Oil & Gas
Authority

UK Oil and Gas Reserves and Resources as at end 2017

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Contents

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1. Executive summary

The Oil and Gas Authority (OGA) estimate for remaining UK Continental Shelf (UKCS) recoverable petroleum resources including discovered and undiscovered petroleum resources, remains at a significant level.

Key messages

- The UKCS petroleum reserves remain at a significant level. The OGA's estimate for proven and probable (2P) UKCS reserves as at end 2017 is 5.4 billion barrels of oil equivalent (boe). On the basis of current production projections[1], this could sustain production from the UKCS for another 20 years or more.

- In 2017, 400 million boe (mmboe) were added to 2P reserves and about 600 mmboe were produced which equates to a reserve replacement ratio of 69%.100 mmboe were matured from new field developments, 80 mmboe as a result of infield activities and approximately 220 mmboe of the reserves replacement was due to field-life extensions. The limited rate of replacement of proven and probable reserves by resource maturation remains a main concern.

- The UKCS contingent resource level is significant with a central estimate (2C) of discovered undeveloped resources of 7.5 billion boe. Much of this resource is in mature developed areas and under consideration for development. 2.1 billion boe is expected to be added through new field developments coming forward, 2.1 billion from incremental projects in producing fields and 3.2 resides in undeveloped discoveries where no development proposals are currently being proposed.

- The maturation of contingent resources presents a significant opportunity for the continued development of the UKCS petroleum resources. This will require substantial investment in both new field developments and incremental projects.

- UKCS petroleum reserves and discovered resources are 70% oil and 30% gas, when expressed in oil equivalent terms.

- Exploration success in 2017 delivered an addition of 181 million boe to the total of contingent resources. A key part of exploration Stewardship is now to progress the many attractive opportunities within the prospective resource portfolio into drill-ready prospects, and into subsequent discoveries.

- Over the last two years the OGA has undertaken an exercise with the British Geological Survey (BGS) to re-evaluate the UKCS mapped leads & prospects inventory. Volumetric and risk adjustments have been made, with a risked mean prospective resource in mapped leads and prospects now estimated at 4.1 billion boe. In addition the OGA has undertaken statistical play analysis and an additional risked mean prospective resource of 11.2 billion boe is estimated to reside in plays outside of mapped leads and prospects. The proportion of gas is estimated to be greater than 60%. The methodology and approach has been auditied by Rose & Associates and subsequently endorsed by the MER UK Exploration Task Force.

- Taking account of the range for discovered reserves and resources together with the range of possibilities for prospective resources, the OGA's current estimate of remaining recoverable hydrocarbon reserves and resources from the UKCS's producing fields, undeveloped discoveries and mapped leads and prospects is in the range 10 to 20 billion boe plus. This range can be justified by field life being extended due to lower opex and higher oil price, additional producing field incremental projects, actively worked undeveloped discoveries being unlocked by technology, and innovative commercial and supply chain arrangements, and a robust prospect & lead inventory with significant upside potential derived from statistical play fairway analysis.

[1] https://www.ogauthority.co.uk/data-centre/data-downloads-and-publications/production-projections/

2. UK Reserves and Resources

The OGA estimate for remaining UK recoverable petroleum resources is in the range 10 to 20 billion boe, including discovered and undiscovered petroleum resources. A total of some 44.1 billion boe had been produced to end 2017 from the UKCS.

The OGA's current central estimates as at the end of 2017 are summarised in Table 1 below (estimates as at the end of 2016 are in parentheses).

Ranges for these estimates are shown in sections 4 and 5.

Overall oil and gas reserves as at the end of 2017 showed a reduction compared to end 2016. This is a result of production of 600 mmboe in 2017 exceeding additions to the reserves base as a result of Field Development Plan ('FDP') approvals and reserves adjustments for producing fields.

Table 1 – Oil and gas reserves and resources central estimates as at end 2017 (end 2016) in billion boe

Reserves	**2P**
Reserves	5.4 (5.7)
Contingent resources	**2C**
Producing fields	2.1 (2.3)
Proposed new developments	2.1 (1.9)
Marginal discoveries	3.3 (3.2)
Prospective resources	**Mean**
Prospects and Leads	4.1 (6.0)
Plays	11.2 (-)

Note: The classification of reserves and resources is explained in Appendix B.

The OGA's estimate of prospective (i.e. undiscovered) resources has been revised significantly during 2018. The OGA now considers that the mean prospective resources of mapped features (leads and prospects) in the prospect inventory is 4.1 billion boe. For the first time, the Yet-to-Find estimate also includes Prospective Resources added through Play Analysis and this contributes an additional mean prospective resources of 11.2 billion boe. This is estimated to reside in both mature and more underexplored plays, for which there are few or no mapped features.

Summing the overall estimates of the four categories of resources (reserves, contingent resources prospective resources associated with mapped features and play-level prospective resources) does not imply any particular levels of probability that those volumes will ultimately be produced.

Note:

Definitions of these terms, and how the OGA categorisation compares to the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE), are set out in Appendix B. Reserves and resources for developed fields and fields where development projects are under discussion were compiled from data provided by operators – these data have not been audited by the OGA.

Proven, probable and possible reserves and resources for a large number of individual fields and discoveries have been aggregated to provide the totals shown. Note that figures for prospective (i.e. not yet discovered or "yet-to-find") resources are naturally subject to a higher degree of uncertainty than those for discovered resources. There will also be varying degrees of uncertainty in how much of the contingent resources will ultimately be developed

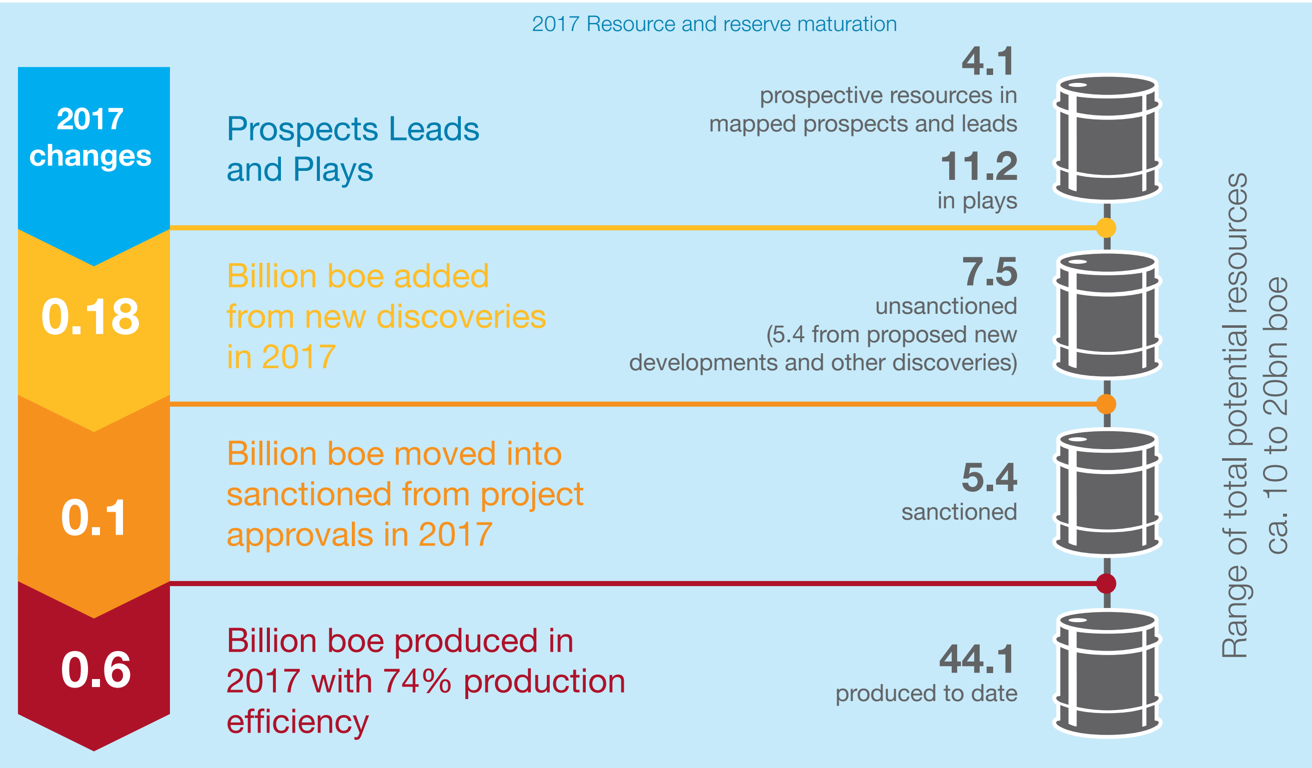
3. Oil and gas reserves and contingent resources progression

3.1 UKCS reserves and resources progression in 2017

Figure 1, below, illustrates the progression of resources and reserves between the major categories during 2017.

