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Technical and Economic Appraisal for Onshore Wind Generation

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Executive Summary

This technical and economic appraisal for onshore wind generation completed by Mott MacDonald (MM) aims to provide the Isle of Man Government with an overview of wind farm operation and the impact onshore wind development would have on the Manx Electricity Authority's public electricity network.

The environmental impact of a wind farm is outside the scope of this appraisal, however if a suitable site could be found, it is technically possible to connect such a facility to the existing public network. If economically favourable conditions could be achieved such as low cost of borrowing, then an onshore wind farm of up to 20MW becomes a viable proposal. This would provide 12% of installed on-island renewable capacity from onshore wind.

The technical assessment indicates the maximum capacity for onshore wind generation is 20MW, with system security and stability maintained. Wind farm capacity is influenced by the examined boundaries such as load profile, voltage step limit and available shadow capacity provided by on-island thermal generation plant. The assessment explored various scenarios for system operation and considered: the MEA load demand, the availability of the MEA transmission system infrastructure, availability of the wind farm and the IOM-UK Electricity Interconnector. The technical analysis identified boundaries which limit the wind farm installed capacity or power output. The boundaries are the MEA transmission system constraints, the voltage step limit, the IOM-UK Interconnector spinning reserve, the island mode of system operation and the ability to comply with the UK Grid Code.

The economic impact of an onshore wind farm on MEA's internal and external market and commercial activities, were identified. The issues considered included the typical load factor of onshore wind, fuel cost savings, efficiency losses, plant cycling costs and revenue losses.

The associated issues with trading obligations including Short Term Operating Reserve (STOR), Renewable Obligation Certificates (ROC), Emissions Trading Scheme (ETS), and Climate Change Levy (CCL) have been summarised to assist the development of the Isle of Man energy policy strategy.

Fuel Cost Savings

Economic analysis indicates the 2008/09 MEA marginal price of generation is £56.8/MWh. Sensitivity analysis indicates that fuel cost displacement offered by a wind farm could provide a net benefit of up to £3.2million should gas prices reach 80p/therm.

Efficiency Losses

The Combined Cycle Gas Turbine (CCGT) station would have to provide shadow capacity for the wind farm. This operating philosophy would enable the MEA to comply with the UK Grid Code. Operating thermal plant in a sub-optimum regime would decrease the efficiency. Where a typical wind farm load factor of 30% is assumed, efficiency losses could be up to £0.82million per annum.

CCGT Cycling Costs

Additional CCGT costs are expected when the CCGT is operated at varying load levels as the wind fluctuates, to meet the system load requirements. Annual cycling costs on increased plant maintenance requirements are expected to be £0.2million per annum.

Reduction in Export Profit

The provision of shadow capacity reduces trading and export opportunities where the wind farm introduces a reduction of available capacity for trading use. Economic modelling of the export revenue losses could be £0.52 million per annum.

The economic appraisal represents a summary of data assembled to date. More detailed economic appraisal is required to consider the cost of capital, operational and maintenance costs.

In conclusion, the total net benefit of an onshore wind farm of up to 20MW on the Isle of Man could increase installed renewable capacity from onshore wind to 12% of total generation, providing fuel cost savings of £3.2 million per annum but introducing operating losses of £1.54million.

Glossary

Ancillary Services These are required for the security and stability of the transmission system.

Balancing and Settlement Code (BSC) Sets out the rules governing the operation of the Balancing Mechanism (BM) and the Imbalance Settlement process and also sets out the relationships and responsibilities of all market participants.

Balancing Mechanism (BM) Operates from Gate Closure through to real time and is managed by the GB System Operator. It exists to ensure that supply and demand can be continuously matched or balanced in real time.

Base Load The minimum amount of power that a utility or distribution company must make available to its customers, or the amount of power required to meet minimum demands based on reasonable expectations of customer requirements.

Capacity Factor The ratio of the actual output of a power plant over a period of time and its output if it had operated at full capacity for that time period.

Capital Cost The cost of field development and plant construction and the equipment required for the generation of electricity.

CCGT Combined Cycle Gas Turbine

CCL Climate Change Levy

ETS Emission Trading Scheme

Firm capacity The capacity available to supply customers following an N-1 event.

FPN Final Physical Notifications

Gate Closure The last point in time at which power can be traded for delivery at a future time. Currently, this is 1 hour before the start time of the period in which traded power is to be delivered.

Higher Heating Value or the gross calorific value or gross CV includes the heat of condensation of water in the combustion products.

IOM Isle of Man

Imbalance Energy Prices Reflect of the cost incurred by the System Operator in its role of managing system imbalance.

Island Mode IOM-UK Interconnector is unavailable; island demand and statutory limits maintained by on-island generation only.

Load Factor The ratio of the actual energy output of a generating plant to the maximum possible energy output over a time period.

Lower Heating Value The amount of heat released by combusting a specified quantity and returning the temperature of the combustion products to 150 °C.

MEA Manx Electricity Authority

Merit Order In cases where multiple generation sources are available, generating facilities and individual generating units within those facilities are ranked according to their availability and the price that will be applied to the energy they produce. This ranking is referred to as merit order rank.

MW Megawatt

MWh Megawatt-hour, A unit of energy equal to one MW applied for one hour.

N-1 Contingency A notation used to account for the loss of a single power system item (i.e. generator, transformer or circuit).

N-2 Contingencies A notation used to account for the loss of two power system items. It is sometimes bounded by assuming that the first loss of plant is planned (typically for maintenance) whilst the second loss of plant is unplanned.

Power Factor Is the ratio of real power flowing to the load to the apparent power, represented as a number between 0 and 1 or a percentage e.g. 0.5 pf or 50% pf

Perturbed operation The destabilised operation of the electrical network following an unwanted event.

RO Renewable Obligation

ROC Renewable Obligation Certificate

ROI Return on Investment

Security of Supply A brief description for the recognition that the supply of electricity needs to be as reliable as economically possible.

Self-Balancing Self balancing occurs when a portfolio generator deviates from FPN to compensate for changes within his portfolio.

Shadow Capacity The reserve capacity needed to meet demand when wind generation drop unexpectedly.

Spark Spread A theoretical gross income of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. All other costs (operation and maintenance, capital and other financial costs) must be covered from the spark spread.

Spinning Reserve A reserve of generation capacity, where generators are kept online, but operating at less than full load, in anticipation of an unexpected increase in demand or decrease in supply; also referred to as shadow capacity.

STOR An ancillary service - Short Term Operating Reserve.

System Buy Price (SBP) Payment made by BSC Trading Parties who have a net deficit of imbalance energy.

System Sell Price (SSP) Payment made to BSC Trading Parties who have a net surplus of imbalance energy.

System Stability A brief description for the recognition that the frequency and voltage of the power system should remain stable and not collapse for faults on the network.

Tap Changer A mechanical device fitted to power transformers that by moving a contact to different tap positions on a transformer winding will change the output voltage by a small percentage step (normally in the range 1-2% per tap).

Therm A unit of energy equivalent to 29.31kWh.

Thermal Plant Cycling This refers to thermal plant operation at varying load levels.

Transmission System High voltage electricity network

TRIAD The three half hours of peak demand in the UK between November and February in a financial year that comprise the half hour of peak system demand and two other half hours of highest system demand which are separated from peak system demand and from each other by at least ten days.

WTG Wind Turbine Generator

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Introduction and Overview

1.1 Introduction

In September 2008, the Isle of Man Government's Council of Ministers approved the formation of the Energy Policy Working Group which brings together political members, Government Departments and Statutory Boards who have key roles and responsibilities for energy and the environment.

The Energy Policy Working Group is established therefore to provide: policy, direction and strategy in accordance with the requirements of the Isle of Man Government Strategic Plan (2007 – 2011). A key outcome of this group's work is to explore opportunities for exploitation of renewable energy. This includes preparation of a renewable generation strategy to assist with the determination of renewable targets and investment opportunities across all energy sectors.

1.2 Scope of Works

The purpose of this report is to identify the technical and economic impact of onshore wind development on MEA's existing operating regime.

An overview of the operation of wind turbine generation is presented in Appendix A; this includes wind turbine technology, wind speed and energy yield prediction and a summary of technical requirements for connection to the grid.

The economic impacts of an onshore wind farm on the Isle of Man's internal and external market and the trading opportunities with the UK were also identified, combined with the current commercial trading positions and UK markets identified below:

- Renewable Obligation Certificates (ROCs)
- Emission trading scheme (ETS)
- Climate change levy (CCL)

1.3 Isle of Man Electricity Industry Overview

1.3.1 Isle of Man Energy Policy

In 2002 the Isle of Man's Council of Ministers agreed that the UK's ratification of the Kyoto Protocol would be extended to include the Isle of Man (IOM). Although the IOM is not obligated to reduce its greenhouse gas emissions by a specific target; it must demonstrate that its own policies support a generic commitment to reduce greenhouse gas emissions.

The Council of Ministers produced a report on energy policy which was endorsed by Tynwald in October 2006 (Reference [1]). The core energy policy is to maintain and build on the high quality of life enjoyed by the Island's community by providing the energy needed to allow economic growth at a financial price that is affordable for all consumers and at an environmental cost that does not compromise the ability of future generations to meet their own needs.

The three key aims are:

- To maintain the security of energy supply
- To secure the efficient use of affordable energy
- To minimise the impact of the energy use on the environment

The UK is currently diversifying its energy mix to reduce greenhouse gas emissions and offset some of the risks from an increase in fossil-fuel prices. The IOM-UK Electrical Interconnector allows the MEA to participate in the UK electricity market and provides system resilience.

Electricity generated on the Isle of Man now produces less carbon per kWh of generation than electricity produced in the UK – around 0.43g/kWh against the UK's 0.53g/kWh (Reference [13]).

