13. Onshore Terminals

13.1 This Section

This section covers the onshore terminals sector, as part of an overall project for DTI on *"EU Emissions Trading Scheme (ETS) Phase II – UK New Entrants Spreadsheet revisions"*.

The overall aim of this project is to validate and revise appropriately the existing New Entrants (NE) allocation spreadsheet. The following sub-sections present the findings for this sector.

In particular, this section seeks consistency with the other onshore gas distribution section (Section 3 – Gas Compressors) and the Other Combustion section (Section 8) where appropriate.

13.2 Background and Sector Description

13.2.1 Sector Structure

Oil Pipelines to Terminals

There is an extensive network of pipelines in the UK to carry oil extracted from North Sea platforms to coastal terminals in Scotland and northern England, as shown in Table 13.1 below.

Table 13.1 UK oil pipelines

Operator	From	To	Details
BP	Forties fields	Cruden Bay Terminal, Scotland	177km, 36-inch
BP	Cruden Bay	Kinneil refinery Grangemouth	
BP	Ninian system	Sullom Voe terminal, Shetland Islands	177km 36-inch
Total	Bruce & Forties fields	Cruden Bay	240km, 24-inch
Total	Piper system	Flotta terminal, Orkney Islands	210km, 30-inch
Shell, Esso	Cormorant field	Sullom Voe	150km, 36-inch
Talisman Energy	Beatrice field	Nigg Bay terminal	60km, 16-inch

There are also numerous, small pipelines that connect each North Sea oil platform to these major backbones. The UK does have a few onshore crude oil pipelines, including a 145km, underground pipeline operated by BP that links the Wytch Farm field to the refinery at Fawley and the nearby oil export terminal at Southampton.

Ocean terminals allow import of crude oils by ship for example at Finnart on Loch Long for pipeline (90km) transfer to BP Kinneil and Grangemouth and at Birkenhead (Ocean Terminal) to the Shell Stanlow refinery.

The UK has a single international crude oil pipeline, the 354km, 34-inch Norpipe operated by ConocoPhillips. With a capacity of 900,000 bbl/d, Norpipe connects Norwegian oil fields in the Ekofisk system to the oil terminal and refinery at Teesside.

Gas Pipelines to Terminals

There are seven locations of offshore pipeline gas terminal facilities in the UK and three additional interconnector sites; these are briefly summarised in Table 13.2.

Table 13.2 UK gas pipelines

Terminal	Operator	Pipelines (from)	Details
St Fergus	ExxonMobil	SAGE - Scottish Area Gas Evacuation (Beryl, Brae, Scott), Britannia, Atlantic & Cromarty	320km, 30-inch
	Shell	FLAGS - Far North Liquids and Gas System (Brent Cormorant Tern etc)	450km, 36-inch
		Fulmar (Fulmar Clyde Nelson)	289km, 20-inch
		Goldeneye	110km, 20-inch
	Total	UK Frigg (Otter, Alwyn, Bruce & Dunbar),	
		Vesterled (Norwegian Frigg & Heimdal), Miller	362km, 32-inch
	Chevron/ConocoPhillips	Brittannia line	
Teesside	BP CATS	CATS - Central Area Transmission System (Armada, Everest, Lomond, ETAP)	400km, 36-inch
	Enron	CATS	
Dimlington / Easington	BP	Village, West Sole, Amethyst	
		Ormen Lange interconnector	1,200km (2007 completion)
Theddlethorpe	ConocoPhillips	Viking Transport System, LOGGS, CMS	
Bacton	Shell	SEAL - Shearwater-Elgin Line (Leman, Brigantine etc)	467km, 34-inch
	Gasunie	Balgzand (NL) interconnector	235km (2006 completion)
	Interconnector (UK) Ltd	Zeebrugge (BE) interconnector	can flow in either direction
	Tullow Oil	Hewett, Thames, LAPS	

Terminal	Operator	Pipelines (from)	Details
	Perenco		
Point of Ayr	BHP Petroleum	Liverpool Bay	
Barrow	Hydrocarbon Resources Ltd / Centrica	Morecambe North & South	
	Hydrocarbon Resources Ltd / Burlington	Rivers	
Brigghouse Bay	BGE	Loughshinny (IRL) interconnector	
Beattock	BGE	Gormanston(IRL) interconnector	
South west Scotland	Phoenix Natural Gas	Northern Ireland interconnector	

In addition, Windermere and Markham fields export gas direct to the Netherlands.

Most of the gas going into the gas transmission system comes from offshore fields, however, some gas is produced from onshore oil fields and is co-produced with oil (e.g. BP Wytch Farm) to the transmission system.

Following gas treatment National Grid Transco is responsible for the transmission of natural gas throughout the UK.

Other Terminals

There are other terminals where refinery products may be exported such as Braefoot Bay at Aberdour which exports NGLs and ethylene from Mossmorran Fractionation Plant (Shell) and Fife Ethylene Plant (Exxon). The NGLs are sent to Mossmorran by pipeline having been separated in the various gas processing plants at St. Fergus. Most coastal/estuarine based refineries will have import and export jetties for oil and products where they are not supplied by pipeline.

13.2.2 Process Overview

The processing requirements of onshore terminals are characterised by whether they are predominantly handling oil or gas or both. Essentially the function of the terminals is to take incoming oil or gas and treat it ready for export into pipelines in the case of gas or by ship or to refineries in the case of oil. It is appropriate to cover the two types of installation separately. Note that not all of the described processes are covered by the EU emissions trading scheme, but information is given for completion.