- Seven new discoveries from exploration successes in 2017 added 181 mmboe to the contingent resource base.
- Field Development Plans (FDPs) consented to in 2017 (two new field developments and six FDP addenda for incremental projects) resulted in a 100 million boe movement from contingent resources to reserves
- Production during 2017 of 600 mmboe resulted in a reduction in reserves

Figure 1 Reserves and Resources Progression

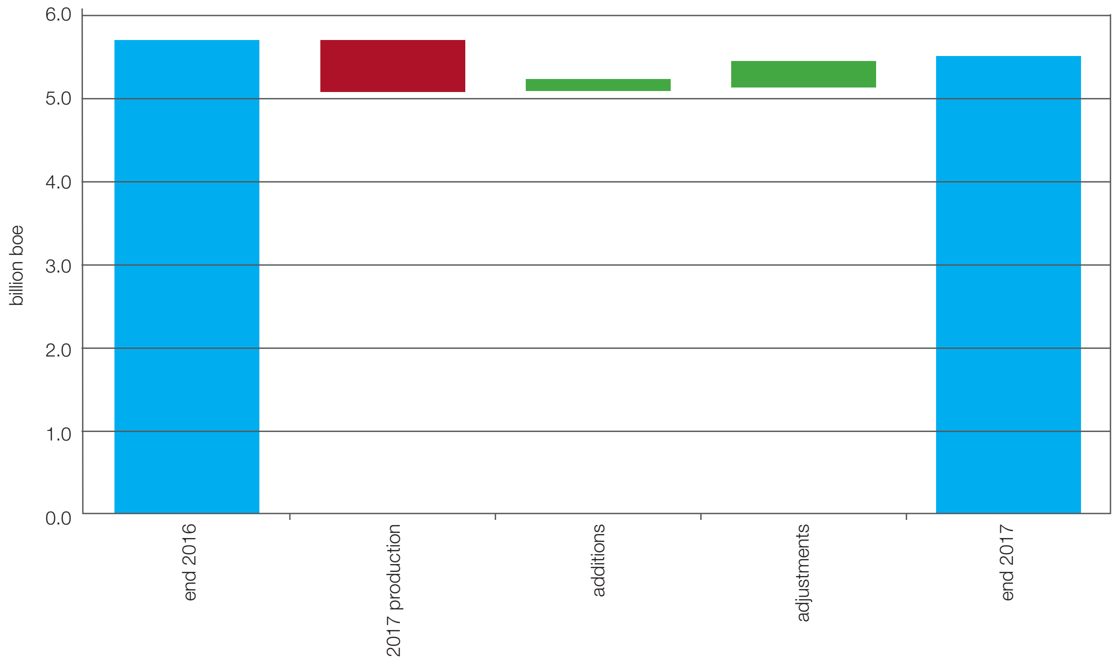


3.2 Reserves progression

Reserves fell from 5.7 as at end 2016 to 5.4 billion boe as at end 2017. This was a result of:

- Production during 2017 of 600 mmboe
- FDPs consented to in 2017 (two new field developments and six FDP addenda for incremental projects) resulted in 100 mmboe movement from contingent resources to reserves.
- Positive adjustments to the reserves estimates for producing fields, ca 80 mmboe as a result of the sanction of some in-field activities and ca 220 mmboe due to life of field extension (CoP deferral)

Figure 2: 2P reserve changes from end 2016 to end 2017



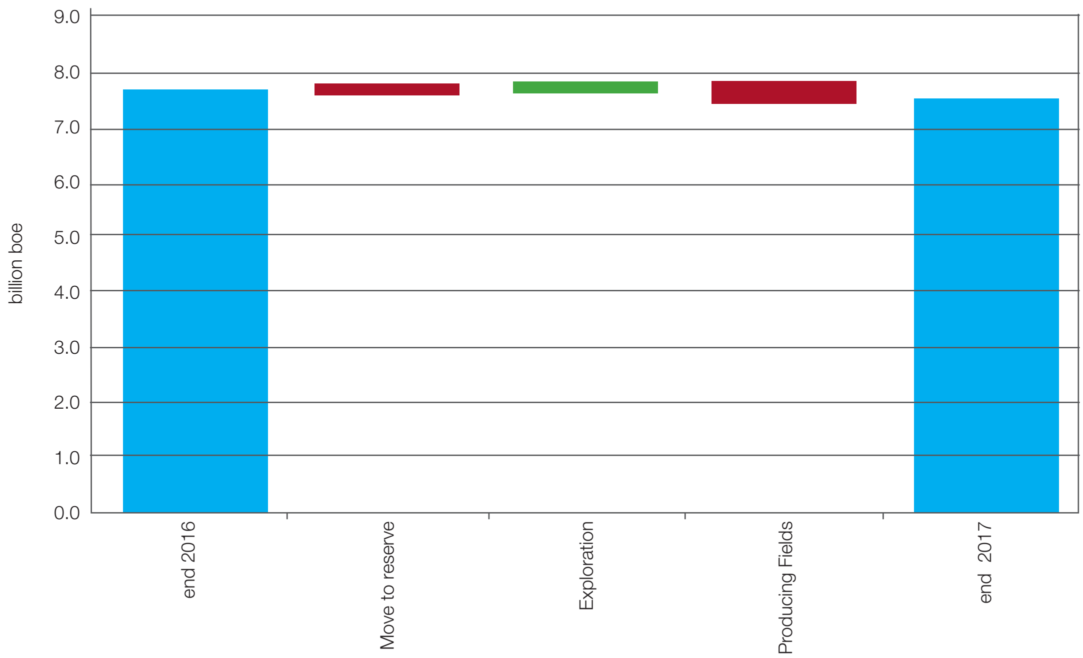
3.3 Contingent resources progression

The UK's contingent resources represents a significant opportunity to progress discovered resources to development. There was only a small change in the central estimate of total contingent resources during 2017, the overall estimate remaining at ca 7.5 billion boe. There were a number of changes within the contingent resources categories, as a result of:

- FDPs consented to in 2017 (two new field developments and six FDP addenda for incremental projects) resulting in 100 mmboe movement from contingent resources to reserves.
- Seven new discoveries from exploration successes in 2017 adding 181 mmboe to the contingent resource base.
- A number of adjustments made by operators resulting in an overall decrease in contingent resources in producing fields.

There have been some minor movements within the contingent resources categories not represented in Figure 3 below. 72 mmboe has moved from contingent resources in marginal discoveries to the "proposed new developments" category as a result of development projects being progressed during 2017 for seven undeveloped discoveries

Figure 3: 2C resource changes from end 2016 to end 2017



3.4 Production and reserves replacement trends Reserves replacement ratio

This provides an indication of how current production levels are being replenished through the maturation of contingent resources and exploration discoveries into reserves.

The underlying reserves replacement ratio in 2017 was 69%. 100 mmboe of reserves were added as a result of two Field Development Plans and six Field Development Plan addenda consents, while ca 80 mmboe were added as a result of other infield activities. This compares to production of around 600 mmboe in 2017. It should be noted that significant proportion of the reserves replacement volume (220 mmboe, just over half) is due to the adjustments to the reserves from the producing fields as a result of field life extension as a result of improvements in production efficiency and with the oil price increase over 2017. Replacement of proven and probable reserves by resources maturation remains a main concern: less than 20% of the reserves replacement in 2017 came from approved new field developments.

Figure 4 opposite top shows how 2P reserves and the reserves replacement ratio have changed over the last 20 years. It can be seen there is a large variation in reserves replacement ratio from year to year, partly as a result of oil price fluctuations. The negative reserves replacement ratio in 2015 was a result of the OGA re-categorising certain types of project from reserves to contingent resources. Prior to 2015, DECC and its predecessors included in the reserves category projects that had not yet been sanctioned but were expected to be sanctioned in the near future. This is permitted under the SPE PRMS (the "Justified for Development" category), however the OGA now includes projects in the reserves category only where the project has been sanctioned by the participants and the OGA has issued a Development and Production Consent.

Figure 5 opposite bottom shows how production and the central estimate of reserves have changed in the last 5 years. As can been seen, overall the UK reserves decrease gradually.

Figure 4: Oil and gas 2P reserves replacement

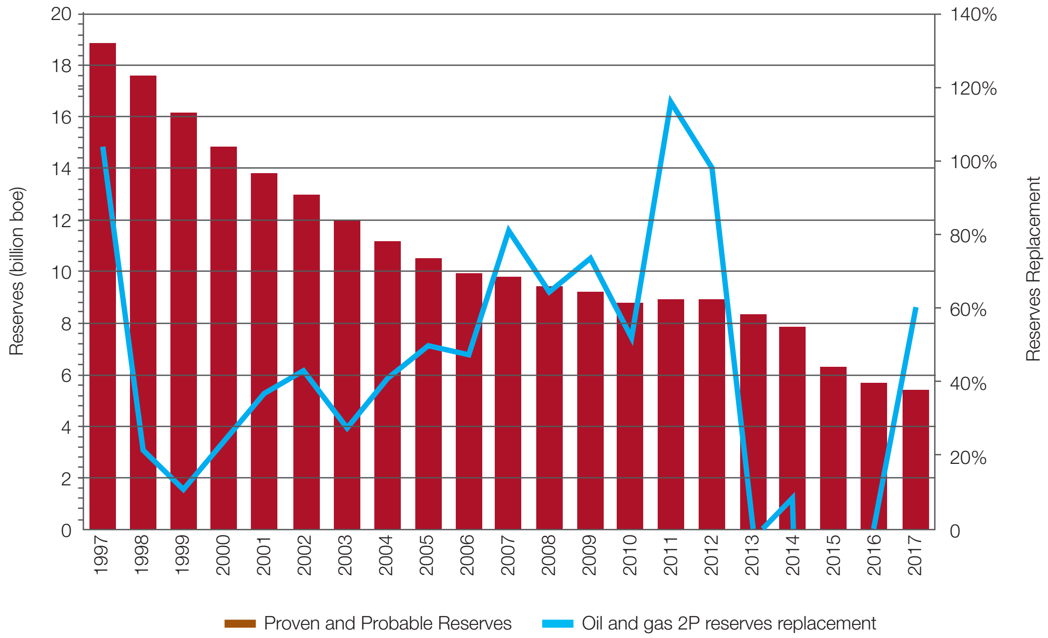
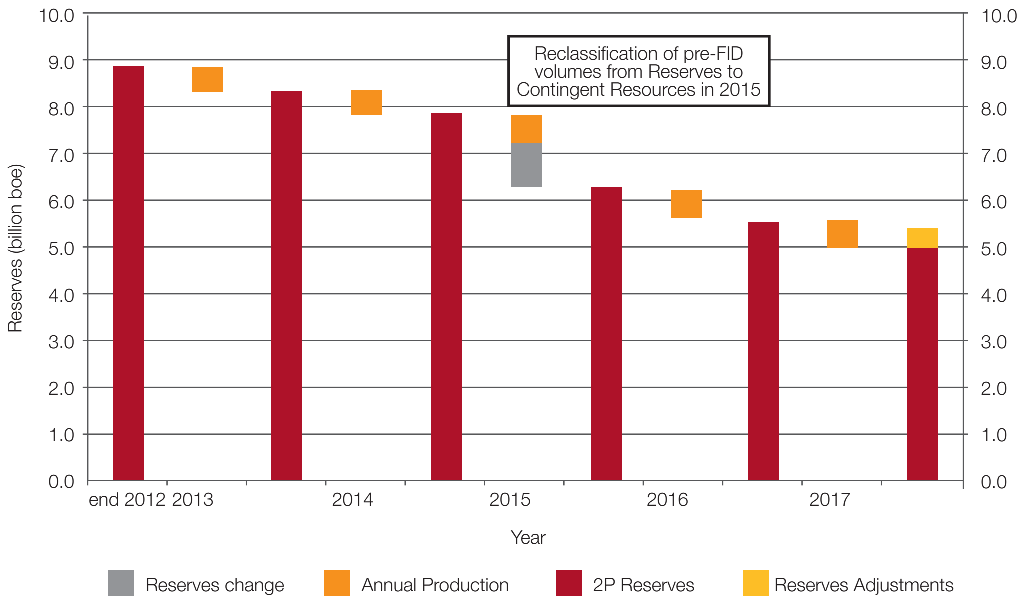


Figure 5: 2P reserves and production 2013 to 2017



3.5 Estimated Ultimate Recovery historic trends

Estimated Ultimate Recovery (EUR) is defined as production (to date) plus (remaining) reserves. Figures 6 and 7 shows how the EUR from the UKCS based on known reserves (proven, probable and possible) has evolved over time for oil and gas fields, respectively.