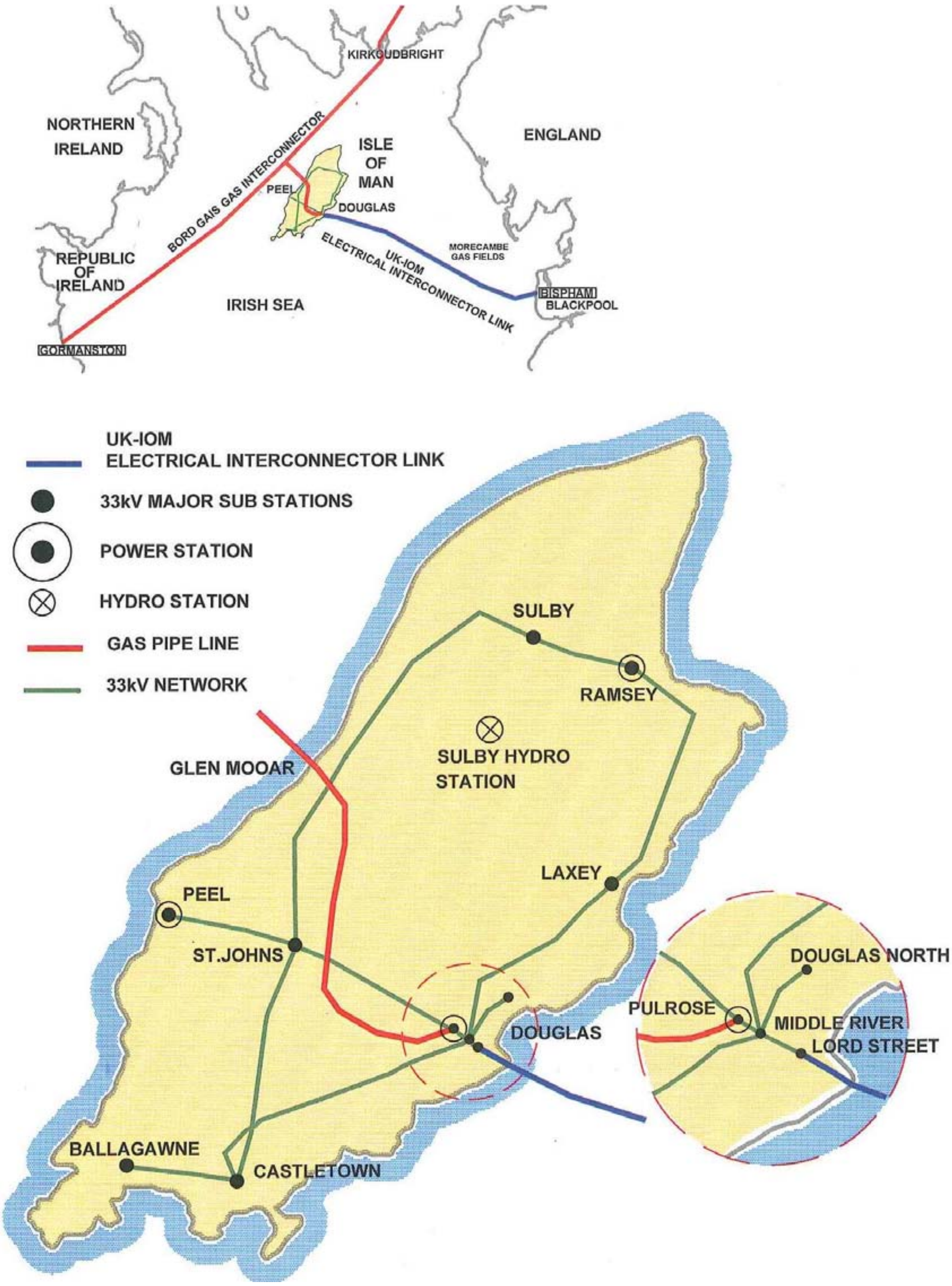
1.3.2 MEA Operating Regime

The MEA is a statutory body charged with providing the Island with a safe, reliable and economic electricity supply. The Authority has responsibility for the generation, transmission and distribution of electricity and for the billing and collection of revenue from these activities.

Until October 2000 power was provided by MEA independently of the UK National Grid. Generation was provided by oil fired stations at three locations at Pulrose, Peel and Ramsey and 1% renewable energy from Sulby Hydro station. In October 2000, the IOM-UK Electrical Interconnector was commissioned with a rated capacity of 40MW. At this time the Interconnector was used as the primary source of power for the IOM with Diesel generation used to meet demand in excess of 40MW.

In 2002/2003, a natural gas connection to the Scotland – Ireland IC2 Gas Interconnector was established, as shown in Figure 1.1. Commissioned in 2003, it was used to provide natural gas to a new CCGT power station comprising of two gas turbines and a steam turbine; providing a total CCGT output of 80MW. In 2008, the IOM-UK Electrical Interconnector rating was increased to 60MW.

Figure 1.1. Main System Features on the Isle of Man



1.3.3 Generation Assets

The generation assets on the Isle of Man and their locations have been listed in Table 1.1 below and shown in Figure 1.1 overleaf.

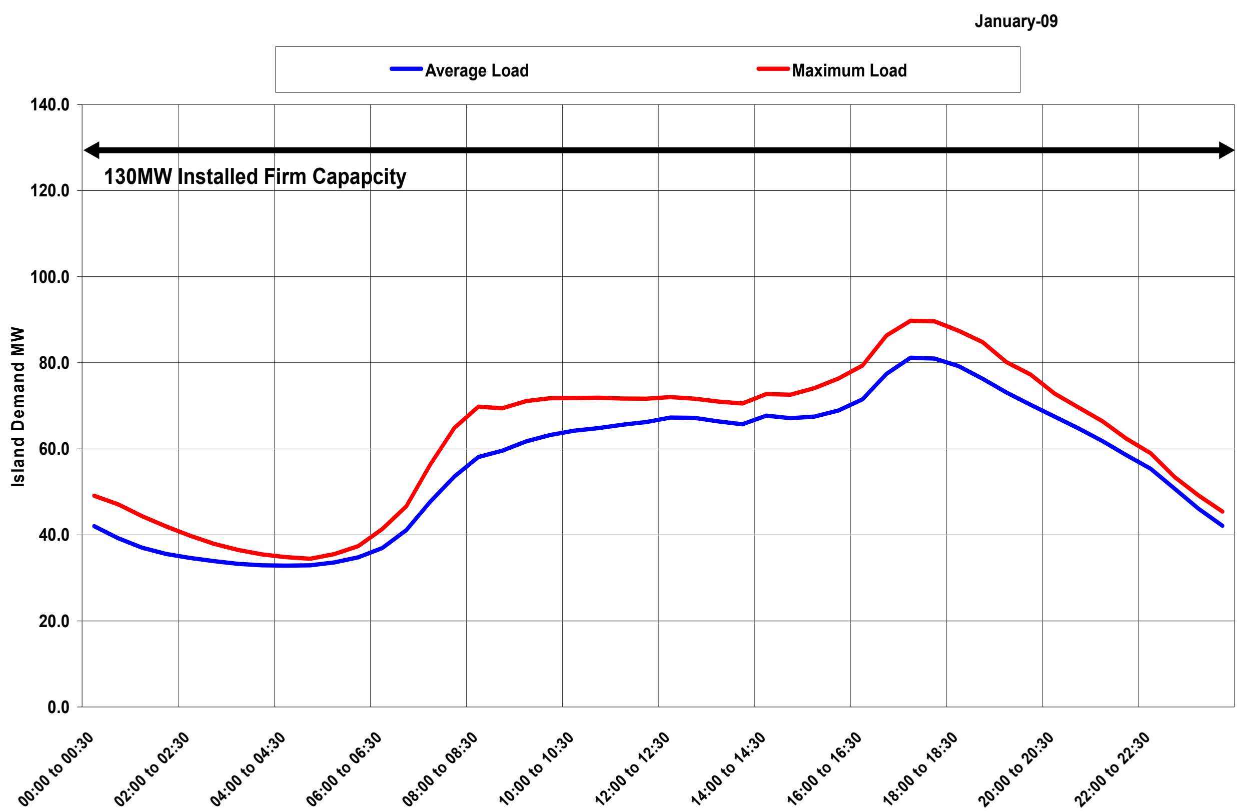
Table 1.1.: MEA Generation Sites

Location	Type	Installed	Fuel	Nominal Output
Pulrose	CCGT	2003	gas/oil	80 MW
Peel	Diesel	1994	oil	38 MW
Pulrose	Diesel	1988	oil	48 MW
Sulby	Hydro	1981	water	1 MW
Richmond Hill	Waste	2003	waste	6 MW

1.3.4 Load Profile

Power system maximum demand (MD) records dating back to the 1950's show that the island has seen typical load growth of 3%. Figure 1.2 below shows a typical daily profile of load demand for January 2009.

Figure 1.2 Half Hourly Profile of Load Demand



1.3.5 Firm Capacity

The installed firm generation capacity is the total amount of generation available taking into account an N-2 scenario (i.e. the loss of the two largest generators due to planned and unplanned outages). The firm capacity for the Isle of Man is 130MW.

It is important to note that wind energy is in effect a "fuel substitute" rather than a source of generation capacity and has limited contribution to providing support to the Island's security of supply. Therefore the capacity from the wind farm will not be considered as firm capacity and cannot contribute to enhancing security of supply.

1.3.6 Energy Trading

Currently, MEA operates a 60MW, 90kV Electrical Interconnector between the IOM and the UK and also a spur natural gas connection to one of the Scotland - Ireland gas pipelines providing gas for use in the MEA's CCGT generation plant. MEA applies a natural gas hedging strategy to protect itself and its consumers from volatility in gas markets. MEA's power trading is based on half hourly settlement periods; the power trading portfolio is facilitated by a route to market agreement and includes the following:

- The sale of spare capacity from the CCGT plant both for profit and in order to maximise plant thermal efficiency and thereby minimise the cost of meeting Island demand.
- The sale of diesel generated power when market prices are higher than the marginal cost of diesel fired generation; typically during UK winter peak load periods.
- The provision of Short Term Operating Reserve (STOR). This is an ancillary service based contract which requires the MEA to provide fast start generation within twenty minutes of receiving an instruction from the GB System Operator (National Grid). STOR generation is met by diesel generation plant. Interconnector capacity and generation capacity must be matched and reserved for STOR contracts, typical STOR windows are 10 to 12 hours per day.
- Additional revenue is generated from TRIAD benefits. Between November and February the highest half hourly system demand and system demand peaks are referred to as TRIAD periods. TRIAD periods are determined retrospectively at the end of February each year and greatest revenue is generated where a maximum export position is maintained during predicted TRIAD periods. Conversely, significant import charges are incurred where an import position is taken during a TRIAD period.
- Power can be imported to meet all or part of the IOM demand either when market prices make this the most cost effective means of meeting IOM demand or during plant maintenance outages.

2 Technical Appraisal

2.1 Introduction

Based on experience accumulated by Mott MacDonald through assisting National Grid, UK distribution network operators and wind farm developers throughout the UK, MEA system operational scenarios were selected and opportunities appraised for connection of onshore wind generation at selected MEA substations. The analysis carried out was tailored to fully consider the specific constraints of the MEA transmission system and provide commentary upon the ability to accept the connection of onshore wind generation.

The analysis was carried out assuming operational scenarios for a future timeline reflecting the most rapid advancement of onshore wind farm development which is considered to be circa 2014.

2.2 Methodology

The analysis of the MEA network's ability to accept onshore wind generation was carried out through system studies using the ERACS network model. ERACS is a Power System Analysis Software package from ERA Technology used for simulating power system dynamics. Extensive consultation was completed with MEA's Technical Services Department to ensure that all network parameters and constraints were identified.

The MEA transmission system has features that require a methodology that combines the recommended practice for transmission capacity assessment typically based on strategic performance assessment and the dynamic analysis of the system response to selected events. Network modelling must fine tune operational scenarios whilst providing a coherent analysis framework using the recommended practice for transmission system capacity assessment.

