UK OFFSHORE OPERATORS ASSOCIATION LIMITED
(SURVEYING & POSITIONING COMMITTEE)

Guidelines for

CONDUCT OF MOBILE DRILLING RIG SITE SURVEYS

Volume 2

Issue 1

While Regulations clearly establish a requirement for rig site surveys be undertaken, the survey methods described in these guidelines are not mandatory. Operators may adopt different methods in particular situations where to do so would maintain an equivalent standard of quality and of Health, Safety and Environmental protection.

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Contents

Introduction

The Offshore Installations (Safety Case) Regulations 1992 require owners of mobile installations in the UKCS to submit a Safety Case for each installation. The Case must include particulars of (a) the limits of the environmental conditions beyond which the installation cannot be safely stationed or operated and (b) the properties of the seabed and subsoil which are necessary for the safe stationing and operation of the installation. The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 require well operators to assess (a) the geological strata and any fluids within them and (b) any hazards which the strata may contain. A rig site survey is required by the well operator to adequately assess the hazards of shallow formations and for the rig owner to demonstrate that the environment and seabed conditions are suitable for the rig.

These Guidelines aim to clarify current (March 1997) regulatory requirements and describe what is regarded as "good industry practice" for the conduct of rig site surveys in support of mobile drilling rig operations. As a more formally mandated UKOOA document, they are an update and take the place of the **"Technical Notes for the Conduct of Mobile Drilling Rig Site Surveys"** issued in 1990.

Volume 1 of the UKOOA Guidelines for the Conduct of Mobile Drilling Rig Site Surveys summarises objectives and requirements for such surveys. *Volume 2* describes in greater detail, the basis for the requirements, and the technical standards and methods required to fulfil them. It is recognised that the guidelines will need to be revised as new equipment and techniques become available.

It is not intended that these Guidelines are a text book on geophysics or geodetic positioning. Literature on these subjects is abundant and a selection is given in the References and Bibliography Section of this *Volume (Section I).*

While regulations clearly establish a requirement for rig site surveys to be undertaken, the survey methods described in these guidelines are not mandatory. Operators may adopt different methods in particular situations where to do so would maintain an equivalent standard of quality and of Health, Safety and Environmental protection.

It is stressed that it is the responsibility of Operators themselves to keep abreast of Legislation, Regulations, Statutory Instruments and Departmental Notices, as well as local government laws and bye-laws.

SECTION A summarises existing **Legislation, Regulations and Guidelines** relevant for UKCS rig site survey operations.

SECTION B briefly describes the principles of **rig site surveys and the Interpretation and Reporting** of the acquired data. This Section includes prompts to aid the planning and communication elements to ensure maximum benefit from such site surveys. Guidelines are provided for retention and validity of survey data.

SECTION C provides a brief but comprehensive guide to the **Geophysical Considerations** which will determine optimum acquisition techniques and equipment for the seismic element of rig site surveys. It is the seismic element which provides information for prediction of potential drilling hazards and constraints and the study of variation in shallow soil conditions.

SECTION D describes the principles which should be considered when specifying or proposing **Positioning** systems for use in rig site surveys.

SECTION E provides a detailed overview of the **Survey Equipment** which may be encountered on rig site surveys. The selection of appropriate instrumentation is essential to ensuring adequate data is acquired to meet the survey objectives.

SECTION F provides a detailed summary of **Data Processing,** which is an important element in ensuring that acquired data is presented for analysis in the best possible format, to achieve its full potential.

SECTION G summarises the **Statutory Record and Sample Requirements** for rig site survey data.

SECTION H provides an explanation of **Abbreviations** and **Units** which feature in these Guidelines and are in common use in UKCS rig site survey operations.

SECTION I is a list of **Reference Bibliography** used in the Guidelines or of direct relevance to UKCS rig site survey operations.

Definitions

For the purposes of these Guidelines, the following terms and meanings apply:

Operator - is the person or company having a valid UK Government Licence to explore for and/or produce hydrocarbons in a defined area of the UKCS and who is responsible for specifying the drilling requirements. Current legislation defines this person or company as the "Concession Holder".

Rig Owner or **Owner** - is the person or company who controls the operation of the rig.

Survey Contractor or **Contractor -** is the company contracted by the Operator or the Rig Owner to conduct geophysical, hydrographic and/or geotechnical investigations at a proposed drilling location.

Specialist Advisor or **Specialist** - is a qualified and experienced geophysicist, hydrographic surveyor or geotechnical engineer, as appropriate to the technical context of the subject in question.

It should noted that within the Regulations quoted within the introductory paragraph, there are various definitions of “operator” which are not the same as listed above. These only strictly apply to the Regulations in which they are stated. To minimise confusion, the definitions are reproduced below as they emphasise the separate duties of the rig owner for which a site survey is required.

Operator (Safety Case) - in relation to a mobile installation means the person for whom the owner has agreed to carry out the operation concerned, or where there is no such agreement, the owner.

Well Operator (Design and Construction) - in relation to a well means the person appointed by the concession owner for a well to execute the function of organising and supervising all operations to be carried out by means of such well or, where no such person has been appointed, the concession owner.

Section A - Existing Legislation, Regulations & Guidelines

Offshore site surveys on the UKCS should be undertaken within the confines of the following legislation, regulations and guidelines. Relevant excerpts are included.

A.1 Legislation and Regulations

A.1.1 Coast Protection Act, 1949

"An Act .... to provide for the restriction and removal of works detrimental to navigation."

Part 2 (as amended)

At Section 34(1) the consent of the Secretary of State (for Transport) is required for the construction, alteration, or improvement of works on the seashore that may cause an obstruction or danger to navigation.

Section 34(2) - "The [Secretary of State] may as a condition of considering the application for consent under this section, require to be furnished with such plans and particulars of the proposed operation as he may consider necessary."

A.1.2 Continental Shelf Act, 1964

Section 4(1) of this Act extends the provisions of Part 2 of the Coast Protection Act to "any part of the seabed in the designated area". From the guidance notes issued by the Department of Transport this in effect covers all parts of the UKCS where oil and gas exploration and development is taking place.

A.1.3 Minerals Workings (Offshore Installations) Act, 1971

“An Act to provide for the safety, health and welfare of persons on installations concerned with the underwater exploitation and exploration of mineral resources in the waters in or surrounding the United Kingdom, and generally for the safety of such installations and the prevention of accidents on or near them.”

As regards the need for site surveys, the requirements have now been repealed.

A.1.4 Petroleum and Submarine Pipelines Act, 1975

Schedule 2, Model Clause 17 provides for the consent to drill requirements as set out in the Department of Trade and Industry (DTI) PON 4.

A.1.5 The Health and Safety at Work Act, 1974 (HSWA)

This is an enabling act which imposes extra general duties on employers whilst still requiring them to comply with all current legislation which is relevant to their particular business.

Under the Act, employers of staff have a statutory responsibility to provide a safe place of work, and employees are required to take reasonable care in their work activities, and to co-operate with their employers.

A.1.6 Offshore Safety Act, 1992

This Act brought existing offshore legislation within the scope of the HSWA. It also made provision for the formulation of new goal setting (rather than prescriptive) regulations which would implement specific Cullen recommendations including revocation or reform of outdated regulations.

A.1.7 Petroleum Act (Production) (Seaward Areas) Regulations, 1988, No. 1213 (as amended)*

"The Licensee shall execute all operations in or in connection with the licensed area in a proper and workmanlike manner in accordance with methods and practices used in good oilfield practice."

Also, Schedule 4, Model Clauses 31 and 33 lay out the requirements to keep specific records and samples (as detailed in DTI PON 9).

(* SI 1990/1332; SI 1992/2378; SI 1995/1435)

A.1.8 The Offshore Installations (Safety Case) Regulations, SI 1992, No. 2885

Reg. 5 - 'The owner of a mobile installation shall ensure that the installation is not moved in relevant waters with a view to its being operated there unless:

a) he has prepared a safety case containing the particulars specified in Reg. 8 and Sch. 3.'

Schedule 3 - 'Particulars to be included in a safety case for a mobile installation:

b) the properties of the seabed and subsoil which are necessary for the safe stationing and operation of the installation;

c) the locations in which the installation may be stationed and operated safely,

Reg. 11(2) - "The Operator of a mobile installation shall ensure that the carrying out of any operation in relation to a well or proposed well from the installation is not commenced unless at least 21 days before its commencement he has sent the Executive a notification containing particulars specified in Schedule 6."*

Schedule 6 - "Particulars to be included in Notification of Well Operations

Where operations in relation to a well are to be carried out from a mobile installation, particulars of:-

a) the meteorological and oceanographic conditions to which the installation may forseeably be subjected;

b) the depth of water;

c) properties of the seabed and subsoil;

at the location at which operations will be carried out."

A.1.9 The Offshore Installations and Wells (Design and Construction, etc.) Regulations, SI 1996, No 913

The Offshore Installation Design and Construction Regulations (DCR) came into effect on the 30th of June, 1996 and are part of the new regulatory regime for offshore safety cases, the formal notification of well operations and follow-up inspections and audits. With regard to well operations, the DCR requires the duty holder to guarantee the integrity of a well throughout its life. This will involve a full assessment of the subsurface conditions before the well is designed, accurate forecasts of the geological sequence and pressure conditions, identification of all subsurface hazards and the formulation of contingency plans to deal effectively with a well control incident.

A.1.10 Application for Consent to Drill Exploration, Appraisal and Development Wells. DTI PON 4, May 1996.

“Applications for consent to drill should normally be submitted, by the licence Operator, to the address above, **not less than 21 calendar days** prior to expected start of operations.”

“The following sections describe the information about the proposed well which should comprise the application:-

7. Shallow Hazards and Hydrogen Sulphide

    a) It should be clearly indicated if there is a possibility of shallow gas at the drilling site. A brief summary of the site survey should be included.”

A.1.11 Record and Sample Requirements for Surveys and Wells. DTI PON 9, May 1996

This Notice applies to **all** wells; Exploration, Appraisal, and Development, in both Landward and Seaward areas.

Section 2 and 3 of this notice set out guidelines which indicate the type of information that should be recorded, the detail which is required and the format in which it should be presented. Section 4 lists the type and minimum amounts of samples that are required. Section 7 indicates where the records and samples should be sent.”

Only if requested, the following data shall be supplied within 30 days of the request.

Section 2.3 - "Site Survey Data (if requested)

(i) One reproducible transparency of each final processed seismic section together with a reproducible transparency of the shot point location map at a suitable scale.

(ii) Where acquired copies of side scan sonar records with their track charts.

(iii) If available a copy of the final interpretation report of the seabed/superficial deposits investigation of drilling locations or installation sites.

These data comprise the detailed record of the survey and are not the results asked for by PON 4 Section 7 concerning shallow gas.

Section 4.2 - "Samples from the Seabed"

Portions of seabed samples and/or cores from boreholes penetrating below the seabed if acquired.

A.1.12 Notification of Geophysical Surveys. DTI PON 14, May 1996

"Section 2 of PON 9 states the DTI's requirements. However, other Government Departments need to be notified and, in certain cases, other interested parties consulted, prior to geophysical surveys, including sea floor surveys for platform or rig sites, being undertaken."

"The DTI .... has the duty to ensure as far as possible that all Departments concerned and BT are given at least 28 days written notice of intended surveys."

"It should be noted that in the case of Site Surveys, while 28 days is desirable, shorter notice is acceptable with a minimum of 14 days."

A.1.13 Liaison with other bodies. HSE, Offshore Operations Division. Operations Notice 3, February 1995

Section 5 - "Operators should maintain close relations at all times with the local officers of the fisheries' departments and for operations within Territorial waters with the appropriate Sea Fisheries Committee. This will enable operations to be planned and avoid interfering unnecessarily with seasonal or intensive fishing activities."

Section 6 - "At least 14 days notice of all seismic activities should be given to the submarine Controller, HMS Warrior, Northwood, Middlesex HA6 3NP so that the necessary warning notices may be issued."

A.2 Guidelines

A.2.1 Seabed and Subseabed Data Required for Approvals of Self Elevating Platforms. Noble Denton International Ltd, 1987

"The purpose of the site survey is to provide data with which to evaluate potential foundation hazards."(Section 1.3)

"The seabed surface shall be surveyed using side scan sonar techniques and shall be of sufficient competency to identify obstructions and seabed features and should cover the immediate area of the intended location." (Section 2.4.1)

"A shallow seismic survey should be performed over a 1 kilometre square area centred on the location. Line spacing of the survey should typically be not greater than 100 metres by 250 metres over the survey area. Equipment should be capable of giving detailed data to a depth equal to the greater of 30 metres or the anticipated footing penetration plus one footing diameter." (Section 2.5.1)

"The shallow seismic survey shall be interpreted by the competent persons who were responsible for performing the work. Every effort should be made in the interpretation to comment on the soil type(s) and strength(s); this will require correlation (by means of a tie line) with a borehole in the vicinity and some degree of local experience". (Section 2.5.2)

A.2.2 Guidelines and Recommended Practice for the Site Specific Assessment of Mobile Jack-up Rigs. American Society of Naval Architects and Marine Engineers, May 1994.

In the Recommended Practice document, Sections 3.11 to 3.15, covering the site survey aspects, reference is made to the original 1990 UKOOA "Technical Notes for the Conduct of Mobile Drilling Rig Site Surveys". The Technical Notes provides the basis for recommended survey practice. These Guidelines supersede the Technical Notes.

"Site specific geotechnical information must be obtained .... such information may include shallow seismic survey, coring data, cone-penetrometer tests, side-scan sonar, magnetometer survey....." (Section 2.4.1).

"The site should be evaluated for the presence of shallow gas deposits." (Section 2.4.2)

"At sites where there is any uncertainty [about shallow soils], corings and/or cone penetrometer tests (CPT) data are recommended. Alternatively the site may be tied-in to such data at another site by means of shallow seismic data." (Section 2.4.4).

"The site should be evaluated for potential scour problems........" (Section 2.4.5)

N.B. *Evaluation for potential scour is not an easy procedure and may require Specialist assistance.*

A.2.3 Guidelines for the Anchoring of Vessels in the Vicinity of UKCS Installations and Pipelines and their Subsea Equipment. UKOOA, December 1994.

"When an Operator undertakes a site survey prior to locating a vessel, it is recommended that this survey should also include location and verification of the position of any pipelines and other sub-sea installations in the vicinity of the intended location."

N.B. *Definition of 'in the vicinity' will depend upon the type of vessel which will be anchoring and the installation Operator requirements. It is recommended that* an area extending at least 1 km out from the proposed anchor spread is surveyed.

A.2.4 Guidelines for the Use of Differential GPS in Offshore Surveying. UKOOA, September 1994.

These Guidelines seek to provide guidance on quality standards in all aspects of the use of DGPS in seismic positioning from installations to minimum training standards for Operators.

Section 2 - Quality Measures

"Differential GPS has evolved as an attractive method of position fixing offshore. There has not existed, however, a standard set of quality measures to enable users of this technique to verify that required positioning standards are being met.

The aim of this section is to present a set of quality measures to the industry and to describe the ongoing statistical testing which must take place during processing if these measures are to be meaningful."

A.2.5 Environmental Guidelines for Exploration Operations in Near-Shore and Sensitive Areas, UKOOA, September 1995.

The aim of these Guidelines is to describe the best current industry environmental management practices which can be adopted by Operators in near-shore waters, without compromising safety or operational viability.

Section 3.1.2 - Preliminary Environmental Assessment - "In order to be fit for its purpose as an introduction to potential new acreage, the preliminary environmental assessment needs to be concise and focused, and will typically contain descriptions of the following [amongst others]:

- Hydrography and meteorology; bathymetry, salinity, etc.
- Other maritime activities: pipelines and cables, "

Section 3.3 - Provides guidelines on the possible environmental impact of seismic surveys including fishing and marine mammals.

Section 3.6 - Preparing an Oil Spill Recovery Contingency Plan - "Operators in near-shore areas need to pay particular attention to predicting the effects of local weather and hydrography on the movement of spilled oil."

Section 3.8 - Seabed Surveys - "Geotechnical surveys are required to confirm the seabed is suitable for location of a drilling rig."

Section 4.7- Seabed Clearance - "The Operator has a duty to ensure the seabed is clear of any debris after the operation is complete."

A.2.6 Guidelines for Minimising Acoustic Disturbance to Small Cetaceans. Department of Environment, February 1995. (See also, revised edition issued under the same title by the Joint Nature Conservation Committee (JNCC), February 1996).

These Guidelines reflect principles to be used by anyone planning marine operations that could cause acoustic and physical disturbance to Cetaceans (dolphins, etc.). The recommendations contained in the guidelines should assist in ensuring that cetaceans in areas of seismic activity are protected against possible injury. These guidelines are mandatory in relation to the two most recent Oil Licence Rounds.

A.2.7 Offshore installations: Guidance on design, construction and certification. Section 14, Site investigations. HSE (formally Department of Energy (DoE)). Fourth Edition (June 1990).

"This section provides guidance on site investigation and selection of design soil parameters for Installations supported by the seabed."

"Consideration should be given to very resolute geophysical surveying as an aid to initial site selection, understanding the soils distributions away from the borehole positions, and to detecting sub-surface anomalies such as shallow gas."

Section 14.5.5 - "Bathymetric and side-scan sonar surveys should provide detailed information on the seabed configuration including the presence of any features, such as slopes or obstructions, that would affect the siting of the structure."

"Geophysical surveys should generally be performed to help formulate requirements for sampling and testing at the site. Selection of high resolution profiling equipment should consider the various frequency responses and energy contents required to optimise recovery of sub-bottom information. Particular attention should be given to selection of appropriate equipment and procedures, as quality in data acquisition is sensitive to these factors."

Section 14.9 - Site investigations for Jack-up Installations - "If a similar jack-up has previously been installed at a site then the investigation can be limited to an inspection of the seabed. In other circumstances bathymetric, side-scan sonar and geophysical surveys should be performed."

A.2.8 Offshore installations: Guidance on design, construction and certification. Section 20, Foundations. HSE (formally DoE). Fourth Edition (June 1990).

Section 20.1 - "This section provides guidance on foundation design of installations intended to be supported on the seabed."

Section 20.5 - Foundations for Jack-up Installations - "This section applies to mobile jack-up installations engaged in normal exploration, drilling or other activities involving a limited period at a particular site."

Section 20.7 - Surveys (Foundations) - "NO TEXT" - no text written.

A.2.9 A guide to the Offshore Installations (Safety Case) Regulations 1992. Guidance on Regulations, HSE, L30, 1992.

The text of each regulation is given, followed by guidance. A concluding section sets out more detailed guidance on the preparation of safety cases as required under the regulations.

A.2.10 New Guidance on the Coast Protection Act - Consent to Locate and the Marking of Offshore Installations. HSE Offshore Safety Division (OSD), Operations Notice No. 14, February 1995.

Section 1.9 - Mobile Installations - " Applicants for consent to exploratory drilling are asked to specify the proposed location using precise co-ordinates. Alternatively, if an exact location cannot be specified for any reason, consent may be sought to drill in a precisely drawn area defined by co-ordinates in the same way. The Department will say at once .... if more specific information is required for any location."