EUR increased significantly from 1970 to 1990, indicating that exploration success was adding to the contingent resource base and significant contingent resources were being matured to reserves. However, in recent times the trend has reduced considerably and now is almost flat, because of low maturation of contingent resources to reserves and the low level of discoveries.

It should be noted that the drops observed in EUR in 2015 are because of the change in the OGA's approach to defining reserves described earlier in this section.

Figure 6: Oil Estimated Ultimate Recovery vs time (to end 2017)

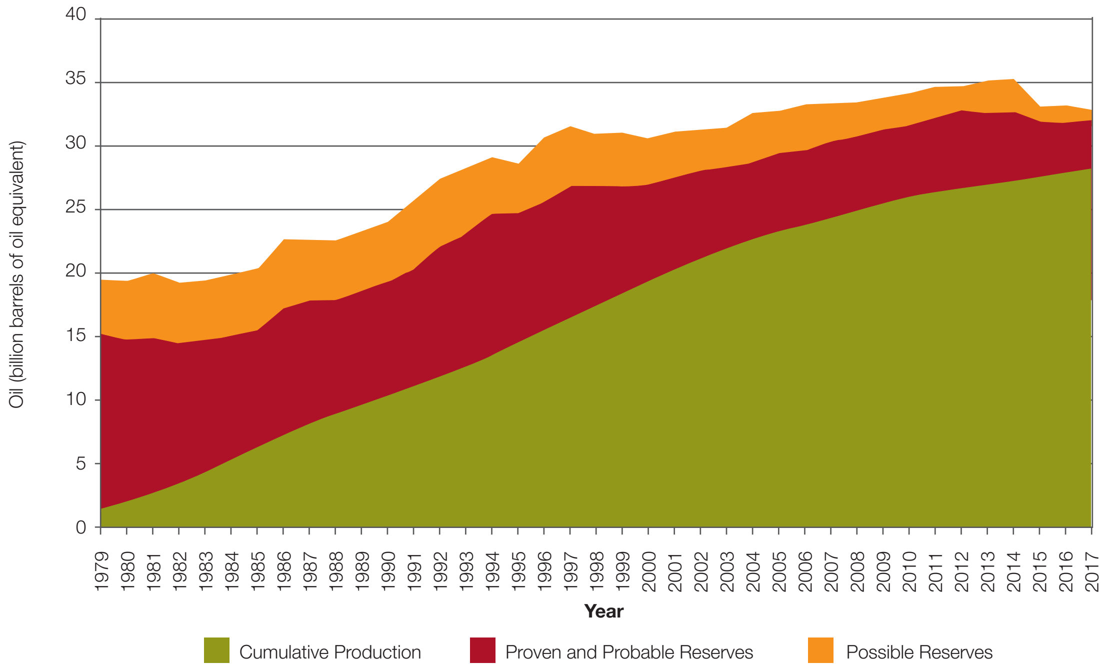
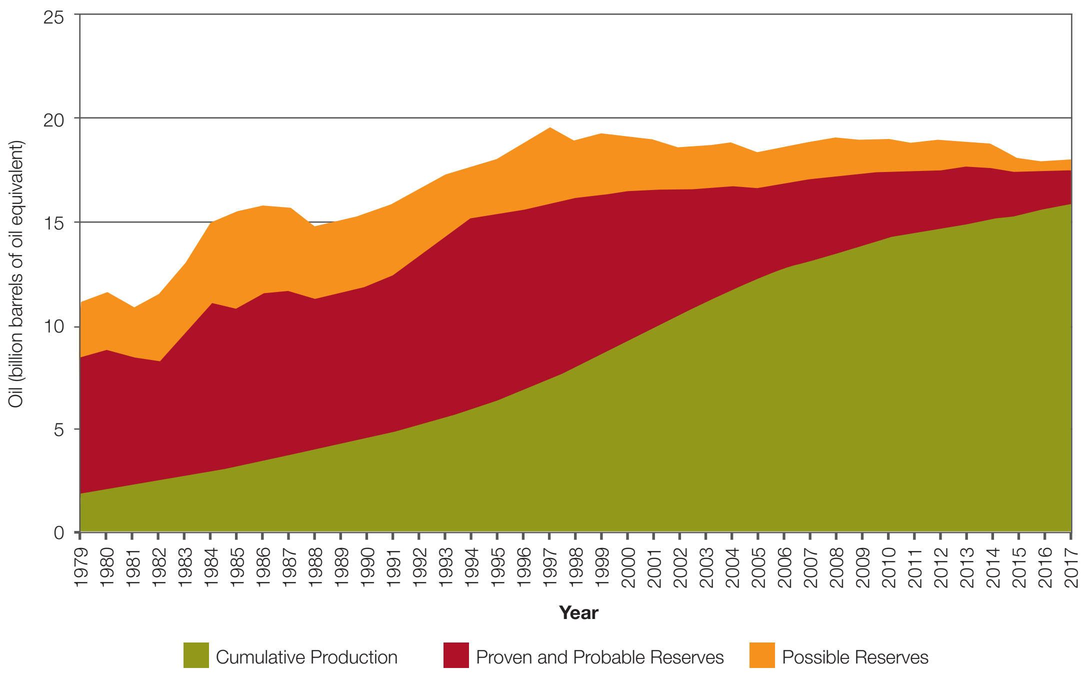


Figure 7: Gas Estimated Ultimate Recovery vs time (to end 2017)



4. Detailed breakout of oil and gas reserves and contingent resources

In this section, ranges for the estimates of oil and gas reserves and contingent resources are presented. The gas reserves and contingent resources for proposed new field developments are categorised according to whether they are "dry gas", "gas from gas condensate fields", or "associated gas from oil fields". The oil and gas reserves and contingent resources are also split out by area (Northern North Sea (NNS), Central North Sea (CNS), Southern North Sea (SNS), Irish Sea (IS) and West of Shetland (WoS)).

4.1 Ranges for oil and gas reserves and contingent resources

Oil and gas reserves can be classed into three categories (proven, probable and possible, or 1P, 2P and 3P) depending on the level of confidence that they will eventually be produced (see Appendix B for definitions). Contingent resources can similarly be classed as 1C, 2C, 3C depending on confidence level.

The following tables indicate the spilt of petroleum liquids and gas discovered reserves and resources and the 1P/2P/3P and 1C/2C/3C ranges according SPE PRMS definitions as explained in Appendix B. Proven, probable and possible reserves and resources for a large number of individual fields and discoveries have been aggregated to provide the totals shown. Summing the overall estimates of the three categories of reserves and resources does not imply any particular levels of probability that those volumes will ultimately be produced. The ranges tabulated below should be considered as indicative of the various underlying uncertainties.

UK remaining reserves and contingent resources are approximately 70% oil and 30% gas when expressed in oil equivalent terms. It should be noted that the split of oil and gas in the total production during 2017 was 370 mmboe oil and 230 mmboe gas.

Table 2 – Oil and gas reserves and resources as at end 2017 (2016) in billion boe

Reserves	1P	2P	3P
Reserves	3.6 (3.6)	5.4 (5.7)	6.7 (7.5)
Contingent resources	**1C**	**2C**	**3C**
Producing fields	1.2 (0.3)	2.1 (2.3)	2.3 (2.5)
Proposed new developments	1.5 (0.9)	2.1 (1.9)	2.8 (3.0)
Marginal discoveries	1.4 (1.4)	3.2 (3.2)	6.1 (6.0)
Total contingent resources	4.1 (2.6)	7.5 (7.5)	11.2 (11.5)

Note: The classification of reserves and resources is explained in Appendix B.
Due to rounding, subtotals may not exactly equal the sum or difference of the values entered elsewhere in the table

Table 3 Oil reserves and resources as at end 2017 (2016) in billion boe

Oil	1P	2P	3P
Oil reserves	2.5 (2.5)	3.8 (3.8)	4.5 (5.2)
Oil contingent resources	**1C**	**2C**	**3C**
Producing fields	0.8 (0.2)	1.4 (1.6)	1.6 (1.7)
Proposed new developments	1.3 (0.6)	1.7 (1.4)	2.3 (2.3)
Marginal discoveries	0.8 (0.8)	2.0 (2.0)	4.1 (4.0)
Total contingent resources	2.9 (1.6)	5.1 (5.0)	8.0 (8.0)

Table 4 Gas reserves and resources as at end 2017 (2016) in billion boe

Gas	1P	2P	3P
Gas reserves	1.1 (1.1)	1.7 (1.8)	2.1 (2.3)
Gas contingent resources	**1C**	**2C**	**3C**
Producing fields	0.3 (0.1)	0.7 (0.7)	0.9 (0.8)
Proposed new developments	0.2 (0.3)	0.4 (0.5)	0.5 (0.7)
Marginal discoveries	0.6 (0.6)	1.2 (1.3)	2.0 (2.1)
Total contingent resources	1.1 (1.0)	2.3 (2.5)	3.4 (3.6)

Due to rounding, subtotals may not exactly equal the sum or difference of the values entered elsewhere in the table

