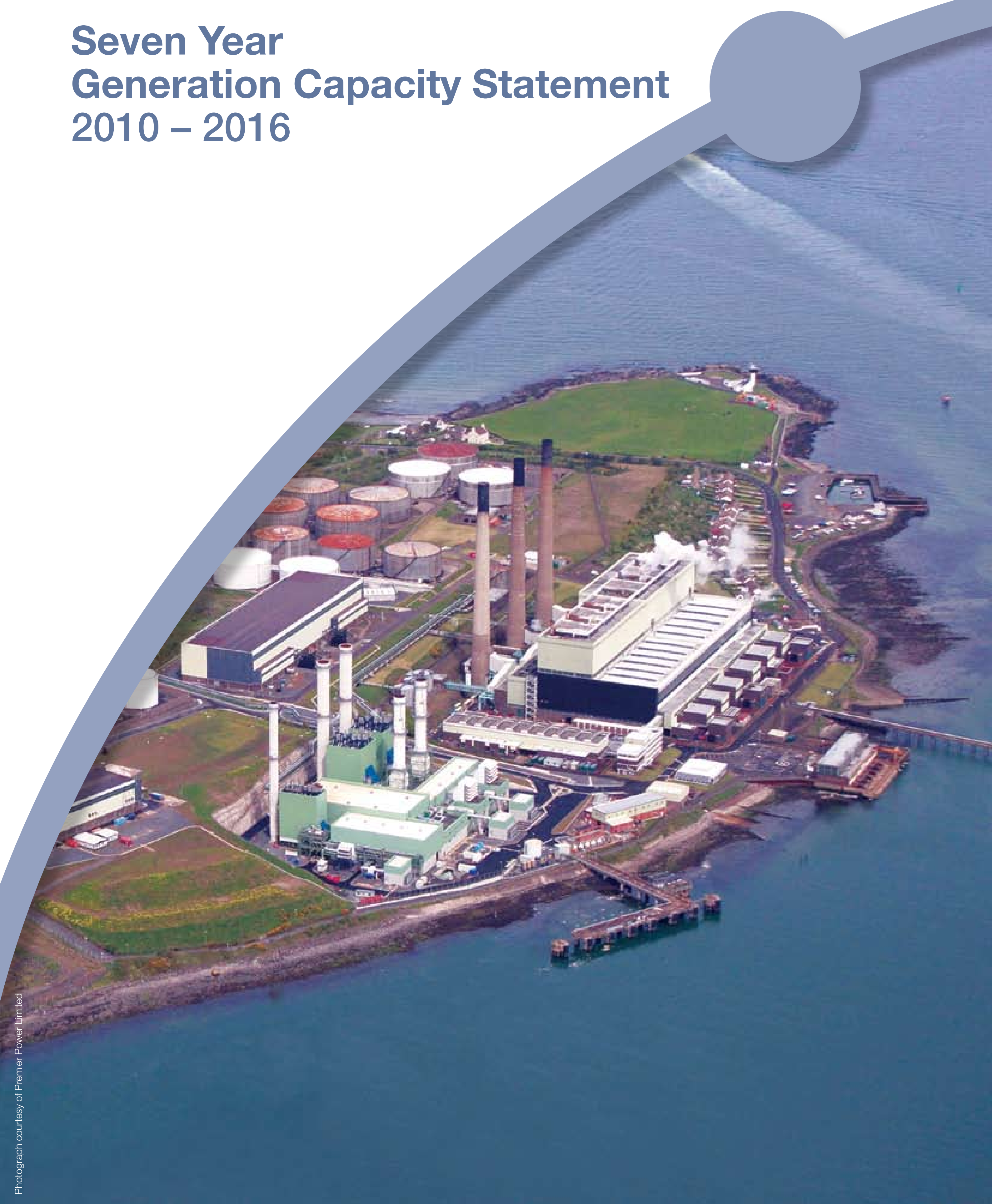
System Operator for Northern Ireland

Seven Year Generation Capacity Statement 2010 – 2016



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SONI Ltd

SEVEN YEAR GENERATION CAPACITY STATEMENT

For the years 2010 to 2016

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December 2009

12 Manse Rd, Belfast, BT6 9RT

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- *The Generation Security Standard is met until 2016 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 2015.*

- *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 2010-2012. For the period 2013-2016 an All Island Generation security standard of 8 hours is used.*

- *The large reduction in demand forecasts in NI and Ireland has led to a significant increase in generation adequacy.*

This 2009 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 2010 to 2016 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 Ireland 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 Ireland separately but moving towards an all-island approach when additional tie-line capacity is available between NI and Ireland in 2012. 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 NI 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 Ireland 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 Ireland respectively.

This is now the fourth 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. The impact of the economic slowdown is to reduce the percentage growth in demand compared to previous statements. 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 446MW - 720MW for the years 2009-2012. In the 2009 Generation Seven Year Capacity Statement, the same scenario shows surpluses of circa 469MW - 890MW for the years 2010-2016.

The 2009 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 2008 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.

- The additional generating capacity that was assumed to be commissioned at Kilroot in 2013 has been postponed until 2015.

- A revised decommissioning plan has been received from Ballylumford. The 2008 Statement had assumed that the two steam units at Ballylumford (ST5 & ST6) would be decommissioned by 2014 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 ST4, ST5 and ST6 will all be available up until the end of 2015. Environmental legislation will inhibit any further generation from these units after this date.

This statement concludes that during the period from 2010 to 2016 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 and a reliance on generation in RoI. There remains however a risk of operational scenarios 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. The decommissioning of 12GW of plant in GB, due to the LCPD may see the availability of energy from GB decrease due to the end of study. This will require careful monitoring over the next few years.

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

1.0 INTRODUCTION

1.0 INTRODUCTION

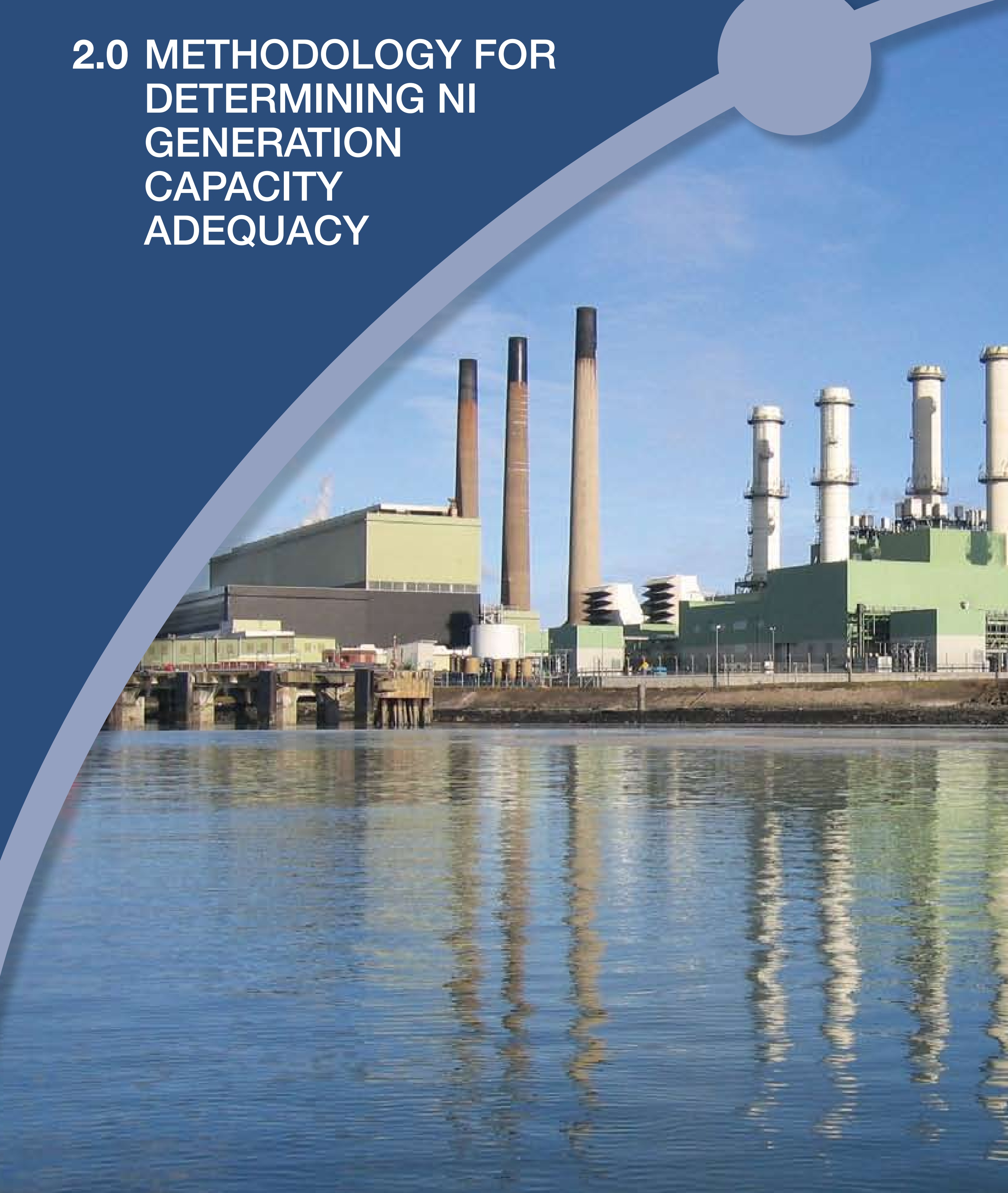
This Generation Seven Year Capacity Statement is produced in accordance with Condition 35 of the Licence to participate in the Transmission of Electricity granted to SONI Ltd by the Department of Enterprise Trade and Investment. This statement is produced in a form and based on methodologies approved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

This statement covers the seven year period from 2010 to 2016. The freeze date for the input data that forms the basis of this statement was 30th September 2009. 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 industry and more particularly the regulatory agencies, policy makers and electricity 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 ADEQUACY



2.0 METHODOLOGY FOR DETERMINING NI GENERATION CAPACITY ADEQUACY

This section of the statement describes the methodology on which the analysis is based.

2.1 NI Generation Security Standard and Methodology

The methodology determines 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 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 from 2013-2016

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 from 2010-2012

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. Ireland rely on 200MW capacity from NI, whereas NI rely on 100MW from Ireland.

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

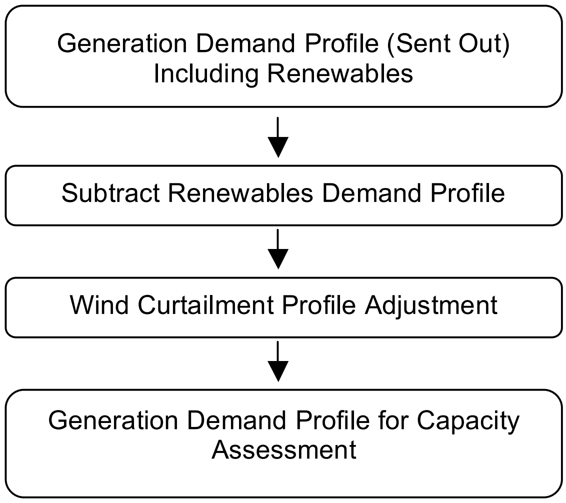
The demand profile data used is on a sent out basis or net of power station auxiliary load. It is the power directly injected onto the 275/110kV transmission network to meet the demand by centrally dispatched generating plant.

The demand profiles that are utilised over the last decade reflect customers running private embedded diesel generation 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. Further analysis has been carried out over the 08/09 winter period to calculate the amount of private generation that was actually running. This is explored in more detail in Section 4.4.

