Title: New Shale-Friendly Model Clauses for Landward Areas	**Impact Assessment (IA)**
IA No: DECC0162	**Date:** 26 June 2014
	Stage: Final
Lead department or agency: Department of Energy and Climate Change (DECC)	**Source of intervention:** Domestic
	Type of measure: EANCB Validation
Other departments or agencies: None	**Contact for enquiries:** Mike Earp 03000 685784 mike.earp@decc.gsi.gov.uk

Summary: Intervention and Options

RPC: VALIDATED

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, Two-Out?**	**Measure qualifies as**
£883.4 million	£883.4 million	-£45.8 million	Yes	OUT

What is the problem under consideration? Why is government intervention necessary?

Exploration for and development of onshore oil and gas resources in Great Britain is possible only in areas where licences have been awarded. Much of the prospective area is currently unlicensed. Since licensing began in 1923, DECC and its predecessors have honed the terms of licences until they are very well-suited to facilitate the exploitation of conventional oil and gas, by allowing licensees to retain exclusive rights only as long as they meet certain minimum targets for progress. By now, though, conventional resources are thoroughly explored and current interest lies in shale gas. Industry tells us that the licence terms are not well-suited to shale gas and need to be adjusted if they are not to inhibit it.

What are the policy objectives and the intended effects?

Secondary legislation is required to set out new Model Clauses. The aim of the new clauses is to facilitate exploration for and development of unconventional hydrocarbons (especially shale gas) as well as conventional. The commercial viability of shale gas is as yet unproven in Great Britain but there is a significant resource in areas that are currently unlicensed. New licensing is expected to double the developable shale gas resource. The value of this measure is expected to be greater than assessed here because timely and comprehensive exploration for and development of shale gas will also benefit from policy being explored to simplifying access rights to underground land.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base) Licences confer exclusivity on companies, without which no company is likely to make the considerable investment needed to develop the UK's native hydrocarbons, so abolishing the licensing system will not facilitate the development of shale gas. Within a licensing system, various approaches have been considered to the licence terms. Industry believes that the Do-Nothing Option would inhibit or even prevent the development of shale gas. Relaxing the terms of licences without a new approach would allow licensees to do 'landbanking'; i.e. holding exclusive rights as a valuable asset rather than to develop the resource, which would have the same effect. The preferred option is therefore to add a new mechanism of retention by agreement between DECC and licensee where it is justified by plans to develop shale gas (or other) resources.

Will the policy be reviewed? It will not be reviewed. **If applicable, set review date:** Year

Does implementation go beyond minimum EU requirements?			**No**		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro:** No	**< 20:** Yes	**Small:** Yes	**Medium:** Yes	**Large:** Yes
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:** N/A	**Non-traded:** N/A	

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: Michael Fallon Date: 26 June 2014

Summary: Analysis & Evidence — Policy Option 1

Description: Introduce new shle-friendly Model Clauses

FULL ECONOMIC ASSESSMENT

Price Base Year 2014	PV Base Year 2014	Time Period Years 21	Net Benefit (Present Value (PV)) (£m)		
			Low: 0	**High:** 1766.8	**Best Estimate:** 883.4

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	0	0	0	**0**
High	0		0	**0**
Best Estimate	0		0	**0**

Description and scale of key monetised costs by 'main affected groups'

Costs are netted off in arriving at the benefits reported below.

Other key non-monetised costs by 'main affected groups'

Given the scope of environmental regulation on shale gas activity there are not expected to be environmental impacts from the extra activity enabled by this option (see https://www.gov.uk/government/publications/guidance-on-the-preparation-of-an-environmental-risk-assessment-of-shale-gas-operations-in-great-britain-involving-the-use-of-hydraulic-fracturing).

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	0	0	0	**0**
High	0		137.2	**1766.8**
Best Estimate	0		68.6	**883.4**

Description and scale of key monetised benefits by 'main affected groups'

Benefits come from the value of additional gas production net of the costs of discovery, development and administration. They all accrue directly to petroleum licensees (oil and gas companies) though much of their benefits would eventually flow through to the Exchequer through higher taxation receipts.

