

Section 4

Draft Plan and alternatives

4 Draft Plan and alternatives

4.1 Introduction

The IOSEA1 is a result of the Irish Government's decision to conduct a fresh review of the hydrocarbon potential of the Atlantic Ireland Basins, starting with the acreage covering the Slyne, Erris and Donegal Basins. Successful applicants will be offered Frontier Exploration Licences in 2006 that will last 15 years, as detailed in the Draft Plan (Appendix 1) and summarised below. The license period will be divided into four phases, each with work obligations as follows.

First phase	15 May 2006 to 14 May 2009	- seismic data acquisition
Second phase	15 May 2009 to 14 May 2011	- at least one exploration well
Third phase	15 May 2011 to 14 May 2016	- at least one exploration well
Fourth phase	15 May 2016 to 14 May 2021	- to be agreed with the Minister

In the first phase, the licensee must undertake a work programme that shall generally include 3D seismic data acquisition to cover an area equivalent to at least 50% of the licence (unless 3D already exists). Where exploration drilling is not included in the first phase, planning for drilling in the second phase should take place and be proposed prior to the start of the second phase. The third phase should include a proposal to drill a further exploration well. Licensees will be required to undertake reasonable site-specific environmental studies as may be appropriate to the work programmes. The Licensing Terms for Offshore Oil and Gas Exploration and Development, 1992 will apply to licences granted under the Round (see Section 3). The IOSEA1 covers the first and second phases only, ie the period 2006 to 2011. It is proposed that subsequent phases and licensing rounds for exploration in this area will be the subject of further SEA at a future date.

4.2 Scenario and assumptions for Draft Plan

The scenario being considered for the range in activity levels following licensing awards comprises the undertaking of 2D seismic data gathering in 2006 to 2007, 3D data gathering in 2008 to 2010, exploratory drilling 2008 to 2011, and appraisal drilling over the period 2009 to 2011. Although IOSEA1 is an assessment of exploration activities only, recognition of the possibility that a proportion of the exploration may ultimately result in development drilling taking place is also made. Estimates for minimum and maximum levels of each activity have been made by the PAD on the basis of experience are shown in Table 4.1. These are consistent with the levels of interest actually shown in the applications received by the PAD since the commencement of this SEA.

These activities will take place alongside pre-existing exploration programmes planned as a result of previous licensing rounds. For the purposes of assessment of cumulative impacts, activity levels for these pre-existing programmes have also been forecast by the PAD and shown in Table 4.2.

Table 4.1 New Exploration activities (and potential development activity) forecast in the IOSEA1 area from Slyne, Erris and Donegal Basins licensing round between 2006 and 2011

Type of activity	2006		2007		2008		2009		2010		2011	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
2D seismic survey (km)	-	1,500	-	1,000	-	-	-	-	-	-	-	-
3D seismic survey (km ²)	-	-	-	-	-	1,000	500	3,000	500	3,000	-	-
Exploration drilling (numbers of wells)	-	-	-	-	1	2	1	2	1	2	1	2
Appraisal drilling (numbers of wells)	-	-	-	-	-	-	-	2	1	2	1	2
Development drilling (numbers of wells)	-	-	-	-	-	-	-	1	-	2	-	2

Table 4.2 Exploration activities forecast in the IOSEA1 area from pre-existing licensing rounds between 2006 and 2011

Type of activity	2006		2007		2008		2009		2010		2011	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
2D seismic survey (km)	1,000	1,500	1,000	2,000	-	-	-	-	-	-	-	-
3D seismic survey (km ²)	500	1,600	500	1,500	-	-	-	-	-	-	-	-
Exploration drilling (numbers of wells)	1	1	1	3	1	3	1	1	1	1	1	1
Appraisal drilling (numbers of wells)	-	-	-	1	-	1	1	2	-	2	-	2
Development drilling (numbers of wells)	3	4	3	4	-	3	-	2	-	1	-	1

4.3 Alternatives

The SEA Directive requires that the environmental report identifies and evaluates reasonable alternative strategies to the proposed plan.