A.2.11 Environmental Guidelines for Worldwide Geophysical Operations. IAGC, January 1994 (Under review, Jan. 1996)

Guidelines for the protection and conservation of the environment. Outlines good industry practice in a wide variety of conditions including marine operations.

"Members should conduct their geophysical operations in accordance with the IAGC Environmental Guidelines, as well as local, national, and international regulations. To meet these responsibilities, members should:

- Plan and conduct geophysical operations in a manner that conserves the environment.
- Train geophysical personnel in environmentally responsible procedures.
- Consult appropriate authorities .... and users of the area.
- Evaluate environmental performance and appropriate reclamation measures of geophysical operations."

A.2.12 Health, Safety and Environmental Schedules for Marine Geophysical Operations. E&P Forum. Report No. 6.34/206 July 1994.

"The Schedules A to F set out minimum Health, Safety and Environmental (HSE) standards for Marine Geophysical Operations, with attention placed on the management of HSE, and can be considered as guidelines of good industry practise."

A.2.13 Procedures Relating to the Notification of Vessels Intending to Anchor in the Vicinity of Pipelines or Other Subsea Installations. UKOOA Procedures Guide, agreed August 1986

"When a Contracting Operator undertakes a Site Survey prior to locating a Vessel, it is recommended that this survey should also include location and verification of the position of any pipelines or other Sub-sea Installations in the vicinity of the intended location."

N.B. *Definition of 'in the vicinity' will depend upon the type of vessel which will be anchoring and the installation Operator requirements. It is recommended that an area extending at least 1 km out from the proposed anchor spread is surveyed.*

Section B - Survey Planning, Interpretation & Reporting

There are two, equally important key objectives of rig site surveys. The first key objective is to provide information on seabed conditions to ensure the safe, secure and efficient emplacement of the mobile drilling rig onto the drilling location. The second key objective is the subsequent safety and efficiency of the initial drilling. Both of these objectives are usually combined in one integrated survey using a range of specialist equipment. The rationale behind the survey requirement is discussed in *Volume 1* of these Guidelines.

Figure 1 is a flowchart illustrating a basic sequence of events in the planning of a rig site survey *(reproduced from Figure 1 in Volume 1*). The following text expands on many of the stages and decision making elements of this sequence and cross-references relevant Sections within this Volume. Some sections include a sequence of bullet points which can be used as planning aids. *Figure 1* shows 22 weeks from the start of the planning cycle to the earliest spud date of the well. This should allow sufficient time to implement and obtain maximum benefit from a rig site survey. However, if surveys are undertaken too early, the validity of some rig site survey data may expire *(see Section 6 of Volume 1).* In addition, timing may be constrained by conditions of recent Oil Licence Rounds which may contain limit the time of year that seismic surveys can be undertaken.

Communication between the Operator and the Contractor and the transfer of information is an essential factor to ensure the survey satisfies all Operator and Statutory requirements.

B.1 Initial Planning

The preparation of a "Desk Study" is the first element of the sequence. In its simplest form it is a review of available relevant data. The aim of this study is to ensure that the site survey is planned correctly and efficiently and that maximum use is made of available data. The following prompts may aid this review:

- **How well defined** is the proposed drilling location? If there is any possibility of a change of surface location then any planned survey may need to be expanded to include alternative locations.
- Are there any specific exploration **licence requirements** for the proposed well location, such as a requirement for an environmental survey? Are there restrictions limiting the time of year that seismic surveys can be undertaken?
- Is there a **history** of shallow gas, lost circulation problems or other restrictions to drilling, in the top-hole section of nearby wells? A review of previous drilling reports may also indicate difficulties anchoring within specific soil types, ensuring adequate support for the drill guidebase, problems driving initial entry casing, leg penetration problems, and the presence of boulders or coarse aggregate within the shallow geological sequence.
- An examination of 2D and 3D **exploration seismic data** may indicate areas of concern such as potential shallow gas accumulations, faults and other structural elements, potential leakage paths for deep sourced overpressured gas, major glacial erosion and drainage patterns which can be expected to control the shallow soils distribution. In deep water surveys gas hydrates may affect the type of survey commissioned. This review can also be used to determine an optimum "dip-line" direction for the planning of survey line directions for the site survey. The review may also help to determine the areal extent for the planned site survey coverage both to ensure that potential problems are adequately surveyed and to define extended survey lines to set the survey area within a regional geological context.

- An examination of nearby **existing site survey** data and reports may indicate where problems can be expected. It may also help to determine optimum selection of survey instrumentation and techniques, and specific contractor expertise. Existing site survey data may also cover part or all of the prospective rig site. Seismic and geotechnical data should have a long-term validity provided the data is judged to be of sufficient quality. However, the need for a re-survey should be considered if there has been recent activity (man-made or environmental/geological) which would invalidate the data.
- **Published data** may aid in the selection of optimum survey instrumentation and techniques. The significant shallow soils variations on the UKCS are described by British Geological Survey (BGS) charts and publications. The potential for shallow gas occurrence has also been examined for certain UKCS areas in specialist publications *(Section I).*
- The **type of drilling rig** will determine the nature and areal extent of the site survey and the selection of optimum instrumentation. With jack-up drilling rigs the areal extent of the survey can be limited but there is a need for detailed shallow soils information including direct correlation with geotechnical data. With anchored semi-submersible rigs, the seabed survey usually covers the potential anchoring radius *(Section 9.4 of Volume 1).*
- For a **jack-up drilling** rig there may be a rig owner or insurer requirement for a geotechnical borehole. Ideally this should be scheduled just after the site survey data acquisition so that the borehole is acquired in an appropriate location and results can be integrated with the geophysical analysis. Such a borehole may be acquired from the jack-up at the location prior to pre-loading if local soil conditions are known to be acceptable. The results from an existing nearby geotechnical borehole may be sufficient to predict shallow soils conditions provided that it can be confidently demonstrated that the rig site is in the same shallow soils province as the borehole by mean of a reliable interpretation along a survey tie line. In harder seabed areas the use of a Piezocone Penetrometer Test (PCPT) system (preferred) or Cone Penetrometer Test (CPT) system may be sufficient and these can be undertaken as part of the geophysical site survey.
- A review of in-date **Admiralty Charts** should show existing infrastructure and other features such as wrecks, or telephone cables, which may influence the survey design and equipment selection. The presence of shipping lanes may also limit survey activities. Also the range of water depth within the survey area will dictate the selection of geophysical instrumentation and underwater positioning.
- Databases maintained by the **UK Hydrographic Office** can provide additional information to supplement the detail shown on Admiralty Charts for features such as wrecks, cables and suspended wellheads. Contact details are provided in *Section G.4*.
- Deep seismic exploration activity or engineering / installation **activity** within the local area of the proposed site survey can severely impede survey and the quality of the data acquired. Careful scheduling of survey activity is required.
- The shallow gas seismic data may be used or extended to **aid deeper seismic** exploration studies or unexplained features.

ACTIVITY	CONSIDERATIONS	MAXIMUM ELAPSED TIME TO UNDERTAKE ACTIVITY
DESK STUDY	* Review existing data - seismic 2D (& 3D if available) - previous site surveys - previous wells - previous soil borings - geological data * Shallow gas/top-hole drilling history * Is well location covered by valid sonar survey ? * Specific exploration licence requirements (eg. environmental survey) * Existing seabed facilities (pipelines/cables) * Admiralty Charts (wrecks etc)	
IS SITE SURVEY REQUIRED? (NO / YES)	* Dependent on results of desk study, Operator's policy, HSE requirements, rig owner/insurer requirements	
STATUTORY NOTIFICATIONS	* PON 14 requirement (ex CSON 35)	Preferred 28 days Minimum 14 days
SURVEY PLANNING	* Jack-up or semi-submersible rig * Vessel & availability * Work scope - survey area - line plan, spacing, orientation * Specification of equipment & operational parameters * Metocean/environmental surveys * Soil sampling * Tie-line(s) to nearby wells/soils borings * Positioning requirements - surface - subsurface	4 weeks (Longer in winter)
DETAILED QC: DATA ACQUISITION	* Safety * Quality Control	
DATA PROCESSING, INTERPRETATION & REPORTING	* Integration of results with existing data * Quality Control * Top-hole hazard analysis (shallow gas, etc) - post-stack - pre-stack (if necessary)	4 weeks
IS SOIL BORING REQUIRED? (YES / NO)	* Dependent on results of desk study and geophysical survey, operator's policy, rig owner/insurance requirements, HSE requirements	
UNDERTAKE SOIL BORING	* Geotechnical Specialist advice	Allow an additional 2 months
WELL PLANNING	* Use site survey results to : - identify potential top-hole drilling hazards - plan casing design - identify seabed obstructions - provide information on anchoring conditions (semi-sub) and spud can penetration/footing conditions/scour potential for jack-up - confirm water depths & seabed topography	4 weeks
DATA ARCHIVING	* PON 9 requirement (ex CSON 41)	
CONSENT TO DRILL	* PON 4 requirement (ex CSON 11)	minimum 21 days
NOTIFICATION OF WELL OPERATIONS	*Regulation 11, Offshore Installations (Safety Case) Regulations, SI1992	
SPUD WELL		

B.2 Initial Notifications

As discussed in *Section A.1.12,* the DTI require notification of any intended marine site survey by means of the form in PON 14. The DTI request that these notifications should be submitted 28 days in advance of the survey but for site surveys they will accept shorter notice to a minimum of 14 days. However, to ensure all parties receive adequate notification of intended surveys and thereby maintain good working relationships with third parties, Operators should make every attempt to conform to the 28 days requirement. The notification requires details of the type of survey plus the geographical boundaries which define the potential survey area. An A4 chart showing these boundaries may be requested.

In addition, as discussed in *Section A.1.13*, Offshore Notice 3 states that the Health and Safety Executive (HSE) require that HMS Warrior and local Sea Fisheries Committees are notified of geophysical surveys. In the case of HMS Warrior this should be at least 14 days prior to the survey. Submission of the form of PON 14 will provide adequate notification to HMS Warrior and Sea Fisheries. However, if the proposed survey area is inshore then the appropriate local Sea Fisheries Committee may require separate notification and agreement.

Each licence may have special conditions attached to operations in that licence. These may impact upon the type and timing of survey operations.

B.3 Survey Planning

After the "Desk Study" *(Section B.1),* the rig site survey can be formulated and commissioned. Consideration should be given to the following:

B.3.1 Contractor and Vessel Selection

The following should be considered:

- Vessel availability within the required time frame of the prospective spud date.
- Is the vessel suitable and safe for operations in the prospective sea area?
- Is the available equipment suitable for the key objectives of the survey?
- Previous experience of the contractor in the area of operations, and the techniques and equipment required.

B.3.2 Positioning System Selection

Section D provides some guidance on the accuracies and positioning tolerances which are required when specifying a rig site survey. *Section E.9* provides technical details of equipment. Positioning system selection is area dependant but with the increasing use of Differential Global Positioning Systems (DGPS), this is less of an issue.

Where towed geophysical or sonar systems are to be used, consideration should be given to tow fish positioning, particularly where surveys are planned in deep water. The importance of calibration (gyro compass, VRU/MRU, acoustic velocity) will become increasingly relevant with extended offsets.

B.3.3 Geophysical and Hydrographic Equipment Selection

Section C provides some guidance on the geophysical considerations which should be taken into account when specifying a rig site survey. *Section E* provides technical details of equipment. The following should be considered:

- The hydrographic **echo sounder** should have selectable frequency of operation, commensurate with survey objectives. The system should be capable of an accuracy of better than 1% of the water depth. Transducers should preferably be narrow beam, particularly in deep water surveys. The system should also be equipped with accurate means for draft and full depth water velocity calibration. In areas of complex seabed topography, steep slopes or deep water then the alternative use of a swathe bathymetry system (multi-beam echo sounder) should be considered *(Section E.5).*
- The choice of **side scan sonar** is dictated by the resolution required and the selected maximum range. The range should be at least equivalent to the maximum line separation *(Section E.4).*
- Search magnetometers should have sufficient sensitivity and repetition rates to adequately discriminate the objective *(Section E.6).* Tow cable length should allow the sensor to be towed close to the seabed (if practical).
- The choice of **shallow seismic profiling** instrumentation should be determined by the required resolution and sub-seabed penetration *(Section E.1).*
- The choice of the **shallow gas seismic** source; multi-channel hydrophone streamer length, group length and group interval; seismic recorder, and sample rate should be determined by the key objective of shallow gas detection within the top 1000 metres subseabed. The system should be selected on the basis of *providing maximum resolution within this zone *(Section C).* The following are recommended as the basis of a minimum specification:

Seismic source:	Output >5 Bar metres, preferably minimum phase, *(Section E.1)*.
Multi-channel hydrophone:	Active length 600 metres. Minimum 48, 12.5 metre groups *(Section E.2).*
Recording system:	48 channels recorded at 1 ms sample interval *(Section E.3).*

B.3.4 Seabed Sampling and Geotechnical Requirements

Seabed sampling systems such as gravity corers or grabs should be available to provide data to assist the interpretation of shallow soils. Where information on potential rig leg penetration, scour, guide-base stability or anchor holding are important, PCPT/CPT and/or vibrocorer should be considered. Alternatively the separate commissioning of a geotechnical borehole may be necessary if the sub-seabed penetration of the vibrocorer or PCPT/CPT is not likely to be sufficient.

Seabed sampling (e.g. bottom grab) for environmental purposes may be also be required as a licence condition.

B.3.5 Survey area, Line Orientation and Line Spacing

The results of the "Desk Study" will dictate survey area, line orientation and spacing. Consideration should also be given to existing infrastructure and shipping fairways and other areas where vessel movement may be restricted.

For reliable interpretation of geophysical data, tie lines should always be acquired to nearby wells, boreholes or other data calibration points. Such tie lines should allow sufficient overlap for differences in positioning accuracies and, in the case of multi-channel seismic data, comprise full fold stacked data.

Primary survey line orientation should be based on geological "dip" direction, particularly in the case of any shallow gas or structural geology investigation. If this is not a significant issue, there are practical advantages in selecting the primary line heading to agree with the dominant tidal current direction and/or wind direction. Alternatively, if the proposed drilling location has been selected on the basis of a 2D exploration seismic line then there may be an advantage in setting the primary line heading to coincide with the 2D line heading and thereby increase the scope for minor adjustments to the final drilling location.

B.3.5.1 Anchoring / Foundation Conditions

Survey line spacing is determined by the key objectives of the site survey and the nature of the intended drilling rig. *Figures 2 and 3* show typical survey line plans for jack-up rig and a semi-submersible rig. These line plans are for guidance only and should be modified to meet the survey needs and the local geology. In the case of a jack-up drilling rig site survey, if the seabed topography and/or shallow soils distribution are complex then additional lines at a narrower spacing than the quoted 50 metres may be necessary in the immediate vicinity of the proposed spud can positions. There may also be a requirement to survey an approach corridor for the jack-up rig entry to the proposed location to ensure there are no obstructions to rig navigation. In deep water, or where the selected semi-submersible will be using wire anchor lines instead of chain, or where shallow soil conditions indicate a necessity to extend or piggy-back anchors then the survey area will need to be extended to encompass the prospective anchor spread. Additional survey lines should be considered to locate and verify the position of seabed obstructions *(Section A.11).*

The line spacing may also be influenced by the water depth. In shallow water the effective range performance of the side scan sonar system and swathe bathymetry system may require denser line spacing in order to ensure full coverage of the seabed. In deep water where the shallow geology is relatively uniform and no obstructions are anticipated then the use of longer range / lower resolution side scan sonar systems may be sufficient, allowing wider survey line spacing.

In addition, tie-lines should be acquired to selected nearby geotechnical boreholes or coring locations. The tie lines are necessary for the reliable prediction of anchoring / foundation conditions and potential hazards and constraints.

B.3.5.2 Shallow Gas

Figure 4 shows a typical shallow gas survey line pattern. This line plans is for guidance only and should be modified to meet the survey needs and the local geology. The "Desk Study" may dictate an expansion or reduction of this basic survey grid. The 3 km centre lines allow the 1 square km grid of survey data to be set into a regional context. In addition, tie-lines should be acquired to selected nearby wells where good top-hole data is available and/or where the shallow gas history is known. The tie lines are necessary for the reliable prediction of shallow drilling conditions and potential hazards and constraints.

B.3.6 Recommended Survey Parameters

- **Position control** for the survey vessel should be better than ± 5 metres. Position control of towed sensors should be better than 10% of the relevant line separation, though this may be impractical in deep water surveys.
- **Offtrack deviation** for the vessel, or the specified steered point, should not exceed 10% of the line separation or 15 metres, whichever is the greater. The steered point may not always be the vessel. In deep water, with long laybacks, there may be advantages in specifying a towed sensor, or an offset position as the steered point. e.g. specify sonar fish to prevent gaps in sonar coverage.
- **Survey speed** should be maintained between 3.5 and 4.5 knots in order to maintain optimum side scan sonar and seismic data quality.
- **Side scan sonar frequency** for obstruction identification should be not less than 100kHz using narrow beam transducers. This may be impractical in deep water investigations.
- **Side scan sonar range** for obstruction identification should not exceed 200 metres for standard 100kHz systems. The maximum range selected for 500kHz systems should not exceed 100 metres. Increased resolution can be achieved by a reduction in range but this may require a reduction in survey line separation to ensure full sonar coverage.
- **Side scan sonar height** above seabed is recommended to be between 10 and 15% of the selected range It should not be less than 5% or greater than 20%. In shallow water this may result in a reduction of the sonar range with a resultant requirement to reduce the line spacing.
- **Magnetometer sensitivity** to be better than 1 Gamma (nanoTesla) at a sampling interval of 1 second or less. Sufficient cable should be available to ensure that the sensor can be deployed at least 4 times the vessel length astern, and close to the seabed at normal survey speed.
- **Multi-Channel Digital Seismic Acquisition**. Recommended minimum acquisition parameters for shallow gas surveys are:
  - 48 channel acquisition system.
  - Active streamer length of 600 metres or greater.
  - Streamer group length of 12.5 metres.
  - Shot interval of 6.25 metres (to generate full-fold coverage).
  - Seismic source peak to peak pulse output > 5 Bar metres, wide band width and preferably minimum phase.
  - Source and streamer maintained at constant/uniform depth not greater than 3 metres (+/- 0.5 metres) sub-sea level.

  The separation between the seismic source and the centre of the nearest streamer channel should not exceed half the minimum water depth of the survey area.

B.3.7 Operator / Contractor Liaison

When planning site surveys, in addition to geophysical and positioning parameters, communication between the Operator and the Contractor is very important.