Other key non-monetised benefits by 'main affected groups'

None.

Key assumptions/sensitivities/risks — **Discount rate (%)** 3.5

Extent of additional activity and resultant level of production are both uncertain as are the costs of exploration and development and future gas prices.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of OITO?	Measure qualifies as
Costs: 0.0	**Benefits: 45.8**	**Net: -45.8**	Yes	OUT

Evidence Base

Problem under Consideration

Model Clauses Petroleum is a valuable national resource that includes unconventional hydrocarbons (e.g. shale gas) as well as conventional oil and gas. The Petroleum Act 1998 vests all rights to the petroleum resources in Great Britain in the Crown but empowers DECC to grant licences that confer exclusive rights to the licensees to ‘search and bore for and get’ petroleum. These licences are essential to secure the exploitation of this valuable national resource, because they protect the value of a company’s investment from rivals that might otherwise seek to exploit hydrocarbons that it has discovered by competitive drilling. The case for making the necessary investment would be very much reduced without that protection.

Section 3 of the Petroleum Act 1998 empowers the Secretary of State to grant licences to such persons as he thinks fit to explore for and extract naturally-occurring hydrocarbons (including shale gas). Section 4 of the Act requires him to make regulations that prescribe “model clauses which shall, unless he thinks fit to modify or exclude them in any particular case, be incorporated in any such licence”. Any change to the usual terms and conditions of licences must, therefore, be made by regulations. The measures proposed here would partially amend or replace the Petroleum Licensing (Exploration and Production) (Seaward and Landward Areas) Regulations 2004 (No 352), which among other things set out model clauses for Landward Licences. Changes to the model clauses affect only licences issued under that set of Regulations, and have no retrospective effect on existing licences.

Where a licence confers this exclusivity, though, its terms are designed to ensure that licensees use it productively and do not simply bank it as a valuable but unused asset. Traditionally, that was done by requiring the surrender of certain proportions of acreage at specified deadlines, and by imposing an increasing rental paid by the square kilometre to incentivise the voluntary surrender of acreage. These mechanisms, applying equally to all cases as they do, may not achieve the stated objective by themselves, because no two cases are alike, and no single solution will accommodate all cases equally well. For example, one licensee may be prepared to pay a higher rental than another, and one area may be known to be far more valuable than another of the same size. In these cases, the current model clauses give DECC discretion in the power to demand and/or serve work programmes on licensees who are failing to exploit their acreage satisfactorily, though the mechanisms for doing so would be cumbersome and time-consuming.

A Petroleum Act licence covers all natural hydrocarbons within its licensed area, so it is important that the model clauses are compatible with all types of hydrocarbon – coalbed methane, shale gas, shale oil, conventional oil and gas and others. However, the industry body UKOOG (UK Onshore Operators’ Group) and individual firms have brought to DECC’s attention that the existing model clauses, designed for conventional hydrocarbons, may not be appropriate for the technologies and economics involved in shale gas production. This is because shale gas is not concentrated in small, high-value fields, but is likely to be dispersed across a whole licensed area, so shale gas companies are unlikely to be able to identify any low-value acreage to surrender.

DECC accepts that the current provisions are not best suited to shale gas. However, simply removing them would allow all licensees to keep prospective acreage without cost as a valuable but untouched asset, depriving the nation of both energy supplies and revenue. Currently DECC’s only means of limiting such unproductive retention would be the routine service of “work programmes” on licensees requiring them to develop areas.

DECC is therefore seeking to introduce a new set of model clauses for landward licences to introduce a new level of flexibility into the provisions governing the retention of acreage. In particular, DECC will introduce a new flexibility to its licences, allowing the retention of greater areas than before. This will enable the level of retention that shale gas companies say they need, but because it will be based on agreement between DECC and licensee, it will not create a risk of landbanking. These changes will make licences compatible with shale gas while remaining compatible with conventional oil and gas.

These changes could be implemented either by amending the existing set of Model Clauses piecemeal or by laying a whole new set. For the sake of clarity and transparency, the latter option has been selected.

