Oil & Gas Authority

Moray Firth – Central North Sea Post Well Analysis

Christian Mathieu - 21st Century Exploration Road Map

[08.12.2015]

Acknowledgments

The author thanks the Companies currently owning the analysed wells for their time and data without which this project would not have been possible, as well as a few other that contributed data to the project. The author would also like to thank Andy Leonard (O&GUK) who proofread this report, the OGA Management as well as the owning companies for their authorization to publish it.

The author would also like to thank the seismic data providers for their authorization to publish selected seismic images.

Any enquiries regarding this publication should be sent to us at
[Nick.Richardson@oga.gsi.gov.uk]

Contents

Executive summary 7

1. Project overview 9

1.1. Project Objectives………………………………………………………………………… 9

1.2. Time Line 10

1.3. The Post Well Analysis Sheet 11

2. Statistics 12

2.1. Setting the Scene 12

2.2. Targeted Objectives 12

2.3. Trap types 13

2.4. Chance of Success 13

3. Well Analyses 14

3.1. Apache North Sea: well 22/07-4, TEP3prospect …………………………………………..14

3.2. BG: 13/22c-30, Hermes prospect……………………………………………………………17

3.3. BG: 14/28b-4, Moonraker prospect

3.4. BG: 22/14a-7, Mallory prospect

3.5. BG: 23/21-5, Toad prospect

3.6. BG: 28/5a-7, North Channel prospect

3.7. BG: 30/2a-10, Thunderer prospect

3.8. BG: 30/8-3, Calloway prospect

3.9. BP: 22/20a-7, TP1 prospect……………………………………………………………………32

3.10. Bridge Resources: well 15/11b-6, North Piper prospect……………………………………..35

3.11. Century Exploration UK Ltd: well 19/2-2, Dolphin prospect………………………………….36

3.12. CNR International: well 22/27a-4, Deep Banff prospect……………………………………..39

3.13. ConocoPhillips: well 15/30-12, Macallan prospect……………………………………………41

3.14. PetroCanada well operator, (Dana Petroleum current well owner): well 12/20b-1, Gemini prospect…………………………………………………………………………………………….43

3.15. Dana Petroleum: well 13/23a-7 &-7A, Magnolia prospect

3.16. Dana Petroleum: well 13/23d-8, Liberator prospect

3.17. Dana Petroleum: well 21/20f-7, Morgan prospect

3.18. Bow Valley Energy well operator, (Dana Petroleum current well owner): well 22/11b-13, “L” prospect

3.19. Dana Petroleum: well 23/11-04, Fiacre prospect
3.20. Endeavour: well 15/27-10, Roisin prospect……………………………………………………52
3.21. Endeavour: well 30/23b-4, Balgownie prospect
3.22. Endeavour: well 31/26b-17, Turnberry prospect
3.23. Endeavour: well 31/26b-18, Turriff prospect
3.24. Lundin Operator, (EnQuest current well owner): well 12/17b-1, Ridgewood prospect…...58
3.25. Centrica Operator, (EnQuest current well owner): well 21/17a-6, Whitethroat prospect
3.26. Walter Operator, (EnQuest current well owner): well 30/28-2, Beta prospect
3.27. EOG Resources: well 15/30a-14, Dunkeld prospect…………………………………….....63
3.28. EOG Resources: well 21/12b-6, "B" prospect
3.29. EXXONMOBIL: well 37/25-1, Corbenic prospect………………………………………..67
3.30. First Oil: well 29/06a-8, Centurion South prospect……………………………………………69
3.31. GdFSUEZ (now Engie): 22/23c-8 and side tracks, Taggart prospect………………………71
3.32. Ithaca: well 11/29-1, Manuel prospect……………………………………………………………73
3.33. Ithaca: well 12/26c-5, Polly prospect.
3.34. Maersk: well 13/26a-5, Stephenson prospect………………………………………………76
3.35. Maersk: well 15/19c-11, Dunvegan prospect
3.36. Maersk: well 15/20b-18, Dunglass prospect
3.37. Kerr McGee Operator, (Maersk current well owner): well 22/01a-11, Brodie prospect
3.38. Kerr McGee Operator, (Maersk current well owner): well 29/15-3, Fyvie prospect
3.39. Kerr McGee Operator, (Maersk current well owner): well 30/16-14, Western Terrace prospect
3.40. Nexen-CNOOC: well 12/14-2, Zanzibar prospect……………………………………………86
3.41. Oilexco well operator, (Nexen-CNOOC current well owner): well 13/30b-7, Oddjob prospect
3.42. Nexen-CNOOC: well 14/26a-9, Hobby North prospect
3.43. BG well operator, (Nexen-CNOOC current well owner): well 14/27a-2, Octopus prospect
3.44. Nexen-CNOOC: well 15/13b-11, Stingray prospect
3.45. Nexen-CNOOC / Granby: well 15/13b-18, Guinea prospect
3.46. Nexen-CNOOC: well 15/18b-10, Fox prospect
3.47. Nexen-CNOOC: well 15/22-18Z, Stareek prospect
3.48. Nexen-CNOOC: well 15/28c-9, Deacon prospect
3.49. Nexen-CNOOC: well 19/3-1, Pineapple prospect
3.50. Nexen-CNOOC: well 19/4-2, Full Moon prospect
3.51. Nexen-CNOOC: well 19/5b-2, Griffon prospect
3.52. Nexen-CNOOC: well 19/8-1, Peacock prospect
3.53. Nexen-CNOOC: well 19/15-1, Firefly prospect

3.54. Nexen-CNOOC: well 20/1-5, Buzzard North Terrace East prospect

3.55. Nexen-CNOOC: well 20/1-5Z, Lily prospect

3.56. Nexen-CNOOC: well 20/4a-8 and -8Z, Polecat prospect

3.57. Nexen-CNOOC: well 20/4a6a-7, Bluebell prospect

3.58. Nexen-CNOOC: well 20/7-7, Bardolph prospect

3.59. Nexen-CNOOC: well 20/7a-4, Squirrel prospect

3.60. Nexen-CNOOC: well 20/7a-6, Black Cat prospect

3.61. EDC well operator, (Nexen-CNOOC current well owner): well 20/7b-5, Joppa prospect

3.62. Nexen-CNOOC: well 20/11-1, Flint prospect

3.63. Nexen-CNOOC: well 21/2-10, Saracen prospect

3.64. Nexen-CNOOC: well 28/5a-6, Porcupine prospect

3.65. Nexen-CNOOC: well 39/1b-3, Edgware prospect

3.66. Perenco: well 21/30-25, Spitfire prospect……………………………………………………129

3.67. OilExco Operator, (Premier Oil current well owner): well 14/21a-1, Halibut prospect…..131

3.68. OilExco Operator, (Premier Oil current well owner): well 14/28a-5, Laurel Valley prospect

3.69. Premier Oil: well 15/24c-10, Bluebell prospect

3.70. OilExco Operator, (Premier Oil current well owner): well 15/25b-7, Sheryl prospect

3.71. OilExco Operator, (Premier Oil current well owner): well 15/25b-7Z, “Sheryl 2nd target”

3.72. OilExco Operator, (Premier Oil current well owner): well 15/25c-14, Joy prospect

3.73. Apache Operator, (Premier Oil current well owner): well 18/5-2, Golden Arrow prospect

3.74. Premier Oil: well 20/10b-5, Criollo prospect

3.75. OilExco Operator, (Premier Oil current well owner): well 21/04b-6, Muness prospect

3.76. Premier Oil: well 21/6a-7, Palomino prospect

3.77. Premier Oil: well 21/7b-4, Cyclone prospect

3.78. Premier Oil / OilExco: wells 21/23a-10 & -10Z, Constance prospect

3.79. OilExco Operator, (Premier Oil current well owner): wells 22/13b-7, Coronado prospect & 22/13b-7Z, Morro prospect

3.80. Premier Oil: well 22/19c-6, Oates prospect

3.81. Premier Oil: well 28/10a-3, Coaster prospect

3.82. OilExco Operator, (Premier Oil current well owner): wells 29/6b-7 & -7Z, Danica prospect

3.83. Premier Oil: well 39/2c-5, Peveril prospect

3.84. Shell: well 22/12a-11, Stavro prospect…………………………………………………………159

3.85. Shell: well 29/10-7, Quasimodo prospect

3.86. OilExco Operator, (Sterling Resources current well owner): well 21/23a-8, prospect Disraeli, Eocene Tay segment……………………………………………………………………163

3.87. OilExco Operator, (Sterling Resources current well owner): well 21/23a-8, prospect Disraeli, Upper Jurassic Fulmar segment

3.88. Talisman-Sinopec: well 13/29b-9, Skate prospect…………………………………………..166
3.89. Talisman-Sinopec: well 14/18a-14, Dunnottar prospect
3.90. Talisman-Sinopec: well 14/20b-32, Cardhu prospect
3.91. Talisman-Sinopec: well 14/25a-6A, MacDonald prospect
3.92. Talisman-Sinopec: well 15/17-27, North Saltire prospect
3.93. Talisman-Sinopec: well 20/05c-11, Sligachan prospect
3.94. Talisman-Sinopec: well 30/13-8, Jenny prospect
3.95. Talisman-Sinopec: well 30/17b-16, Eta 2 prospect
3.96. Total: well 30/1c-9, Kessog discovery……………………………………………………..180
3.97. Wintershall: well 20/2b-10, Volante prospect……………………………………………..183
4. Reasons for Failure.. ..……..186
4.1. Tertiary Plays……………………………………………………………………………..186
4.2. Upper Jurassic Plays - Interpod settings…………………………………………………187
4.3. Upper Jurassic Plays - Deep water turbidites……………………………………………188
5. Interpretation Pitfalls.. 190
6. Conclusions - Recommendations 197

List of Figures 201
List of Appendices.. 208

Executive summary

The recently created Oil & Gas Authority (OGA) which took over from the UK Department of Energy and Climate Change (DECC) carried out post well analyses of Exploration and Appraisal wells drilled during 2003-2013 in the Moray Firth and the UK Central North Sea. Wells fall into three categories: dry, technical success, and commercial success. The project focused on the first two categories.