2.3 Impact upon the System

The capacity of a wind farm that may be connected to the MEA system is affected by the combined action of diverse factors such as:

- Circuit ratings of the MEA network
- Variability of the MEA load demand
- Export or import utilising the IOM-UK Interconnector
- The IOM-UK Interconnector availability
- Availability of on-island thermal generation
- Voltage limits as defined by the IOM Electricity Act 1996

By analysing the impact of each of the above factors, the system studies will determine a set of boundaries for the wind farm capacity to be used when deciding on the recommended installed capacity and the power outputs during various operational scenarios. The boundaries will be determined on the basis that the MEA system including a wind farm will meet all applicable statutory requirements (in respect of voltage and frequency limits) in the event of a perturbed operation scenario (disturbance on the power system) resulting from the loss of the wind farm output or loss of any circuits adjacent to the connection point.

2.4 Modelling Conditions and Boundaries

2.4.1 Voltage Requirements and Load Shedding

The voltage requirements concern the voltage levels at supply points and the acceptable maximum loading of the circuits. Assuming normal operation the voltage profile should be within ±5% of nominal voltage.

An extended range of variation applies for the pre-tap changer action conditions depending on the type of perturbation or power system disturbance that affects the system. In the case of N-1 contingencies the voltage profile should be within ±6% of nominal whereas for N-2 contingencies the requirements for voltage profile are relaxed to ±10% of nominal.

For circuit loading it is normal practice to check that power flows caused by perturbed operation do not exceed 95% or circuit rating for the appropriate winter or summer season.

In order to prevent the MEA transmission system losing stability following the loss of critical circuits or power plant a load shedding scheme is in operation. The MEA multi-stage load shedding scheme is set up to initiate instantaneously when the frequency reaches 49Hz and to continue until the system frequency fall is arrested and the system recovers to a stable operation point. Therefore, to avoid unnecessary disconnection of customers, an MEA design requirement is that on the sudden loss of the wind farm generation the load shedding scheme should not be activated (i.e. the frequency remains above 49Hz).

2.4.2 MEA Circuit Rating Boundary

The MEA circuit rating is an intrinsic electrical characteristic which is utilised in the transmission capacity assessment. Under selected operational scenarios the power flows and voltage profile should meet the specific statutory requirements. The conventional capacity assessment usually reveals local restrictions for the installed capacity of a wind farm and relies on the analysis of the load flow results obtained through simulating single contingencies and double contingencies. Single or N-1 contingencies represent operation scenarios when one circuit becomes unavailable. Double or N-2 contingencies represent operation scenarios when a second circuit becomes unavailable while typically maintenance is being undertaken on another circuit.

Although the MEA transmission design philosophy is to withstand N-1 contingencies without load shedding at all times, based on Mott MacDonald experience the N-2 contingency scenarios are highly relevant for the transmission system. In the context of connecting onshore wind generation to the MEA system, the analysis of N-2 contingencies will complete the overview of transmission system capacity and will outline potential constraints.

2.4.3 Substation Specific Capabilities

Load flow studies were completed assuming the wind farm may be connected to an MEA primary substations at either:

- Ramsey
- St Johns
- Castletown
- Douglas North
- Pulrose

Site specific maximum installed capacities were determined; these are independent of the in-service or out-of service status of the IOM-UK Interconnector. The realistic operation of transformer tap changers were also simulated. Selected sites of the MEA system were analysed in this iterative process.

2.4.4 Voltage Step Limit Boundary

Depending upon local load demand, the generation merit order and the output of the wind farm generator, the voltage deviations experienced after the loss of one on-island generator could exceed the statutory requirements. Therefore an additional boundary for wind farm operation should be defined in the form of the maximum output of a wind farm that would cause a voltage deviation still meeting the reviewed voltage requirements should the wind farm become disconnected.

The boundary is called the voltage step limit and was determined taking into account the load demand variability and the availability or unavailability of the on-island generation. The determination process relies on steady-state analysis of the simulated scenarios assuming either export or import to and from the UK. The realistic pre-tap changer action conditions were assumed in the simulation of the steady state response to the loss of wind.

2.4.5 IOM-UK Interconnector Boundary

The normal operating regime for the Isle of Man public power network is with the IOM-UK Interconnector in service. Following incidents that disconnect on-island generators, two types of effects are observed in small power systems interconnected with very large counterparts i.e. the UK Grid. These effects involve the system's voltage profile and the power flows over the Interconnector circuit and are indicative of the potential boundaries for the wind farm installed capacity, or the recommended power output under special operating regimes.

Due to the large inertia of the UK power system, any loss of an on-island generator will cause a frequency deviation which is insufficient to be picked up by the governors of the on-island generators. Therefore the UK system will pick up the load and the IOM-UK Interconnector will behave like spinning reserve for any load generation imbalance occurring in the MEA system. It is critical the IOM-UK Interconnector does not experience power flow exceeding its maximum continuous rating or triggering its disconnection after the sudden loss of on-island generation. These form significant restrictions which are grouped into the IOM-UK Interconnector spinning reserve boundary.

Steady-state studies and dynamic analysis were employed in determining this boundary whilst taking into account the MEA's load demand variability, the power export / import and on-island generation. The realistic tap-changer action conditions were assumed in the simulations of the steady state response to the loss of the wind farm.

2.4.6 Island Mode Boundary

The final boundary for the wind farm allowable power output during special operational circumstances originates from the MEA system operating with the IOM-UK Interconnector out of service. The loss of a generator during island mode will cause significant frequency deviation because of the relatively small inertia of the MEA system. It is critical that the system frequency deviation caused by a loss of generation should not fall below 49Hz in order to avoid triggering the MEA load shedding scheme. The minimum frequency boundary is defined as the power output from a wind farm which would cause a frequency deviation below 49Hz during the system transient recovery to another stable operation point should the wind farm become disconnected.

The determination of this boundary is carried out exclusively through dynamic analysis of the system response assuming MEA load variability. The recommended power output from these special scenarios is conditional upon the remaining generation plant having sufficient spinning reserve. An iterative process simultaneously targeting the wind farm power output and the adequate generation availability was carried out for each scenario.

2.4.7 Fault Level Studies

The analysis of the MEA transmission systems capacity for connecting onshore wind generation does not include fault level studies. It is not expected fault levels will be a design or location-deciding factor.

2.4.8 MEA Transmission System Constraints Boundary

This boundary is independent of the availability of the IOM-UK Interconnector and originates from typical circuit ratings within the MEA transmission system. Circuit ratings are localised constraints that limit the amount of power delivered by the wind farm depending on the substation selected for connection. The MEA transmission circuits have an average power capacity equalling 20MW. The more transmission circuits that are connected to a primary substation the more capacity will be available for a wind farm connection.

A local substation would be connected to the wind farm and this will impact upon the capacity of the wind farm. This boundary is highlighted by an N-1 contingency affecting the circuits connected to the substation. Therefore an approximation for the available capacity for a wind farm connection is that the wind farm capacity is equal to the number of connecting circuits less one multiplied by the average circuit capacity plus the local substation minimum load.

For the MEA 33kV northern ring which includes daisy-chain connected substations the maximum connection would be approximately 22.3MW at Ramsey. For the southern ring this equates with approximately 24.5MW at Castletown because the Ballagawne minimum load demand is also added to Castletown load. For St. Johns substation the approximate limit of a wind farm could be 63MW due to the increased number of connections which are available at this substation following the loss of one circuit. However additional operational and technical constraints will limit this capacity such as the site selection, MEA operating regime, optimisation of existing assets, availability of on-island thermal spinning reserve and the MEA system transmission capacity.

2.4.9 IOM- UK Interconnector in Service

Provided the UK Interconnector is in service two types of factors which define boundaries for the wind farm capacity were identified. One is the voltage step limit and the other is the IOM-UK Interconnector spinning reserve. The loss of wind farm from the MEA generation impacts the operation of the system in two aspects.

The voltage profile within the system following the loss of the wind farm will experience deviations which may violate the voltage requirements for perturbed operation. The voltage deviations will be at a maximum prior to tap changer action and influenced by changes in the power flow over the IOM-UK Interconnector.

The immediate loss of the wind farm will cause an increase or reverse power flow over the IOM-UK Interconnector. Due to the larger UK system inertia, any wind farm loss on-island will not affect the MEA system frequency. The generation-load imbalance will be immediately met by the power supplied over the IOM-UK Interconnector. This phenomenon illustrates the IOM-UK Interconnector spinning reserve concept which defines the maximum output from a wind farm that may become disconnected without causing a power flow that exceeds the maximum continuous rating of the IOM-UK Interconnector.

The findings of the technical assessment demonstrate the sensitivity of these boundaries to the availability of on-island conventional generation.

(i) Voltage step limit boundary - No on-island conventional generation available

Provided the wind farm operates at typical 0.98pf (normal practice for UK wind farms) the wind farm may supply a maximum 20MW to meet the MEA load demand without causing violation of the ±6 % voltage requirements after the loss of the wind farm whilst assuming pre-tap changer action conditions.

The loss of reactive power from the wind farm in conjunction with no reactive power sources available on-island causes significant reactive power to be drawn through the IOM-UK Interconnector. This effect is exacerbated by the reactive power loss increase in the Interconnector transformers caused by increased additional MVA loading. Tap changer action will comfortably restore the reactive power balance over the UK Interconnector within a period of minutes.

(ii) Voltage step limit boundary - On-island conventional generation available

There is no voltage step limit for the wind farm provided the on-island conventional generation MVAr spinning reserve is sufficient to meet the loss of the wind farm reactive power generation and the increased reactive power requirements of the Interconnector transformers due to increased MVA loading. However the capacity of the wind farm will be subject to the other boundaries.

(iii) UK Interconnector spinning reserve boundary

This boundary is applicable whenever on-island generation is available irrespective of the export to or import from the UK position of the MEA system. The inertia of the UK system is so large that any on-island generator loss will not cause sufficient frequency deviation for on-island generators to pick up automatically the load via the droop setting on their governors. Therefore the IOM-UK Interconnector must have sufficient spinning reserve to meet the loss of the wind farm whilst not exceeding its maximum continuous rating should the wind farm become disconnected.

An approximation of the recommended wind farm generation is that the combined wind farm output plus the power import from the UK or minus the export to the UK should not exceed an indicative 55MW threshold assuming conventional generation and wind generators operate within their power capability envelopes.

For an assumed MEA export position of 10MW during the summer peak load demand a maximum of 65MW wind farm output can be included in the generation line-up without causing the UK Interconnector to overload should the wind farm becomes disconnected. However the capacity of the wind farm will be subject to the other boundaries e.g. on-island thermal spinning reserve and MEA system transmission capacity.

For an assumed MEA import position of 23MW during the winter peak load demand a maximum of 32MW wind farm output can be included in the generation line-up without causing the UK Interconnector to overload following the loss of the wind farm. However the capacity of the wind farm will be subject to the other boundaries as cited above

2.4.10 The UK Interconnector out of service – Island Mode

When the IOM-UK Interconnector is out of service the MEA dynamic response to the loss of the wind farm generator is the dominant boundary to the maximum wind farm output capacity. On the loss of the wind farm during island mode there will be a significant frequency deviation because the MEA system has a much smaller inertia compared with that of the UK system.

The system frequency should not fall below 49Hz to avoid activation of the load shedding scheme. System studies have shown that if the wind farm and Energy from Waste station combined output does not exceed 20% of the MEA system load demand then the system frequency will stay above 49Hz during the system recovery following the loss of the wind farm. A satisfactory response is achieved provided sufficient MW spinning reserve is available in the remaining running generators.

