



Oil & Gas
Authority

Consolidated Onshore Guidance

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This guidance, which consolidates previously available guidance, sets out how the OGA will normally consider stated matters and is not a substitute for any regulation or law and is not legal advice. It is intended that the guidance will be kept under review and be revised as appropriate in the light of experience and developing law and practice and any change to the OGA's powers and responsibilities. If the OGA changes its guidance in a material way, it will publish a revised document.

A. Introduction to the OGA's onshore role

The Petroleum Act 1998 vests all rights to onshore petroleum in the Crown, including the rights to search, bore for and get it. It empowers the OGA to grant licences to search for and bore for and get petroleum to such persons as they see fit. The Petroleum Act requires model clauses to be laid in secondary legislation conditions (see [The Petroleum Licensing \(Exploration and Production\) \(Landward Areas\) Regulations 2014](#)), which are then incorporated into new licences (except in particular cases). Existing licences are not affected by the issue of subsequent sets of model clauses (except through specifically retrospective measures such as were present in the 1998 Act). It is the responsibility of every licensee to be aware of all regulatory controls, including the model clauses, and to comply with them.

The OGA regulates the licensing of exploration and development of England's onshore oil and gas resources¹. The OGA issues well consents, development programme approvals, completion of work programme approvals and production consents.

The OGA must approve an operator for each licence upon award and again as activity is proposed. In considering any request for operatorship, the OGA examines the operator's competency, their financial viability and financial capacity.

The OGA has no responsibility for onshore environmental legislation for onshore England. Responsibility for this lies with the [Environment Agency \(EA\)](#), and the local Mineral Planning Authority (MPA).

When considering whether to give its consent/approval to relevant operations, the OGA will consider the position of other regulators although the decision remains solely with the OGA.

The following guidance covers the OGA's licensing, consents and approvals process – and brings together the previously separate guidance into the one document. It is not intended to cover in detail the consents and permitting regimes of other regulators such as the Environment Agency (EA) and Health and Safety Executive (HSE).

¹ Onshore licensing is in the process of being devolved to Scotland and Wales

Oil and Gas Authority (OGA) involvement in the minerals planning process

The OGA does not have a formal role in the consideration of oil and gas related planning applications by Mineral Planning Authorities (MPAs), nor is the OGA a statutory consultee. However, the Minerals Planning Practice Guidance states that there are a number of issues that are covered by other regulatory regimes and that, while such issues may be put before an MPA, the Authority should not need to carry out its own assessment as it can rely on the assessment of those other regulatory bodies. In respect of the mitigation of seismic risks, the OGA is one such body and the Minerals Planning Practice Guidance indicates that, before granting planning permission, an MPA will need to be satisfied that the mitigation of seismic risks can or will be addressed by taking advice from the OGA.

A completion work programme, which includes a Hydraulic Fracture Plan, must be approved by the OGA prior to the start of any fracking operations. The programme may be submitted in advance of, or following, the grant of planning permission by the MPA. When considering whether to approve a programme, the OGA will apply policies aimed at avoiding seismic events altogether or, in the unlikely event that seismicity is induced, minimising disturbance to those living and working nearby and preventing the risk of damage to property. The Hydraulic Fracture Plan must provide detailed geological studies so that fracking operations can be located away from geological faults, provide for the monitoring of natural background seismicity long in advance of operations and include a real-time traffic light scheme incorporating the detailed operational response should an unusual seismic event be detected.

Having considered the Hydraulic Fracture Plan and, if appropriate, undertaken its own independent work or taken the views of others such as the British Geological Survey, the OGA will decide whether or not to approve the completion work programme. If requested, the OGA will advise an MPA of its work on a particular Hydraulic Fracture Plan and inform it if approval is given.

B. Overview of the Licensing Regime

The OGA operates a licensing regime that gives companies exclusive rights to search, bore for and get petroleum. Petroleum licences are issued after a competitive process, usually a licensing round.

1. Licensing Rounds

There have been 14 onshore licensing rounds to date. The last licensing round, the 14th Round, was held in 2014. As it stands, a decision on the timing of the next round has not yet been made. When a future round is announced, it will be placed in the London Gazette detailing the areas on offer and accompanying guidance is provided as to the requirements for applications. Bespoke guidance is produced for each round and is placed on the OGA website. The notice and guidance for the 14th Round can be found [here](#) for information.

When the OGA holds an onshore licensing round, it will assess applications for operator competency, financial capability, geotechnical analysis and the proposed work programme of any application submitted.

The Licence Applications Repository (LARRY) is the OGA's licence application system, which allows applicants to submit and pay for licence applications for onshore (and offshore) licences within the UK.

Detailed guidance on how to create an account and submit licence applications through LARRY can be found [here](#).

2. Licensees

All companies on a licence share joint and several liability for obligations and liabilities that arise under it throughout the lifecycle of the licence. All companies on the licence share the rights conferred in the licence.

Licences can be held by a single company or by several working together, but in legal terms there is only ever a single licensee however many companies it may comprise.

3. Residence Criteria Guidance

Prospective licensees must satisfy the OGA that they have a place of business in the UK. This means at least one of the following:

- Having a staffed presence in the UK
- Being registered at Companies House as a UK company
- Having a UK branch of a foreign company registered at Companies House

To join a licence and take an interest in a producing field, a prospective licensee must either:

- be registered at Companies House as a UK company; or
- carry on its business through a fixed place of business in the UK.

A 'fixed place of business' normally means a staffed presence. For further information see section 148 of the [Finance Act 2003](#) or article 5 of the [OECD Guidelines for Multinational Enterprises](#) for more information.

4. Types of Licences

Onshore licences fall into several categories. The principal distinctions are between exploration licences (XL) (which cover geophysical and other surveys) and production licences (PEDL) (which cover exploration drilling, appraisal, development and production).

Until 1996, the UK Government issued a sequence of separate licences for each stage of an onshore field's life – exploration, appraisal, development and production. The OGA no longer issues any licences of these types but a number of them, and older licences, are still in force. Some older versions of onshore licences are still extant (e.g. AL, DL, EXL, ML and PL) with similar licence terms.

4.1 Licence Rentals

Each licence carries an annual charge, called a rental, set at the time of award. Rentals are due each year on the licence anniversary. Rentals are charged at an escalating rate on each square kilometre the licence covers at that date, with the exception of exploration licences which incur a flat-rate rental. Rentals are designed to encourage licensees to decide which acreage to retain and to surrender acreage they do not want to exploit.

4.2 Petroleum Exploration and Development Licence

The OGA issues Petroleum Exploration and Development Licences (PEDLs), which were introduced in 1996.

PEDLs are usually offered in competitive licensing rounds when an invitation for applications is made and the applications are assessed on their merits based on objective criteria specified in advance.

A PEDL does not give permission for operations but it grants exclusivity to licensees, in relation to hydrocarbon exploration and extraction within a defined area. All operations require other permissions as appropriate, such as access agreement(s) with relevant landowner(s), Environment Agency (EA) permits, Health and Safety Executive (HSE) scrutiny, planning permission and Department for Business, Energy and Industrial Strategy (BEIS) consent.

Except in special circumstances, PEDLs run for three successive periods or terms, since the 7th Round (The Petroleum (Production) (Landward Areas) Regulations 1995) these are:

- Initial term
- Second term
- Production period

The splitting of the lifecycle of an oil and gas licence into these three terms provides clear hurdles for the licensee's progress (essentially finding the hydrocarbons,

planning for their extraction and the extraction itself). It allows the OGA to ensure that licensees do not retain valuable exclusivity of hydrocarbon exploration and extraction without doing enough work for this to be justified.

However, there is inevitably a risk that even the most diligent of licensees will be prevented from meeting these requirements by factors beyond their control (including the vagaries of geology, drilling, oil price and access to land) and the potential for agreed variations of length and requirements of the terms provides a reasonable balance between clear objective milestones and reasonable flexibility. Requests for variations should be made in writing, and if agreed, they will normally be executed by notice. If the said Licence terms are not extended, the Licence will determine.

Initial term

The initial term is associated with an **exploration** work programme that the licensee has committed to the OGA during the competitive application process. Unless varied by agreement, the licence will expire at the end of its initial term unless the licensee has completed the work programme and surrendered a fixed amount of acreage.

While the initial term is associated with a work programme of exploration work that must be completed if the licence is to continue into a second term, the licensee has the possibility to start production during the initial term, if the licensee can progress sufficiently, subject to normal regulatory controls.

For Licences with the 2014 Model Clauses, (The Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014), the OGA can accept Retention Areas, which allow for further definition of the programme of work after the initial term, and the OGA has discretion to allow these agreed work plans to modify licence term event dates.

Second term

The second term is associated with **appraisal and development**. There is no agreed work programme; instead the licence will expire at the end of its second term unless the OGA has approved a [field development plan](#). As with the initial term, the duration of the second term may be varied by agreement in light of the circumstances.

Production period

The third term is intended for construction of any facilities and for **production**. The OGA has the discretion to extend the third term if production is continuing, but it reserves the right to reconsider the provisions of the licence before doing so, including the acreage and rentals.

4.3 Exploration Licences

The OGA also issues exploration licences (XL). A company that wants to explore by means of seismic or other surveys but does not seek exclusive rights to drill or produce can apply for an onshore exploration licence. Exploration licences are useful for seismic contractors who wish to gather data, or holders of production licences who wish to explore outside the areas where they hold or require exclusive rights.

An exploration licence grants rights to explore only, not to drill or produce; and is non-exclusive, covering all acreage outside those areas covered by any of the corresponding production licences that are in force at the time.

If the holder of an exploration licence wishes to explore acreage covered by a production licence, permission is required from the holder of that production licence.