To ensure the quality of the data interpretation, the early transfer of relevant data and information to the relevant parties is important. The following should be considered:-

- Are there geotechnical data available in the area which can be supplied to the Contractor (or other data interpreters)?
- Are there top-hole well log data which can similarly be supplied and, with strategic use of seismic tie-lines, used to calibrate the seismic interpretation?
- Are there any indications of shallow gas or other potential drilling hazards such as shallow faulting on the regional 2D or 3D exploration seismic data which may aid the interpretation?
- Are there any previously acquired Seabed surveys available in the area which can be used to assist interpretation?
- Are there previous jack-up leg penetration, displacement or scour records in the area?
- Are there previous anchor holding and guide base stability records in the area?

B.3.8 Metocean Data

The acquisition of Metocean data is considered to be outside the scope of these procedures. The reader is referred to '*UKOOA Recommended Procedures for Validation and Documentation of Oil Company Metocean Data*'. However, the following should be considered:-

- What is the prevailing wind and current direction in the area (if any)?
- Should the survey lines be oriented to conform with these controls?
- If tidal currents are severe what detailed tide curves are available to ensure optimum use of working conditions?
- How good is the tidal data for reduction of echo sounder data?
- Are there adequate Metocean data within the survey area? If not, should tide and current measurements be included as part of the rig site survey scope? There may be cost benefits in acquiring such data, perhaps on a limited scale, whilst the survey vessel is undertaking the site survey.

B.3.9 Environmental Data

The acquisition of seabed sample data for Environmental data is considered to be outside the scope of these procedures. However, the following should be considered:-

- Are there adequate Environmental data within the survey area? If not, should coring and bottom grab sampling for environmental purposes be included as part of the rig site survey scope? There may be cost benefits in acquiring such data, perhaps on a limited scale, whilst the survey vessel is undertaking the site survey.

B.4 Health, Safety and Environment Management

All injuries at work can be prevented. The Operator should actively promote the high standards of safety awareness, discipline and individual accountability that this principle demands. For field operations, regulations and safety operating standards have been prepared by the E&P Forum and IAGC *(Section A.2.12)*. These should be used as a basis for all offshore operations. A Health, Safety and Environment Management System (HSE-MS) should control all aspects of the field work. The Management System should include a register of Hazards and effects. Control measures shall be in place for these hazards and shall be reconciled with procedures and job descriptions.

When planning site surveys, safety must be given a high profile, wherever activity may take place. A key element of this is the preparation of an Emergency Response Plan which uses the joint resources of Operator and Contractor to establish contingency planning for emergency situations.

To ensure health, safety and environment is given the correct priority the following actions should be considered:-

- Pre-tender Contractor health, safety and environment assessment
- Health, safety and environment clauses in the contract
- Pre-award briefings
- Contractor's health, safety and environment training
- Health safety and environment management workshops
- Health safety and environment system including hazards and procedures
- QC supervision to include health, safety and environment
- On-site health safety and environment meetings
- Drills and exercises
- Health safety and environment audits (including operational)
- Logging of incidents, followed by analysis and feedback
- Logging and analysis of performance indicators

Vessel health, safety and environment audits should be undertaken prior to and during operations. These audits should include mechanical systems and HSE-MS. Any action items identified by these audits should be followed up and closed out. The validity of these audits is subjective. However, 6 months has become an accepted industry practise.

B.5 Quality Management

Rig site survey data make a significant contribution to the safety of drilling operations. The quality of the data and interpretation cannot be taken for granted, and requires a great deal of careful control by Specialists. Standards are established for Quality Systems by the BSI publication BS EN ISO 9000,1994

B.5.1 Quality Assurance (QA)

This can be defined as all those planned and systematic actions necessary to provide confidence that a product or service will satisfy defined needs. QA is a management system which may be established as a set of QA procedures. The system seeks to give assurance to the customer and combines Quality Planning and Quality Control (QC).

In setting up QA procedures, the needs should first be defined and the necessary systematic actions subsequently analysed. At the project level, the requirements of QA can be refined into a chronological, step-by-step process, with a degree of parallel activity and a critical path.

QA procedures embracing the above actions should be established by the Operator to ensure the quality of the product. The basic needs of a rig site survey are defined in accordance with the objectives, which range from shallow gas detection to prediction of soil lithologies, identification of seabed hazards and definition of bathymetry. In order to satisfy these needs, the following actions will have necessarily preceded the final product:

- Definition of the Operator's aims and objectives, overall exploration programme and budget allocation, including contingencies.
- Definition of rig site survey needs, including the planned survey programme.
- Appraisal by geophysical and hydrographic survey staff of the project requirements and the preparation of a scope of work.
- Definition of suitable Technical Specifications, QC parameters and procedures by Specialists.
- Technical and safety audits for Contractor pre-qualification.
- Thorough tender evaluation and pre-award meetings. Award procedures based primarily on technical grounds, but also on safety, performance record and costs. Evaluation should be undertaken by Specialists.
- Briefing of all major participants, using standard checklists wherever possible.
- Quality control supervision of mobilisation, including calibration and acceptance tests of all systems by specialist geophysical and hydrographic survey staff.
- Quality control and safety supervision of on-line data acquisition, including progress control and co-ordination of operations.
- Debriefing of all major participants and analysis of all reports from the field, covering mobilisation, calibrations, acquisition and safety. Conclusions and recommendations are of prime importance for future projects.
- Post processing, interpretation and reporting of data, checking for all possible sources of error by specialists.
- Detailed reporting and charting, including conclusions and recommendations.
- Archiving of reports and data for future reference. Update of relevant databases.
- Feedback of recommendations to all major participants.

The Operator should also ensure that the Contractors undertaking any facets of the work have adequate QA procedures to ensure the quality of his work.

B.6 Survey Implementation and Data Acquisition

Geophysical site survey work should be undertaken by experienced personnel committed to high professional standards. Wherever practical the drilling hazard investigation should precede the more general survey work as the early detection of potential problems may lead to a move of the rig location and associated adjustments to the survey plan.

Geophysical site survey data acquisition within the UKCS is potentially subject to very severe weather and sea state conditions. The choice of vessel, survey equipment and over-side handling equipment should anticipate such potential exposure. It is also important that the contractor and Operator accept that survey work may sometimes need to be terminated early such that the safety of personnel undertaking the recovery of towed equipment is not jeopardised or to avoid damage to the equipment itself.

Data quality should be maintained to a high level. Site survey data quality is very vulnerable to the influence of sea state. Survey work should not continue if the influence of poor weather and sea state causes a reduction in data quality to such an extent that the key objectives of the site survey are jeopardised.

The same control on data quality and acceptability can be extended to the influences of external seismic interference *(Ref: Jack and Lancaster, 1989)*, shipping or construction noise. Acceptable limits of seismic noise depend upon the direction of the interfering noise source. There is currently a draft UKOOA Guideline for establishing when time share between seismic vessels is required to minimise seismic interference. This does not advocate prescriptive noise limits but a location specific, fit for purpose assessment of seismic interference. Interference should always be measured in accordance with the UKOOA Guidelines which will enable unambiguous communication of seismic interference levels between the parties involved in time share discussions. In the past, as a general guideline, external seismic interference to a maximum acceptable limit of 25 microbars peak signal has been shown to be tolerable on multi-channel seismic site survey data provided the move-out is in excess of 100 milliseconds across 600 metres of active streamer length. Desynchronisation of the vessel and the interfering source is vital with a desynchronisation of 250ms recommended.

B.7 Data Processing

The objectives of processing seismic data include improvement of signal-to-noise ratio, improvement of vertical and lateral resolution, suppression of multiple events, and enhanced display of data *(Section C.1)*.

Processing of data should be undertaken with extreme care since it is possible to create and destroy events on the seismic record. As a rule of thumb, minimal processing of data should be undertaken. Processing which destroys relative amplitude information should be avoided. Careful analysis of processing tests permits selection of those processing steps which enhance the data. When undertaking processing tests, the area selected should be representative of the site. Care should be taken to alter only one variable at a time so the effect can be assessed. Processes should not be applied unless there is obvious benefit. On occasion, even though a process may be of obvious benefit in one way (e.g. multiple suppression) it may be disadvantageous in another (e.g. data suppression and noise creation).

Careful velocity analysis is of particular importance to ensure correct CMP stacking of the data. Velocity analyses should be undertaken at locations chosen with reference to the local geology. The minimum interval should be every 500 metres along the seismic lines. In some areas, where the geology is rapidly changing, (e.g. channels, salt domes), velocity analyses may be required more frequently.

Velocity analyses will be severely degraded by significant lateral velocity variations, e.g. gas charged sand. This can be particularly important for stacked anomalies, and a more careful approach to velocity estimation is necessary if data are to be stacked correctly and reflection amplitudes preserved. Similarly, excessively tight band-pass filter limits will degrade vertical resolution, whilst excessive trace mixing or harsh FK dip filters may degrade both lateral and vertical resolution.

Section F provides further detail on seismic processing. The recommended minimum processing sequence for rig site surveys is:-

- Demultiplex
- Designature
- Gain recovery
- Normal Moveout (NMO)
- Mute

- Stack
- Deconvolution after Stack (DAS)
- Time Variant Filter (TVF)
- Relative amplitude display
- Equalised display

B.8 Seismic Data Interpretation

These data to be interpreted should be to a high quality. A key factor in the interpretation is the type of drilling rig planned for the site.

As discussed in *Section B.3.7*, communication between the Operator and the Contractor is an important element in data interpretation. Early transfer of relevant data and information to the relevant parties is essential. The following data should be available to aid interpretation:-

- Any geotechnical data and lithological data in the area.
- Top-hole well log data.
- Any indications of shallow gas or other potential drilling hazards such as shallow faulting on the regional 2D or 3D exploration seismic data.
- Relevant seabed surveys in the area.
- Previous rig installation history in the area.

B.8.1 Calibration

Direct calibration of the data in the form of nearby top-hole well data or borehole and other sample data is the most useful tool for assessing the significance of the seismic response and should always be carefully integrated with the data. Where relevant nearby data exist, tie lines should always be acquired to these calibration points. If the calibration data belongs to other Operators and is not in the public domain, Operators should request such data from the relevant Operator. In areas where no direct calibration is available, drilling departments should be encouraged to acquire top-hole petrophysical data for correlation with the geophysical data and therefore improve confidence in the interpretation of an area.

B.8.2 Shallow Gas Hazard Determination

B.8.2.1 Conventional Seismic Analysis

One characteristic seismic response of a gas charged sediment is a high amplitude reflection, although under certain conditions, low amplitude reflections are also possible. Theoretically, the reflection should also be phase reversed where gas is present, but this may not be apparent. Other indicators of gas in sediments are masking of underlying reflections and 'pull down' of underlying reflections, caused by the seismic wave passing through the lower velocity gas pocket. In practice these last two indicators are rarely seen, as they are very sensitive to the geometry of the acquisition spread with respect to the size and depth of the gas pocket. Consequently, identification of possible gas pockets primarily depends on identifying anomalously high amplitude reflections.

The following list is based upon a list provided in the AAPG Memoir 42. The interpreter should look for the following indicators of shallow gas.

- Is the reflection from the suspected reservoir of anomalously high amplitude?
- Is the amplitude anomaly structurally consistent?
- If of anomalously high amplitude, is there one reflection from the top of the reservoir and one from the base?
- Do the reflection amplitudes of the top and base reflections vary in unison, decreasing at the same point at the limit of the reservoir?
- Is a flat spot visible?
- Is the flat spot horizontal or is it dipping consistently with gas velocity sag?
- Is the flat spot unconformable with the structure but consistent with it?
- Is the flat spot located at the downdip limit of anomalously high amplitudes?
- Is a phase change visible?
- Is the phase change structurally consistent and at the same level as the flat spot?
- Is there a low frequency shadow below the suspected reservoir?
- Is a study of amplitude versus offset on the unstacked data likely to assist?
- Are there indications of gas migration on the shallow gas (or other) survey data?
- Are there pockmarks at, or buried beneath, the seabed indicating gas seepage?

In practice, any one indication can be spurious. Shallow gas interpretation on seismic data necessarily involves accumulation of evidence. The more positive answers to the above points, the greater the confidence in the identification of shallow gas.

High amplitude reflections are caused by a strong impedance contrast. Impedance depends upon the seismic velocity and density of the strata. Therefore, strong impedance contrasts may be purely of lithological origin rather than due to gas accumulation. Constructive interference of reflected seismic waves may also cause high amplitude reflections (tuning effects). The more resolute the seismic data, the easier it is to discriminate genuine high amplitude events from tuning effects.

A small proportion (about 5 percent) of gas in a sediment will cause a high amplitude reflection of similar magnitude to that caused by a large proportion of gas (say 75 percent), so it is difficult to directly quantify gas content from the seismic response. If a closure can be mapped, and the top and bottom of the reservoir unit detected, gas overpressure (in excess of hydrostatic pressure) caused by the height of the gas column can be calculated. However, this is a simplistic approach, based on hydrostatic pressure variations only. It also assumes accurate detection of the top and bottom of the reservoir. Predictions of gas pressures based upon seismic data should be used with extreme care.

Where the geological structure and interpreted lithologies provide a potential trap and no direct calibration is available, anomalous amplitude reflections should always be assumed to be related to gas accumulations.

B.8.2.2 Seismic Workstation Techniques, Attribute Analysis and AVO

The use of workstations can assist in the interpretation of seismic data for shallow gas detection *(Section F.1.6)*. Workstations allow expansion of data displays in areas of interest for easier identification of shallow gas indicators. Tuning effects can also be more easily discriminated from high amplitudes caused by shallow gas, on the basis of changes in relative amplitude along the reflection.

Seismic attributes can be examined using colour displays such as colour coded amplitude, instantaneous amplitude, instantaneous phase, and instantaneous and averaged frequency and these can be used as diagnostic indicators of shallow gas presence. However, variations in these attributes can also be caused by lithological changes (e.g. Lignite) and seismic processing, so interpretation based only upon attributes should be undertaken with caution.

Amplitude versus Offset (AVO) effects are generated by changes in plane-wave reflection coefficients as a function of angle of incidence. AVO variations can be caused by many factors (e.g. reflection coefficient, array attenuation, tuning, noise, spherical spreading, absorption, emergence angle, reflector curvature, hydrophone sensitivity, and instrumentation and processing). With care, AVO analysis may assist in distinguishing gas related amplitude anomalies from other types of anomalies. In general, over the range of angles of incidence typical of rig site survey data, the top of a gas charged sand layer will show an increase of amplitude with offset, whereas a water charged sand will show a very small decrease of seismic amplitude with offset. However, in the shallow section these amplitude variations will be very subtle. With a ‘standard’ site survey 600 metre long streamer, the offset range at depths of greater than 500m sub-seabed is limited. If AVO data are required at these depths, longer streamers should be considered.

B.8.3 Shallow Soils Interpretation

Interpretation of shallow soils from acoustic geophysical data requires careful analysis of seismic reflection characteristics integrated with all relevant available data. With adequate local knowledge and careful interpretation, general soil lithology and conditions can be predicted. On its own, the survey data will not provide quantitative data for jack-up leg penetration, guide base stability or anchor holding conditions. Important geotechnical characteristics such as shear strength, friction angle and relative density cannot be defined directly from the geophysical data.

Prediction of geotechnical properties and anchoring / foundation conditions should only be undertaken by Specialists and will need to be based upon geotechnical data at the proposed location or tie-lines acquired to relevant nearby geotechnical boreholes or coring locations which permit reliable interpretation of shallow soil conditions at the proposed location. If significant variation in shallow soils are interpreted between the proposed location and the calibration point, reliable predictions will not be possible and acquisition of geotechnical data at the proposed rig site location will be required.

Resistivity techniques *(Section E.7)* can also be used for prediction of soil lateral variations and acquisition of these data could be considered for areas where shallow soils variations will impact significantly on rig installation. The data also require careful integration with calibration data and interpretations for geotechnical characteristics should be used with care.

The use of workstations can also assist in the interpretation of seismic data for shallow soils *(Section F.1.6).* Workstations allow expansion of data displays in areas of interest for easier identification of seismic characteristics.

Seismic attributes can be examined using colour displays such as colour coded amplitude, instantaneous amplitude, instantaneous phase, and instantaneous and averaged frequency and these can be used as diagnostic indicators of litholgy. However, variations in these attributes can also be caused by pore fill and seismic processing, so interpretation based only upon attributes should be undertaken with caution.

B.8.4 Depth Conversion

The conversion from seismic two way travel time to depth below seabed, based on stacking velocities or interval velocities, is accurate to better than 5 percent of the depth when determined with care. Depth predictions can be further improved if top-hole well data or other calibration data are available.

B.9 Reporting and Charting

Reporting should be concise and relevant to the survey objective. Full consideration should be given to all potential users of the report and any information they require should be readily accessible. As many users are not geoscientists, geological/geophysical descriptions and jargon should be avoided. The end-user of a site survey report is much more likely to be a drilling engineer than a geologist or geophysicist. Speculative interpretations, unless substantiated by published data (e.g. BGS publications), should be avoided.

Interpretation of the data and subsequent reporting should, as far as possible, be a team effort incorporating the views of geologists, geophysicists, and drilling engineers. If the likely rig owners/insurers are known at the time of reporting, they should also be included in the reporting of results.

The reporting should provide a brief but clear statement of the expected conditions. This statement should not be confused by discussion of features in the survey area which have no relevance to either rig installation or subsequent drilling at the location. Where estimated dimensions or depths are quoted then an indication should be given as to the level of confidence assigned to these estimates.

Datum for water depths should be Lowest Astronomic Tide (LAT) or Mean Sea Level (MSL). The report should provide the relationship between LAT and MSL for some users (e.g. drillers). An estimate of the full tidal range at the location should be considered along with a diagram showing the principle direction and velocity of currents in the area. This prediction may be based upon published data or, as discussed in *Section B.3.8,* acquisition of suitable data may be included as part of the site survey.

It is recommended that a concise one page summary of this information is provided in the report. This can be used to provide part of the submission for drilling consent approval *(See Section A.1.)*

Topics to be addressed by the full report should include:-

- Summary of results.
- Results (e.g. bathymetry, seabed features and obstructions, shallow geology, anchoring/foundation conditions, shallow gas and other top-hole drilling hazards including channels, faulting, coarse sediments etc.).

In addition, certain report users will require:-

- Operations.
- Calibrations.
- Data reduction and processing.
- Survey equipment.
- Data quality.

To reduce paper and prevent circulation of unnecessary information, it is recommended that a results only volume is produced for most report users. A separate volume can be produced for the other survey information and only circulated to those who require these data.

Recommended chart scales are 1:5,000 or 1:10,000. All charts should include a clear indication of mapping Datum and Spheroid. Charting should include the following:-

- Vessel fix reference position (e.g. antenna, or steered point).
- Side scan sonar and other tow fish position tracks (if relevant).
- Bathymetry, with water depth reduced to LAT or MSL (soundings and contours).
- Seabed features, with variations in seabed sediments, and wrecks or other obstructions.
- Depth below seabed to seismic reflections which delineate significant sub-seabed soil variations. Channels on or near the proposed location should be charted. Soils province distribution may be appropriate.
- Shallow faulting if relevant to survey objectives.
- Interpreted profiles through the proposed location highlighting potential hazards or constraints to rig emplacement. Significant soil units or soil provinces should be annotated together with their correlation with any geotechnical data.

