Comment on

'Life cycle environmental impacts of UK shale gas' by L. Stamford and A. Azapagic.

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Highlights

Commentary on the work cited in the title, published in the journal Applied Energy.

This work significantly exaggerates the impacts of shale gas development in the UK.

The first cause of exaggeration is underestimation of gas production per well.

The second is the assumption that 'dirty' practices that are illegal will be adopted.

Accurate information is readily available and should have underpinned this work.

A B S T R A C T

In the recent work entitled ''Life cycle environmental impacts of UK shale gas" (Applied Energy, 134 (2014) 506–518) Stamford and Azapagic [1] make a first attempt at quantifying a range of overall lifecycle impacts of shale gas production in the UK. Their analysis led to some very unfavourable comparisons with other energy technologies and concluded that, for three types of impact (depletion of the stratospheric ozone layer, photochemical pollution, and terrestrial eco-toxicity), shale gas is 'worse' even than coal as an energy source for generating electricity; furthermore, uncertainties in input data mean that it might also be worse than coal for three additional impacts (on global warming, acidification, and human toxicity). One of their principal inferences is, therefore, that shale gas development in the UK should be subject to stringent environmental regulation, to ensure that it is only developed where it can be demonstrated to regulatory authorities on a well-by-well basis that these and other impacts can be minimized. The present commentary reassesses some of the conclusions reached by this published analysis.

1. Discussion

We see three fundamental difficulties regarding the Stamford and Azapagic [1] analysis. First, it determines impacts in terms of each unit of gas production rather than in absolute terms. The environmental impact of each drilling operation can be estimated with confidence, but by making unfavourable assumptions regarding the gas production from an individual well, disproportionate impacts (per unit of gas production) are inferred. Although this point is noted in the body of the paper, it is not mentioned in the abstract, the Conclusions section, or the research highlights. The paper indeed considers 'best', 'central', and 'worst' case scenarios, but the first of these are hardly discussed in their text. The 'best' case results are illustrated in Fig. 4 of Stamford and Azapagic, where their results are presented graphically, as the lower limits of 'error bars', but this style of presentation is not explained anywhere; the overall effect is thus to focus on the 'worst' case scenarios, which are emphasized in their text, and on the 'central' case scenarios, which are emphasized in their graphical presentation of results. Furthermore, conclusions that only apply for 'worst' case scenarios (such as the aforementioned claims that shale gas is 'worse' than coal for the various impacts) are presented as though they are always true. As a result, overall, the Stamford and Azapagic paper therefore gives the impression of much more severe impacts than are likely ever to be the case; it has thus been seized upon by environmental objectors to shale gas. Second, the analysis assumes that various 'dirty' environmental practices, allowed under lax regulatory regimes in the USA, will operate in the UK, when it should be obvious from the established legal framework that they will not. Extreme statements such as 'shale gas might be 98 times worse than North Sea gas and 18 times worse than … coal …' follow from their analyses that incorporate both assumptions in combination: that production per well will be very low; and that dirty environmental practices which are already illegal in the UK (such as unrestrained dumping of contaminated drilling waste without treatment, subsurface injection of wastewaters, and the use of various banned chemicals that damage the stratospheric ozone layer) will for some inexplicable reason be permitted. Third, the authors argue that a developer will need to undertake a detailed analysis of every well site to determine shale gas output and regulatory authorities will need to approve these analyses before drilling is allowed to begin, to establish that the well will produce enough gas to justify the environmental impact of its drilling.