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 forecasted wind profile 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. For the purposes of this study wind was curtailed when conventional generation levels were below 380MW. During the years 2010-16 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. A more detailed description of wind curtailment assumption is in attached in Appendix B. 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 2010-2016 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. The 2008 demand profile was not used as a base year as it was deemed to be an abnormal year. This is due to NI economy entering a recession and the reduction in the demand for electricity. The 2008 demand profile was continuing to grow at the start of the year, however the second half seen a reduction and electricity dropped to approximately 2005 levels. 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

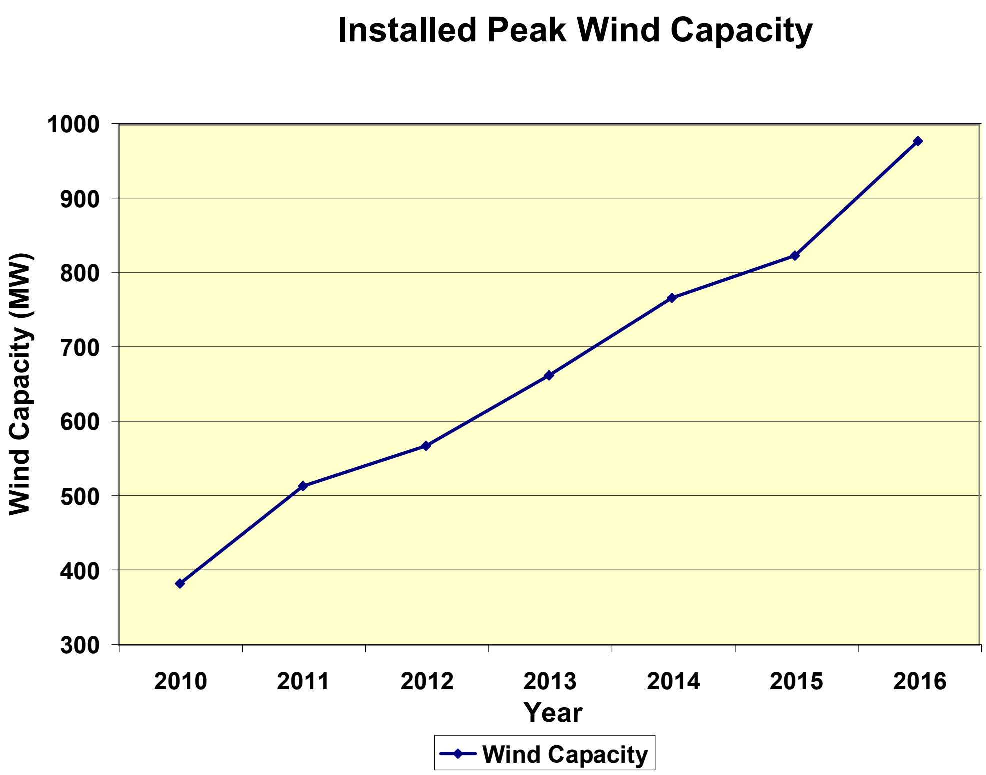
In 2008 there was a peak installed wind capacity of 272MW in NI. Individual wind farm generated demand (sent out MW) data was summated for 2008 to provide a base year aggregated profile total. The characteristics of the profile were validated against previous years to ensure it was a satisfactory representation 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 2008 wind profile to ensure a consistent wind shape throughout the year. When this adjustment was made the remaining peak installed capacity equated to 187MW. 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 of work provided by developers to secure connections to the network. The data provided was updated by NIE T&D immediately prior to the freeze date.

The scaling factor is calculated by dividing the average installed capacity for that year by that of the 2008 base year capacity (187 MW). The 2008 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
2010	383	350	1.87
2011	514	449	2.40
2012	568	537	2.87
2013	663	613	3.28
2014	767	717	3.83
2015	824	800	4.28
2016	978	900	4.81



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 may be necessary to adjust forecasts to account for significant unexpected events.

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 2008/2009 Winter Period

The generation peak demand forecasts represent the total NI generated demand. They include private customer generation (100MW), renewable generation, interconnector contributions and NI centrally despatched generation units (CDGU).

The peak demand for 2008/09 occurred on 29th January 2009 @ 17:30pm. The total generation peak demand was as follows:

Figure 3.3 – Review of 2008/09 Winter Period

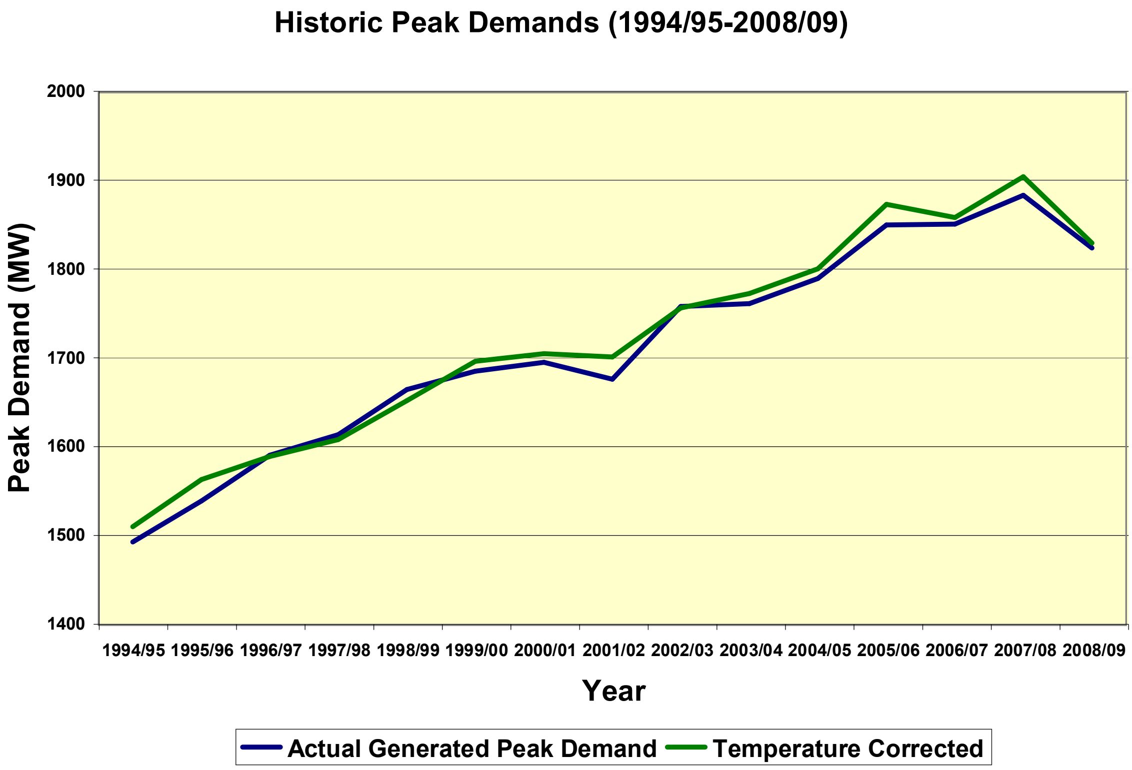
Generation type	MW
CDGU + Interconnections	1530
Renewables	195
Customer Private Generation	100
Total NI Generated Peak Demand	1825

When average cold spell temperature correction (ACS) is applied this figure is corrected up by 6MW, providing a figure of 1831MW for the 2008/09 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 Peak 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
2008/09	1825	1831

Peak Demand in NI has generally seen steady incremental growth over the last fifteen years. It should be noted however that the 2008/09 peak demand fell significantly due to the NI economy experiencing a recession. 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 2008/2009

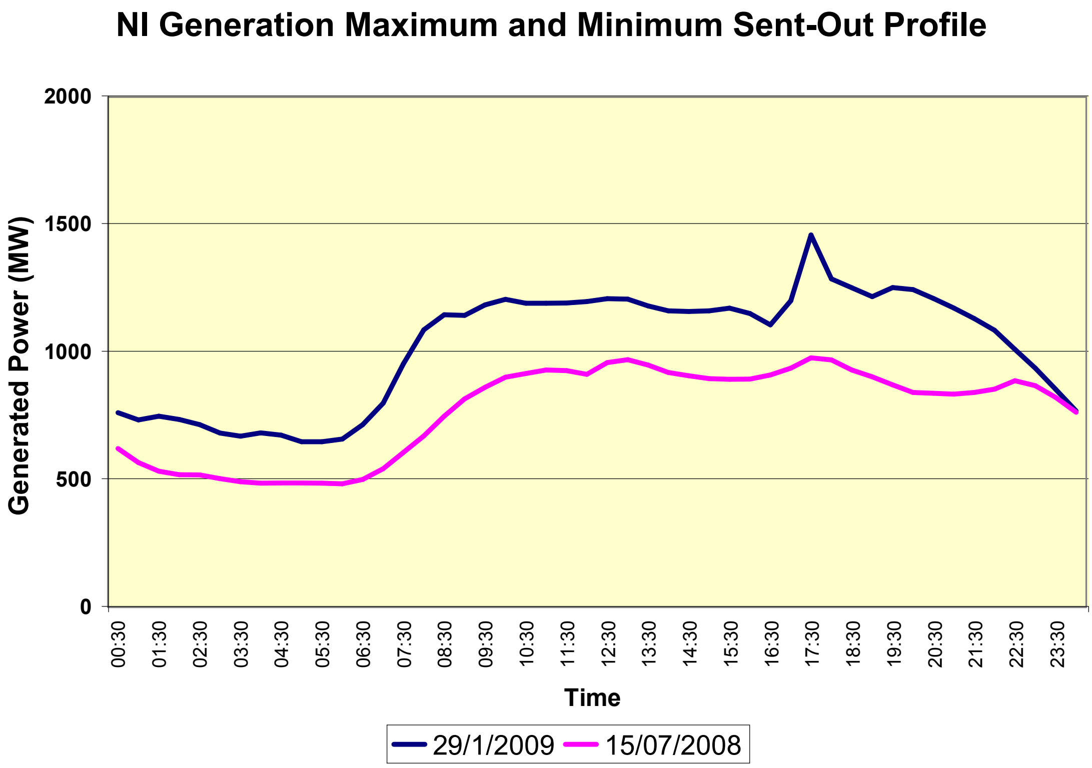
It should be noted that the generation adequacy assessment is based on generation sent out or in net terms. To express the forecasts in Section 3.4 in sent out terms it has been necessary to remove wind generation, private generation and power station works units. A conversion factor of 0.954 is applied 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 day demand profile as compared with the "flatter" summer profile.

The summer minimum sent out demand value of 484MW occurred on 15/07/2008 at 06:00hrs.

The winter maximum sent out demand value of 1460MW occurred on 29/1/2009 at 17:30hrs.

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 during 2008 greater than what was anticipated in last year's document. However at that time the full extent of the economic downturn was not known. The NI economy has been less severely affected by the downturn compared to other economic regions in the UK during 2008. Ireland has also experienced a deeper downturn than NI.

The NI economic outlook for 2010 is for a return to economic growth albeit at a very small level (0.5%). GDP levels for 2009 are expected to be -2.5%[1].

The 2008 demand reduction has provided a unique insight into the relationship between GDP levels on the demand for electricity. Forecasting analysis will consider econometric indices such as GDP, employment etc. to estimate electricity consumption trends as the NI economy pulls out of recession.

Figure 3.6 – GDP Growth Predictions (%)

	2008	2009	2010
NI	0.25%	-2.50%	0.50%

[1] First trust economic Outlook & Business review, volume 34.3, September 2009

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. These forecast scenarios have been derived from a SONI document published in June 2009 (Forecasting Peak Demand & Annual Energy Consumption in the Economic Downturn).

3.4.1 Medium Demand Forecast Scenario

This scenario assumes that the demand for electricity will fall in 2009, with zero demand growth being experienced in 2010. Modest growth will then emerge for the remaining years of the study.

Figure 3.7 – Medium Demand Forecast Scenario

Year	Gen Demand (MW)	Gen Energy (GWh)
2010	1660	8960
2011	1667	9005
2012	1683	9095
2013	1708	9231
2014	1734	9369
2015	1760	9510
2016	1786	9653

This forecast represents an underlying growth rate of circa 1.2%. The generation peak demand (MW) increases by an average of 21MW per annum and the generation energy forecast by 115GWh per annum. NI demand is not expected to grow in 2010, but growth will continue slowly thereafter reaching approximately 1.5% per annum in the later years of the study.

3.4.2 Low Demand Forecast Scenario

This scenario assumes that the economy falls deeper into recession continuing to 2010. Economic recovery and demand growth will not resume until 2011.

Figure 3.8 – Low Demand Forecast Scenario

Year	Gen Demand (MW)	Gen Energy (GWh)
2010	1633	8826
2011	1639	8859
2012	1650	8925
2013	1662	8992
2014	1680	9093
2015	1700	9203
2016	1720	9313

This forecast represents an underlying growth rate of circa 0.8%. The generation peak demand (MW) increases by an average of 14MW per annum and the generation energy forecast by 81GWh per annum. The rate of economic recovery and demand growth is lower than the medium forecasted figures.

3.4.3 High Demand Forecast Scenario

This forecast assumes that the various stimulus plans being applied will allow the economy to recover faster than some analysts predict and the NI economy will experience economic and demand growth from 2010.

Figure 3.9 – High Demand Forecast Scenario

Year	Gen Demand (MW)	Gen Energy (GWh)
2010	1704	9095
2011	1722	9186
2012	1746	9323
2013	1778	9491
2014	1810	9662
2015	1843	9836
2016	1876	10013

These forecasts represent underlying growth rates of circa 1.6%. The generation peak demand (MW) increases by an average of 29MW per annum and the generation energy forecast by 153GWh per annum. There is demand growth in each year peaking at 1.8% per year towards the end of the study.