13.2.3 Crude Oil processing (Stabilisation)

Oil is usually brought in by pipeline from offshore oil fields and stored in large floating roof oil tanks. Alternatively it may be imported by shuttle tanker from FPSO (Floating, Production, Storage and Offloading) vessels or by large oil tankers importing from overseas. The oil may be 'live' and so it is stabilised by degassing which involves oil, gas and water separation and possibly further degassing in degassing units. These may operate at below atmospheric pressure and stabilise the crude to a saturated vapour pressure (SVP) below the storage temperature and pressure. As a pressurisation process there are no CO_2 emissions as the vacuum pump will be electrically driven. The gas produced in this process may be flared or captured for use as a fuel. It may undergo further treatment for separation into components such as methane / ethane for fuel gas / flaring, propane and heavier components for export as Natural Gas Liquids (NGLs). The fuel gas will usually be used on site where it is combusted for heat and power generation or sent to an adjacent refinery either as a fuel or feedstock. Steam generation may be required for heating and cleaning purposes and this would depend on oil composition and site requirements. For example in low ambient temperatures this may be needed for pipe tracing and tank heating purposes and to aid the flow of heavier oils or for any associated gas processing.

Vacuum pumps and other terminal pumps (e.g. produced water) are likely to be electrically driven and gas compressors for supplying fuel gas to gas turbines may be electrically driven or gas turbine driven depending on site requirements and the availability of electrical power.

Export of the crude oil by pipeline will generally go to a refinery which may be adjacent to the terminal or at a terminal/refinery located at some distance from submarine pipeline landfall (e.g. Cruden Bay to Kinneil, Grangemouth). Here, the oil will be further processed into various fractions depending on market demand.

Where the oil is exported by ship then the oil will be pumped from the storage tanks and loaded into oil tankers at the jetty or harbour facility for the terminal. This process will also result in VOC and gaseous emissions from the ships tanks. This will still be the case even if some degassing of the crude has taken place upstream prior to storage in the tanks. The installation of vapour recovery facilities at ship loading terminals is increasingly being considered especially at larger terminals. For example one is currently being constructed at the Conoco Phillips terminal on Teeside for a cost of $30million. The vapours from marine loading operations at a rate of 16,000m^3/h are recovered using carbon bed adsorption in twin beds. The vapours are recovered from the carbon under vacuum and the vacuum pump is electrically driven. The recovered VOCs are re-injected into the crude rather than being destroyed for example by thermal oxidation or combustion. The electrical power required by the process and the vacuum pumps will be an additional load on the site which will indirectly result in increased carbon dioxide emissions. The facility is due for commissioning in 2007. There are no combustion processes in this project but in some vapour recovery processes there may be a need for combustion / thermal oxidation resulting from the use of (as fuel) or destruction of the recovered vapours. Emissions associated with such a process are not included in the benchmark calculations. Depending on whether electrical power is generated on site then the power requirements may or may not lead to increased carbon dioxide emissions which are attributable to the site.

Gas is frequently produced from stabilising the oil, so there will be a requirement for gas processing plant at the oil terminal. The types of gas processing required will be similar to those used at gas terminals where oil is not processed, as described below.

13.2.4 Gas Processing (drying, sweetening, fractionation)

Natural gas processing will be highly site specific and will depend on the nature and composition of the gas coming ashore. The objective of the gas processing at the terminals will be to produce sales quality gas that can be compressed and injected into the national gas transmission network. If the site is remote then treatment adequate to meet equipment (e.g. turbine) specifications may be all that is required.

In some cases the quality of gas coming from submarine reservoirs is of high enough quality to inject directly into the transmission network with only minimal processing such as dehydration (e.g. Kinsale Head Gas Fields off Ireland). Where there is an increasing quantity of heavier components or significant concentrations of inert gases such as nitrogen or carbon dioxide then these components may need to be removed. Where hydrogen sulphide is present in sour gas then this too will require removal and sweetening by the appropriate process.

Liquids and any solids not removed in offshore production separators require separation from the gas and this is done in 'slug catchers' and/or filter-separators, as the submarine pipeline arrives in the terminal. Some of the liquids might include corrosion inhibitors and alcohols injected to prevent hydrate formation. Gas usually arrives at pressures between 10barg, for low pressure fields where compression occurs onshore, and up to 160barg (barg indicates the value is relative to atmospheric pressure) and densities of 300kg/m^3 for high pressure fields where compression is done offshore. Where compression is undertaken by gas turbine the delivery pressure from the incoming pipeline will significantly influence the onshore combustion requirements and hence CO_2 emissions.

The gas processing train downstream of the slug catchers will be site specific depending on gas composition and the selection of process technology used.

A typical processing schematic for wet gas treatment is shown in Figure 13.1. Some of the processing details are described below with reference to where combustion may be utilised.

Dehydration / NGL Extraction

Incoming high pressure streams are reduced in pressure to slightly above transmission system pressure of 68-76barg. Pressure reduction cools the gas and allows condensate formation and aids dehydration. Turboexpanders may be used to recover the energy on decompression and is used where possible for re-compressing the treated gas. Where glycol absorption is used as the dehydration process, the glycol is regenerated in fuel gas fired re-boilers (similar in design to a standard boiler), a distillation column or in a heat exchanger using steam or thermal oil from a boiler. Other dehydration processes (e.g. molecular sieves) will also require heat for regeneration. If the sales gas is too cold for injection into the distribution network then it requires re-heating before export.

Where heavier components (e.g. ethane, propane, butane) are present in the gas, removal of these NGLs (Natural Gas Liquids) is necessary to produce sales gas to NTS specification. This is typically by chilling followed by fractionation stages similar to low temperature distillation prior to stabilisation and fractionation to produce component parts such as propane, butane, pentane etc. Sweetening (and possibly further dehydration) of liquids is required before export as LPG or condensate (C5+).

Heat requirements of these processes will be supplied by suitable exchange with other process streams or from appropriate heaters.