On the basis of geotechnical and physical properties, the Barnett Shale of Texas is a good analogue for the Bowland Shale of northern England (e.g., [2]), the UK's principal shale gas resource (e.g., [3]). Many numerical values for the Estimated Ultimate Recovery (EUR) of shale gas per well have been published; Stamford and Azapagic [1] thus adopted for their analysis 'best', central and 'worst' case values of 3.0, 1.0 and 0.1 billion cubic feet (bcf, measured under standard conditions; 1 bcf $\approx 2.83\times10^7$ m^3 = 28.3 Mm^3). The source they cited for this information [4] gives, respectively, 10.0, 1.0, 0.7 and 0.02 bcf as the maximum, mean, median and minimum EUR values for the Barnett Shale and also includes a cumulative frequency graph that shows the 5th and 95th percentile values as 0.2 and 3.0 bcf. However, the data thus presented were based on a survey in 2003; the design strategy of shale gas wells has changed markedly since then: wells are nowadays drilled horizontally within gas-bearing formations and fracked at multiple 'perforation clusters', rather than being drilled vertically and fracked at a single stratigraphic horizon as was formerly the case. Although the properties of the Barnett Shale vary in a complex manner across different spatial scales and from place to place (e.g., [5], [6], [7], [8], [9]), by fracking at multiple points within it (8 perforation clusters per horizontal 'lateral' being one standard strategy; e.g., [10]) the likelihood of very low yields of shale gas is significantly reduced. The need to quantify the available resource over an appropriate spatial scale has long been appreciated in the shale gas industry; for example, a report to potential investors a decade ago [11] stated 'The Barnett Shale is a highly complex reservoir. Significant variability of well results exists even within concentrated areas. As the industry has yet to figure out how to identify the good wells from the bad …, a large acreage position is a necessity in order to minimize the risks and allow the law of large numbers to take effect.' The same point, that output should be considered for developments as a whole, not on a well-by-well basis, is equally applicable to lifecycle analysis. The recent study by Browning et al. [12], which utilized data from more than 15,000 Barnett Shale wells drilled by 2010, determined mean EUR values for different localities ranging from 0.4 to 4.3 bcf, the principal factor governing this variation being the rate of decline of shale gas output once production has begun (e.g., [13], [14]). Other factors, such as taxation policies and the pricing of other energy resources, including alternative sources of shale gas, also influence the point of diminishing returns at which no further attempt is made to produce shale gas from any particular well (e.g., [15]).

Insufficient is currently known about the properties of the Bowland Shale to determine precisely where it will fall within this range of variation for the Barnett Shale, but there is no basis for the assumption made by Stamford and Azapagic that anyone has any intention to develop wells with EUR as low as 0.1 bcf in the UK. The large number (many thousands) of wells that will be needed if shale gas is to have any significant impact on UK energy supply means that the aforementioned 'law of large numbers' will be applicable. Thus, the estimation by Browning et al. [12], that ~29000 wells will have been completed within the Barnett Shale by 2030 and that the resulting production will have amounted to ~45000 bcf of shale gas by 2050, indicates a mean EUR per well of ~1.5 bcf. We therefore agree with Stamford and Azapagic [1] that 3 bcf is reasonable as a 'best case' value for EUR per well in the UK and/or in the Bowland Shale. However, based on the above reasoning we would consider ~1.5 bcf as a reasonable 'central' figure, rather than their 1.0 bcf. Likewise, we would regard their 'central' figure of 1.0 bcf as a reasonable 'worst case' value for the EUR per UK and/or Bowland Shale well, since anything less would be uneconomic under UK conditions, and consider their 'worst case' figure of 0.1 bcf to be so far off track that it should never have been introduced in the first place. For comparison, both Mackay and Stone [16] and Bond et al. [17] have favoured 'best case', 'central' and 'worst case' production figures of 5, 3 and 2 bcf under UK conditions, rather higher values than we now support and even more at odds with Stamford and Azapagic [1].