Landward Exploration Licence Separately, DECC has also become aware of opportunities for exploration that DECC policy would favour in principle, but which DECC cannot license because of a gap in the licensing system. There has never been a set of Model Clauses that can be used to award a licence to explore onshore for oil and gas without forcing the applicant to compete for exclusive production rights that they may not want, need or be able to justify. This problem would be faced by an existing licensee who wants to undertake a seismic survey more than 1 km from a licence, to tie the results of several wells together, or by a company who wants to gather landward data for sale in its own right. Operating offshore, such companies could apply for a Seaward Exploration Licence, but there is no landward equivalent. As a result, DECC was unable to license otherwise-legitimate exploration by one company in 2011, and had to turn away a seismic company that wanted to gather onshore data for sale; we do not know how many other cases have simply not been drawn to our attention. DECC now wishes to make a new set of Model Clauses to remove this unintended regulatory obstacle, so that we can license such activities in future.

Rationale for intervention

Industry itself has asked DECC to adjust its licence terms so as to facilitate work on shale gas, while continuing to accommodate conventional oil and gas; and the UK Onshore Operators Group (UKOOG, the relevant trade body) has warmly welcomed DECC's proposals.

The commercial viability of shale gas is as yet unproven in Great Britain but there is a significant resource, much of it in unlicensed areas. New licences are expected to double the shale gas resource that might be developed.

The current proposal should be considered alongside policy being explored to simplifying access rights to underground land.

The onshore exploration licence will encourage expeditious and thorough identification of prospective areas outside the areas covered by production licences.

Policy Objective

The aim of the new Model Clauses is to allow exploration for and development of both conventional and unconventional hydrocarbons.

Nothing in the proposed changes will have any effect on other regulatory or legal provisions (including landowner rights, planning permission, health and safety regulation and environmental regulation).

Options Considered

In the Do-Nothing option (carry on licensing using the existing **Model Clauses**), the exploitation of shale gas in currently unlicensed areas would be seriously inhibited.

The option of removing the provisions that incentivise timely work by the licensee would remove those obstacles to shale gas exploitation, but it would also remove all restrictions on 'land banking' by licensees. Licensees would be free to hold exclusive rights to shale gas (and other hydrocarbons) as a valuable but unused asset on their books. That too would inhibit the exploitation of shale gas, so that option was rejected.

The <u>favoured option</u> is to add a new flexibility, which will allow the retention of acreage, at reduced cost to the licensee, by agreement between DECC and licensees where it is justified by the license's plans for actual work on hydrocarbons. Two new mechanisms will deliver this new flexibility: Retention Areas and Development Areas. Any licensee may at any time propose to DECC the creation of a Retention Area, with proposals for the work it plans to do there, and if DECC is satisfied that the plans represent an efficient proposal to exploit the shale gas potential of the area, DECC will create the Retention Area simply by written notice to the licensee. When DECC approves a Field Development Plan, it will also create a related Development Area for each one. The work plans will consist of elements all of which are regulated by DECC (principally drilling and seismic surveys), so there will be no new regulatory burden to allow DECC to monitor compliance and delivery. The requirement for a 50% surrender of acreage before the Second Term will be made subject to the licensee's right to keep all his Retention and Development Areas, however much of the Licensed Area they cover; and Retention and Development Areas will also attract a reduced rental rate. These two mechanisms will allow licensees to keep more acreage and at lower cost than is allowed by the current Model Clauses. In order to ensure that the Retention and Development Areas concepts do not open the door to land-banking by licensees, failure by the licensee to carry out the work on which licensee and DECC had agreed for a particular Retention or Development Area will empower DECC to terminate that area; and during the Third Term DECC will have the power to remove acreage outside of a licensee's Retention and Development Areas so that it can be offered for relicensing. Such power would be exercised in order to free up unused acreage for relicensing to other companies, where the current licensee does not offer a realistic prospect of exploiting the hydrocarbon resource or where he fails to carry out the work that he had agreed with DECC.