Gas Sweetening

Hydrogen sulphide and excess carbon dioxide in incoming sour gas requires removal in gas sweetening plant. Several processes are available for this, all of which will require a heat treatment process for absorbent regeneration. Sulphur recovery (e.g. Claus Process) and tail gas treatment are other parts of the gas sweetening process. Several gas terminals simply incinerate the gas stream containing H_2S, other sulphur compounds and CO_2 which arises from the regeneration of the solvent. This may involve the addition of fuel gas (often ethane rich) to ensure combustion. If large quantities of H_2S are released then it may be necessary to install a sulphur recovery plant. There are various tail gas clean up processes available depending on the emission limits for the site. These can involve controlled combustion of H_2S and fuel gas to produce SO_2 and syngas so there is some requirement for combustion resulting in CO and CO_2 emissions.

Gas Pressure Reduction / Fuel Gas Processing

Where gas is imported from high pressure interconnectors pressure reduction requires preheating of the gas. Sales quality gas on the export header is usually the preferred source for fuel gas which will also require heating to compensate for cooling on pressure reduction. This can be supplied by dedicated hot water heaters (boilers) or exchange with other suitable heat sources on the terminal.

Power Generation

Fuel gas may be used in on-site power generation using gas turbines or for CHP plant. The heat from the CHP plant could be used for steam generation which might be one of the sources of heat utilised on the gas processing plant e.g. for re-boilers etc.

Allocations for onsite CHP plant will be calculated using the CHP section of the spreadsheet. Gas turbines used for power generation will be covered by the other generators section of the spreadsheet.

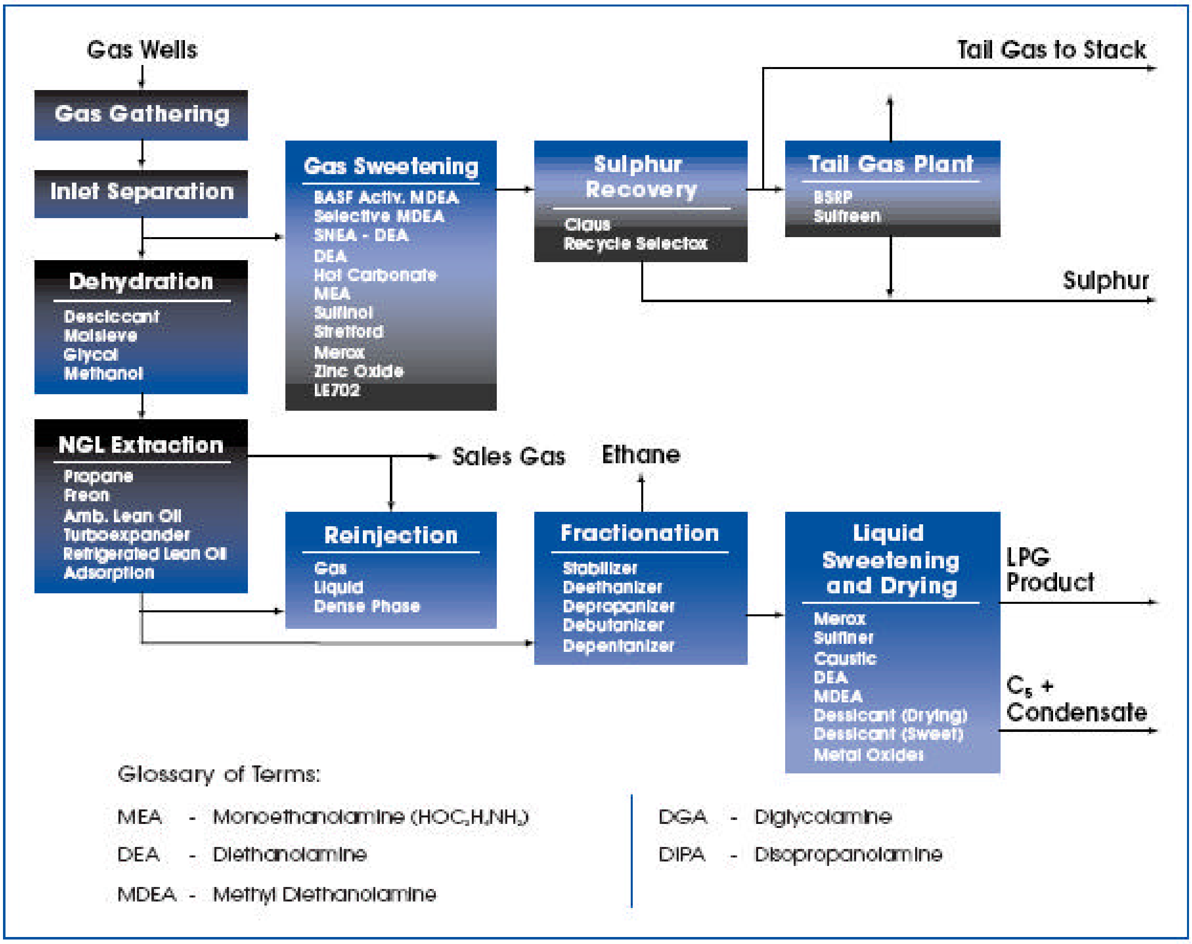
Table 13.3 Carbon Dioxide Release Processes for Onshore Oil and Gas Terminals

CO_2 Release or Combustion Process	Description	Examples
Flaring (oil processing)	Flaring may be required to destroy excess gas derived from oil degassing that cannot be utilised.	E.g ethane flaring at some oil terminals
Flaring (gas processing)	Terminals endeavour to minimise flaring but pressure relief, depressuring and vent systems will be routed to the flare which would be operated during process upsets or maintenance activities. There maybe a continuous destruction of tail gas flow from gas sweetening trains. The tail gas must be flammable and if CO_2 is a significant component then fuel gas may be added to ensure combustion.	All terminals are likely to have flares (elevated or ground) for handling excess and unwanted gas and to cater for process upsets. Gas could be released from any area of the high pressure processing plant so it could be sales quality or untreated gas. Flares and incinerators need a continuous supply of purge or fuel gas.
Fuel gas combustion for power generation and CHP.	Gas turbines will be used for power generation. These may be associated with the site or provided from an adjacent power station probably operated by another company. Sales quality gas from gas processing is likely to be the fuel gas used. Alternatively, where gas export to the grid is not required, suitably treated fuel gas that meets equipment specification requirements (e.g. turbines) may be used. CHP plant will also provide some of the heat requirements of the terminal.	Due to the remote location of Sullom Voe gas is not exported to the grid but incoming gas is dried and sweetened for use in the site power station. Excess gas is exported to platforms for enhanced oil recovery. Power output will depend on the size of the terminal but 50MW to a few hundred MW is likely to be the range for larger terminals especially if power is to be exported. For smaller sites with lower power requirements 10 to 20 MW maybe adequate and probably provided by multiple smaller units to provide the necessary flexibility and efficiency. The ConocoPhillips Teesside CHP plant will generate around 36MW of steam and 41MW of electricity.