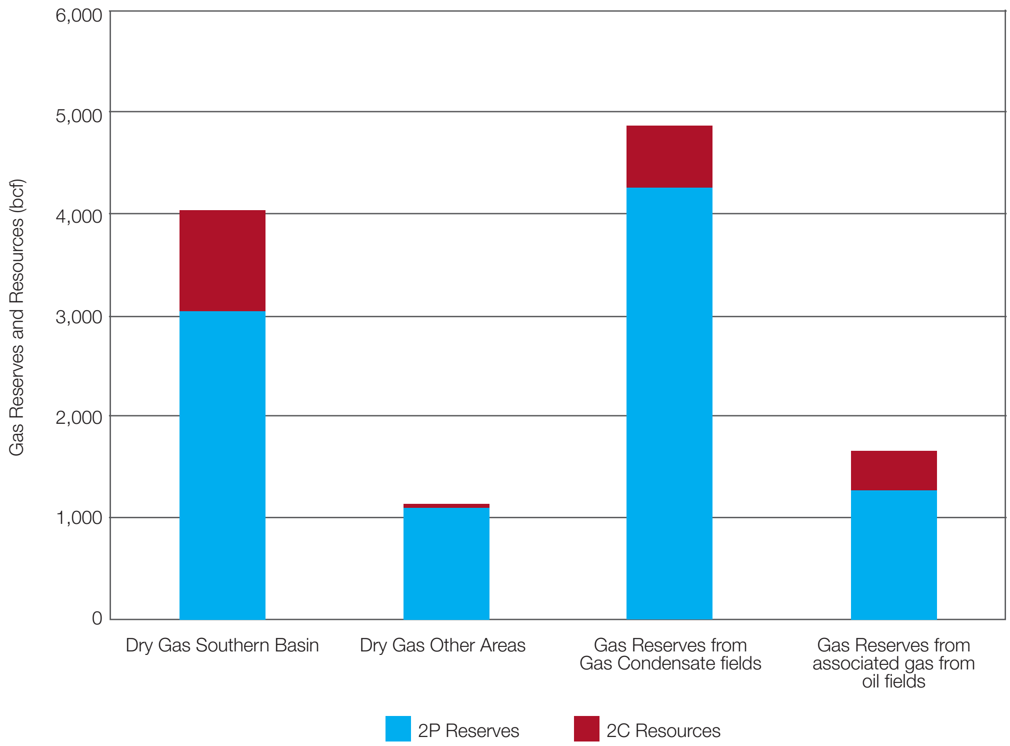
Versions of the above tables in metric units (million tonnes of oil and billions cubic metres of gas) are presented in Appendix D

4.2 Gas reserves distribution by type

Figure 8 indicates how UKCS gas reserves are distributed between dry gas fields (primarily located in the SNS), gas from gas condensate fields and associated gas from oil fields (both primarily located in the CNS, NNS and WoS).

The largest contribution to future gas production is expected to come from gas condensate fields. These fields tend to be produced at constant rates throughout the year (periods of planned and unplanned downtime apart), compared to dry gas fields where production rates can be higher during periods of peak demand (e.g. in winter) and lower during periods of low demand (e.g. in summer). Ca 75% of the condensate gas reserves and resources lie in the CNS.

Figure 8: Distribution of UKCS gas reserves and resources (central case)



Tables 5 and 6 indicate the range of resources associated with gas reserves and contingent resources in proposed new developments.

Table 5 Gas reserves by field type as at end 2017 (2016) in bcf

Fields in production or under development	1P bcf	2P bcf	3P bcf
Gas reserves from dry gas fields			
Southern basin (i.e. SNS)	2019 (2130)	3040 (3239)	3949 (4353)
Other areas	754 (402)	1101 (602)	1533 (769)
Gas reserves from gas condensate fields	2732 (2806)	4309 (5372)	5379 (6760)
Gas reserves from associated gas from oil fields	862 (882)	1274 (1292)	1520 (1725)

Table 6 Gas contingent resources by field type as at end 2017 (2016) in bcf

Fields where proposed development plans are under discussion	1Cbcf	2Cbcf	3Cbcf
Gas resources from dry gas fields			
Southern basin (i.e.SNS)	605 (539)	992 (767)	1421 (1020)
Other areas	20 (20)	35 (35)	188 (125)
Gas resources from gas condensate fields	308(225)	571 (1048)	774 (1198)
Gas resources from associated gas from oil fields	270 (184)	399 (354)	570 (476)

4.3 Petroleum resource distribution by geographic area

Figures 9 and 10 show the distribution of UK oil and gas reserves and contingent/discovered resources by area. Indicatively, most oil reserves are within the CNS and WoS areas with significant gas potential in the CNS.

Figure 9: Oil reserves and resources by area (2P/2C)

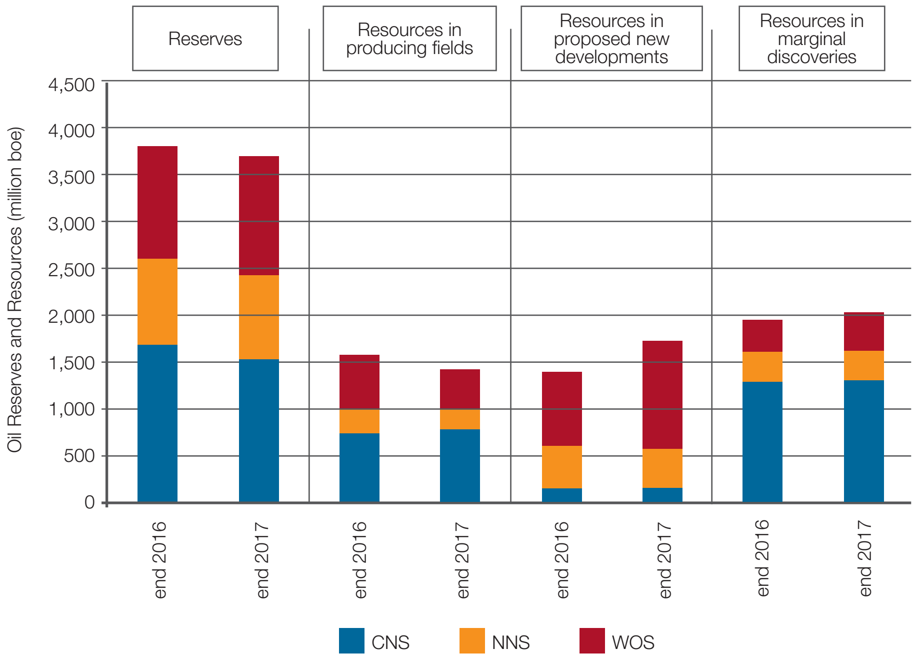
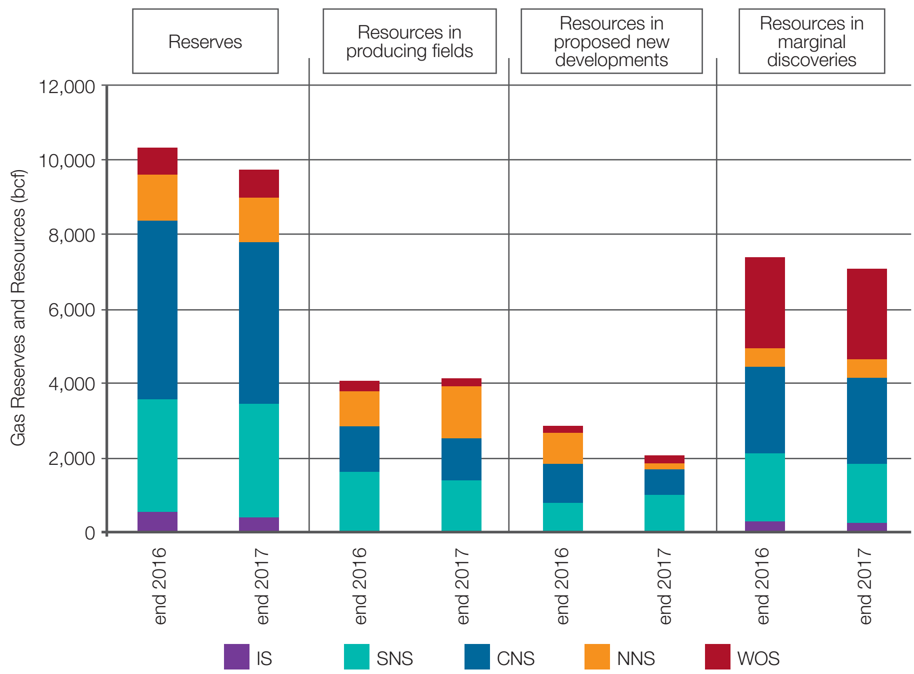


Figure 10: Gas reserves and resources by area (2P/2C)



5. Prospective Resources (Yet-to-Find)

5.1 Summary

During 2017/18, the Oil & Gas Authority, has made substantial changes to the methodology (Figure 5.1) by which the UK's Yet-to-Find Prospective Resources are estimated, using industry best-practices and building upon the legacy inventory of leads and prospects inherited from the OGA's predecessor organisations, and maintained by the British Geological Survey (BGS).

For the first time, the Yet-to-Find estimate also includes Prospective Resources added through Play Analysis, building upon the OGA's recent regional geoscience initiatives and activities including the Government-Funded Seismic Programmes, the Regional Mapping Project (delivered by Lloyds Register), and post-doctoral research projects (delivered by Heriot-Watt University, the University of Aberdeen and the University of Durham). This work has benefitted from the guidance of MER UK Exploration Task Force members, and the new Prospective Resource estimation process has been independently audited by a third-party specialist from Rose & Associates, LLP.

Consequently, the OGA's estimate of prospective resources has been revised significantly. The OGA now considers that the Mean Yet-to-Find Prospective Resources of leads and prospects in the inventory is 4.1 billion barrels of oil equivalent (Bboe). Within this inventory, a range of volume outcomes is possible, as illustrated in Table 5.1.

Table 5.1. Prospective Resources Associated with Leads & Prospects, with Cut-Offs

UKCS	P90	Mean	P10
Total	2.8	4.1	5.6

All values calculated stochastically using the Monte Carlo method, with no dependencies. Volumes are risked recoverable prospective resources. 10 MMboe unrisked volume cut-off (30 MMboe West of Shetland; unrisked) and 15% Geological Chance of Success (CoS) cut-off applied.