For an island load demand of 90MW the maximum power output from the wind farm should not exceed 18MW. The system studies simulating the loss of a 20MW wind farm demonstrated that system frequency falls just below the 49Hz threshold to 48.9Hz. For this situation the MEA thermal generation should include the CCGT power station delivering a total 65.2 MW (25.1 MW from each GT generator), 15MW from the Steam Turbine and one Diesel Generator scheduled at its technical minimum, i.e. 4MW. This generation line up has sufficient MW spinning reserve to pick up the load resulting from wind farm sudden disconnection without causing system frequency deviations below 49Hz.

2.4.11 MEA Operating Regimes

The MEA generation line-up has to be adapted to load demand variability within the limits stated above in order to successfully recover the islanded system frequency and maintain MEA system stability hence security of supply following the loss of wind farm. The MEA operating regimes would require further analysis to ensure cycling of plant and thermal deviations and operating regimes are clearly understood to maintain security of supply and stability of the network. Also the need to maintain a traded import/export constant figure at Bispham, which means that any wind farm generation output variations must be ‘self balanced’ by reciprocal changes in the CCGT output. This would be an automatic control system operating over a period of minutes.

2.5 Technical Appraisal Summary

The level of wind farm generation output within the identified boundaries should not exceed 20MW in order to avoid reinforcement requirements on the existing MEA system. The system stability will be maintained during all scenarios where the IOM-UK Interconnector is available or MEA operates in island mode (IOM-UK Interconnector out of service).

All these boundaries are linked with operational scenarios that each depends on different combinations of conditions being fulfilled at the same time. The non-overlapping (e.g. availability of the on-island thermal generation or the UK Interconnector) or partially overlapping (e.g. power import from or export to the UK while on-island thermal generation is available) conditions involved in these combinations introduce difficulties for selecting the combination that would lead to the most stringent boundary for the wind farm capacity. The simultaneous occurrence of all conditions that are linked with the assumed dominant boundary may be a rare event of short duration that would place a disproportionate restriction on the wind farm capacity.

The UK Interconnector spinning reserve boundary together with the MEA transmission system constraints boundary form a more coherent envelope for the selection of the wind farm installed capacity. However they can not provide by themselves a definitive single value to use for the installed capacity of the wind farm because many conditions must be fulfilled at the same time for this value to be determined. Some of these conditions are linked with the daily load demand variability and the coincidence of power export to or power import from the UK the latter driven by market conditions which are difficult to forecast for a long time horizon.

Taking all the above into account, the system studies demonstrated the existence of four boundaries for the determination of the wind farm installed capacity. The analysis of the envelope created by these boundaries indicated that 20MW represents a conservative estimate for the onshore wind farm capacity. It would not be prudent to construct a bigger wind farm since the extra capacity could be constrained off for significant time periods as identified by the system operating conditions. Furthermore the wind farm reduces the commercial flexibility of the existing generation fleet.

Based on the identified transmission system constraints boundary the size for an onshore wind farm should be set at 20MW as this would increases the flexibility of choice in connection onto the public power network and hence site selection location on the Isle of Man. Appendix B provides a summary of additional factors which should be considered when completing the site selection process for an onshore wind farm.

3 Economic Appraisal

3.1 The Economics of Wind Energy

The economic appraisal has analysed the impact of onshore wind generation upon the Manx Electricity Authority's operating regime. It is recognised the primary benefit of wind generation is its ability to displace proportionate amounts of fuel costs otherwise required for thermal generating plant. More detailed economic modelling and appraisal is required should an onshore wind farm development be progressed.

The economic impacts related to the integration of wind generation into interconnected power networks stem from the variability and intermittency of the wind resource. The minute-by-minute balance between the aggregate output from generating resources and load demand required to operate a stable power network is central to this problem. In order to achieve network generation–demand balance, wind generation requires back up generation also known as spinning reserve from other generating resources to be ramped up or down to cater for the fluctuating wind resource. For the purpose of this report spinning reserve intended to back-up electricity generation from wind is referred to as "shadow capacity". The process of providing shadow capacity for wind generation is similar to load-following and has economic cost implications.

These costs include:

- opportunity costs of holding back generation in reserve (shadow capacity)
- the loss of efficiency resulting from running generators at sub-optimal levels in sub-optimal modes
- wear and tear resulting from cycling the "shadow capacity" generators

3.1.1 Economic Appraisal Assumptions

The following assumptions were used throughout the high level economic appraisal

- 20MW wind farm connected to MEA public network
- MEA operating regime - wind farm shadow capacity met by CCGT plant; thereby ensuring compliance with the UK Grid Code. System self-balancing in the event of the loss of the wind farm generation could be controlled by the CCGT automatic control system
- A wind farm load factor of 30% i.e. the wind farm would produce an energy output equivalent to 30% of its rated capacity output per annum
- A CCGT thermal efficiency of 45% (at Higher Heating Value NB: Lower heating value is 49%)

- MEA marginal cost of generation 08/09 - £56.8MWh

3.1.2 CCGT Shadow Capacity

In undertaking this economic study, it was assumed that shadow capacity for the wind farm generation would be provided by the CCGT plant under the self-balancing CCGT automatic control system. Utilisation of the Interconnector for shadow capacity may compromise compliance with the UK Grid Code, similarly diesel generators are reserved for STOR and Triad trading and introduce higher operating costs.. CCGT plant costs are increased due to reduced efficiencies from the part-load operations associated with carrying shadow capacity and revenue losses from exports.

The CCGT plant efficiency is highest at generation levels close to the maximum rated output and reduce as the output drops towards the minimum permissible generation level. The part-loading of the generators would mean that energy exports from the shadow capacity are not possible. Further costs would result from high thermal plant cycling which would increase the frequency of overhauls and possibly reduce the economic life of the CCGT plant.

On average a 20MW wind farm at 30% load factor would yield 6MW output. Shadow capacity from CCGT plant would be required in order to compensate for real time variations in wind yield, therefore, the shadow capacity to be considered would be an average of 6MW such that CCGT generation is available at all times to replace wind generation in the event of variable weather conditions. A lower level of shadow capacity may be appropriate, especially under predictable wind conditions.

Provision of shadow capacity results in reduced CCGT thermal efficiency and hence increased costs and CO_2 emissions per MWh generated. These losses are quantified in the economic analysis overleaf.

3.1.3 Wind Farm Output at 30%

The wind resource is neither consistent nor constant and varies with time of the day, season of the year, height above the ground, type of terrain and from year to year. With all factors remaining constant, the higher the wind turbine hub from ground the higher the wind energy yield. High towers and large rotors are required to yield more energy.

The British Wind Energy Association (BWEA) reports that modern wind turbines produce electricity 70-85% of the time, but at different outputs dependent on wind speed. They further report that, in the British Isles wind turbines would generate about 30% of their theoretical maximum output per annum. The Institute of Engineering and Technology (IET) in their Wind Power fact file give a range of load factors between 24.1% and 28.2% for the UK for the years 2000 to 2005. Some areas of Scotland have reported wind load factors between 35% and 40%. Given the ranges of load factors presented above, a wind load factor of 30% for the Isle of Man was adopted within the economic study.

3.2 Costs and Benefits of an Onshore Wind Farm

3.2.1 Fuel (Gas) Displacement Savings

The major economic benefit from the integration of wind into an interconnected network is the savings realised from displacing some fuel costs associated with thermal generation. Mott MacDonald carried out an assessment of the likely fuel costs that could saved by integrating wind generation into the public electricity network and used the 20MW wind farm as a model of installed capacity that could be connected to the MEA system without compromising system stability as identified in the technical appraisal. Wind farm capacity levels below 20MW were also assessed for comparison purposes.

The models and fuel cost estimates that were used in the fuel sensitivity analysis were provided by MEA and examined by Mott MacDonald. It was assumed, in carrying out the evaluation, that only the CCGT plant would be affected by the integration of a large scale wind farm into the MEA network and that the diesel plant would predominantly be utilised to meet MEA's STOR capacity and TRIAD obligations. In this respect, installing and commissioning 20MW of wind generation into the MEA system is not anticipated to have significant impact on revenues from STOR and TRIAD energy trades.

Table 3.1 below shows the fuel cost savings, at different gas costs, which would result from the displacement of CCGT generation by integrating wind generation into the MEA electricity system. The sensitivity analysis gas cost range has been selected to represent potential future gas prices.

Where future gas costs are between 60p and 80p/therm and an average load capacity of 30%, the net benefit from the wind farm development is a fuel cost saving of between £2.4 and £3.2million.

Table 3.1: Gas fuel Sensitivity Analysis at Different Gas Costs/therm

	Varying Gas Costs (pence per Therm)		
Wind Farm Capacity (MW)	60	70	80
5	£600,000	£700,000	£800,000
10	£1,200,000	£1,400,000	£1,600,000
15	£1,800,000	£2,100,000	£2,400,000
20	£2,400,000	£2,800,000	£3,200,000

3.2.2 CCGT Plant Cycling Costs

Cycling refers to plant operating at varying load levels to meet system load and fluctuating wind generation requirements. Most thermal plants including CCGT are designed to provide base-load generation. Cycling imposes significant stresses and maintenance costs to these plants

Detailed analysis regarding the impact of cycling in this manner on CCGT plant maintenance costs is not available across the fleet. Following consultation with a number of plant engineers Mott MacDonald deemed it feasible applying £200,000 as the annual maintenance and overhaul cost due to cycling MEA CCGT plant.

3.2.3 CCGT Efficiency Losses

CCGT generator designs are generally aimed at base-load operation and their efficiency is highest when generating at their maximum capacity. The typical operating efficiency for the MEA CCGT plant is 45% (higher heating value).

An average 1MW shadow capacity has an associated efficiency loss of 0.20%. Assuming CCGT generation marginal cost (MGC) of £56.8/MWh as given by MEA, the cost for a 1MW pull-back can be calculated as follows:

$$\text{Efficiency Loss} = AL \times \left[MGC \times \left(\frac{TTE}{TTE - RE} \right) - MGC \right] \times 8760$$

Where:

AL = Average CCGT Load (based on average CCGT load during FY 08/09; excluding major outage periods))

MGC = the 08/09 marginal cost of generation for a fully loaded generator

TTE = the typical thermal efficiency for MEA CCGT generators

RE = the reduction in efficiency per 1MW reduced load

Based on Table 3.2 with data obtained from MEA, the thermal efficiency loss per MW of reduced load is £0.24. At 10% shadow capacity (6MW) on the average CCGT loading, the average annual efficiency loss is £817,920 per annum during the first year of operation

Table 3.2: CCGT operation and cost figures

Average Island load	50 MW
Average CCGT load (Island +export)	60MW
Average Export spark spread	£10.00
Average drop in thermal efficiency per MW reduced load (RE)	0.20%
Typical MGC for fully loaded CCGT plant (MGC)	£56.8
CCGT typical operating thermal efficiency (TTE)	45%

3.2.4 Reduction in Export Profit

The economic model for annual revenue losses is defined as the average CCGT annual shadow capacity multiplied by the average export spark spread. Table 3.2 shows an export spark spread of £10. Where this spark spread is used for 6MW (10%) CCGT shadow capacity, relative to 30% average production from a 20MW wind farm, the amount of export revenue loss per annum would be:

£10 X 6MW x 8760 = £525,600.00

Spark Spreads are variable. The spark spread presented is a conservative estimate supported by the EU Greenhouse Gas Emission trading Scheme which does not apply on the Isle of Man but adds a premium to the UK cost of generation.