If the rig site includes a shallow gas survey then charting should also include the following:-

- Seismic shot point.
- The lateral extent of anomalous amplitude reflections presented in time and depth below mean sea level or seabed. Several charts may be required for clarity. The recommended time datum is Two Way Travel Time (TWTT) and depth datum is True Vertical Sub Sea (TVSS).
- If there is a potential structure, depth below mean sealevel to reflections of interest, combined with the anomalous reflections.
- Shallow faulting if this is relevant to potential shallow gas distribution.
- Lateral extent and depth of any features which may affect drilling operations (e.g. channels).
- Interpreted profiles through the proposed location, highlighting potential hazards, significant soil units and correlation with well data.

B.10 Final Notifications and Drilling Consent Arrangements

As discussed in *Section A.1.8*, the Operator of a mobile installation must send a notification to the HSE at least 21 days before starting operations. The notification should contain the particulars specified in Schedule 6 of the Offshore Installations (Safety Case) Regulations 1992. At the location at which the operations will be carried out, these include the meteorological and oceanographic conditions to which the installation may foreseeably be subjected, the depth of water and the properties of the seabed and subsoil. In addition, particulars of the geological strata and any fluids within them and any hazards with the potential to cause a major accident shall be included.

As discussed in *Section A.1.10*, a copy of the site survey report should be available with the Operator at the time of Application for Consent to drill. A statement to this effect should be included in the information package accompanying the application which has to be lodged with the DTI not less than 21 calendar days prior to the spudding of the well. It should be clearly indicated if there is a possibility of encountering shallow gas at a drilling site.

B.11 Data Retention and Archiving

Rig site survey data may be in paper form or in computer compatible media format (CCM), or both. Data produced during the course of the survey may include the following:

- Raw and processed positioning data for all sensors utilised
- Echo sounder records
- Raw and processed digital swathe bathymetry data
- Analogue (paper) side scan sonar records
- Digital side scan sonar records
- Analogue (paper) seismic records
- Raw and processed digital seismic data
- Processed seismic sections (paper/film)
- Magnetometer data
- Geotechnical data including seabed core/grab samples, cone penetration tests, and core logs
- Acquisition, processing, and interpretation reports
- QA/QC data

All data acquired during the rig site surveys should be retained by the Operator or their agents until the well has been drilled and the rig has been moved off location. If there is further drilling or engineering activity (field development) in the area, any survey records may have value throughout the field life and they should be kept until field abandonment. Before any data disposal, careful consideration should be given to the data value for future developments in the area. The following minimum criteria are recommended in regard to longer term data retention policy for all records created during the rig site survey process.

Reports, positioning data and seismic data (raw and processed) should be retained by the Operator or their agents for as long as there is drilling activity in or around the surveyed area. These data will be useful in planning future surveys and may be incorporated into later interpretations.

Analogue sonar and bathymetry records should be retained by the Operator or their agents for a minimum of two years. In areas with stable seabed conditions and little maritime activity, these data may be of use for longer periods. Requirements for the provision of data and reports to Government bodies are defined in *Section G*.

B.12 Data Validity

The validity of rig site surveys is a subjective issue, and is dependant on a variety of considerations, amongst which are:

- Operator familiarity with the area
- previous well history and shallow gas problems
- recent oil industry activity (wells, pipelines, boreholes)
- recent maritime activity
- water depth and (associated) seabed sediment movements

Top-hole lithology and foundation conditions assessments are potentially valid indefinitely.

In many areas shallow gas assessments are also valid indefinitely unless there has been drilling activity in the area which could have resulted in movement of hydrocarbons. However, changes in shallow gas distribution can occur within the time scale of field development *(Ref: Judd 1990)*. The Operator should undertake an area specific study to ensure validity of shallow gas assessment over time. This could include acquisition of a few survey lines for confirmation of shallow gas assessment.

For very shallow foundation conditions, bathymetry, and seabed features/obstructions, data validity will depend upon activity (natural and man made) in the area of the location. The following tentative validity periods are proposed:-

- in shallow water with known seafloor movements and/or high level of activity - 6 months
- at open locations in deeper water (> 80 m) - 2 years

Data validity should be assessed on a site specific base. a review should be undertaken of the activity (natural and man made) which has taken place in the area since the date of the last survey. This review should include all relevant data.

Section C - Geophysical Considerations

C.1 General

A simple seismic velocity model has been used for computations in this section. It approximates to conditions found in parts of the Central North Sea. Within the range of likely velocities in the UKCS (in the top 2000 metres sub-sealevel) the computations are not particularly velocity sensitive so the derived figures are valid for general application. Table 1 below tabulates these velocities.

Depth (m) Sub-sealevel	Stacking Velocity (ms^{-1})	Two Way Travel Time(ms)
0	1500	0
100	1500	133
200	1550	260
300	1600	375
400	1650	480
500	1700	590
750	1800	830
1000	1900	1050
*1250	2000	1250
1500	2100	1430
2000	2200	1820

Table 1 Velocity Model used for computations

C.2 Sub-seabed Penetration

Penetration is partially controlled by the amplitude of the seismic wavelet and the band width. As with resolution, anything that affects the seismic wavelet in terms of amplitude or frequency content affects the penetration.

Absorption characteristics of the strata are particularly significant. *Figure 5* shows attenuation of the seismic signal due to absorption for various sub-sealevel depths and frequencies. An absorption of 0.2 dB per wavelength has been used. (For glacial tills and Tertiary strata this may be optimistic but it permits ‘best case’ conclusions). If no more than a 20 dB loss in signal is tolerable, then 50 Hz signals will penetrate 2000 metres sub-seabed, 100 Hz ≈ 1000 metres, 500 Hz ≈ 180 metres, 2000 Hz ≈ 45 metres.

Low frequencies are required for greater penetration but, this generally dictates the use of high power sources which do not have suitable band widths for good resolution. A careful compromise is required, therefore, between penetration and resolution, depending on the survey objective.

C.3 Vertical Resolution

Resolution is defined as the ability to separate two very closely spaced seismic reflectors. Vertical resolution will therefore dictate the minimum thickness of a bed which can be detected at the objective sub-seabed depth. Resolution is controlled by the time duration of the seismic wavelet which is itself dependent upon the band width of the transmitted pulse. If the seismic wavelet consisted of a single frequency, the optimum resolution would be one quarter of the wavelength ($\lambda/4$). However, in an acoustically noisy environment, resolution of half the wavelength ($\lambda/2$) may be more realistic. The wavelet does not consist of a single frequency, but a range of frequencies (the band width), with a particular fundamental frequency. Resolution is controlled by a combination of band width and fundamental frequency.

Bad weather conditions will degrade vertical resolution due to band width reduction caused by depth variations in the source and streamer *(see Section C.6)*. In addition, signal-to noise ratio will be reduced which will impact upon resolution *(see Section C.9)*.

Anything that affects the seismic wavelet in terms of amplitude or frequency content affects the vertical resolution. The major factors are listed below:-

(i) Characteristics of transmitted seismic signal.

(ii) Water column losses (spherical spreading).

(iii) Reflection/refraction losses at interfaces (seabed and sub-seabed).

(iv) Absorption (frictional losses during propagation).

(v) Acquisition/recording parameters and equipment limitations.

(vi) Seismic data processing.

Items (i), (v) and (vi) are controllable and should be carefully selected and supervised *(see Sections F, and G)*. Item (ii) can be controlled to some extent by utilising deep tow systems, where appropriate. Items (iii) and (iv) are not controllable and depend completely upon the geology of the area. Within the UKCS, considerable variations are experienced in the shallow geology and corresponding variations in resolution are observed.

Table 2 shows the variation of vertical resolution with frequency, based solely on fundamental frequency and assuming the $\lambda/4$ criteria. It is a simplistic model but it illustrates the degradation of resolution that occurs with decreasing frequency. This is important, as the high frequency signals are lost as the signals propagate through the sub-seabed strata and, consequently, resolution decreases with increasing sub-seabed depth *(Section C.2 and Figure 5)*.

	Vertical Resolution (m)	
Fundamental Frequency (Hz)	Velocity 1500 ms^{-1}	Velocity 2000 ms^{-1}
5000	0.08	0.10
1000	0.38	0.50
500	0.75	1.00
250	1.50	2.00
100	3.75	5.00
75	5.00	6.67
50	7.50	10.00
25	15.00	20.00

Table 2 : Vertical resolution for various fundamental frequencies and seismic velocities (l/4 criteria)

C.4 Detectability and Interpretability

Resolution dictates the ability to separate two very closely spaced seismic reflections, but beds thinner than the resolvable thickness will still generate a seismic response and can thus be detected. For these thin beds, the amplitude of the reflection is linearly proportional to the thickness of the bed.

The detectability is particularly dependent on signal-to-noise ratio. On noise free data, very thin beds can be detected. On seismic data, as a rule of thumb, the detectability is a factor of four greater than the resolution i.e. a sand 4m thick may be detectable but its thickness can not be resolved.

If a bed is detectable, it does not necessarily imply that it can also be interpreted. The interpretability depends upon resolution, detectability and geological complexity. In rapidly varying geology, a change in seismic response cannot be uniquely related to the properties of a single bed.

C.5 Signal Stretch

Although only relevant to multi-channel seismic data which is subsequently CMP stacked, signal stretch should be considered when designing survey acquisition parameters as it dictates the acceptable source to hydrophone offsets. Signal stretch will degrade vertical resolution unless 'over-stretched' data are muted. Stretch will be particularly severe in the shallow section when offsets are long. If multiplicity is required in the shallow section, short offsets are therefore required. Unfortunately, the longer offsets are useful for water bottom multiple suppression so the stretch mute should be selected with care. To maintain resolution, it is recommended that signal stretch is limited to a maximum of 10 percent.

Figure 6 shows stretch factors for various sub-seabed depths and offsets assuming a simple geological and acquisition model. With an offset of 50 metres and a receiver group interval of 12.5 metres, Figure 6 shows that the 10 percent stretch would dictate the use of only receiver groups 1-4 at 100 metres below sea surface, 1-17 at 300 metres and full multiplicity only at 850 metres below sea surface.

An acceptable angle of incidence of reflected data arriving at the streamer of up to 20 degrees is often quoted in the literature. This 20 degree criteria is advised for several reasons including signal stretch, avoiding total internal reflection, avoiding refracted events, favouring compressional rather than shear waves and permitting a simple relationship between reflection coefficient and impedance. *Figure 6* shows that this agrees approximately with the line of 10 percent stretch factor.

C.6 Tow Depth Ghosts

When towed near the sea surface, the depth at which both seismic source and receiver are towed is critical due to the presence of secondary signals reflected from the sea surface (ghosts). Destructive interference of signals will generate notches at frequencies dependent on the tow depths. If these notches occur within the band width of the signal, the usable band width will be reduced and resolution degraded.

Some systems (deep tow and sub-tow) can be towed at depths which avoid these constraints by avoiding pulse shaping effects. The sea surface effects are then limited to seismic multiple reflections.

The source and receiver should be towed at a depth equivalent to one quarter of the wavelength of the desired frequency. This is illustrated in *Figure 7* which shows the notches in the frequency spectra produced by a variety of tow depths.

Table 3 tabulates the optimum tow depth for various fundamental frequencies. For example, if a fundamental frequency of 200 Hz is available, a tow depth in the order of 2 metres should be utilised. If a fundamental frequency of 750 Hz is available, a tow depth in the order of 50 centimetres should be utilised.

Fundamental Frequency (Hz)	Optimum Tow Depth (m)
50	7.5
100	3.8
200	1.9
500	0.8
750	0.5
1000	0.4
2000	0.2

Table 3 : Optimum tow depth for various fundamental frequencies based upon tow depth 'ghost' reflections

C.7 Lateral Resolution

Lateral resolution will dictate the smallest areal extent of a feature which can be detected. Lateral resolution is controlled by seven major factors:-

(i) Characteristics of transmitted seismic signal.

(ii) Trace interval.

(iii) Hydrophone array length (smearing across the CMP).

(iv) Survey line spacing.

(v) Feathering *(see Section C.8)*.

(vi) Seismic data processing.

(vii) Seismic wave propagation.

Items (i) to (vi) are controllable and should be carefully selected to meet the objective. Item (vii) is out of our control and depends upon physics and the geology of the area. However, with careful selection of line spacing and orientation, its effects can be minimised.

Item (vii) is discussed below in more detail to assist the understanding of how its effects can be minimised. A seismic path from source to receiver involves propagation along a wavefront, not a single ray path. Signals are reflected from an area, called the Fresnel Zone, not from a single point. The Fresnel Zone is dependent on the period of the wave, which is large for low frequencies and small for high frequencies. The higher amplitude returns are from the central area of the Fresnel Zone, which is often called the reflecting zone. The reflecting zone diameter is roughly half of the Fresnel Zone diameter. The larger the area of the reflecting zone, the greater the 'smearing' of events with a corresponding reduction in resolution. Therefore, the ideal signal for lateral resolution is a high frequency signal, producing a narrow reflecting zone. Unfortunately, such signals will not penetrate very far sub-seabed *(Section C.2 and Figure 5)*.

When deciding upon survey line spacing it is essential to ensure that the spacing is of the correct order, such that the area between lines is covered by the reflecting zone of the available frequencies, particularly the fundamental frequency.

Table 4 tabulates the diameter of reflecting areas for a range of sub-source depths and frequencies. For example, if seismic reflections at a fundamental frequency of 100 Hz at 300 metres sub-sealevel are required, a line spacing in the order of 50 metres is required to avoid gaps in the seismic coverage.

Depth Below Source (m)	Frequency (Hz)								
	25	50	75	100	250	500	1000	2000	5000
50	39	27	22	19	12	9	6	4	3
100	55	39	32	27	17	12	9	6	
200	79	56	45	39	25	18	12		
300	98	69	57	49	31	22			
400	115	81	66	57	36	26			
500	130	92	75	65	41				
750	164	116	95	82	52				
1000	195	138	113	97					
1250	224	158	129	112					
1500	251	177	145						
2000	297	210							

Table 4 : Diameter of reflecting zone (in metres) for various frequencies and depths

The Fresnel Zone criteria indicate the size of the reflection area, but not the minimum areal extent of a feature that is detectable. For an event within the Fresnel Zone to be noticeable, it should make a significant contribution to the returns from the zone, to such an extent that it is recognisable as variations in signal amplitude when compared to returns from adjacent CMP's. Lateral detectability therefore depends on the reflection contrast between the event and the adjacent or background reflections.

In the case of a gas bearing sand, the background reflection coefficient is the reflection coefficient of the reflection marking the top of the reservoir where no gas is present. This differs significantly from the area where gas is present.

Table 5 tabulates the diameter of an object which could be detected for a variety of background reflection coefficients. For the computations, the reflection coefficient of the object was assumed to be -0.25, a typical value for a gas bearing sand in a clay sequence. Object size is computed for various fundamental frequencies.

The criterion used for the recognition of an event is an increase of reflection amplitude to five times the background level. This recognition criterion depends upon the object having a sharp boundary, therefore it will not be applicable in areas of lateral lithological variation.

	Background Reflection Coefficient		
Frequency (Hz)	0.1	0.05	0.02
250	58.0	41.0	25.9
100	91.9	65.0	41.4
50	130.1	92.0	58.2
25	183.9	130.0	82.2

Table 5 : Minimum diameter of an object (in metres) which can be detected, at500 metres below the seismic source, assuming the eye can only recognise a 5-fold increase in amplitude on the paper record.

If a 5-fold increase in reflection amplitude is required, *Table 5* shows that an object would have to be 41 metres in diameter at 500 metres sub-seabed for a 100 Hz fundamental frequency (assuming there is good reflection contrast).

Excessive feathering *(Section C.8)* will degrade lateral detectability, since the size of the reflection area will increase. This means that the size of objects provided in *Table 5* are the 'best case' as zero feathering angle is assumed.

C.8 Feathering

Excessive feathering will degrade lateral resolution when the data are CMP stacked, effectively increasing the size of the area from which reflections are received. In extreme cases of feathering, reflecting areas may not even overlap at higher frequencies.

This is illustrated in Table 6, which shows the spread of CMP positions for various feather angles and sub-seasurface depths. As long offsets will be muted in processing at shallow depths *(Section C.5)*, shorter offsets have been used with the shallower depths.

Depth Below Source (m)	Source-Receiver Offset (m) assuming 10% Stretch Mute (Fig 1)	CMP Spread (m)		
		1°	6°	10°
50	50	0.4	2.6	4.4
100	90	0.8	4.7	7.9
200	180	1.6	9.5	15.9
300	250	2.2	13.1	22.0
400	320	2.8	16.8	28.2
500	380	3.3	20.0	33.5
750	570	5.0	30.0	50.3
1000	750	6.6	39.4	66.1
1250	930	8.1	48.9	82.0
1500	1120	9.8	58.9	98.7
2000	1250	10.9	65.7	110.2

Table 6 : CMP spread (in metres) for 1°, 6° and 10° feather angles.

For optimum resolution, zero feather angle is required. In practice, this is very difficult to achieve and a typical value for maximum acceptable feather is 6 degrees. As shown in *Table 6*, for a 600 metre source-receiver offset, this may produce a spread of CMP positions in the order of 30 metres at deeper objective levels. It will, however, ensure that the centre of the Fresnel Zone for the last CMP will fall well within the Fresnel Zone of the first CMP (for all frequencies at the sub-sealevel depths which they are likely to penetrate). With the 6 degrees feather, the extension of the Fresnel Zone radii should be less than 50 percent. However, 6 degrees feather will reduce the Fresnel Zone overlap to approximately 66% and the reflecting zone overlap to approximately 40%.

Excessive feathering where there is cross line dip will also introduce stacking velocity errors.

Key lines requiring optimum resolution such as those which pass through the proposed location, should be acquired at slack tide when feathering is at a minimum.

C.9 Signal-to-Noise Ratio

Seismic signal should be distinguishable from background noise at the objective level. Low amplitude signal may be significant, so every attempt should be made to minimise noise and maximise signal.

Output signal levels will depend upon the seismic source characteristics, and the returning signal levels are linked to sub-seabed penetration.

Noise depends on the data acquisition parameters and recording and processing techniques. In addition, noise in the field may be created by sea state, seismic interference, vessels, rigs or platforms, cable jerk, etc.

Although data processing will enhance signal-to-noise ratio, careful consideration should be given to noise levels which can be tolerated during acquisition, and care should be taken to avoid inducing noise during subsequent recording and processing.

Noise will also affect resolution as it may reduce the detectability of thin beds. It will also affect vertical and lateral detectability since subtle changes in amplitude will not be noticed. In some cases it may be advantageous to improve signal-to-noise by using high power sources or frequency filtering, at the expense of band width.

Significant noise is often source related in the form of linear coherent events. This is a particular problem in the shallow geological section where non optimum stack array geometries may be used *(Ref: Larner 1983 and Vermeer 1990).*

CMP stacking of multi-channel seismic data will improve the signal-to-noise ratio of the data. If n is the fold of data in the stack, the signal-to-noise ratio will be improved by a factor $\sqrt{n}$. Increasing from 24 to 48 fold stack will therefore only produce a 41% improvement in signal-to-noise ratio and then, only if the CMP stacking velocity is correct.