The flat rate rental of an exploration licence is £2,000 per year and covers non-intrusive exploration whether carried out for the sake of hydrocarbon production, gas storage, carbon sequestration, or any combination of them.

[Exploration Licence application form](#)

4.4 Methane Drainage Licences

A Methane Drainage Licence is required if the operator or owner of a coalmine must capture natural gas to make the mine safe. Safety is a high priority for the OGA and we will consult the Coal Authority about each case to seek its advice about the safety issues that a case raises and to ensure that the operations are consistent with the Coal Authority's own regulation of the mine.

4.5 Underground coal gasification

Underground coal gasification is regulated by the Coal Authority and does not require a Petroleum Act licence from the OGA.

5. Applications for Access to Land (Ancillary Rights)

PEDL holders should make reasonable and sustained efforts to negotiate with landowners for any ancillary rights required to carry out licensed activities.

Where it is not practical to obtain such rights through private negotiations, the PEDL holder could consider applying for ancillary rights through the Mines Act.

Section 7(1) of the Petroleum Act applies the Mines Act for the purpose of enabling a licensee to acquire such ancillary rights as may be required for the exercise of the rights granted by the PEDL.

More guidance on applications for ancillary rights can be found [here](#). The information in this document does not constitute legal advice. It is advisable for a licensee to take legal advice in connection with the making of an application under the Mines Act.

6. Operatorship Guidance

Licences stipulate that the licensee shall ensure that another person (including, in the case where the licensee is two or more persons, e.g. a company, any of those persons) does not exercise any function of organising or supervising all or any of the operations in pursuance of this licence. The only exception is if that person is approved in writing by the OGA and the function in question is one to which that approval relates. This is called operatorship.

In considering any request for operatorship, which can occur either at the time of licence application or other times during the lifetime of a licence, the competence of the proposed operator is assessed by the OGA, taking into consideration the following factors:

- technical experience and capability to supervise, manage and undertake the proposed operation;
- their risk-assessment and hierarchy of decision-making, and plans for public engagement.

The amount of information required will depend on the circumstances, including the complexity and scope of the planned activity. A new entrant or small company with little onshore experience should expect to provide more information than an established onshore operator.

6.1 Basic information required for Onshore Operators

A company wishing to discuss a case, and the criteria that the OGA applies, should contact the onshore team (onshore@ogauthority.co.uk).

The information the OGA may require is as follows:

Company details

- UK registered name, address and company number
- UK places of business – addresses, public contact email and telephone numbers
- website address and, during operations, a 24-hr telephone response line for members of the public

- primary contact for the OGA and accountable Board member (email and telephone numbers)

Previous operating and technical experience

- details of any previous experience of supervising or carrying out drilling operations within the past two years, including location and description of the company's responsibilities for those operations
- details of production within the past five years, including location and description of the company's development responsibilities
- details of the proposed operator's relevant emergency management experience

Management Structure and Strategy

- corporate governance, including names of the Board of Directors and Management Team and reporting roles
- organisational chart, noting role, location and identifying use of contractors
- summary of approach to risk-assessment and hierarchy of decision-making for wellsite and production operations
- monitoring and incident management plan
- community engagement plan

People

- CVs of the key personnel involved in decision-making, including their previous experience and the basis on which they are employed (e.g. part-time or contracted)
- key individuals responsible for key roles including geotechnical, health and safety, interaction with Local Planning Authorities, public engagement, environmental and drilling expertise describing which skills exist in-house and those that are contracted.

Use of Contractors

- list areas of technical assessment or operations to be outsourced to contractors, and the name(s) of contractor(s) and contact information. Note that operators must retain

overall responsibility and cannot subcontract their licence responsibilities and obligations.

- description of operator's relationship with the contractor, describing the decision-making process and what arrangements are in place to deal with any unexpected incidents.
- track record of sub-contractors proposed for any activity for subcontractors and mechanism for aligning management system of contractors with that of the operator

The OGA will require a letter from the board of the proposed operator confirming scope of insurance or availability of necessary funds for any required remedial work.

Licensees and operators are encouraged to be a member of the UK Onshore Operators Group (UKOOG), which has worked with regulators to publish industry guidelines for best practice, which contain what is good industry practice and refer to the relevant legislation, standards and practices.

7. Financial Guidance

Licensees must meet certain financial criteria to demonstrate that they have the financial capacity to exploit the exclusive rights granted by the Licence.

The OGA has two distinct types of financial criterion: Financial Viability and Financial Capacity. Financial Viability refers to a company's ability to remain solvent while Financial Capacity refers to a company's ability to meet known and specific costs.

The OGA's financial guidance can be found [here](#). The measures described in the OGA's financial guidance are solely for the purpose of establishing whether Licensees have the viability and capacity to undertake the obligations of their Licence. These measures should not be assumed to meet the needs of third parties who have an interest in a licensee's financial capability.

C. Licence Assignments and Relinquishments

1. Licence Assignments

A company that is party to a licence may wish to sell its interest, or a part of it, to another company. It requires the OGA's prior consent to do so.

Any transaction in which one or more companies enters a licence, or one or more companies withdraws from it, is referred to in this guidance as a licence assignment.

The OGA will consider any assignment made without prior consent as a very serious breach of the licence, and as grounds for immediate revocation of the licence or to reverse the assignment using powers granted in the Energy Act 2008. This applies equally to assignments between unaffiliated companies, to assignments between sister companies within a single company group, and to the withdrawal of a company from a licence.

Onshore licence assignment applications should be submitted using the [Licence assignment application form](#) and completed forms should be submitted by email to approvals@ogauthority.co.uk.

If there are no reasons to withhold it, the OGA will consent to the assignment for execution by the applicant. We require notification of execution (in the form of an Execution Deed) so that accurate records can be maintained. The OGA will not consider an assignment to be effective until it is satisfied with the validity of the documentation.

2. Licence Relinquishments

If the licensees request to relinquish the acreage on the licence, before agreeing to this the OGA will verify that all wells within the licensed area have been plugged and abandoned.

There are two ways in which a licensee can give up acreage on a licence:

- A '**surrender**' of part of the licensed area while the licence continues over the remaining area
- A '**determination**' of the entire licence.

An operator may submit a licence relinquishment application at any time to surrender or determine acreage. This can be done by submitting a licence surrender or determination application using a [licence determination form](#) for each licence. Completed forms should be submitted to licence.relinquishments@ogauthority.co.uk

The surrender of acreage from a licence does not remove any company from a licence, even a company that is left with no beneficial interest under a JOA. The withdrawal of such a company must be implemented separately by an assignment.

A Relinquishment Report is required for any significant area surrendered or determination of the entire licence (see Relinquishment Report guidelines)

D. Wells

1. Well Operations Notifications System

The Well Operations Notifications System (WONS) is an Energy Portal application that allows operators and licensees to apply for, notify and receive consent from the OGA for a wide range of drilling and well-related activities.

The primary focus of WONS is the technical (geological and geophysical) basis for planned wells, collating information and assigning consent for activities required under the model clauses of PEDLs.

Licensees should apply for a Portal account with WONS access at the helpdesk ukop@ogauthority.co.uk (0300 067 1682) and must identify designated contacts within their organisation(s) who have authority to act on behalf of the organisation.

For WONS application support please contact wons@ogauthority.co.uk

More guidance on WONS can be found [here](#).

2. Applications for Consent to Drill and/or Side-track a well

When the OGA receives an application for consent to drill or to side-track a well, the OGA will review the operator's financial capability (more information on the OGA's assessment of financial capability can be found [here](#)). The OGA will notify the Environment Agency (EA) and the Health and Safety Executive (HSE) of planned activity and, in determining whether to give its consent to relevant operations, the OGA will, amongst other things, take into account the position of other relevant regulators.

A minimum of 28 days' notice is required for consent to drilling operations once all the information is provided, but licensees are encouraged to have pre-application discussions with the OGA at an early stage in the well planning process.

Any well consent issued since April 2016, includes a condition that BEIS consent is required where operations will involve associated hydraulic fracturing (see Hydraulic Fracture Consent section).

To apply for consent to drill or side-track a well, the Operator should apply for consent in WONS on the [UK Energy Portal](#).

As part of our assessment of application for activity, the OGA will require a letter from the board of the proposed operator confirming scope of insurance or availability of necessary funds to manage its consequences of unforeseen events, including third party liability. All applications for well consents require the following supporting information.

2.1 Required Supporting Information

Board confirmations

- A Board letter confirming scope of insurance or availability of necessary funds for any required remedial work
- A Board letter confirming availability of planning permission and indication of on-going planning disputes

Technical

- Site location OS map showing the general area and proposed drilling location, proposed wellpath(s) and key information (licence boundary, existing well paths, field boundaries)
- Two orthogonal seismic sections showing well path
- Expected lithologic/stratigraphic column
- Top reservoir target depth map (showing well path) with map border annotation National Grid Easting/Northing using the OSGB NG Datum
- Wellbore design schematic including mudweight plot, maximum pore pressure gradient, casing design
- A description of the logging programme (both open and cased hole) for each casing depth plus any intermediate survey point must be included, including CBL, wireline fluid samples, leak-off or mini-fall off (DFIT) tests are planned. Conditional logging runs should be included and the conditions noted (e.g. where shallow gas or artesian flow might be encountered)
- The absolute minimum well data collection criterion for a well is that the stratigraphy and presence of hydrocarbons must be identified along the well. However, it is expected that exploration wells will be cored or have sidewall cores cut in the reservoir section if there are hydrocarbon shows. A terminal core should also be cut if age dating is uncertain. It is anticipated that all appraisal wells will be cored in the reservoir section. A VSP or checkshot survey is also expected

Under Section 23 of the [Mining Industry Act 1926](#), landward licensees are required to give prior notification to the Natural Environment Research Council (through the British Geological Survey - ngdc@bgs.ac.uk) of their intention to undertake drilling so the council can decide if it wishes to attend the drill site to collect samples.

