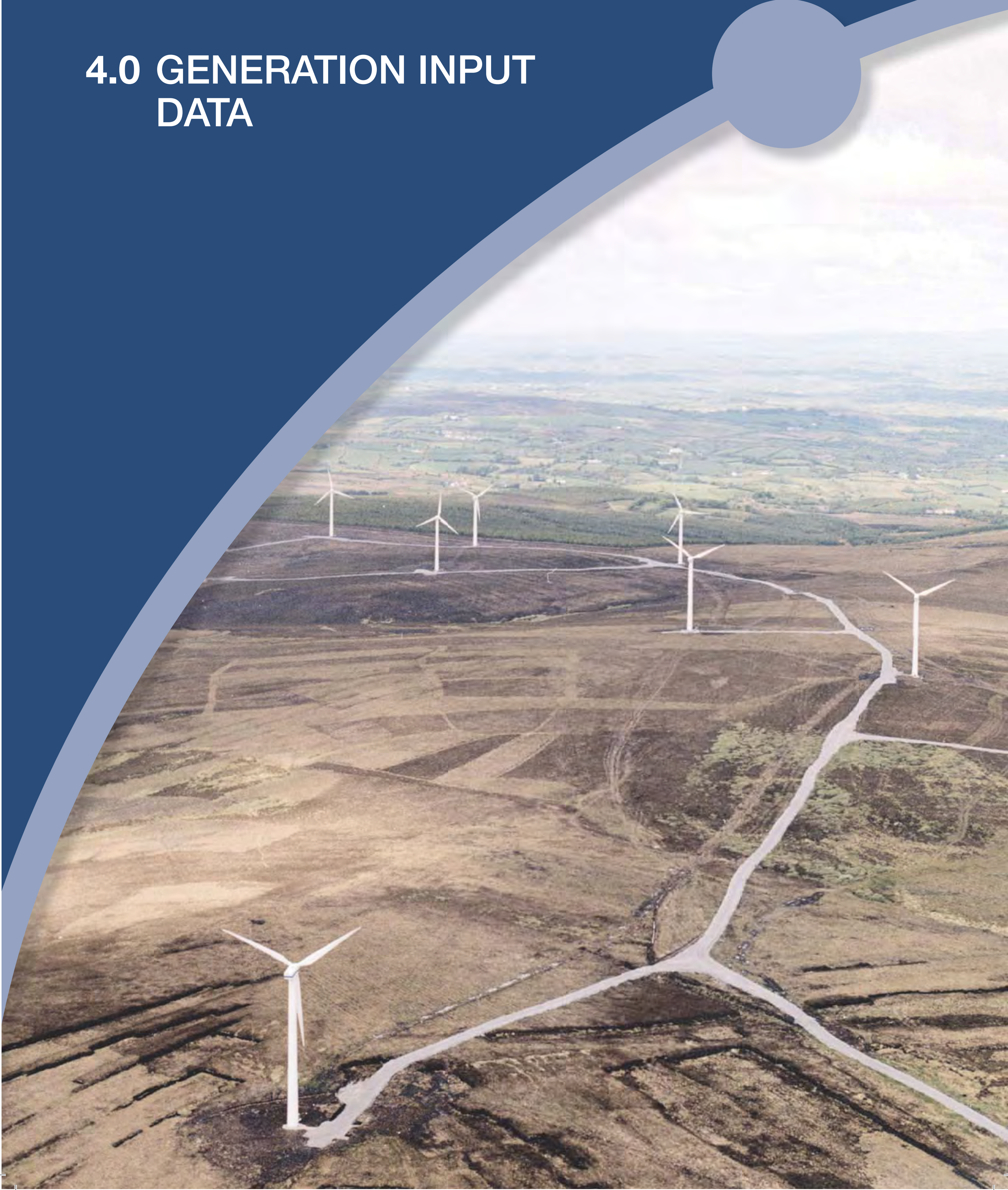


Figure 3.11 – Comparison of Generation Demand Forecasts (MWH)



4.0 GENERATION INPUT DATA



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 Appendix A2. Over the time period 2009-2015, generation capacity, forced outage probabilities (FOPS) and scheduled outage duration (SOD) information is required for each generator. This is used 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 mechanism has encouraged participants to invest in new generations projects (Figure 4.1).

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 an assumption that the generator will opt to become a participant in the new SEM.

Figure 4.1 – Generation Capacity

Centrally Despatched Generating Plant	Fuel Type	Sent-Out Generating Capacity (net - MW)						
		2009	2010	2011	2012	2013	2014	2015
Ballylumford ST 4	*Gas/HFO	170	170	170	170	170	170	170
Ballylumford ST 5	*Gas/HFO	170	170	170	170	170		
Ballylumford ST 6	*Gas/HFO	170	170	170	170	170		
Ballylumford CCGT 21	*Gas/Gasoil	160	160	160	160	160	160	160
Ballylumford CCGT 22	*Gas/Gasoil	160	160	160	160	160	160	160
Ballylumford CCGT 20		170	170	170	170	170	170	170
Ballylumford CCGT 10	*Gas/Gasoil	97	97	97	97	97	97	97
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	238	238	238	238	238	238	238
Kilroot ST 2	*Oil/coal	238	238	238	238	238	238	238
Kilroot GT 1	Gasoil	29	29	29	29	29	29	29
Kilroot GT 2	Gasoil	29	29	29	29	29	29	29
Kilroot GT 3**	Gasoil	40	40	40	40	40	40	40
Kilroot GT 4**	Gasoil	40	40	40	40	40	40	40
Kilroot CCGT	*Gas/Gasoil					440	440	440
Coolkeeragh GT 8	Gasoil	53	53	53	53	53	53	53
Coolkeeragh CCGT	*Gas/Gasoil	402	402	402	402	402	402	402
Scottish Interconnector	DC Link ***	450	450	450	450	450	450	450
Total Generation Capacity		2732	2732	2732	2732	3172	2832	2832

- *Where dual fuel capability exists this indicates the fuel type assumed to be utilised to meet peak demand
- **Kilroot GT3 & 4 will be commercially available from the 1st March 2009.
- ***The Moyle Interconnector has a winter/summer rating of 450/400MW. This is due to network security considerations

In Figure 4.1 the only units that SONI has assumed to be decommissioned by 2014 are Ballylumford G5 and G6 and this is due to environmental constraints introduced by EU legislation.

From 2008 the two stacks at Ballylumford are limited to a total of 20,000 running hours each. Unit G4 enters stack 2 solely, whereas Units G5 & G6 share stack 3. For this adequacy statement we have assumed that G4 will be running for a maximum of 30% of the year. This low amount of running time should allow G4 to be available from 2009-15.