In terms of Ireland's total energy requirements, there are very few indigenous resources and these provide only a small fraction of the overall requirement. Ireland has no indigenous oil, and only about 15% of its gas requirement comes from indigenous sources, ie the Kinsale field in the Celtic Sea. As highlighted in Section 1.3.2, one of the recommendations to Ireland from the International Energy Agency is that Ireland should develop a long-term strategy for an optimal energy mix striking an appropriate balance between energy security and climate change mitigation, noting a rapidly growing share of natural gas in the electricity sector (IEA, 2003). A recent European green paper on energy set a target of 10% of the Community's requirement from alternative energy sources by the year 2012 (European Commission, 2001). A crucial factor in the outlook for Irish energy policy is the fact that the UK, which has to date been Ireland's source of imported gas requirements, is now becoming a net importer of gas. In the medium to long term Ireland will either have to develop its own sources or find new sources, probably in Eastern Europe. This brings issues of security of supply and price stability or volatility.

As a means of testing or assessing Ireland's offshore hydrocarbon reserves, there is no realistic alternative to the exploration activity proposed in the Draft Plan. However, alternatives within the Draft Plan to offer blocks for seismic data acquisition and exploration drilling in the Frontier Exploration Licensing Round 2006 have been identified as:

- 1) to proceed with the offer, subject to licensing and/or drilling conditions which may derive from the SEA process;
- 2) to restrict the area in terms of time or size;
- 3) to postpone the offer for licensing in the Slyne, Erris and Donegal Basins.

4.4 Description of exploration scenario

This section provides a general description of the seismic and drilling operations likely to be used to undertake these activities.

4.4.1 Seismic surveys

Offshore seismic surveys are conducted by a vessel towing acoustic sound sources (air guns) that release pulses of compressed air into the water column. The air guns are towed 5 to 10 m below the sea surface and will release a bubble of compressed air at intervals of 10 to 20 s, equivalent to a spacing of approximately 12 m on the sea bed. Air guns produce loud impulsive low frequency sounds at regular intervals which are usually around 226 dB for a single air gun or 242 to 252 dB for an array.

The generated sound waves travel to the sea bottom, both penetrating and reflecting off the sea bed itself and successively deeper rock strata beneath (Figure 4.1). The reflected signals are detected by hydrophones towed in streamers behind the survey vessel. Each streamer is constructed in sections comprising a central core containing the electronics, surrounded by a layer of cable oil (a light