Well consent

If a licensee wishes to drill into a coal seam, whether to test for methane within the coalbed (CBM) or to test a deeper structure, they should consult the Coal Authority (CA) at an early stage in the planning process. The Coal Authority will wish to enter into an agreement with the licensee covering the conditions under which access to the coal seams will be permitted.

If the OGA is satisfied with the application and supporting documentation, it will issue a well consent. The notification will be issued through WONS and also includes consent to the following activity on the well: spud, respud (restart the well before significant drilling has taken place), and side-track mechanically (if necessary for operational reasons to the same target location).

The Operator must notify OGA within two hours of the commencement of any activities covered by the consent through WONS. Until a well spud notification is received, a well registration number is not assigned, but upon notification, the OGA will issue a well number following a convention which is available as Petroleum Operations Notice 12 ([PON12](#)).

The data requirements after drilling are described in the Petroleum Operations Notice 9b ([PON 9b](#)). Following the grant of consent, a notification must be submitted once the proposed activity has been completed and the information must be updated. Please note that payment is not required for submitting notifications and updates.

3. Applications for Completion Work Approval

If a licensee wishes to get petroleum from a well, it will need to apply for approval of completion programme of work.

“Completion Work”, means work, by way of the installation of a casing or equipment or otherwise for the purpose of bringing the well into use as a Development Well.

“Development Well” means a well which the licensee uses or intends to use in connection with the getting of Petroleum in the Licensed Area, other than a Well which for the time being he uses or intends to use only for searching for Petroleum.

The operator should apply in WONS on the [UK Energy Portal](#), and provide a supporting document with detail information on the proposed completion programme of work.

If hydraulic fracturing is proposed as part of the completion programme of work, OGA agreement to a Hydraulic Fracture Plan is necessary (see relevant section) and if the proposed injection volume exceeds the threshold for “Associated Hydraulic Fracturing” in s4A of the Petroleum Act 1998 then in addition to the OGA completion approval, a separate Hydraulic Fracture Consent (HFC) granted by BEIS Secretary of State is required.

Well Tests

Drill Stem Tests (DST) – Standard drill stem tests following drilling or well intervention operations should be included as part of the assessment of the proposed drilling or intervention operations and details provided in the WONS application.

When testing discrete section of the well, each section can be produced for a maximum of 96 hours but the total quantity of oil produced from all sections should not exceed 2,000 tonnes in total in order for the test not to be classed as an EWT. A well test would be classified as an EWT where the well test of the different sections exceeds the 96 hour threshold per section or exceeds the 2,000 tonnes of oil and a total combined quantity for all tested sections. Volumes produced during clean-up

flow periods should be included and count towards the 2,000 tonnes of oil and the 96 hour thresholds, but the 96 hour period relates to the production duration and therefore periods between production, e.g. when the well is shut in to build up pressure, is not counted in the overall 96 hours.

For exploration and appraisal wells, consent for up to 96 hours or 2000 tonnes of test production (whichever is exceeded first) may be included in the well consent issued by WONS. Applicants are required to complete the appropriate WONS well test application for this purpose and upload a document describing the rationale and planned operation of the test. This volume does include any clean-up period, so if there is any risk of breaching these limits, operators are advised to make an application for an Extended Well Test (EWT) to cover operational contingencies.

4. Extended Well Test Guidance

The OGA may consider authorising production testing over periods less than 96 hours (or max 2000 tonnes) as part of the drilling consent but any more extensive testing is considered to be an extended well test (EWT). The OGA may authorise an EWT from an exploration or appraisal well prior to a full field development approval if it can be demonstrated that the licensees will thereby gain the technical understanding or confidence in the performance of the field needed to progress towards a development.

The operator is required to submit an application for an EWT approval through the Well Operations Notification System (WONS) on the UK Energy Portal, and provide the required supporting information (including a description of the objective and rationale for the test programme, the proposed test period, relevant works and the estimated range of volumes of oil and gas to be won and produced from the well).

To approve an EWT, the OGA requires a formal letter of application containing the following information:

- the Relevant Works which the Licensee proposes to erect or carry out during that period;
- the proposed location of the Relevant Works (pad area coordinates show on a plat that forms part of the Mining Waste permit), a detailed plan of activity, objectives of the test and the requested duration; and
- maximum quantities of oil and/or gas to be produced and saved or flared/vented in the period of the requested EWT (in tonnes and cubic metres)

“Relevant Works” is defined as: *“any structure and any other works whatsoever which are intended by the Licensee to be permanent and are neither designed to be moved from place to place without major dismantling nor intended by the Licensee to be used only for searching for Petroleum”*

Similar to the requirements at the well consent stage, the following letters are required.

- A Board letter confirming scope of insurance or availability of necessary funds for any required remedial work
- A Board letter confirming availability of planning permission and indication of on-going planning disputes

The OGA will notify the Environment Agency and the Health and Safety Executive of planned activity and, in determining whether to give its consent to relevant operations, the OGA will, amongst other things, take into account the position of other relevant regulators.

An EWT should have realistic and definable appraisal objectives essential to the success of a development and not be prejudicial to ultimate recovery. There are no strict criteria governing the maximum volume to be produced or the duration of an EWT, but they are usually issued for 90 days to allow for operational delays. The duration may be extended if there is a technical justification, but it should be noted that EWTs are not an alternative to production under a Field Development Plan. There is no obligation to proceed with a development following an EWT.

Throughout the test, the operator must keep the OGA informed of activity and must report monthly oil, gas and water production figures in the UK Energy Portal. Within 30 days of completion of the EWT, the Operator must submit to the OGA an EWT report fully detailing the test results.

If hydraulic stimulation is proposed as part of the EWT, the operator must secure consent for completion works as part of which a Hydraulic Fracture Plan (HFP) will be agreed with the OGA. A Hydraulic Fracturing Operations Report must be completed within 30 days of completion of hydraulic fracturing (see relevant guidance)

5. Applications for Suspension Consent

The operator must not suspend a well or recommence operations except with consent of the OGA. Applications for these activities must be submitted in WONS and the OGA's consent to well suspension or temporary plugging given before this operational activity is undertaken.

If well suspension is one possible outcome after drilling, then an application to suspend the well should be applied for in parallel with the application for a well consent. A decision rationale is required which includes a plan for the length of time the well might remain suspended while well studies or other work is completed that is necessary to make a decision regarding well abandonment. Then once the well is drilled, if suspension is desired, a Wellbore Update Notification (WUN) in WONS is required to report what was encountered in the well and the plan for analysis before a decision on well abandonment is made. A well engineering diagram must be submitted at this time.

6. Applications for Abandonment Consent

The licence prohibits the operator from abandoning any well without the consent of the OGA. The operator must submit an application for consent to abandon a well in WONS on the [UK Energy Portal](#), and provide detailed information regarding the results of the well. OGA's consent to well abandonment must be given before this operational activity is undertaken.

If proposed abandonment is the last well in a previously producing field see Cessation of Production ([COP](#)) guidance.

After well abandonment consent is given, the operator must notify the OGA upon completion of the work and a well engineering diagram must be submitted at this time.

7. Hydraulic Fracture Plan Guidance

The Hydraulic Fracture Plan (HFP) sets out how the operator will control and monitor the fracturing process. It will be agreed independently by the OGA and the Environment Agency. The HSE will also have an opportunity to comment. The OGA will assess any risks of seismic activity and must be satisfied that controls are in place to avoid an event altogether or, in the unlikely event that seismicity is induced, to minimise disturbance to those living and working nearby, and to reduce the risk of any damage.

Operators are required to identify and assess the locations of existing faults to prevent hydraulic fracturing from taking place near them.

To note, the OGA agreement to a HFP is not a separate regulatory consent or approval, but part of OGA granting approval to complete a well.

If the proposed injection volumes fall below the BEIS associated hydraulic fracturing thresholds, the OGA may decide less information or monitoring is appropriate, but an HFP will always still be required.

A summary of what the OGA may require is as follows:

- a map and seismic lines showing faults near the well and along the well path, with a summary assessment of faulting and formation stresses in the area and the risk that the operations could reactivate existing faults;
- information on the local background seismicity and assessment of the risk of induced seismicity;
- a comparison of proposed activity to any previous operations and relationship to historical seismicity;
- summary of the planned operations, including the techniques to be used, the location of monitoring points, stages, pumping pressures, volumes and the predicted extent of each proposed fracturing event;
- proposed measures to mitigate the risk of inducing an earthquake and a description of decision tree for a real-time traffic light scheme for monitoring local seismicity;

- the processes and procedures that will be put in place during hydraulic fracturing for fracture height monitoring to identify where the fractures are within the target formation and ensure that they are not near the EA permitted boundary;
- in the event that the fractures extend beyond the EA permitted boundary, the steps that would be taken to assess and, if necessary, mitigate the effect and limit further propagation outside the target rocks;
- the type and duration of monitoring and reporting during and/or after hydraulic fracturing has taken place and the geological data to be published; and
- procedures for post fracturing reporting of the location, orientation and extent of the induced fractures to demonstrate that the EA permit has been complied with. This will need to include provision for reporting on proposed mitigation measures to prevent propagation, should fractures extend to within a short distance of the permitted boundary.