CO_2 Release or Combustion Process	Description	Examples
Fuel gas combustion in thermal oil heaters / fired heaters / process heaters	Many of the processes for oil and gas treatment require heat input at various stages. This heat input can be provided by a variety of methods which involve fuel gas combustion. Thermal oil systems heat a low volatility oil which is circulated and heat is exchanged with the process stream. Other process heaters use direct firing and direct exchange with the process fluids (e.g. gas, oil, or regenerant).	Gas is cooled for dew point control and reheat may be required for gas export. Regeneration of glycol or mol sieves in dehydration plant. Regeneration of amine stream on sweetening plant. Heat requirements will vary but may typically be in units from a few MW to up to 20 MW. Multiple units will be used to supply the required heat load which could be in the range 50 to 100MW for larger terminals.
Fuel gas combustion in steam boilers	Some terminals have steam generation plant/boilers for a variety of on-site heating purposes.	Heating of heavier oils, steam supply to re-boilers where steam is used as the heat source, pipe tracing, tank and process cleaning requirements.
Fuel gas combustion for gas compression	Gas compression for export (70-80barg) or for pressurisation for onsite power generation in gas turbines (15-20barg) by gas turbine driven compressors.	Examples might be Solar Titan, Mars, Taurus gas turbines. Rolls Royce Avon gas turbines etc. Typical unit rating would be 10 to 20MW power output with multiple units provided for larger power requirements. Smaller units at less than 10MW are also available. Larger compression requirements may require 100MW or more.
Tail gas combustion*	Burning / Incineration of waste gas streams	e.g. Tail gas from sweetening plant containing sulphur rich waste gas streams, if there is a high CO2 content there is a need for support fuel gas to ensure combustion.
Fuel gas support fuels. Combustion*	Incineration or thermal oxidation units for VOC control	For VOC control support fuel may be required for start-up and shutdown of plant where vapours from marine loading operations are destroyed and not recovered.
Non combustion CO2 release*	Separation of carbon dioxide from high CO2 concentration raw gas will be part of the process. The separated CO2 may be directly vented to the atmosphere or used for export	Some gas in the Irish Bay fields has high carbon dioxide content and requires treatment for its removal. Increasingly capture of carbon dioxide is being considered for storage in depleted fields or as an aid for enhanced oil recovery.

* Outside scope of EU ETS

Figure 13.1 Schematic of Gas Processing Plant



Gas and Light Hydrocarbon Processes for Sulphur Removal and Recovery

Source: Parsons E&C

13.2.5 Phase I incumbent and new entrant installations

Identification of how sector is covered unde r EU ETS

Existing onshore terminals are covered in Phase I under the offshore sector and other oil and gas in the other combustion sector. For sites in the offshore sector emissions from flares would be covered, however a working assumption is that benchmark methods are not to be developed for flaring for Phase II due to the nature of the process and the need to minimise flaring where possible.

CO_2 emissions from sector

Total CO_2 emissions in recent years for the installations which would fall under this new onshore terminals calculation are presented in Table 13.4.

Table 13.4 Total CO_2 emissions from the onshore terminals sector

Total emissions (tCO_2)			
2000	**2001**	**2002**	**2003**
2,634,098	2,691,481	2,716,840	2,723,666

Source: 2000 – 2003 NAP database

Identification of Non-benchmarked incumbents, Benchmarked incumbents and New Entrants

An indication of incumbent installations, in Phase I of the NAP, to be covered by the onshore terminal methodology is shown in Table 13.5. Sullom Voe is an onshore oil terminal, however, all steam used in the process is generated in the CHP plant, and the only other combustion process is flaring.

Table 13.5 Onshore Terminals – Phase I Incumbents

Installation	Current sector
Bacton	Offshore, Other Oil & Gas
Beattock	Other Oil&Gas
Brigghouse Bay	Other Oil&Gas
Cruden Bay	Not included
Flotta	Offshore
Nigg Bay	Offshore
Point of Ayr	Offshore
Seal Sands, Middlesborough	Offshore
St Fergus	Offshore
Teesside	Offshore
Theddlethorpe	Offshore
Phoenix	Not included

Source: NAP database

New entrants in Phase I are shown in Table 13.5.

These sites give a good indication of the likely application of many of the combustion processes that might occur on terminals as described in the previous sections. The combustion equipment covered includes:

Gas-fired process heaters - for glycol dehydration plant.

Gas turbines -	for natural gas compression
	main source of CO_2 emissions
Package Boiler -	for steam generation for terminal use
Hot water heaters (boilers) -	for heating gas on decompression

Table 13.5 Onshore terminals – Phase I New Entrants

Installation	Current sector
Langeled (Part of the Ormen Lange Project)	Not included
Barrow (North and South Morecombe, Rivers).	Offshore
Bacton Interconnector	Other Oil & Gas
Dimlington / Easington	Offshore

Source: NAP database

Although not covered by the above New Entrants there are likely to be increased indirect CO_2 emissions. That is that the installation of electrically driven prime movers (e.g. pumps or compressors) would result in an increased electrical power demand. If power is generated on site by CCGT or CHP gas turbines then there will be an increased fuel gas demand and hence CO_2 emission. This will need to be recognised in an overall assessment with the additional emissions calculated in the corresponding CHP or Other Generators spreadsheets.