Leads and prospects meet a volume threshold of 10 MMboe Mean Prospective Resources (or a 30 MMboe mean volume cut-off West of Shetland) and have an estimated technical (geological) chance of success greater than 15%. These thresholds are consistent with drilling activity taking place under current market conditions. It is important to recognise that the final Prospective Resource that industry is able to deliver will depend on the interplay of a number of other factors which will vary spatially and temporally, including economics, infrastructure status, capital availability, technology development, social and environmental factors, and a host of other constraints and enablers.

The Prospective Resources available in the Lead and Prospect Inventory are potentially supplemented by an additional 11.2 Bboe of Mean Prospective Resources that are estimated in plays where the Industry has yet to map leads and prospects systematically, partly due to the need for improved geophysical datasets. By their nature, these resources are more speculative, with greater risk, but also greater opportunities for value creation due to the impact of successful de-risking of chance factors that are shared among a collection of related leads and prospects (play risk).

It is important to recognise that these estimates (illustrated in Figure 5.2) reflect the current state of subsurface knowledge, limited by the extent of the work that could be performed by the OGA, and that the figures will be revised over time as work on the prospect inventory and play portfolio matures. Of fundamental importance to this process is the flow of ideas, and improvements in data that will allow new opportunities to be identified and risks to be polarised such that concepts can be progressed through to operational activity, adding to the reserves base and sustaining future production. This prospect maturation process takes time and requires the investment of human and financial capital.

Through the course of this work, it has become clear to the OGA that there are a large number of excellent exploration opportunities that are waiting to be matured by Industry towards drill-ready status (Figure 5.3). If Industry can accelerate the pace of exploration activity, and work through the extensive inventory to drive plays and leads to drill-ready prospect status, it will be able to realise more fully the value of the UKCS prospective resource base. By publishing the break-down of Yet-to-Find estimates by region and evaluation maturity/ resource category (plays to leads to prospects), the OGA aims to assist industry's efforts to deliver the potential value from prospective resources across the UK Continental Shelf.

The OGA will publish additional detail and insights from its play and prospect evaluations in the first half of next year with the intent to provide additional support to Industry's data acquisition and technical work. This follow-on publication will include further details on the methodology, play maps, the impact of E&A activity constraints and enablers, portfolio performance, and value. The OGA also intends to publish information for leads and prospects that reside in the UKCS prospect inventory, in support of the 32nd, and subsequent, licensing rounds.

5.2 Methodology

In earlier years, the OGA's predecessor organisations estimated prospective resources primarily by summing risked recoverable resources associated with leads and prospects held in the national prospect inventory (PI). The new approach (Figure 5.1) incorporates several key changes:

- Play-Based Exploration. The introduction of a play-level estimate of Yet-to-Find prospective resources through play-based assessments using common risk segment mapping to capture volumes lying outside of areas with mapped leads and prospects, but where it is believed (based on current knowledge and data) that the key play-elements, including reservoir, top seal and hydrocarbon charge, may exist. This has allowed a more complete assessment of potential volumes in plays and basins where mapped leads and prospects are sparse or absent.
- Volume Estimation Adjustments. It has been widely recognised that Industry commonly overestimates pre-drill exploration volumes, both within national portfolios (e.g. NPD Resource Report, 2018) and within company portfolios (e.g. Citron, Brown et al., 2016). Typically, this overestimation manifests itself in the exclusion of downside volume-scenarios, resulting in unpredictable (i.e. uncalibrated) portfolio outcomes. The OGA has applied a systematic method to correct industry resource estimates, allowing calibration of leads and prospects against their respective play success-rates and field-size distributions. This calibration has been validated against the discovered volumes delivered in recent years.
- Resource Maturity Categorisation. The OGA has adopted the SPE's Petroleum Resources Management System resource categories; distinguishing between different levels of technical maturity by subdividing Prospective Resources into Plays, Leads and Prospects. Prospects have been further subdivided into Prospects-Under-Evaluation, and Drill-Ready-Prospect categories (definitions applied by the OGA are appended below). Monte-Carlo stochastic analysis has been used throughout to allow statistically-valid estimates to be made.
- Leads and Prospects comprise those submitted through the OGA's LARRY portal at bid submission stage, with subsequent modifications adopted from licence work programmes, and at relinquishment stage. The Lead category is supplemented by features mapped on behalf of the OGA by the British Geological Survey. All features are subsequently calibrated such that geological chance-of-success (CoS) and volume estimates are consistent with historical play performance.

5.3 Results

All volumes presented in this section (including tables and figures) are risked recoverable prospective resources. Onshore and unconventional hydrocarbon resources are not included in the assessment. Ultimately the Yet-to-Find potential of the UK Continental Shelf will be determined by activity levels. The ultimate volume that can be delivered will depend critically on how industry generates new targets, and the efficiency of resource progression from plays through to drill-ready prospects.

Lead and Prospect-Level Prospective Resources

The lead and prospect inventory held by the OGA currently contains almost 3500 features derived largely from operator evaluations, supplemented by in-house evaluations. The inventory has been cleaned-up as part of this work, removing invalid leads and prospects, and classifying features according to their technical maturity. Volume estimates have undergone a sense-check and been adjusted to ensure that the maximum resource estimate (P1 case) is realistic, and that the minimum resource estimate (P99 case) is reasonable and consistent with play statistics. Industry risk estimates have not been adjusted, since at a portfolio level, historical pre-drill risks broadly match actual success rates. This ‘calibrated’ portfolio has been modelled stochastically to produce a range of volume estimates, which can be categorised in various ways, most simply at a basin and resource category level (see Table 5.2)

Table 5.2.A shows the split of prospective resources associated with mapped features in the mature UKCS basins, with no volume or Chance of Success (CoS) cut-offs applied. Note that as the OGA continues to review its inventory of leads and prospects, further changes should be anticipated. Figures reflect the position at end-2017, including those features submitted in the 30th Licensing Round.

The high feature count in **Table 5.2.A** reflects the small size and/or low chance-of-success of many features. In order to progress towards drilling, these features require increased volumes and/or de-risking, via improved geological understanding and/or technology improvements. **Table 5.2.B** shows the distribution of Prospective Resources by Resource Category

It would be reasonable to expect that only a subset of the resource base in **Table 5.2** could be produced commercially, since ultimate recovery will be limited by a number of factors. There are a number of potential methods by which such a subset of potentially recoverable resources could be extracted. To model which leads and prospects the industry would consider to be viable targets from a geological perspective, we have used a simple set of cut-offs that are consistent with recent drilling activity and so capture features that may, if matured to a drill-ready status, be targeted under current market conditions. This is illustrated in **Table 5.3 (Overleaf)** which shows the impact of applying a 10 MMboe volume cut-off (increased to 30 MMboe West of Shetland) and a 15% geological chance of success cut-off.

Table 5.2. Prospective Resources Associated with Leads & Prospects

A) Lead & Project-Level Prospective Resources, by Basin (Without cut-offs applied)

Basin	Oil Equivalent (billion boe)						% Gas	Feature Count
	P99	P90	P50	Mean	P10	P1		
West of Shetland	0.5	0.8	1.3	**1.6**	2.6	5.7	64%	207
Northern North Sea	0.7	0.8	1.2	**1.3**	1.9	4.1	55%	623
Central North Sea	2.3	2.7	3.4	**3.5**	4.6	7.0	56%	1,454
Southern North Sea	0.6	0.7	1.0	**1.1**	1.6	2.9	96%	1,009
East Irish Sea	0.0	0.0	0.1	**0.1**	0.2	0.7	84%	132
Total Prospective Resources	**5.3**	**6.1**	**7.3**	**7.7**	**9.6**	**13.5**	**62%**	**3,425**

B) Lead & Project-Level Prospective Resources, by Resource Category (Without cut-offs applied)

Resource Category	Oil Equivalent (billion boe)						% Gas	Feature Count
	P99	P90	P50	Mean	P10	P1		
Leads	2.7	3.2	4.2	**4.5**	6.2	9.9	62%	2,362
Prospects	01.7	2.0	2.6	**2.7**	3.5	5.5	62%	1,000
Drill-ready Prospects	0.1	0.2	0.4	**0.4**	0.7	1.3	58%	63
Total Prospective Resources	**5.3**	**6.1**	**7.3**	**7.7**	**9.6**	**13.5**	**62%**	**3,425**

Notes: All totals calculated stochastically using Monte Carlo method, with no dependencies (i.e. totals are not calculated arithmetically). Volumes are risked recoverable prospective resources

A) Lead & Propect-Level Prospective Resources, by Basin (With cut-offs applied)

Basin	Oil Equivalent (billion boe)						% Gas	Feature Count
	P99	P90	P50	Mean	P10	P1		
West of Shetland	0.2	0.3	0.8	**1.1**	1.9	5.2	60%	46
Northern North Sea	0.2	0.3	0.5	**0.6**	1.0	2.1	56%	97
Central North Sea	0.9	1.2	1.7	**1.9**	2.7	5.4	58%	281
Southern North Sea	0.1	0.2	0.4	**0.5**	0.9	2.1	95%	58
East Irish Sea	0.00	0.00	0.01	**0.04**	0.6	0.6	93%	4
Total Prospective Resources	**2.2**	**2.8**	**3.7**	**4.1**	**5.6**	**9.4**	**61%**	**486**

B) Lead & Propect-Level Prospective Resources, by Resource Category (With cut-offs applied)

Resource Category	Oil Equivalent (billion boe)						% Gas	Feature Count
	P99	P90	P50	Mean	P10	P1		
Leads	1.0	1.4	2.1	**2.4**	3.6	7.4	63%	260
Prospects	0.6	0.8	1.2	**1.4**	2.1	4.2	61%	191
Drill-ready Prospects	0.0	0.1	0.3	**0.3**	0.6	1.2	58%	35
Total Prospective Resources	**2.2**	**2.8**	**3.7**	**4.1**	**5.6**	**9.4**	**62%**	**486**

Notes: All totals calculated stochastically using Monte Carlo method, with no dependencies (i.e. totals are not calculated arithmetically). Volumes are risked recoverable prospective resources. *10 MMboe unrisked volume cut-off (30 MMboe West of Shetland; unrisked) and 15% Geological Chance of Success (CoS) cut-off applied.

Table 5.3.A presents prospective resources by basin with 15% Geological Chance of Success (CoS) and 10 MMboe volume cut-offs applied (30 MMboe West of Shetland). The volume cut-off is applied to the Mean Prospective Resource estimate for each feature. The feature count is now reduced to a figure that is more consistent with the UKCS's history of approximately 2,500 offshore exploration wells to date.