Test Examples	Type	LEAK OFF TEST (Pressure Integrity Test)	MINI FALL OFF TEST (DFIT)	COMPLETION ACID WASH	HYDRAULIC FRACTURE STIMULATION
Purpose		Drilling Engineering Evaluation	Reservoir / Rock Engineering Evaluation	Commercial Production Evaluation	Commercial Production Evaluation
Pressure		< Frac Gradient	= Frac Gradient	< Frac Gradient	> Frac Gradient
Typical Fluid		Drilling Fluid / Mud	KCL Water < 20 m ³	Dilute HCL < 15 m ³	Frac Fluid
Use of Proppant		NO	NO	NO	YES
Typical Chemicals		-----	-----	HCL 15%	Gel Surfactant Breaker Biocide
Flow Back Fluids	Back	NO	NO	YES	YES
HFP Needed?		-----	-----	-----	✓

8. Traffic Light Monitoring System Guidance

The OGA is responsible for managing the risk of induced seismicity as part of its regulation of onshore hydraulic fracturing operations. As reported in the [2012 Hydraulic Fracturing Review by the Royal Society](#), whilst large seismic events induced by hydraulic fracturing are generally rare, the OGA has in place two main policies to manage the risk.

Firstly, the OGA requires detailed geological studies to be undertaken by an operator to prevent such operations taking place near geological faults, which greatly reduces the likelihood of an event.

Secondly, the OGA requires certain controls and requirements to be adhered to by an operator, including the monitoring in advance of background seismic activity, a real-time traffic light scheme during injection, and detailed operational precautions to be incorporated in an HFP. It is for the operator to propose a methodology and design (as part of the HFP) to be approved by the OGA, but the OGA would typically expect:

- a real-time traffic light scheme for monitoring local seismicity so that operations can be quickly paused and reviewed if unexpected levels of seismic activity are detected amidst the normal background seismicity;
- additional recording to measure levels of ground motion close to nearby dwellings and other structures; and
- a decision tree to describe what actions would be taken in response to the detection of induced seismicity and measured ground motion.

As part of the traffic light scheme, operators must propose an array of sensors capable of ensuring reliable detection and focal location of any seismic activity of magnitude $>0.0 M_L$ in the rock in the vicinity of the well. The OGA must agree to the design of this array.

The decision tree must be agreed to independently by the OGA and the Environment Agency. HSE will have an opportunity to comment; it must clearly set out the actions

that would be taken in response to the detection of induced seismicity and resultant ground motion to minimise the disturbance to those living and working nearby and to prevent the risk of damage to buildings.

Currently, the action level for the traffic light system (the “red light”) is set at a magnitude of 0.5 M_L . The OGA considers that this is far below what would cause a perceptible event at the surface but is greater than the level expected to be generated by the fracturing of the rock itself.

This level may be adjusted upward if actual experience shows this can be done without compromising the effectiveness of the controls.

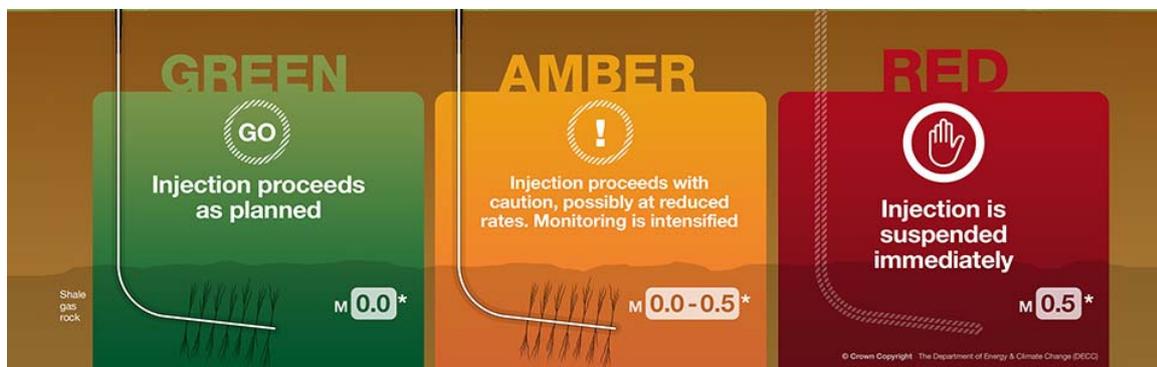


Figure 1: High level summary of Traffic Light System

If an event with a magnitude $>0.5 M_L$ is detected, the operator must immediately suspend injection, reduce pressure and monitor seismicity for any further events. The focal location and mechanism should be determined to see whether the seismicity is natural or, if induced, whether it accords with the assumptions and expectations set out in the HFP.

While M_L is useful for operational decisions because it can be computed very rapidly and defines a unique value for each seismic event, it may not fully reflect any resultant ground motion, which is dependent on such things as depth, distance and surface geology. Accordingly, the HFP should assess potential associated ground motion to identify the potential for damage to buildings². Ground motion data is recorded by the array of sensors installed for the traffic light scheme, but additional detectors might also be located to monitor the levels of ground motion close to dwellings and other structures.

The OGA has commissioned a paper to provide further technical background information regarding the prediction and monitoring of ground motions induced by hydraulic fracturing, which can be found [here](#).

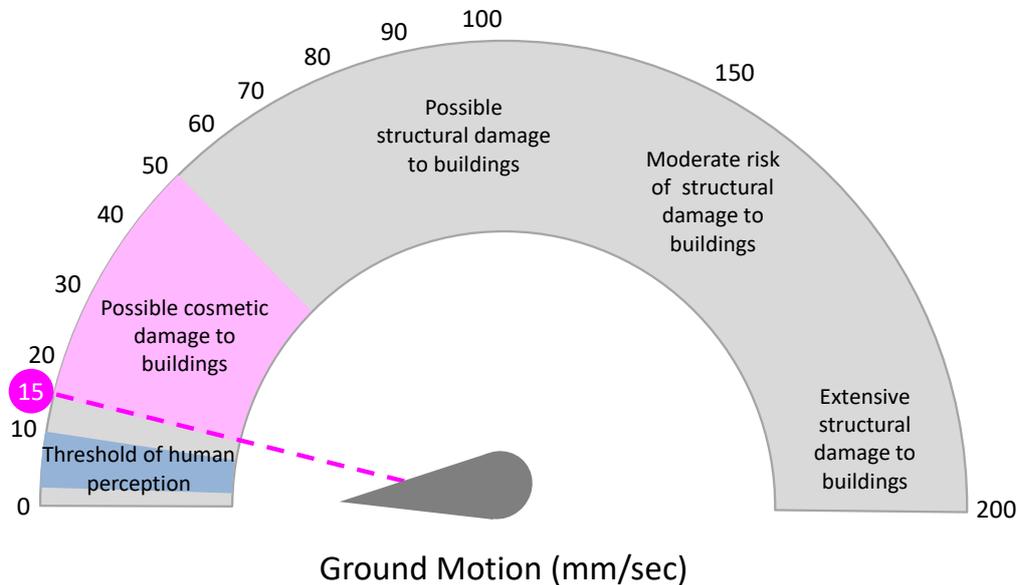


Figure 2: Ground motion levels and their potential impacts in the context of BSI ground motion standards²

Where the magnitude and ground motion of an induced seismic event confirm the assumptions and predictions in the HFP, then this indicates the geological understanding is still valid and injection operations can resume, subject to any mitigation or other measures as part of the agreed HFP.

This protocol is not, at this stage, to be regarded as definitive, but as an appropriate precautionary measure for the present state of knowledge. Initial operations under these controls will be subject to careful scrutiny to ensure their effectiveness and will be revised as experience develops, to ensure that they are proportionate to the risks.

² The British Standards Institution (BSI) is the national standards body of the United Kingdom. BS 6472-2 is for blast induced vibration and recommends satisfactory levels for peak particle velocity below which the probability of adverse comment from the public is low. It is recommended that the maximum of 2 mm/s for night and 6 -10 mm/s for daytime blasting adjacent to residential areas should not be exceeded by more than 10% of the events. Doubling these recommended levels could result in adverse comment and this will increase significantly if the levels are quadrupled. BS 7385-2 assesses the effect of ground vibrations on buildings and identifies levels for transient events above which cosmetic damage might occur of 15 mm/s at 4 Hz increasing to 50 mm/s at 50 Hz.

9. Hydraulic Fracture Consent (HFC)

All well consents issued after 6th April 2016 contain a requirement that the licensee obtain consent from the Secretary of State (SoS) for Business, Energy and Industrial Strategy (BEIS) in the form of a Hydraulic Fracture Consent (HFC) before carrying out any associated hydraulic fracturing.

The HFC is a separate authorisation and does not form part of the OGA's consenting regime. More information on HFCs can be found on the Government's website [here](#).

E. Development and Production

1. Field Development Plan

The Field Development Plan (FDP) is the support document for the OGA's development and production authorisations and should provide a brief description of the technical information on which the development is based.

As Licensees are jointly and severally responsible for the FDP, it must represent a single view of all the licensees. The Licence operator is usually responsible for producing the FDP and to ensure that all necessary consents and authorisations are obtained. It is usual for the OGA to conduct discussions with the operator as the representative of all the licensees.

The document should provide a summary of the operator's understanding of the field although more information must be provided if required by the OGA. A suggested structure for the document is set out at [Appendix A](#) of this guidance. The OGA encourages operators to engage with the OGA early to discuss content, drafting and development options before submitting an FDP, this will help make the process more efficient.

The OGA is committed to making information publicly available as soon as is reasonable but recognises that FDPs typically contain commercially sensitive information. The OGA will publish FDPs six years after they have been approved, but will consider representations to extend the period of confidentiality.

In addition, the OGA will require:

- a Board letter confirming scope of insurance or availability of necessary funds for any required remedial work;
- a Board letter confirming availability of planning permission and absence of any on-going planning disputes; and

- a Board letter from each licensee confirming that they support the development plan and have the necessary funds available. This “Board Letter” should also include a statement confirming that the OGA’s licensee [residence requirements](#) have been met.

2. Field Development Plan Approval and Production Approval

The development will be authorised once the OGA is satisfied that the FDP meets its requirements.