3.2.5 Summary of Losses Associated with Wind Farm

On average the CCGT capacity required for a 20MW wind farm with a load factor of 30% is 6MW. This equates to 10% of the average MEA CCGT loading of 60MW. Using the models presented above. The losses associated to CCGT shadow capacity as efficiency losses and export revenue loss are detailed below:

Total losses = Export Revenue Loss + Efficiency Losses + CCGT Cycling

= £525,600 + £817,920 + £200,000

= £1,543,520

The combined annual effect of sub optimal operating conditions by providing shadow capacity on the CCGT plant with subsequent reduced efficiency and reduced exports could be £1.54million. However, the net benefit of fuel cost displacement of fuel costs of up to £3.2 million presents an overall net benefit of £1.66million.

This economic appraisal does not consider the additional cost of capital, operations and maintenance costs. This would be subject to a more detailed analysis upon selection of a suitable wind turbine generator and investment framework.

3.3 Economic Impacts of Onshore WTG on External Markets

3.3.1 Electricity Trading

Electricity trading revenue is generated from maintaining plant availability and capitalising on the excess generation capacity available from surplus CCGT capacity and diesel generation. The fast response capability of diesel plant makes them ideal candidates for STOR contracts.

The MEA operates the IOM-UK Interconnector in compliance with the UK's Grid Code and the Balancing and Settlement Code (BSC) through contractual obligations with UK energy suppliers. MEA has a bespoke energy trading agreement with UK energy suppliers and this agreement acts as a vehicle for compliance with the regulatory codes.

Appendix C provides further information relating to the electricity market which can be divided into three types: energy market, ancillary service market, and transmission right market (Appendix C & Reference [8]). Ancillary services include Automation Generation Control (AGC), operating reserve, load following, voltage control, demand side management (DSM) and black-start capability, as shown in Figure C.2. (See Appendix C). MEA's participation in the Ancillary market sector is currently limited to the provision of operating reserve.

3.3.2 Commercial Trading Mechanisms

The commercial trading mechanism with the UK provides a cost effective means for the IOM-UK Interconnector to be operated in compliance with the BSC and Grid Code and generate revenue for the MEA. Failure to comply with the BSC and Grid Code could result in loss of contracts with UK energy trading partners and non-compliance costs from the UK energy regulator.

MEA must maintain its contracted export/import position. Intermittent output from a wind farm would place the MEA at risk of failing to meet contractual obligations; hence compliance with the Grid Code. MEA would reduce its exposure to high imbalance costs by utilising part of the CCGT output to provide shadow capacity. This exposes UK energy trading partners and the MEA to significant imbalance costs and the additional cost of any export/import requirements.

The economic impact of self-balancing through the utilisation of the CCGT for shadow capacity has been considered and included within the economic appraisal. High thermal cycling of the CCGT could increase overhaul costs by £200,000 p.a. Additional hidden costs may be evident if the MEA needs to provide ancillary services to cope with voltage and frequency variations for those occasions when both Island demand and wind farm output are subject to significant fluctuations.

Wind generators will invariably be expected to discount their offer prices for energy below the base-load market price. This reflects the fact that wind generation is unpredictable and therefore the off-taker of the energy is forced to take-on the imbalance penalties. Imbalances penalties arise because top–up and spill energy (required to balance contracted and metered volumes) tend to be priced punitively.

In the extreme case where a wind generator did not contract forward and spilled energy into the system in contravention of the Grid Code and BSC it would receive the System Sell Price (SSP). This price is extremely volatile, ranging from minus £10 to over £200/MWh. Even on an average basis there are big variations: monthly average SSP values in 2008 have ranged between £30 to £50/MWh.

Given that the imbalance penalties have shown a tendency to increase with the overall level of market prices, this would suggest that the discount on intermittent electricity generation would increase. The Mott MacDonald assumption is that the discount would be about 25% of the base-load price.

This discount may not necessarily be fully applied to variable generators. Wind generators, for example, can mitigate the risks through using aggregation agents to pool risks and fine tune contract cover right up to gate closure. It is possible that using an aggregation agent would reduce the discount to 15-20% however it is yet to be determined whether such an aggregation system could be applied to MEA's output.

3.3.3 STOR Impact

During FY 2008/09 MEA are contracted to reserve 40MW for export capacity Currently these contracts are tendered up to six to twelve months in advance. Utilisation of the IOM-UK Interconnector in this manner impacts upon the size and potential for export of wind farm generation.

It is noted however, that the STOR contract period does not cover the night-time period, where the Island load drops to circa 30MW; this may present an opportunity to export at night, or back off the wind farm where this becomes uneconomical. The economic trading opportunities would require further detailed financial modelling taking into account return on investment and possible feed-in tariff obligations. It should be noted that electricity has its lowest value during the night time period. Regardless of the economics, the spirit of the Grid and BSC codes is for generators to maintain their contracted positions.

An overview of the MEA revenue generation from utilisation of the diesel and Interconnector capacity in this manner is presented in Table 3.3 below. Given the high value of these contracts, the export of wind during a STOR window is currently not economical.

Table 3.3: MEA's Forecast Revenue from STOR - 2009/2010 to 2014/2015

STOR	2009/10	2010/11	2011/12	20012/13	2013/14	2014/15
Avail capacity	48	50	52	54	56	58
Net contribution	£ 2,100,000	£ 2,200,000	£ 2,300,000	£ 2,400,000	£ 2,500,000	£ 2,600,000

During 2009, the STOR capacity could be increased to 48MW given that export opportunities may be limited by the depressed market conditions, i.e. STOR profit margins exceeding spark spreads. The total revenue from STOR in 2009 is estimated to be £2,1million. If the available capacity for exporting power is 58MW in 2015, the total revenue from STOR would reach up to £2.5 million. As STOR net contribution is generated from diesel plant and the IOM-UK Interconnector capacity, the power network must be dispatched so that it does not affect the STOR net contribution if this revenue is to be protected.

3.3.4 Transmission Network Use of Systems Charges (TNUOC)

The utilisation of on-island generation to generate electricity during predicted TRIAD periods gives the potential for revenue. Conversely failure to export during these unknown periods may result in charges up to £0.8million. Example of revenue in the form of TRIAD benefits from 2009 and 2015 are forecasted below for illustrative purposes only.

Table 3.4: MEA's Forecast Revenue in the form of TRIAD from 2009 to 2015

TRIAD	2009/10	2010/11	2011/12	20012/13	2013/14	2014/15
Capacity	60	57	54.2	51.4	48.9	46.4
Triad Benefit	£ 940,000	£ 1,000,000	£ 1,050,000	£ 1,105,000	£ 1,200,000	£ 1,200,000

As shown in Table 3.4, TRIAD values could be approximately £1 million in 2009/2010 and increase to £1.2 million in 2014/2015.

There is also opportunity for MEA to trade surplus generation capacity in the form of energy trading and ancillary services. The benefit of onshore wind availability during the TRIAD season would benefit the MEA by partly displacing the cost and emissions of diesel plant normally used to deliver TRIAD benefit.

3.4 Support Mechanisms and Their Impacts on the Isle of Man

3.4.1 Renewable Obligation Certificates (Rocs)

The Renewable Obligation scheme incorporating Renewable Obligation Certificates (ROC's) is the primary support scheme for renewable electricity projects in the UK. Currently renewable technologies cannot compete with fossil fuel based plants; if they could there would be no ROC subsidy. ROCs are issued as evidence that electricity from an eligible renewable source has been supplied to customers in Great Britain by a licensed supplier.

A ROC is a green certificate issued to an accredited generator for eligible renewable electricity generated within the UK and supplied to customers within the UK, current subsidy levels are approximately £34./MWh.

The ROC subsidy or additional financial support provided to generators of renewable electricity ultimately increases the overall costs per unit to electricity customers. Coupled with meeting subsidy costs there are additional administration costs imposed on both renewable generators and suppliers.

3.4.2 The Impacts of Renewable Obligations Certificates

The Renewable Obligation (RO) obliges suppliers of electricity to take a minimum amount of renewable electricity, or pay a buy-out price. The purchase of renewable electricity is deemed to occur by the purchase of ROCs. The price of ROCs depends on the buy-out price and the balance of supply and demand for the Rocs, which will in turn be a function of the minimum level of renewable electricity. Holders of ROCs are entitled to a proportion of the total cash generated by buy-out payments made, so the scheme is overall cash neutral. It also enables the ROC price to exceed the buy-out price. For example, if the obligation is 3%, the available qualifying generation is expected to be 2%, and the buy-out price is £30/MWh, the value of ROCs will be: 3/2 * £30/MWh = £45/MWh.

The ROCs will be based on metered output, rounded to whole MWh, and will be issued electronically to generators. They will follow the same format as the Climate Change Levy Exemption Certificates (LECs) and will be issued in units of 1MWh. Each 1MWh certificate will have a unique number and will detail the generating station, the renewable source used and the period in which the electricity was generated. A supplier may discharge the Obligation by buying ROCs from generators or another party as ROCs can be sold separately from the electricity.

The following list provides an overview of the impacts of extending the ROC scheme to the Isle of Man:

- New UK legislation and amendments to the Manx Electricity Act incorporating an agreed percentage of IOM energy supply from IOM green sources, would be needed.

- The price of buying ROC's is determined by the UK Ofgem reflecting the UK market conditions, not those on the Isle of Man.

A significant risk exists therefore to Isle of Man customers who could pay the price for delivery of UK targets out of proportion to any benefit realised on the Island.

If the UK ROC subsidy was extended to the Isle of Man, currently MEA's hydro generation (c.1% of supply) would not be eligible for ROC's as it was built prior to 1st January 1990. 50% output from the Energy from Waste plant and would qualify at present under the UK ROC scheme

3.4.3 Climate Change Levy (CCL)

The UK currently has two out-of-market support mechanisms for renewable generation: the climate change levy (CCL), which affects all fuels – not just electricity – and RO. The former is quite wide in its scope, and includes combined heat and power (CHP). The latter is narrower in scope.

The Climate Change Levy (CCL) is a tax on energy delivered to non-domestic users in the UK. Its aim is to provide an incentive to increase energy efficiency and to reduce carbon emissions; however there have been ongoing calls to replace it with a proper carbon tax.

Introduced on April 1, 2001 under the Finance Act 2000 it was forecast to cut annual emissions by 2.5 million tonnes by 2010, and forms part of the UK's Climate Change Programme. The levy applies to most energy users, with the notable exceptions of those in the domestic and transport sectors. Electricity generated from new renewable and approved cogeneration schemes is not taxed. Electricity from nuclear is taxed even though it causes no direct carbon emissions.