Table 5.3.B shows the distribution of Prospective Resources by Resource Category with cut-offs applied. In order to progress towards drill-ready status, leads and prospects must mature successfully via technical work programmes. The number of drill-ready prospects is equivalent to around 3 to 4 years-worth of drilling activity at current rates, which is insufficient for industry to meet its current Key Performance Indicator of discovering an additional 200 MMboe of resource per year (as a five-year rolling average) through exploration.

Play-Level Prospective Resources

For the first time, the OGA has invested substantial effort in systematically estimating the prospective resources at a play level, adopting industry best-practice methods. Maps of source rocks, reservoirs and seals have been generated at a level appropriate for the scale of this study, and constrained by the available data. Common Risk Segments have been mapped, allowing the separation of proven and unproven plays. Prospective resources at play level have been separated from leads and prospects using standard mapping techniques. Prospective resources within each play have been quantified by estimating the notional lead- and prospect-density (i.e. feature count per thousand square km), resource-range, play-risk, and average prospect-risk, based on suitable analogues. As at the lead and prospect level, risked prospective resources have been modelled stochastically to produce a range of volume estimates, which can be categorised in various ways, most simply at a basin level (Table 5.4). The number of plays included in this study is not exhaustive, and the mapping of sub-plays will be beneficial in future work. A high-level list of plays is appended to this report in Appendix C. Building on the results presented here, future work will target the highest-impact plays and basins.

Table 5.4. Play-Level Prospective Resources

Basin	Oil Equivalent (billion boe)					
	P99	P90	P50	Mean	P10	P1
West of Shetland	2.0	3.1	4.6	**4.7**	6.3	7.8
Rockall Trough	0.0	0.3	2.1	**2.5**	5.1	8.6
Northern North Sea	0.2	0.4	0.8	**0.9**	1.7	2.7
Central North Sea	0.6	0.9	1.4	**1.5**	2.1	2.8
Mid North Sea High	0.0	0.1	0.5	**0.5**	1.1	1.6
Southern North Sea	0.2	0.4	0.8	**0.8**	1.7	2.7
East Irish Sea	0.0	0.0	0.0	**0.0**	0.1	0.3
SW Britain	0.0	0.0	0.2	**0.3**	0.6	1.0
Total Prospective Resources				**11.2**		

Notes: Play-Level Prospective Resources by Basin, no volume or Chance of Success (CoS) cut-offs applied, Total calculated using Monte Carlo with no dependencies. Volumes are risked recoverable prospective resources. Northern North Sea includes East Shetland Platform, SW Britain includes SW Approaches and Cardigan Bay. Mid North Sea High includes Forth Approaches Basin.

Footnotes

Prospective Resource Category Definitions:

A Lead is a trapping feature that is associated with a speculative volumetric and chance-of-success assessment, and requires additional seismic analysis/acquisition or other key data in order to progress to a prospect.

A Prospect-Under-Evaluation is a robust trap that has been mapped with a higher degree of confidence using good quality seismic and other key data.

A Drill-Ready-Prospect requires no further evaluation, and has an associated well location and plan.

References

Gary P. Citron, P. Jeffrey Brown, James MacKay, Peter Carragher and David Cook (2016) ***The challenge of unbiased application of risk analysis towards future profitable exploration****. Geological Society, London, Petroleum Geology Conference series, 8, 259-266, 27 October 2016*, https://doi.org/10.1144/PGC8.2

Norwegian Petroleum Directorate (2018) Petroleum resources on the Norwegian continental shelf 2018 – Exploration. http://www.npd.no/en/Publications/Resource-Reports/2018/

Figure 5.1: Flow-diagram summarising the process used to estimate Yet-to-Find potential (Prospective Resources) of the UKCS.

The workflow has two strands to estimate, A) the Play-Level Yet-to-Find and B) the Mapped-Feature-Level Yet-to-Find (Leads & Prospects).

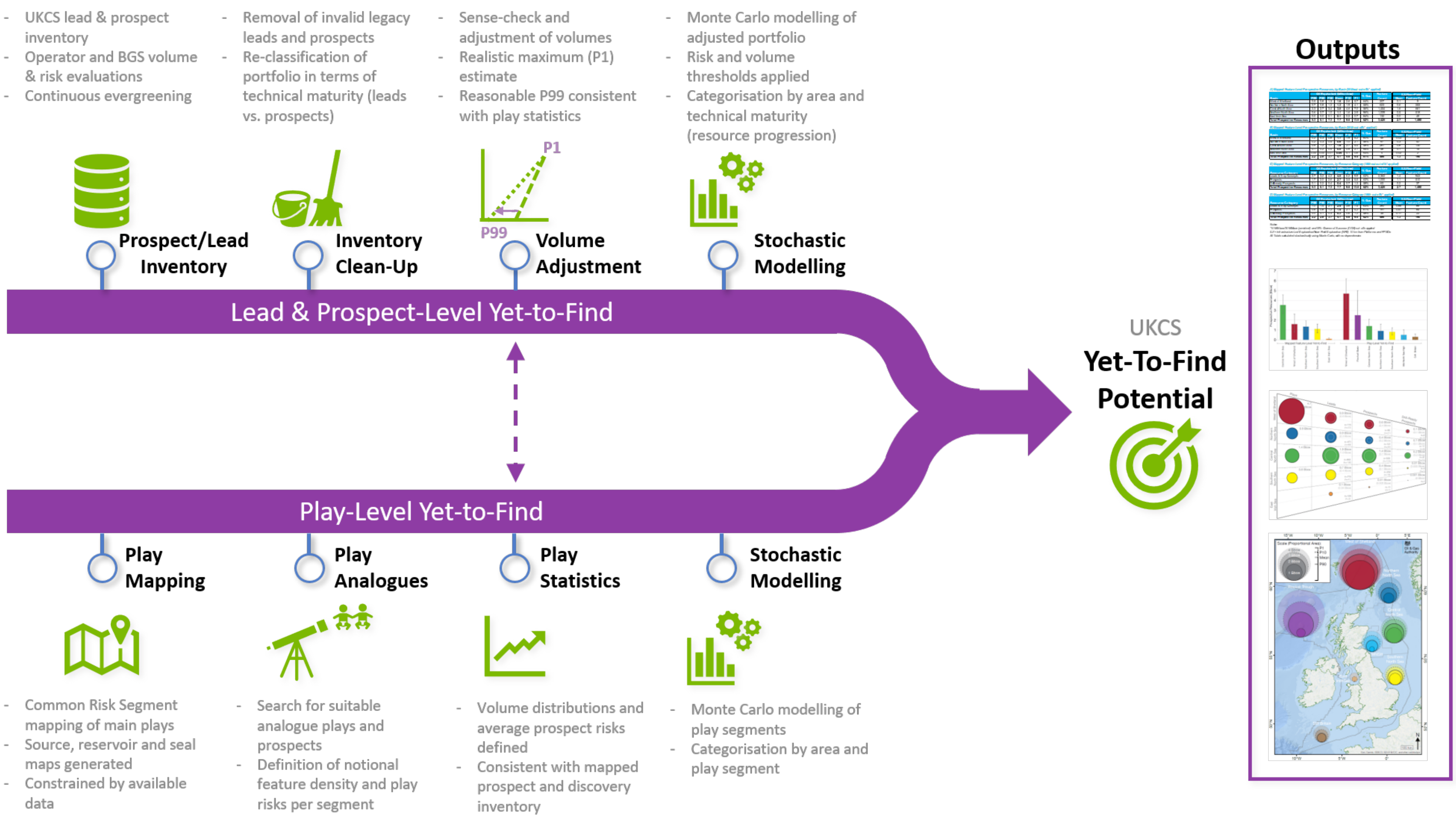


Figure 5.2: Bar chart showing Mean Prospective Resources (Yet-to-Find)

In each UKCS basin, with the P90 and P10 volume range displayed by the error bars.
The Lead and Prospect-Level Yet-to-Find values have no risk and volume cut-off applied.