Section D - Positioning Considerations

Surface positioning facilities and capabilities have changed over the last few years due to the advance of satellite positioning techniques, and in particular to (Differential) Global Positioning Systems (DGPS) being widely available. In almost all situations DGPS can provide the required positioning accuracy for rig site surveys. The usage of radio positioning systems is gradually being phased out, and some systems have already been dismantled or downgraded. However, radio positioning systems are not yet fully obsolete, and some consideration has to be given to their characteristics and performance. This Section will discuss rig site survey positioning accuracy requirements, followed by specific DGPS and radio positioning dependent considerations.

D.1 Requirements

D.1.1 Precision

For rig site surveys, the precision required from a positioning system is dictated primarily by the ability to recover a position repeatedly. This position may be an existing seismic or site survey data grid or a fixed point such as a well, borehole or seabed feature (e.g. a wreck).

Precision is also dictated by the requirement for high vertical resolution of the seismic data which requires limitation of residual phase shifts in the CMP gather for preservation of the seismic data band width. For horizontal reflections, erratic positioning will not produce phase shifts, due to the fixed source-streamer geometry. However, for dipping reflections, erratic positioning will produce phase shifts.

In *Section C.5*, a typical value for maximum acceptable signal stretch of 10 percent (36 degrees phase shift) is advised. With a CMP positioning tolerance of ± 1 metre, signal stretch in excess of 10 percent (for a 250 Hz signal) will occur with reflection dips of 10 degrees or more. With a CMP positioning tolerance of ± 0.5 metres, signal stretch in excess of 10 percent will occur with reflection dips of 20 degrees or more. Fortunately, reflection dips are generally of very low angle in the zone of interest for shallow gas surveys in the UKCS, therefore, a relaxation of CMP positioning tolerance should not produce excessive signal stretch.

Fresnel zone criteria *(Section C.7)*, dictate that the CMP positioning tolerance is not a significant factor in the preservation of horizontal resolution. Streamer feathering *(Section C.8)* has more effect on CMP position than erratic positioning.

D.1.2 Ship/Source/Receiver Geometry

In the inline-direction, undetected errors in the spread will not incur residual moveout errors due to the fixed source streamer geometry. Errors in the crossline-direction will potentially reinforce the effect of streamer feathering *(see Section D.8)* and degrade the CMP stack of multi-channel seismic data.

Offsets and laybacks should therefore be carefully measured. Careful field quality control should constrain these errors to less than ±1 metre on a single steamer spread. Analysis of seismic data using seismic processing packages in the field is very useful for offset quality control. If multiple streamer operations are contemplated careful consideration should be given to streamer positioning to minimise these errors.

D.1.3 Elevation

The application of Normal Move Out (NMO) relies on high precision in the measurement and control of the elevation of the streamer hydrophones. This will restrict the residual phase shifts in the CMP gather to an acceptable limit and thus preserve higher frequencies. Streamer and source depth control and the ability to measure their depth are therefore of significant importance. Therefore, streamer depth controllers and depth indicators should be at a maximum of 100 metre intervals.

Table 7 tabulates elevation accuracy tolerances for phase shifts of 36 degrees (the recommended maximum), 50 degrees and 100 degrees. At 250 Hz, tolerances of 0.3 metres to 0.8 metres are required, imposing a serious constraint on the ability to stack data and maintain resolution.

	Elevation Accuracy Tolerance (m)		
Frequency (Hz)	Phase Shift 36° (± 18°)	Phase Shift 50° (± 25°)	Phase Shift 100° (± 50°)
25	± 3	± 4.2	± 8.3
50	± 1.5	± 2.1	± 4.2
75	± 1.0	± 1.4	± 2.8
100	± 0.75	± 1.05	± 2.1
250	± 0.30	± 0.4	± 0.8
500	± 0.15	± 0.21	± 0.4
1000	± 0.08	± 0.05	± 0.2

Table 7 : Elevation tolerances for various frequencies assuming 36°, 50° and 100° maximum phase shifts, and a velocity of 1500 ms^{-1} (worst case velocity)

D.1.4 Off-line Tolerance

Off-line tolerance should be specified to ensure the vessel surveys reasonably straight lines in a regular grid. There may also be requirements for running survey lines across a particular point, such as the proposed well location, or boreholes and wells which are to be tied to for correlation purposes.

Acceptability criteria for off-line tolerance should therefore consider three factors:-

(i) How straight do the survey lines need to be?

(ii) How important is the regular spacing of the survey grid?

(iii) How far from the particular point of interest can data be acquired without invalidating the correlation?

Items (i) and (ii) will depend upon the sensors deployed and the local geology or bathymetry. Item (iii) depends very much upon the local geology and bathymetry. Acceptable off-line tolerance should depend upon survey objectives, not upon the positioning system used. Unfortunately, off-line tolerance will also depend upon the accuracy of the positioning system utilised and this dependence may conflict with the acceptable off-line tolerance when particularly small features are to be investigated.

D.2 Differential Global Positioning Systems (DGPS)

Since 1994, the use of DGPS for rig site surveys has almost become industry standard, based upon the increased confidence in operating reliability, technical capabilities and quality control facilities. DGPS can be used as a standalone positioning system for rig site surveys provided the system complies with the requirements laid down in *the "UKOOA Guidelines for The Use Of Differential GPS In Offshore Surveying"*. However, the use of a secondary positioning system, whether an independent DGPS system or a radio positioning system, should be considered for Quality Control, increased reliability and reduction in possible operational downtime.

As an absolute minimum, the following items should be considered before, and when, employing a DGPS system.

- Availability of at least one suitably equipped reference station which has co-ordinates determined in the WGS84 reference system.
- The type and availability of the differential link to be used.
- Differential corrections being available in approved format (for example RTCM SC 104).
- The differential corrections not exceeding a specified age (minimum 10s).
- The capabilities of the DGPS system with regard to the use of statistical testing and the computation of rigorous statistical quality measures.
- The provision of a monitor station, to provide assurance against errors, with the facility to transmit QC parameters and warning messages to remote stations (users) in near real time.
- Survey planning with respect to GPS constellation considerations.
- Elevation angle weighting and height aiding.
- Deliverables and data logging.
- The parameters to be used for the datum transformation from WGS84 to the relevant local datum, and an unambiguous convention for the direction of the rotation parameters.
- Training requirements for all personnel involved in operating the DGPS system, either onshore or offshore.

D.3 Radio Positioning

For details of items to be considered before, and when, employing a Radio Positioning System refer to *Section I, Reference Bibliography*.

D.4 Sensor Positioning

The requirement for sensor positioning should be considered, particularly where deep water surveys are planned. Deep tow survey sensors and seismic streamers may be towed a considerable distance from the survey vessel and their position will be affected by prevailing currents and winds. Off-line tolerance is as relevant to survey sensors, as it is to the survey vessel, therefore, the sensor position should be known. Determination of streamer feathering is also important *(Section C.8)*.

The most common method for sensor positioning is underwater acoustic positioning. However, its success is dependant upon range, ambient noise and water velocity conditions.

D.5 Calibration

Calibration of radio and underwater acoustic positioning systems is needed to determine the systematic errors inherent in the systems, and to check that the equipment is functioning correctly before the start, and upon completion, of the survey. For all field operations, careful attention should be paid to the calibration of the positioning system prior to the start of the survey.

Section E - Survey Equipment

E.1 Seismic Sources

Sources can be characterised by their signal levels, band width and peak frequency. These factors control the resolution and sub-seabed penetration of the seismic signal. The seismic source should be carefully selected to ensure its characteristics meet the survey requirements. In addition, lowest signal levels should be used consistent with the survey needs to minimise disturbance of cetaceans *(see Section A.2.6)*. To ensure seismic sources conform to their specifications, static pulse trials are advisable prior to utilisation.

The ideal seismic source should produce a repeatable, short duration pulse, preferably minimum phase. A minimum phase pulse is preferred since the filtering actions to which seismic signals are subjected to during propagation are minimum phase, as is much of the seismic data processing *(Section F.1)*. Non-minimum phase sources therefore require additional seismic processing to convert the data to minimum phase. Any variations in repeatability of the pulse will complicate this conversion so non-minimum phase sources should only be used if there are specific needs for their characteristics.

Some seismic sources are only suitable for operation near the sea-surface. Others may be towed either near sea-surface or near seabed. If a source is towed near sea-surface, consideration should be given to sea-surface ghost reflections *(Section C.6)*. Outgoing signal amplitudes and band width can be changed considerably by adjusting depth of tow. If a source is deep towed, less energy is lost due to spherical spreading in the water column and lateral resolution will be improved *(Section C.7)*.

Repeatability of the seismic signal is important, particularly if excessive post-processing of the data is to be avoided. To ensure good repeatability, sources will generally require regular maintenance to ensure optimum performance. Sources are particularly susceptible to fluctuations in tow depth which will affect the outgoing seismic signal. If source arrays or clusters are used, gun synchronisation is very important to ensure optimum performance and repeatability. For those sources prone to lack of repeatability or gradual degradation, shot to shot monitoring of the outgoing signal is advised. For multi-channel seismic work the far field signature of the source should be recorded on a shot by shot basis to assist processing of the data *(Section F.1.5.1)*.

It is possible to fire and record two different seismic sources on one survey pass with minimal mutual interference. This may require time gating of the two sources if they operate within the same band width. However, this requires a reduction in firing rate, degrading lateral resolution. The higher frequency sources generally used for single channel seismic work can be operated simultaneously with lower frequency sources generally used for deeper penetration single channel analogue or multi-channel digital seismic acquisition. Some compromise will be required in data quality for one or both systems and the commissioning of such dual-seismic-source surveys should be carefully considered. The deployment positions of the towed sensors should also be selected with care to prevent them from physically damaging each other.

The seismic sources recommended for use in soils investigation surveys on the UKCS are the EG & G Boomer (or similar), the Huntec Deep Tow Boomer and the NSRF Deep Tow Sparker. These systems have a broad band width, providing resolution of better than 50 centimetres and sub-seabed penetration of up to 100 metres. However, sub-seabed penetration will depend upon local soil conditions and may be severely limited compared to the figures quoted below (e.g. in gravels and tills).

If deep tow systems are to be considered, the water depth should be adequate. When using alternative seismic sources, such as pingers and chirp profilers, consideration should be given to their restricted sub-seabed penetration.

If there is an additional requirement for deeper data to assist in casing setting studies or deeper foundations, the seismic sources discussed above are unlikely to provide adequate sub-seabed penetration. For these objectives an additional survey pass with an alternative seismic source may be required. Alternatively, as discussed above, it is possible to fire and record two seismic systems on one survey pass with minimal mutual interference. If shallow gas survey data is available, this may be adequate for these deeper objectives.

E.2 Hydrophones

Hydrophones may be single element receivers but are more commonly arranged as an array consisting of multiple elements.

The advantages of a hydrophone array are an improvement in the signal-to-noise ratio, improved response to reflected signals from the target area below the receiver array, a reduction of ambient noise and a reduction of coherent noise arriving along the line of the array.

Hydrophone arrays have a pattern and spacing response which is related to the number of elements and the overall array length. The pattern response controls the directionality of the receiver. Directionality is greater for higher frequencies than for lower frequencies. The longer the hydrophone array, the more directional it becomes. It is the directionality of the array which results in the reduction in ambient and organised noise. However, if array lengths are not chosen with care they will also reduce signal levels due to this directionality. With increasing offset, signal suppression will become more of a problem, particularly at higher frequencies. Emergence angle, i.e. the angle of incidence of reflected data arriving at the receiver, is therefore very important.

If high frequency data is required, source to receiver offsets should be small and array lengths short.

When using a hydrophone array, consideration should also be given to spacing of the individual hydrophones. They should be equi-spaced to uniformly sample the wavefront, and their spacing should satisfy Nyquist sampling criteria. *Table 8* lists maximum frequency which can be sampled for different hydrophone element spacing and emergence angles.

Element spacing is usually less than 1 metre. Therefore, for acceptable emergence angles *(Section C.5)*, data in excess of 2200 Hz will be recorded (assuming the seismic source can generate these high frequencies and that there are primary reflections at these frequencies).

Emergence Angle

Element spacing	5°	10°	20°	40°
2 m	4300 Hz	2200 Hz	1100 Hz	600 Hz
1 m	8600 Hz	4300 Hz	2200 Hz	1200 Hz
0.5m	17200 Hz	8600 Hz	4400 Hz	2300 Hz

Table 8 : Maximum frequency for various hydrophone element spacing and emergence angles (velocity = 1500 ms^{-1}).

If multi-channel data is acquired, consideration should also be given to the spacing of the hydrophone receiver groups. These should also be equi-spaced to sample the wavefront uniformly, and their spacing should also satisfy Nyquist sampling theory. As receiver group spacing is usually an order of magnitude greater than element spacing, it is of far greater importance when considering Nyquist sampling criteria. *Table 9* below lists maximum frequency which can be sampled for different hydrophone group spacing and emergence angles.

	Emergence Angle			
Group spacing	5°	10°	20°	40°
25m	340 Hz	170 Hz	90 Hz	50 Hz
12.5m	690 Hz	350 Hz	180 Hz	90 Hz
6.25m	1380 Hz	690 Hz	350 Hz	190 Hz

Table 9 : Maximum frequency for various hydrophone group spacing and emergence angles (velocity = 1500 ms^{-1}).

The most common hydrophone group spacing is 12.5m, so if frequencies in excess of 200 Hz are required, the emergence angle should not exceed 18 degrees (approximately). If 25 metres group spacing is used, the emergence angle should not exceed 9 degrees. Figure 5 shows the effect of 18 degrees and 9 degrees emergence angles, assuming a simple geological and acquisition model. At sub-sealevel depths of 200 metres this may mean that only single fold data can be acquired without aliasing of the data.

Figures 8, 9 and 10 show the array response for a 6.25 metres, 12.5 metres and 25 metres group length streamers, respectively. The Nyquist Wavenumber (Kny) is shown on the plots for 6.25 metres, 12.5 metres and 25 metres group intervals. Also shown are noise, aliased noise and seismic data (10 degrees and 20 degrees emergence angles) on a FK (Frequency - Wavenumber) plot. If the group length is the same as the group interval, the first notch produced by the array will provide some attenuation of data aliased by the group interval, protecting seismic data. However, if either the group length is less than the group interval, or the group length is more than the group interval (overlapping arrays), aliased data will not be attenuated and will appear in the seismic data as noise.

Figures 8, 9 and 10 also show that aliased noise and data will be suppressed when they cross the K=O axis, particularly at low emergence angles. If the group interval is twice the group length, the Nyquist Wavenumber will be halved and the suppression of the first notch will not benefit the data.

The need for short group lengths for high frequency data is clearly indicated in *Figures 8 - 15*. The figures show the benefits of acquiring data with short group length/interval streamers. The shorter the group length, the less directional the array at high frequencies, and the higher the frequency which will be protected from aliasing of noise or seismic data.

Hydrophones may be towed near sea-surface or, in the case of deep tow systems, near seabed. If they are towed near sea-surface, consideration should be given to sea surface ghost reflections *(Section C.6)*. Received signal amplitudes and band width can be changed considerably by adjusting depth of tow.

Preservation of signal-to-noise ratio is of great importance for the seismic method. Noise should therefore be minimised when towing hydrophones. The condition of the hydrophone array is of importance for minimising noise. Air bubbles within the kerosene filling of the streamer, and external fittings such as lead weights or depth controller birds, will generate noise. Survey vessels should be acoustically 'quiet' as vessel generated noise must not severely degrade signal-to-noise ratio. Therefore, the offset from the stern of the vessel is also of importance to reduce ship generated noise.

The basic characteristics of hydrophones commonly used for rig site surveys are summarised below. Where relevant, array response curves are provided to illustrate the directionality and Nyquist sampling criteria.

E.2.1 Single Channel Hydrophone Characteristics

Band width	:	20 - 10,000 Hz
Directivity	:	See array response curves, *Figure 11 and 12*

E.2.2 Hydrophone arrays for multi-channel acquisition

The streamer arrays in common usage in the UKCS have group lengths of 6.25 metres, 12.5 metres or rarely 25 metres. Due to the large number of manufacturers of these arrays, only typical characteristics are listed below.

Band width	:	5 - 1000 Hz
Directivity	:	See array response curves, *Figures 13-15*

Typical parameters for a streamer array for use in shallow gas surveys on the UKCS follow below:-

- 48 groups minimum.
- Group length 6.25 to 12.5 metres.
- 600 metres minimum active length.
- Depth controllers and indicators at least every 100 metres.
- Preferably equal spacing of hydrophone elements throughout the streamer.

A 600 metre streamer may not provide adequate moveout for deeper objectives (1000 metres). For good velocity control at these levels, longer streamers, 1000 - 1200 metres in length, should be considered.

3 Seismic Recording and Display

E.3.1 Multi-channel Digital Recorders

The purpose of these systems is to convert analogue signals into digital form for recording on magnetic medium.

They are designed to record seismic data with minimal loss of fidelity. Upon replay of the data it should be possible to reconstruct the original input analogue signals. To ensure the systems are operating to specification, comprehensive system tests are required on a daily and monthly basis.

Important characteristics are discussed below.

- **Digital Sampling:** The sampling interval of the system should allow preservation of the band width required for resolution. When applying Nyquist sampling criterion it must therefore be less than half of the shortest wavelength of the frequency to be sampled. To sample 1000 Hz then a sample interval of 0.5 milliseconds is required, whereas to sample 250 Hz then a 2 millisecond sample interval will suffice. In practice, the signal phase is affected at 70 percent of the Nyquist frequency.
- **Anti-alias Filter:** Any signal with a frequency greater than the Nyquist frequency will alias back into the signal spectrum. A high cut filter is required therefore to reduce the amplitude of these frequencies. Traditionally, the filters are selected to start at ½ Nyquist frequency. The slope of the filter is chosen to conform with the source and hydrophone characteristics and is steep (~ 72 dB per octave) so that there is high attenuation of noise (and any data) at the Nyquist Frequency. However, to preserve the band width of the data, without the requirement for increased sampling intervals, the filter should start at around ¾ of the Nyquist frequency. This may allow a small amount of aliasing, but will preserve higher frequencies.
- **Low-cut Filters:** Low cut filters can be used to attenuate low frequency noise. Such noise, however, is best attenuated in the seismic processing stage. The low-cut filter should therefore be designed such that it does not affect the band width of the source. A low-cut filter in the order of 8-12 Hz is recommended for the sources typically used for rig site surveys. Care should be taken to ensure the low-cut filter is designed to exclude noise which might overdrive the analogue-digital signal converter. If this happens the dynamic range available for the seismic data may be substantially reduced.
- **Dynamic Range:** The dynamic range of a digital recorder is limited by the number of bits available in the system. The standard for UKCS operations is 16 bit recording with IFP which gives typical dynamic ranges in the order of 72-84 dB. The amplitude ratio between RMS signal and RMS noise is generally greater than 100 dB (1:100,000). New technology is constantly improving the effective dynamic range of the reproducible signal. This extends the signal to noise range and increases the potential for computer workstation analysis of seismic data, including attribute analysis techniques. 24 bit recording will increase the dynamic range to 115-120 dB. Careful selection of filter and amplifier gain settings, as well as seismic source and hydrophone selection and geometry, are required to ensure that the dynamic range in the signal matches the recorder performance.