Stamford and Azapagic [1] call for 'tight' regulation of the UK shale gas industry, notably with regard to stringent controls on drilling waste disposal, compulsory reduced-emission well completions, and careful estimation of ultimate recovery before commencing drilling in order to avoid high emissions associated with a low-output well. However, this putative industry is already covered by default by many regulations, including the EU Mining Waste Directive [18], as incorporated into UK law ([19] for England and Wales, with similar regulations for Scotland [20] and Northern Ireland), and the EU Water Framework Directive [21] with its daughter Groundwater Directives [20, 22]; a range of regulatory agencies have roles in this process (Fig. 1). A consultation took place in 2013 regarding many aspects of shale gas regulation in the UK [23, 24]. This process established no lack of clarity regarding the requirement to treat solid drilling waste (drill chippings, etc.), so no new regulation of this aspect was necessary. On the other hand, it established a need to clarify regulations governing groundwater use in relation to shale gas production; as a result, new regulations, compliant with the underlying directives, were issued in February 2014 [25]. One consequence of this regulatory framework is that 'flowback fluid' from fracking will have to be stored in closed containers and ultimately treated, rather than stored in open tanks or disposed of by borehole injection, as is common practice in the USA, thus significantly reducing the potential for harmful environmental impacts. The analysis by Stamford and Azapagic [1] indeed assumed that flowback fluid from a future UK shale gas industry would likewise be stored and treated; this aspect of their analysis was, thus, consistent with the applicable regulatory framework and, therefore, entirely reasonable. However, as regards the first of the three specific regulatory requirements called for by Stamford and Azapagic [1], stringent controls on drilling waste disposal, the 2013 consultation [23] did not mention 'landfarming' (i.e., uncontained dumping of untreated drilling waste, irrespective of any contamination therein, on the land), for the simple reason that this practice has long (since 1994 [26]) been illegal in the UK: even from shallow drinking-water wells, boreholes cuttings have to be disposed to landfill. In response to this regulatory regime, specialist contractors for safe disposal of drilling waste have been established [27] and well operators are totally familiar with this requirement. Thus, although 'landfarming' is a common U.S. practice, there is no possibility that it will be allowed for shale gas wells in the UK. Nevertheless, all but the 'low' calculations of environmental impacts by Stamford and Azapagic [1] assume that some or all of the drilling waste from a given shale gas well will be disposed of by 'landfarming'; as a result, the effects that they have calculated are significantly exaggerated. As regards their second proposal, compulsory reduced-emission well completions, Stamford and Azapagic [1] drew upon the Mackay and Stone (2013) report [16] for guidance about UK shale gas practice, without noting that one of its key recommendations was, indeed, compulsory reduced-emission well completions. Furthermore, the UK government's response [28] to MacKay and Stone [16] (published in April 2014; i.e., months before the Stamford and Azapagic paper [1] was finalized) accepted all its recommendations, including the principle that UK shale gas boreholes should adopt these 'green completion techniques', whereby (except for safety reasons) venting or flaring of methane will be prohibited. The 'central' and 'worst' case calculations by Stamford and Azapagic [1], which include methane emissions during well drilling and completion, thus also exaggerate the resulting impacts. Their third proposal, careful estimation of ultimate recovery before commencing drilling in order to avoid high emissions associated with a low-output well, would appear to mean a requirement for detailed analysis of each proposed well site to estimate its shale gas production, followed presumably by approval of these production estimates by a designated regulatory authority. We are not aware of any previous suggestion of anything like this as a basis for regulation of shale gas. We indeed see no necessity for any regulator to become involved in the proposed details of the development strategy for shale gas, on a well-by-well basis; if, despite the best efforts of the developer, the occasional UK shale gas well proves unproductive, it will be a commercial loss for the developer, not an issue over which any regulator need become involved.

The first impact noted by Stamford and Azapagic [1], whereby shale gas will in their view be 'worse' than coal, concerns terrestrial ecotoxicity; in their view, regarding this particular impact, shale gas may be as much as 30 times more polluting than coal, in terms of pollution per unit energy output. However, it is evident that this inference results from the assumption that only 0.1 bcf of shale gas is produced from a well (an unrealistically low and uneconomic value for shale gas wells in general; see above), combined with the assumption that all the associated drilling waste is disposed of by 'landfarming' (i.e., it is dumped, untreated on surrounding land, so any contaminants therein pollute the underlying soil). As already noted, this method of disposal of drilling waste is forbidden in the UK and elsewhere within the EU; any consequences that it might have for the future shale gas industry are, therefore, irrelevant. Stamford and Azapagic indeed seem oblivious of the long-term and widespread environmental impacts of former coal mines represented by perennial discharges of polluted mine water, which often remain polluted for centuries and even millennia [29]. In contrast, the lack of hydraulic connectivity to any recharge area, which results in the absence of any driving head, together with insufficient permeability (even in the fracked zones), mean that no such scenario can reasonably be anticipated in the case of abandoned shale gas wells ([20], [30]). The only part of the Stamford and Azapagic analysis of terrestrial ecotoxicity that has any relevance is for their 'best case' scenario, of 3 bcf of shale gas per well, as this was assumed to be associated with safe disposal of the drilling waste rather than 'landfarming'. Stamford and Azapagic briefly noted that if this approach were to be followed, shale gas would indeed become one of the least polluting energy technologies from the point of view of terrestrial ecotoxicity. This is indeed evident from their Fig. 4, where as a 'best' case scenario the impact of shale gas was assessed as ~0.15 grammes of dichlorobenzene-equivalent (g DCB*) per kilowatt-hour, higher than the value of 0.13 g DCB* kWh^{-1} for North Sea gas but lower than the values for all other energy sources considered. However, this particular case was not mentioned in their abstract, conclusions, or research highlights.