This new mechanism is supplementary to the existing licence terms; so licences will retain a three-term structure, with an Initial Term in which a Work Programme must be completed if the licence is to continue into a Second Term and a Second Term in which a Field Development Plan must be approved if the licence is to continue into a Third Term. The term lengths will change very slightly, 6+5+20 years becoming 5+5+20 years. The requirement for a 50% surrender of acreage before the Second Term (which industry was particularly concerned about) will remain, but the new option will offer a mechanism by which exceptions can be made.

This is DECC's favoured option and industry (UKOOG and its members) has welcomed it warmly, saying: "We believe there is much to be encouraged by in the proposed licensing approach. The approach suggested offers an increase in flexibility in terms of work programme and timing which will complement how shale and coal bed methane is likely to be developed. The 'one licence' approach across all hydrocarbons reduces complexity, avoids definitional challenges and provides the operator with the opportunity to target a range of hydrocarbon types." This is therefore the option selected.

We will also introduce a **Landward Exploration Licence**, to expedite the acquisition of new seismic data onshore.

Impact of Policy Options

The primary benefits and costs which drive the NPV in this IA are the direct net benefits to business.

We believe administrative costs from the proposed measure will not be additional to DECC or to business. The costs will not appear for several years, with few Retention or Development Areas, if any, being agreed before the end of the five-year Initial Term. We anticipate requests for Retention Areas to climb to a handful per year after around five years, and the administrative cost for DECC of dealing with each one will amount to no more than four hours per case. The cost of creating a Development Area will be negligible, because it represents no more than the formalisation of one of the steps that will in any case be carried out as part of DECC's approval of a Field Development Plan. The cost to industry is negligible, because it consists of no more than the submission to DECC of a summary of the plans that any responsible company would have made anyway.

Methodology (Model Clauses)

Benefits to business from the revised Model Clauses would arise from the surplus of revenue over costs from the additional activity that would result. The key assumptions are therefore the change in activity levels, production levels, gas prices and finding and development costs.

To test the surplus of revenues over cost from the additional activity, we assess in this IA the cumulative impact of the additional production levels caused by a change in model clauses multiplied by the annual projected mark up of gas prices relative to underlying finding and development costs. The key assumptions are considered in turn below.

(a) Activity Levels

An assessment has been made of the scale of shale gas activity in the currently unlicensed parts of Great Britain that is likely (a) in the absence of and (b) with the introduction of new Model Clauses. Because the current Model Clauses are fit for purpose as regards conventional hydrocarbons it is assumed that there would be no change to the number of new fields being developed; the currently unlicensed areas are anyway the least prospective for conventional hydrocarbons.

In the case of unconventional hydrocarbons it is thought that there is a significant resource in the currently unlicensed parts of Great Britain, possibly as much again as in the areas that are currently licensed (see *Strategic Environmental Assessment for further onshore oil and gas licensing: environmental report* ["the SEA"], December 2013, available online at https://www.gov.uk/government/consultations/environmental-report-for-further-onshore-oil-and-gas-licensing).

The level of future shale gas activity is at present extremely uncertain. It is also currently constrained by the need to negotiate rights of access to underground land. Even without action on underground access rights, there is expected to be a significant increase in unconventional (shale gas) activity as a result of issuing new licences with shale gas-friendly Model Clauses. The current assessment does *not* presume action on underground access rights, so this assessment does *not* capture the full benefit from enabling more timely and complete exploration for and development of shale gas across currently unlicensed parts of Great Britain. Nonetheless the impact of Model Clause reform should not be understated; these are major changes to the regulatory environment designed specifically to make shale gas development much more economically viable.

If action is taken on underground access rights following award of licences incorporating amended Model Clauses it is assumed that activity would pick up quite quickly and reach a plateau level of 6 pads (i.e. shale gas well centres) per year from 2023 onwards. Without action on underground access rights it is assumed that the pick-up in activity would be deferred and reach a lower level (reaching 4 pads a year from 2027 onwards) and without award of licences incorporating amended Model Clauses would be restricted to the currently licensed parts of Great Britain. Because the shale gas resources of the currently unlicensed parts of Great Britain are thought to be around as great as those in the currently licensed parts (source: the SEA as referenced above) the level of activity is assumed to double if licences are awarded incorporating shale gas-friendly Model Clauses. For the central assessment, the number of new shale gas pads whose exploration and subsequent development is assumed to start each year in Great Britain is as follows:

	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Do nothing	0.00	0.05	0.05	0.05	0.05	0.05	0.05	0.50	0.75	1.00	1.25	1.50	1.75	2.00
Change Model Clauses	0.00	0.10	0.10	0.10	0.10	0.10	0.10	1.00	1.50	2.00	2.50	3.00	3.50	4.00
Change	**0.00**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.50**	**0.75**	**1.00**	**1.25**	**1.50**	**1.75**	**2.00**

The level of activity after 2027 is assumed to continue at the same rate through to 2034.