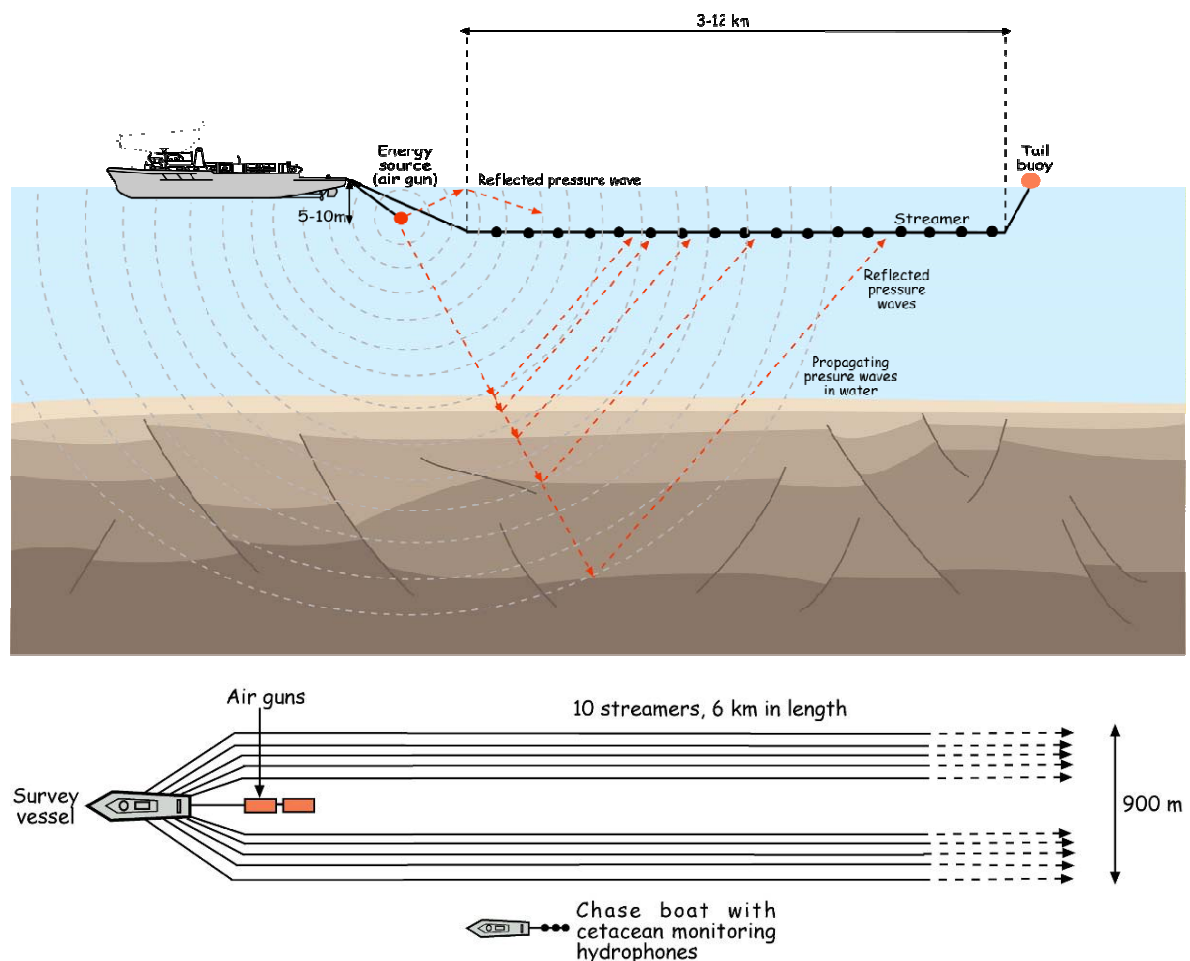
kerosene-type oil), and enclosed in a durable outer skin. The streamer is towed at 5 or 6 m depth behind the noise source, and has a tail buoy attached which locates the furthest extent of the towed array behind the survey ship (Figure 4.1). The reflected signals picked up by the hydrophones are recorded and processed by geo-physicists and geologists using computer software to create either a 2D vertical section or a 3D picture of the seabed and underlying geological formations.

A 3D seismic survey is basically derived from a dense grid of 2D survey lines. However, the way in which it is processed and interpreted is different from that of 2D data. If enough closely-spaced seismic survey lines are sailed, the data can be used to create a 3D image of the subsurface rock by layering the 2D cross-section images side by side. This difference enables practitioners to take the data from linear (2D) to volume (3D) information. In 3D surveys, the subsurface is closely sampled in every direction, leaving no open loops or gaps in the structure or stratigraphy when it is analysed.

The greatest advantage of 3D data is that it provides the ability to map the subsurface more completely, allowing the interpreter to fill in the 'gaps' that are inherent in 2D data. Other advantages of 3D over 2D stem from the greater density of data points, leading to more accurate positioning of drilling targets through improved horizontal and vertical resolution, and a choice of viewing perspective in the software-generated 3D models.