The OGA will require:

- a Board letter confirming scope of insurance or availability of necessary funds for any required remedial work;
- a Board letter confirming availability of planning permission and absence of any on-going planning disputes;

The OGA's approval will cover both the construction of the facilities and other infrastructure, and the production of hydrocarbons from the field. Subject to the terms of the licence, agreement will usually be given for production over a period that can be reasonably forecast with appropriate tolerances in the levels to be produced. Conditions may be imposed to give the OGA powers to require a review if performance falls outside these tolerances or if the field is found to differ from the initial perception to such an extent that there is a risk of a loss of significant economic reserves.

If production consent is issued for a duration that is less than the anticipated life of the field it is the responsibility of the operator to apply for renewed approval to allow production to continue, and an updated Field Development Plan Addendum (FDPA) may be required at that time.

If, either at the time of the authorisation of a FDP or during the period of production, it appears that production is likely to continue beyond the term of the licence(s) involved, it is the responsibility of the operator to apply for an extension to the licence, and this extension will, among other considerations, be subject to the continuing satisfactory performance of obligations under the licence.

2.1 How to Submit an Application

The OGA's consent will be given in the form of production consent through the [UK Energy Portal](#) and the FDP needs to be uploaded in the application. Online applications can only be applied for using the Portal so all applicants should ensure that an appropriate individual within that company has user access rights. Separate applications for production, flare and vent consents will need to be completed as appropriate.

Users who do not have a UK Energy Portal account should send an email to ukop@ogauthority.co.uk requesting an account and including the reason: 'to gain access to the UK Oil Portal Field Consents system'. The following information about the user should be supplied: Forename, Surname, Organisation Name (Employer), Job Title, Work Telephone Number & Email Address.

Users who already have UK Oil Portal accounts should check that they know their login details and password and that details held about them on the Portal are correct - by logging in to the Portal.

3. Field Development Plan Addendum

The focus of the OGA, once a development has been authorised, will be to ensure that the Field Development Plan is being followed or modified appropriately as the understanding of the field develops.

If an operator wishes to deviate from the agreed Management Plan authorised by the OGA in an FDP, they are required to submit a Field Development Plan Addendum (FDPA). The process for agreeing an FDPA is similar to that for an FDP and a suggested structure for the document is set out at Annex B of this guidance. An FDPA will also be required when an extension of long term production consent is requested, and should be uploaded to the PORTAL consent application and a copy emailed to the onshore team (onshore@ogauthority.co.uk).

4. Further information relating to FDPs and FDPAs

Operatorship and Licensee Requirements

Information about regulatory requirements for operator competency and financial viability and capacity requirements are covered in other guidance, and these will be considered at various stages of the regulatory process.

Field Returns

Monthly Petroleum Production Reporting System (PPRS) returns are required from a producing field. Annual Field Returns are currently not required onshore, although the OGA may introduce this requirement in future.

Licensees are requested to promptly contact the onshore team (onshore@ogauthority.co.uk) if production does not fall within the consented range or the geotechnical understanding or economic recoverable resource potential changes significantly.

Flaring and Venting of Gas

The OGA recognises that during the appraisal, commissioning and production phases of a development, the flaring and/or venting of some gas may be unavoidable. However, this flaring or venting must be kept to the minimum that is technically and economically justified. The OGA controls gas emissions by requiring licensees to apply for consent to flare or vent gas emitted by their fields. The main purpose of this requirement is to ensure that gas is conserved where possible by avoiding unnecessary wastage. The Environment Agency considers the environmental impact of emissions.

Unit Development

Where a Field Development Plan is proposed for a field which extends into the area covered by a neighbouring licence operated by different company the OGA needs to be satisfied that the ultimate economic recovery of petroleum is maximised and that unnecessary competitive drilling is avoided. The most efficient way to satisfy these requirements and therefore avoid any possible delay in the authorisation process is

for licensees to discuss with the neighbouring licensees at an early stage and propose an agreed FDP.

In cases where the licensees have not reached an agreement, the OGA has powers to require a unitisation between licensees. However, licensees should be aware that the OGA will not necessarily refuse to authorise development to a particular group of licensees who have not concluded an agreement with the licensees of an adjacent block on the basis that they have not concluded such an agreement. The OGA does not consider that powers to require unitisation extend to issues of fairness and equity between groups of licensees. The OGA's position is that proprietary rights do not exist in unextracted hydrocarbons and ownership of hydrocarbons arises only once they have been extracted under appropriate regulatory consent. The OGA's acceptance or rejection of any Field Development Plan will, therefore, be on the basis of whether it is the optimum development in the light of its objectives. If, in any intended development, there is a likelihood of claims or disagreement between adjacent licence groups related to the field's extent, the OGA should be consulted at an early stage.

Field Determination

So that the licensees understand what constitutes a field for both development and tax purposes, the OGA will issue a proposed Field Determination at an early stage in the FDP authorisation process, utilising the geological information that is available to it at that time.

For Abandoned Mine Methane fields, this will normally be a 1km square around the vent or mines gas well, rather than the workings expected to be drained by the development because of the uncertainty and complexity of many abandoned workings.

For Coalbed Methane (CBM) fields the area will usually be defined by the areal limits of the coal seams to be accessed by the proposed development. In the case of a phased project, this might mean that the field will need to be redefined as further blocks of coal are drilled. Fields draining from shale formations will also usually be defined by the extent of the area likely to be accessed by the planned development and if there are decision points to expand the development later in a phased project, the field

determination will change incrementally as more information is known. Where a proposed field development seeks to develop only a subset of stacked prospective horizons, the field determination may include a depth cut-off.

Wider Regulatory Regime

There are wider controls on onshore oil and gas development and production which do not come within the jurisdiction of the OGA. The Environment Agency and the relevant local mineral planning authorities implement environmental controls, the local mineral planning authority is responsible for site reclamation, and the Health and Safety Executive (HSE) regulates health and safety. An oil and gas development must have the relevant authorisations from each of these relevant regulators for both construction and production operations.

Board Confirmations

Before approving an FDP, FDPA or EWT the OGA requires:

- A board letter from the operator confirming scope of insurance or availability of necessary funds for any required remedial work;
- A board letter from the operator confirming availability of planning permission and details of any planning disputes; and
- A board letter from each licensee confirming that they support the plan and have the necessary funds available.

5. Cessation of Production

The OGA expects to be made aware long in advance of when production is anticipated to cease. Please contact the onshore team (onshore@ogauthority.co.uk) to arrange a technical review. A report is required. The amount of detail to be included in the report will depend on whether options to extend field life have been appropriately covered in previous field reports and should cover:

- Definition of economic limit and determination of cut-off rates and timing.
- Possible options for extending field life.
- Cash flow over the period up to this economic limit and approximately 2 years beyond.
- The costs and any revenues associated with cessation of production itself (capital and operating expenditures and any residual value of field assets).
- The form and costs of abandonment if these affect the timing of the economic limit.
- Production and injection profiles together with projections through to economic limit and approximately 2 years beyond.
- Details of any remaining licence obligations.
- Appropriate reservoir maps indicating the estimated location and distribution of remaining technically recoverable oil/gas that will be undrained at the time of cessation of production. In addition, some conception of likely changes in such distributions over time should be given for completeness of the record.
- Confirmation that all abandonment requirements in the relevant planning consents will be met and details of what is involved

It is important that sufficient information is retained after the cessation of production to enable other interested potential operators to take a reasonably informed view about the potential for field redevelopment. Redevelopment may become feasible if, for example, new technology allows a significantly improved recovery factor. For this reason, the COP Relinquishment Report documents will be released once the licence(s) involved are relinquished with the Relinquishment Report.

The EA and HSE also have specific regulatory requirements which must be met.

6. Petroleum Production Reporting System (PPRS)

On 9 June 2017, the Oil and Gas Authority (OGA) launched its refreshed Petroleum Production Reporting System (PPRS) on the Energy Portal, allowing Operators to report their monthly flow rates for gas, oil, condensate, flare, venting, gas and water injection data with improved functionality and capability and aid and inform the OGA's Asset Stewardship model. More information on PPRS can be found [here](#).

Portal Support for PPRS will be offered through the usual UKOPs helpdesk (ukop@ogauthority.co.uk, Tel 0300 067 1682).

F. Reports and Data

The Licensee must provide the OGA with any information that they may ask for and the OGA require copies of data acquired. Historically this guidance was set out in a list of **Petroleum Operations Notices** (PONS), and although some only relate to offshore operations, some are still relevant to onshore. These are:

PON 4 - Application for consent to drill exploration, appraisal, and development wells (this is now integrated into WONS)

PON 5 - Application to abandon or temporarily abandon a well (this is now integrated into WONS)

PON 6 - Measurement of petroleum

PON 7 - Reporting of petroleum production (this is now PPRS)

PON 8 - Application to complete and/or workover a well (this is now integrated into WONS)

PON 9b - Record and sample requirements for onshore surveys and wells

PON 12 - Well numbering system

PON 14b - Notification of intention to carry out (onshore landward) geophysical surveys

1. Record and sample requirements

The OGA is committed to making information publicly available as soon as is reasonable. Under current regulations, the data specified in the **PON9b** is usually available for release once a period of confidentiality has passed (3-5 years, depending on the licence, except for geologic and operational information relating to the hydraulic fracturing a well, which must be supplied within three months). The OGA holds the

right to access, inspect and take copies of any materials kept by the Licensee in connection with the licence. The same applies to access to and inspections of installations and equipment used in relation to searching, boring for or getting petroleum within the licensed area.

Please read the Notice fully before sending any information, as it contains changes to earlier editions.

Operators are obliged to meet the legislative requirements for data required by both OGA and the Natural Environment Research Council (NERC). Copies of all well log data should also be sent to the British Geological Survey (BGS) for distribution to OGA's well data release agents in addition to those sent to UKOGL.