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

Figure 3.10 – Comparison of Generation Demand Forecasts (MW)

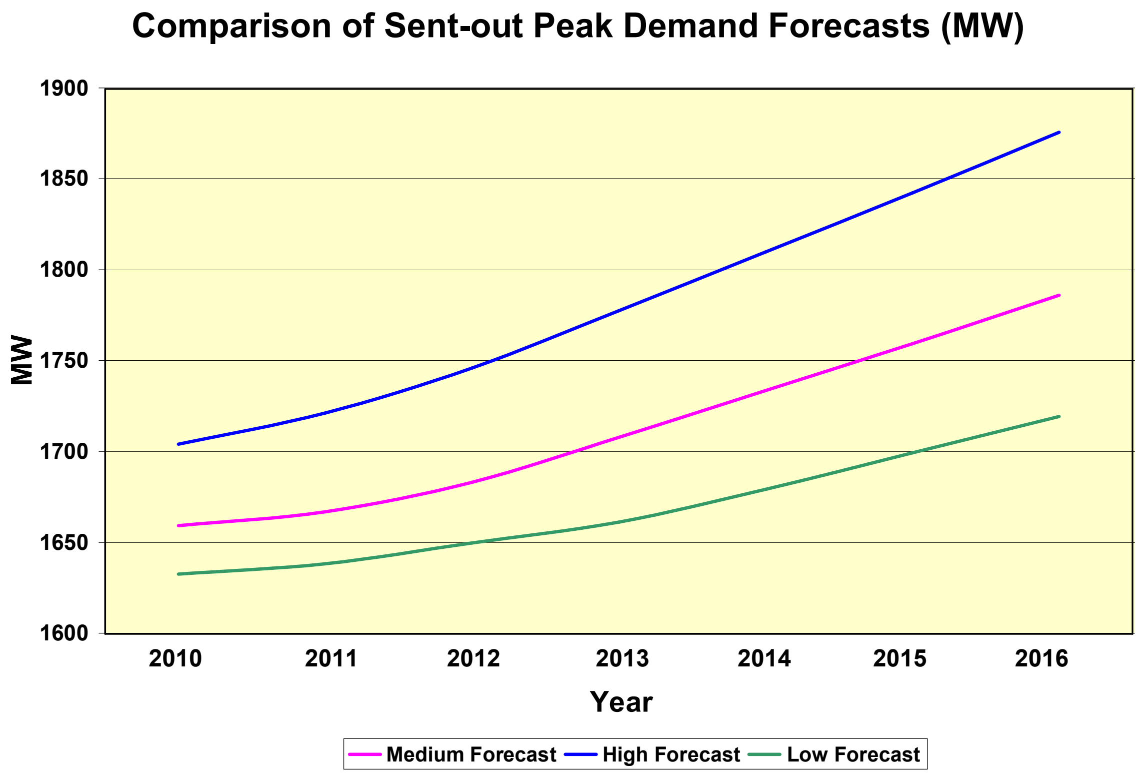


Figure 3.10 represents how the maximum demand is expected to increase over the next seven years. In previous statements a consistent growth rate was used for each scenario. From 2010 to 2012 demand growth is very low in each scenario. The following four years represent a return to familiar levels of growth (circa 1.5% for the medium forecast); this is to coincide with the expected economic recovery.

Figure 3.11 – Comparison of Generation Demand Forecasts (GWH)

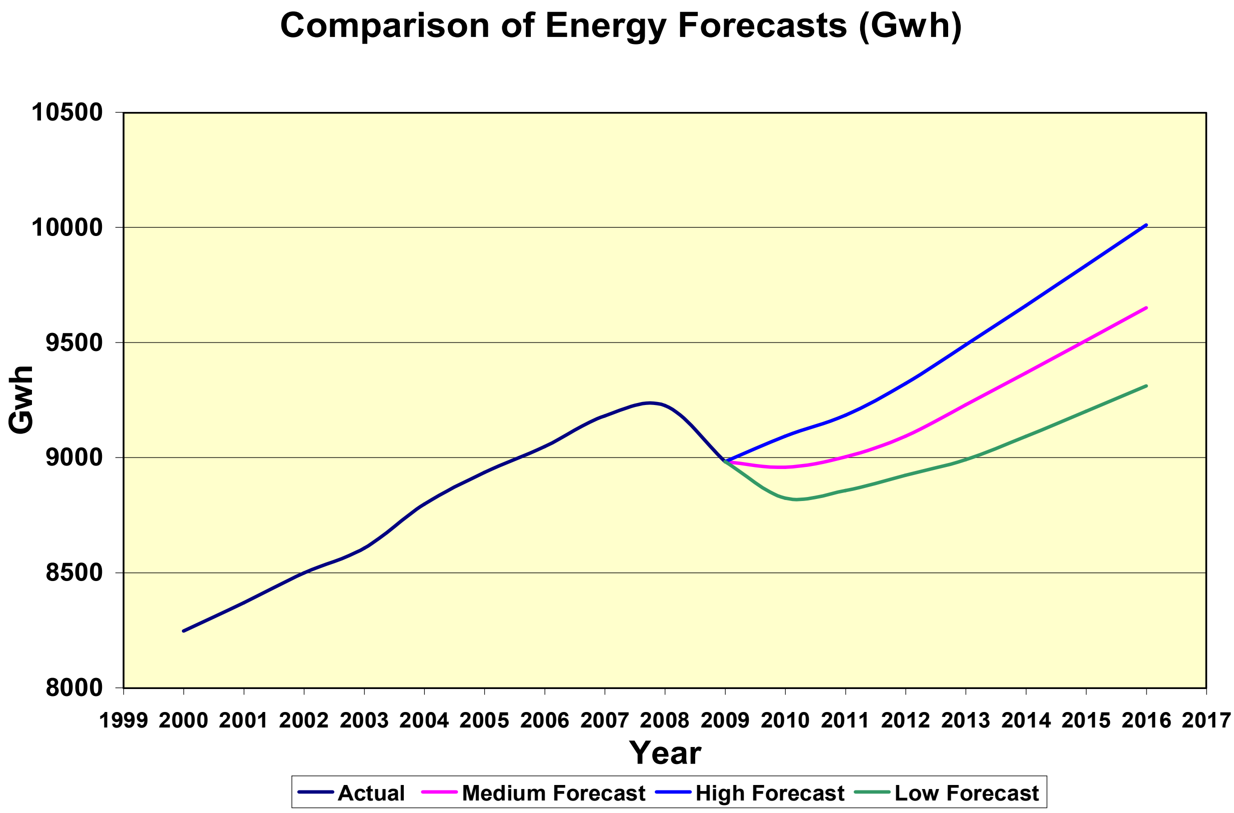
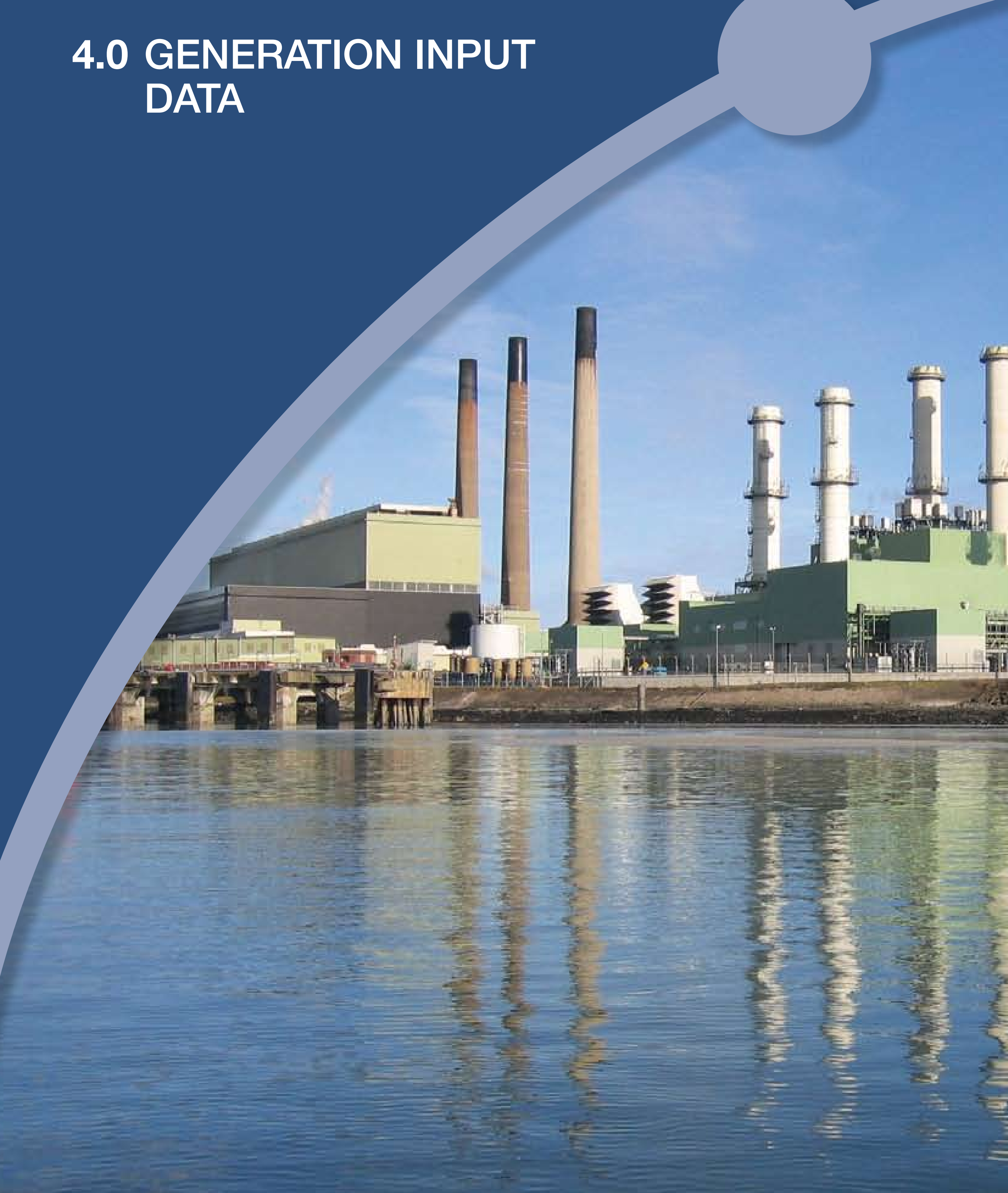


Figure 3.11 provides a good representation of how the economic downturn has affected the demand for electricity in NI. Up until 2008 demand was growing steadily year on year. A sudden drop is being experienced in 2009 with recovery expected to return around 2011. This “ladle affect” seems to be common amongst other publications on the economic recovery.

4.0 GENERATION INPUT DATA



4.0 GENERATION INPUT DATA

Over the time period 2010-2016, 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 capacity payment mechanism has encouraged participants to invest in additional generation projects in Northern Ireland i.e. GT3, GT4 and the assumed new CCGT plant at Kilroot Power Station.

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 SEM.

Figure 4.1 – Generation Capacity

Centrally Despatched Generating Plant	Fuel Type	Sent-Out Generating Capacity (net - MW)						
		2010	2011	2012	2013	2014	2015	2016
Ballylumford ST 4	*Gas/HFO	170	170	170	170	170	170	
Ballylumford ST 5	*Gas/HFO	170	170	170	170	170	170	
Ballylumford ST 6	*Gas/HFO	170	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	42	42	42	42	42	42	42
Kilroot GT 4	Gasoil	42	42	42	42	42	42	42
Kilroot CCGT	*Gas/Gasoil						400	400
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 - note 1	450	450	450	450	450	450	450
Total Generation Capacity		**2736**	**2736**	**2736**	**2736**	**2736**	**3136**	**2626**

- *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/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 2016 are Ballylumford ST4, ST5 and ST6 and this is due to environmental constraints introduced by EU legislation. Last years document had assumed that additional generating plant at Kilroot would have been commissioned by 2013, however this is not expected to be available now until 2015 subject to connection agreement.

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

There is a total capacity of 2736MW in 2009. This does not include the 100MW transfer capability available from RoI (see appendix A3).

The generation capacities represented are for peak periods. For example the capacities at Kilroot ST1 and ST2 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 5MW.

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 2009/10 Transmission and Generation map (See Appendix C).

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. Assumption - plant to be decommissioned from 2016
Ballylumford ST 5	*Gas/HFO	This is an Independent Power Producer, commercial operation commenced 1 August 2008. Assumption - plant to be decommissioned from 2016
Ballylumford ST 6	*Gas/HFO	This is an Independent Power Producer, commercial operation commenced 1 April 2008. Assumption - plant to be decommissioned from 2016
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 commenced April 2009
Kilroot GT 4	Gasoil	This will be an Independent Power Producer, commercial operation commenced April 2009
Kilroot CCGT	*Gas/Gasoil	This will be an Independent Power Producer, assumed availability from 2015.
Coolkeeragh GT 8	Gasoil	Contracted until 2020
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 power 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.

The plant portfolio over the next seven years has considerable reliance on gas-fired generation. Figure 4.3 shows how natural gas has replaced much of the older coal/oil plant since its introduction to NI. In NI over 1000MW of CCGT plant has been commissioned since 2002.

The dependency on Gas for electrical generation has continued to rise and will require careful monitoring over the next seven years. Currently 66% of installed generation capacity is capable of running on gas. Figure 4.3 and 4.4 below highlight how the generation mix has changed in NI and the highlights the dependency on Gas fired generation.