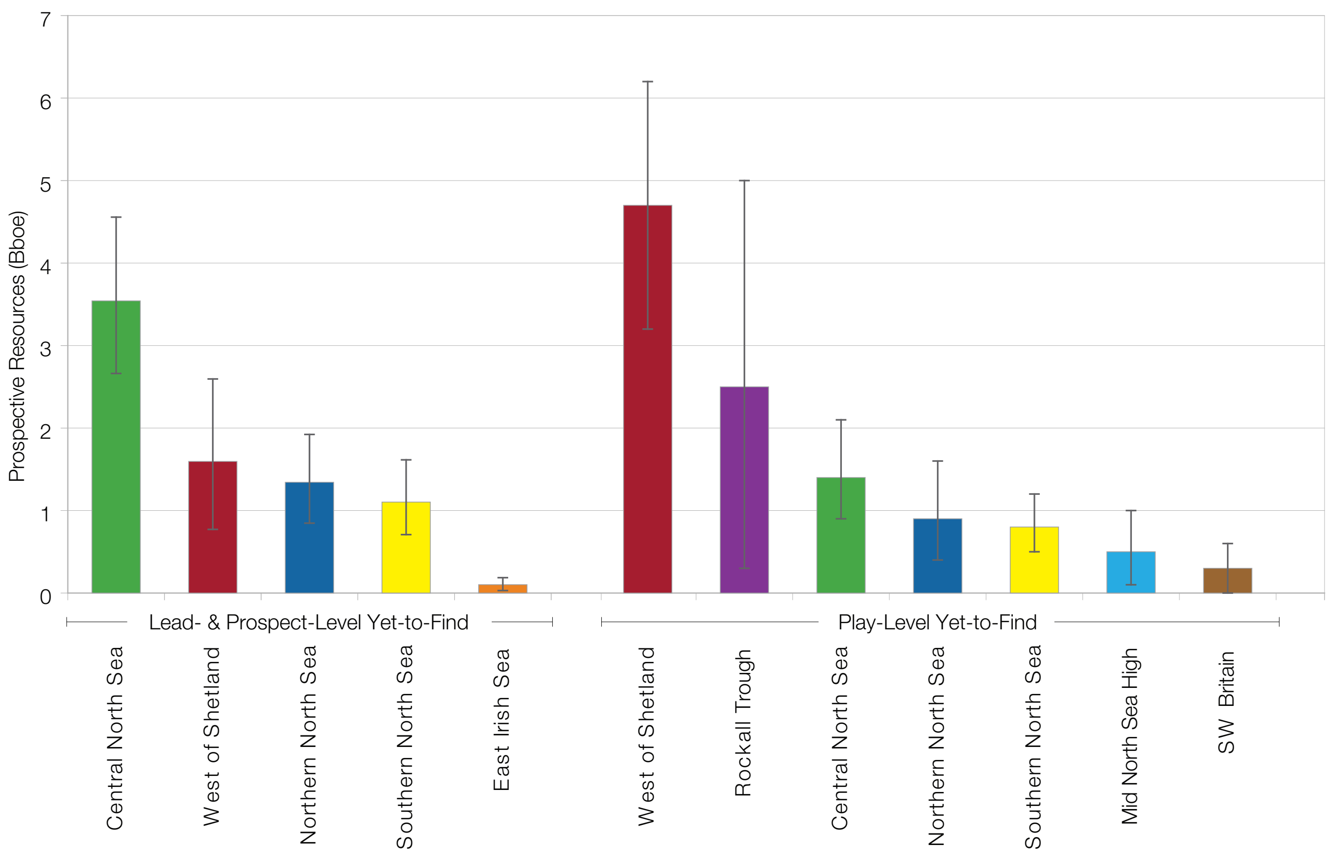


Figure 5.3: Prospective Resource Maturation Funnel

Showing the Mean Yet-to-Find Resources in the UKCS's producing basins, split by Resource Category. Coloured Circle Areas are proportional to the mean risked prospective resource (value in top right of each category box). Inner Dashed Circle Areas are proportional to the resource after cut-offs are applied (Volume in brackets represents viable features after cut-off has been applied). The number of lead/prospect features, n, is shown in the bottom right of each category box (number after cut-off shown in brackets).

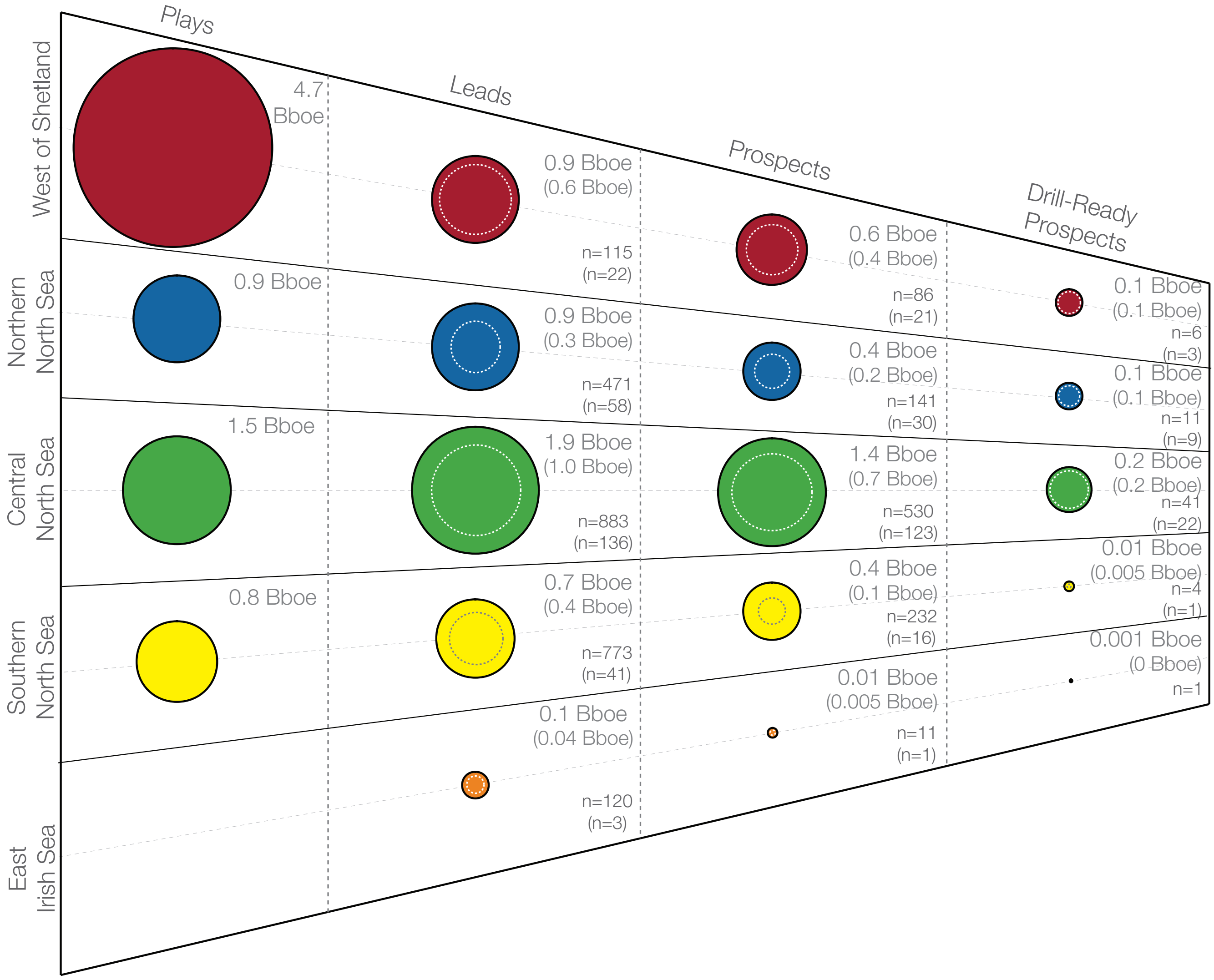
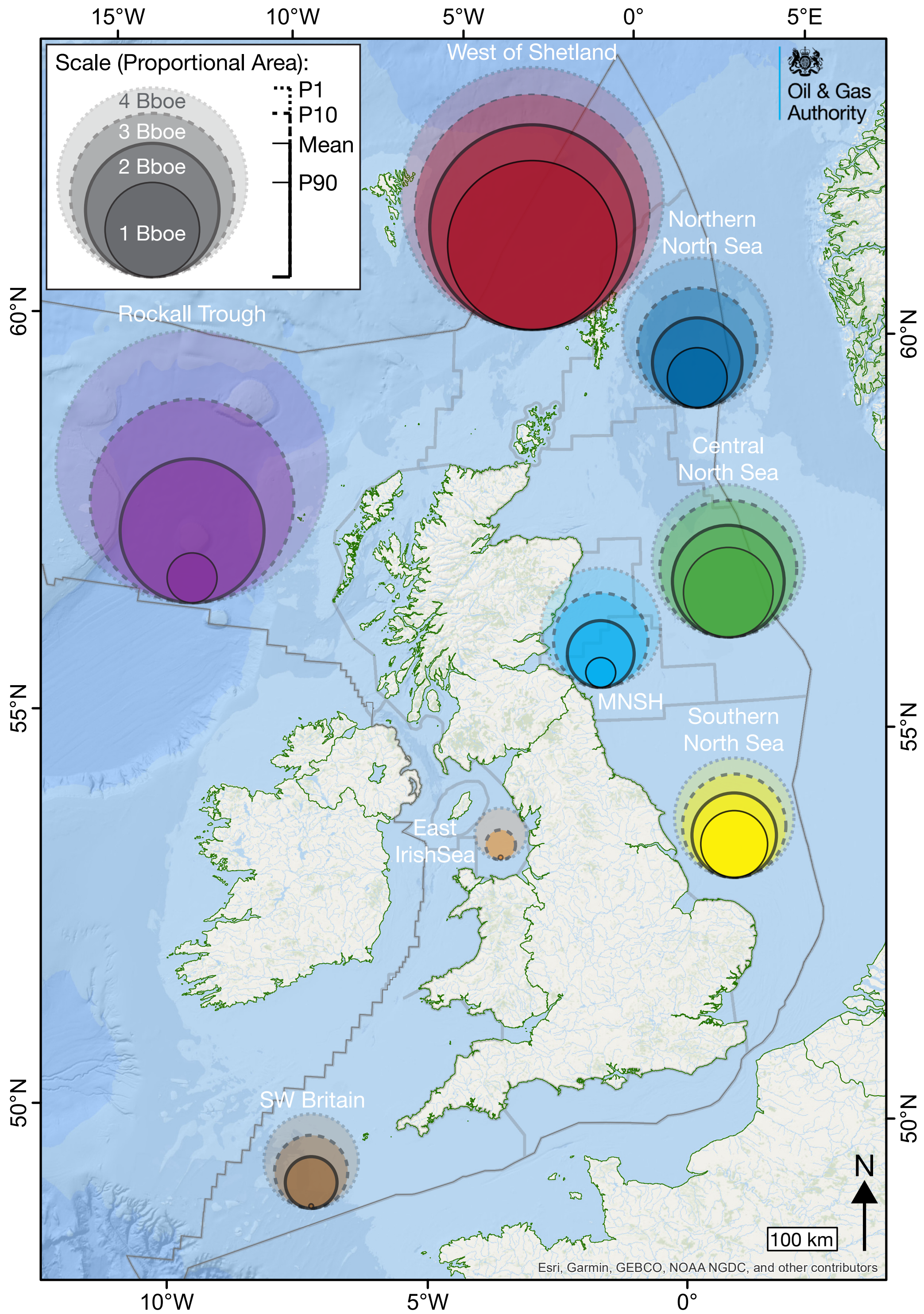


Figure 5.4: Play-Level Yet-to-Find Prospective Resources.

Circle areas represent volumes at P90, Mean, P10 and P1 ranges. Basin outlines are shown as grey lines



Appendix A

Data sources

The data for both developed fields and development projects under discussion were compiled from data provided by operators via the OGA's annual UKCS Stewardship Survey. The Survey also collected data on contingent resources in producing fields – these data were not collected prior to 2016.

The survey covered:

- 318 producing fields
- 13 projects where an FDP had been approved but production had not yet started
- 33 other projects where FDPs were under discussion as at the end of 2017

Data for unsanctioned discoveries where no development project is under discussion (referred to as potential additional resources in previous Department of Energy and Climate Change reports) were not collected via the UKCS Stewardship Survey.