Regarding the second impact, photochemical ozone, Stamford and Azapagic [1] asserted that 'Leakage of [volatile organic compounds] during the removal of H_2S (sweetening) is the main potential cause of [photochemical ozone] (photochemical smog) in the life cycle of shale gas.' They also stated that the assumption underlying their 'central' case, that if half of the gas that is produced requires sweetening (H_2S removal), a photochemical ozone impact about 9 times higher than that of

North Sea gas will result. The basis underlying both these assertions was not stated and so both remain unclear. It is a long-standing assumption that much of the 'conventional' North Sea gas used in the UK is derived from Carboniferous source rocks similar to the Bowland Shale; some of it is sour, much of it is not (e.g., [31]). Even in the absence of any data, there was thus no obvious reason for Stamford and Azapagic to assume that the mix should be any different for shale gas obtained, say, from the Bowland Shale, compared with 'conventional' North Sea gas. Nonetheless, they might have made estimates of the range of H_2S concentration in shale gas produced from the Bowland Shale, based on the available information that reported sulphur concentrations in Carboniferous mudstones in England have an upper bound of ~9-10% and are often much less (e.g., [32], [33], [34]). Furthermore, should they be necessary, technologies for 'sweetening' gas are standard and readily applicable to production on the scale envisaged for future shale gas pads in the UK, and the decision-making process for how to choose the optimum technology to suit a particular flow rate and gas composition is well established (e.g., [35], [36]). Stamford and Azapagic [1] did not state what H_2S concentration within shale gas they consider problematic, nor what sweetening technology they envisage as being used, nor what proportion of volatile organic compounds in any fugitive emissions from it might be anticipated, so it is not possible to check their calculations in relation to this topic. Nonetheless, some 'sweetening' technologies (e.g., [37]) do not use volatile organic compounds, and so could be adopted if fugitive emissions of these are considered an issue, whereupon such emissions would be reduced to zero. In fact, comparative chemical and isotopic analyses of shale gas from the Preese Hall – 1 well, within the Bowland Shale, and 'conventional' gas from other sites in northern England, have been reported ([38]; Table 1). These analyses confirm the long-standing assumption that Carboniferous sediments are, indeed, typically the source of 'North Sea gas'; for example, shale gas from the Preese Hall–1 well is chemically and isotopically very similar to 'conventional' gas from the nearby Elswick-1 well. In principle, any shale gas well may become 'sour' due to injection of sulphate-reducing bacteria within the fracking fluid; to guard against this possibility, a biocide agent is added to the fluid. However, thermal decomposition of a standard sulphate-based biocide has been inferred to be the cause of the 'souring' observed in some shale gas wells [39]; a different agent can thus be substituted. Future development plans for shale gas in northern England can thus proceed with confidence on the basis that H_2S concentrations will be no different from those in 'conventional' natural gas. Furthermore, at all sites studied the H_2S concentrations in the gas that was analysed were measured as zero (Table 1). As is customary for safety reasons, for projects carried out under UK jurisdiction, H_2S sensors were in operation at the Preese Hall-1 well but were not triggered, indicating that concentrations did not exceed 10 ppm [40]. It is on the basis of both kinds of measurement that H_2S concentrations are assumed to be zero for the purposes of planning other shale gas projects in the UK (e.g., [41, 42]). Nonetheless, if H_2S is present in any UK shale gas well it is clear that the operator is required to remove it (e.g., [43]), not allow it to vent into the atmosphere. In addition, Stamford and Azapagic [1] reported that, as regards creation of photochemical ozone, 'In the worst case, shale gas might be 98 times worse than North Sea gas and 18 times worse than the coal power life cycle.' However, this calculation was for their notional 'worst case' well from which the ultimate recovery of shale gas was specified as only 0.1 bcf (2.83 Mm^3), although 0.31 Mm^3 (0.011 bcf) of this, or 11%, was for some reason assumed to be able to escape during well construction, contributing to the creation of photochemical ozone. Well construction practices that are allowable in the USA typically result in leakage in the range 0.6-3.2% [44], but the proportion will be less in the U.K. due to the requirements of more stringent regulation ([17], [28]; see also below). Stamford and Azapagic [1] are, of course, correct that sound well construction should be standard in shale gas development to avoid fugitive emissions of gas; others have already made this point (e.g., [20], [30]), as well as noting, aside from any possible issue over fugitive gas emissions into the atmosphere, that poor well construction can result in gas contamination of aquifers [45]. However, we do not consider that adoption of such an extreme case as this, combining an extreme upper bound for fugitive emissions with what we established above is an extreme lower bound for gas recovery, and expressing the environmental impact per unit of gas recovery, rather than in any absolute terms, is a reasonable way to quantify the potential environmental impact of shale gas.