The CNS / MF Well Failure analysis was the first key project undertaken under the 21st Century Exploration Road Map, a project first recommended by the Exploration Task Force, aligned with the Wood Review.

This first piece of work was sponsored entirely by DECC / OGA and initial findings were presented to the industry at the O&GUK Exploration Conference “Pitfalls, Peaks and Progress” on February the 5th, 2015 in London. A second talk presenting more comprehensive results was given at the Oil and Gas Industry Conference held in Aberdeen (17th-18th June 2015). The final results were presented at the 8th Petroleum Geology of Northwest Europe conference held in London from the 28th to the 30th September 2015 and then at a PESGB evening lecture in Aberdeen on the 20th October 2015.

The Project objectives were to:

- Fully understand the reasons why a prospect was drilled i.e. understanding its geological and petroleum settings,
- Understand the reasons for success and failure during exploration in the Moray Firth (MF) and the Central North Sea (CNS) between 2003 and 2013,
- Share the main findings with the Industry,
- Test the “Collaborative Model” recommended by Sir Ian Wood.

150 exploration and appraisal wells, plus exploration side-tracks were drilled between 2003 and 2013 by 42 Operating Companies. 98 wells, currently owned by 24 companies, were reviewed in this study.

Although this study was mostly devoted to understanding dry holes and a few technical successes, one must keep in mind that over the 2003 – 2013 period, the overall technical success in the Moray Firth and Central North Sea amounted to 40%. However, there are many more lessons to be learned from wells where results did not meet expectations than from positive wells where the outcomes were within the pre-drill expected ranges.

The project comprised 4 main stages.

1. Selecting the wells to be reviewed, establishing the template of a Post Well Analysis Sheet (PWAS), data gathering plus summarizing the main results of each well analysis, and sending invitation letters to the current well owners. When a well targeted a single objective (= segment) or when information was only available for the main objective a single PWAS was established and recorded under the well number and prospect name. Some wells targeted more than one objective: in such cases, a dedicated PWAS was built for each documented segment, all being recorded under the same prospect name and well number. The project tried and analysed each separate objective.
2. One-to-one workshops with each company currently owning the studied wells to compare the pre-drill prospect description with well results and subsequent interpretations in order to understand and agree the main reasons for well failure.
3. Three multi-company workshops pulled together companies, who have drilled the same petroleum play in the same geological basin / entity, to openly share their understanding of the main reasons for failure through the presentation of selected case histories.
4. Writing of the report and presentation of the results during September / October 2015.

Executive summary

After analysing 104 segments belonging to 97 wells, the following should be highlighted:

- 33% of these segments have been drilled because of a perceived Direct Hydrocarbon Indicator ("DHI"),
- 39% of the well failures were due to three clear causes,
- Even more strikingly, 36% of the main pre-drill risk was not accurately predicted,
- The reasons for failure were distributed as follows: Seal = 38%, Trap = 28 %, Reservoir = 17%, Charge = 14%.

The overall main reason for failure was the lack of lateral seal (27%) followed by the absence of target reservoir (23%) and the lack of trap (17%). The reasons can be further analysed by stratigraphy:

- Tertiary plays: when looking at prospects that are solely dependent on AVO it is necessary to produce and risk the geological model unsupported by AVO. Does the play make sense without AVO support?
- Upper Jurassic Fulmar Formation: in an inter-pod setting, a common cause for failure is the lack of effective migration pathway.
- Upper Jurassic deep water turbidites: the lack of lateral seal is the main reason for failure (39%).

12.6% of the analysed segments failed for 1 clear reason (eg. absence of target reservoir): in these cases, only the drill bit could check and test the segment. Almost half of the reviewed segments were dry because of 2 main reasons. There are still a resounding 38.8% which failed for of 3 main reasons: in these cases, either the prospect was not ready to drill, or one can wonder why the decision was made to drill despite multiple risks in a mature well calibrated play.

Some of the common pitfalls in interpretation are highlighted below:

- Maps are cut short: this does not allow an optimal understanding of the trap and a proper focus on the main weak points of a prospect,
- Seismic picking is questionable: this highlights the need to improve the Quality Control of the interpretations. There is probably a real need for additional skilled advice (Peer review?) before validating an interpretation,
- Charge issues are involved in 1 in 7 well failures, neglecting the nature of the inferred carrier beds, overlooking the potential sourcing pathways and sometimes downplaying the effect the kitchen geometry will have on effective drainage towards the prospect,
- Underestimation of the physical content of the seismic response is a common problem. Seismic data must be properly processed prior to any AVO study,
- What could be called "cognitive bias" lead to a flurry of dry exploration wells being drilled immediately after some discoveries were made (Buzzard, Golden Eagle…etc…). This translated into a too fast move to drill what was deemed to be an analogue amplitude feature / an analogue stratigraphic trap without carrying out a detailed prospect assessment.

As stated by Charles Stabell (*Geoknowledge A.S.*), "making accurate and unbiased prospect assessment is challenging. So is measuring assessment performance. Systematic tracking of Exploration results relative to pre-drill predictions is critical for improving both Assessment Performance and Exploration decisions. All efforts that can assist in delivering accurate, un-biased and consistent assessment will ultimately enhance company exploration performance."

As a consequence, Post Well Analysis must be part of the full circle Quality Control process to be applied to the prospect assessment. It is expected that sharing the findings of this post well analysis project within the industry will help nurturing an Exploration revival across the UKCS and will be the first step to improve future Exploration results.

1. Project Overview

1.1. Project Objectives

The recently created Oil & Gas Authority (OGA) which took over from the UK Department of Energy and Climate Change (DECC) carried out post well analyses of exploration wells drilled during 2003-2013 in the Moray Firth (MF, **Fig. 1**) and the UK Central North Sea (CNS, **Fig. 2**). Wells fall into three categories: dry, technical success, and commercial success. The project focused on the first two categories.

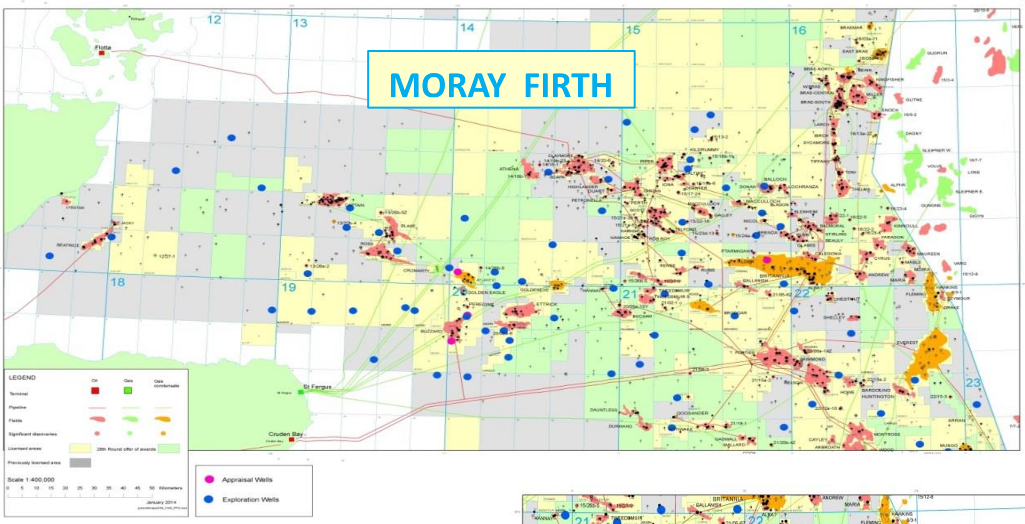


Fig. 1 - Moray Firth E&A wells analysed

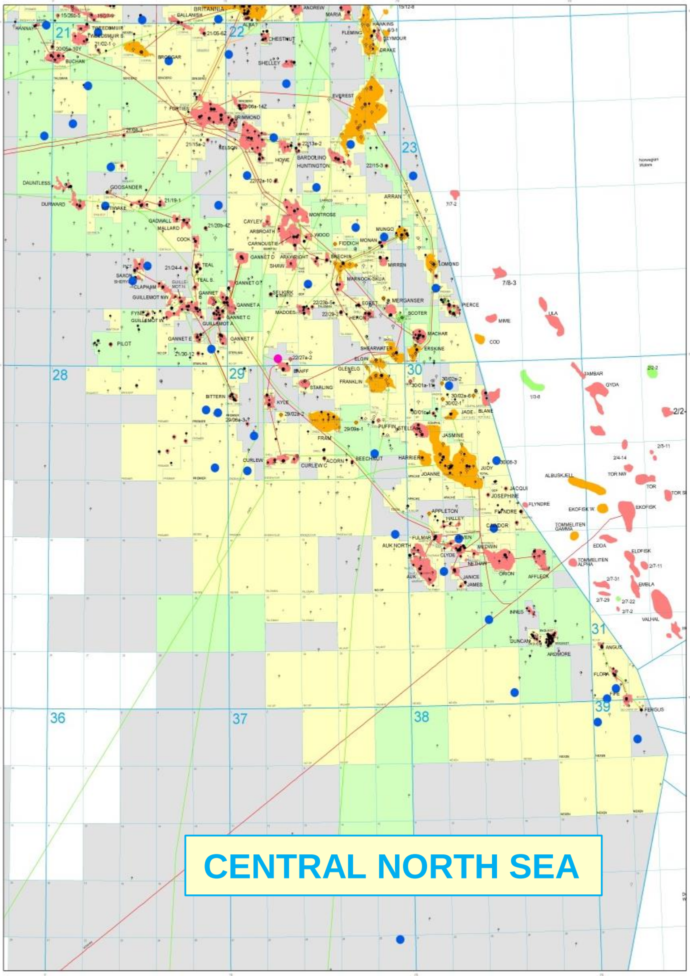


Fig. 2 - Central North Sea E&A wells analysed

The CNS / MF Well Failure analysis was the first key project being undertaken under the 21st Century Exploration Road Map, a project first recommended by the Exploration Task Force, aligned with the Wood Review.