Figure 4.3 – NI Changing Generation Capacity Mix (1995-2016)

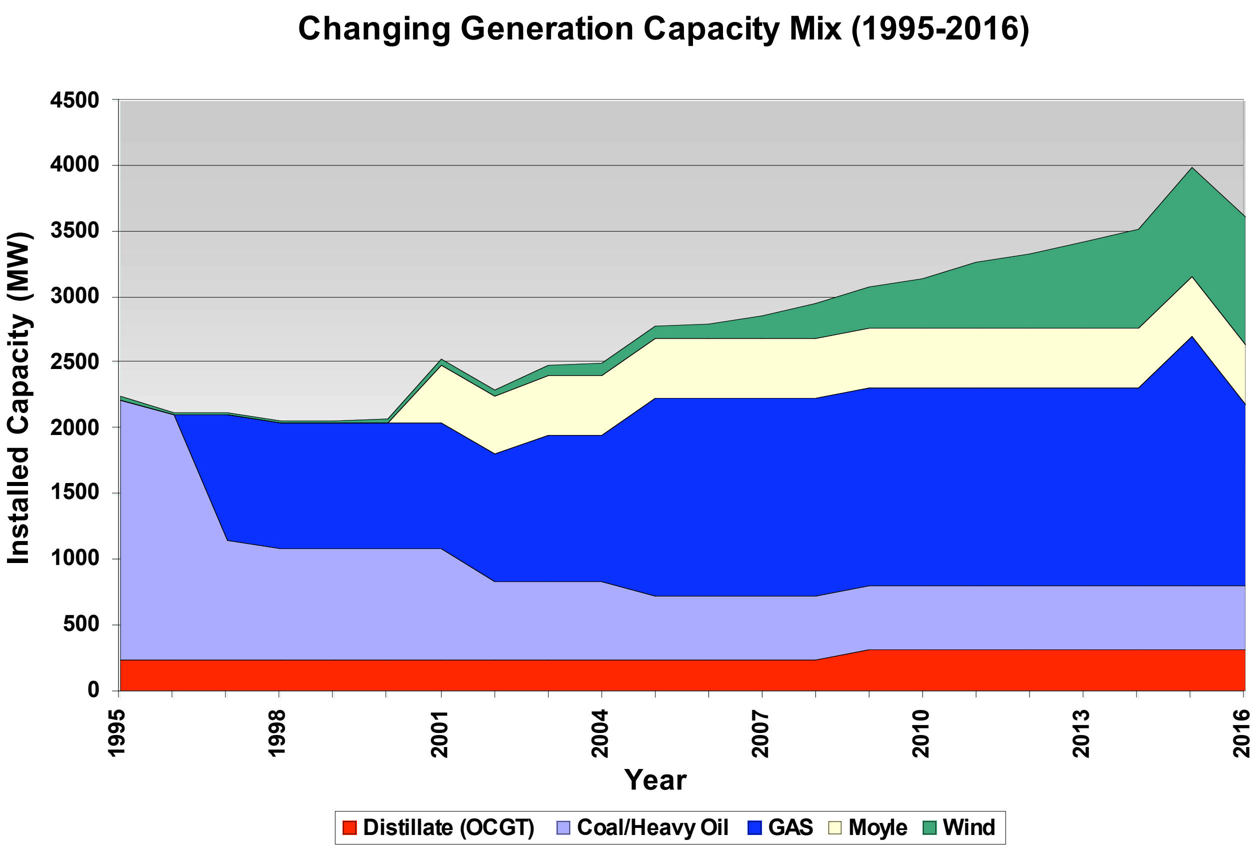
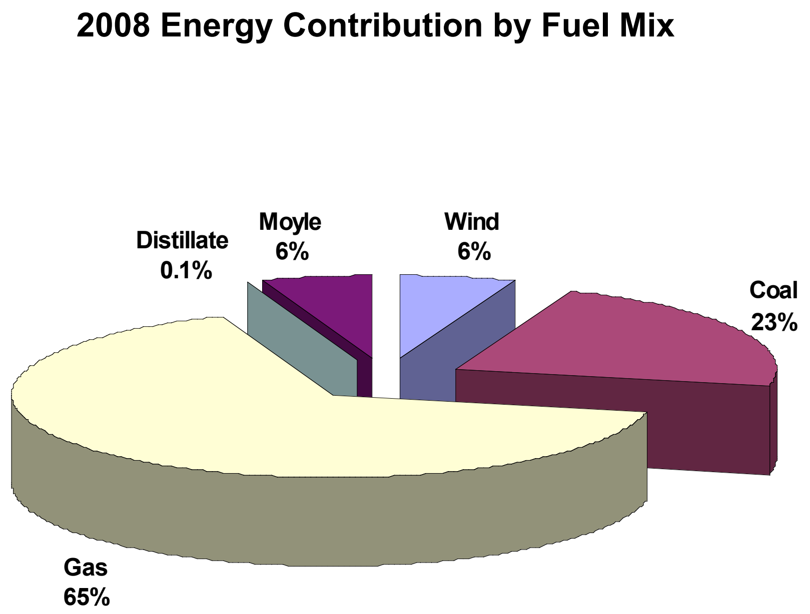


Figure 4.4 – 2008 Energy Contribution by Fuel Mix



4.2 Renewable Generation

There has been a continuing amount of connection applications from wind farms to the NI transmission and distribution networks. This has in part been driven by EU Policy. The European Union agreed to adopt a binding target on the use of renewable energy, such as wind and solar power. By 2020, 20% of the EUs energy supply must come from renewable sources. As a result of this the British government has set a UK target of 32% of electricity by 2020. DETI has released a draft consultation paper[1] which has set specific NI renewable targets, 12% of electricity from renewable sources by 2012 and 40% of electricity from renewable sources by 2020. Figure 4.5 highlights the size of the task that lies ahead to reach these targets.

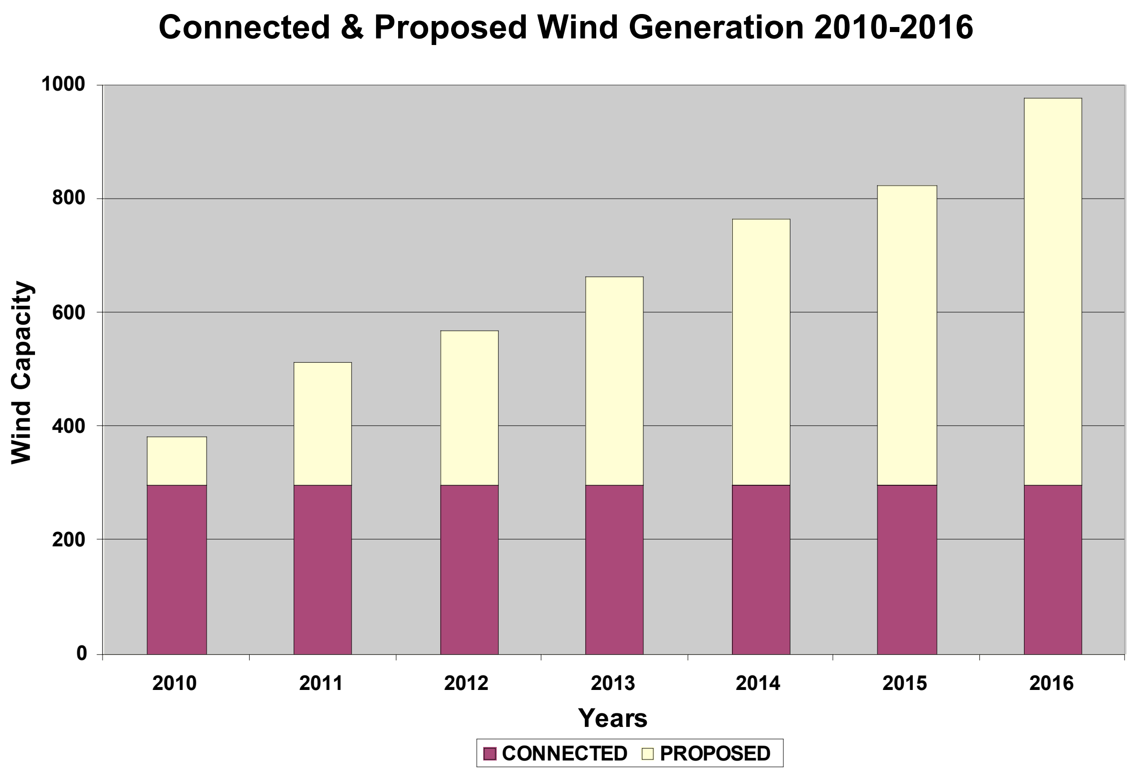
The system operator will have to manage the variability of renewable energy and system security issues at a system level. To achieve this it is important that consideration is given to ensuring that centrally despatched plant is of the correct plant type mix to meet the future needs of the network.

Section 3.0 explains how future wind profiles are created. The methodology agreed with the Regulatory for the production of the NI capacity statement, 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.

[1] A Draft Strategic Framework for Northern Ireland 2009

Figure 4.5 below shows the expected installed wind generation capacity from 2010-2016. With this level of wind penetration it may be necessary to curtail wind at low demand times for system security and stability reasons. A more detailed description on wind curtailment is provided in Appendix A. The annual values are estimated average values for the year as generation is connected progressively throughout the year.

Figure 4.5 – 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 4.6 lists projects, which have already been commissioned. The wind capacities in Figure 4.6 are expressed in power output MW as at 30 September 2009. A full list of wind farms that are in planning and have received planning permission can be obtained from the planning service website.

Figure 4.6 – Installed Wind Farms

Wind Farm name	Installed Cpacity (MW)
Corkey	5
Rigged Hill	5
Elliott's Hill	5
Bessy Bell 1	5
Owenreagh	5.5
Lendrum's Bridge	13.2
Altahullion	26
Tappaghan	28.5
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
Slieve Divena	30
Total	**301.2**

The network connection points of these wind farms are shown in Appendix C. Appendix C 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 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.

The All Island Grid Study reported on the technical and economic issues associated with the development of renewable energy with a vision for 2020 and beyond. 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. Specifically major reinforcement was identified in Donegal and NI with extensive reactive compensation required. NIE, SONI and EirGrid are working on a joint study in this geographical area to consider the options. The TSOs are also currently completing joint studies to consider the practical, operational and technical issues associated with managing large quantities of wind. The results of these studies are expected in the first quarter of 2010.

4.3 Non Fossil Fuel Obligation (NFFO) Capacity

A number of wind farms in Figure 4.7 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 4.7 below. NFFO1 contracts expired in March 2009 and NFFO2 expire between April 2012 and August 2013. Some of NFFO1 plant will now be operating as IPP's in the SEM. Further analysis is required into the installed NFFO plant to determine their contribution to renewable targets and their capacity factors. NFFO capacity is included in the wind generation profiles.

Figure 4.7 – NFFO Capacity

Scheme Name	Technology	Capacity (Kw)
Corkey	Wind	5000
Rigged Hill	Wind	5000
Elliott's Hill	Wind	5000
Bessy Bell	Wind	5000
Owenreagh	Wind	5000
Slieve Rushen	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**
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**

4.4 Customer Private Generation

A number of customers reduce their energy consumption by load shifting or by running private generation. 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. Private generation has been steadily growing from a figure of 38MW in 1994. A figure of 140MW was assumed to be running during the 2007/2008 winter period. This figure has been produced from the extrapolation of historic assessments.

4.4.1 2008/09 Private Generation Figure

During the last year SONI has acquired accurate metered data for each individual private generator. An analysis of this metered data has showed that 100MW of private generation was running during the 2008/2009 winter period. This is 40MW less than what was previously thought. As this document assesses adequacy in sent out terms then this 40MW reduction in private generation will have to be met by conventional generation.

4.4.2 Forecasting Private Generation Figures

Future forecasting on private generation will now be more accurate than previous years by using actual metered data for each private generator. This will allow an historic trend to be developed. Economical analysis will also be carried out to determine whether it is economical for organisations to run private generation compared to buying electricity from suppliers. A questionnaire has also been developed and various private generators will be asked each year if they intend to run during the forthcoming winter period.

This in depth private generation analysis has been conducted for this document. Due mainly to changes in UoS tariffs and generating costs The results of the questionnaire suggests that circa 50MW of private generation will be running during the 2009/2010 winter period. This figure has been used for each year of the study and will be reviewed on an annual basis.

4.5 Moyle Interconnector

The Moyle interconnector is a dual monopole HVDC link with 2 co axial under sea cables from Ballycronanmore (Islandmagee) to Auchencrosh (Ayrshire). The total 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 450MW during the winter and 410MW from April to October inclusive. An emergency flow of up to 50MW is available should the frequency in Ireland reach 49.6Hz and a further 25MW available at 49.5Hz. All interconnector capacity is auctioned by the

Transmission System Operator (TSO) in NI on behalf of Moyle Interconnector Ltd (MIL). This capacity is purchased by market participants. In the SEM the unused capacity can, in emergency situations, be used solely to meet 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 appropriate NTC 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 Ireland can be assumed in adequacy assessments.