An assumption of 20% running time for unit's G5 & G6 means that the limit of 20,000 running hours allowed per stack will be used up by 2013. Figure 4.1 shows units G5 & G6 decommissioned from the start of 2014. These assumptions will be reviewed on an annual basis.

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

There is a total capacity of 2732MW in 2009. This does not include the 100MW of 'perfect' plant available from RoI (See Appendix A4).

The generation capacities represented are for peak periods. For example the capacities at Kilroot G1 and G2 on coal fuel are reduced by 35MW 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 B).

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

Figure 4.2 – Contract Details

Centrally Despatched Generating plant	Fuel type	Contract Details
Ballylumford ST 4	Gas/HFO	Contracted until 31 March 2012, can be cancelled earlier.
Ballylumford ST 5	Gas/HFO	This is an Independent Power Producer, commercial operation commenced 1 October 2008. Assumption - EU legislation on emissions will limit generation beyond 2013
Ballylumford ST 6	Gas/HFO	This is an Independent Power Producer, commercial operation commenced 1 April 2008. Assumption - EU legislation on emissions will limit generation beyond 2013
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
Kilroot GT 3	Gasoil	This will be an Independent Power Producer, commercial operation due to commence 1 March 2009.
Kilroot GT 4	Gasoil	This will be an Independent Power Producer, commercial operation due to commence 1 March 2009.
Kilroot CCGT	Gas/Gasoil	This will be an Independent Power Producer, assumed availability from 2014.
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.

Transmission Network Capacity limitations restrict the amount of energy that can be exported onto the transmission network to the east of province at Islandmagee. This adequacy assessment is based on establishing the peak demand which can be met. Under these conditions it is not possible to exit the total plant capacity at Islandmagee. It is for this reason that generating unit ST5 is not included in the adequacy analysis.

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.

The dependency on Gas for electrical generation is continuing to rise and will require careful monitoring over the next seven years. Currently 66% of installed generation capacity is capable of running on gas.

4.2 Renewable Generation

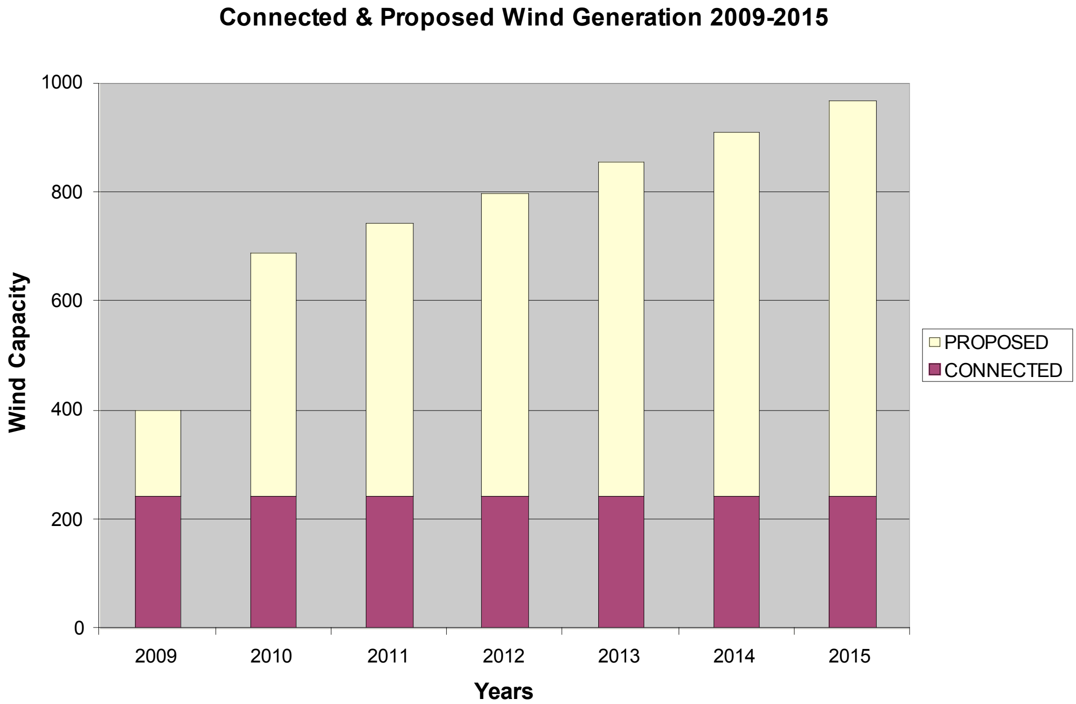
One of the areas of considerable change is the level of connection applications from wind farms to the NI transmission and distribution networks. This has in part been driven by EU Policy. European Union leaders agreed to adopt a binding target on the use of renewable energy, such as wind and solar power. 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 consideration is given to ensuring 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 2009-2015. 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 – 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/SONI for connection to the network. The wind capacities in Figure 4.4 are expressed in power output MW as at 15 September 2008.

Figure 4.4 – Expected Wind Capacity

Wind Farm name	2008	2009 Q1	2009 Q2	2009 Q3	2009 Q4	2010
Corkey	5					
Rigged Hill	5					
Elliott's Hill	5					
Bessy Bell 1	5					
Slieve Rushen 1	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	54					
Altahullion Ext	11.7					
Owenreagh Ext	5.1					
Garves	15					
Bessy Bell 2	9					
Gruig		25				
Curryfree						15
Hunters Hill				20		
Crockagarron				18		
Slieve Divena		30				
Glenbuck						3
Crighshane						32.2
Church Hill						18.4
Tievenameenta						45
Drumadarragh						20
Screggagh					18.4	
Slieve Kirk					48.3	
Eglish						27
Thornog						9.2
Tullinoid						15.75
Ora More						30
Rakelly						6
Slieve Divena 2						20
Carrickatane						45
Quarterly Total	242	55	0	38	66.7	287
Total (MW)	242	297	297	335	401.7	688

The network connection points of these wind farms are shown in Appendix B. Appendix B is a geographical representation of the NI transmission network in 2010 and shows the location of generation. It can be seen that the majority of the chosen wind generation sites are located to the west of the province. It should be noted that the majority of wind farms are connected to the distribution system.

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

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), which accommodates up to 42% of renewables, is feasible. 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 TSOs also plan to carry out joint studies to consider the practical, operational 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 – NFFO Capacity

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 140MW. This figure has been produced from the extrapolation of accurate historic assessments. There is a requirement to carry out a detailed study over the 2008/09 winter to establish the impact of SEM on current customer private generation 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. An emergency flow of up to 75MW is available should the frequency drop below 49.6Hz in the NI system. 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 SEM the unused capacity can, in emergency situations, be used solely to meet the?? 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 the GB system; which has circa 80GW 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. 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 power and reserve power capability. Total Transfer Capacity (TTC) is the maximum that can flow (including provision for flow of reserve) in any period and is determined by the TSOs. The market flow that is determined from the commercial data is calculated such that it cannot be greater than TTC less the reserve. It has been agreed that a reliance of 100MW on ROI can be assumed in adequacy assessments.