From when it was introduced, the levy was frozen at 0.43p/kWh on electricity, 0.15p/kWh on coal and 0.15p/kWh on gas, which can be 80% abated under certain conditions. In the 2006, UK budget it was announced that the levy would in future rise annually in line with inflation, starting from April 1, 2007. A reduced levy applies to energy-intensive users provided they sign a Climate Change Agreement. The use of renewable energy sources is one method of achieving this.

Revenue from the levy was offset by a 0.3% employers' rate reduction in National Insurance. However, the 2002 Finance Act subsequently increased that rate by 1%, reversing the reduction. Part of the revenue is used to fund a number of energy efficiency initiatives, including the Carbon Trust. The Climate Change Levy effectively replaced the Fossil Fuel Levy.

3.4.4 The Impacts of Climate Change Levy

The issue really reduces to asking how effective it is relative to what the alternative measure might have been. Different commentators use different counterfactuals, with most believing that a 'pure' carbon tax would have been better. In contrast, the levy is inversely related to the carbon content of fuels – gas being taxed more heavily in terms of carbon content, than coal. The electricity generators have no incentive to switch between fuels by carbon content because the tax is levied downstream rather than upstream. Coverage is limited because of the exemption of households, who must nonetheless bear some incidence of the tax, and transport which is subject to other tax measures. The climate change agreements appear to have been very successful with over-compliance with targets even in the first year or so of operation. Others believe this reflects the 'soft' nature of the targets from the outset, with the system being largely 'captured' by industry. What is clear is that the levy's design very much reflects the political economy considerations of government. A pure tax would have come into conflict with government goals concerning household vulnerability, competitiveness concerns and the sensitivity of some sectoral interests.

It has made a contribution to the UK climate change targets, but this measure of effectiveness assumes that the alternative was doing nothing. It may well have fared better than some outright regulation measures, but whether it has done better than a pure carbon tax is very much open to debate. The problem, then, is one of the counterfactual against which the levy is compared. The political economy literature argues that there is little point in comparing actual measures against ideal measures if the ideal measures could never be implemented. Equally, there is a risk in the political economy approach that explaining why policy measures look as they do will amount to justifying those measures.

The UK Government could seek to impose additional green initiatives on the Isle of Man including Climate Change Levy and through the Emission Trading Scheme, if the UK government or other neighbouring jurisdictions extended a ROC or equivalent subsidy.

Climate Change Levy (CCL) places an additional levy on supply of electricity from non-CCL exempt sources. This includes Non-domestic Users: 58% of MEA's supplied electricity and the current levy rate of £4.41/MWh would add an additional £1.6m to customer's electricity bills per annum (payable to the UK).

3.4.5 Emission Trading Scheme (ETS)

The European Union Emission Trading System (EU ETS) is the largest multi-national, emissions trading scheme in the world, and is a major pillar of EU climate policy. The EU ETS currently covers more than 10,000 installations in the energy and industrial sectors which are collectively responsible for close to half of the EU's emissions of CO_2 and 40% of its total greenhouse gas emissions.

Under the EU ETS, large emitters of carbon dioxide within the EU must monitor and annually report their CO_2 emissions, and they are obliged every year to return an amount of emission allowance to the government that is equivalent to their CO_2

emissions in that year. In order to neutralise annual irregularities in CO2-emission levels that may occur due to extreme weather events (such as harsh winters or very hot summers), emission allowances for any plant operator subject to the EU ETS are given out for a sequence of several years at once. Each such sequence of years is called a Trading Period.

The 1st EU ETS Trading Period expired in December 2007; it had covered all EU ETS emissions since January 2005. With its termination, the 1st phase EU allowances became invalid. Since January 2008, the 2nd Trading Period is under way which will last until December 2012. Currently, the installations get the allowances for free from the EU member states' governments. Besides receiving this initial allocation on a plant-by-plant basis, an operator may purchase EU allowances from others (installations, traders, and the government.) If an installation has received more free allowances than it needs, it may sell them to a third party.

In January 2008, the European Commission proposed a number of changes to the scheme, including centralized allocation (no more national allocation plans) by an EU authority, a turn to auctioning a greater share (+60%) of permits rather than allocating freely, and inclusion of other greenhouse gases. These changes are still in a draft stage; the mentioned amendments are only likely to become effective from January 2013 onwards, i.e. in the 3rd Trading Period under the EU ETS. Also, the proposed caps for the 3rd Trading Period foresee an overall reduction of greenhouse gases for the sector of 21% in 2020 compared to 2005 emissions. EU ETS will cover airlines by 2013.

3.4.6 The Impacts of Emissions Trading Scheme

EU Carbon Trade System (EU ETS) places a cap on all large carbon emitting plants, including generation plant and allows participants to trade emission permits. Currently the price of phase II CO2 is 8 euro/tCO2e (February 2009).

It would be reasonable to assume the MEA would not receive sufficient emissions allowances to cover the power it generates to the UK market. This could be a minimum additional cost of £0.3m / annum to the MEA. The CCL and ETS costs are equivalent to a 7% increase in the customer tariff.

In 2002 the Council of Ministers agreed the UK's ratification of the Kyoto Protocol would be extended to include the Isle of Man. The Isle of Man is not obligated to reduce its greenhouse gas emissions by a specific target; it must demonstrate its policies are developed to meet the generic commitment to reduce greenhouse gas emissions.

The pace of growth towards the Government's target (and aspiration) for renewable electricity could be constrained by a number of factors, in particular: delays in the planning and grid connection of renewable energy projects, constraints on the practical resource available for the most economic forms of renewable energy, and the higher costs of renewable energy projects in less mature or emerging technology areas, such as offshore, onshore wind and biomass.

The quantity of CO2 emitted as a result of meeting Isle of Man electricity needs is directly related to the amount and type of fossil fuels used in conventional power stations. Producing electricity from wind reduces the consumption of fossil fuels and therefore leads to emissions savings.

However to accurately quantify the emissions saving which can be derived from wind farm generation the growing inefficiency of the conventional plant portfolio must also be taken into account. It is not sufficient to estimate the amount of energy which can be obtained from a given capacity of wind turbine generator (WTG), and to assume that the equivalent percentage of fossil fuel and therefore CO2 can be avoided. This ignores the impact of the increasing number of start-ups, lower capacity factor and thermal efficiency as WTG increases.

3.5 Renewable Targets

During 2007/08 the Energy from Waste pant and the MEA Sulby Hydro plant contributed to approximately 5% of total electricity generation on the Island without the consumption of fossil fuels.

Recognising the potential benefits of renewable energy to the UK's energy objectives, in 2002 the UK Government introduced the Renewable Obligation (RO) to drive and support the growth of renewable generation. The Obligation allows generally higher cost renewable electricity generation to compete directly with conventional, fossil fuel based electricity generation. The Government further underlined its commitment to renewables by setting a challenging target of increasing renewable electricity generation to 10% of electricity by 2010, it also set out an aspiration to double this by 2020.

Where a 20MW wind farm generates at 30% load factor, this could generate 6MW of renewable electricity. This could provide the Isle of Man with a renewable generation output from onshore wind of approximately 12%.

4 Conclusion

The technical and economic appraisal for onshore wind farm generation provides a clear overview of the impacts of an onshore wind farm on the Manx Electricity Authority's operating regime, internal and external energy markets and generation costs.

Technical Appraisal

The report includes the overview of the methodology used in the technical assessment of the MEA transmission capacity for connecting onshore wind generation and the main findings of the assessment.

Several technical boundaries for the wind farm installed capacity were identified during the analysis. These emerged from taking into account individual impacting factors such as the system load demand variability, the transmission circuits rating, and the availability of on-island thermal generation and the availability of the IOM-UK Interconnector. The identified boundaries are overlapping due to their dependence on different combinations of the same factors and introduce therefore difficulties for selecting the most stringent boundary for the wind farm installed capacity. Two of the boundaries are either localised, such is the MEA transmission system constraints, or assume special operating conditions such is the island mode boundary.

The technical analysis concluded that two of the boundaries, i.e. the voltage step limit and the UK Interconnector spinning reserve, form the envelope which includes the most probable wind farm installed capacity that could be selected. However from the technical point of view no definitive solution for the installed capacity can be formulated because this would involve additional assumptions upon the future opportunities for power exports to the UK market. However, an emerging capacity of 20MW of wind generation could be connected onto the MEA network whilst maintaining security of supply and without voltage deviation.

Economic Appraisal

The economic impacts of onshore wind turbines on the internal operating regime and the trading opportunities with UK, were analysed. The issues considered include economic and technical position of wind output to the UK.

Significant fuel saving costs are identified and further sensitivity analysis could be carried out based on data assembled to date and presented in Section 3. Direct fuel cost savings range from between £2.4 million and £3.2 million where gas prices range from 60p to 80p/therm.

The utilisation of the IOM-UK Interconnector for energy trading revenue sterilises the capacity on this asset for export from onshore wind generation. Further detailed analysis of the wind farm capital investment options, operation and maintenance regimes are required.

Shadow capacity is required to maintain system stability and security of supply. These introduce losses into the economic model for wind farm appraisal. These include:

- CCGT plant cycling costs
- Efficiency losses
- Reduction in Export Profit

Membership of the UK renewable obligations scheme will result in an increase in the cost of compliance to the Isle of Man from the Climate Change Levy and Emissions Trading Scheme, and has a high potential to be disadvantageous to the Manx customers.

The price of renewable output may well be dominated by the value of the environmental credits, which for the Isle of Man may be sought locally, whether the support is via, a feed in tariff, a minimum price guarantee, or through some other mechanism. The economic trading and operating regime of any proposed wind farm development should be examined to identify the level of subsidy or tariff increase required to meet the financial model of the project.

Renewable Targets

A 20MW wind farm generating at a 30% annual load factor, could generate an average 6MW of renewable electricity. This could provide the Isle of Man with an onshore wind renewable generation output of 12% per annum.

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Appendix A The Operation of Wind Turbine Generators

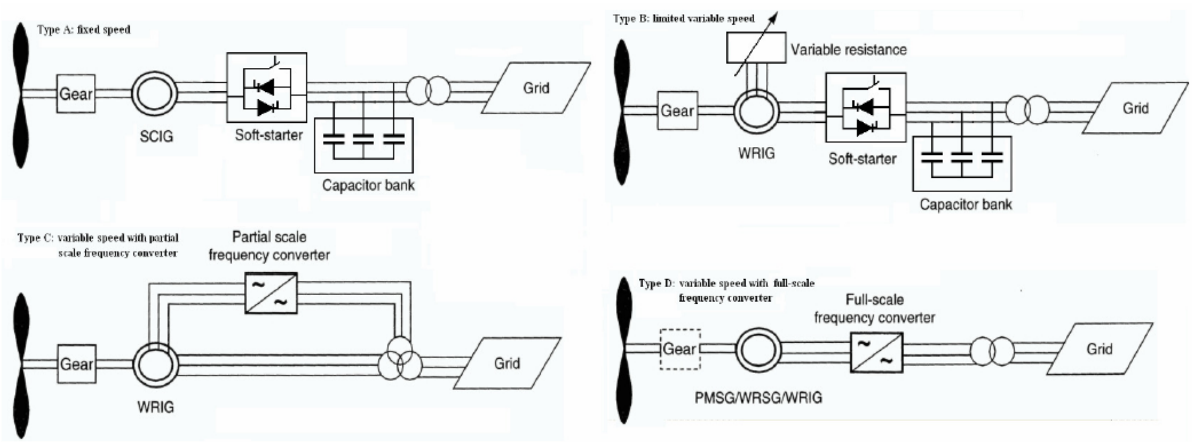
As a renewable power, wind energy is becoming increasingly important throughout the world due to its strength on reducing the greenhouse effect caused by the burning of fossil fuels. As one of the most mature of the various renewable energy technologies, wind energy plays an important role.