(b) Production Levels

Both the number of wells and the average recovery per well are uncertain in the absence of any current development of shale gas in Great Britain and the extremely limited exploration that has been undertaken to date. We have therefore adopted assumptions based on advice from industry which in turn is informed by their North American experience. Each pad is modelled on the basis of a common assumption of 12 producing wells with an average recovery of 4 billion cubic feet of gas per well. Recovery rates per well vary within and between pads in a given play and between plays and as yet we have no actual experience of the productivity of UK shale wells so we have had to rely on industry expectations as reported confidentially to DECC.

The assumptions on numbers of pads and recovery per pad imply total annual production of shale gas of some 3 billion cubic metres (bcm) of gas by 2035. With resolution of the access rights issue that might increase further to around 6 bcm a year across the whole of Great Britain (and a cumulative total of around 70 bcm from pads started before 2035). That rate is in line with the central scenario illustrated on page 118 of National Grid's July 2013 *UK Future Energy Scenarios* publication (http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/) but double the estimate of the International Energy Agency in its *World Economic Outlook 2013* (November 2013, page 121; http://www.worldenergyoutlook.org/) which forecasts UK shale gas production of 3 bcm in 2035. But it is some way below the rates of production projected in the IoD's May 2013 report *Getting shale gas working* (http://www.iod.com/influencing/policy-papers/infrastructure/infrastructure-for-business-getting-shale-gas-working) and EY's April 2014 report *Getting Ready for UK Shale Gas* (http://www.ukoog.org.uk/images/ukoog/pdfs/Getting_ready_for_UK_shale2_gas_FINAL2022.04.14.pdf) which reflect higher assumptions on numbers of pads and/or wells per pad.

In February 2014, Pöyry (http://www.poyry.co.uk/news/new-poyry-point-view-uk-shale-gas-where-are-we-now) assumed 100 new wells a year by 2024 spread over about 10 new pads but they did not explicitly report the assumed recovery per well or the implied annual rate of production. The SEA said "It is expected that significant volumes of domestic oil and gas could be produced following the licensing round. If the volume of gas anticipated by the high activity scenario were realised, this would generate some 0.12 to 0.24 trillion cubic metres (4.32 to 8.64 trillion cubic feet) of gas" but no time frame or production rate is reported.

(c) Development Costs

The timing and level of development costs and the profile of production are informed by confidential advice from industry, but there is uncertainty about these costs and – due to the absence of experience in the UK in shale gas exploration and production – they have not been tested and proven yet. Average unit costs for each shale gas pad are DECC estimates based on industry assumptions which are consistent with marginally commercial developments allowing for recovery of the costs of successful and unsuccessful exploration. The implied average unit full-cycle development and production cost for new pads is 58.3p/therm (in 2014 prices). The costs include the costs of exploration, appraisal and development drilling including fracking costs, operating costs including assumed business rate payments and decommissioning costs. A total of £400,000 per site has also been included for the assumed cost to business associated with securing underground access rights (exclusive of payments to landowners which are treated as a transfer payment). This cost is an average cost on the basis of 1,000 landowners and considers the staff and administration costs of the following: identifying landowners, negotiating access, ensuring access is established on a legal basis, setting up the payment and ensuring this is appropriately recorded.

(d) Gas Prices

Gas prices have been assumed to remain constant at 75.5p/therm in 2014 prices. This level is consistent with the central gas price case from DECC's latest published fossil fuel price scenarios (https://www.gov.uk/government/publications/fossil-fuel-price-projections-2013) converted from 2013 to 2014 prices using the latest HM Treasury GDP deflator forecast (https://www.gov.uk/government/publications/gdp-deflators-at-market-prices-and-money-gdp-march-2014-quarterly-national-accounts). DECC's fossil fuel price scenarios are widely used across Government to assess energy market interventions.