4.7 North-South High Capacity Transmission tie line

EirGrid and NIE are committed to establishing a new tie line between RoI and Tyrone in NI. 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. It is assumed that the second transmission tie line will be completed by 2012. After that, there will no transmission constraints and an All-Island system can be assessed for generation adequacy.

4.8 Generator Availability Data

The Methodology Section 2.0 and Appendix A2 describe 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 availability. The availability can be separated into two categories; 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 SODs and FOPs. 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 (used to derive payments for availability under the System Support Services Agreements) 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 shut down. Historic performance is used to determine future FOPs for Moyle HVDC link.

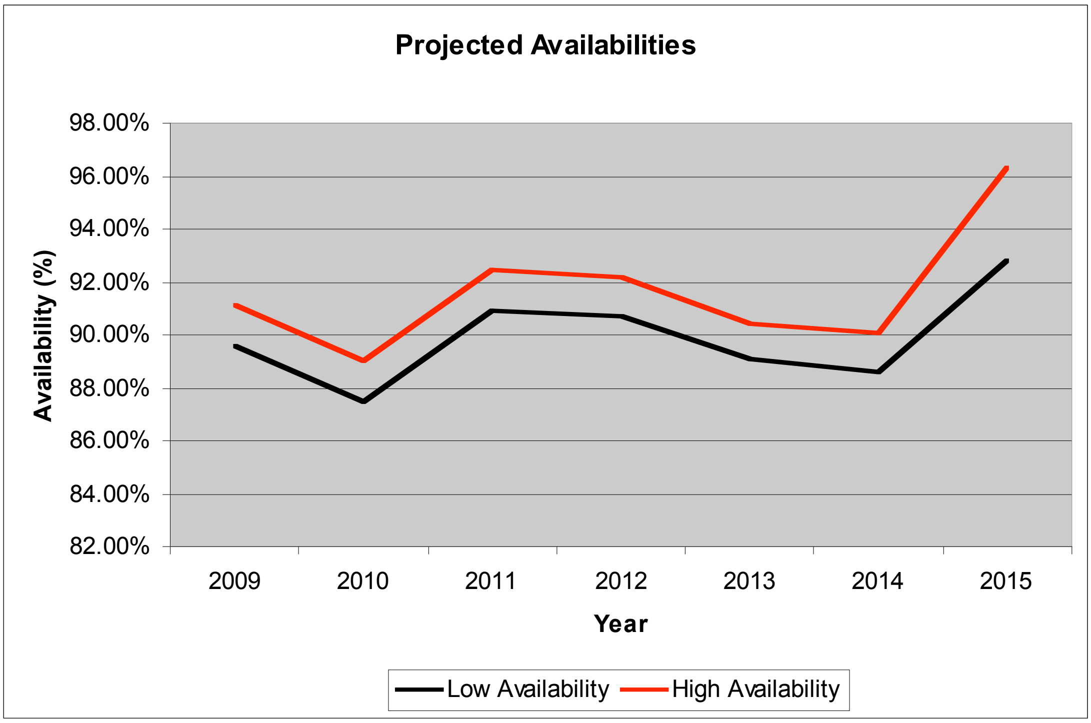
4.8.3 Generator Availability Scenarios on a Network Basis

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. 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 availability for the seven year period covered by this statement.

Figure 4.6 – Projected Availabilities

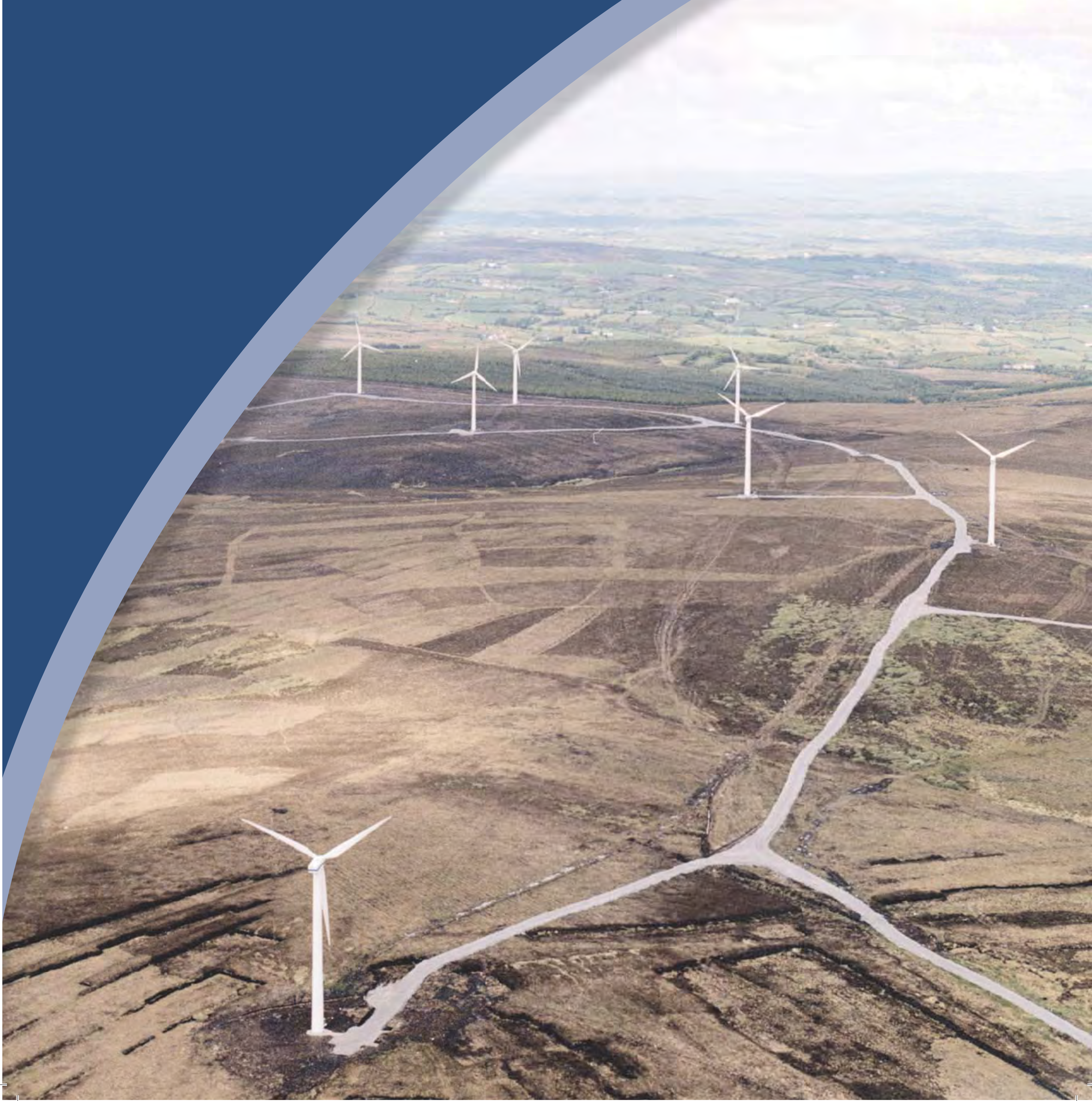


Year	2009	2010	2011	2012	2013	2014	2015
High Availability	91.14%	89.01%	92.48%	92.20%	90.39%	90.09%	96.33%
Low Availability	89.60%	87.47%	90.94%	90.67%	89.11%	88.62%	92.80%

The average high availability over the seven-year period is 91.66% and the low availability figure is 89.89%.