13.2.6 Possible types of new entrants in Phase II

Brief description of known or likely new entrants and market developments

It is not considered likely that there will be significant new developments in new combustion technology in this sector. There will always be the economic drive to improve energy efficiency which will mean relatively small increases in combustion efficiencies for gas turbines or other combustion systems such as boilers or heaters. With increasing energy prices the economics of energy recovery and hence CHP projects are likely to become more favourable and hence there is likely to be a greater uptake in CHP plant. It is possible that alternative fuels may be considered in order to supply the primary energy demand. These could be biofuels or hydrogen but the take-up of such fuels will be dependent on economics and is uncertain.

The location of many of the terminals in coastal locations could mean that operators might consider installing some renewable energy sources such as wind power. Supply from a few wind turbines might produce up to say 10MW which is only likely to make a small contribution to overall terminal power demand.

Membrane separation technology is a potential alternative to solvent acid gas removal processes. There are no associated CO_2 emissions with this technology.

Power plants associated with hydrocarbon processing may find that pre- or post-combustion removal of carbon is attractive if there is a local sink or use for CO_2. Pre-combustion removal using reformer technology and acid gas removal would also ensure some other pollutants are removed and lead to efficiencies in the subsequent power / heat generation.

A summary of known or likely new entrants in Phase II is presented in Table 13.6.

Table 13.6 Onshore Terminals – Possible Phase II New Entrants

Project	Owner/ Proposer	Size	Date	Status
Langeled South pipeline supplying gas from the Ormen Lange gas field development and other Norwegian fields	Norsk Hydro Shell Norge	Pipeline capacity about 70 Mcm/day	First gas planned 2006/7	Pipeline construction has commenced
Statfjord Later Life Project: Delivery via FLAGS pipeline	Statoil	17 Mcm/day at plateau	First gas planned 2007/08	Under consideration by UK and Norwegian Governments. Decision mid June 2005
Compressors at Zeebrugge to increase import capacity into UK at Bacton	Interconnector UK	Increase from 25 Mcm/day to 47 Mcm/day, then further increase to 66mcm/day	First phase due for completion December 2005; second phase by December 2006	Construction on schedule for Phase I and Phase II
Interconnector from Balgzand to Bacton (the “BBL” pipeline)	BBL	Potential capacity up to 44 Mcm/day	First gas planned December 2006	Under construction

Source: First Annual Report to Parliament on the Security of Gas and Electricity Supply in Great Britain by the Secretary of State for Trade and Industry (July 2005)

Summary of possible types of New Entrants in Phase II

A summary of possible types of New Entrants in Phase II is given in Table 13.7.

Table 13.7 Summary of possible types of New Entrants in Phase II

Type of New Entrant	Is this type of New Entrant realistically possible in Phase II?	Technology type	Fuel type	Examples (known or likely)
New installation	Yes	Interconnector to mainland Europe		Bacton

Type of New Entrant	Is this type of New Entrant realistically possible in Phase II?	Technology type	Fuel type	Examples (known or likely)
New piece of equipment to increase capacity at existing installation	Yes	Gas turbines and/or boilers	Gas	
Extension to existing piece of equipment to increase capacity at existing installation	Possible			

13.3 Review of Relevant Data

13.3.1 Data sources

General Information on Oil / Gas Processing

For processing oil and gas there is some general information available on emissions from terminals, energy usage and Best Available Techniques which can give an indication of individual terminal performance. A source of this data is the Refineries BREF note[1] which incorporates natural gas refining or processing.

Carbon Dioxide Emissions

As indicated above the fuel gas use will frequently be sales quality gas which is predominantly methane. In certain locations and in some circumstances other fuel gas compositions may be used that might include heavier components and the resulting emissions would be likely to resemble refinery fuel gas emissions. Generally the use of liquid fuels results in lower thermal efficiencies and higher CO_2 emissions than the use of gaseous fuels.

The Refinery BREF note confirms the main source of emissions to air as coming from compressors, boilers and furnaces, acid gas wastes, fugitive emissions and glycol dehydrator vent streams if installed.

Utility Consumption

There is some data available on utility consumption for terminals although as indicated above this will be highly site specific and will be significantly governed by the quality of the incoming oil and gas. Also the pressure of the incoming gas will determine the degree of additional gas compression required.

Electrical demand for gas separation processes varies from 15 to 20 kWh per tonne and between 300-400 kg of steam per tonne of feedstock processed.

The following table also gives an indication of consumptions for existing and new terminals.

1 Refineries BREF Note – IPPC Reference Document on Best Available Techniques for Mineral Oil and Gas Processing. February 2003.

Table 13.8 Gas Processing Utility Demands

Energy Consumption	Existing Terminals (Statpipe and Sleipner)	New Terminal (Asgard)
Capacity	22 MSm^3/day of Rich Gas	39 MNm^3 /day
Fuel Gas	29 tonnes/h	14 tonnes/h design
Power (gas power)	30MW	16MW (design)
Water (steam production)	$30m^3$/h	$15m^3$/h
Cooling Seawater	22,400 m3/h (average energy flux 274MW)	14,000 m3/h (including ethane plant (energy flux 200MW)

Source: Refinery Bref Note – Original Statoil 2000.

BAT for Gas Separation / Gas Processing

The refinery Bref identifies a few aspects of BAT that need to be considered for gas separation and processing plant and these are summarised as:

- Enhance heat integration with upstream plant streams using low level heat streams
- Re-use fuel gas used for regeneration of molecular sieve dryers
- Apply generic BAT and minimise fugitive emissions
- Apply BAT relating to energy system / integration.
- Apply BAT for waste gas treatments
- Use as fuel preferably gas of saleable quality
- Consider, particularly for large carbon dioxide flows, alternatives to direct release of CO_2.