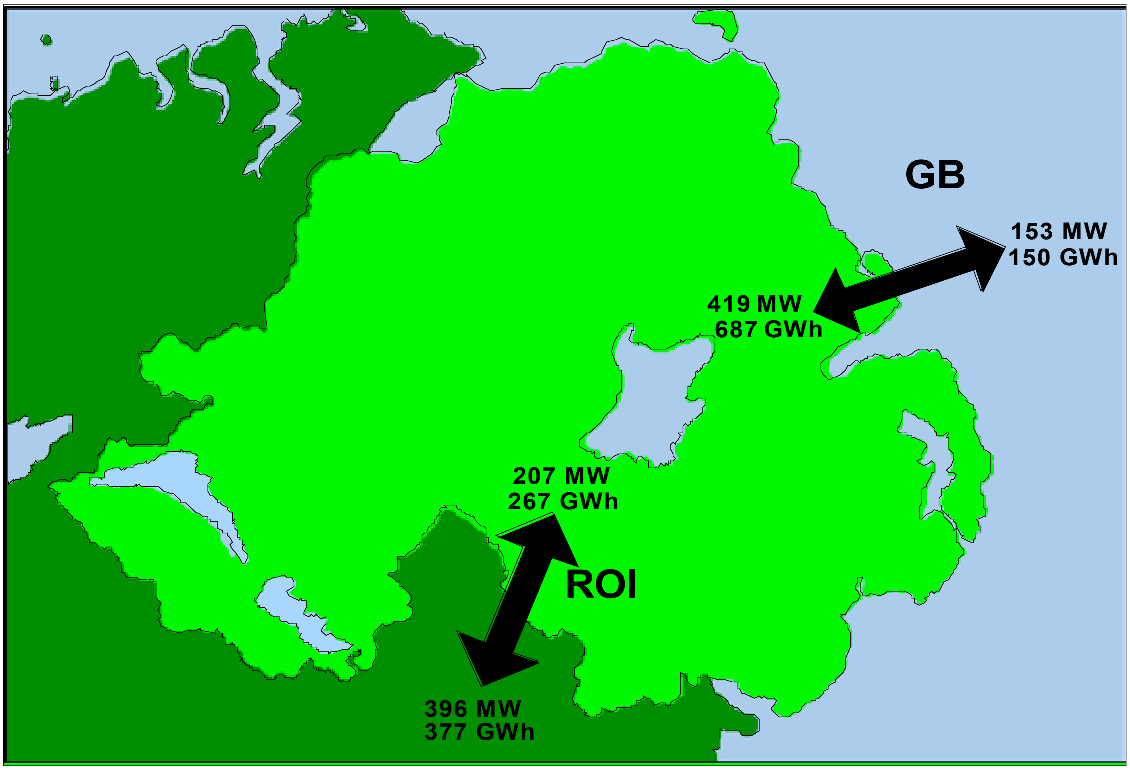
4.7 North-South High Capacity Transmission Tie Line

EirGrid and NIE are committed to establishing a new tie line between Ireland 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 2013. After that, there will no transmission constraints and an All-Island system can be assessed for generation adequacy.

4.7.1 Increasing Interconnection

Exchanges with neighbouring power systems have a large part to play in maintaining the supply-demand balance. In the event of sudden unfavourable conditions such as intermittent wind or generator failure, interconnection allow system operators to call on back up supplies which may be located in other countries. Interconnection between NI, the BETTA market and tie-lines to Ireland, enables demand to be met from other generating sources in the most economical way. With regard to increasing levels of renewable generation and its fluctuating output, increased interconnection will allow excess generation to be transferred to neighbouring power systems and vice-versa in times when generation is low. Figure 4.8 shows the maximum values of power exchanges and the total energy exchanged between GB and Ireland during 2008. It should be noted that the magnitude of these values are a result of rescue flows or 'SO trades,' which occur occasionally to support neighbouring systems and not steady state flows.

Figure 4.8 – 2008 Maximum Power and Energy Exchanges



4.8 Generator Availability Data

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

The size of the PCC is influenced by a number of factors one of which is generator 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 the Moyle HVDC link.

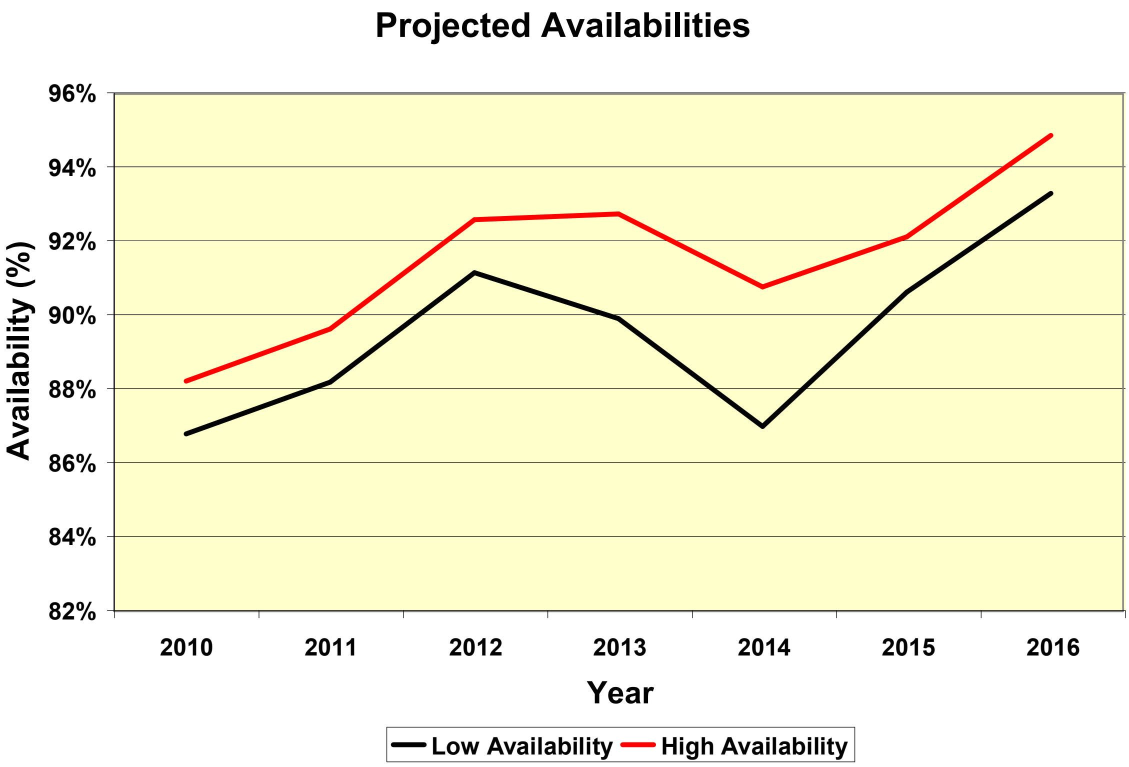
4.8.3 Generator Availability Scenarios on a Network Basis

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.

It is necessary to present a range of availability 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 4.9 below shows the projected overall availability for the seven year period covered by this statement.

Figure 4.9 – Projected Availabilities

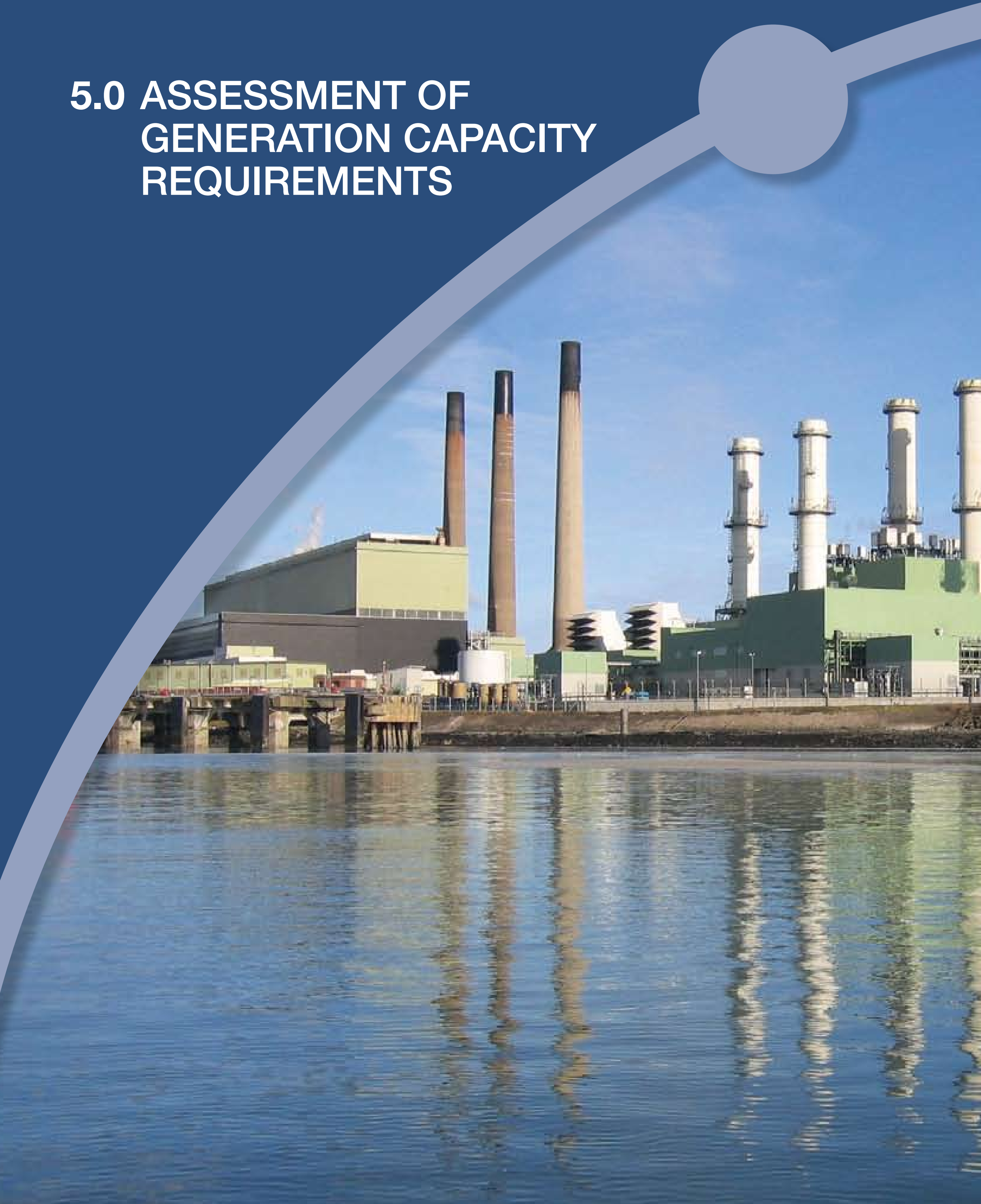


Year	2010	2011	2012	2013	2014	2015	2016
High Availability	88.2%	89.6%	92.6%	92.8%	90.8%	92.1%	94.9%
Low Availability	86.8%	88.2%	91.2%	89.9%	87.0%	90.6%	93.3%

The average high availability over the seven-year period is 91.6% and the low availability figure is 89.6%.

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



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 2010 to 2016. This follows the methodology described in Section 2.0. From 2013 to 2016 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 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

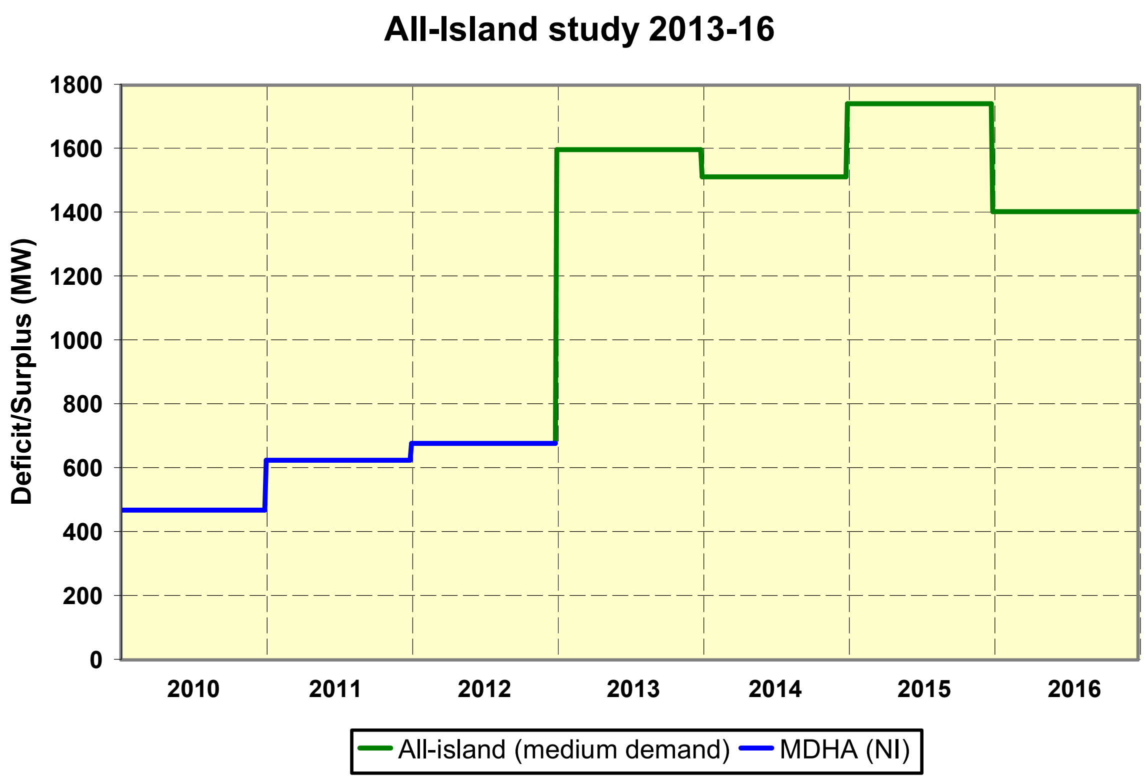
Each of these demand forecast predictions are analysed for both high and low generator availability performance. The scenarios and codes then become:

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 2013-2016

The first graph, Figure 5.1 describes the deficit/surplus that will be experienced from 2010-2016 based on a medium demand scenario. 2010-2012 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 an unconstrained transmission system between North and South.