In 2D seismic surveys, one streamer with a length of 3 to 12 km is used. In 3D seismic surveys, many parallel traverses must be carried out, and it is therefore more efficient to collect swathes of data by towing six to twelve streamers, each separated by approximately 100 m from its neighbours. Ensuring that a large number of streamers remain straight and parallel to each other is difficult and 3D survey vessels rarely tow streamers that are longer than 3 km.

Figure 4.1 Typical seismic survey set-up



Normally, a seismic survey vessel travels at approximately 4.5 to 5.5 knots, or around 10 km/hour (Turnpenney & Nedwell, 1994).

Thick basalt formations have been found north of the IOSEA1 area in the UK west of Shetland province. Basalt structures tend to be opaque to traditional surface-towed seismic arrays, and if basalt layers are likely to be encountered, a different survey system making use of multiple geophones and hydrophones arranged along cables deployed on the seabed. These benthic arrays are either towed along behind the vessel (dragged array), or lifted and replaced in a new location as the survey progresses. Such surveys normally involve two vessels, one attached to and processing the data from the sensors, and one from which the source is deployed. Multi-component systems are considered to be better at penetrating basalt structures which are opaque to traditional towed seismic survey techniques. However, this method of hydrophone deployment is presently uncommon in deep water and not usually used in initial seismic surveys (DTI, 2000), in addition to which basalt formations are not thought to be present in the IOSEA1 area (see Section 5 and Technical Annex to this report).

Seismic scenario assumptions

The seismic survey effort estimated by the PAD (Table 4.1) for the IOSEA1 area amounts to a likely maximum of 2,500 km of 2D and 7,000 km² of 3D survey. In terms of ship time at sea this amounts to approximately 100 days vessel time for 2D seismic over the period 2006 to 2007, and 250 days vessel time for 3D seismic over the period 2008 to 2010 (based on the experience of the PAD and ERT).

For the purposes of impact assessment for shipping activity and fuel use in later report sections, this amounts to 350 days ship time over 5 years (including weather downtime and other delays), or approximately 70 days per year on average. The shipping requirements of this proposed level of activity would probably be met by one or two vessels working over the IOSEA1 area during the summer months each year, with operators clubbing together or 'piggybacking' surveys together in order to achieve economies in vessel hire (PAD, pers comm.). In the absence of fuel consumption data specific to seismic survey vessels, a figure of 15 tonnes diesel per day has been used, which is roughly midway between that for a large tug or anchor handling vessel (ERT, unpublished information). This information is summarised in Table 4.3, and estimates for survey ship activity and fuel use for pre-existing exploration activity from previous licensing rounds is shown in Table 4.4.

Table 4.3 Seismic survey vessel activity and fuel use in the IOSEA1 area from Slyne, Erris and Donegal Basins licensing round between 2006 and 2010

Time span of activity	Coverage	Ship time (days)*	Fuel use at 15 tonnes/day
2D 2006 to 2007	2,500 km	~100	1,500
3D 2008 to 2010	7,000 km ²	~250	3,750
Total		~350 days over 5 years, or 70 days/year	5,250 tonnes or 1,050 tonnes/year

* Based on survey rate of 25 km/day for 2D and 30 km²/day for 3D (including weather downtime and other delays).

Table 4.4 Seismic survey vessel activity and fuel use in the IOSEA1 area from previous licensing rounds between 2006 and 2010

Time span of activity	Coverage	Ship time (days)*	Fuel use at 15 tonnes/day
2D 2006 to 2007	3,500 km	~150	2,250
3D 2006 to 2007	3,100 km ²	~100	1,500
Total		~250 days over 2 years, or 125 days/year	3,750 tonnes or 750 tonnes/year

* Based on survey rate of 25 km/day for 2D and 30 km²/day for 3D (including weather downtime and other delays).