The [model clauses](#) attached to all licences require operators to retain all the data collected during their operations and to send any or all of this data to OGA as required. This Notice details OGA's current data requirements and therefore applies to all onshore geophysical surveys and all onshore exploration, appraisal, and development wells.

[The Mining Industry Act 1926](#) (section 23) as modified by the [Petroleum Act 1998](#) (section 1) requires Onshore Licensees to give prior notification to the Natural Environment Research Council (NERC) through the British Geological Survey (BGS) of their intention to undertake drilling.

This document contains a summary of requirements, the destination for records and samples, and the timeframe within which the items should be sent together with relevant addresses and details of the process for the release of onshore.

2. Proposed geophysical surveys

Operators must advise OGA and any other parties specified in the licence conditions of all proposed geophysical surveys 28 days before the survey is commenced. The [PON 14b form](#) must be used, and the same form used again to report on completion of the survey. In an area known to have coal potential the operator must also, in addition to any planning conditions, consult the Coal Authority before commencing any survey.

3. Seismic data

The UK Onshore Geophysical Library (UKOGL) manages the archiving and release of onshore seismic data for OGA. All operators are now required to archive seismic data with UKOGL as soon as it has been acquired. The location of newly acquired data will be made public on the UKOGL website when survey is finished.

The new data will be kept confidential until it is released, except for the map location of the data acquired which will be posted on the UKOGL website. For the purpose of data release, the start of the confidentiality period is deemed to be the end of the calendar year when data acquisition was completed for seismic data. For data acquired under onshore licences awarded up to and including the 11th round (up to and including PEDL132) the confidentiality period is 5 years. For data acquired under later onshore licences (from PEDL133 on) the confidentiality period is 4 years. For Exploration Licences (XL) the confidentiality period is 3 years. Archiving with UKOGL absolves an operator from his statutory duty to store such data. The following are the recommended practices for data to be sent to UKOGL.

4. Location data

Navigation data in UKOOA format for CDP locations, shot/VP locations and geophone locations.

5. Digital field data

Original field format tapes together with one demultiplexed version of the field data in SEG-Y format (original sample rate and record length to be retained and demultiplexed data to be unfiltered and not edited). Test records to be retained.

6. Paper acquisition data

All paper or digital operational data for each line should be stored together and an index provided of the data available e.g. observer's reports, statics, omissions, LVLs, line intersections etc.

7. Stack data

Digital versions in SEG-Y for all final stacks and migrations.

8. Reprocessed data

Digital versions in SEG-Y for all reprocessed stacks and migrations. All reprocessed navigation data in UKOOA format as above.

9. 3D data

Archiving of this data is still being addressed by UKOGL. Contact them for required data formats.

10. Magnetic, Gravity and other geophysical survey data

This data should be sent ONLY if requested and then within 30 days of the request. The required format/media will be specified with the request.

11. Well data

The following is the information required from all wells. Note that these requirements therefore also apply to all shallow “boreholes” drilled as part of an operator’s exploration and development activities under a Production Licence including those drilled to test coal seam thickness and gas content, mine water flooding levels etc.

Licensees are reminded that if they wish to make a press release regarding the results of the well, they should send a copy to the onshore team (onshore@ogauthority.co.uk) for information.

12. Data required on completion of a well

Logs

Petrophysical logs including CBL and Image Logs, if acquired, should be supplied within 4 weeks of completion of the well unless specifically requested earlier. The data must be supplied digitally, preferably on CD or DVD, in an industry standard format

i.e. DLIS, LIS, LAS, BIT or API. Associated digital image files of the log data should also be supplied in industry standard image format, such as TIF, JPG, CGM or PDS. All data should be clearly labelled with OGA Well Registration Number, well name, tool type and run depth range.

Any reprocessed logs such as dipmeters and true vertical depth logs should be sent as soon as they become available. These should also be supplied digitally on CD or DVD. Again, all data should be clearly labelled with OGA Well Registration Number, well name, tool type and run depth range.

Geological Composite Log

Within six months of completion of any well including abandonment, or suspension after reaching the first potential producing horizon, the following information must be included on a digital composite log (1:500 scale):

The OGA Well Registration Number and well name. The Operator's well number, if different, may be added.

The Composite Log should integrate the geological columnar section with selected petrophysical logs i.e. a lithology indicating log, a porosity log and a resistivity log.

The log should indicate all logging and coring intervals, testing intervals and casing/liner seats and it should carry abbreviated information concerning the geology and testing or shows.

The digital image file can be in TIFF, CGM or PDS format.

13. Data associated with hydraulic fracturing following consent to a Hydraulic Fracture Plan (HFP)

Within three months of the end of hydraulic fracturing a well, the geologic and operational data must first be submitted to OGA and updated in three month intervals until the end of an extended well test. Micro-seismic data acquired for use in the Traffic Light System (TLS) to mitigate frac-induced seismicity and data acquired to measure the fracture growth height must be submitted to the BGS.

Also like any EWT, the monthly PPRS reporting is required.

The HFP report required (in .pdf format) should include:

- operations summary including result of well integrity monitoring
- well diagram with perf stages
- deviation survey
- wireline log images of zones
- gas chromatograph
- core intervals
- mineralogy from cuttings
- summary of stress interpretation
- location of frac stages posted on seismic display
- visualisation of fracture extent on micro-seismic and/or optical fibre data
- plot containment within permitted boundary
- comparison of modelled vs actual Stimulated Reservoir Volume
- summary of Traffic Light System seismicity monitoring and actions taken
- injection/flowback volume plotted vs induced seismicity over time
- summary of key learnings

Digital file (in .xls format) should include the following profile data over time:

- Bottom Hole pressure
- Injection rate
- Well Head pressure
- Proppant concentration

- Injection volume
- Flowback volume

Within 30 days of completion of hydraulic fracturing, a Hydraulic Fracturing Operations Report containing data in respect of the geology, operations or results associated with hydraulic fracturing of shale or other strata encased in shale must be submitted to the OGA, and followed by updated reports, in three month intervals from the commencement of the test and until the end of testing operations. These reports are to be provided within 30 days of the period reported upon, and the OGA shall be entitled to publish these reports after the expiration of the period of six months beginning with the date when the report was due to be supplied to the OGA, or if earlier, the date when the OGA received the report.

14. Completion report (End of Well Report)

- Within 6 months of the completion of any well including abandonment, or suspension after reaching the first potential producing horizon, a completion report must be submitted containing the following information (NOT simply a mudlogger's report) digitally in PDF format.
- OGA Well Registration Number, well name and the target reference for the well. Where the operator has its own numbering system on fields the alternative number should be included.
- Status of well - i.e. abandoned, suspended, production, injection or observation.
- Well Chronicle - dates of rig on location, drilling commenced (spud), drilling completed, operations completed and rig off location. Intermediate dates and depths should be included where operations were suspended for any reason prior to end of operations on the well.
- Height of drilling reference point (e.g. KB or RT or RF) above Ordinance Datum
- Location – National Grid coordinates and relevant latitude and longitude for top hole location.

- Total Depth. If there is significant deviation give TVD of total depth together with bottom hole National Grid coordinates with bearing and distance from top hole location.
- Drilling unit.
- Licence number and round with licence operator.
- Table of geological formations encountered giving depths (MD and TVDSS) and thicknesses (apparent and TVTH). A brief geological description, with significant age determinations and structural information (dips and faults, include true stratigraphical thickness if applicable).
- A listing or log of hydrocarbon indications recorded whilst drilling.
- A record of all cores and side wall cores, intervals and recoveries together with stratigraphical core log, conventional poroperm results and any special core analyses including those to determine petrophysical rock parameters.
- A record of all logs taken (see also above) with brief determinations of porosity and water saturations in reservoirs and potential reservoirs.
- The depths (MD and TVDSS) and results of all repeat formation tests performed in the well. State whether psi(a) or psi(g).
- The depths (MD and TVDSS) and results of all drill stem and/or production tests of the well. Include details of intervals, chokes, rates and/or volumes of hydrocarbons and/or water obtained and their gravities together with pressure and temperatures measured with computer extrapolated reservoir pressure and reference depth. Additionally, the results of the test should include perforation details of type, size, density of shots and when applicable details of stimulation such as type, volume, rate, pressures.
- The results of chemical and physical analyses of fluids produced by testing or of minerals found in the well. For CBM wells, also the results of core studies of permeability, desorption, adsorption and gas content.

- Drilling history of the well including mud record, chronological report and, as an appendix, copies of all drilling reports with the exception of the IADC and other daily reports. Clear copies of which should be available on demand to OGA.
- Details of the well's casings/liners and their seat depths including cement volumes, location of cement tops outside the casings and the method of location. Company/contractors cementing reports and records should be submitted as an appendix. Details of all formation integrity tests whether immediately below casing seats are required. Information should be supplied as total pressure versus depth indicating either that leak off has been achieved or that it was a simple limit test.
- The kick-off point of a side-tracked or deviated hole. If the deviation data is requested, it should be submitted in digital format.
- If the well is abandoned or suspended details of packers, plugs, casing retrieval and site clean-up. A diagram showing all components, cement, perforations and obstructions left in the hole are required.
- If the well is completed details of packers, subsurface chokes; nipples and safety valves; tubing size, grade weight and pipe thread and well head Christmas tree.
- A completion diagram showing components of the completion, casing strings, cement tops, perforations and obstructions left in the hole is required.
- Digital log image files can be in TIFF, CGM or PDS format.

For development wells the following information concerning the reservoir should be included in the completion report:

- Reservoir unit tops as depths (MD and TVDSS) and thickness (apparent and TVTH).
- Fluid contacts or limits i.e. gas/oil, or oil/water, or gas/water or lowest known occurrences of hydrocarbon fluids as depths (MD and TVDSS).
- Subsea National Grid co-ordinates of reservoir unit tops and fluid contacts.
- Net pay-thickness (MD and TVDSS) for units and total reservoir.