The OGA in-house data used for the UK Continental Shelf unsanctioned discoveries information pack3 were updated to reflect the status as at end 2017 (taking into account activity in the second half of 2017).

The methodology for deriving estimates for prospective resources is presented in Appendix C.

Conversion factors:
The approach used to calculate barrels of oil equivalent is based upon the following (approximate) conversion factors:

1 tonne of crude oil = 7.5 barrels of oil equivalent
1 cubic metre of gas = 35.315 cubic feet of gas

1 cubic foot of gas = 1/5,800 barrels of oil equivalent

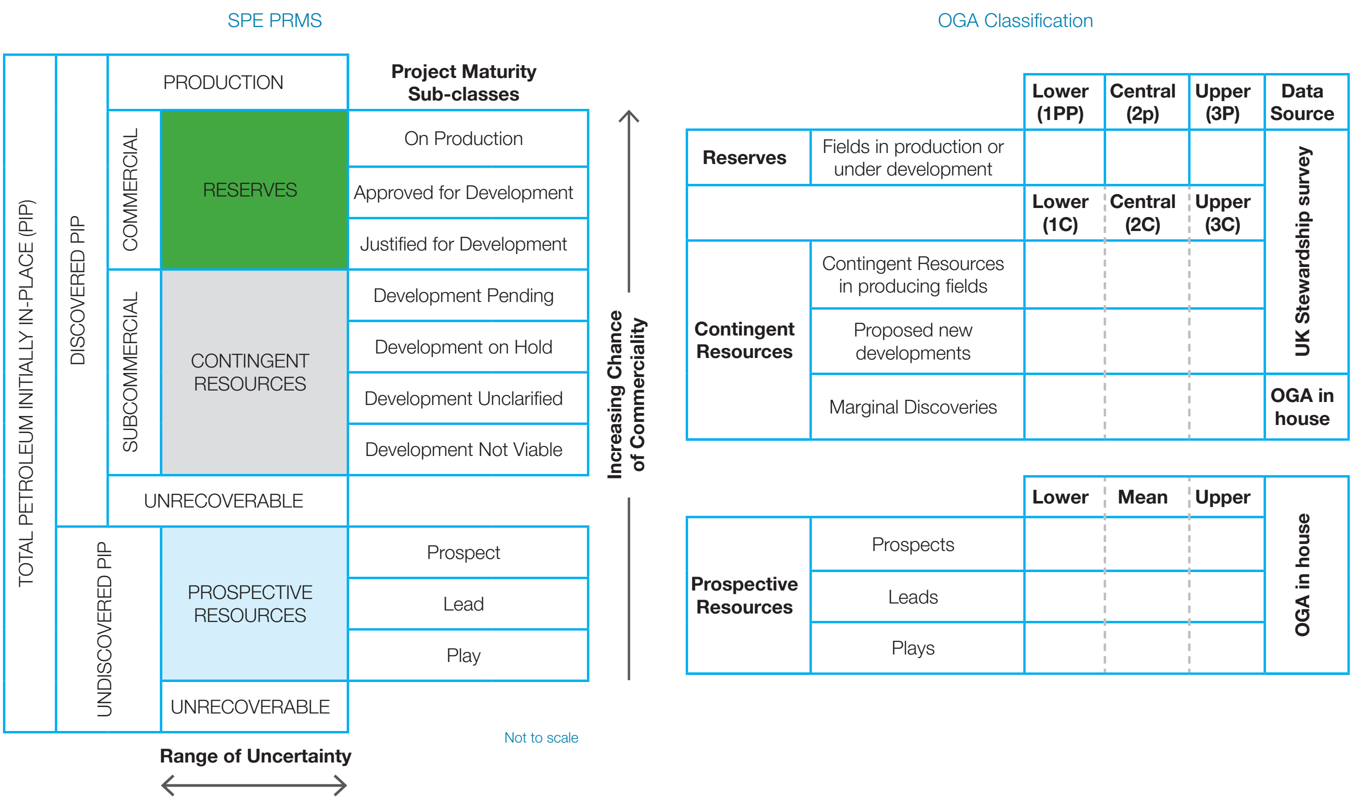
Appendix B

Comparison of OGA terminology with SPE PRMS

The OGA has sought to adjust its definitions and they are now more closely aligned with those recommended by the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE). The full definitions associated with this classification system can be found in SPE PRMS 2005 (updated 2011 and 2018)[1].

The OGA now classifies reserves and resources into the following main categories: reserves, contingent resources and prospective resources, with further sub classes aligned with SPE PRMS as laid out in Figure 11.

Figure 11: Comparison of OGA classifications with SPE PRMS



Source: SPE 2018

[1] https://www.spe.org/industry/reserves.php

Reserves

These are discovered, remaining volumes that are recoverable and commercial. They can be proven, probable or possible, depending on confidence level.

In the UKCS Stewardship Survey, operators were asked to provide reserves data in accordance with the following definitions for fields in production or under development (which are broadly in line with previous DECC guidance)

- Proven (1P): Reserves that, on the available evidence, are virtually certain to be technically and commercially producible, i.e. have a better than 90% chance of being produced
- Probable (2P): Reserves that are not yet proven, but which are estimated to have a better than 50% chance of being technically and commercially producible
- Possible (3P): Reserves that at present cannot be regarded as probable, but which are estimated to have a significant – more than 10% but less than 50% – chance of being technically and commercially producible

Contingent resources

Contingent resources are those quantities of petroleum estimated to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development.

The “contingent resources in producing fields” represent discovered undeveloped resources in the field determined areas.

The “contingent resources in proposed new developments” represent discovered undeveloped potential in new field developments under consideration.

The “contingent resources in marginal discoveries” represent undeveloped discoveries where no development proposals are currently being proposed, in licensed and unlicensed areas.

In the UKCS Stewardship Survey, operators were asked to provide information on contingent resources in future planned developments:

- In producing fields (including incremental projects)
- Where development plans are under discussion but have not yet been approved

Contingent resources in other discoveries:

- The OGA assessed contingent resources in other discoveries based on in-house information compiled from a variety of sources
- Resource confidence levels are defined as follows:
- 1C: Resource volumes that on the available evidence, are virtually certain to be technically producible, i.e. have a better than 90% chance of being producible
- 2C: Resource volumes that are not yet 1C, but which are estimated to have a better than 50% chance of being technically producible
- 3C: Resource volumes that at present cannot be regarded as 2C, but which are estimated to have a significant – more than 10% but less than 50% – chance of being technically producible

Prospective resources

Undiscovered potentially recoverable resources in mapped leads and prospects that have not yet been drilled, plus those undiscovered potentially recoverable resources that are estimated to reside in plays for which there are few or no mapped features.

Appendix C

Central North Sea & Moray Firth

- Eocene (Proven)
- Paleocene (Proven)
- Upper Cretaceous (Proven)
- Lower Cretaceous (Proven)
- Upper Jurassic (Proven)
- Middle Jurassic (Proven)
- Lower Jurassic (Proven)
- Triassic (Proven)
- Devonian (Proven)

Plays not included: Rotliegend, Carboniferous.

Forth Approaches Basin

- Carboniferous (Unproven)
- Rotliegend (Unproven)

Plays not included: Zechstein Dolomites.

Mid North Sea High

- Zechstein (Unproven)
- Rotliegend (Unproven)
- Carboniferous (Unproven)
- Devonian (Unproven)

Northern North Sea and East Shetland Platform

- Eocene (Proven)
- Upper Paleocene (Proven)
- Middle Jurassic (Proven)
- Lower Jurassic (Proven)
- Triassic (Proven)
- Devonian (Unproven)

Plays not included: Upper Jurassic interpreted as fully mapped therefore excluded. Upper & Lower Cretaceous excluded as these have been interpreted to be non-reservoir bearing intervals. Intervals younger than Eocene excluded due to biodegredation risk.

West of Shetland (Faroe-Shetland Basin)

- Paleocene (Proven)
- Upper Cretaceous (UnProven)
- Lower Cretaceous (Proven)
- Jurassic (Proven)
- Triassic (Proven)

Plays not included: Fractured Basement.

Rockall Trough

- Triassic (Unproven)
- Middle Jurassic (Unproven)
- Upper Jurassic (Unproven)
- Lower Cretaceous (Unproven)
- Paleocene (Partially Proven)

Southern North Sea

- Triassic (Proven)
- Zechstein (Proven)
- Rotliegend (Proven)
- Carboniferous (Proven)

Plays not included: Intra-Carboniferous, Tight-Gas.

South West Britain (including SW Approaches & Cardigan Bay)

- Triassic (Unproven)
- Middle Jurassic (Proven)
- Permian (Unproven)

Plays not included: Carboniferous.

Appendix D

Tables D3, D4, D5 and D6 are the metric equivalents of tables 3,4,5 and 6 in section 4

Table D3 Oil reserves and resources as at end 2017 in million tonnes

Oil	1P	2P	3P
Oil reserves	333	507	600
Oil contingent resources	**1C**	**2C**	**3C**
Producing fields	113	191	183
Proposed new developments	168	229	305
Marginal discoveries	105	268	552
Total contingent resources	387	688	1040

Due to rounding, subtotals may not exactly equal the sum or difference of the values entered elsewhere in the table

Table D4 Gas reserves and resources as at end 2017 in billion cubic metres

Gas	1P	2P	3P
Gas reserves	181	279	345
Gas contingent resources	**1C**	**2C**	**3C**
Producing fields	56	118	143
Proposed new developments	36	59	85
Marginal discoveries	95	201	332
Total contingent resources	187	378	560

Table D5 Gas reserves by field type as at end 2017 in billion cubic metres

Fields in production or under development	1P	2P	3P
Gas reserves from dry gas fields			
Southern basin	57	86	112
Other areas	21	31	43
Gas reserves from gas condensate fields	77	122	152
Gas reserves from associated gas from oil fields	24	36	43

Table D6 Gas contingent resources by field type as at end 2017 in billion cubic metres

Fields where proposed development plans are under discussion	1C	2C	3C
Gas resources from dry gas fields			
Southern basin	**17**	**28**	**40**
Other areas	1	1	5
Gas resources from gas condensate fields	9	16	22
Gas resources from associated gas from oil fields	8	11	16

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