Depletion of the stratospheric ozone layer is the third environmental impact for which Stamford and Azapagic [1] considered shale gas to be potentially more polluting than coal. In their view, this high potential impact results from two major factors, primarily leakage of the ozone-depleting gas halon 1211 (bromochlorofreon; bromochlorodifluoromethane; $CBrClF_2$) as a result of its use in fire-suppression systems and cooling plants for gas pipelines. The second factor, in their view, the use of diesel engines to power plant at drilling sites, resulting in emissions of nitrogen oxides (NOx), which also cause ozone-depletion, will be discussed below. As regards halon 1211, the UK is a signatory to the 1987 Montreal Protocol, which banned the production of halons from 1 January 1994, although trade in these chemicals continues as it is legal to recycle them between permitted installations. Information on this topic is widely available (e.g., [46]); the applicable law ([47], [48]) only permits continued use of halon 1211 within the EU in a few situations such as in fire-suppression systems in aircraft, warships, and military vehicles. None of these remaining permitted uses of halon 1211 therefore has any bearing on energy production. A different halon (halon 1301; bromotrifluoromethane; $CBrF_3$; which Stamford and Azapagic did not mention) is currently permitted within the EU for use in fire-suppression systems in gas industry facilities: however, it passed its 'cut-off date' on 31 December 2010, meaning that no new installations are permitted; and will reach its 'end date' on 31 December 2020, when all existing installations will have to be decommissioned. Since no new gas installations using any form of halon will be permitted, any expansion of the UK shale gas industry will not add to halon emissions beyond those that would have occurred anyway; we are in any case unaware of any part of the existing UK gas distribution infrastructure that currently uses any form of halon, at all. The situation is rather different in the USA, where halons 1211 and 1203 continue to be widely used in the energy sector (even though new halons cannot be produced) as a result of large-scale trading in recycled halons, users being merely 'encouraged' to switch to alternatives, and with no timetable for phasing them out (e.g., [49], [50]). This is one of several aspects in which the regulation of the energy sector in the USA is lax compared with the UK (cf. [2]). There is therefore no reason why expansion of the UK shale gas industry should be considered responsible for ANY depletion of the stratospheric ozone layer as a result of emission of halons.