- **Cycle Rate:** This is the minimum time between successive fire commands that the system will record. It depends on the system performance and the chosen record length. With fast source firing, record length may need to be chosen carefully.
- **Number of Channels:** This is the number of data channels which can be recorded at each shot point. Data from the hydrophone streamer should be recorded together with the far field source signature and time break.
- **Number of Samples Recorded:** This will depend upon sample interval and record length.
- **Data Recording:** The standard recording formats are SEG B or SEG D formats at 1600 or 6250 bits per inch. New data recording technology is increasing the available options.

E.3.2 Analogue Chart Recorders

Data can be recorded on electrosensitive or thermal paper. The dynamic range of such recording is in the order of 24 dB.

A wide variety of recorders exist, but the important characteristics for seismic data are repetition rate, sweep speed and rate of paper advance. The recorders should permit display of the seismic data at a scale which allows the resolution of the data to be exploited without excessive scale distortion. Vertical exaggeration of such records is valuable. Excessive overlap or undue spacing of traces should be avoided.

As discussed in more detail in *Section E.2*, several options exist for processing analogue, single channel data. This is usually undertaken on line.

E.3.3 Other Data Recorders

Single channel analogue seismic and sonar data may be recorded in analogue form on magnetic tape or in digital form on DAT tapes, computer discs or optical discs. No standard formats exist for these data although attempts are being made to standardise digital formats. These seismic data are now often recorded in SEG Y format. Multi-channel recordings should include raw data, trigger, and event mark or fix data on separate channels.

Dynamic range of the RMS signal to RMS noise of these recordings is in the order of 48 dB. Tape speed should be selected to ensure the full band width of the data can be recorded.

E.3.4 Video Display Units

These allow colour display with a greatly improved dynamic range of at least 65 dB. However, unless hard copy colour records are also available, these displays are more suitable for search and inspection work.

E.4 Side Scan Sonars

To detect obstructions on the seabed and delineate seabed features, dual channel side scan sonars with operational frequencies of 100 kHz or higher should be used. These systems provide transverse (perpendicular to track) resolution of events to 20 centimetres in good weather conditions. If there are particular requirements for identification of very small seabed features or objects, then a very resolute system should be used, operating at around 500 kHz. These systems will allow resolution of events to 10 centimetres or less in good weather conditions.

The selected sonar range should be greater than the survey line spacing to ensure adequate overlap of sonar coverage. 100 percent overlap is the accepted industry standard.

Transducer beam widths and depression angles should be selected for optimum resolution and data coverage in the survey area.

True-scale systems, which remove scale distortions in the sonar record are commonly available. These systems do not offer any enhancement of data quality (in fact the reverse may be true), but may be useful for interpretation purposes.

A wide variety of side scan sonar systems are available, many of which are suitable for rig site surveys. Sonars can be characterised by their frequency of operation, horizontal and vertical beam width, pulse length and pulse repetition rate. These factors will control the resolution and range of the sonar system.

E.4.1 Resolution

Theoretically, resolution of side scan sonar systems is primarily controlled by pulse length, pulse repetition rate and the beam widths. Also of great importance are the sonar height above seabed and the range. However, as discussed in *Section E.4.4*, the resolution limitations of the display media are usually greater than those of the rest of the system, and the theoretical resolution values discussed below are therefore somewhat academic. In addition, sonar fish movements such as yaw and pitch will degrade the theoretical resolution figures provided below. Resolution can be sub-divided into transverse (or perpendicular to track) and axial (or along track).

The transverse resolution primarily depends on pulse length. Due to the way in which the data is displayed (amplitude modulated), transverse resolution is not likely to be better than the pulse length of the system. This equates to resolution of features on the record which are separated by one half of the pulse length, due to two way travel time considerations. The following resolution should therefore be possible:-

Pulse Length (ms)	Range Resolution (cm)
0.2	15.0
0.1	7.5
0.02	1.5
0.01	0.75

However, due to the slant range distortion within the sonar data, these range resolutions will only be "correct" at extreme sonar ranges, where the angle of incidence is close to the horizontal.

The axial resolution is controlled by the beam width and the pulse repetition rate combined with the vessel ground speed. Beam width along track is dependent on the sonar transducer. Figures for beam width are quoted by manufacturers but they should be treated with caution as they are often optimistic. Beam width will dictate better resolution at short ranges than at longer ranges. Point source reflections become axially stretched at increased range. Some systems perform better than others in suppressing this stretch effect. Primary lobe widths are quoted, whilst secondary lobes are usually ignored. Beam width for side scan sonars is usually quoted as being defined by the -3 dB points. Table 10 tabulates the diameter of the area insonified by the sonar beam at various ranges for different beam widths.

	Slant Range (m)					
Beam width	5	10	25	50	100	200
0.2°	2 cm	3 cm	9 cm	17 cm	35 cm	70 cm
1°	9 cm	17 cm	44 cm	87 cm	175 cm	349 cm

2°	17 cm	35 cm	87 cm	175 cm	349 cm	698 cm
5°	44 cm	87 cm	218 cm	437 cm	873 cm	1746 cm

Table 10 : Diameter of area (in metres) insonified by the sonar beam at various ranges, for different beam widths

Repetition rate will depend upon the range required since there should be sufficient time between pulses to display the required seabed returns. However, along track sampling interval is linked to repetition rate and vessel ground speed. Vessel speed is therefore important as a control for axial resolution. *Table 11* tabulates the along track sampling interval in centimetres for various repetition rates, assuming a vessel ground speed of 2 metres per second (3.9 knots survey speed).

Repetition Rate (Hz)	Theoretical maximum slant range (m)	Along track Sampling interval (cm)
16	47	12.5
10	75	20
8	94	25
5	150	40
4	188	50
2.5	300	80
2	375	100

Table 11 : Along track sampling interval (in centimetres) for various sonar repetition rate (vessel speed 2 ms^{-1} or 3.9 knots ground speed).

The beam width effect, combined with the repetition rate, may result in undersampling at close ranges (with narrow beam widths) and the possibility of missing small features. At far ranges, the resolution degrades due to the size of the area from which reflections are received, but data will not be undersampled. 100% overlap ensures that areas undersampled on one pass are sampled on the adjacent line.

Sonar fish movements (e.g. yaw, pitch, heave and roll) additionally degrade lateral resolution, resulting in irregular sampling of the seabed.

It can be seen from the above that resolution depends on several factors. In general, axial (along track) beam width is the limiting factor, which only loses its importance at either very short ranges and/or with very narrow beam-width systems.

E.4.2 Detectability

Theoretically, when using narrow beam width systems at short ranges, very small objects, e.g. 20 centimetres by 10 centimetres, should be detected. However, for the eye to recognise a significant event, the event should be large enough to cause returns from several sonar scans. A linear object oriented perpendicular to the sonar fish track will be less easy to detect than one oriented parallel to the sonar fish track. Also, small features falling within the acoustic shadow of larger features may not be detectable. See also the cautionary note in *Section E.4.4* about use of slant range corrected side scan sonar.

E.4.3 Range

The range of side scan sonar systems is controlled by signal level, signal-to-noise ratios and carrier frequency of operation. Lower frequency signals are required for longer range operations, but this will reduce resolution, due to increased pulse length and beam width. In some circumstances, particularly in shallow water, surface returns and/or thermoclines may limit effective range.

E.4.4 Recording and Display

Apart from the characteristics of the sonar transducer, the display/recording media is of great importance for resolution. Data can be recorded on electrosensitive or thermal paper which have a dynamic range in the order of 24 dB. A wide variety of recorders exist but the important characteristics for sonar data display are repetition rate, sweep speed and rate of paper advance. Recorders should permit display of the sonar data at a scale which allows the resolution of the data to be exploited without excessive scale distortion or loss of information. The axial resolution of the system will be degraded unless the data is digitised and displayed on some other medium than the conventional wet/dry or thermal paper analogue recorders.

Table 12 tabulates sonar display resolution in centimetres for various ranges and paper widths. The table assumes the minimum spacing on a record for being able to resolve two events by eye is 0.2 millimetres.

	Range (m)				
Paper width per channel	50	100	150	200	500
10 cm	10 cm	20 cm	30 cm	40 cm	100 cm
20 cm	5 cm	10 cm	15 cm	20 cm	50 cm

Table 12 : Sonar display resolution for various ranges and paper widths.

True scale recording systems which remove distortions in the sonar record have become popular within the offshore survey industry. These require digitisation of the sonar signal which may limit the band width of the signal, depending on the sample rate. Resolution and the effective dynamic range of the display will be degraded, due to restricted band width and to the geometric expansion of each sample. These systems are useful for data interpretation but should be used with care if resolution is of great importance. Objects located directly below the side scan towfish may not be resolved in a slant-range corrected display due to a combination of restricted sampling and smoothed height correction which often relies on primary lobe signal strength and not the attenuated side lobe energy.

Side scan sonar data may be recorded in analogue form on magnetic tape or in digital form on DAT tapes, computer discs or optical discs. No standard formats exist for these data although attempts are being made to standardise digital formats. Multi-channel recordings should include raw data, trigger, and event mark or fix data on separate channels. Dynamic range of the RMS signal to RMS noise of these recordings is in the order of 48 dB. Tape speed should be selected to ensure the full band width of the data can be recorded.

Video Display Units are becoming more common. These allow colour display with a greatly improved dynamic range of at least 65 dB and the ability to undertake interactive interpretation of the data. However, unless hard copy colour records are also available, these displays are more suitable for search and inspection work.

E.5 Echo Sounders

Bathymetric measurements should be undertaken with a precision, heave compensated echo sounder. Echo Sounder frequency of operation shall be commensurate with survey objectives. Dual recording of data with and without heave compensation is recommended. Depending upon the sea state, it may not be necessary to apply heave compensation.

Careful calibration of the echo sounder should be undertaken for index error, transducer draught and speed of sound through the water column.

A wide variety of echo sounder systems are available, many of which are suitable for rig site surveys. Echo sounders can be characterised by their frequency of operation, beam width and signal levels. These factors will control the resolution and range of the echo sounder. Careful consideration should also be given to heave compensation to remove the effects of swell on the records.

Swathe (multi-beam) echo sounder/bathymetry systems are becoming increasingly available. However, the requirement for such detailed bathymetry is generally difficult to justify for rig site surveys in the UKCS. In areas where bathymetry is particularly irregular, there may be some benefit in utilising these specialist systems. If these systems are used, careful calibration and the addition of suitable motion sensors are essential.

E.5.1 Resolution

Theoretically, resolution of echo sounders is primarily controlled by beam width and pulse repetition rate. Frequency of transmission, water depth and the display medium are also of importance.

The beam width of the transmitted signal is dependent on the echo sounder transducer characteristics. Figures for beam widths are quoted by manufacturers but should be treated with caution, as they rarely provide their criteria for measuring beam width. The beam width results in reflections from an area of the seabed (area insonified), not a single point. This effect produces better resolution at short ranges than at longer ranges. It also limits the width of deeper areas which are capable of being identified e.g. deep localised depressions such as some pockmarks. In areas with steep gradients contours can be displaced and the depth of water beneath the vessel will be greater than that displayed by the echo sounder.

Beam width for echo sounders is usually quoted as being defined by the -3 dB points. *Table 14* shows the diameter of the area insonified in metres for various beam widths and water depths. For example, with a beam width of 3 degrees in a water depth of 100 metres, the detected water depth will be the shallowest point within an area of 5.2 metres diameter.

	Water Depth (m)				
Beam Width	25	50	100	150	300
3°	1.3	2.6	5.2	7.9	15.7
8°	3.5	7.0	14.0	21.0	42.0
15°	6.6	13.2	26.3	39.5	79.0
20°	8.8	17.6	35.3	52.9	105.8

Table 14 : Diameter of the area insonified (in metres) by an echo sounder, for various beam widths and water depths.

Repetition rate will depend upon the water depth, since there should be sufficient time between pulses to display the seabed return. *Table 15* tabulates the along track sampling interval in centimetres for various repetition rates, assuming a vessel speed of 2 metres per second (3.9 knots).

Repetition Rate (Hz)	Range (m)	Along track Sampling Interval (cm)
10	75	20
5	150	40
2.5	300	80
0.5	1500	400

Table 15 : Along track echo sounder sampling interval for various repetition rates and ranges (vessel speed of 2 ms^{-1}).

Due to beam width effects, even with low repetition rates it is very unlikely that the seabed will be undersampled unless the vessel is surveying at high speed.

Operating frequency also controls resolution, since the sharpness of the pulse, and therefore the ability to recognise precisely the time of the seabed return, will depend upon it.

E.5.2 Range

The range (maximum water depth) in which an echo sounder can operate is controlled by signal level, signal-to-noise ratio and frequency of operation. Low frequency signals are required for deep water operations, but this will reduce resolution due to increased pulse length and beam width.

E.5.3 Chart Recorders

Data is generally recorded on electrosensitive or thermal paper. The important characteristics of the recorder for echo sounder data are repetition rate, sweep speed and rate of paper advance. The recorders should permit display of the data at a scale which allows the resolution of the data to be exploited.

E.5.4 Digital Recording

Digital recording of depth is commonly employed. Analogue signals are converted to binary form and displayed, and should then be recorded on Computer Compatible Media (CCM). Resolution of the data will then depend upon the sampling interval employed for analogue to digital conversion and the ability of the recorder to respond to the repetition rate of the echo sounder.

E.5.5 Heave Compensators

For precise measurements of seabed depth, heave compensation systems are required. Heave compensation may be applied on-line or during post processing of the data. If applied on-line, raw echo sounder data should also be recorded.

E.5.6 Calibration

Careful calibration of echo sounders should be undertaken for index error, transducer draught and speed of sound through the water.

E.6 Marine Magnetometers

These systems are required for the detection of ferromagnetic objects on or near the seabed. A search of the relevant Admiralty charts and Operator records should be undertaken to decide upon the need for a magnetometer survey. Of particular interest are objects which would be dangerous to rig installation and subsequent drilling operations, which may not be identified by the other survey sensors e.g. abandoned ordnance, buried wrecks, power cables, telephone cables, etc.

The sensor should be towed at a distance from the vessel such that the vessel will not produce electromagnetic interference on the magnetometer records. A generally accepted rule is that the sensor should be towed astern of the vessel with a separation of at least three times the vessel length. In addition the sensor should be towed close to the seabed, preferably at a constant height just above the seabed as the distance of the sensor from the object, controls the amplitude of the magnetic anomaly recorded. For example, to detect a buried telephone cable, the sensor should be towed within 3metres of the seabed, perpendicular to the cable. As a 'rule of thumb', for objects with a finite length, such as wrecks, the amplitude of the anomaly varies inversely as the cube of the distance. For objects with infinite length compared to their diameter, such as pipelines, the amplitude of the anomaly varies inversely as the square of the distance.

The important characteristics of a magnetometer are the sampling rate and the sensitivity.

Typical **sampling rates** should be in the order of 1 per second. At a survey speed of 2 metres per second this provides a resolution of 2metres. For the detection of small objects such as cables, slower survey speeds are therefore required. This may require the vessel to drift with prevailing winds and currents.

Sensitivity should be better than 1 gamma (nanoTeslar) to ensure detection of small anomalies against background magnetic effects. The display system, whether on a hard copy strip chart recorder or as a computer generated graphical display should also be capable of discriminating to this resolution.

Table 17 and Figure 16 show the typical maximum anomalies which can be expected from various objects, depending on their distance from the magnetometer sensor.

Object	Near Distance	Far Distance
Background Noise	10 gamma	
Ship (1000 TONS)	300 - 700 gamma (30m)	0.3 - 0.7 gamma (300m)
Pipeline (12 inch diameter)	50 - 200 gamma (8m)	12 - 50 gamma (24m)
Wellhead and Casing	200 - 500 gamma (15m)	2 - 5 gamma (150m)
Telephone Cable	100 gamma (3m)	0.1 gamma (30m)

Table 17 :Typical maximum magnetic anomalies of common objects (adapted from 'Applications Manual for Portable Magnetometers', S Breiner).

E.7 Resistivity

Seabed resistivity can be used for prediction of soil lateral variability but the surveys are much slower to acquire than acoustic surveys. Although the level of detail provided by such data is more appropriate for engineering geophysical surveys, acquisition of these data could be considered for areas where shallow soils variations will impact significantly on rig installation.

Seabed resistivity surveys can detect a similar range of objects as marine magnetometer surveys. Resistivity surveys could be considered for specific rig site surveys where identification of objects is of importance. These data will give the opportunity to image in 3D the location, size and shape of the object.

E.8 Seabed Sampling and In Situ Measurements

Seabed sampling for calibration of the geophysical data should be undertaken.

It is recommended that gravity core and/or grab sampling is undertaken as a minimum. The number of coring locations and their desired position should be selected from the survey data. Core samples should be treated with care to minimise disturbance. Samples should be sealed into their liners using wax, clearly labelled and then stored in a vertical position.

Seabed sampling to obtain samples for jack-up leg penetration studies is considered to be outside the scope of these procedures. This is covered by the guidelines referred to in *Section A.5, A.6 and A.7*. However, it is possible to deploy lightweight PCPT/CPT systems and vibrocorers from some survey vessels. These systems provide suitable data for analysis of geotechnical characteristics of shallow soils but have limited sub-seabed penetration. In the case of vibrocores, samples can be very disturbed and geotechnical characteristics of the core may not be representative of in-situ conditions.

A wide variety of systems for seabed sampling are available. The systems can be characterised by their depth of sub-seabed penetration and degree of sample disturbance. These technical notes cover geophysical and hydrographic aspects of rig site surveys. Discussions on seabed sampling are therefore confined to systems which can be deployed from the vessels undertaking these surveys. Seabed sampling in this context is usually only undertaken for calibration of the seabed and shallow geophysical data to improve the reliability of the interpretation. It is generally limited to a maximum of 6 metres sub-seabed penetration.

For semi-submersible rigs such limited sampling may be adequate for interpreting anchoring conditions. However, Specialist advice should be taken on the suitability of the data. For jack-up rigs, it is likely that additional geotechnical data will be required. This is covered by the guidance referred to *in Section A.2.1, A.2.2, A.2.7 and A.2.8.*

The systems used for rig site surveys can be divided into four categories:

(i) Grab samplers.

(ii) Gravity and piston corers.

(iii) Vibrocorers.

(iv) PCPT and CPT systems.

Basic characteristics of the systems are discussed below.