Figure 5.1 – All Island Study



5.1.1 Discussion of All-Island Study Results

The NI system study from 2010-2012 indicates a surplus of circa 600MW. The studies are based on a medium load growth which under normal circumstances would decrease the amount of surplus year on year. 2010 sees the lowest level of generation surplus; this is due to a higher level of scheduled outages compared to the other six years of the study.

An All-Island study was carried out from 2013-2016. There is an increase in surplus capacity in 2013 to 1600MW. This 900MW increase from 2013 is caused by modelling generation adequacy on an All-Island system, were generation adequacy is modelled with no constraint between north and South.

There are a number of other reasons explaining this large surplus increase experienced from 2013. A decrease in demand and demand forecasts in Ireland and NI makes it easier to achieve the LOLE standard. New plant and the East-West interconnector are being commissioned on the Island which can be utilised in both jurisdictions. Other knock on effects have seen plant availability increase possibly due to less generating time as a result of demand reduction and incentives from the SEM.

From 2013-2016 generation surplus is circa 1600MW. It increases to almost 1800MW in 2015. This is due to the assumed introduction of new generating plant at Kilroot and is reduced to 1400MW in the final year coinciding with the decommissioning of plant 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 (2013-2016). 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 2012

The following three graphs, consider the possibility that the proposed N-S tie-line will not be complete by the 2016, this study uses only NI generation data with a reliance of 100MW from the Ireland system. Figure 5.2 shows the full extent of surplus/deficit for each scenario as described in section 5. Figures 5.3 and 5.4 show the low and high availability scenarios.

Figure 5.2 – N-S Interconnector Delay (All Scenarios)

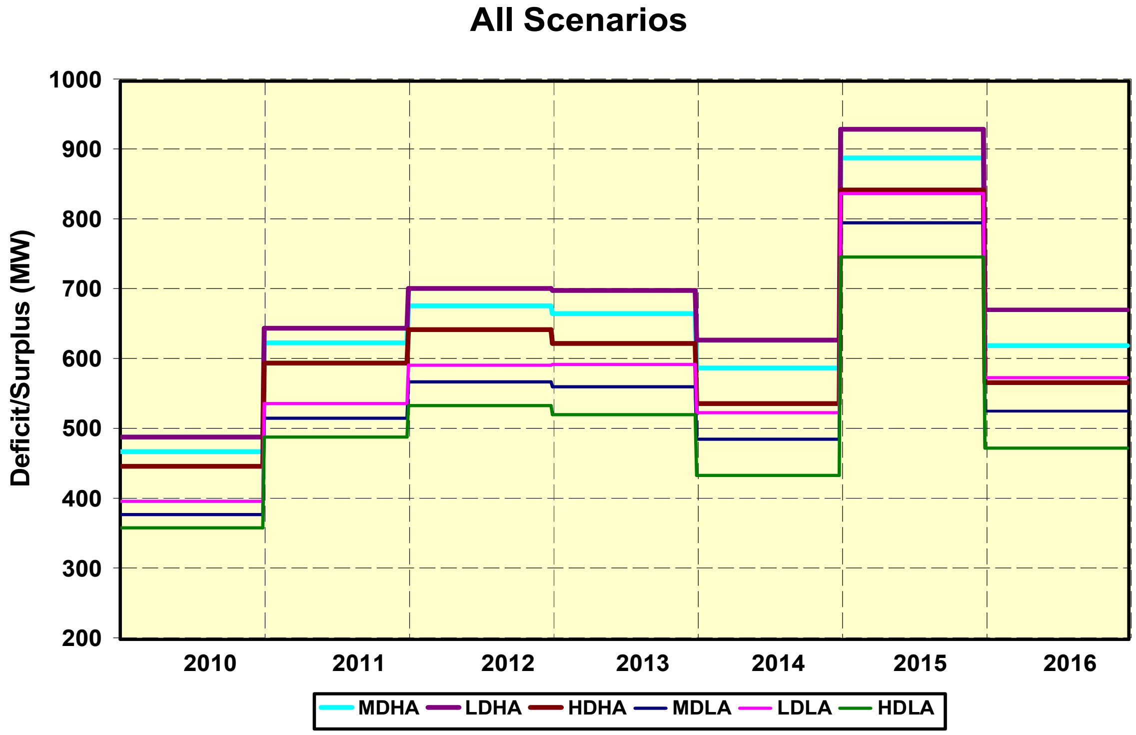


Figure 5.3 – N-S Interconnector Delay (Low Availability)

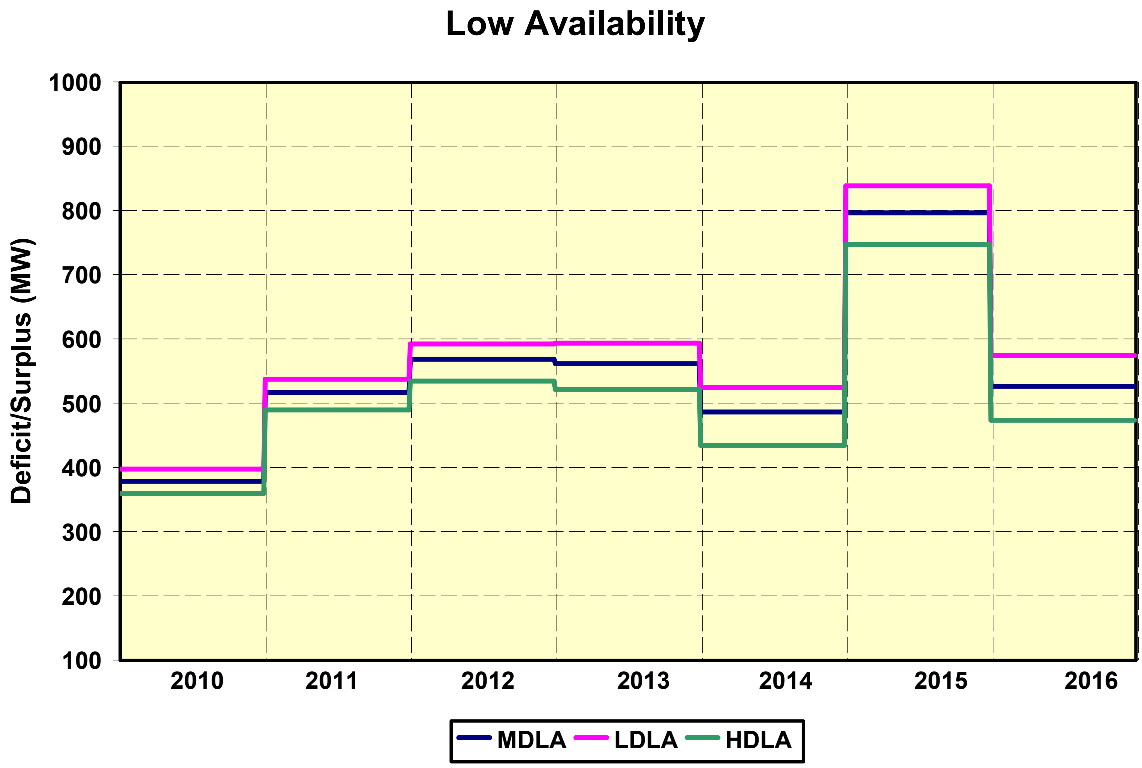


Figure 5.4 – N-S Interconnector Delay (High Availability)

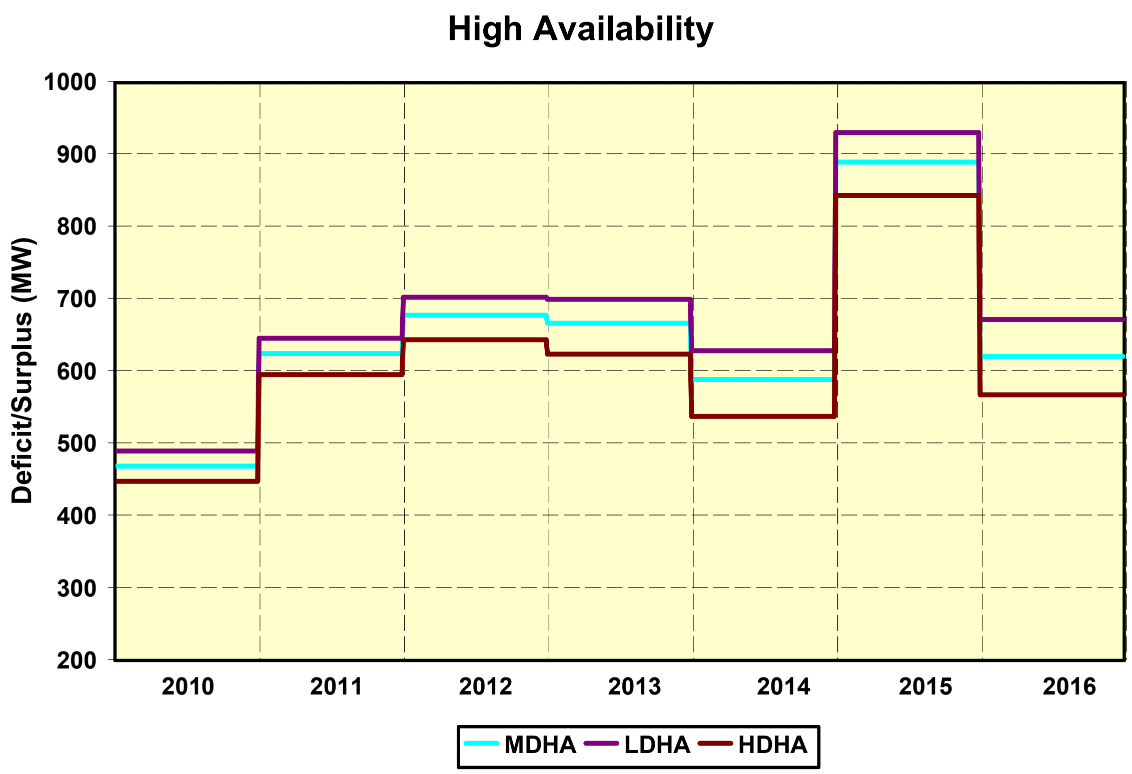


Figure 5.5 provides a tabular summary of the previous analysis.

Figure 5.5 – Tabular Summary of N-S Interconnector Delay Analysis

Demand	Availability	2010	2011	2012	2013	2014	2015	2016
High	Low	360	490	535	522	435	748	474
	High	448	596	644	624	538	844	568
Medium	Low	379	517	569	562	487	797	527
	High	469	625	678	667	589	890	621
Low	Low	398	538	593	594	525	839	575
	High	490	646	703	700	629	931	672

5.2.1 Discussion of Results

This contingency analysis has been undertaken to determine if the delay in the second N-S tie-line would leave NI in a deficit position. Without the second N-S tie-line, NI will still be in generation surplus for each year of the study. As discussed in Section 5.1.1 the proposed 400MW plant at Kilroot will provide an increased surplus in 2015, and the decommissioning of units ST4, ST5 & ST6 in 2016 sees the surplus within NI return to similar levels experienced before 2015.