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



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 2009 to 2015. This follows the methodology described in Section 2.0. From 2013 to 2015 an all-Island system is modelled to determine generation adequacy. This is due to the assumption that the additional N-S tie-line will be in operation. 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 – All Island study 2013-2015.

The first graph, Figure 5.1 describes the deficit/surplus that will be experienced from 2009-2015 based on a medium demand scenario. 2009-2012 illustrates generation adequacy in NI only whereas from 2013 it relates to an all-Island generation adequacy. This is due to the assumption that the second North-South tie-line will be in operation and results in a reduction in constraints between North and South.

Figure 5.1 – All Island Study

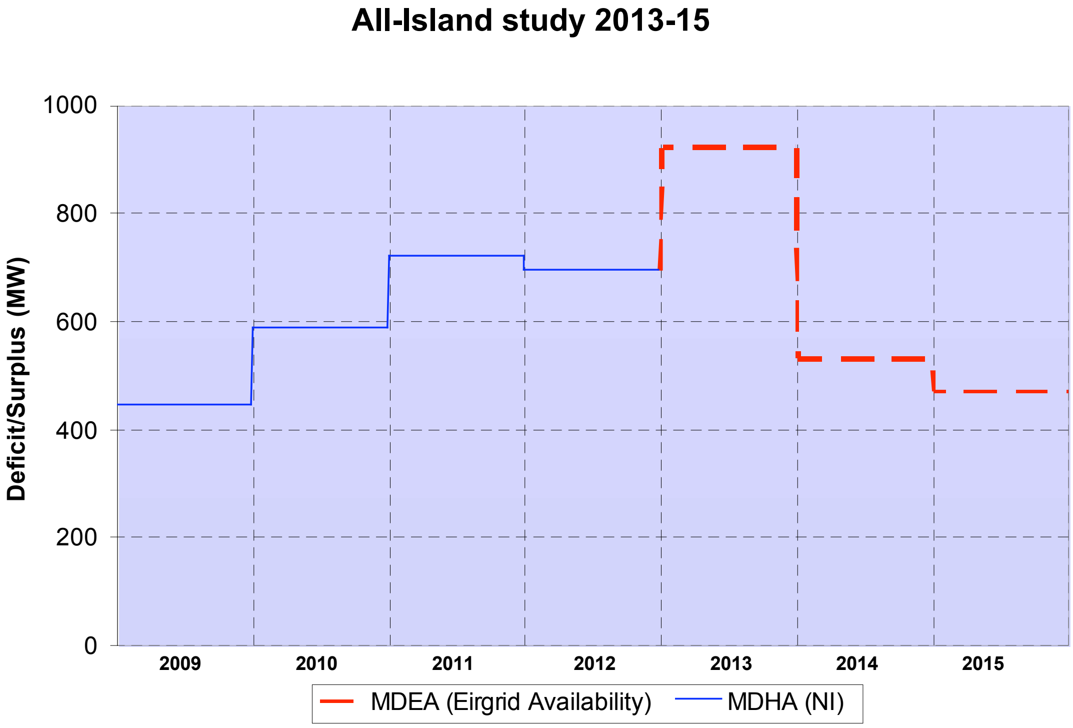


Figure 5.2 provides a tabular summary of the above analysis. Note that the surpluses obtained for years 2013-2015 are based on an all-Island study.

Figure 5.2 – Tabular Summary of All Island Study

Demand	Availability	2009	2010	2011	2012	2013	2014	2015
Medium	High	446	586	719	695	924	532	472

5.1.1 Discussion of all-Island study results

The NI system study from 2009-2012 indicates a surplus of circa 600MW. The studies are based on a medium load growth of 1.6% which under normal circumstances would decrease the amount of surplus year on year. Figure 5.1 shows that the surpluses have marginally increased due to the introduction of new plant (KPS 80MW) and reduced scheduled outages.

An all-Island study was carried out from 2013-2015. There is an increase in surplus capacity in 2013 to 925MW. This 230MW increase from 2012 is caused by the 440MW of additional capacity at Kilroot, the introduction of the East-West interconnector, the reduced transmission constraint resulting from increased N-S tie line transfer capacity and the capacity benefit derived from a single plant portfolio on the island of Ireland. The downward step in 2014 results from the withdrawal of the two phase 2 units at Ballylumford.

Figure 5.1 considers medium demand and high generation availability (MDHA) up until 2012. It should be noted that the NI high availability scenario is similar to the Eirgrid Availability scenario. The Eirgrid availability scenario is combined with the NI availability to determine an all island plant availability (2013-2015). This is deemed to be the most likely scenario to occur based on historic performance and projected availabilities.

5.2 Results – Second N-S interconnector delay beyond 2015

The following three graphs, consider the possibility that the proposed N-S interconnector will not be complete by the end of 2015 this study uses only NI generation data with a reliance of 100MW from the ROI system. Figure 5.3 shows the full extent of surplus/deficit for each scenario as described in section 5. Figure 5.4 and 5.5 show the high and low availability scenarios.