This first piece of work was sponsored entirely by DECC / OGA.

150 Exploration main bores + Exploration Side-tracks have been drilled between 2003 and 2013 in the MF and CNS by 42 Operating Companies. 98 wells, currently owned by 24 companies (ref. Appendix 1), have been reviewed.

The Project objectives were:

- Fully understand the reasons why a prospect was drilled i.e. understanding its geological and petroleum settings,
- Understand the reasons for success and failure in dur9ng exploration in the Moray Firth (MF) and the Central North Sea (CNS) between 2003 and 2013,
- Share the main findings with the Industry,
- Test the “Collaborative Model” recommended by Sir Ian Wood.

1.2. Time Line

The project time line consisted of 4 main stages as shown on **figure 3**.

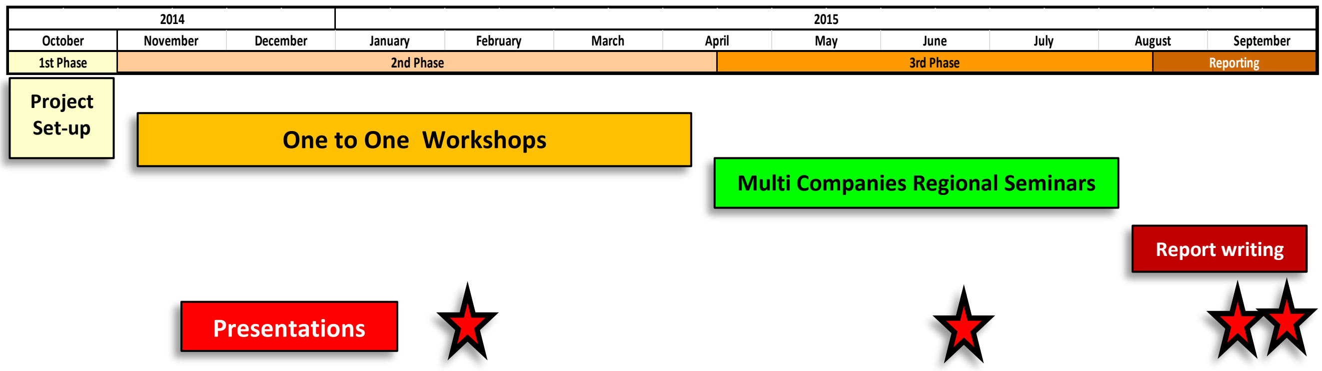


Fig. 3 - Project time line

The first stage involved selecting the wells to be reviewed, establishing the template of a Post Well Analysis Sheet (**ref. chapter 1.3, Appendix 1**) in order to gather data and summarize the main results of each well analysis, and sending invitation letters to the current well owners.

The second stage comprised one-to-one workshops with each company to compare the pre-drill prospect description with well results and subsequent interpretations in order to understand and agree the main reasons for well failure. Twenty two such workshops were held allowing for detailed prospect analysis through power point presentations followed by open discussions; in some cases this was followed by a review of the seismic data (**Appendix 2)**. For 2 companies (Premier Oil and Wintershall) power point presentations, well logs and reports have been shared via e-mail or ftp servers. Finally, valuable data about wells drilled by companies either having exited the UKCS or being bankrupted, was gained thanks to Centrica Energy, Faeroe Petroleum, Ikon Science and Trap Oil. The complete listing of the reviewed wells can be found in **Appendix 3**

The third phase comprised 3 multi-companies workshops which pulled together companies who have drilled the same petroleum play in the same geological basin / entity in order to openly share their understanding of the main reasons for failure through the presentation of selected case histories. These meetings were hosted by Oil & Gas UK and simultaneously run from their Aberdeen and London offices thanks to an efficient video link.

- Workshop 1 (16th of June 2015) focussed on Tertiary Plays (Eocene-Palaeocene) in the Central North Sea: 6 wells owned by 6 companies were presented to 20 participants.

- Workshop 2 (29th of June 2015) focussed on various pre-Base Cretaceous Unconformity (BCU) Plays (Jurassic to Devonian) in the CNS: 7 wells owned by 7 companies were presented to 34 participants.
- Workshop 3 (9th of July 2015) focussed on Cretaceous Plays in the Moray Firth: 7 wells owned by 5 companies were presented to 18 participants.

All three workshop agendas are included in **Appendix 4** while the corresponding attendee lists are presented in **Appendix 5**.

A number of talks were delivered during the project in order to share the main findings across the industry. Initial findings were presented to the industry at the O&GUK Exploration Conference "Pitfalls, Peaks and Progress" on February the 5th, 2015 in London. A second talk, presenting more comprehensive results, was given at the O&G Industry Conference in Aberdeen (17th-18th June 2015). The final results were presented at the 8th Petroleum Geology Conference held in London from the 28th to the 30th September 2015 and then at a PESGB evening lecture in Aberdeen on the 20th October 2015.

Finally, this report will be made available to the industry following permission to publish from the owning companies.

1.3. The Post Well Analysis Sheet

98 Exploration and Appraisal wells were reviewed throughout the project. Most of these wells explored a single objective (= segment) but a few explored 2 or more superimposed objectives. When a well targeted a single objective or when information was only available for the main objective a single PWAS was established and recorded under the well number and prospect name. Some wells targeted more than one objective: in such cases, a dedicated PWAS was built for each documented segment, all being recorded under the same prospect name and well number. The total of analysed segments (exploration and appraisal) amounts to 104. Only one well drilled by Oilexco (15/25c-14, Joy) could not be analysed because of the loss of relevant data over time.

A dedicated template was designed to gather the main data pertaining to each segment allowing a straightforward comparison between its pre-drill geological description and the actual well result.

This template, so called "Post Well Analysis Sheet" (PWAS, **Appendix 1**) is divided into 6 sections.

The upper horizontal section shows general data about the well such as well operator; well name; well category well TD and geological formation reached at total depth; number of targeted segments; name, play type, inferred source rock, trap type and overall Chance of Success (CoS) of the analysed segment.

The left hand side vertical section summarises the pre-drill geological segment description going through the source rock, the hydrocarbon (HC) migration pathways and timing of HC expulsion, the reservoir properties, the trap geometry and the expected seal. When available, the individual risking of each of these parameters is noted. This section also displays the nature of the expected hydrocarbons, the in-place volumes and corresponding resources. Finally, information about any potential Direct Hydrocarbon Indicator (DHI) is also reported in this section.

The adjacent section to the right hand side of the sheet summarises the well results in the same order. This allows a quick and easy colour coded comparison to be made in the next vertical section on the extreme right hand side of the PWAS. Highlighting those parameters which were correctly forecasted in green, those wrongly forecasted in red and those where the results are unclear / unresolved in amber.

At the bottom of the sheet, a horizontal section shows which seismic data set was used to define the prospective segment and which reports / data have been made available to make the segment analysis both pre-drill and post-drill.

Finally, the 6th section at the very bottom of the PWAS shows the main differences between post-drill results and pre-drill expectations, the inferred reasons to explain these differences and finally what could / should have been done differently?

2. Statistics

2.1. Setting the Scene

One hundred and four (104) segments have been analysed (ref. **Appendix 3**), corresponding to 97 wells: well 15/25c-14 drilled by Oilexco could not be reviewed because both pre and post drill data were lacking. Amongst the 104 studied segments there were 9 cases where it was not possible to find the overall Chance of Success (CoS) and/or the corresponding detailed risking assessment.

More than 90% segments were Exploration segments: 93% Exploration wells – 7% Appraisal wells. 33% were firm commitment wells. 5 were contingent wells and 6 'Drill or Drop'; all others were non-obligation wells.

Almost two-third (62.5 %) of these segments belong to post 20th Round licenses while 28.8 % were drilled on licenses awarded during the Rounds 1 to 7.

90% of the segments (90.4%) were dry holes; 8.6% Technical successes; 1% Commercial success.

It's worth highlighting that one third (32.7 %) of the 104 analysed segments have been drilled because of some sort of Direct Hydrocarbon Indicator ("DHI"): AVO (Amplitude Versus Offset), amplitude, gas cloud, "impedance indicator"…etc…

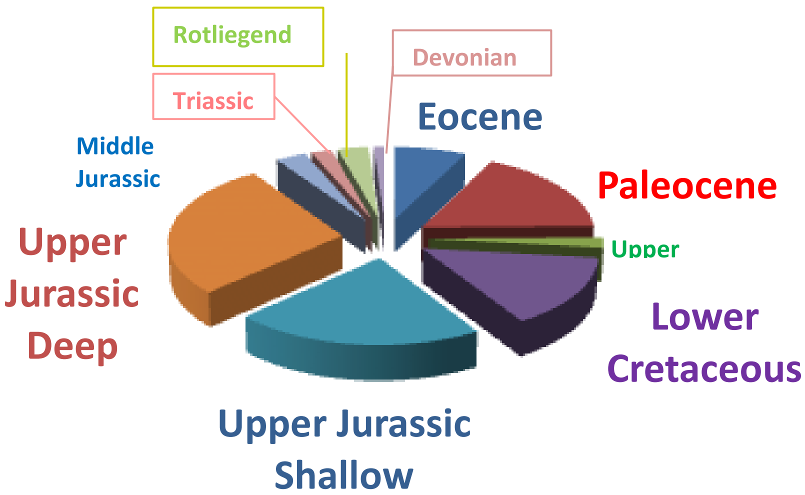
- 41.2% were perceived as AVO supported,
- 35.3% were simply amplitude supported,
- 14.7% were interpreted as having some other form of DHI, such as gas cloud, "Impedance indicator" etc…
- Last but not least, 3 segments exhibited negative pre-drill AVO response but have been drilled either because of commercial reasons or because they were commitment wells.