A.1 Wind Turbine Technology

The demanding market drives the application of innovative concepts with proven technologies both for generators and for power electronics to wind turbines. At present, four key wind turbine technologies dominate the market. Figure A.1 provides an overview of the differences and common ground between these types of technologies [7].

- Type A: The "Danish concept" – fixed speed
- Type B: The "Danish concept" – limited variable speed
- Type C: The pitch concept with a doubly fed asynchronous generator
- Type D: The pitch concept with a synchronous generator

Figure A.1: Wind Turbine configurations



In the Danish concept, which dominated the market up to the mid-1990s, the asynchronous generator "naturally" limits power production in strong wind or gusts. It restricts the speed of the system to the frequency of the power grid, so that the rotor cannot turn faster when the wind blows stronger. In this concept, the rotor blades are designed to create turbulence at a certain wind velocity, preventing the lift from accelerating rotation any further even though the blades are not themselves pitched.

The pitched concepts developed from 1990 to 2000 turn the rotor blades in and out of the wind along their axis. Depending on the wind velocity, the machines run at various speeds. The blades are turned out of the wind to limit power generation when the wind becomes too strong (above 12 m/s). The blades are only turned into the wind to start the system. Under normal conditions, the turbines are run at a set optimal angle for the best power generation, with the speed of rotation increasing until nominal output is attained. From then on, the pitch of the blades is activated to keep power production constant.

In the pitch concept with a synchronous generator (full scale frequency converter), a frequency converter ensures that the fluctuations in electricity caused by the changing speed of the turbine are nonetheless fed to the grid at the frequency of the grid.

In the concepts of a doubly fed asynchronous generator, this is not necessary for all of the electricity generated, but rather only for the share coming from the generator's rotor. As this share only makes up around 40% of nominal output, the converter can be smaller.

For the modern high-power wind turbines, Double-Fed-Induction-Generator (DFIG) has been internationally used due to the key advantages of cost effective, improved power quality, improved system efficiency and acoustic noise reduction, etc.

A.2 Size of Wind Turbines

Since the late 1990s, wind turbine technology has been developing rapidly. Due to economies of scale the development is towards larger wind turbines. The amount of energy captured by a turbine is proportional to the square of the length of the turbine blade. The current largest wind turbine is the Enercon E-126. This turbine installed in Emden, Germany by Enercon has a rotor diameter of 126 meters (413 feet). The E-126 is a more sophisticated version of the E-112, formerly the world’s largest wind turbine and rated at 6 megawatts. This new turbine is officially rated at 6 megawatts too, but will most likely produce 7+ megawatts (or 20 million kilowatt hours per year). That is enough to power about 5,000 households of four in Europe. A quick US calculation would be 938 kWh per home per month, 12 months, that is 11,256 kWh per year per house. That’s 1776 American homes on one wind turbine.

It could be argued that turbines began to outgrow conventional mobile cranes when the hubs started to be built above approximately 60m. A conventional mobile crane can only lift weights under 200 tonnes to heights of beneath 50m. Therefore all turbines installed with a capacity of greater than 1.5 MW need a heavy crane. With the present market, the biggest crane can lift approximately 60-100 tonnes to 90-120m.

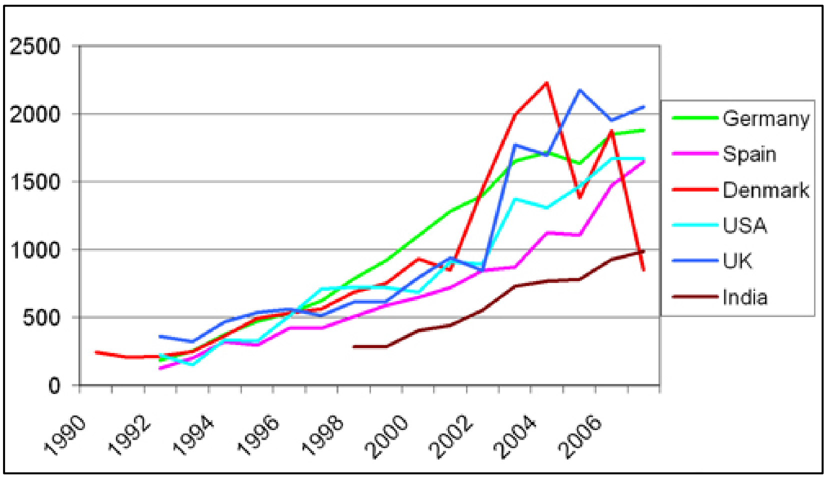
In recent years, three major trends have dominated the development of grid-connected wind turbines:

- Turbines have become larger and taller – the average size of turbines sold on the market has increased substantially.

- The efficiency of turbine production has increased steadily.
- In general, the investment costs per kW have decreased, although there has been a deviation from this trend in recent years.

Figure A.2 shows the development of the average wind turbine capacity (kW) for a number of the most important wind power countries. It can be observed that the annual average size has increased significantly over the last 10-15 years, from approximately 200 kW in 1990 to 2 MW in 2007 in the UK, with Germany, Spain and USA not far behind.

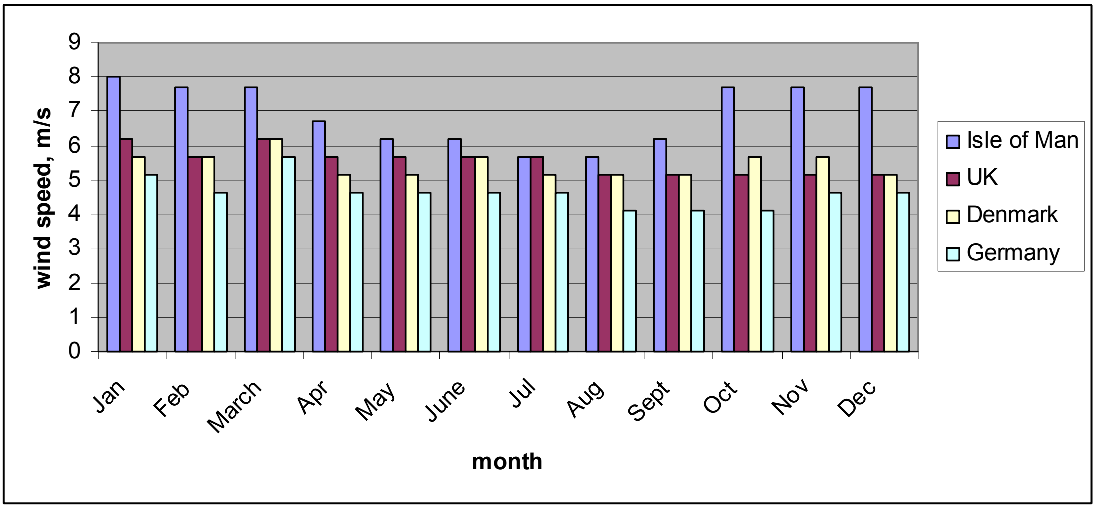
Figure A.2: Average wind turbine capacity (kW)



A.3 Wind Speed and Energy Yield Prediction

It is noted that the wind speed has decreased in recent 20 years due to increasing urbanisation. The average wind speed of selected countries in Europe is shown in Figure A.3. As can be seen from figure A.3 below, Isle of Man has on average the highest wind speed throughout the year compared to UK, Denmark and Germany. The energy cost of a wind farm depend on the amount of electricity generated as well as the capital and operating cost, therefore choosing the right site is critical to achieving economic viability. It can be assumed here that wind farm generation in Isle of Man can be optimized because of the wind distribution scenarios throughout the year. However as highlighted in Appendix C site selection is constrained by a number of different factors, not just wind yield.

Figure A.3: Average wind speed of selected countries in Europe



It has been recognized that the greatest problem associated with individual wind turbines is the intermittent nature of the wind. It varies in strength and direction on fairly short timescales. Therefore, the individual variability of any given wind farm is quite high as the power input to a turbine depends on the cube of the wind speed. The actual power output is a function of the turbine efficiency and its structure. At low speeds, no power can be generated. At very high speeds, the turbine might need to be switched off. Furthermore, not all the power of the wind can be converted to output energy. A theoretical conversion limit of 16/27 exists, and this is generally not achieved in practice because of gearbox losses, generator and transformer losses, and because turbine efficiency generally varies with wind speed.

Typically wind turbines will start to produce at about 3 m/s, however, with an average wind speed of 5 m/s it gets economically interesting to produce electricity with a wind turbine. Stronger wind produces more electricity. Recommendations should be for a top quality wind survey at a number of locations and heights to ensure valid wind yield and hence wind predictions are available for specific turbine parameters.

Table A.1: Electricity produced by two different types of wind turbines

WES18 Wind Turbine	
wind speed	annual production
4.5 m/s	80,000 kWh
5.5 m/s	135,000 kWh
6.5 m/s	200,000 kWh

WES30 Wind Turbine	
wind speed	annual production
4.5 m/s	200,000 kWh
5.5 m/s	400,000 kWh
6.5 m/s	580,000 kWh

Wind speeds tend not to be highly correlated across the whole surface area of a country as large as the UK. So, the variability in aggregate output of a large number of small wind farms geographically spread over the UK is fairly small. It is unfortunate therefore that in the UK, BETTA penalised small generators for individual differences, positive or negative, from the forecast position based on any one metering location, particularly in the early days of implementation. The treatment of imbalances for disaggregated wind turbines is of critical importance for the development of wind power in liberalised electricity markets.

A.4 Reliability for Wind Turbines

The technical development of large wind turbine generator facilitates the connection of the large wind farm into the transmission network. However, some new requirements are put forward. The most important concerns are those relating to the ability of wind farms to ride through transmission faults, and the impact of wind farms on voltage and frequency regulation.

To ensure the reliable operation, fault ride-through specifications listed in modern transmission and distribution grid codes specify that wind-turbine generators (WTGs) must remain connected to electricity networks at voltage levels well below nominal. The standard controller for converter-based WTGs that is designed for reliable operation around nominal voltage levels may not work as designed during low network voltages that can occur during a fault. A consequence of this is greatly increased converter currents, which may lead to converter failure. Therefore, fault ride-through capacity is one of key criteria that wind turbine generator (obligation of the wind turbine manufactory) must comply.