Regarding NOx emissions, diesel engines powering plant at shale gas drilling sites count, in EU terminology, as 'non-road mobile machinery' (NRMM), and so are regulated on a par with other forms of NRMM, such as railway locomotives and inland waterway boats. The applicable EU directive [51] has introduced a series of increasingly stringent regulations for NOx emissions from NRMM, the current set being designated as EU Stage IIIB. Stamford and Azapagic [1] did not state for what specification of diesel engine their emissions data were obtained. However, they stated that the software that they used was released in 2010, making it clear that its inputs were based on older regulations that allowed much more polluting emissions than at present, making them irrelevant to predicting emissions by a future UK shale gas industry and likely to result in significant exaggeration of any effect. Stage IIIB – compliant diesel engines for powering drilling machinery are already available (e.g., [52]) and so can be used in shale gas development. Older equipment enjoys so-called 'grandfather rights' with respect to EU emission regulations (i.e., it only has to comply with the regulations in force when it was manufactured, not subsequent amendments), and so could in principle be used instead, to develop shale gas in the UK in a more polluting manner than would otherwise be possible. However, it is straightforward to adapt such equipment to make it Stage IIIB compliant, by adding urea (diaminomethanone; $CO(NH_2)_2$) to the diesel fuel to catalytically decompose NOx and by slightly enriching the fuel mix to produce less NOx in the first place [53]; such measures could easily be specified in permissions to develop shale gas and would only add marginally to costs. Of course, as Stamford and Azapagic [1] noted, it is likely that many UK shale gas developments will take place at sites where mains electricity is available, so the resulting contributions to NOx emissions will reflect the national mix of generating plant and will be even lower than if Stage IIIB–compliant diesel engines were being used.

Regarding the most familiar environmental impact of shale gas, its Global Warming Potential (GWP), Stamford and Azapagic [1] made best, central and worst-case estimates of 412, 462 and 1102 grammes of carbon dioxide equivalent per kilowatt-hour of electricity generated (Q_E, in gCO_2* kWh^{-1}). They compared these with a figure of 1068 gCO_2* kWh^{-1} for coal; thus, in their view shale gas is only potentially 'worse' than coal for GWP as a worst case scenario. However, it is more customary to express GWP per unit of energy content of any fuel (Q_T) and in SI units (where 1 kWh = 3.6 MJ). Taking the figure of 52.5% for the combustion efficiency for electricity generation, from Stamford and Azapagic [1], their results equate to 60, 67 and 161 gCO_2* MJ^{-1} for the best, central and worst-case estimates of Q_T, respectively. Such figures, expressed in terms of 'CO_2 equivalent', factor in the GWP of methane emissions, this being a very potent greenhouse gas (its impact being typically expressed over a 100 year timescale as a 'GWP100' value). Stamford and Azapagic [1] stated that their results are broadly comparable with other studies, such as the 84-114 gCO_2* MJ^{-1} range for Q_T for shale gas production under U.S. conditions, determined by Howarth et al (2011) [44], which incorporates the impact of methane as GWP100 and has been converted into equivalent units for comparison. However, they are far higher than the 2.8-6.9 gCO_2* MJ^{-1} (i.e., 10-25 gCO_2* kWh^{-1}) range of mean values of Q_T per well based on central production assumptions, determined by MacKay and Stone (2013) [16] for different sets of regulatory conditions potentially applicable to a future UK shale gas industry, this being a study that Stamford and Azapagic [1] cited. Furthermore, as already noted, the UK government's response [28] to MacKay and Stone [16] (published months before the Stamford and Azapagic paper [1] was finalized) accepted its recommendation to prohibit (except for safety reasons) the venting or flaring of methane during the drilling or completion of UK shale gas wells. This is the essential reason why the subsequent analysis by Bond et al. (2014) [17] has reported Q_T values of 1.7-3.0 gCO_2* MJ^{-1}, even lower than MacKay and Stone (2013) [16]; it has excluded potential contributions from activities that will not be permitted in the UK. Like for other potential impacts of shale gas, the analysis of GWP by Stamford and Azapagic [1] has evidently exaggerated the impact due to failure to consider the regulatory regime that will apply in the UK.

2. Conclusion

Overall, we consider that through their combination of tacitly assuming that dirty environmental practices that are already illegal in the EU and UK will nevertheless be followed there, and their emphasis on worst-case scenarios in which wells are assumed to yield unrealistically low amounts of shale gas, Stamford and Azapagic have seriously exaggerated the potential environmental impact of a future UK shale gas industry.