Figure 5.3 – N-S Interconnector Delay (All Scenarios)

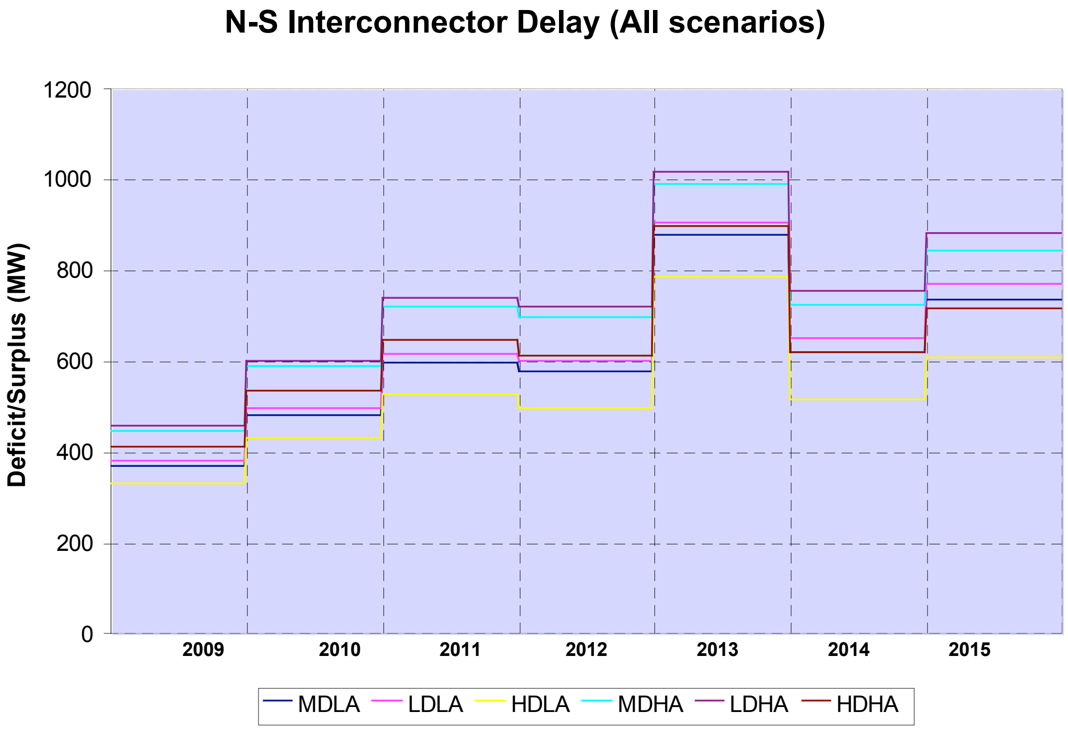


Figure 5.4 – N-S Interconnector Delay (All Scenarios)

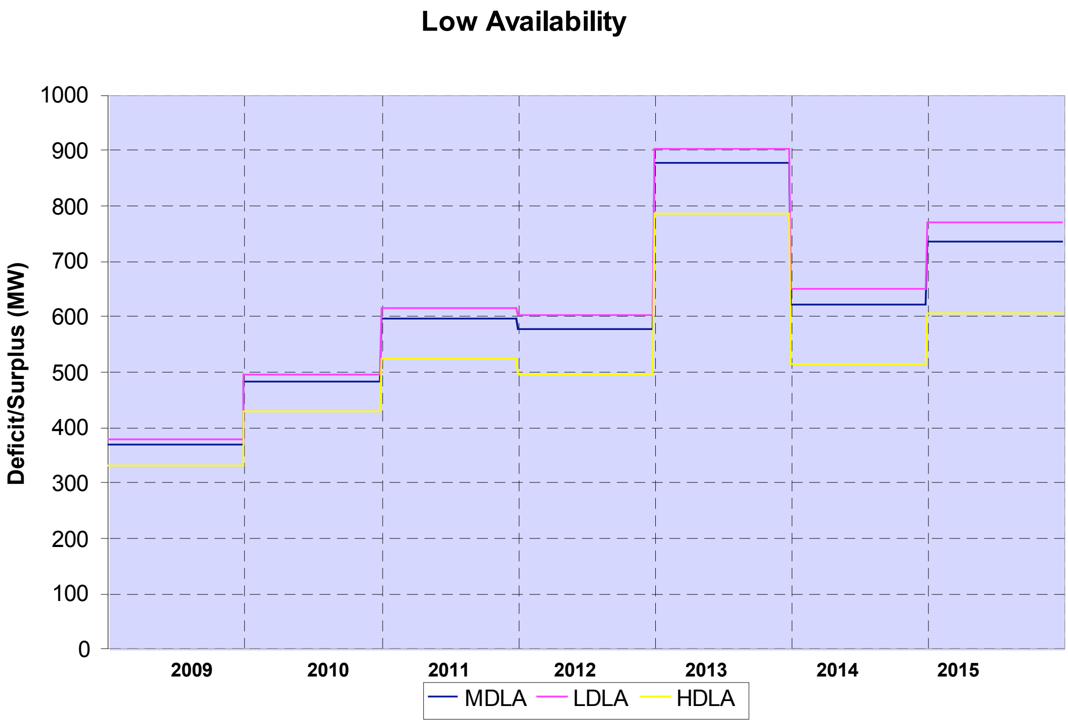


Figure 5.5 – N-S Interconnector Delay (High Availability)

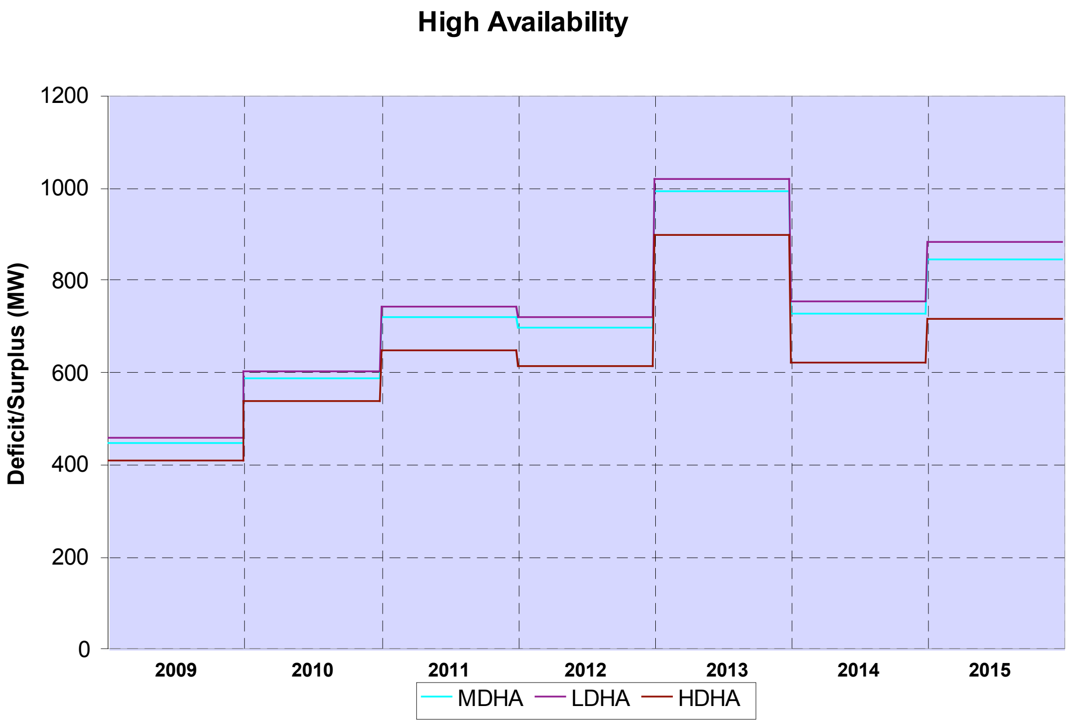


Figure 5.6 provides a tabular summary of the above analysis.