E.8.1 Grab Samplers

Grab samplers provide highly disturbed seabed samples. Although of limited value, they can sometimes be useful for obtaining samples of coarse sands or gravels which are difficult to core with gravity corers. They are, however, occasionally the only method by which some seabed data can be obtained without resorting to more expensive systems such as those in *E.8.3 and E.8.4*, below.

E.8.2 Gravity and Piston Corers

These systems are cheap and do not require heavy lift capability. Penetration is usually less than 50 centimetres unless soils are soft. Sample disturbance is high. They are very useful for providing basic soils data to assist shallow geophysical interpretation.

There are various designs of gravity corer. Important characteristics which need to be incorporated in the design in order to ensure maximum penetration and sample retention are:

- A hydrodynamic design to ensure vertical entry of the gravity corer into the seabed after free-fall.
- One way core retention devices and top-valve systems to ensure maximum retention in a variety of soil types.
- A low ratio of maximum annular core cutter and barrel cross-sectional area to the cross-sectional area defined by the minimum inside diameter of these components.
- The availability of a selection of core cutters to suit different soil conditions.
- A variable weight system to suit different soil conditions.

Piston corers are difficult to use and are only suitable for soft clays. This precludes their use throughout much of the UKCS. However, the use of piston corers may increase in the soft clays which prevail in the deep waters of the Atlantic Margins.

E.8.3 Vibrocorers

These systems require the vessel to remain on station by means of anchors or thrusters.

Maximum penetration is 6metres but sample disturbance is high. They are useful for providing soils data to assist geophysical interpretation, but may also provide samples suitable for basic geotechnical analysis.

The use of a vibrocorer with in-built penetration indicator and in situ retraction of the core barrel before lifting the device off the seabed, improves the quality of the vibrocore samples.

E.8.4 Piezocone Penetrometer Test (PCPT) and Cone Penetrometer (CPT) systems

PCPTs are preferred as they also supply pore pressure measurements. Some of these systems require a heavy lift capability but light weight systems are now available. The vessel should also be able to remain on station by means of anchors or thrusters.

Penetration is generally good. Sleeve and point resistance's on the cone are measured, in conjunction with pore pressures. From these measurements, information can be obtained on soil lithologies, and an empirical estimate of either the in situ shear strength of clays or the relative density of sands can be made. The results are therefore useful for providing very good in situ data on soil properties and also soils data to assist geophysical interpretation. However, if sampling of the seabed is of importance for geological input on soils, PCPTs or CPTs should be supplemented with cores.

E.9 Positioning

A suitable positioning system should be chosen to provide the precision required for the survey. For rig site surveys, the requirements for precision are dictated primarily by the ability to recover a position repeatedly, and the ability to run straight lines in a regular grid.

E.9.1 Differential Global Positioning Systems (DGPS)

DGPS potentially enables users to fix their horizontal and vertical position continuously and in near real time to better than five metres, provided that certain conditions are fulfilled. For further information and guidance please refer to the Guidelines for the Use of Differential GPS in Offshore Surveying *(Section A.2.4.)*.

The variety of systems available to cover the UKCS (and many systems also offer coverage world-wide) apply different techniques for calculating the Differential Corrections and relaying them to users. Differential Corrections can be taken from one or more Reference Stations. The Differential Corrections can either all be received by the user and used in the position calculation, or be received at a central location and reworked into one set of Corrections before being sent to users. Differential Corrections can be sent by communication satellite (Inmarsat or Eutelsat), by radiolink or as add-on to existing radio positioning frequencies (PulseLink via Pulse/8 signals).

E.9.2 Radio Positioning

Radio positioning systems can be characterised according to frequency of operation, method of signal transmission and their pattern geometry. As a general rule the lower the frequency the longer the range, the less the precision and the higher the cost.

For further details on the operating principles of Radio Positioning Systems refer to *Section I, Reference Bibliography*.

E.9.3 Underwater Acoustic Positioning

Underwater acoustic positioning is the most common method of positioning towed sensors. For rig site survey work vessel mounted systems are required. These can be divided into two main categories.

E.9.3.1 Ultra Short Baseline (USBL) Systems

These systems may also sometimes be referred to as Super Short Baseline (SSBL) systems and are commonly fitted to rig site survey vessels. Manufacturers quoted precision for such systems is typically +/- 1% of the range but this deteriorates with very long ranges.

These systems use a single, hull mounted, multi-element, transducer. They utilise acoustic ranging and phase comparison techniques to measure range and bearing to a responder, or transponder, attached to the towed sensor. Transducers may be fixed or tracking. The tracking transducer offers improved performance at longer offset distances.

Maximum range is frequency dependent and also limited by ambient noise levels. It is normally in the order of 1000 metres which is adequate for most operations on UKCS. High power transponders are available which can more than double this range for deep water surveys which require longer sensor lay-backs.

USBL systems should be compensated for the vessel's pitch and roll and require a Motion Reference Unit (MRU) installed as close as possible to the transducer head. They also require input of vessels heading from a calibrated gyro compass. Calibration of these systems is of prime importance for the precision of the measurements.

USBL systems are, inherently, without redundancy in the measurements, making quality control difficult. The main sources of error are incorrect initial bearing, arising from gyro compass and transducer alignment errors, and ranging errors arising from unpredictable acoustic propagation in an inhomogeneous water column.

E.9.3.2 Short Baseline (SBL) Systems

These systems are commonly used for exploration seismic surveys but are rarely available on rig site survey vessels. They use three or four transducers mounted on the vessel hull, or occasionally suspended from booms, and utilise acoustic ranges to develop a network by normal survey techniques.

Maximum range is limited by ambient noise levels. It is normally in the order of 2000 metres.

The systems should be compensated for the vessel's pitch and roll and require a MRU to be installed as close to the vessel centre of gravity as possible. They also require input of vessels heading from a calibrated gyro compass. Calibration of these systems is of prime importance for the accuracy of the measurements.

The precision of the system is largely a function of the separation of the ship-borne transducers. Transducer positions should be measured in dry dock when they are fitted to the hull. Other main sources of error are incorrect initial bearing, arising from gyro compass error, and ranging errors arising from unpredictable acoustic propagation in an inhomogeneous water column.

SBL systems allow for redundancy in the measurements, meeting the basic requirements for positioning quality control. The systems are very effective for tracking sensors close to a vessel with precision in the order of 2-3 metres. However, without independent checks (e.g. GPS tail-buoy tracking) to adjust scaling errors, precision decays rapidly with range.

Typical frequencies and ranges are listed below:-

	Band width	Maximum Range
MF	18 - 36 kHz	2 km.
HF	32 - 64 kHz	> 1 km.

Section F - Data Processing

F.1 Multi-Channel Seismic Data

F.1.1 General

Careful quality control of processing should be maintained throughout a project as poor processing can degrade seismic data. Involvement of a seismic processing Specialist is recommended.

Operational constraints may require data to be processed with a very short turnaround. This should be avoided wherever possible.

Previous projects undertaken in the area should be reviewed to see what problems were encountered in processing, which processes were successful, and which processes failed.

F.1.2 Supply of Information to the Processing Centre

The Operator should ensure that the processing centre is fully briefed on the project's aims. The processing centre should be aware of features of particular interest, e.g. channels, faulting or critical hazard levels.

The following data should be supplied to the processing centre before the start of the processing:-

- An exploration seismic profile which passes through the well location. If the deeper data is confidential, the seismic profile can be cut off at a shallow time level, e.g. 1500 milliseconds TWTT. Velocity data should be provided to assist in analysis of velocity trends.
- Examples of previous site survey seismic data from the same, or an adjacent area.
- An example of the single channel sub-bottom profiler data acquired in the survey. This can be useful in distinguishing real events from processing artefacts in the top 30-40 metres sub-seabed.
- The results of any velocity calibration surveys from nearby wells.
- Acquisition parameters.
- Seismic shot point chart and Post Plot Positioning Data on tape *(UKOOA P1/90 format).*
- Far field signature of the seismic source in use.

F.1.3 Quality Control

All processing should be subjected to rigorous Quality Control (QC).

Unless a detailed processing strategy is specified by the Operator, the processing centre should be expected to show its own initiative in the suggestion of processes to be applied to the data. All processes that are applied should be justifiable. This should be demonstrated by the supply of relevant test panels.

The following types of general QC display are recommended (excluding parameter testing):-

- Display of near streamer group for each shot, on each line. This will check for timing errors and source degradation.
- Display of at least one shot (all traces) every 50 shots, on each line. This will check for dead, noisy, or reversed polarity traces.
- A "brute" stack section using a single velocity function. This will check general data quality.

- Velocity analyses from each line. This will ensure that the correct velocity trend has been picked.
- Iso-velocity displays for each line, to check for velocity anomalies.
- NMO corrected gathers, displayed at each velocity analysis location. This will check velocity corrections have been properly applied.
- Display of each line with pre-stack processing applied. This is another type of velocity check, as well as being a tool for the QC of pre-stack processing.
- Display of the migrated data (if relevant) for each line. This will check that an acceptable output from migration has been achieved.
- Electrostatic display of the final processed data (in scaled and relative amplitude form) for each line. This will check the acceptability of final processing quality and display.
- Dyeline print of film (if required) displays for each line. This will check for the acceptability of presentation quality, plot direction, polarity, line intersections, side label etc.

The above displays are to check for errors in data acquisition and the correct application of chosen processing parameters. With the exception of velocity analyses, this list does not include any parameter test displays.

F.1.4 Parameter Testing

Parameter testing should be applied on data that is representative of the whole dataset. If conditions differ widely across the survey area then the use of two, or more, test areas should be considered.

The application of different processes is described in *Section F.1.5*.

To determine which processes need to be applied to the data, the following processes should be tested as a minimum:

- Designature
- Gain recovery
- Deconvolution Before Stack (DBS)
- Mute (outer and inner)
- Deconvolution After Stack (DAS)
- Time variant filter
- Balance/scaling
- Display trials (bias, polarity, dual polarity etc.)

Additional processes which should be considered include:

- Demultiple
- Dip Moveout (DMO)
- Stack parameter tests
- Zero phase conversion
- Time migration
- Post-stack noise attenuation (FK dip filter)

The number and type of parameter variations to apply within each test level should be agreed prior to starting the testing.

In choosing processing parameters, an open mind should be maintained. It is quite possible that data from adjoining locations, shot with similar acquisition parameters, will respond in a very different way in processing due to variations in geology. A set of processing parameters should not be applied purely on the basis of their success on a previous project. Changes in noise levels, streamer tow depths, source characteristics etc., may have an impact on the effectiveness of a previously successful processing sequence.

F.1.5 Processing Techniques

This section briefly describes the processing techniques named in *Section F.1.4* above. The discussion includes benefits to be gained from the techniques as well as problems that may be generated by their application. The techniques are discussed in the order in which they should be applied. If any particular technique is not required it can simply be omitted without affecting the order in which the remaining processes are applied.

At the end of each section, a reference is given for the process, providing specific technical background should further detail be required. For general reference to processing techniques, Yilmaz (1987) and Hatton, Worthington and Makin (1986) are recommended.

F.1.5.1 Designature

A designature operator which converts the outgoing (far field) source signature to its minimum phase equivalent should be applied. The frequency spectrum should be left unaltered. Although the majority of sources available in the UKCS provide minimum phase, repeatable signatures, application of designature will benefit the data. Designature should be applied to all watergun data.

The operator should be designed using the far field source signature, recorded in the field on an auxiliary channel. If, due to operational circumstances, this was not recorded, a library source signature should be used, or an operator extracted from the seabed return.

Correct application of the process should improve the vertical resolution by the compression of the pulse. In addition, subsequent deconvolution should be improved as these processes assume data to be minimum phase.

F.1.5.2 Gain Recovery/Amplitude Manipulation

Corrections for spherical spreading and absorption have to be applied to the data. This is a critical process as a great deal of the later interpretation effort is based purely on a consideration of reflection amplitude. If amplitude manipulation is handled carelessly, an anomaly can be either created or hidden. The preservation of relative amplitude relationships should therefore be addressed throughout processing.

Traditionally, gain recovery was the first step in processing, using either a linear gain, or a spherical spreading compensation function of the form TVV (where V is the RMS velocity at time T). The use of the TVV approach is recommended. It is more likely to provide more consistent results than a "hand-picked" gain recovery function, and will allow easier comparison between datasets.

It is recommended that the application of gain recovery is undertaken post-stack in the processing sequence. However, some pre-stack processes, such as deconvolution, benefit from the input trace amplitudes being balanced beforehand. In such cases the amplitude manipulation should be of a type that can be accurately backed off after the intermediate process has been applied. This will then leave the original amplitude relationships unaffected. A simple exponential gain function is commonly used.

Automatic Gain Control (AGC) techniques should be used with care. They should only be used as a last step before production of an equalised or scaled *display (see Section F.1.5.14 below).* However, techniques are available for application of removable AGC processes. These could be used as treatment of data prior to some pre-stack processes. Such techniques should be used with extreme caution, ensuring that scalars are removed correctly.

With noisy data there may be the temptation to apply a long gate AGC pre-stack to attenuate high noise amplitudes from entering the stack. This is not advised as real reflection amplitude relationships will be adversely affected.

Ref: Hatton, Worthington and Makin (1986).

F.1.5.3 FK Demultiple

FK demultiple techniques should be considered in deep water areas where long period multiple trains cannot be adequately removed by use of predictive deconvolution techniques alone. The technique can also be used successfully on any dataset where there is adequate differential between primary and multiple signal energy in the FK domain.

The technique will not remove the multiple on the inner, short offset traces, where the multiples are more horizontal and harder to split from the primaries in the FK domain. In these cases an inner trace mute is often applied.

Great care should be taken in the definition of the reject zone for the FK filter. If a multiple remains, the effect of predictive deconvolution in removing the remaining multiples should be evaluated. If this is unsuccessful, a carefully chosen inner trace mute should be evaluated.

Prior to use of FK demultiple, a preliminary evaluation of velocities should be made to establish the multiple velocity trend. Final velocity analyses should be performed on data that has been output from FK demultiple.

Ref: Peardon L.G. (1986).

F.1.5.4 Partial Pre-Stack Migration or Dip Move Out (DMO)

Although rarely used in site surveys the technique can be useful. The most obvious case would be in a heavily faulted data set, such as over a diapir, where fault definition may be enhanced. In fact, wherever conflicting dips exist a benefit may be gained from this process. DMO also has other beneficial effects including improvement of cross-line ties, attenuation of steeply dipping coherent noise, and enhanced velocity analysis.

The disadvantages of DMO are the extra time and cost the process incurs. Careful inspection of previous datasets or the shallow section of the exploration seismic data should indicate whether a test of the process is required before a project is commenced.

Ref: Deregowski S.M. (1986).

F.1.5.5 Velocity Analysis

Accurate and spatially frequent velocity analysis is necessary for preservation of the data, particularly high frequencies, through CMP stack. If incorrectly performed, the velocity correction applied prior to stack will result in a degradation of resolution. In the extreme case a seismic reflection may disappear completely.

An accurate velocity model is also required as an input to migration. The velocity model is normally a smoothed stacking velocity function.

Time-depth conversion is often based on RMS stacking velocities or Dix interval velocities, derived from the RMS velocities. Incorrect velocity analyses can result in errors in depth estimation to levels of interest.

he interval at which velocity analyses are spaced is important. In a similar way to sampling theory for the seismic trace, a velocity anomaly will not be properly resolved unless it is correctly sampled. Theoretically, this could imply that velocity analysis spacing should be as close as 50 metres. In practice, a compromise of a 500 metre spacing between velocity analysis points is recommended. Extra velocity analyses may still be required to sample small velocity anomalies and significant changes in geology.

The main velocity analysis techniques are:-

- Constant or Velocity Function Gather: This technique is particularly good in the shallow section, where moveout is large and the signal-to-noise ratio is good.
- Constant Velocity or Velocity Function Stack: The technique is complimentary to the gather version as it helps to define velocities at sub-seabed depths where the signal-to-noise ratio on the gather is poor.
- Contoured Coherency or Semblance Plot: Numerous types exist. All of them are fast to produce and are low cost. These analyses are not truly continuous in time or velocity as time gates and velocity steps are specified. The larger these parameters are made, the coarser the sampling and the less accurate the result. Interpretation of the data is of a purely statistical form and therefore divorced from the real data's appearance. it is important therefore, that use of this type of analysis is closely supported by comparison to the "real data" being analysed.

The recommended most useful type of display is a combined display which, for each analysis location, displays gather, stack and semblance plots. The disadvantage occurs in terms of longer processing time and, therefore, cost.

Workstations can be used for interactive velocity analysis. Continuous, automatic, event-following velocity analyses are available on workstations, which may improve both the quality and speed of analyses.

Ref: Cordier J-P (1985).

F.1.5.6 Deconvolution Before Stack (DBS)

This is applied to further attenuate unwanted source signature effects, reverberations and multiples. An offset dependent DBS should be applied.

Pure spiking deconvolution operators should be treated with caution.

Ref: Ziolkowski A. (1984).

F.1.5.7 Mute

Outer trace mutes are required to preserve vertical resolution. As discussed in *Section B.5*, signal stretch on the far offset will degrade vertical resolution if allowed to enter the CMP stack in the shallow section. Data on traces beyond a certain offset should, therefore, be omitted from the stack by muting.

Inner trace mutes may be useful for multiple suppression. However, they remove those traces with the greatest vertical resolution *(see Section C.5).* If used, they should be applied to as few traces as possible.

The mute should be chosen with care. A mute test where increasing numbers of traces are included in a stacked section of data is recommended to back up direct inspection of an NMO corrected CMP gather.

F.1.5.8 CMP Stack

The CMP stack is the most significant process in the processing sequence for improving the signal-to-noise ratio in a dataset. Its application should be handled carefully. Stack should not be looked on as a unique process. There are a number of slightly different algorithms for normalisation, scaling and the way in which muting is compensated for. In addition, other types of stack such as weighted and median stack are common. The type of algorithm in use should be checked.

Offset weighted stacks are not recommended as they help to stack out multiples but will also degrade vertical resolution. Close comparison of results from normal and weighted stack sections should be made before adopting a weighted stack. The effect of deconvolution after stack and FK demultiple for attenuating multiples should be assessed first.

Ref: Hatton, Worthington and Makin (1986).

F.1.5.9 Deconvolution After Stack (DAS)

Predictive deconvolution after stack is normally performed to remove seabed and other multiple effects. The process can also be applied with the aim of improving vertical resolution by compressing the signal wavelet.

A common guide for choice of deconvolution operator length is to choose an operator length equal to 1.3 times the water depth in milliseconds. For efficient removal of multiples the design window should then be approximately ten times the operator length. In deep water areas this will be difficult, given the short record lengths in use. In these cases, the use of other demultiple techniques should be considered *(see Section F.1.5.3).*

Deconvolution is a process which works on the assumption that the signal wavelet in the data is minimum phase. It should, therefore, be applied prior to zero phasing.

Ref: Ziolkowski A. (1984).

F.1.5.10 Time Migration

Migration, correctly applied, improves lateral resolution by either collapsing diffractions to the zero offset origin, or collapsing the Fresnel zones. It can be beneficial for plane layered data as well as dipping data. Consideration should be given to migrating the centre and tielines on all sites as a minimum.