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Figure caption

Figure 1. Flowchart illustrating the procedure for obtaining permission for a shale gas exploration well in the UK. This diagram, modified from Fig. 5 of [43], illustrates the variant of the process applicable in Scotland, where environmental and planning issues are devolved to Scottish government agencies but energy policy and prevention of work-related accidents are matters reserved for the UK government. DECC denotes the UK Department for Energy and Climate Change; SEPA is the Scottish Environment Protection Agency (whose role would be exercised by the Environment Agency in England or by Natural Resources Wales in Wales); and HSE denotes the UK Health and Safety Executive. Also included are the UK Coal Authority and the 'local authority', which is whichever of Scotland's 32 unitary 'council areas', ranging in population from ~21,000 (the Orkney Islands) to ~593,000 (Glasgow City), in which the proposed well is located. As part of the process of granting planning permission, the local authority will expect the developer to engage in public consultation; the developer will also have to negotiate with the landowner for site access. Furthermore, the Scottish government may 'recall' the process of granting planning permission and determine this aspect for itself.

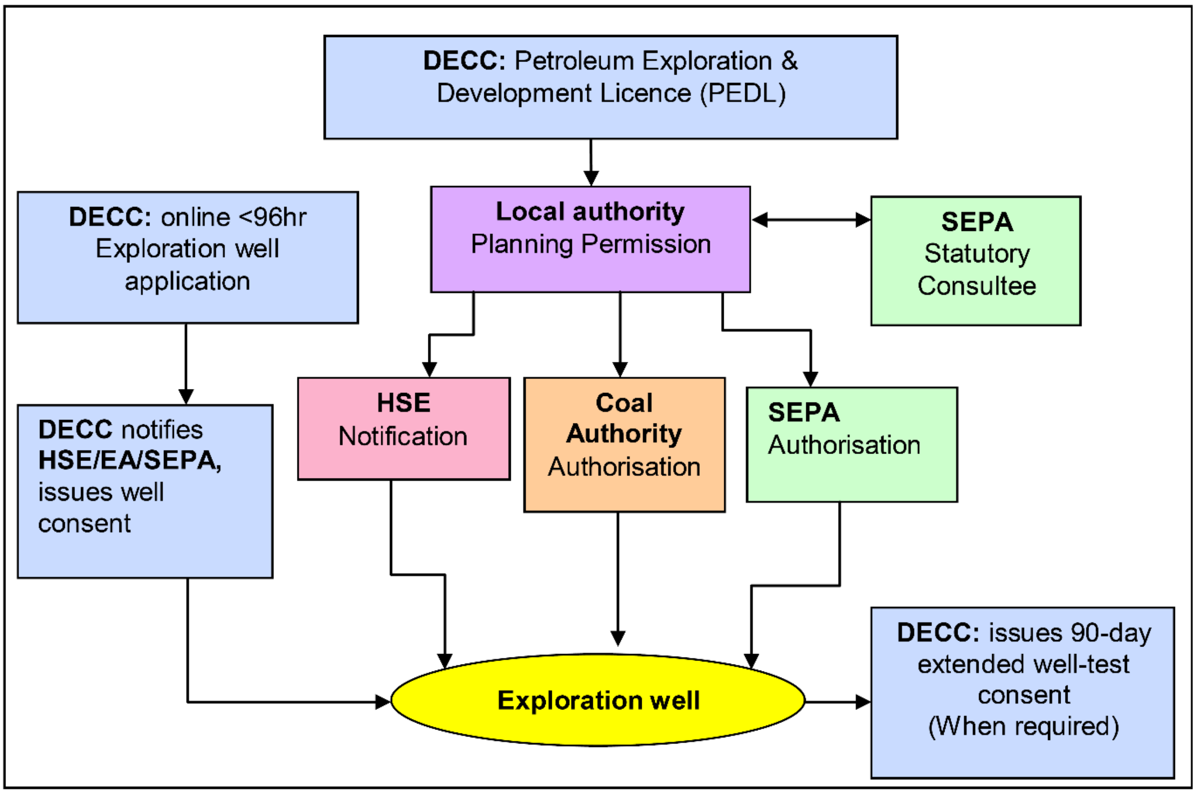
DECC: Petroleum Exploration &
Development Licence (PEDL)
DECC: online <96hr
Exploration well
application
Local authority
Planning Permission
SEPA
Statutory
Consultee
DECC notifies
HSE/EA/SEPA,
issues well
consent
HSE
Notification
Coal
Authority
Authorisation
SEPA
Authorisation
DECC: issues 90-day
extended well-test
consent
(When required)
Exploration well

Figure 1