2.2. Targeted Objectives

The targeted objectives are distributed as follows (**Fig. 4**):

- 38 % above BCU with 23% targeting Tertiary Plays and 15.4% Cretaceous Plays,
- 56 % Jurassic with Upper Jurassic shallow marine and deep water turbidite accounting for 52.9% of the 104 analysed segments,
- 2 % Triassic,
- 4 % below Zechstein Salt (Rotliegendes and Devonian).

Fig. 4 - Distribution of Objectives



2.3. Trap Types

The distribution of trap types is as follows (**Fig. 5**) with 55% being stratigraphic traps and 45% being structural.

It must be noted that slightly more than one in four are pure structural traps (4-way dip closures or 3-way dip tilted fault blocks). The remaining structural traps are downthrown and require a key element of lateral fault sealing to be effective.

NB: the overall number of cases exceeds 104 because several traps are combined 4 way dip closure / stratigraphic trap (as an upside).

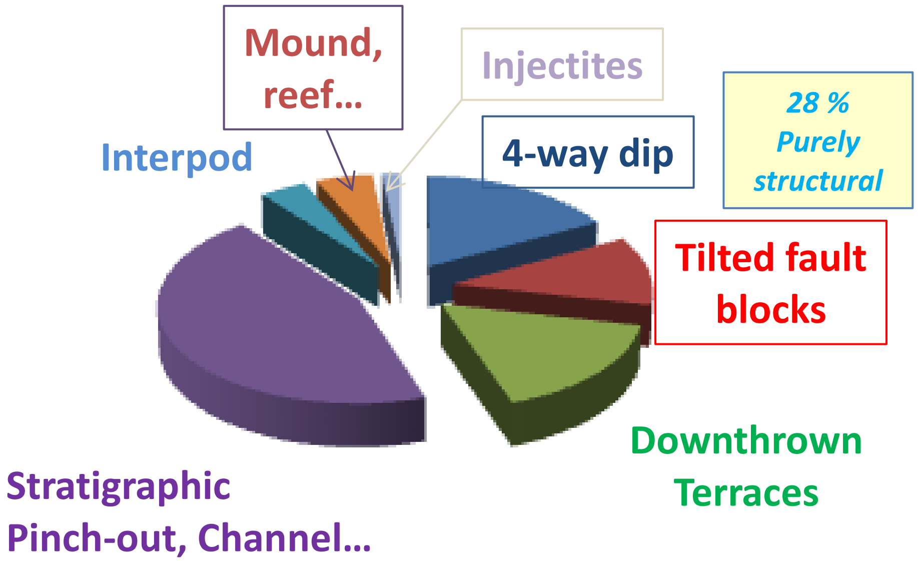


Fig. 5 – Distribution of Trap Types

2.4. Chance of Success (CoS)

Roughly one third (34%) of the 98 segments with available pre-drill risking fall within the 21 to 30% CoS, i.e. what you would expect in such mature Basins.

However, more than a third (40%) of these segments has CoS > 31%: this highlights a trend towards over-confidence in the risking assessment. This is happening in parallel with over confidence in estimating the expected resources size.

It must also be noted that the main risk was not adequately predicted in 36 % of the cases, meaning that the prospect pre-drill analysis was not good enough. This highlights the strong need for a compulsory post well analysis in order to improve the overall exploration results.

3. Well Analyses

Ahead of each workshop, all well data had been obtained and reviewed. These data came from the various data bases accessible in DECC (subsequently OGA). Pre-drill data was mostly found in the DECC consent system (WONS), but proved to be mostly sparse and not consistent: indeed some companies provide a comprehensive well location report which includes a detailed G&G prospect description as well as the well architecture and drilling details, while most others offer the bare minimum (2 cross sections, a map and 1 well prognosis!). Some information was also gleaned amidst the presentations delivered during the so called annual "Fallow Reviews".

Regarding the post-drill data, the vast majority was found via CDA (www.ukoilandgasdata.com): it mainly consisted of logs and reports. Some other relevant information has been gathered either from the Relinquishment Reports or various other folders available to DECC / OGA.

As a result, in order to get a more in-depth insight and to access both the regional context and the seismic data, appointments were made with the owning companies (**Appendix 2**). In most cases the meetings were welcomed and frank and open reviews took place for all the selected wells.

Amongst the owning companies, only one could not be reached, Bridge Resources. Indeed this company had left the UKCS and nobody from the Canadian parent company replied to e-mails or letters. However access to valuable information was finally given by John Clure, former Managing Director of ICENI.

Each well review has been summarised by filling one "Post Well Analysis Sheet" (PWAS, ref. **Appendix 1**, **Chapter 1.3**) per drilled segment. Indeed a few wells have drilled several segments. All completed PWAS are included in **Appendix 6**.

Each segment will be briefly discussed in this chapter ordered by present day owning company (in alphabetical order and then by increasing well number).

3.1. Apache North Sea: well 22/07-4, TEP 3 prospect

The TEP3 well was part of a campaign to drill three wells on Shell operated blocks to satisfy farm-in obligations. The 22/7-TEP3 well targeted a small 4 way dip closed structure at Top Forties (**Figs. 6 & 7**). Stratigraphic trapping was seen as potentially providing an upside. The primary target was the Forties Sandstone and secondary targets were defined through the Palaeocene clastic section and in the Chalk. There are many discoveries showing a similar setting i.e. beneath the regional Sele Fm. seal and within the Forties Sandstone system. Overall CoS was set at 36% with effective migration pathway being the main risk: indeed less than 1 out of 10 apparently valid Palaeocene closures have succeeded in the area to the NE of the Forties-Montrose High. No shows in wells 22/7-1 and 22/7-2 suggest that migration may have by-passed the prospect. An additional minor risk (P seal = 90%) was interpreted because of possible leakage into overlying Eocene sandstones as is the case in well 22/2-4.

A thick water bearing Forties reservoir was found deeper than predicted and outside of the uncertainty range.

The main reasons for failure are not clearly understood: is it because the TEP 3 prospect was located in a migration shadow? Is it because of a Time/Depth conversion issue? It must also be underlined that there was no AVO anomaly over this feature although AVO tends to highlight hydrocarbon presence in the Palaeocene.

<u>Company perspective main lessons learned:</u>

- The available limited 3D PGS Megamerge did not allow discriminating hydrocarbon presence. Would a new 3D acquisition and associated detailed rock physics modelling have prevented drilling this prospect?

- Would a detailed pre-drill Basin modelling have led to a better understanding of the migration differences between success (shows in 22/3-1) and failure (no shows in wells 22/7-1 and -2) and the corresponding complex migration pathways?
- No clear technical lesson can be learned from this 10 years old case study but it's pretty clear that the corporate knowledge must be better stored and easier to share across the successive generations of geoscientists if one wants to learn from past mistakes and improve exploration performance.
- Well 22/7-4 found 1m of gas pay in a Pleistocene sand (Crenulate): this lead to the Aviat discovery where the sand developed from the 1m in 22/7-4 to about 7m in the Aviat field.

OGA perspective:

- OGA must improve the way it collects stores and protects all well data information pertaining to the UKCS. Indeed, for this particular well there are only 23 items available in CDA: mostly logs, the composite well log and a sixteen (16) pages "Geological End of Well Report" written by a contractor. This is clearly not sufficient to adequately understand the G&G prospect description (indeed there is no "Well Location Report") and carry out a decent post well analysis.