(e) Timing

Each pad is included in the analysis at the point at which exploration is assumed to start on the basis of the NPV of future revenues minus costs which may extend beyond the assessment period (which has been extended to 2034 given the slow build-up of activity assumed and the long life of such projects, which are expected to last for around 25 years).

(f) Administrative Costs

The administrative costs for HMG depend entirely on the extent of activity, in particular the number of Retention Areas (Development Areas are part of an existing procedure so they would not change the administrative burden greatly). On the central assumption, there would probably be 1 to 5 Retention Areas to be agreed per year, which could be handled within existing DECC resources. Given the scale of benefit to industry it is not thought to be proportionate to cost the relatively insignificant incremental administrative cost associated with the licensing of, and regulating the exploration for and development of, unconventional hydrocarbons in the currently unlicensed parts of Great Britain.

(g) Environmental Impacts

All significant oil and gas operations, such as drilling, fracking or production, require planning permission and are subject to operational regulation by the relevant environmental agency (i.e. the Environment Agency, the Scottish Environment Protection Agency or Natural Resources Wales, as the case may be). The operators may be required to carry out an Environmental Impact Assessment (EIA) before planning permission is considered and the industry are committed to carrying out an EIA in all cases where fracking is involved. Planning permission will be granted only where the proposed activity is acceptable in terms of land use planning, and the conduct of permitted operations will have to meet the environmental standards specified by the environment agency.

DECC has conducted a strategic environmental assessment on the potential environmental effects of the activities which might be consented subsequent to the issue of new licences (see https://www.gov.uk/government/consultations/environmental-report-for-further-onshore-oil-and-gas-licensing), and this has been published for public consultation (which closed on 28 March). The results of the assessment, and the views received in the consultation, will be considered before any decision is made on further onshore licensing.

A recent report by Professor David MacKay and Dr Tim Stone (see https://www.gov.uk/government/publications/potential-greenhouse-gas-emissions-associated-with-shale-gas-production-and-use) shows that we can develop shale and keep emissions low – shale emissions are likely to be lower than the liquefied natural gas it is likely to replace. In addition, a report published in June 2014 by Public Health England (see http://www.hpa.org.uk/Publications/Environment/PHECRCEReportSeries/PHECRCE009/) concluded that “the currently available evidence indicates that the potential risks to public health in the vicinity of shale gas extraction sites will be low if shale gas extraction is properly run and regulated”. Further to this, in 2012 the Royal Academy of Engineering and the Royal Society conducted an independent review of the scientific and engineering evidence on the risks associated with hydraulic fracturing for shale gas (see https://royalsociety.org/~/media/policy/projects/shale-gas-extraction/2012-06-28-shale-gas.pdf). They concluded that the risks can be managed effectively in the UK, provided that operational best practices are implemented and enforced through regulation.

There are robust regulations in place to ensure on-site safety, prevent water contamination and mitigate seismic activity and air pollution, the proposed model clauses policy would not change any of these existing requirements.

Landward Exploration Licence

No monetary value (or cost) has been ascribed to the introduction of an onshore exploration licence because the alternative is to not introduce such a licence, in which case there would be an absolute regulatory bar on the exploration that this licence is designed to cover. If DECC can issue such a licence, companies can apply for them, and then the possibility exists of incurring the cost of carrying out exploration work. But it would be misleading to count this as a cost being imposed by the regulatory change. No company will be obliged to apply for a licence, nor to incur the cost of carrying out the work that the exploration licence would enable.