- Reservoir units' average porosities and water saturations.

In addition to the completion report, the following data is also required, within one year, for development or EWT wells, digitally (in a TIFF, CGM or PDS format).

- Results of any significant chemical and physical analysis of petroleum including PVT analyses, water or minerals found in the well or injected into the formation subsequent to well completion report.
- Results of any significant physical analysis carried out on rock samples or fluid from the well including special analyses to determine matrix or fluid parameters subsequent to well completion report.
- Results of any significant tests on production, injection and observation wells including downhole formation pressure and temperature surveys carried out, and also including time, pressure and flow listings of draw down and build-up surveys subsequent to well completion report.
- Any measurements relating to well-head to down-hole pressures (static or flowing) should be reported.
- Details of any changes in perforations or completion hardware or any further operations to stimulate or inject fluids. The TVD or drilled depth of flowing perforation intervals should be reported.
- Details of any other significant changes to the well.

15. Well velocity information

- The results of any velocity surveys and vertical seismic profiling including velocity logs, VSPs and synthetic seismograms, within two months, supplied digitally in a TIFF, CGM or PDS format.

16. Samples requirements

Cuttings samples - representative, washed and dried samples, depth labelled, collected whilst drilling the well at selected intervals. Wherever possible each sample

should be at least 100g weight. The collection of cuttings samples in the top hole section of development wells drilled from a single surface location may be waived following discussions with OGA.

Slabbed cores - from all cores taken as a continuous vertical section comprising at least a width of the core, which will allow standard poroperm plugs to be taken. Any operator wishing to dispose of any other core material after the expiry of five years should inform the onshore team (onshore@ogauthority.co.uk) giving six months' notice in order that their preservation may be arranged if required.

Oil samples are no longer required. However, a representative sample of stock tank oil should be retained for 5 years. After this period, any operator considering the disposal of any hydrocarbon fluid samples from discoveries made before the issue of this notice should contact the onshore team to discuss the proposed disposal. A basic sample analysis will be required before any sample is disposed of.

Samples from the sea bed (note some onshore licences include "watery areas" that have sea bed)

Portions of sea bed samples and/or cores from boreholes penetrating below the sea bed are required.

Raw data from subsampling released wells will be held confidential for 2 years and interpretative reports for 5 years from the date of sampling. Thereafter copies may be obtained from BGS, subject to the usual procedures for the supply of data.

It will not normally be permitted for a second company to duplicate an analysis at previously sampled horizons. Any subsequent applicant will be expected to sample above or below previous samplers. Where a subsequent applicant has a strong scientific case to duplicate a previously sampled horizon, they may apply to OGA for authorisation to contact the original sampler, who shall then make the basic analytical results available, either freely after 6 months from the date when they received the analytical results, or at a proportion of the analytical costs, not exceeding 50%, before 6 months from the date when they received the analytical results.

17. Licence Relinquishment Reports

Upon relinquishing or partially relinquishing a licence, the licence operator is required to send the OGA a Relinquishment Report within three months of the licence being relinquished, and these reports are made available in the public domain on UKOGL under [Industry Activity Reports](#). Relinquishment reports should be sent to the onshore team (onshore@ogauthority.co.uk)

This report should contain a full summary of the work carried out on the Licence, including descriptions of any newly acquired seismic and reprocessed data, any studies and the results from these and an account of the prospectivity for the relinquished area. Copies of reprocessed seismic data should be made available to [UKOGL](#).

If production has ceased on a field, the operator should document, within the relinquishment report, the basis of their decision to cease production and provide an estimate of the remaining recoverable resources.

17.1 Relinquishment Report Guidelines

The relinquishment report should include the following information:

1. Licence Information

- Licence Number
- Licence Round
- Block Number(s)

Also provide, in this section, a statement to say that all permissions to publish have been obtained.

2. Licence Synopsis

- Licence Status (e.g. end of Initial Term, other reasons for relinquishment)

Include a summary of the award and participants, the work obligations (depending on the Term of the Licence) and any licence extensions agreed.

Outline the prospectivity identified at the time of application and whether any undeveloped discoveries were analysed.

If Production ceased under the licence, detail Cessation of Production information is required (see Cessation of Production ([COP](#)) guidance with Field Development Plan).

3. Work Programme Summary

If the Licence was in the Initial Term, specify the exact Work Programme agreed for the Licence, and what was undertaken.

If the Work Programme included reprocessing of seismic data, give clear seismic examples of pre- and post- processing as figures, and describe where there were any noticeable uplifts in the seismic data. Similarly, for new seismic data acquired and interpreted, give clear seismic comparison examples of older and newly acquired seismic data as figures. Specify whether the data was of sufficient quality to address the geology of the block(s). Where there were new wells drilled on the licence, give brief details of the results.

4. Database

The report should include a map of the seismic and well database utilised in the evaluation of prospectivity and/or discoveries.

5. Prospectivity Update

Provide a brief review of prospectivity presented in the original licence application and a more detailed review of prospectivity following any reprocessing/new seismic data/etc. This should include structure maps and examples of the seismic interpretation. If any drilling has taken place, show examples of the revised or new interpretation/mapping incorporating the well results.

6. Further Technical Work Undertaken

Give a summary of any further detailed technical analysis or studies undertaken to derisk the prospectivity on the licence. This may include, for example, inversion, rock physics, AVO, spectral decomposition, more detailed well analysis, etc.

7. Resource and Risk Summary

Include a summary table of recoverable resources associated with the remaining undrilled prospects and leads. An example is shown below:

Resource and Risk Summary										
Prospect Lead Discovery Name	PLD	Stratigraphic Level	Unrisked Recoverable Resources						Geological Chance of Success (%)	Risky P50 (MMboe)
			Oil (MMbbls)			Gas (BCF)				
			Low	Central	High	Low	Central	High		
Venus	P	Paleocene	4	6	10	90	130	160	22	
Pluto	P	Namurian	5	11	21				17	
Mars	L	Cretaceous	3	17	33				12	
Earth	D	Jurassic	5	7	9				100	

8. Conclusions

Comment on any remaining potential prospectivity on the licence and the reason for relinquishment.

9. Clearance

It is important that the submitting operator confirms, within the Report, that the OGA is free to publish the Report and that all 3rd party ownership rights (on any contained data and/or interpretations) have been considered and appropriately cleared for publication purposes.

The OGA will only consider withholding publication of the report until after the next licensing round on a clear request in the covering email from the operator.

10. Maps and Figures

As a minimum, provide a Location Plat, a Structure Map (which can be cut and pasted into the text) at an appropriate scale (but which must cover sufficient National Grid coordinates to enable geo-referencing of the prospects within the Licence) on appropriate horizon(s), illustrative seismic sections and illustrative geoseismic cross-section(s).

18. The data release process

Well data

OGA requires onshore well data to be submitted in digital rather than hard copy format. One copy of the data should be sent to BGS* and another to UKOGL (see contacts below). These data will be stored for the confidentiality period specified under the terms of the licence under which the data was acquired. At the end of the confidentiality period, OGA's Data Release Agents will release the data according to the terms of their contract with OGA.

If the data is deemed to be complete, the operator will be notified that he is released from his obligations under the terms of the licence to retain it or provide it.

* Section 23 of the Mining Industry Act 1926 requires onshore well data to be sent to BGS who will maintain the data and observe the confidentiality period specified by OGA. Well records and data supplied under this provision are Public Records and the Science and Technology Act 1965 places a duty on BGS to disseminate (subject to confidentiality restrictions) its knowledge in the earth sciences.

Seismic data

The release of onshore seismic data is through the UK Onshore Geophysical Library (www.ukogl.org.uk).

19. Data Summary Table

Data Type	Send data to:	Timeframe
Notification of Seismic Surveys (PON14b)	OGA and UKOGL	28 days prior to survey, and upon completion of survey
Seismic Data	UKOGL	As soon as possible once data has been acquired
Magnetic Gravity & Other Geophysical Data	UKOGL	As soon as possible once data has been acquired
Application for Consent to Drill	WONS	Minimum 21 days prior to drilling
Notification of Spud	WONS	Earliest opportunity (within 2 hours where possible)
Well Summary	WONS	Prior to Completion, Suspension, or Abandonment of a well
Petrophysical Logs	UKOGL & BGS	Within 4 weeks of completion
Completion Report	UKOGL & BGS	Within 6 months of completion
Composite Log (digital copy)	UKOGL & BGS	Within 6 months of completion
Well Velocity Information	UKOGL & BGS	Within 2 months of completion
Reservoir Information (Development Wells)	UKOGL & BGS	Within 2 months of completion
Shale Gas Exploration Frac report	OGA, UKOGL & BGS	Within three months
EWT or Development well test report	OGA, UKOGL & BGS	Within three months
Cuttings, Cores & sea bed samples	BGS Keyworth	Within 6 months of completion

G. Appendix A

1. Field Development Plan (FDP) Content

The following are suggested section headings together with the topics that should be addressed, but can be modified as needed. The actual content of the document should be agreed with the OGA prior to the submission of the FDP. Please contact the onshore team (onshore@ogauthority.co.uk) to arrange a technical review or provide a draft document for comment at an early stage.