Fig. 6 - Prospect TEP3 Top Forties Depth Structure Map

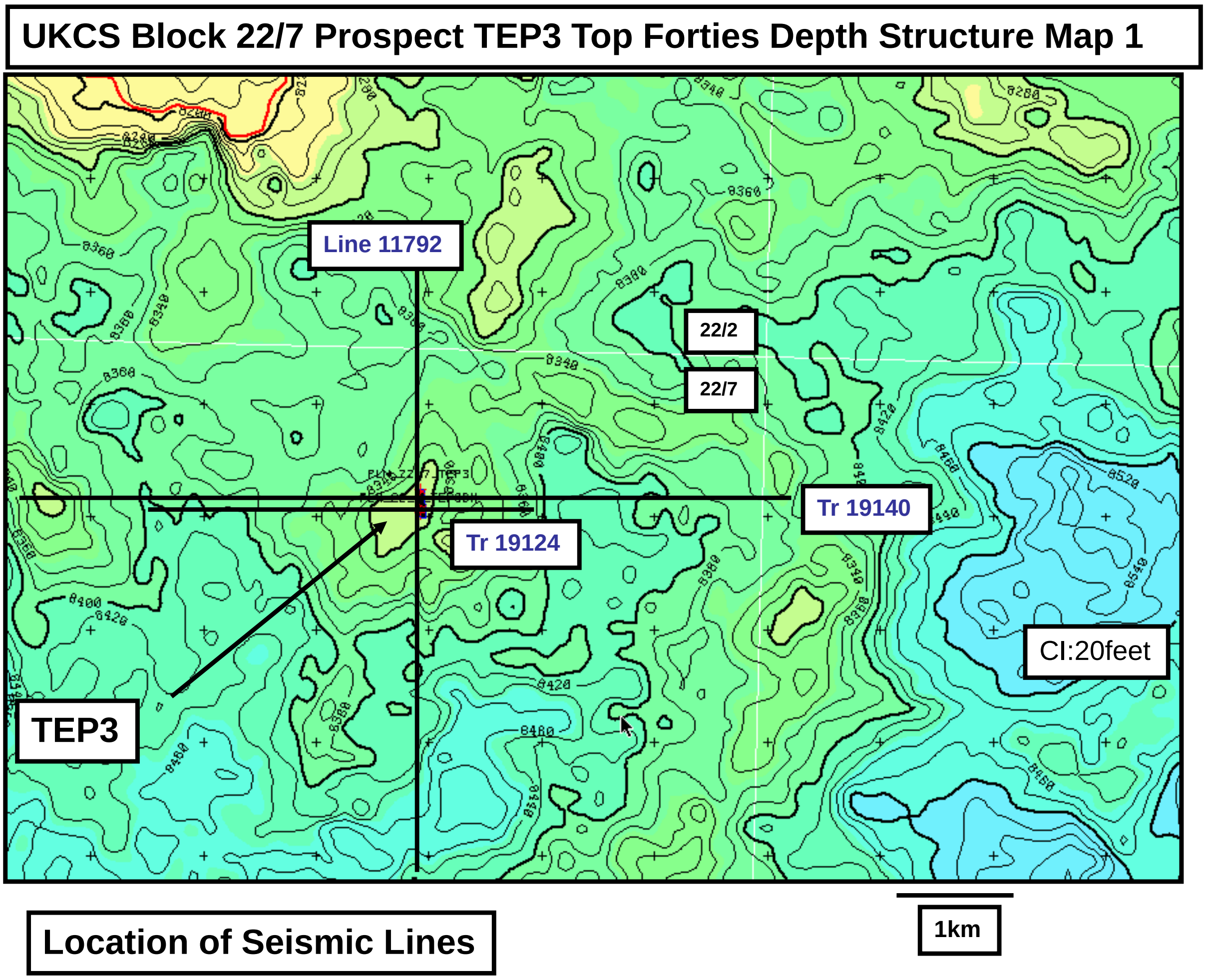
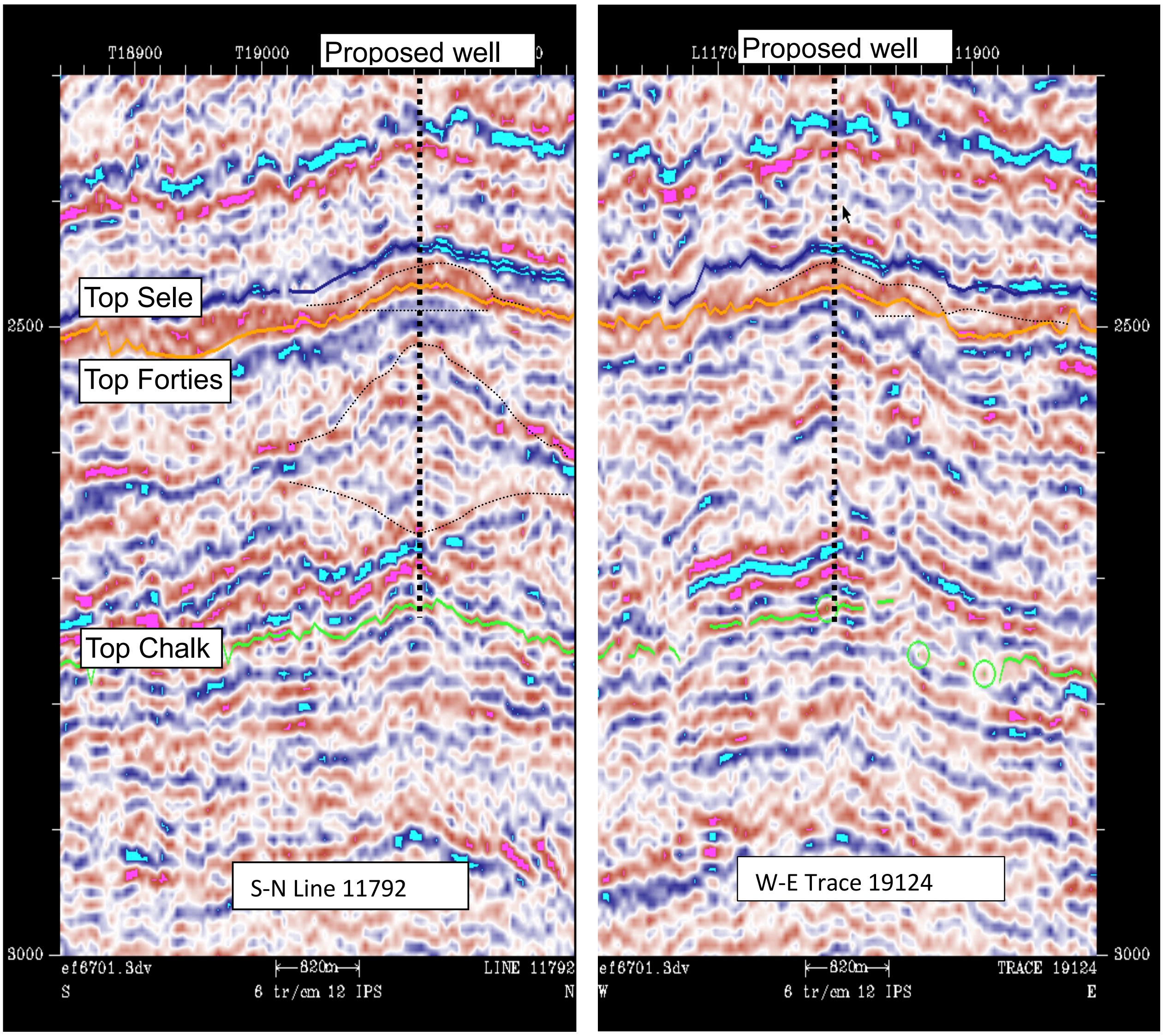


Fig. 7 - Line 11792 and Trace 19124 from the PGS megamerge detailing approximate planned position of the 22/7_TEP3 exploration well.



(Data courtesy of PGS)

3.2. BG: 13/22c-30, Hermes prospect

This 21st Round prospect was defined as a stratigraphic trap targeting Upper Jurassic Ettrick "B" and "A" sandstones pinching-out to the east, south and west and dip closed to the North and was a 52-day well drilled in 2006. The Hermes prospect was located between the Captain Field to the North, the Ross Field to the south and the Blake Field to the east in a fairly prolific area of the Moray Firth Basin.

The lateral up dip sealing was recognised as the main pre-drill risk and it was deemed that lateral pinch-out into Kimmeridge Clay Formation (KCF shales) should provide good lateral seal. Despite thin stringers corresponding to distal turbidites being possibly present in the westerly well 13/21b-2, preferential cementation of thin sandstones was expected to afford sealing properties to distal turbidite facies. Although effective reservoir was proven in Phoenix gas discovery located ~ 2.5 km to north, a secondary risk was assessed regarding reservoir quality which may degrade closer to pinch-out. The overall CoS was set at 28%.

Sandstones came in as expected and reservoir quality was not an issue: indeed Ettrick B sand exhibit better quality than prognosed and better quality (less inter-bedded) than encountered at Phoenix. Although Hermes was considered (pre-drill) to be more proximal to the pinch-out edge, rapid degradation of the sandstones was not observed at the well location.

Hermes most likely failed due to trap effectiveness, which was considered the critical pre-drill risk. According to the immediate post-drill analysis, juxtaposition of overlying sandstones with the thicker than expected reservoir package was thought to be the probable cause of trap failure. However, following trade of 13/27a-4 Dee, the most likely failure cause appears to be the lack of pinch-out up-dip to the south and continuation of the sandstones into, and beyond the Dee prospect. Indeed well 13/27a-4 targeting the Dee prospect was drilled in 2005 but BG succeeded in trading this key well 1 year after. The 13/27a-4 found water wet massive reservoirs the same age as the Ettrick sandstones targeted in Hermes prospect.

Company perspective main lessons learned:

- The inversion volume, which was used to help with interpretation and determining the limit of the pinch out, was proven to not be totally reliable as it would have predicted poorer sand at Hermes than was encountered.
- When targeting pinch-out plays in turbidite systems, degradation of the reservoir is often predicted towards the pinch-out. This does not appear to be the case in Hermes, suggesting a more complex tectono-stratigraphic development that initially interpreted.

OGA perspective:

- This particular example underlines the fact that publication of a press release summarising the 13/27a-4 Dee well results immediately after it was completed (as per the Norwegian model), would most likely have impacted BG's interpretation of the Hermes prospect so that the well 13/22c-30 would not have been drilled.