Summary

The net (undiscounted) benefits of the policy intervention are estimated as follows:

$$Net\ Benefit = \sum_{t=1}^{20} [((\square]G_t - D_t).\frac{1}{100}).R.\Delta P_t$$

Where t is time (years), G_t is the gas price in pence per therm at time t, D the cost of development and exploration in pence per therm, R is the average discounted gas reserves per project and ΔP_t is the change in the number of projects begun in year t as a result of the policy intervention. For a single project started at time t, the NPV at time t is £60.4 million, calculated as follows:

(75.5p/therm – 58.3p/therm) / 100 * 366 million therms

[366 million therms is the total discounted production from a 12 well pad where each well produces a total of 4 bcf (3.05 bcf discounted) with an average calorific value (BTU/scf) of 1,000.]

Based on the assumptions described above, the NPV of selecting the favoured option rather than the do nothing option is £883.4 million (in 2014 prices) with a range from zero to double that reflecting the extreme uncertainty attaching to most if not all of the key parameters. It is considered that this type of sensitivity analysis is more appropriate than making arbitrary changes to one or a few key assumptions since most if not all of the assumptions are subject to very wide margins of error. It is possible that shale gas will not prove to be commercially exploitable in Great Britain but equally it is possible that gas prices will be much higher than assumed in the central case or the average well might be much more productive. For the central case, the time profile of net benefits is as follows:

Net Value (£ million)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Do nothing	0.0	3.1	3.1	3.1	3.1	3.1	3.1	31.3	46.9	62.5	78.1	93.8	109.4	125.0
Change Model Clauses	0.0	6.3	6.3	6.3	6.3	6.3	6.3	62.5	93.8	125.0	156.3	187.5	218.8	250.0
Change	**0.0**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**31.3**	**46.9**	**62.5**	**78.1**	**93.8**	**109.4**	**125.0**

The administrative costs for HMG depend entirely on the extent of activity, in particular the number of Retention Areas (Development Areas are part of an existing procedure so they would not change the administrative burden greatly). On the central assumption, there would probably be 1 to 5 Retention Areas to be agreed per year, which could be handled within existing DECC resources; they would still represent a (small) opportunity cost to the public sector.

Rationale and evidence that justify the level of analysis used in the IA

The effects of the policy options being considered have a large range of uncertainty. With no change to the Model Clauses (the Do Nothing option) the onshore industry has said that licences would be so unsuitable for work on shale gas that there would be little exploitation of shale gas in Great Britain. With new Model Clauses it will be possible to offer new licences where exploration for and development of shale gas can take place in a timely fashion. However, there are uncertainties about the value of the activity, the nature and scale of the hydrocarbon resource and finding and development costs as stated above.[1] To reflect the extent of uncertainty the focus in sensitivity analysis has been to consider:

- a low case where the large shale gas resource in currently unlicensed areas cannot be developed commercially; and
- a high case with double the shale gas activity (and thus double the net benefits) of the central case.

Changes to assumptions on future gas prices, average reserves per well and costs per well could also have been considered but the range of net benefits presented is thought to be wide enough to bracket the likely true impact of the measure.

1. In addition, most industry assessments presume the removal of remaining regulatory obstacles to activity (e.g. granting of automatic rights of underground access for deep horizontal wells) and do not offer a separate estimate for currently unlicensed areas.

One-in, two-out

Apart from the administrative costs, all of the monetary costs and benefits of the policy options fall to business; the ones being counted result directly from the intervention since it is the changes to the Model clauses that will make additional activity commercially attractive. The costs and benefits do not include indirect effects such as those on the oil and gas supply chain. Any environmental effects are indirect.

The introduction of an onshore exploration licence is deregulatory as it avoids the need for companies to compete for exclusive production licences unless they actually need exclusivity.

The EANCB has been derived using the EANCB calculator with input annual net benefits calculated as described above.

Wider impacts

Additional hydrocarbon (whether oil or gas) produced as a result of the chosen policy option is assumed to displace imports. Consequences for security of supply and energy prices have not been quantified as they are judged to be second order. With no material effect on UK oil or gas demand there should be no impact on UK carbon dioxide emissions.

Summary and preferred option with description of implementation plan

Given the significant net benefit of introducing shale gas-friendly Model Clauses that is the preferred option. The Petroleum Act 1998 requires new Model Clauses to be introduced by negative-resolution Statutory Instrument. Once the regulations come in to force a new onshore licensing round can commence with new licences expected to be awarded in 2015.