Figure 5.6 – Tabular Summary of N-S Interconnector Delay Analysis

Demand	Availability	2009	2010	2011	2012	2013	2014	2015
High	Low	331	428	524	494	784	513	606
	High	409	535	647	612	897	618	713
Medium	Low	368	480	595	577	876	619	734
	High	446	586	719	695	990	724	843
Low	Low	378	494	615	600	902	648	770
	High	455	600	739	719	1016	753	880

5.2.1 Discussion of results

Figure 5.3 follows a similar pattern to figure 5.2 with the only difference being the surpluses experienced in the last three years, when the second N-S Interconnector is due to be operational. This contingency analysis has been undertaken to determine if the delay in the second interconnector would leave NI in a deficit position. Without the N-S interconnector NI will still be in generation surplus for each year of the study. As discussed in 5.1.1 the proposed 440MW CCGT at Kilroot will provide an increased surplus in 2013, and the decommissioning of units G5 & G6 in 2014 sees the surplus within NI return to similar levels experienced in 2012. Figure 5.6 shows that the generation surpluses are higher in NI when considering the NI system only. The all island study in figure 5.1 shows less generation surplus for the years 2013-2015 by circa 200MW. The reason reduced amount of surplus is because of deficits in the ROI system.

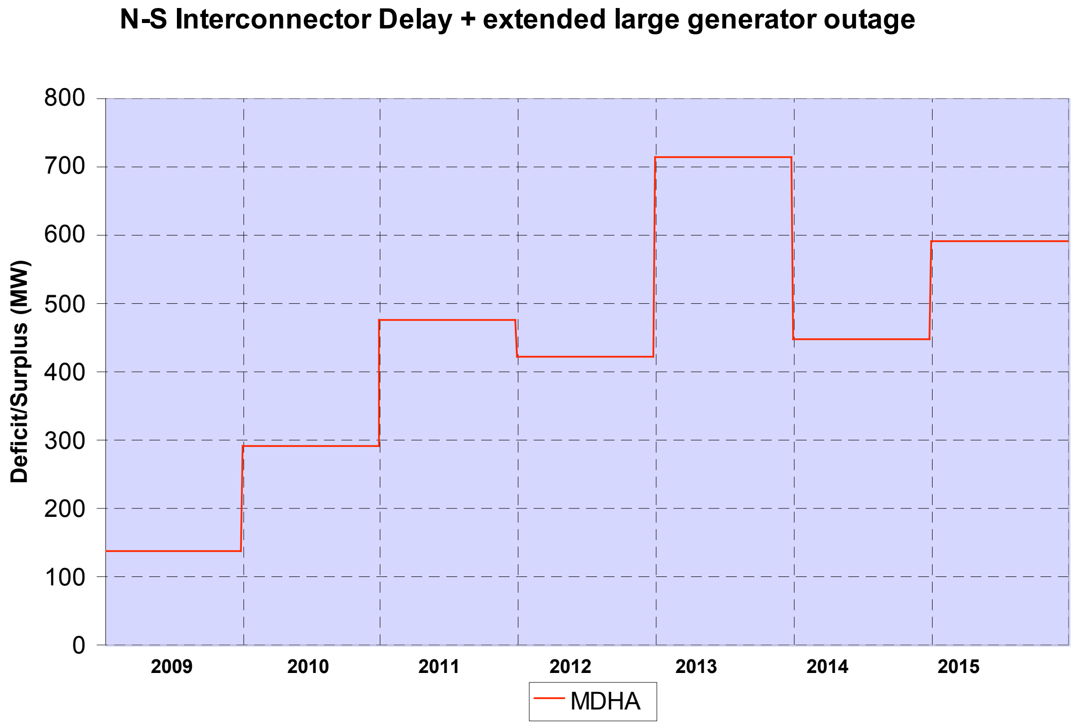
Figure 5.4 considers only the Low Availability scenarios on a single graph. The low availability figures are determined by using the highest FOP rate experienced from NI plant and applying it to all generators. This reduces their availability and so the surpluses experienced are less than the figures in figure 5.5. The low availability figures used for this study can be seen in Figure 4.

Figure 5.5 considers only the High Availability scenarios on a single graph. The High availability figures are determined using historical analysis of each individual generator. An average figure is determined over the available historical years and agreed with the generators. This is the most likely figure that will be experienced. The High availability figures used for this study can be seen in Figure 4.

5.3 Results – N-S tie line delay + extended large generator outage

Figure 5.7 considers the situation if additional tie line capacity is not in operation and in addition there is an extended outage of a large generating unit. The extended outage modelled for this scenario is a large unit of approximately 200MW which was unavailable for the whole year. This scenario assumes that the plant is not available for the full year, covering every year (2009-2015). It provides a view of generation adequacy in NI under these circumstances. The MDHA has been applied to this scenario.