Fig.8 – Hermes prospect, Top Ettrick "B" depth structure map

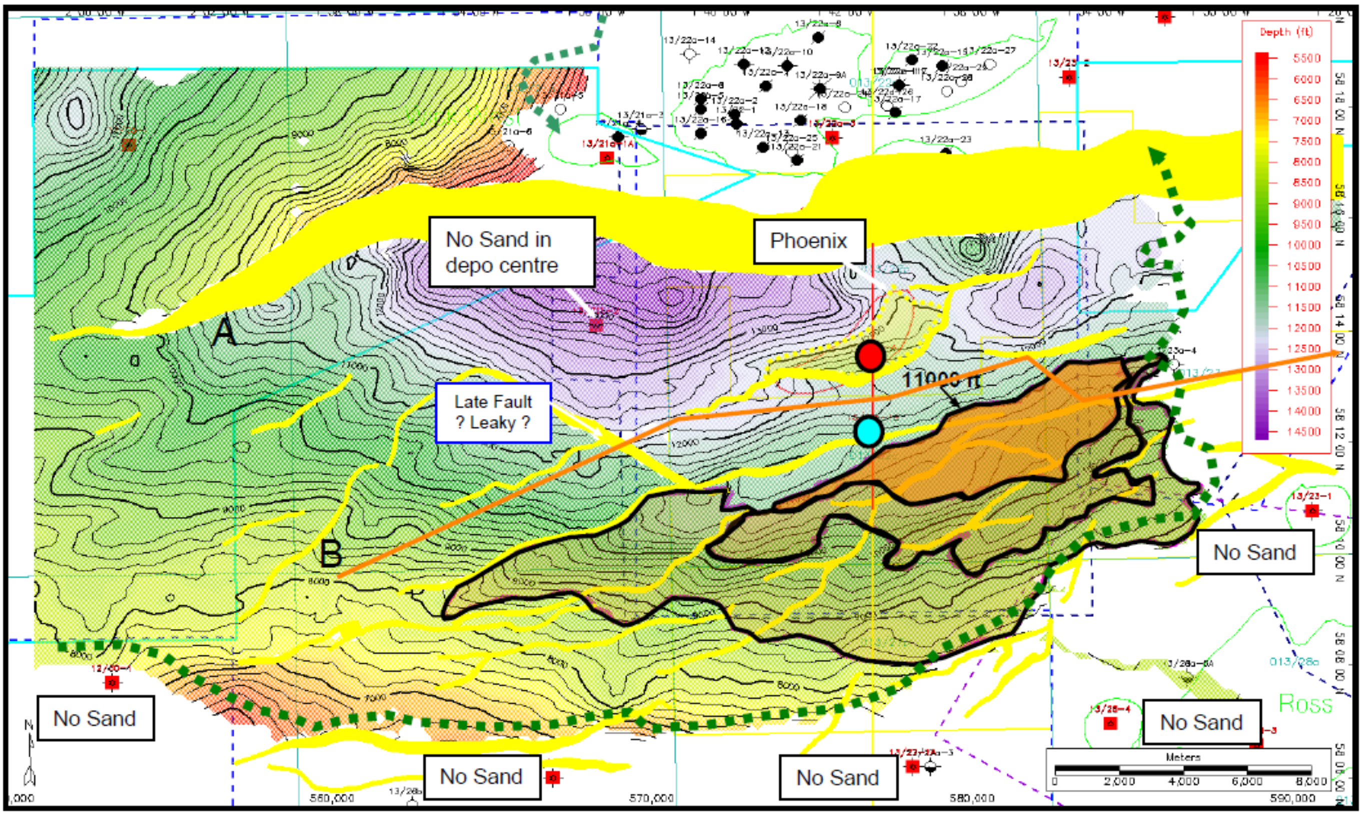
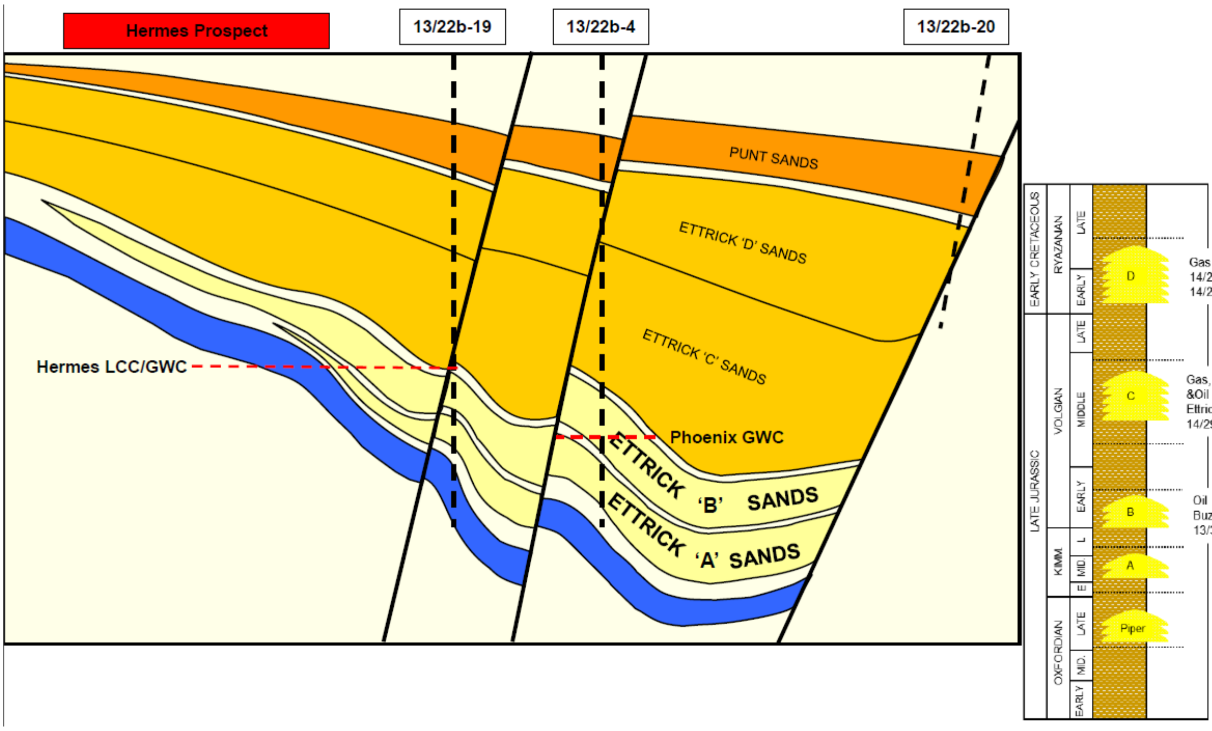


Fig. 9 - Hermes prospect schematic geological cross section



3.3. BG: 14/28b-4, Moonraker prospect

The Moonraker prospect lay in a hanging-wall wedge thinning and fining away from the main controlling fault segments adjacent to the southern boundary of the Halibut Horst and up dip from the water wet 14/28b-2 well that contained 350ft of sandstone with an average porosity of 17% dated from Jurassic Early Volgian (therefore Ettrick B equivalent). Two trapping scenarios were identified: either a single base-of-slope apron fan constrained model or, an amalgamated base-of-slope apron fan system up-side model.

The 31-day well was drilled in June 2006. The main pre-drill concern was the northerly up-dip seal which was interpreted either as stratigraphic or involving fault seal required against Halibut Horst bounding faults, hence the trap efficiency risk, set at 40%, was the major CoS risk element. The overall CoS was set at 20% (constrained case).

14/28b-4 main results are as follows: on the one hand, according to the Neutron-Density response, Top Captain Sand has 10ft of hydrocarbons (HCs) which is interpreted as residual (70% Sw) suggesting that HCs have migrated through. On the other hand, over 300ft gross section of good quality Ettrick sandstones without shows have been found in the target reservoir.

The main reason for failure was either fault seal failure or a top / lateral seal failure.

- Fault seal capacity of the Halibut Horst fault: in the constrained model the sand has either pinched out by the fault or is very thin but in the unconstrained model there would still be a significant thickness of sand at the main fault,
- Top / lateral seal failure: only relatively thin shale sections between Early Volgian (reservoir) sandstones and shallower Middle Volgian (Ettrick C), Late Volgian / Ryazanian (Ettrick D) and Lower Cretaceous (Punt) sandstones. If the younger sandstones are erosive / down-cutting there is potential for thief zones to exist causing the trap to fail.

Company perspective main lessons learned:

- Poor seismic data does not allow accurate mapping of the pinch-out / up-dip seal of the trap which means there will always be a residual high risk to the trap effectiveness.
- Poor seismic resolution prevents accurately picking the base of other potential sand units – therefore the potential for thief-zones is not quantifiable?
- There is so much sand in the system with Captain acting as a major drain. Fluid Inclusion Studies (FIS) of the Pre-Tertiary may help understand migration route and timing and flag breaches in the overburden if present? Additional FIS analysis of well sections (i.e. Chalk / Valhall) may identify breaches / thief zones.

OGA perspective:

- The quality of the available seismic data set was not good enough to accurately define this prospect. In this kind of situation, should there be any incentive to first improve the seismic quality (i.e. re-processing or new acquisition?) before any drilling decision is taken?

Fig. 10 a & b – Moonraker Prospect definition: map + NNW-SSE seismic section through well 14/28b-2

Fig. 10a

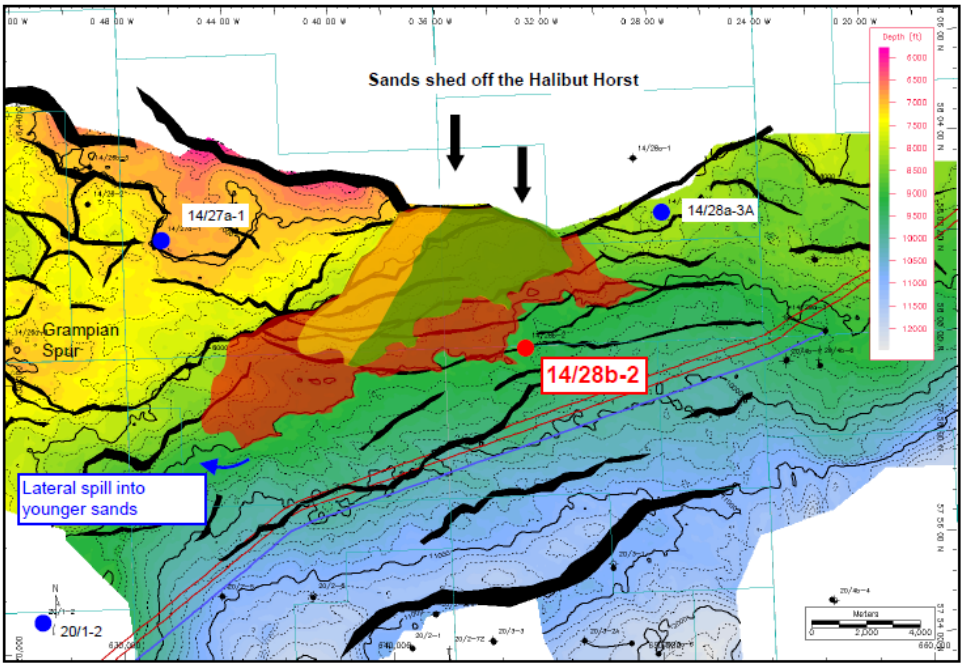


Fig. 10b (Shell proprietary data)