Of these some will result in more CO_2 emissions, such as enhanced waste gas treatments, whereas others such as enhanced energy use and recovery will result in reduced consumption. The capture and avoidance of direct atmospheric venting of carbon dioxide will reduce emissions from non-combustion sources.

BAT for gas turbines

No reference documents have been found which explicitly identify BAT or similar benchmarks for efficiency for turbines at compressor stations. However, recent ISO performance data for all available turbines is available in an annual publication ‘Gas Turbine World 2004-2005 Handbook’ [2]. This is a bi-monthly industry publication, the annual Handbook is an associated reference publication which lists standard data for all gas turbines in production. Efficiency is one of the indicated values and the three models identified in the Phase I spreadsheet (Solar

[2] Gas Turbine World, 2004-2005 Handbook, Vol 24, Pequot Publication, USA

Titan, Alstom Cyclone and GE LM2500+) have been confirmed as the most efficient (BAT) for their respective capacity range.

The general pattern is that larger turbines have higher efficiency. The turbine is at maximum efficiency near maximum load. The choice of capacity of a turbine at a site is determined by the required shaft power of the compressor and by the intended throughput.

The proposed methodology utilises data collected for the Onshore Gas Distribution sector. These models can be categorised as either large or small turbines. For the large turbines (26-34 MW) there is one model which has a higher efficiency than other available models and therefore is identified as BAT for this range. In the small turbine range (10-15MW) there is a high efficiency model in the upper and the lower part of the range. To determine the BAT efficiency for small turbines the average efficiency of these two models has been calculated. It is reasonable to apply this data for the Onshore Terminals sector since at the four sites with available data the turbines are all models also found in the Gas Distribution Sector.

BAT for boilers and heaters

Typically, boilers heat water or a thermal fluid or generate steam. Data from the Carbon trust provides efficiencies that can be achieved from a number of different boiler types that are typically used within industrial processes. All of these boilers could be argued as BAT as they have different properties and serve different potential industrial processes. The net efficiencies range from 84% to 102% with the average being approximately 92% (Carbon Trust, 2004). Overall, based on a review of currently available data (see Section 8 Other Combustion), it is considered that 92% efficiency should be broadly indicative of BAT across a range of technology types used within the sector.

Installation specific data

A range of information for many of the onshore terminals is available in the public domain, on operators' websites. However, this information is not comprehensive, for example capacities of some technology units are given, but not all units are listed. Similarly the NAP database provides information on some of the technology units for some of the sites. Figures for installation wide fuel consumption and CO_2 emissions are also included for 1998-2003. However, these data sources do not provide enough data for a full analysis to be made. Note that a number of operators were contacted regarding this study, however, no data has been received within the timescale of this project.

13.3.2 Benchmarks used in other contexts, including other Member States

Investigations have been undertaken to try to identify benchmarking approaches for new entrants in other Member States. Overall, the extent of information available within the tight timescales of this study has been limited. Furthermore, information will tend to relate to Phase I approaches, and hence may not be indicative of approaches in Phase II, which this study is focussed on. Notwithstanding this, it is useful to consider these approaches, as briefly summarised below.

Denmark

The Danish NAP assumes an efficiency factor of 0.9 for new entrants but no distinction is made between sectors for this factor. No discussion of new entrant benchmarks or formula.

Netherlands

$$A_i = E_v \cdot P \cdot \beta \cdot C$$

Where

A_i = Allocation (tCO_2/year);

E_v = Emissions from combustion averaged for 2001 to 2002 (tCO_2/year), information not readily available on the specific approach for new entrants operational after that time;

P = Production growth as a factor for the total of the years 2003-2006 (relative index);

β = energy consumption of the world's best divided by the installation's actual energy consumption in the benchmark year 1999 (relative index);

C = Allocation factor (relative index).

Other Member States

For a number of other Member States, the readily available information simply indicates that new entrant allocations are to be based on BAT levels of performance. This applies to Ireland.

13.4 Review of Phase I Benchmarks

13.4.1 Characterisation of existing New Entrant allocation benchmarks

A characterisation of the existing New Entrant allocation spreadsheet is given in Table 13.9.

Table 13.9 Characterisation of the existing New Entrant allocation spreadsheet

Item	Parameter value / details	Justification for choice of parameter value / details given by FES	Source of data
Coverage of activities *(how does the coverage of activities included in the spreadsheet compare to the activities in the sector that are covered by EU ETS)*	There is no Onshore Gas Storage sector in Phase I. Operator would have to use 'Onshore Gas Distribution' for turbine emissions and 'Other Combustion' for boilers or heaters.		
Level of sector differentiation *(Is there one set of formulae / parameter values for the whole sector, or are there separate formulae /*	There is differentiation in the makes and models of gas turbines used in the sector.	'BAT' models used in FES methodology	National Grid

Item	Parameter value / details	Justification for choice of parameter value / details given by FES	Source of data
parameter values for different technologies, fuels, products etc)	For boilers there is differentiation by sector with regard to load factors.	Load factors were developed based on a comprehensive survey of UK boilers. Stated that a number of factors were used including over design, minimum load and demand swings.	FES 2004
Degree of standardisation of formulae *(i.e. what types of input parameters are required in the formulae?)*	Reliant upon operator for prediction of likely loads. Methodology only takes account of three specific models of turbine – not useful for new entrants NOT using those specific models	'BAT' models used in FES methodology although if turbine is not one of the three that are listed then reference is made to the offshore spreadsheet.	Not specified
	Standardised for boilers. Only input is boiler plant rated output capacity and sector type	Fairly simple and logical	Assumed from FES 2004
Technology / process types *(What types of technologies / processes are used as the basis for the parameter values?)*	Uniform type of technology (gas turbine), but a number of models and makes of gas turbines	Simple logical approach	National Grid
	Standardised boiler BAT efficiency factor assumed at 0.89	Benchmark value stated to be derived from information in the ECA scheme. Relates to net boiler efficiency for heating hot water.	FES 2004
Fuels assumed *(What types of fuels are used as the basis for the parameter values?)*	Natural gas – single fuel	Only relevant fuel	National Grid
		Stated in report logical fuel to assume	FES 2004
Emission factors *(What are the fuel CO_2 and Process CO_2 emission factors?)*	No process CO2 emissions. Standardised Gas emissions factor of 0.21 $kgCO_2/kWh$ (derived by multiplying gross CV emissions factor by 0.9 to get to net figure)	Reliable source of data	DEFRA
Capacity utilisation factors / load factors *(What are the values for these factors?)*	Reliant upon operator predictions	Justification not clear.	Not specified
	Standardised for the sector group but user defined sector choice from the limited list (note 1).		FES 2004
Stand-by factor	No standby for turbines		
	Standardised as 1 boiler out of 3 (0.67)	Stated assumption	FES 2004