Figure 5.7 – Interconnector Delay + Extended Generator Outage



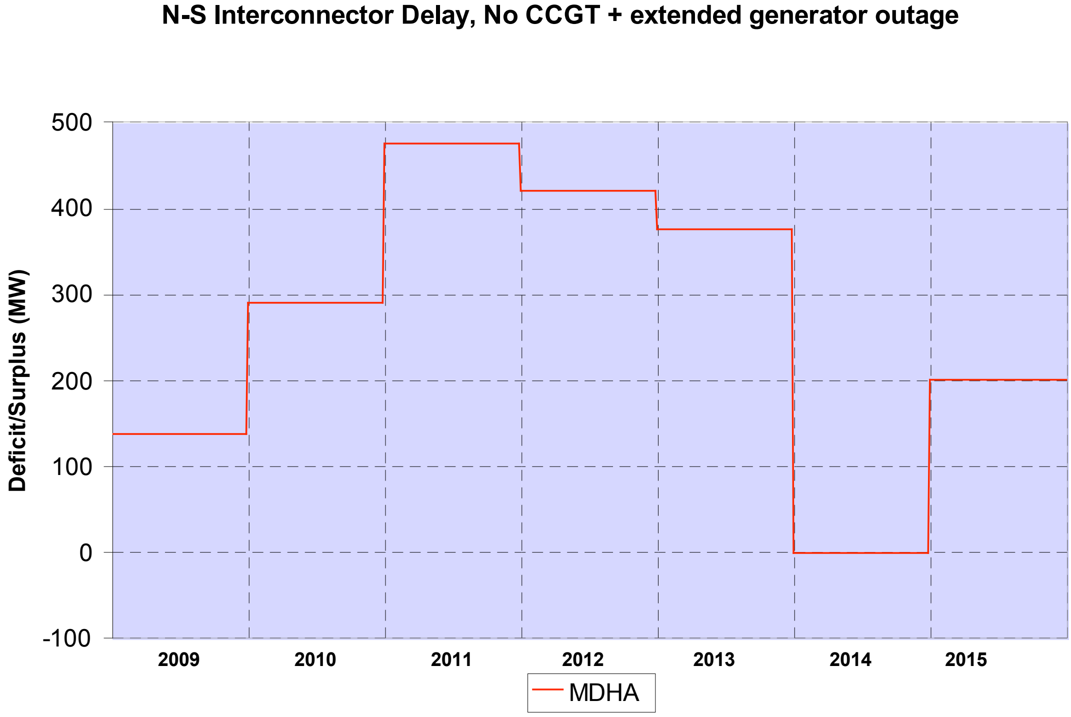
5.3.1 Discussion of results

Surpluses experienced in Figure 5.7 vary compared to previous analysis. The reason for this variability is because with less generation capacity scheduled outages cannot be optimised as efficiently. The extended outage of a large generating unit reduces the surplus in generation by circa 330MW. The lowest generation surplus experienced over the seven years is 137MW and occurs in 2009. This analysis has been carried out using the assumption that the 440MW CCGT at Kilroot will be operational from 2013.

5.4 Results – N-S tie line delay, No CCGT + extended large generator outage

Figure 5.8 considers the situation that the additional N-S tie line is not operational by 2015, that the assumed CCGT at Kilroot is not commissioned and an extended large generating unit outage similar to the scenario in 5.3 is experienced. The MDHA scenario is applied.

Figure 5.8 – Interconnector Delay, No CCGT + Extended Generator Outage



5.4.1 Discussion of results.

Figure 5.8 represents the most pessimistic scenario considered in the analysis with the second N-S tie-line delayed, the CCGT at Kilroot delayed and an extended large generating unit outage occurring each year. Up until 2012 the surplus experienced is the same as in Figure 5.7. A considerably reduced surplus is experienced in 2013 because of the delay in the N-S tie line and the proposed CCGT at KPS. There is a small deficit in generation in 2014 (-1MW). There is a surplus of 200MW in 2015, however it should be noted that in 2015 there is a low level of scheduled outages anticipated.

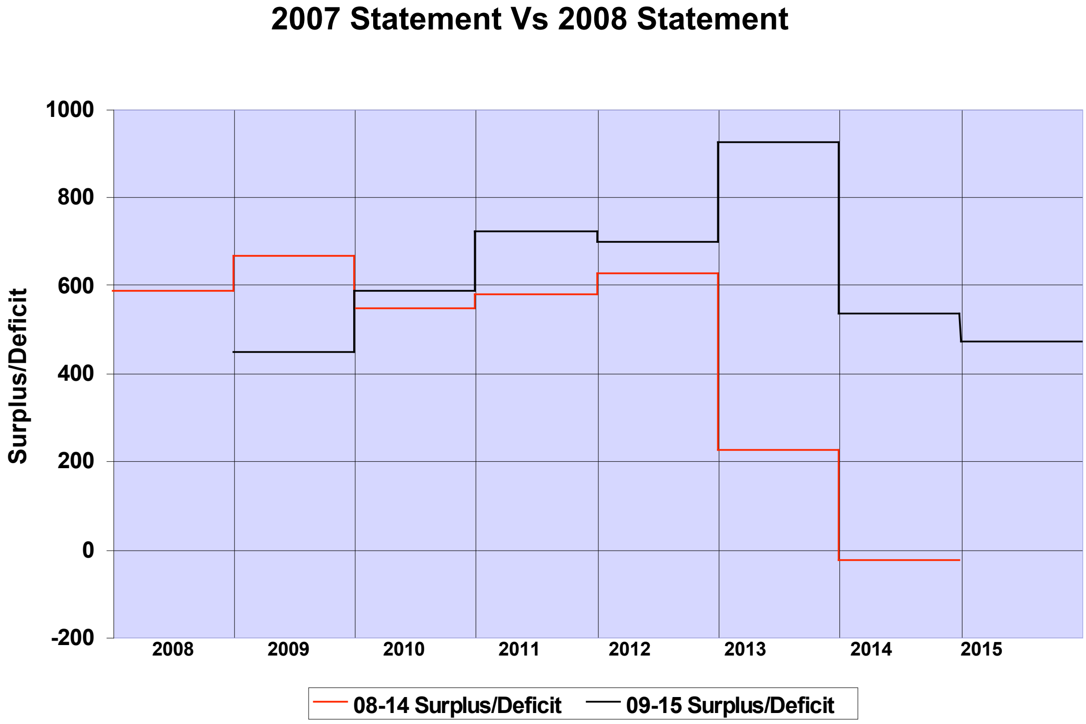
The results of this study show that the decommissioning of the Ballylumford phase two units in 2014 highlights the requirement for additional generation capacity on the NI network.

5.5 Comparison with Previous Capacity Assessments

The methodology used in this statement is similar to previous statements and 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.

Figure 5.8 compares the surpluses/deficits from this statement to last years and is based on an all island study for 2013-2015. The surpluses experienced in last year’s statement show a consistent level of surplus generation capacity until 2013 at circa 600MW. The surpluses derived in this statement are more variable because of a change to the level of scheduled outages which is reflected in the levels of availability.

Figure 5.9 – 2007 Vs 2008 Statement



In 2009 there is over 200MW of extra generation surplus in last years report despite the introduction of 80MW of extra capacity at Kilroot. The reason for this difference is due to more recent information from the generators regarding plant availability. From 2010 to 2012 this report shows an extra surplus of circa 100MW compared to last year. The reason for this increase will be because of the extra 80MW of new plant made available at Kilroot.

There is over 700MW increase in surplus from 2013 compared to last year's results. The reason for this large increase is because kilroot will have installed a new 440MW CCGT plus two OCGT's and the availability of the gas/oil generating units at Ballylumford have been revised from last year (see section 4). When comparing the last year of each statement, it is clear to see that NI is in a more promising position compared to last year with approximately 500MW extra capacity. This large increase has come from extra 520MW availability from Kilroot and an extra 170MW at Ballylumford. It should be noted that the ROI studies have identified a deficit of generation from 2013 onwards. It is reason that the surpluses in Figure 5.9 are less than the NI only studies.

With the introduction of the SEM in November in 2007 the capacity payments are designed to incentivise new entrants into the market and reduce deficits. This statement is used to monitor progress in this regard and the analysis confirms that an increase in capacity is anticipated. However, investments may be made in generating plants that may otherwise have been decommissioned to take advantage of the capacity payment incentive. This may create problems into the future as this plant may be less reliable than modern generating plant. It was this reason that an extra contingency study to include an extended large generating outage in section 5.4 has been included in this statement.