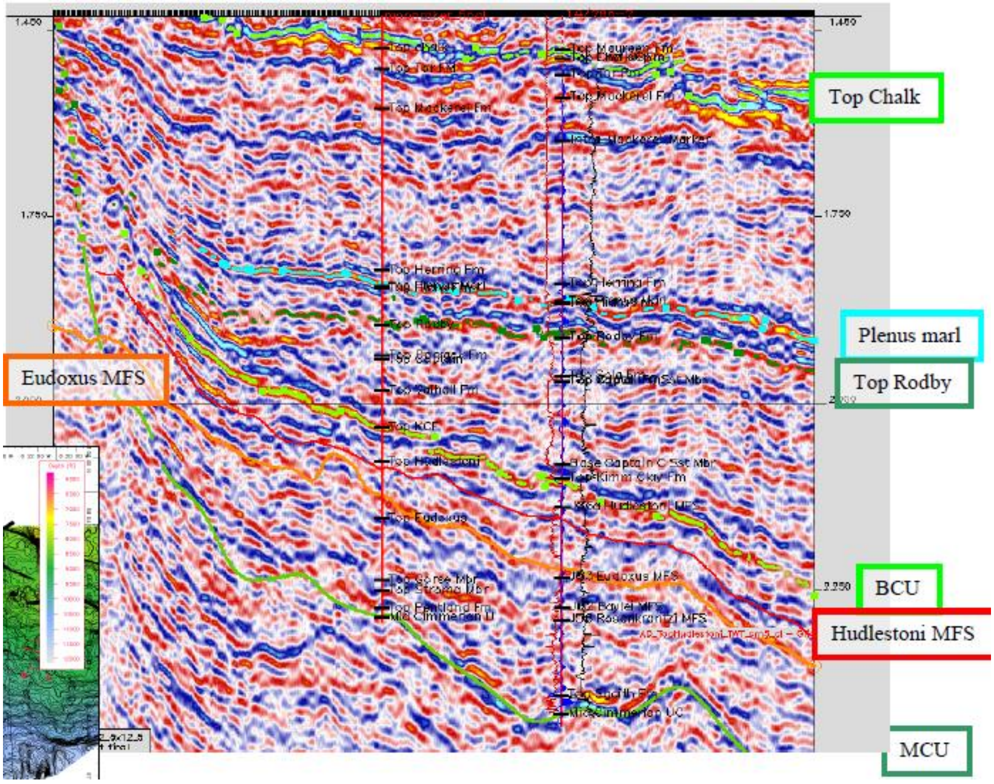
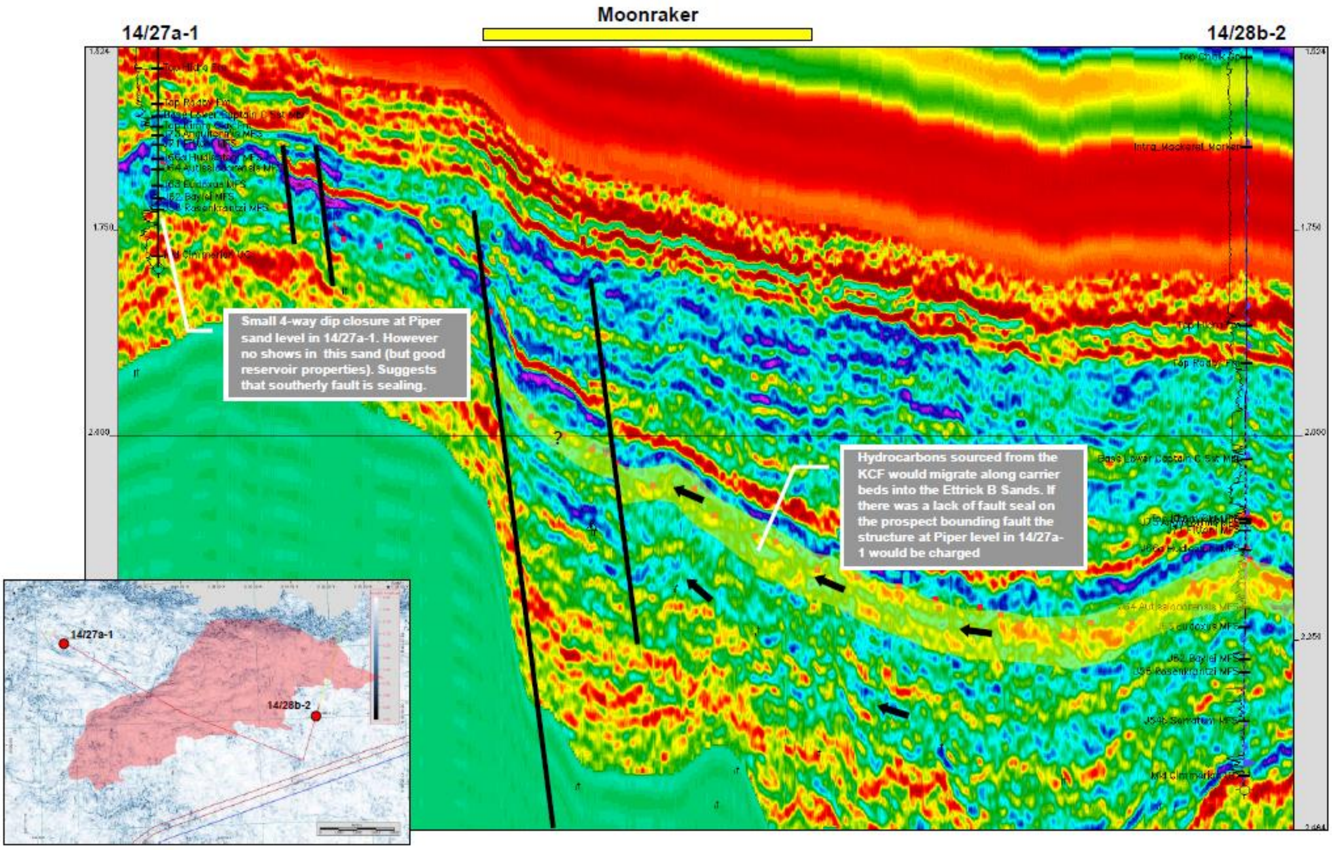


Fig. 11 - Evidence for fault seal (?) according to seismic inversion



3.4. BG: 22/14a-7, Mallory prospect

Regional mapping identified an intra-Triassic pod / Jurassic J54-J62 Fulmar Member shoreface sandstone play, to the south of Everest Field and potentially extending to the Huntington discovery southwest of Everest. The Mallory prospect corresponded to a complex stratigraphic trap with west, east & south stratigraphic seal against Smith Bank and Skagerrak Triassic Formation pods and dip closure to the north-west.

The Jurassic Kimmeridge Clay Formation source rock is deposited regionally and was interpreted to directly overlay the Fulmar reservoir. Offset Skagerrak wells 22/14b-3 & -4 are oil bearing. It was thought that the prospect may be locally oil sourced or may have an effective migration pathway from the Fisher Bank Basin.

Pre-drill, well 22/14a-7 was predicted to find HPHT reservoir conditions. The 71-day well was drilled during winter 2007-2008.

The pre-drill critical risks had been assessed as being trap effectiveness (60%) and reservoir effectiveness (65%) while the overall CoS was set at 24%.

It should also be noted that the recent success at Huntington Deep (Oilexco operator, well 22/14b-5) where BG had predicted KCF on Triassic gave encouragement for an extension of the sand play into 22/14. Oilexco farmed into the deep section of the Mallory well.

This prospect failed due to absence of Fulmar sandstone target reservoir. Indeed shales from the Heather Fm (Oxfordian) directly overlie thick water bearing Triassic Skagerrak Formation.

The post well FIS study showed oil inclusions in the Triassic, however, the tight nature of the Skagerrak prevents a clear understanding of trap integrity potential: is this a migration pathway only at Mallory?

Company perspective main lessons learned:

- Increased frequency range (broad band) with new seismic data would probably enable higher resolution. As a consequence, advanced seismic inversion (based on new broadband data) should help resolve sand vs shale.
- The mandatory core in this exploration well showed the sandstones to be Triassic not Jurassic. Consider coring / side wall coring if age of reservoir could be problematical.
- The Mallory Source Charge area included the prospect area: this mean that this self-sourcing capability may have led to a significant overestimation of the HCs available to the Mallory trap?
- Last but not least, the regional Fulmar geological model was updated pre-drill, still predicting Fulmar development at the well location although this turned out not to be the case. This demonstrates the difficulty in modelling / predicting reservoir presence in an extremely complex depositional setting with regional transgression overstepping a tectonically active and salt dominated region with localised fault blocks / grabens controlling bathymetry and depositional environment, further complicated by erosion / re-working.

OGA perspective:

- There is a need to plan well for optimal formation pressures (particularly by updating pressure cell dataset with recent well penetrations) but prepare a fall-back position for the worst case.

Fig 12 a & b - Mallory prospect summary: Top Fulmar depth map and SW-NE seismic line through well 22/14a-2

Fig. 12a

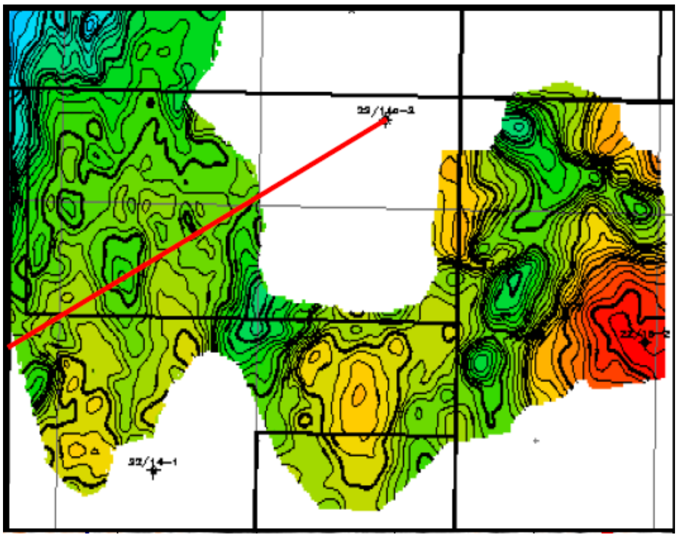


Fig. 12b (Data provenance uncertain, BG proprietary or PGS speculative)