Note 1: Users select the sector they operate in from a list and this picks the load factor. In some cases, e.g chemical installations in refineries, there may be more than one sector. One criticism of the current method is that sites with multiple sectors could select the sector that gave them most allowances.

Overall, the formulae that are used in the existing New Entrant allocation spreadsheet are:

Gas turbines -

A	=	U_j	*	EF_t
Allocation	=	Hours at specified load	*	Emissions Factor at specified load
tCO_2		Hours		tCO_2 / hour

Where:

Parameter / Variable	Value
$U_{j\ idle}$	hours at idle
$U_{j\ 100\%}$	hours at 100% load
$U_{j\ 75\%}$	hours at 75% load
$U_{j\ 50\%}$	hours at 50% load
$EF_{t\ idle}$	tCO_2/hr at idle for XXX turbine model
$EF_{t\ 100\%}$	tCO_2/hr at 100% for XXX turbine model
$EF_{t\ 75\%}$	tCO_2/hr at 75% for XXX turbine model
$EF_{t\ 50\%}$	tCO_2/hr at 50% for XXX turbine model

The operator selects their turbine models from drop down menus, which automatically populates a table with standard CO_2 emissions at 100%, 75%, 50% and idling loads for each model. In practise idle loads are not used since there is no useful output power at idle. The operator then enters predicted hours of operation for each turbine at each of the four loads. Results are then given for a total sum hours of operation, an annual CO_2 emissions value for each turbine, an annual energy allowance allocation and a total Phase I allowance allocation.

Boilers and heaters

In essence the existing spreadsheet forms a benchmarking approach supported with standardised factors. The estimation methodology is characterised as follows:

Table 8.5 Phase I Benchmarking Formula

A	=	C_I	×	S	x	T_S	×	U_S	x	H	x	EF	÷	?
Allocation	=	Capacity (rated output)	×	Standby Factor	x	Ambient Temperature Factor	×	Utilisation	x	Hours per year	x	Emissions Factor	÷	Efficiency Factor
tCO_2		MW_{th}		%		%		%		Hours		tCO_2 / MWh input		%

(lhv)

Note: I = Installation level differentiation; S = Sector level differentiation.

Where:

Parameter/ Variable	Value
$C_{Installation}$	Installation capacity defined by the operator expressed as the rated thermal output of the boiler/heater in MWth.
S	0.67 standby factor standardised (assumes 1 boiler out of 3 is standby capacity)
T_{Sector}	Temperature factor (varies depending on operator selection of sector see below)
U_{Sector}	Utilisation (varies depending on operator selection of sector see below)
H	8760 Hours per year
EF	0.21 tCO_2/MWh fuel consumed (lower heating values) derived from 0.19/0.9
?	0.89 efficiency factor

And:

Sector	Utilisation (U, %)	Temperature (T)
Paper	82%	1.0
Refineries	99.5%	1.0
Mixed Industrial	80%	1.0
Commercial and/or domestic	71%	0.6
Hospitals	80%	0.6
Commercial	71%	0.6
Chemicals	89%	1.0
Food and Drink	80%	1.0
Engineering	70%	1.0

The calculation is intended to estimate fuel consumption with the main applicant defined input parameter being the boiler plant rated output capacity in MW thermal.

Sector differentiation has been introduced through annual hours of operation expressed as full load equivalent and the ambient temperature factor. Load factors and ambient temperature factors have been standardised for the groupings outlined above.

In other respects a standardised approach has been taken for reasons of simplicity and feasibility, verifiability and other criteria as stated in the FES Report on NER allocation. In particular an emissions factor for natural gas (0.21 tCO_2/MWh) is used. This emissions factor is based on the net calorific value (lower heating va lue) and is derived by taking the UK published gross calorific value of natural gas (0.19 tCO_2/MWh) and dividing it by 0.9 (assumed to be the level of moisture in the fuel for which heat is not recovered).

Best available technique performance is intended to be covered by the selection of gas as a fuel and the application of a single BAT efficiency factor of 0.89. It is understood that this figure has been assumed based on the data collected as part of the Enhanced Capital Allowance Scheme. The data represents the net boiler efficiency for heating of hot water.

A further standardised element in the calculation is the element relating to the standby factor. Standardisation based on the assumption that 1 in 3 boilers provide standby capacity at any time means the multiplier is fixed at 0.67.

13.4.2 Validation of Existing New Entrant Allocation Spreadsheet

It is not possible to validate the existing spreadsheet since the disaggregated capacity of each technology unit at the incumbent sites has not been obtained within the timescale of this project. Even if this data was available the verification would not be possible for turbines other than the three selectable models in the Phase I spreadsheet as there is no explanation of how to perform the calculation for other turbine models. The boiler calculation could only be verified if actual disaggregated carbon dioxide emissions figures were also provided, since the NAP database emissions are at a site level and therefore include turbine emissions.

13.5 Assessment of Phase I Benchmarks and Proposed Revisions to these Benchmarks

Any new methodology is required to be repeatable and robust without requiring any complex calculations or hard-to-find parameters.