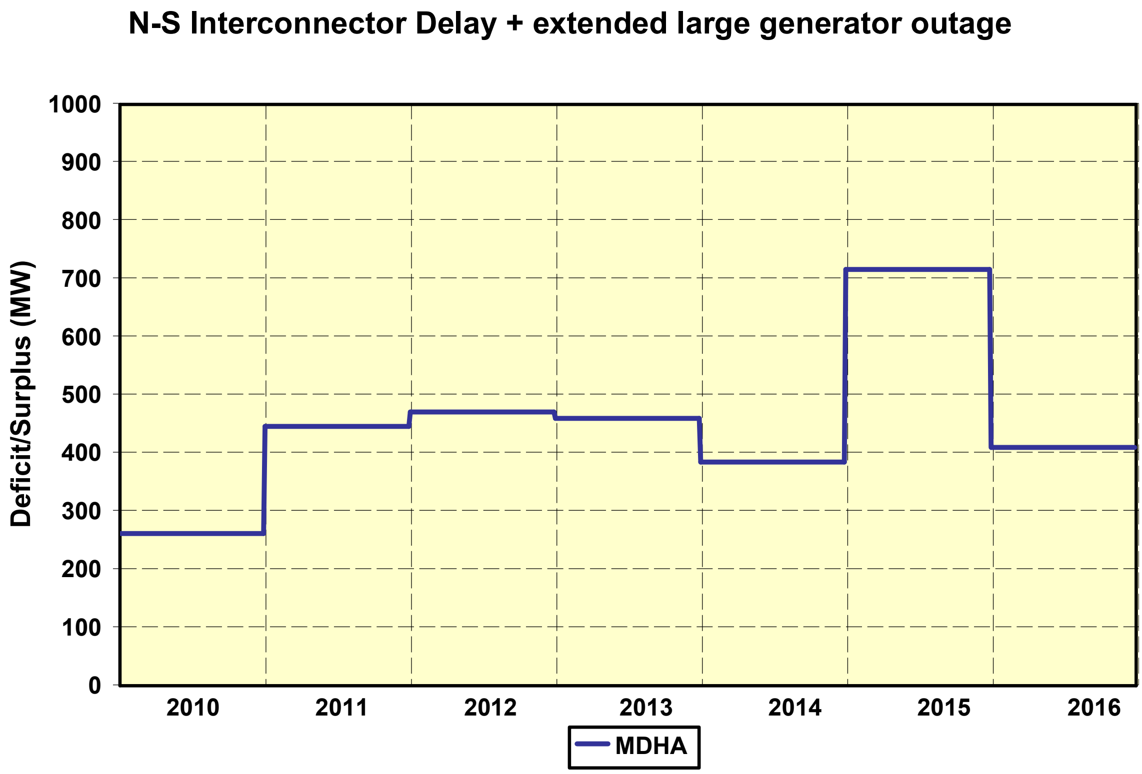
Figure 5.3 considers only the Low Availability scenarios on a single graph. The low availability figures are determined by using the highest FOP rate experienced from NI plant and applying it to all generators. This reduces their availability and so the surpluses experienced are less than the figures in Figure 5.4. The low availability figures used for this study can be seen in Figure 4.9.

Figure 5.4 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 4.9.

5.3 Results – N-S Tie Line Delay + Extended Large Generator Outage

Figure 5.6 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 (2010-2016). It provides a view of generation adequacy in NI under these circumstances. The MDHA has been applied to this scenario.

Figure 5.6 – Interconnector Delay + Extended Generator Outage



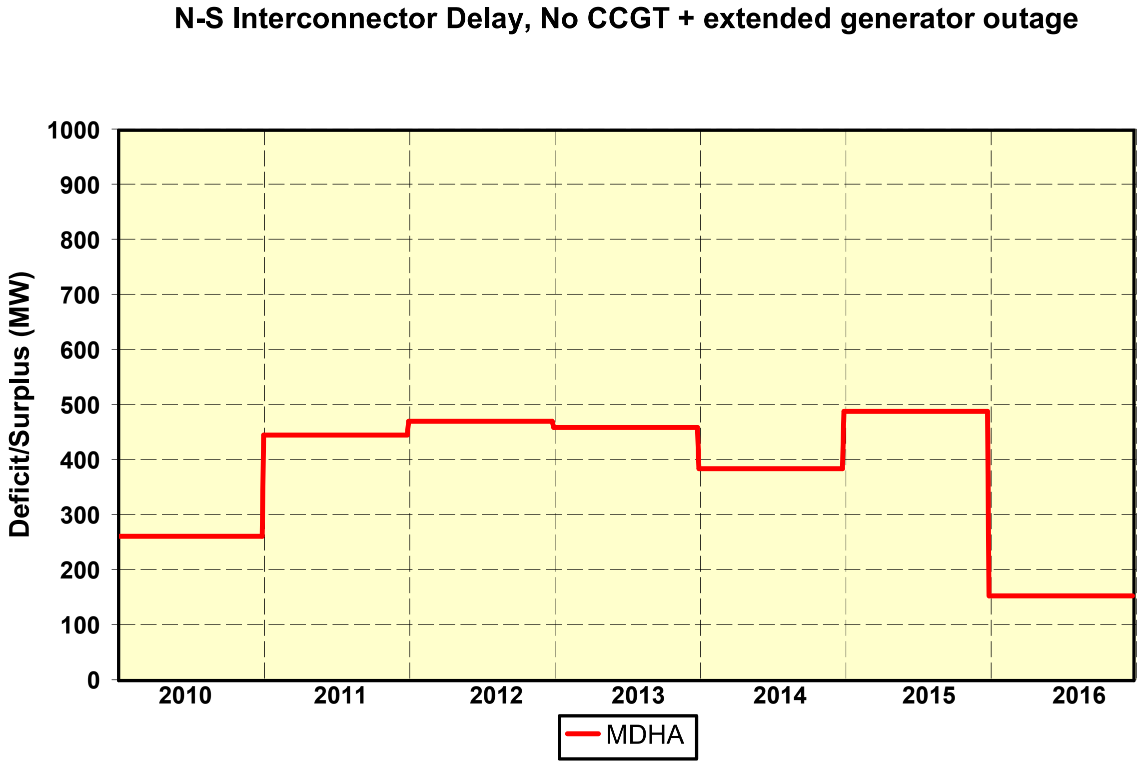
5.3.1 Discussion of Results

Surpluses experienced in Figure 5.6 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 200MW. The lowest generation surplus experienced over the seven years is 262MW and occurs in 2010. This analysis has been carried out using the assumption that the 400MW generating plant at Kilroot will be operational from 2015.

5.4 Results – N-S Tie Line Delay, No CCGT + Extended Large Generator Outage

Figure 5.7 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 Section 5.3 is experienced. The MDHA scenario is applied.

Figure 5.7 – Interconnector Delay, No CCGT + Extended Generator Outage



5.4.1 Discussion of Results

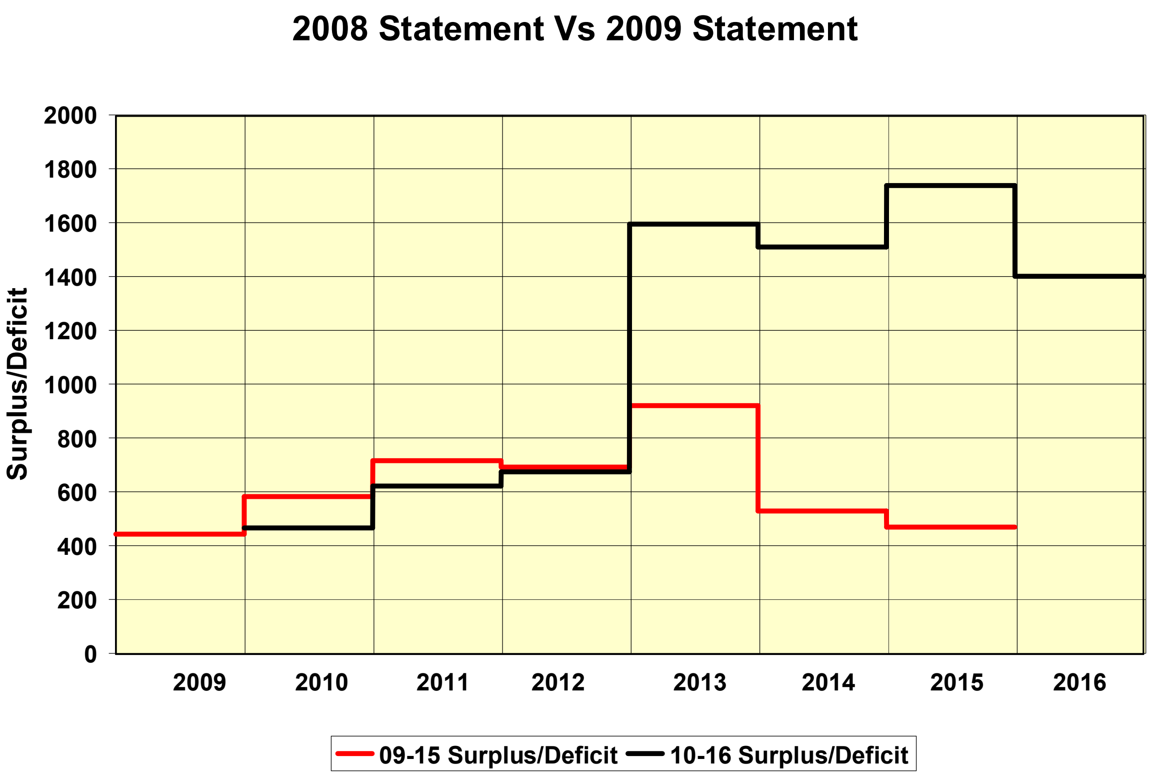
Figure 5.7 represents the most pessimistic scenario considered in the analysis with the second N-S tie-line delayed, the CCGT at Kilroot delayed and an extended large generating unit outage occurring each year. Up until 2014 the surplus experienced is the same as in Figure 5.6. A considerably reduced surplus is experienced from 2015 because of the delay in the N-S tie line, a delay in the CCGT at KPS and the decommissioning of the plant at Ballylumford. There is a surplus of 154MW in 2016, the lowest amount experienced in the study.

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.

Figure 5.8 compares the surpluses/deficits from this statement to last years and is based on an all island study from 2013. The surpluses experienced in last year's statement show a consistent level of surplus generation capacity until 2013 at circa 600MW.

Figure 5.8 – 2008 Vs 2009 Statement



The first three years of the study show similar levels of generation surplus and patterns as last years results. The reason for this difference is due to more recent information from the generators regarding plant availability. Updated software used to carry out the studies also allows for more accurate reporting, especially when modelling units with different generation shapes throughout the year.

There are stark differences in the results from 2013 onwards. This years study sees an overwhelming increase in generation surplus compared to last year's document. The main reasons for this are the enhanced benefits of a fully interconnected electricity system. Increased levels of generating plant, the East-West Interconnector and the extended lifetime of Ballylumford units ST4, ST5 and ST6 also contribute. The most significant factor in the change of generation surplus level however, is the reduction in demand levels that have been forecasted as a result of the NI economy entering recession.

The level of maximum demand is currently similar to 2005 levels, and the forecasted growth levels for the next seven years have also been reduced year on year compared to previous years. The generation portfolio capacity assumptions have not changed significantly. It is not clear however how the global economic slowdown will affect the funding of assumed projects.

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 generation surplus/deficits in this regard and the analysis confirms adequate plant surpluses are anticipated in the short term. 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
OCGT	Open Cycle Gas Turbine
CAES	Compressed Air Energy Storage
UoS	Use Of System

Appendix A

Appendix A

A1 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.

A2 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.

A3 Inter System Reliance Values

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

Appendix B

Wind Curtailment

As mentioned in Section 3.1.1, it is necessary to curtail wind output in order to build accurate demand profile forecasts. This is to ensure a sufficient level of conventional generation plant is connected to the network to respond to wind variability and to provide sufficient system inertia to maintain system stability.

It should be noted that wind curtailment is to ensure system security as a result of having large amounts of installed wind capacity connected on a small system. Wind curtailment should not be confused or compared to a wind constraint. A wind constraint will occur due to network limitations or under certain outage scenarios which would result in certain line ratings being exceeded.

Conventional generation levels are not be allowed to drop below 380MW in NI. The following diagrams show an example of the wind curtailment concept. The example uses a typical summer weekend day from our 2016 medium demand and wind generation forecast. The example also assumes that no energy will be exported to neighbouring power systems.