Glossary of Terms

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

Appendix A

A1 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 Generation Seven Year Capacity Statements pre 2006.

The Cumulative Outage Probability Table (COPT) was derived from the installed capacity of individual generators and forced outage probabilities/winter availability. It was then possible to determine the risk of failure to meet a range of demand levels on the basis of an assessment of existing and future generation capacity and estimates of the capacity of renewable generators expected to connect to the system over the seven year period.

Historic winter demand data was 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 and a high and low demand forecast. 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 are scheduled.

A2 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 A1 – 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 comparable EUE to RoI.

A3 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 tie line capacity 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.

A4 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:

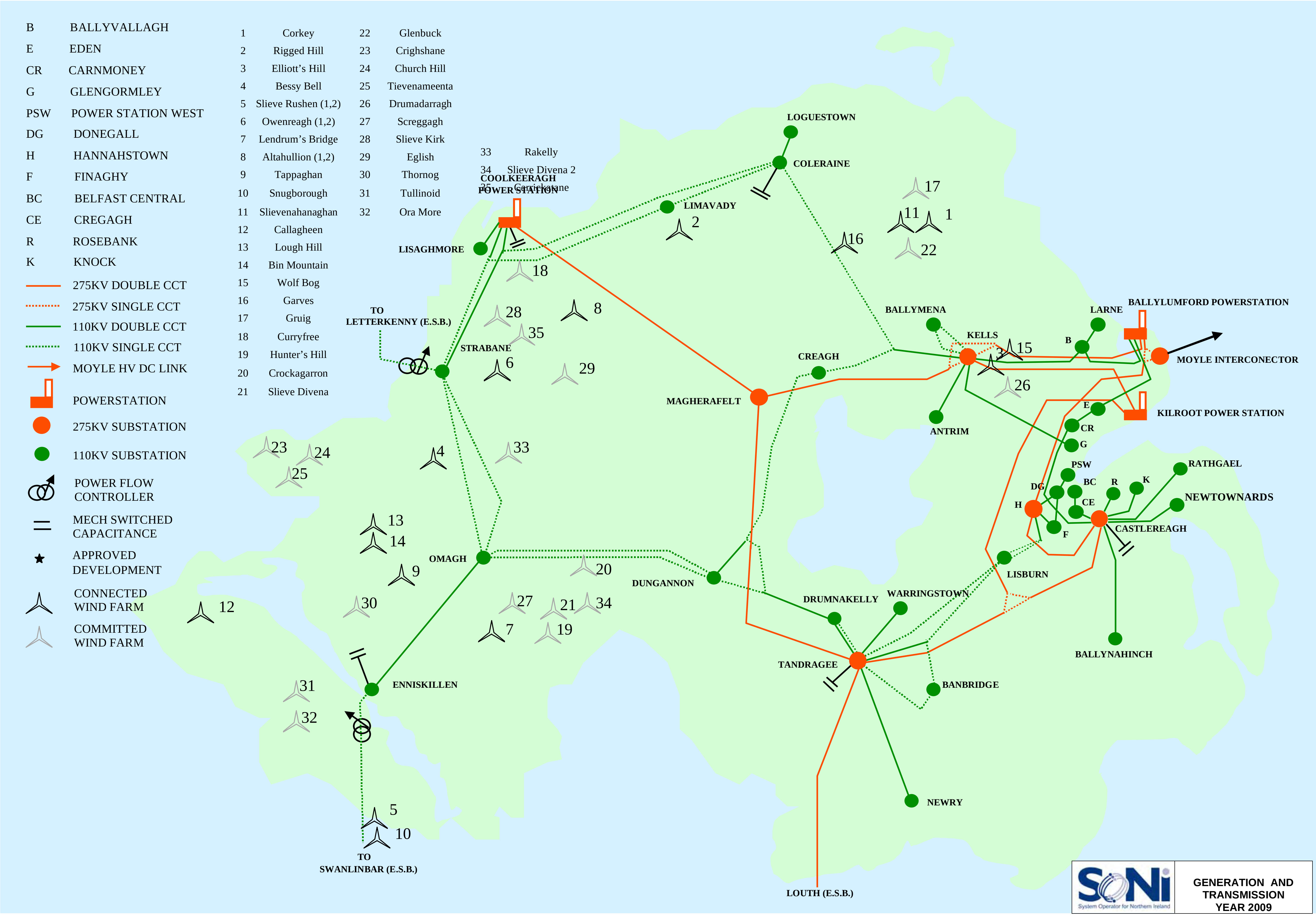
North-South 450MW South-North 400MW

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

Figure A2 – LOLE Standard

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

Appendix B


B BALLYVALLAGH
E EDEN
CR CARNMONEY
G GLENGORMLEY
PSW POWER STATION WEST
DG DONEGALL
H HANNAHSTOWN
F FINAGHY
BC BELFAST CENTRAL
CE CREGAGH
R ROSEBANK
K KNOCK
275KV DOUBLE CCT
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 Rigged Hill
3 Elliott's Hill
4 Bessy Bell
5 Slieve Rushen (1,2)
6 Owenreagh (1,2)
7 Lendrum's Bridge
8 Altahullion (1,2)
9 Tappaghan
10 Snugborough
11 Slievenahanaghan
12 Callagheen
13 Lough Hill
14 Bin Mountain
15 Wolf Bog
16 Garves
17 Gruig
18 Curryfree
19 Hunter's Hill
20 Crockagarron
21 Slieve Divena
22 Glenbuck
23 Crighshane
24 Church Hill
25 Tievenameenta
26 Drumadarragh
27 Screggagh
28 Slieve Kirk
29 Eglish
30 Thornog
31 Tullinoid
32 Ora More
33 Rakelly
34 Slieve Divena 2
35 Carrickatane
COOLKEERAGH POWER STATION
LOGUESTOWN
COLERAINE
LIMAVADY
LISAGHMORE
TO LETTERKENNY (E.S.B.)
STRABANE
BALLYMENA
KELLS
LARNE
BALLYLUMFORD POWERSTATION
MOYLE INTERCONECTOR
CREAGH
MAGHERAFELT
ANTRIM
KILROOT POWER STATION
RATHGAEL
NEWTOWNARDS
CASTLEREAGH
LISBURN
OMAGH
DUNGANNON
DRUMNAKELLY
WARRINGSTOWN
TANDRAGEE
BANBRIDGE
BALLYNAHINCH
ENNISKILLEN
NEWRY
TO SWANLINBAR (E.S.B.)
LOUTH (E.S.B.)
SONI System Operator for Northern Ireland
GENERATION AND TRANSMISSION YEAR 2009

System Operator for Northern Ireland

Photo courtesy of Coolkeeragh ESB.