The proposed methodology consists of separate calculations for the gas turbines and the boilers or heaters at the installation. The formulae used are in the same form as in the Gas Distribution and Other Combustion sectors respectively. However, the values for the utilisation and load factors have been reviewed for this sector. In both cases the operator enters the design capacity of the unit.

13.5.1 Turbine allocation calculation

The user will enter the required shaft power input for their compressor at 100% load, this equates to the shaft output of the turbine and can be verified with a manufacturer's specification sheet. The entered capacity will fall into either the small or large turbine range. In each range the BAT net heat rate has been identified for 100% turbine load. The annual hours are averaged across the turbines at the site.

The calculation is applied individually to each turbine at the terminal.

A	=	C_i	*	U	*	EF	*	HR
Allocation	=	Capacity - Shaft output	*	Utilisation	*	Emissions Factor	*	Net heat rate
tCO_2		kW		Hours per year		$kgCO_2$ / MJ		kJ/kWh

Note: i = Installation level differentiation.

Where:

Parameter / Variable	Value
C_i	kW Turbine capacity (shaft output) at 100% load
U	1750 Hours per year
EF	0.0586 kg CO_2 / MJ (net) of heat input
HR	kJ/kWh at 100% for turbine capacity range

The hours of operation are standardised. This is currently based on information from three separate installations[3], which shows good agreement. Additional data has not been received from the sector within the timescales of this study.

CO_2 emissions allocation is in tonnes per annum, with appropriate conversions of units in the formula to derive this.

Three turbine models have been selected as these representing BAT levels of efficiency for different levels of output:

- up to and equal to 15000 kW - Solar Titan and Alstom (Siemens) Cyclone (SGT 400);
- outputs above 15000 kW - GE LM2500+.

These models have been used to select the standardised heat rates for each operating load. The Cyclone and the Titan have similar heat rates and so the values used for the small turbine range are the average from these two models. The heat rate values for the LM2500+ have been derived from data in the Phase I spreadsheet as it has not so far been possible to obtain data from the manufacturer. For the other two models, heat rate values have been obtained from the manufacturer.

Turbine output (kW)	Heat rate (kJ/kWh) 100% load
< 15000	10,071
> 15000	8,870

It is assumed that the turbines will be operated at or close to 100% load in order to achieve best efficiency.

13.5.2 Boilers allocation calculation

For boilers, it is proposed that the generic 'other combustion' methodology is followed, as described in detail in Section 8.

[3] Hours of operation for the Brigghouse Bay and Beattock interconnector stations were estimated based on fuel consumption and capacity data contained in the NAP database.

This method assumes a standardised utilisation factor of 85%, which is considered to be a reasonable approximation of expected boiler utilisations in this sector, based on our experience and based on limited actual data available from this sector.

13.6 Evaluation of Proposed Benchmarks

Feasibility

- The only user specified parameter is the unit capacity. This data should be readily obtainable from the equipment vendor, and should be straightforward to verify.
- For turbines the net heat rates are standardised and should be easy to replicate, as they are also based on vendor data. These correspond to BAT levels of emissions performance as the revised methodology selects the net heat rate data for the most efficient turbine at any level of shaft output. The methodology is standardised on gas.
- For boilers the efficiency benchmark represents an indicative level of BAT with respect to boilers used for process steam generation or heating, taking into account variations across the 'Other Combustion' sector.
- Hours of operation is standardised. For turbines this is based on the operating hours of three installations. The operating hours for the boilers for the one known site corresponds approximately to the generic value used in the other combustion sector. This standardised approach is preferred to a user defined approach as it is not possible to predict the hours with any accuracy.

Incentives for clean technology

- From the perspective of incentives, the key issue is to have as little differentiation as possible with regard to technology choice (including the type of fuel used). The proposed benchmarks do not include differentiation for technology and in this sector natural gas is identified as the fuel. The only operator input is the capacity.
- Therefore, the proposed benchmarks provide an incentive to choose the most energy efficient turbines and combustion plant. This contrasts with the existing spreadsheet which develops allocations based on the specific type of turbine and has a number of sector specific load factors for boilers.

Competitiveness and impact on investment

- The key issue in relation to the new entrants' benchmark is that there is incentive to install the most energy efficient turbines and that is discussed above. The use of standardised loads seems to be the best possible way to give an overall allocation that meets the site's needs without too high a risk of either over or under allocation.
- As for the other sectors related to gas import, storage or distribution, the facilities covered here are integrated parts of the energy supply system. New entrants are most likely to be gas terminals and they are therefore part of the gas supply system.
- Establishing onshore gas terminals supports the security of gas supply. It could therefore be argued that the benchmark should not discourage investment in new

capacity. This argument supports the proposed benchmark that provides a reasonable coverage of the site's needs.

Consistency with incumbent allocations

- Utilisation is standardised under the new approach and hence actual performance is likely to deviate from this level across individual sites. However, over a number of sites, the standardised utilisation should approximate more closely to actual performance, as the standardised values approximately match actual performance for sites where data is available.
- Emission factors in the proposed Phase II benchmarking approach should be broadly consistent with those incumbents operating with best practice technology for turbines and combustion plant, and utilising natural gas.
- Using data from Phase I NAP it has been possible to estimate results for four installations to compare the proposed methodology with actual emissions. The results are shown in table 13.10. It can be seen that there is likely to be large variation across the sector, but that there is no systematic over or under allocation. Given the lack of robust data it is not possible to draw any conclusive results from this data.

13.10 Comparison of actual emissions and calculated values using the proposed methodology.

Site	Average total annual emissions (excluding minimum year) 2000-2003 from Phase I NAP Data (tCO_2)	Calculated annual emissions using the proposed benchmark calculation (tCO_2)	Comparison of annual emissions from the Phase I NAP with calculated emissions (%)
Dimlington/Easington	74,980	34,050	-55%
Bacton Interconnector	170,629	109,357	-36%
Beattock Interconnector	41,244	120,293	192%
Brigghouse Bay Interconnector	51,410	113,732	121%