1. Executive Summary

The Executive Summary should state the essential features of the development including:

- a brief description of the hydrocarbon reservoirs, hydrocarbon (API, GOR, BTU, etc.), estimated reserves, development strategy, facilities and pipelines
- an outline map showing the field limits, Field Determination boundary, contours of fluid contacts, existing and proposed wells, with Unitary Authority and licence boundaries
- a project schedule, total capital cost and a statement of licence interests
- a central estimate of ultimate recovery, and the minimum, central and maximum hydrocarbon production profiles of:
 - gas, in thousands of metric tonnes and billion cubic feet per year
 - oil, in thousands of metric tonnes and in millions of US barrels per year
- a statement of intent towards any parts of the field area that are not addressed by the Plan, including any commitment to later development of that area, or to the later stages of a phased development. Any provision for the development of other hydrocarbons in the area should also be identified

- a map with the Field Determination boundary and location of any nearby protected area: National Parks, Areas of Outstanding Natural Beauty, World Heritage Sites, Groundwater Source Protection zones and any European Sites of Scientific Interest
- the essential elements of the Field Management Plan and key decision points

2. Field Description

The description should be in summary form and only a brief statement, table or map of the results provided with references to more detailed company-held data, where appropriate. A brief history of the field, referencing the discovery well and significant appraisal wells is useful. Licensees are encouraged to submit only those maps, sections and tables necessary to define the field adequately but should include at minimum a table of in-place hydrocarbon volumes, a representative cross-section and top structure maps for each reservoir. Maps should be in subsea depth, at appropriate scales, and include co-ordinates in the United Kingdom National Grid.

2.1 Seismic Interpretation and Structural Configuration

This should include a summary of the extent, vintage and quality of the seismic data and key mapping horizons noted. The structural configuration of the field should be presented using appropriate figures and maps (e.g. dip and strike seismic lines, depth structure map of target horizon and schematic cross section).

2.2 Geological Interpretation and Reservoir Description

The stratigraphy of the reservoirs, facies variations, the geological correlation within the reservoir and any other relevant geological factors that may affect the reservoir parameters (both vertically and horizontally) and thereby influence reservoir continuity within the field should be described in summary form. Figures and maps should be provided (e.g. stratigraphic column, CPI of key log or log cross section). The geological data provided should reflect the basis of reservoir subdivision and correlations within the reservoir and should include the relevant reservoir maps on which the development is based.

2.3 Petrophysics and Reservoir Fluids

A summary of the key field petrophysical parameters should be presented incorporating log, core and well test data. A summary of the field PVT description should be included.

For CBM fields, this may include Net Coal (ft), Nr. Seams \geq 3ft thick, Coal Rank (HVol Bit), Gas Content (*in situ* scf/t or cm³/g), Gas Saturation (%), Permeability (mD), Gas Composition (% inert gas), Moisture Content (%) and Volatile Matter (%).

For shale fields, this might include Gross Shale and Target Horizon Thickness (ft), Porosity (%), Saturation of Water (%), TOC (%), Permeability (mD), Gas Yield (scf/tonne), Extent of Overpressure and the Mineralogy of Target Horizons.

Fluid and gas characteristics should be summarised.

2.4 Hydrocarbons in Place

The volumetric and any material balance estimates of hydrocarbons in place, for each reservoir unit, should be stated together with a description of the cause and degree of uncertainty in these estimates. The basis of these estimates should be available and referenced.

2.5 Well Performance

The assumptions used in the Field Development Plan for the productivity and injectivity of development wells should be briefly states. Where Drill Stem or Extended Well Tests have been performed, the implications of these on production performance should be given. The potential for scaling, waxing, corrosion, sand production or other production problems should be noted and suitable provision made in the Field Management Plan. The potential and adoption for well stimulation including fracturing.

2.6 Reservoir Units and Modelling Approach

A brief description of the reservoir engineering. Where the reservoir has been subdivided for reservoir analysis into flow units and compartments, the basis for division should be stated. A description of the extent and strength of any aquifer(s) should be given. The means of representing the field, either by an analytical method,

some form(s) of numerical simulation, or by a combination of these, should be briefly described.

2.7 Improved Recovery Techniques

A summary of the alternative recovery techniques considered and the reasons for the final choice is required.

2.8 Reservoir Development and Production Technology

The chosen recovery process should be described and the optimisation method summarised, including references to the potential for artificial lift and stimulation. Plans for hydraulic fracturing and other stimulation should be summarised and reference the agreed Hydraulic Fracture Plan for details.

Any limitations on recovery imposed by production technology or by the choice of production facility or location should be indicated. Remaining uncertainties in the physical description of the field that may have material impact on the recovery process should be described and a programme to resolve these should appear in the Field Management Plan.

3. Development and Management Plan

Regarding the form of the development, describe the facilities and infrastructure, and establish the basis for data gathering and field management during production. Where a topic is not relevant to a development, it should be omitted.

3.1 Preferred Development Plan, Reserves and Production Profiles

This section should describe the proposed reservoir development and indicate the drilling programme, well locations, expected reservoir sweep and any provision for a better than expected geological outcome. An estimate of the range of reserves for each reservoir should be given (excluding fuel and flare) with a brief explanation of how the uncertainty was determined and explicit statements of probability, where appropriate. The assumed economic cut-off should be stated. Expected production profiles per well, for total liquids, oil, gas, gas usage and flare, associated gas liquids and produced water for the life of the field are required. Where fluids are to be re-

injected, annual and cumulative injection profiles should be provided. Quantities can be provided in either metric units or in standard oil field units (but with conversions to metric equivalents provided). Information to allow calculation of sales quantities should be provided.

3.2 Drilling and Production Facilities

The drilling section should briefly describe the drilling package and well workover capability, and should include a description of the proposed well completion.

3.3 Process Facilities

A brief description of the operating envelope and limitations of the process plant should be provided. The use and disposal of separator gas should be described. The section should also include:

- a summary of the main and standby capacities of major utility and service systems, together with the limitation and restrictions on operation
- a summary of the method of metering hydrocarbons produced and utilised
- a brief description of systems for collecting and treating oil, water and other discharges
- a brief description of any fluid treatment and injection facilities
- a brief description of the main control systems and their interconnections with other facilities
- a statement regarding the planning consent and environmental permissions
- a description of the export route

3.4 Costs

Cost information is not required at present.

3.5 Field Management Plan

A brief review is required that sets out clearly the principles and objectives that the licensees will hold to when making field management decisions and conducting field operations and how economic recovery of oil and gas will be maximised over field life.

The rationale and plan for data gathering and analysis proposed in order to resolve the existing uncertainties set out in section 2 and understand dynamic performance of the field during both the development drilling and production phases outlined.

The potential for workover, re-completion, re-perforation, re-hydraulic fracturing and further drilling should be described. Where options remain for improvement to the development or for further phases of appraisal or development, the criteria and timetable for implementing these should be given and described in phases, if appropriate.

3.6 Other Attachments

- if the project involves the exploitation of coal seams, proof of agreement of the Coal Authority
- a letter from each licensee, confirming that they support the development plan and have the necessary funds available. This “Board Letter” should also include a statement confirming that the OGA’s licensee residence requirements have been met
- an Ordnance Survey plat of surface location of planned and existing infrastructure

H. Appendix B

1. Field Development Plan Addendum (FDPA) Content

Suggested headings and content of the report are as follows:

1. Introduction

A brief review of the field operations and export route with any divergence from the Development Plan should be summarised. Any changes in licence equity or of the operator should be given. A map showing the field extent and licence boundaries should be provided.

2. Field Description

2.1 Hydrocarbons Initially in Place and Recoverable Reserves

Changes in estimates of hydrocarbons initially in place and reserves should be identified by reference to the Development Plan base case and to the case in any previous FDPA.

2.2 Well Status and Operations

A table summarising changes in well status (e.g. producer/injector, suspended/abandoned, perforated intervals, reservoir identifier, lift provision) should be included and should note any well operations carried out during the reporting period (e.g. drilling, workovers, data gathering, perforating stimulation). Any significant gap in field production should be explained. A chart of individual well historic production rates (and water cut percentage, if relevant) should be provided. A cumulative production chart, by well, is also requested.

2.3 Geology and Geophysics

A brief summary of the reservoir geology and hydrocarbon type and sample CPI log should be included. A detailed depth structure map for key productive horizons with annotations of the maximum extent (e.g. GDT or OWC) and well paths from the surface to top horizon is required along with an interpreted seismic line across the field and, if available, a schematic cross-section. Where drilling, seismic re-processing or

other work has had significant impact on the reservoir model, a summary of the results should be provided.

2.4 Field Facilities and Infrastructure

An Ordnance Survey plat which shows the location of all field facilities is required. A brief report on the performance of the field production facilities, highlighting features that have impeded operations and also valuable improvements, should be added. Any changes to export routes should also be described.

3. Development and Management Plan

3.1 Field Management

Any changes in development strategy should be reviews. Important reservoir monitoring results, reservoir monitoring limitations and specific production difficulties should be summarised. Where appropriate, plots of reservoir pressure and voidage replacement should be provided. Plans for reservoir monitoring in the coming year should be briefly discussed.

3.2 Studies

The results and relevant of any geoscience, reservoir or facilities/pipeline engineering studies completed during the reporting period should be summarised. Plans and timescale for ongoing and future studies should be briefly discussed.

3.3 Improved Oil Recovery (IOR)

Where appropriate, the potential for IOR should be reviewed and the results of any studies or operations discussed.

3.4 Forecasting

A table of the forecasted production, vent and flare volumes and injection profiles should be provided, together with the current estimate of the Cessation-of-Production date. A summary of the initial estimate STOIP or GIIP, cumulative production and recovery factor (if relevant), remaining reserves and field EUR should be provided.

3.5 Proposed Changes to the Development Plan

Proposed changes to commitments or to conditions in the development consent should be set out clearly, as should plans to extend the development beyond the Development Area. The need to include other deviations should be discussed with the OGA. Where appropriate, a summary of exploration targets or longer-term development opportunities – within or around the field – should be provided.

3.6 Field Operating Costs

CAPEX and OPEX information is not required at this time.

3.7 Other Regulatory Issues

A summary of the status of other regulatory consents and permissions should be provided.



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