There are numerous migration algorithms. In considering the choice of migration algorithm the effects of spatial variation of the velocity field and geological dip should be considered.

A velocity model for the data should be supplied as input to migration. FK migration techniques, although fast, cannot adequately handle a laterally changing velocity field. These should therefore be avoided if there are lateral velocity changes caused by, for example: channels, gas anomalies or major structural changes.

Finite Difference methods can handle a laterally changing velocity field, but they do not perform well on steep dips. They are, however, to be preferred over FK techniques.

Kirchoff based algorithms can handle steep dips but not laterally varying velocities. Kirchoff migration should be considered where steep faults and channel flanks require correct imaging.

Most migration algorithms are dip limited, as they can only correctly image dips up to a specific limit. In most cases such extremes will not be met in site survey work. However, it is possible that channel flank reflections, or reflections overlying shallow diapirs, may exceed dip limitations. The dip limit of the algorithm in use should be known to check its applicability.

Depth Migration is not required for rig site survey work.

Ref: Berkhout A.J. (1984).

F.1.5.11 Post Stack Coherent Noise Attenuation (FK Dip Filter)

The dip filter process removes unwanted coherent noise trains from the section. The process applies a cross trace filter which can adversely effect lateral resolution.

Specified dip limits in the design should be chosen carefully with regard to geological structure and diffractions. Channel edges and similar steep dips should be measured and reflection limits chosen to ensure true dips are passed.

In design of the dip filter, the number of traces and samples included should be minimised, to avoid unnecessary smearing of the data. The dip filter design should not be frequency limited.

Processes which allow a feedback percentage of the original trace are preferred, as smearing will be reduced.

If DMO has been applied, a mild inner trace mute may attenuate much of the undesired dipping noise in the section, negating the need for a dip filter.

The dip filter process should be applied with care. In particular, the process should not be placed before migration in the processing sequence.

Ref: Peardon L.G. (1987).

F.1.5.12 Zero Phasing

The zero phase signal wavelet has the shortest duration and largest amplitude for a given amplitude spectrum. The zero phase wavelet increases the ability to distinguish an event against background noise and enhances resolution. Polarity reversals of seismic reflections are also more easily observed.

Zero phasing of a dataset can be achieved by either statistical means, using a multi-window design, or deterministically by extracting an "uncontaminated" wavelet from the data and converting it to its zero phase equivalent.

With site survey data, it is normal practice to extract a wavelet from the seabed event for design of a zero phasing operator. In interpretation of data processed in this way, careful thought should be given to the possible alteration of wavelet shape with depth.

If a dataset is to be loaded to a workstation, it is advantageous to convert the data to zero phase. There are two reasons for this. Firstly, automatic event picking algorithms follow amplitude peaks more easily, and with less error, than zero crossings. Secondly, peak reflection amplitude can then be directly extracted, allowing amplitude maps to be built automatically.

Ref: Kallweit and Wood (1982).

F.1.5.13 Time Variant Filter (TVF)

For optimum resolution the signal-to-noise ratio should be maximised. Time variant filtering attenuates unwanted frequencies across the section and will therefore improve the signal-to-noise ratio. Resolution is also dependent on maintaining a broad signal band width and a high peak frequency.

Time variant filtering is a zero phase process and should therefore be applied after zero phasing.

Resolution requirements should therefore be considered when choosing frequency cut-offs. The design of the TVF may therefore be a compromise if signal and noise energy of the same frequency is present.

For migration, certain noise frequencies may require exclusion. However, in general, the full band width should be maintained through migration.

Ref: Berkhout A.J. (1982).

F.1.5.14 Balance and Scaling

As a final step to presentation of an equalised or scaled section, a sliding gate Automatic Gain Control (AGC) is applied to the data. An AGC gate length in the order of 100 - 250 milliseconds is normally applied.

As discussed in *Section F.1.5.2*, choice of scale and balance parameters is very subjective. In general, the heavier the balance and shorter the AGC gate applied, the more monochrome the section will appear. It is recommended that this is avoided, and that an overall decay in amplitude with depth is maintained.

AGC's can introduce a low amplitude shadow effect above and below a strong reflection or anomaly. The process can be stabilised either by an iterative approach, or by using a percentage feedback of the original trace.

It is important that AGC processes are not applied to data before presentation in relative amplitude form either for paper display, or SEGY outputs for workstations.

Ref: Hatton, Worthington and Makin (1986).

F.1.6 Data Presentation

Until recently, rig site survey interpretation has been limited to the use of the black and white, single polarity, paper section. With the increased use of workstations there is now a move away from this. The following display parameters and methods should be considered.

F.1.6.1 Plot Scales and Plotting Standards

Plot scales are subject to the Operator's preference. When selecting display scales, the features to be interpreted should be considered. Compressed horizontal scales can be useful for determining structure, whilst expanded vertical displays can be useful for detailed interpretation of a particular interval. The flexibility of the interpretation workstation in terms of alteration of display scales is, therefore, extremely significant.

Vertical scales are usually determined by record length and the frequency content of the data. Either 20 centimetres per second or 30 centimetres per second are recommended.

Horizontal scales are normally dependent on CMP spacing and 1:5,000 or 1:10,000 are recommended.

Colour plots should preferably be produced on a high resolution, electrostatic plotter. Ink-jet plotters, which are much used, are of poorer resolution and are very limited in the size of plot they can produce.

F.1.6.2 Relative Amplitude and Equalised Displays

These two types of display are the traditional basis for rig site survey interpretation. These are normally plotted in variable area wiggle form.

The relative amplitude, low gain or unscaled section is prepared by plotting the data with a low gain level, e.g. 12 dB down on normal. Lateral amplitude variations along a reflection can then be interpreted.

The equalised, scaled, or high gain section is the section plotted with AGC applied at the standard amplitude level. These sections are used for structural interpretation.

Dual polarity displays are commonly used in presentation of exploration data but are also applicable to rig site survey data. These can be plotted in colour but are normally plotted in black, grey and white tones for ease of copying. Dual polarity display of relative amplitude and equalised amplitude can be useful.

F.1.6.3 Colour Displays

average The use of colour for the coding of trace attributes is becoming common through the increased use of interpretation workstations. The problem with the presentation of full scale colour seismic is in plotting and copying.

Attribute displays are recommended for the analysis of key portions of data, such as at a proposed location, or over specific features.

There are a number of different types of colour display that are of use for the interpretation of rig site survey data. These are discussed below:-

Colour Coded Amplitude: This is a relative amplitude section with the variable area fill, colour coded in relation to amplitude strength. This type of plot provides a greater dynamic range in amplitude definition than the use of a standard black fill section.

Instantaneous Amplitude: (Amplitude Envelope): This is derived from the Hilbert transform of a trace. Amplitude is presented irrespective of phase, and the total amplitude of the signal wavelet (envelope) is displayed. This type of information is usually presented in a dual attribute display. Normally, a colour coded contoured amplitude display has the original seismic wiggle trace overlaid upon it. This allows the amplitude information to be directly related to the real data. This type of display is particularly useful for gas hazard analysis.

Instantaneous Phase: Sometimes described as a continuity plot, it is the angle between the trace and its Hilbert transform at a given time and is an amplitude independent estimate of the trace. The data can be plotted either alone, using a colour palette defined *by Taner, Koehler and Sheriff (1979),* or in a dual attribute display. Instantaneous phase is useful because it often enhances weak events not evident on conventional displays. This is particularly helpful in the definition of geological discontinuities, pinchouts, angularities and events with different dip which interfere with each other. As a result the plots are also useful in identifying tuning effects and phase reversals.

Similar results to instantaneous phase can be achieved by applying a very short gate AGC, e.g. 12 milliseconds, to the data.

Instantaneous and Weighted Average Frequency: A sample-by-sample measure of the frequency in the trace and is equivalent to the time derivative of the trace. Instantaneous frequency, plotted in colour, is useful for identifying low frequency shadow zones that may occur below a gas accumulation due to high frequency attenuation. However, the usefulness of this plot is severely dependant on the choice of frequency band width of the palette for colour representation of the frequency data, as well as the signal-to-noise ratio in the data. Due to the latter the weighted frequency plot can be used to make the plot more robust.

F.1.6.4 Amplitude Versus Offset (AVO) Displays

The use of AVO analysis for the identification of gas charged sands is being increasingly applied. However, for rig site surveys there are limitations to the use of AVO *(Section B.7.1.2).* A number of special AVO displays are available. All of the AVO displays described here can be plotted in either traditional black and white, variable area wiggle trace form, dual polarity or colour.

The simplest form of data presentation for AVO analysis are NMO corrected gathers over, and adjacent to, a feature of interest. Plot scales should be chosen carefully in conjunction with the chosen plot gain. Trace spacing should be such that adjacent traces do not overlap so that the full amplitude can be viewed. Similarly, all wavelet perturbations should be visible, so the vertical scale should not over compress the data. The simplicity of this approach makes it more robust than the displays described below. It is a recommended approach, and should always be used to support any other display type.

Other AVO displays include zero offset amplitude and absolute amplitude gradient sections. The accuracy of these plots is highly dependant on velocity analysis and careful amplitude scaling. If these displays are used, they should be supported by conventional section displays and the NMO corrected gathers described above.

F.1.6.5 Tape Output

Tape output in the form of SEG Y concatenations of CMP stacked data are of use both as a means of data storage, and for loading data to interpretation workstations. AGC should not be applied to the data.

Some Operators have special formatting requirements for SEG Y regarding the order and form of data for inclusion in trace headers. The Operator should clearly state which processes are to be applied to the data prior to tape output. The processing centre should be informed clearly of any special requirements which the individual Operator may have regarding the SEG Y format.

Some workstations require pre-scaling of amplitudes prior to the data being loaded. This is most easily performed by the processing centre prior to output of the tape. Any such requirements should be clearly stated.

F.2 Single Channel Seismic Data

The objectives of processing single channel data include amplitude manipulation, improvement of signal to noise ratio and removal of wave or tow depth effects on the data. Suppression of multiple events is also of importance and techniques for this are under development.

Processing of single channel data is usually carried out on line. It should be undertaken with great care therefore, or the seismic data may have to be reshot. Analogue tape recording of raw, unprocessed data permits replay with different processing parameters, avoiding the need for reshooting data. When deciding upon processing parameters, care should be taken to alter only one variable at a time so the effect on the data can be assessed.

F.2.1 Amplitude Manipulation

Corrections to the data are required to compensate for attenuation of signals due to geometric spreading, absorption and transmission losses.

TVG amplification is the usual method and can be very useful for data enhancement. Systems are available which scale the data by means of a sliding gate AGC.

F.2.2 Band Pass Filters

For optimum resolution, good signal-to-noise ratio, a broad band width and a high fundamental frequency are required. When selecting filters, these factors should be considered. Filter parameters should include as much as possible of the frequency range of the desired events, whilst removing unwanted noise of other frequencies. The design of the filter may be a compromise if signal and noise energy of the same frequency is present.

As discussed in *Section C.7*, lateral resolution will be degraded by low frequencies. When choosing low cut filters, band width may have to be sacrificed as long as degradation of vertical resolution is not apparent.

With increased sub-seabed depth, low frequencies will be favoured and signal-to-noise ratio will decrease. Different filter settings may therefore be required with increasing travel time. For optimum data quality a time variant band pass filter should therefore be used.

F.2.3 Swell Filters

Swell filters may be used to remove statics caused by wave action or swell. Although they permit an increase in the operational weather window, they should be used with care since signal-to-noise ratio will also degrade with poor weather. As they utilise signal comparison from adjacent traces, they may also remove real variations in seabed topography e.g. sand ripples, thereby distorting the data sub-seabed.

F.2.4 Heave/Depth Compensation

These systems are useful for systems towed below the sea-surface, to remove statics caused by wave action, swell or tow-fish height adjustments. They are based upon accelerometer or pressure transducer data.

F.2.5 Stacking

Stacking or averaging of a number of adjacent traces improves signal-to-noise ratio. Degradation of lateral resolution may occur with such systems and they should be used with care.

F.2.6 Deconvolution

Deconvolution is very useful for removing repeatable events from the data such as reverberations or multiples. Wavelet deconvolution further cleans up the section by optimising the vertical resolution. Although deconvolution is not commonly undertaken on single channel data, several systems are being developed which may provide enhancement of data in certain areas. In particular, deconvolution should be considered in areas of shallow water, where multiple reflections occur within the sub-seabed depth of interest.

F.2.7 Display

Single channel seismic data are conventionally displayed as analogue signals in black and white form on electrosensitive or thermal paper. Positive or negative polarity, or full wave can be displayed. Alternative display media are being developed including CRT (monochrome and colour) and variable area/wiggle trace paper displays.

The vertical scale should allow the resolution of the system to be displayed.

F.3 Positioning Data

Positioning data requires processing on-line to allow the survey vessel to run along the required line pattern and for control of position fix interval. Raw positioning data should also be recorded to allow post-processing. Post-processing should remove spurious data, correct errors (if any) and take advantage of smoothing techniques. It also provides a quality control check on the real-time acquisition and information on potential systematic positioning biases.

Raw Positioning Data exchange should conform to *UKOOA P2/94* format, and Post Plot Positioning Data to *UKOOA P1/90* format.

Care should be taken to ensure that all computed points (antenna, sensor) include the correct offset.

F.4 Echo Sounder / Swathe Sounding Data

Echo sounder data should be processed using heave compensator data to remove survey vessel heave caused by wave action, or swell. The data should be processed to incorporate the correct speed of sound in water and the transducer depth.

Data should be reduced to Lowest Astronomical Tide (LAT) or Mean Sea Level (MSL). Tidal corrections using predicted tides for the survey area can be used for initial data reduction. In certain meteorological conditions there may be a significant difference between predicted and observed tides. Unless measured tidal data is available from the survey area, tidal corrections should be computed from observed tidal elevations measured at the nearest Standard Port, and extrapolated to the survey area using constants derived from Admiralty Co-tidal Charts.

If a swathe sounding system is used, consideration should be given to the basic processing sequence outlined below:-

- Navigation Post Processing
- Raw Data
- Application of tidal data, water column T/S based corrections, depth corrections, and vessel related corrections (squat, roll, pitch, heading and heave)
- Despiking
- Filtering
- Binning / Gridding
- Contouring
- Plotting

Careful consideration should be given to bin/grid size selection. Bin/grid size should be determined by the scale of the final charts, the seabed topography and the contour interval. Bin/grid size tests should be undertaken to ensure the bathymetry is accurately presented.

F.5 Side Scan Sonar Data

The objectives of processing sonar data are amplitude manipulation and, if required, scale distortion removal. This processing is usually carried out on line.

Amplitude manipulation is usually by TVG amplification which may be operator selectable or automatic.

Scale distortion removal does not enhance data quality but assists in speed of data interpretation and provides the ability to mosaic data sets if required. In some areas (e.g. rippled seabeds) scale distortion removal may degrade data *(Section E.4.4).*

Section G - Record And Sample Requirements

G.1 Geophysical Records

DTI PON 9, Section 2.3, defines the type and format of site survey data to be provided:

Only If requested, the following data should be supplied within 30 days of the request.

"Site Survey Data

(i) One reproducible transparency of each final processed seismic section together with a reproducible transparency of the shot point location map at a suitable scale.

(ii) Where acquired, copies of side scan sonar records with their track charts

(iii) If available a copy of the final interpretation report of the seabed/superficial deposits investigation of drilling locations or installation sites.

These data comprise the detailed record of the survey and are not the results asked for by PON 4 Section 7 concerning shallow gas."

G.2 Sea bed Samples

Section 4.2 of PON 9 defines sample data to be supplied as

"Samples from the Sea bed

Portions of sea bed samples and/or cores from boreholes penetrating below the seabed if acquired."

The Petroleum (Production) Regulations 1976, Petroleum (Production) Regulations 1982 and Petroleum (Production) (Seaward Areas) Regulations 1988 all require that samples be correctly labelled and preserved for reference for a period of five years.

G.3 Provision of Data to BGS

The British Geological Survey have requested that all site survey data, including analogue and digital survey data on paper and/or tape be sent to them in confidence for addition to their archive. Core sample data can also be sent to BGS for archive provided locational information accompanies the material.

G.4 Provision of Data to the Hydrographic Office

The Hydrographic Office is notified of all site surveys through DTI PON 14. Following completion of the survey, the Office has requested one copy of the final report together with digital and analogue copies of the corrected bathymetry and seabed maps.

The contact address is:

UK Hydrographic Office
Admiralty Way
Taunton
Somerset TA1 2DN
Tel: 01823 337900
Fax: 01823 248077

Section H - Abbreviations And Units

Abbreviations

AGC	Automatic Gain Control
AVO	Amplitude Versus Offset
BGS	British Geological Survey
BOP	Blowout Preventer
BSI	British Standards Institute
CCM	Computer Compatible Media
CMP	Common Mid Point
CPT	Cone Penetrometer Test
CRT	Cathode Ray Tube
CSON	Continental Shelf Operations Notice
DAS	Deconvolution after Stack
DBS	Deconvolution before Stack
DEn	Department of Energy
DGPS	Differential Global Positioning System
DTI	Department of Trade and Industry
EG&G	Edgerton, Germhausen and Grier (equipment manufacturer)
E & P	Exploration and Production
F	Frequency
FK	Frequency – Wavenumber
HF	High Frequency
HSE	Health and Safety Executive
IAGC	International Association of Geophysical Contractors
IFP	Instantaneous Floating Point
K	Wavenumber
Kny	Nyquist Wavenumber
LAT	Lowest Astronomical Tide
LF	Low Frequency
LOP	Lines-of-Position
MF	Medium Frequency
MRU	Motion Reference Unit
MSL	Mean Sea Level
NMO	Normal Moveout
NSRF	Nova Scotia Research Foundation
PCPT	Piezocone Penetrometer Test
PON	Petroleum Offshore Notice
QA	Quality Assurance
QC	Quality Control

RMS	Root Mean Square
SBL	Short Baseline
SEG B	Society of Exploration Geophysics Format B
SEG D	Society of Exploration Geophysics Format D
SEG Y	Society of Exploration Geophysics Format Y
SSBL	Super Short Baseline
TWTT	Two Way Travel Time
TVF	Time Variant Filter
TVG	Time Variant Gain
TVSS	True Vertical Sub Sea (Mean Sea Level)
TVV	Time Velocity Squared
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
UKOOA	UK Offshore Operators Association
USBL	Ultra Short Baseline
V	Seismic velocity
VHF	Very High Frequency
VRU	Vertical Reference Unit
Vw	Seawater velocity
Z	Depth
λ	Wavelength

UNITS

cm	Centimetre
cu	Cubic
dB	Decibel
gamma	Gamma
Hz	Hertz
kHz	Kilohertz
KJ	Kilojoule
km	Kilometre
in	Inch
m	Metre
mm	Millimetre
ms	Milliseconds
ms^{-1}	Metres per second
s	Seconds

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