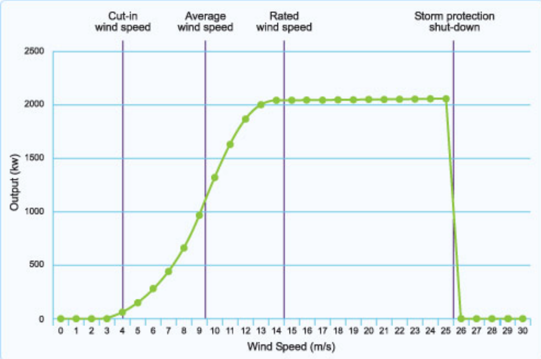
A.5 Overview of Wind Generation

Integrating wind the grid presents some problems to network operators and energy traders. Most of these problems boil down to the fact that wind energy is intermittent – in one period the wind conditions could be favourable and in the next they could have changed. As the amount of power from wind is proportional to the cube of wind speed, a small change in wind speed can result in quite a significant change in power output. It is therefore paramount that wind farms are located at sites with very good wind conditions for the best technical and commercial results.

See Figure A.4 for the relationship between wind speed and wind turbine output power.

From Figure A.4 it can be seen that at very low wind speeds there is no generation. The cut-in wind speed is the speed at which the generator starts to produce some electricity. Maximum power output is realised at rated wind speed. The maximum power output can be maintained over a range of speeds from rated wind speed to maximum speed at which the generator is shut down as a protective measure to prevent turbine damage.

Figure A.4: Relationship between Wind-Turbine Power Output and Wind Speed

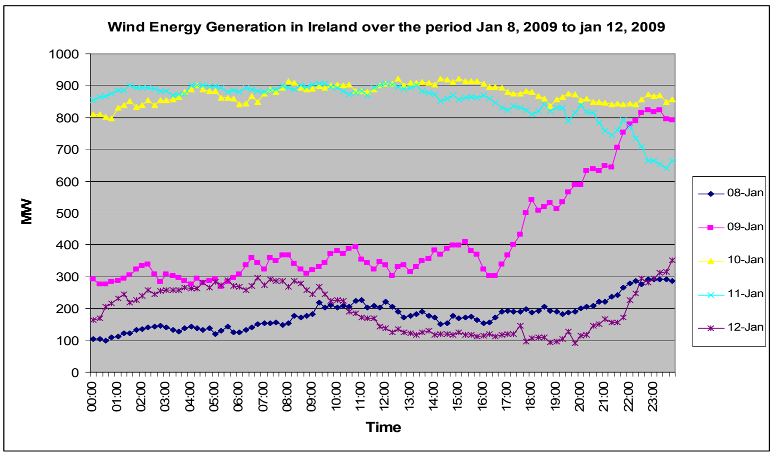


A.5.1 Wind Intermittency

As mentioned earlier in the report, one difficulty in harnessing the wind energy conversion is that wind is not completely predictable, making it impossible to depend upon it entirely, or to commit, well in advance, to a production schedule or long-term firm power sales contract [10]. Due to the variability and intermittency of wind generation, it is often considered non-dispatchable (incontrollable generation in many respects) and treated as "negative" load. This attribute is similar, from the system operator's point of view, to demand fluctuations or the inadvertent loss of conventional generation on the system as they all require the network to hold some generating resources in spinning reserve mode.

The graphs in Figure A.5 were compiled using data from the Irish TSO EirGrid's website for wind generation over a 5-day period from January 8, 2009 to January 12, 2009. The graphs show a significant variation in wind generation for each day and "hour" owing to the varying levels of wind over each period considered. The high and steadier wind generation levels for the two days, January 10, 2009 and January 11, 2009, indicate the availability of good wind conditions compared to the other three days. Assuming a total installed wind capacity of 1085MW, the resulting load factor for wind generation is approximately 49%.

Figure A.5: Wind Farm Generation in the Republic of Ireland during 8-12 Jan 2009



In order to balance demand and generation on a minute by minute basis, in a network with wind generation, back-up conventional generation (spinning reserves) that can be brought on-line upon loss of wind generation, or loss of any other generators for that matter, is required. In the MEA system the largest conventional generator module or unit is 40MW.

A.5.2 Technical Requirements for WTGs connected to the Grid

Wind offers an environmentally friendly, utility-scale renewable resource to meet the ever-increasing demand for power, but its interaction with the grid is unique [11]. Most countries and jurisdictions have developed grid code provisions for controllable wind farm stations, and in some cases a wind farm power station (WFPS) is required to provide the same levels of dynamic reactive compensation and active power management, as an equivalent sized thermal powered synchronous generator would be required to provide. The primary objective of these provisions is to establish the technical rules which controllable WFPSs must comply with in relation to their connection to and operation of the power system. These grid code provisions require WTGs generators to have:

- Fault Ride Through (FRT) Capability - to stay connected for a minimum stipulated time duration for faults on the high voltage network when voltage falls to specified level below nominal system voltage

- Active Power Management and Frequency Response Capability - to regulate their active power output to a level restricted by system operator in response to network frequency changes or commands from initiated by the System Operator.

- Reactive Power Management and Voltage Control Capability - to provide reactive output regulation in response to power system voltage variations, in a similar manner to conventional power plants. This helps in maintaining acceptable/statutory voltage system voltage profiles.

Appendix B Wind Farm Constrains

B.1 Introduction

Whilst the technical and economic appraisal for onshore wind generation forms part of the strategic development considerations, these factors cannot be considered in isolation. Any wind farm location on the Isle of Man would pose several challenges in the identification of appropriate locations (PB Power; 2003). For completeness these factors are summarized below but would be subject to separate appraisal, which is outside the scope of this work.

The planning authority would provide the final determination of the location of a wind farm based on a wide range of environmental, social and land use factors, some of which are referenced below. Further guidance is available within the following Manx and UK publications:

- Isle of Man Strategic Plan – Towards a Sustainable Island (Department of Local Government and the Environment; 2007);
- Planning Policy Statement (PPS) 22: Renewable Energy (Office of the Deputy Prime Minster; 2004)
- Planning for Renewable Energy – A companion guide to PPS22 (office of the Deputy Prime Minister; (2004)

B.2 Technical

Access - Turbines will require delivery, construction and erection on site. This will require access to port unloading and safe access roads to the dedicated site. Delivery vehicle, size, weight and transport routes would require further examination.

Foundations – Underlying ground conditions would require examination and associated foundations suitable to secure the turbine. Land subject to erosion or contamination may require further treatment which may introduce additional environmental costs and installation risks.

Space – Turbine array will determine the overall design footprint and space requirements. Individual turbine footprint is marginal and ongoing land use around turbines is possible.

B.3 Economic

Wind Farm Funding -A financial model would be required to include commercial power purchase agreement terms, which would be examined once renewable generator size and expected operating conditions are identified in more detailed project analysis. Operating regimes and obligations and would need to be identified and formally agreed. The types of operating agreements which may be established include the commercial, legal and technical standards.

Wind Yield – The primary requirement is sufficient wind for viable generation. Characteristics which affect output include speed, duration, direction and turbulence. Specific site wind yield monitoring would be required at any identified site. This would include meteorological mast installation, wind data acquisition, analysis and eventually wind farm modelling. The erection of any meteorological mast would require planning permission, given the duration of installation (over 1 year) and requirement for sound foundations for the same.

Appendix A provides further clarification of wind turbine deign, installation and energy yield prediction.

B.4 Environmental

The Isle of Man Strategic Plan (DOLGE; 2007) identifies the need for an environmental impact assessment for (EIA) “installations for the harnessing of wind power for energy production”. The Planning Authority and other interested bodies would be consulted during early stages in the preparation of the EIA. The following factors likely to be included within the EIA process, this is not an exhaustive list:

- Landscape and visual impact
- Proximity to dwellings
- Noise (including low frequency noise)
- Conservation areas
- Sites of Special Scientist Interest
- Proximity to infrastructure (roads, railways, public rights of way etc)
- Ecological and biodiversity impacts
- Ornithology impact
- Electromagnetic production and interference
- Archaeology heritage
- Areas of high archaeological potential
- Land Contamination
- Protection zone around airfields
- Military sensitivity
- Land erosion

Appendix C

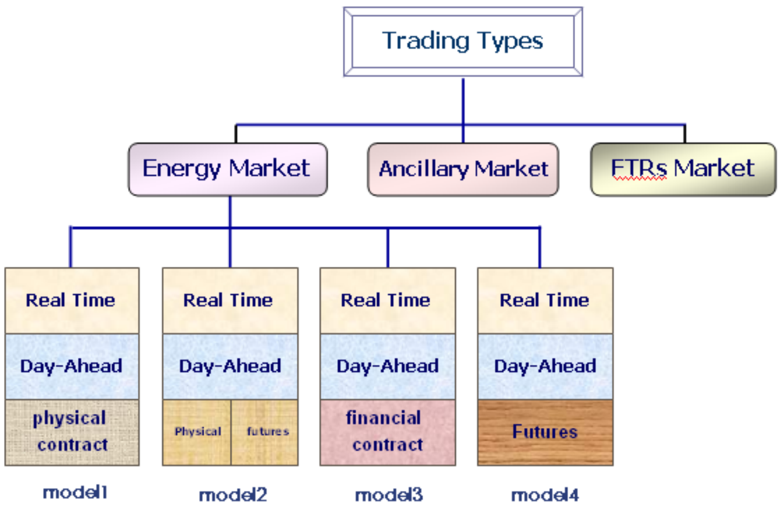
Reviews of Electricity Trading Market

As electricity energy cannot be conveniently stored, its production and use happen simultaneously. The electricity trading market is therefore different from other commodity markets and a key element is therefore the real time provision of operating reserves. These are made up of partly loaded generating units (spinning reserve) and fast start reserve plus fast response demand side management.

The electricity market can be divided into three types: energy market, ancillary service market, and transmission right market (Reference [8]). The energy market can be divided into real time energy market, day-ahead energy market and long - term energy market. The long-term energy trade can be conducted by means of auctions of contract and futures. There are two types of contracts, physical contract and financial contract, and three types of futures, yearly futures, monthly futures, and weekly futures. So the electricity market can take the form of one or more of the four operation models shown in Figure C.1 and summarised as:

- Operation model 1: real time + day-ahead + physical contract;
- Operation model 2: real time + day-ahead + physical contract + futures;
- Operation model 3: real time + day-ahead + financial contract; or
- Operation model 4: real time + day-ahead + futures.

Figure C.1: Types of trading



Ancillary services will include Automation Generation Control (AGC), operating reserve, load following, voltage control, demand side management (DSM) and black-start capability, as shown in Figure C.2.

Due to the special features of electricity commodity, a perfect electricity market should include a real time energy market, a day-ahead energy market and a long-term energy market. How to design the electricity market model depends not only on economy rules of the market, but also on technology characteristics of power systems.

Figure C.2 shows the different types of ancillary and energy markets that could develop over the long term between IOM and UK. The term “reserve” given in Fig B.2 is considered to include load side management as well as reserve provided by part loaded generating units.

Figure C.2: Ancillary market and energy market