Figure B1 – Demand Profile – Wind Profile

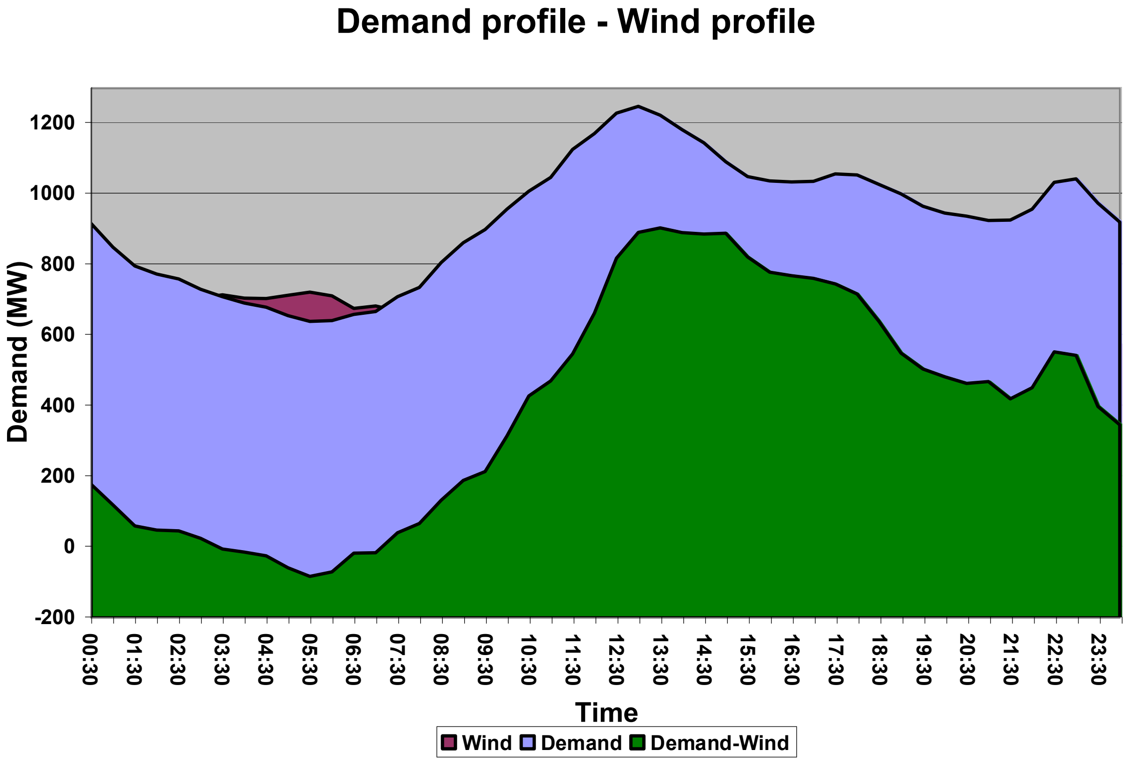


Figure B1 shows a typical forecasted summer weekend day in 2016. During most of the day the wind output is less than the NI demand except during the early hours of the morning when the wind generation is greater (05:30). The green area of Figure B1 is the NI demand which has to be met by conventional generation i.e. wind generation subtracted from the demand profile. When the Demand minus the wind profile reaches levels below 380MW wind will have to be curtailed to ensure system security. In this instance wind generation actually exceeds demand by almost 100MW during the early hours of the day.

Figure B2 – Generation Profiles

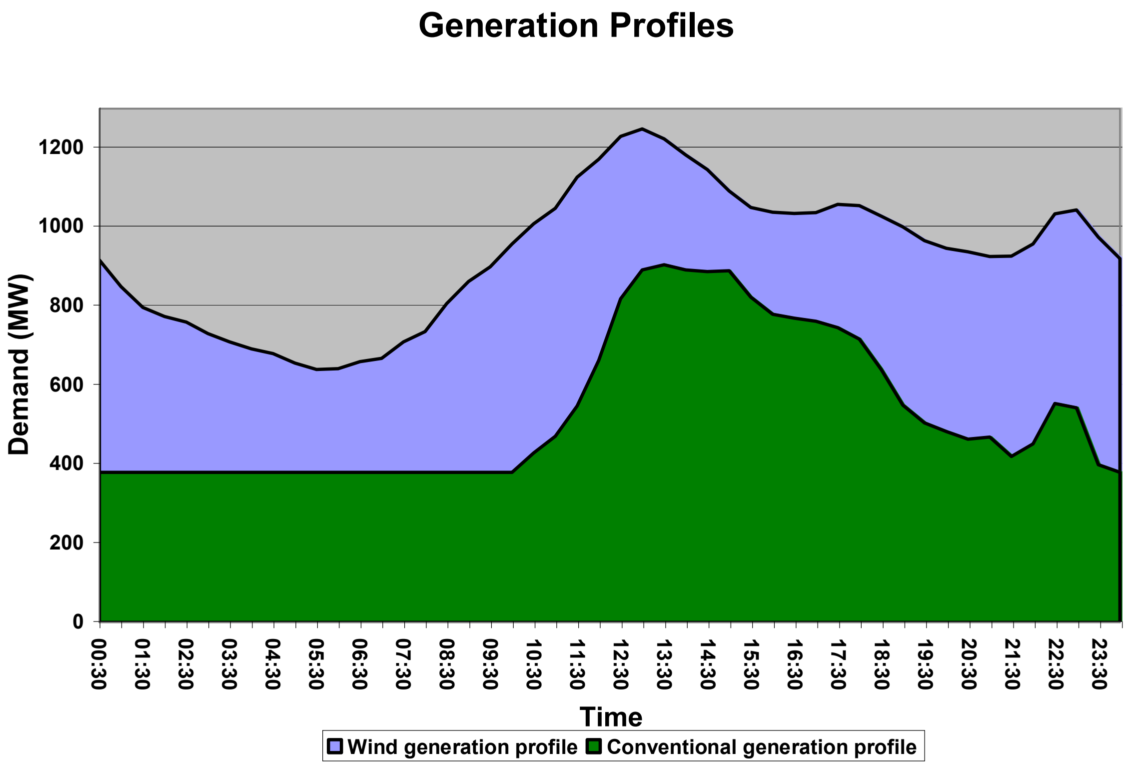


Figure B2 shows how the demand will be met by conventional generation and from wind generation on this particular day. The green area is the level of demand that has to be met by conventional generation. Note that the lowest level is 380MW. The blue area of Figure B2 is the remaining wind generation profile on this particular day.

Another important observation from Figure B2 highlights the importance of conventional generation being able to react to the variability in wind output. Notice how quickly conventional generation must be able to react to changes in demand and to wind output. This is particularly noticeable around 12:00pm were demand is rising and the wind output is decreasing at the same time.

Figure B3 – Curtailed Wind Generation

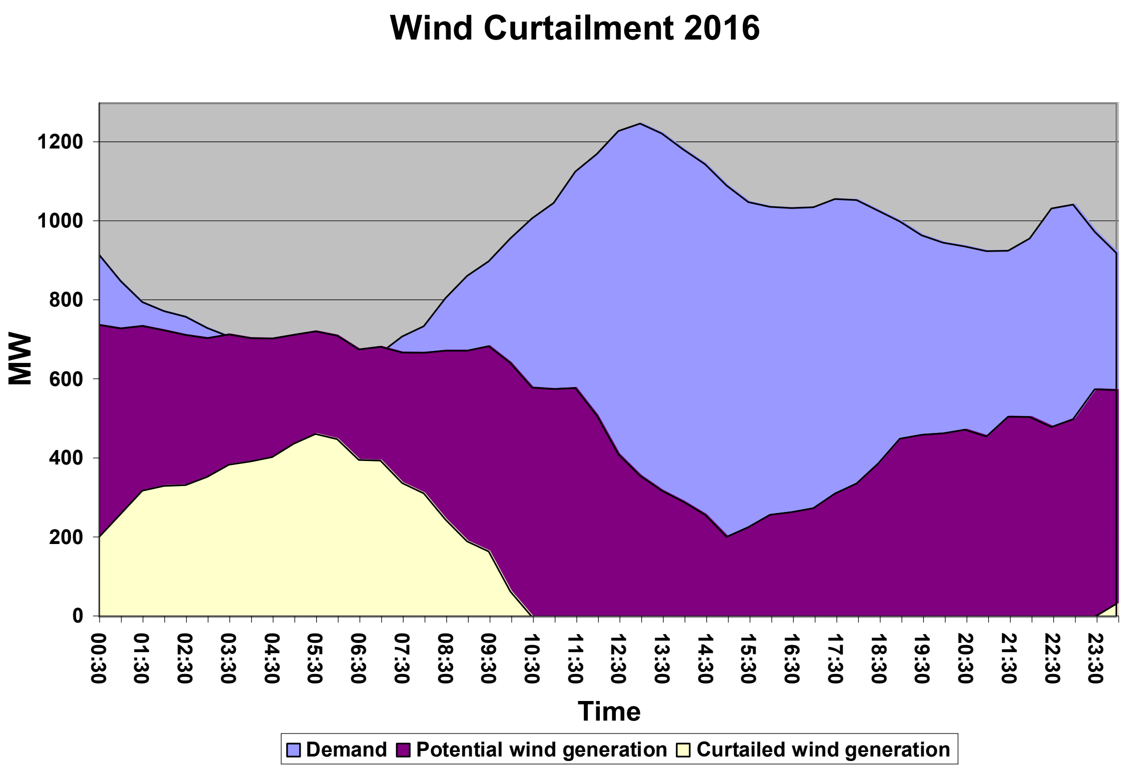


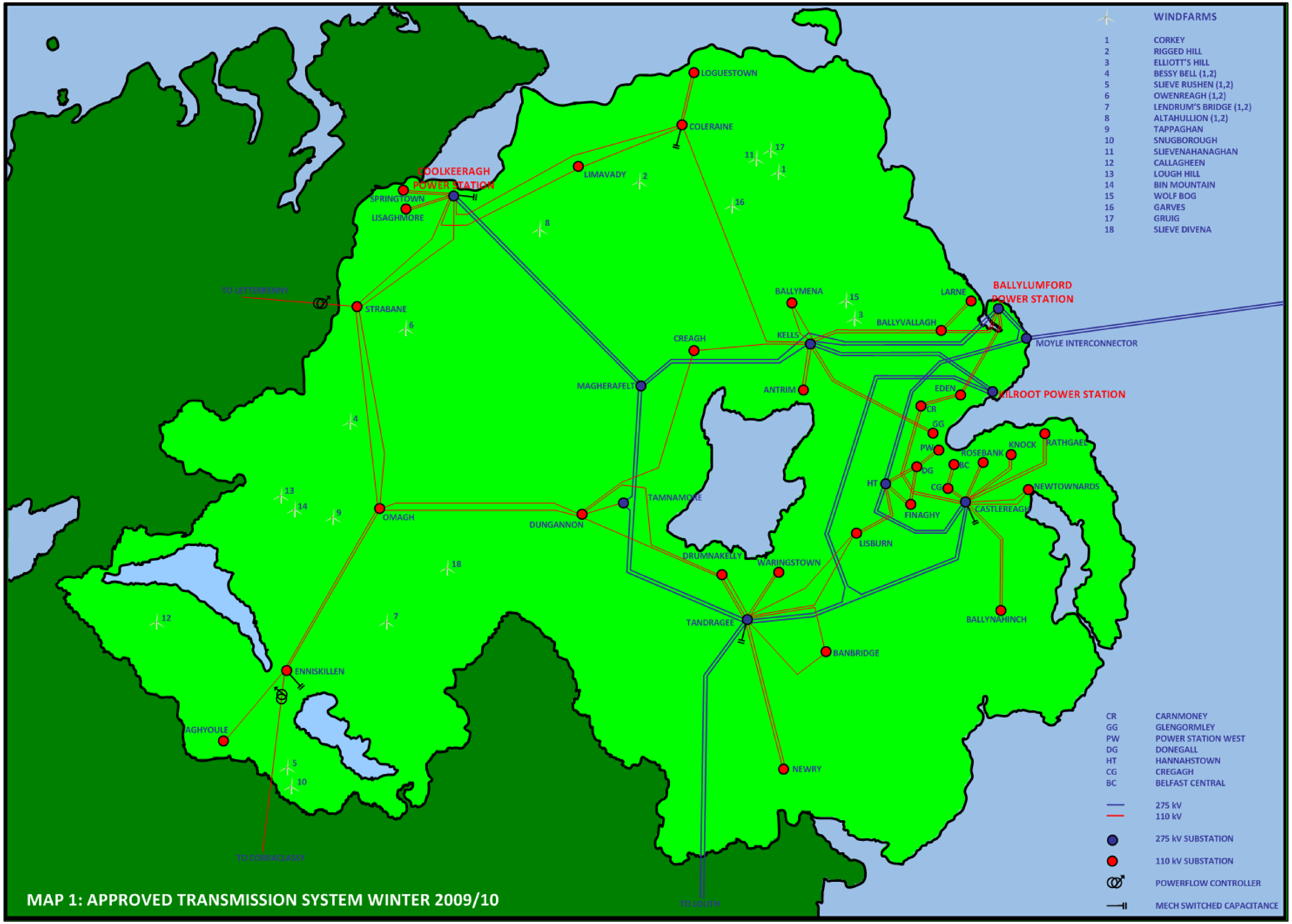
Figure B3 shows the potential amount of wind generation that is available during the day. The lighter shaded area is the amount of wind generation that has to be curtailed to ensure system security. Wind curtailment in this instance is mainly during the early hours of the morning when demand is low.

This illustration represents what potentially could happen when the installed wind capacity reaches the levels mentioned in Section 3.2. It is a worst case scenario that could occur using the forecasted wind and demand levels. This illustration should not be used to make any financial assumptions or decisions.

With the variability and uncertainty of wind it is impossible to accurately predict the amount of energy that will be curtailed. Some form of energy storage such as Compressed Air Energy Storage (CAES) or traditional pumped hydro could help reduce the amount of wind energy curtailed. Energy storage also has the potential to increase the level of renewable energy utilisation and help NI reach the renewable energy targets mentioned earlier in this document.

Appendix C

Appendix C



MAP 1: APPROVED TRANSMISSION SYSTEM WINTER 2009/10

System Operator for Northern Ireland

Photo courtesy of Coolkeeragh ESB.