4.4.2 Exploration drilling

The location of the IOSEA1 area requires specialised drilling equipment able to cope with the deep water and harsh weather conditions of the Atlantic Ocean. The two main options available for drilling operations under these circumstances are a semi-submersible drilling rig or a drill ship. Alternatively, the shallower waters in part of the Donegal Basin could potentially be drilled using a jack-up rig. Whilst jack-up rigs used to be limited to drilling in water depths of 90 m or less, there are now several 'ultraharsh-environment jack-up rigs' operating in the North Sea which are capable of operating in water depths of up to 150 m (Smidth & Wulf, 2005).

Semi-submersible drilling rig

A semi-submersible drilling rig, or semi-sub (Figure 4.2), is a drilling unit which is usually supported on two parallel submersible hulls that are streamlined like a ship. The hulls carry columns extending above the sea surface which between them support the main deck, superstructure and drilling rig.

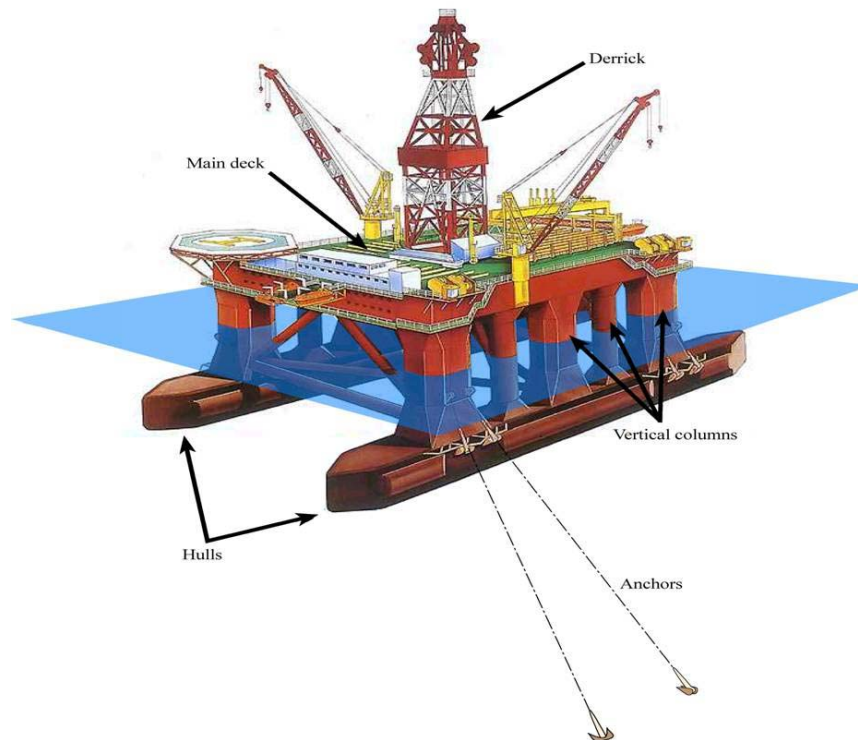
When the lower hulls are flooded they provide ballast to cause the rig to partially submerge. In this half submerged state, the rig becomes a stable work platform and is far less susceptible to wave motion, particularly rolling and pitching, than when de-ballasted and floating on the sea surface.

Typically eight to twelve anchor lines are set at various points around the rig to keep it in position. In deeper water the anchor spread radius might extend to a few kilometres from the drilling location, with a couple of hundred metres of anchor chain resting on the sea bed.

Additionally, several thrusters (or propellers) are mounted around the base of the drilling rig. Controlled by a computer that determines the exact position of the drilling rig relative to the well, the thrusters are automatically actuated as necessary to maintain the rig precisely on station.

Although this kind of drilling rig is usually capable of self propulsion, they are usually towed into position. Once in place, anchor handling vessels (usually the same vessels as the tugs) place the anchors in position in order to secure the rig at the exact drilling location.

Figure 4.2 A typical semi-submersible drilling rig



Drill ship

Modern drill ships are purpose-built, featuring all the equipment normally found on board any conventional drilling rig. The main advantage of a drill ship over a semi-submersible platform is that it can sail to and from the drilling location unassisted. Generally, modern drill ships are equipped with a dynamic positioning (DP) system by which the vessel's position can be maintained over a well site using a number of automatically actuated thrusters, and therefore they do not depend on anchors to keep them in position.

Drilling operations

Typically the first step in the sequence of drilling activities is to drill a top hole section into the sea bed into which the conductor pipe is cemented, following which the well is drilled in successively smaller diameter sections until the hydrocarbon-bearing formation is reached. Once each well section is drilled, steel casing of appropriate diameter is inserted and cemented into place in order to provide stability and a barrier between the wellbore and surrounding formations. In addition the casing

provides a firm anchorage for the blow out preventer (BOP) stack and structural integrity for subsequent drilling, testing and possible future production operations. Once the BOP is in place the marine riser, a large-diameter pipe that connects the BOP stack to the drilling rig, is installed.

The use of drilling fluid, also known as drilling mud, is intrinsic to all drilling operations. Drilling mud assists in a number of functions such as lubrication and cooling of the drilling bit, suspension and transport of rock cuttings to the surface and, most importantly, the provision of hydrostatic pressure to counterbalance formation pressure. Drilling mud consists of a liquid mixture of clay, water or oil, and other chemical additives. The most commonly used drilling fluids contain water as the fluid continuous phase, and are known as water based muds (WBMs). However, certain borehole conditions might require a mud formulation where the continuous phase is oil or a synthetic fluid and these are known as oil based muds (OBMs) or synthetic based muds (SBMs).

The mud is pumped down the drill stem to the drill bit, and then circulated back to the surface via the annulus (the space between the drill stem and the wall of the bore hole) and through the BOP stack and the marine riser back to the drilling rig or ship. Back onboard, these muds and cuttings pass through a mud recovery system where part of the drilling mud is recovered. Once reconditioned, this mud is often used again. However, the cuttings must be disposed of, together with any adhering mud and chemicals not removed by the cleaning system, and for this process three main alternatives are on offer:

- Overboard discharge.
- 'Skip-and-ship' ie to send the cuttings back to a shore facility for cleaning and landfill.
- Cuttings re-injection.

When using WBM the rock cuttings, and any mud remaining at the end of drilling, are usually discharged to the sea. Under the OSPAR Decision 2000/3 the discharge into the sea of cuttings contaminated with oil based fluids at a concentration greater than 1% by weight on dry cuttings is prohibited. This option is therefore not available for oil-contaminated cuttings unless they can be cleaned offshore to meet these requirements. Although certain pilot projects are currently running in the North Sea, this option is not yet considered to be achievable in general industry practice. A more common approach for oil-contaminated cuttings is to ship them to shore where they can be cleaned and re-cycled as, for example, road aggregate, or put into landfill. Cuttings re-injection (CRI) is another disposal option, useful for contaminated cuttings, where drill cuttings are mixed into a slurry with water and pumped at high pressure down a separate injection well. CRI is slowly becoming more widespread in mature oil development areas where there are enough potential injection wells available.

The top hole section of the well has to be drilled without the conductor and BOP in place, and thus with no riser from the seabed to the drilling platform. This means that all drilling fluids, rock cuttings, and cement returns from the top section are discharged directly from the top of the well onto the sea bed. Once the marine riser is in place, the drill fluids and cuttings can be circulated from the well back up to the drilling rig where they will be treated so that the drilling mud can be re-used and the cuttings disposed off appropriately as described above.

Cementing operations

The steel casings that are run into each of the well sections will be cemented into place. When setting the conductor it is normal practice to use a certain amount of excess cement. To minimise the amount of cement being discharged it is considered good practice to have a remotely operated vehicle (ROV) present at the wellhead to observe the cement returns.

Excess cement from the deeper sections is circulated back to the drilling rig or ship through the marine riser, and treated in the same way as the cuttings (ie cleaned and discharged overboard).

Well testing

If hydrocarbons are found, a well test may be required to establish the well performance and well characteristics.

The most conventional well test method involves flowing or producing the reservoir fluids, up to the drilling unit, where they are flared off. Whilst producing the well at different flow rates, a comprehensive evaluation of the well and certain reservoir characteristics can be made which will help in evaluating whether the reservoir could be exploited commercially in the future.

Alternatively a closed chamber well test can be carried out under certain circumstances. During a closed chamber well test, the well bore itself is used to store the produced fluids whilst pressure build-up in the well bore and flow are measured downhole. After the test the oil sample of

approximately 20 to 30 barrels of oil is circulated to the surface, collected into containers/tote tanks and shipped to shore for analysis and disposal of interfaces. Although not as comprehensive as a conventional well test, the data obtained, combined with log and seismic data can, in some cases, provide sufficient information to decide if any future development of the well would be viable.

Well abandonment/suspension

Depending on operational issues and the hydrocarbon reserves found, an exploration well can either be abandoned or suspended.

In case of abandonment, mechanical and cement plugs are placed along the well, plugging off all points where hydrocarbons can possibly enter the wellbore. The casing will then be mechanically cut and recovered from below the seabed.

If further development of the well in the near future might be an option, then the well may be suspended. If this is the case, the well will be left intact and a series of mechanical and/or cement plugs will be placed inside the well to prevent the escape of hydrocarbons. The conductor and casings will be sealed and left protruding approximately 1.8 m (6 ft) above the seabed.

Drilling scenario assumptions

Under the maximum drilling activity scenario in Table 4.1, a maximum of 19 wells may be drilled over the period 2006 to 2011 (4 to 8 exploration wells, 2 to 6 appraisal wells, 0 to 5 development wells), which works out as just over three wells per year over the six year period. In addition, however, the pre-existing maximum drilling activity (Table 4.2) likely to take place from previous licensing rounds could involve the drilling of up to 33 wells (6 to 10 exploration wells, 1 to 8 appraisal wells, 6 to 15 development wells). At the maximum anticipated rate over the period 2006 to 2011, this would average out at between five and six wells per year.

For the purposes of impact assessment for drilling activities, certain assumptions will need to be made such as the length of time taken to drill a well, the fuel used by the drill rig and associated shipping and the likelihood of a well test being needed. These assumptions are made on a conservative basis, and are summarised in Table 4.5.

Table 4.5 Exploration drilling activity and fuel use in the IOSEA1 area from Slyne, Erris and Donegal Basin licensing round between 2006 and 2010 (source: ERT unpublished data)

Vessel type	Time span (days)	Fuel consumption	Fuel used (tonnes)
Drilling rig (semi-sub type)	50	20 tonnes/day	1,000
Large tug	14	25 tonnes/day	350
Anchor handlers	4	25 tonnes/day	100
Standby/safety vessel	50	3 tonnes/day	150
Supply vessel	21	8 tonnes/day	168
Helicopter	9 h/week for 7 weeks	1,050 lbs/hr	30
Well test (for 50% of wells drilled)	2	-	2 million m ³ per well

If hydrocarbons are found (including finds that turn out to be small non-commercial quantities), then a well test may be required to evaluate the potential reserves which will involve producing the hydrocarbon concerned (most likely to be gas) to the surface over a period of 48 hours. In the absence of any production facilities, the produced gas will have to be flared off. The quantity of gas flared in this way is typically in the region of 2 million m³. In previous exploration drilling in the area, well tests have been undertaken for in less than 25% of the wells drilled (PAD, 2006a). However, since the scenario for the Draft Plan includes provision for appraisal and some development drilling, an overall well testing rate of 50% will be assumed, leading to 1.5 well tests per year based on activity arising from the Draft Plan, plus up to three well tests per year for activity coming out of previous licensing rounds. It will also be assumed that the unsuccessful wells will be suspended rather than abandoned.