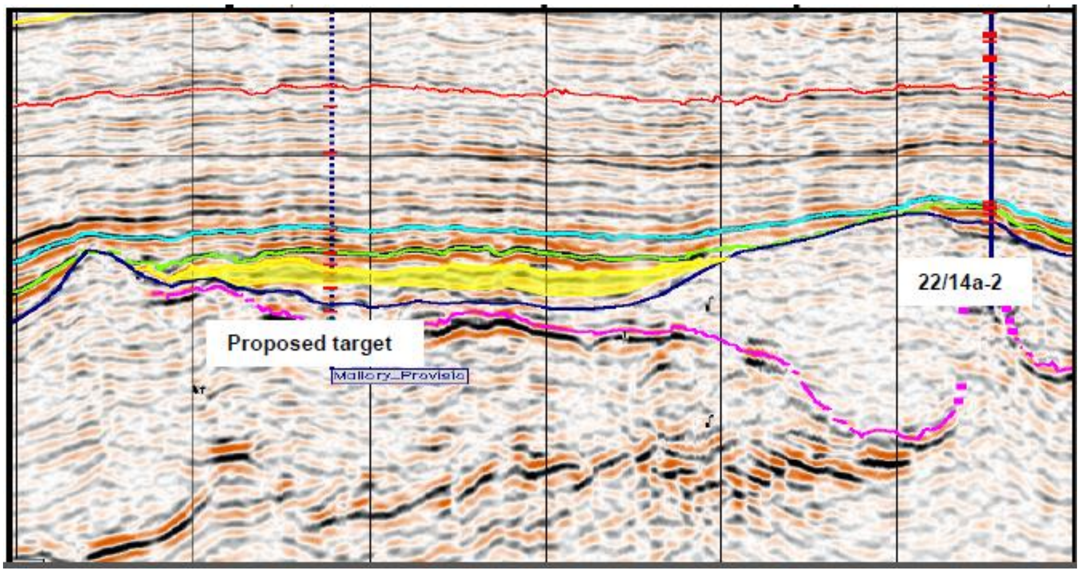


Fig 13 - 22/14a Mallory Prospect: NW-SE Seismic random line **(Data provenance uncertain, BG proprietary or PGS speculative)**

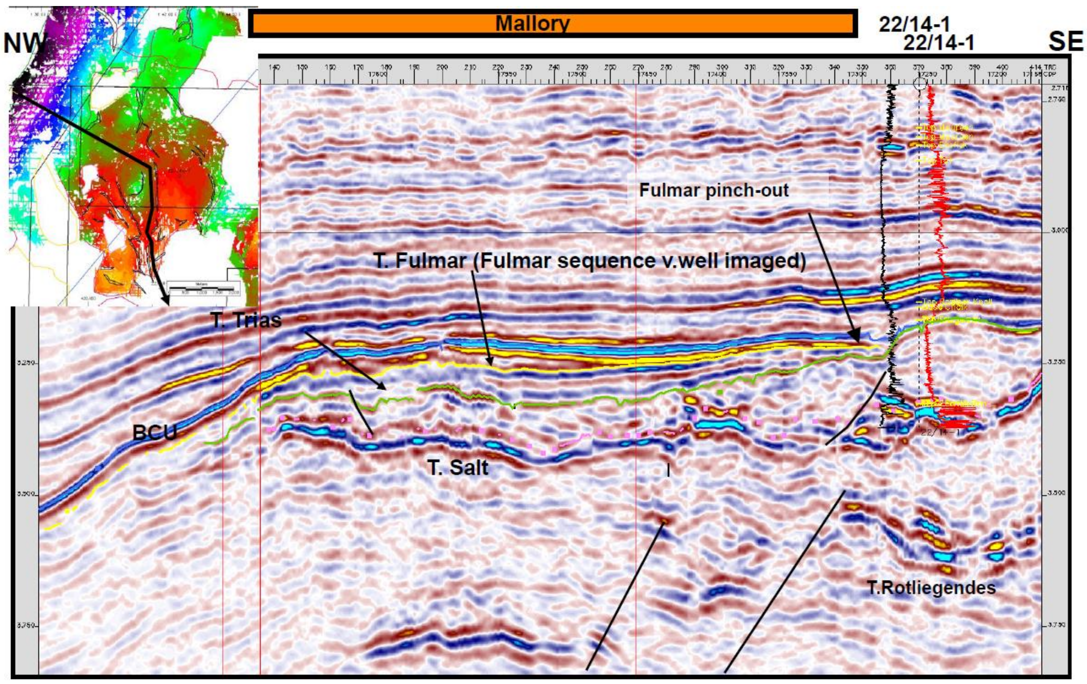
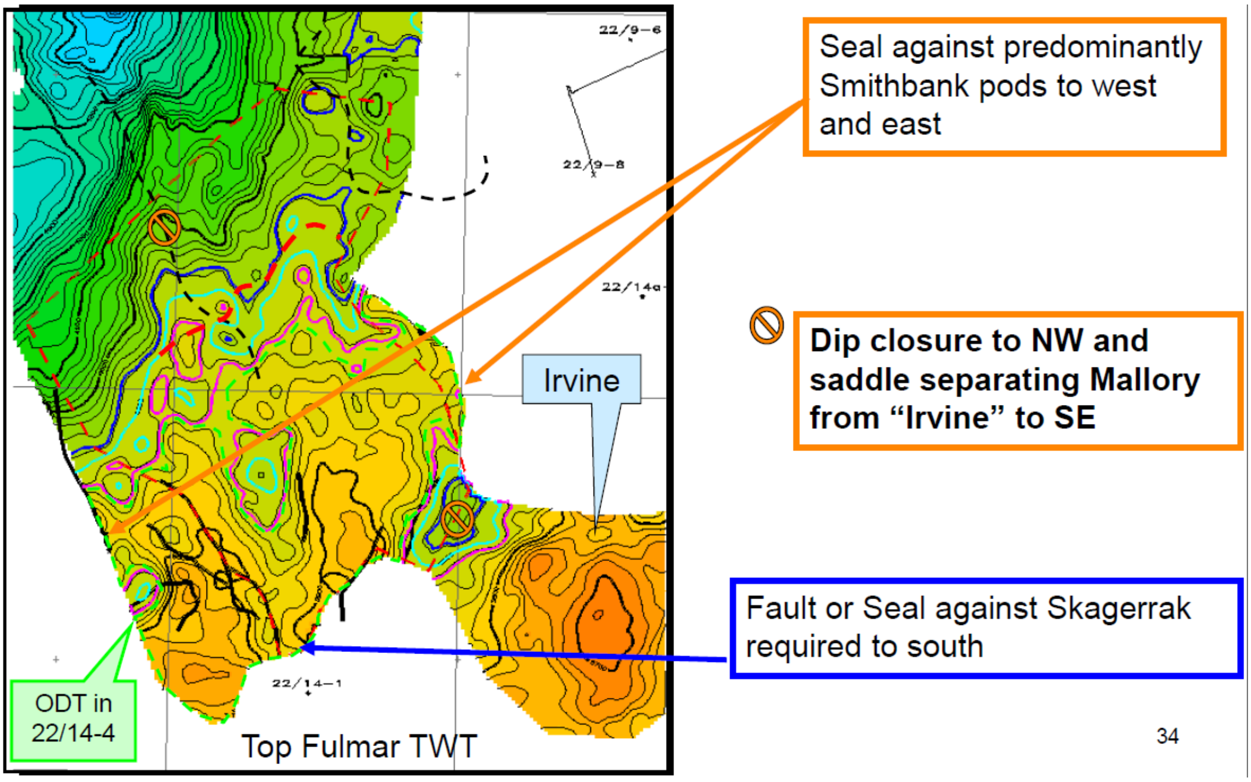


Fig 14 - Mallory: Trap effectiveness - Complex configuration



3.5. BG: 23/21-5, Toad prospect

Toad targeted a Palaeocene Forties channel system located to the south of the Lomond Field (Forties production) and situated on the eastern margin of the East Central Graben (**Figs 15a & b**). The 23/21-5 well targeted a number of stacked deep water turbidite channel sandstones at ~10,000ft identified on seismic attributes in a stratigraphic dominated trap with a suspected DHI. The trap was a stratigraphic channel pinch-out to north, east and south and dip-closure to west (**Fig. 16**). Reservoir was anticipated to be of similar quality to Columbus discovery located to the North of Lomond Field. Basin modelling identified the Kimmeridge Claystone Formation shales as the main source rock (type II oil prone source) and migration is assumed from offset East Central Graben kitchen area.

The Toad opportunity had been worked-up as similar to the neighbouring Serica operated Columbus discovery. BG produced two sets of risking parameters, one without taking into account any DHI (overall CoS = 9%), the other one acknowledging DHI support (overall CoS = 24%). In both scenarios, trap efficiency was the critical risk (40%) as there were fears about potential leakage. Rock physics modelling did not use results from water well 23/22a-4B. The 34-day well was drilled in February 20018. Overall the well confirmed reservoir prognosis (depth, thickness and quality) and found oil as predicted. However resources are markedly below the P90 pre-drill estimate resulting in an uncommercial discovery.

The regional mapping and geological model for the Forties turbidite system appear fit for purpose and the pre-drill top Forties seismic pick as well as its depth conversion are confirmed. Part of the pre-drill trapping model has worked: a producible HC accumulation has been discovered (gross column ~40 ft).

However the pre-drill rock physics modelling gave over confidence. The "cherry picking" of regional pressure trends resulted in an over optimistic Gross Rock Volume assumption. These two facts resulted in inadequate volumetric model range pre-drill.

The fill is likely constrained by seal integrity with the actual trap leaking as demonstrated by the Fluid Inclusion Study, which is a cheap and efficient tool.

Company perspective main lessons learned:

- Toad was a prospect volumetrically modelled on seismic attributes extracted from a quasi-regional study. At prospect level, without a well penetration the seismic model was un-calibrated and post-well proven to be not as robust as initially thought.
- The brine saturated sandstones in 23/16b-Z have similar density to the gas saturated sandstones of 23/21-T10.
  This highlights the variability of the rock physics properties of the Forties Formation.
- Pre-drill regional aquifer pressures / HC column heights and fluid types falsely gave additional belief that the pre-drill Toad volumes were valid.
- Toad is an oil accumulation trapped by an eastern stratigraphic margin and 3-way dip closed. In addition to a seal integrity issue, the fill may have also been constrained by source effectiveness?

Fig. 15a - Top Forties Formation Depth Map

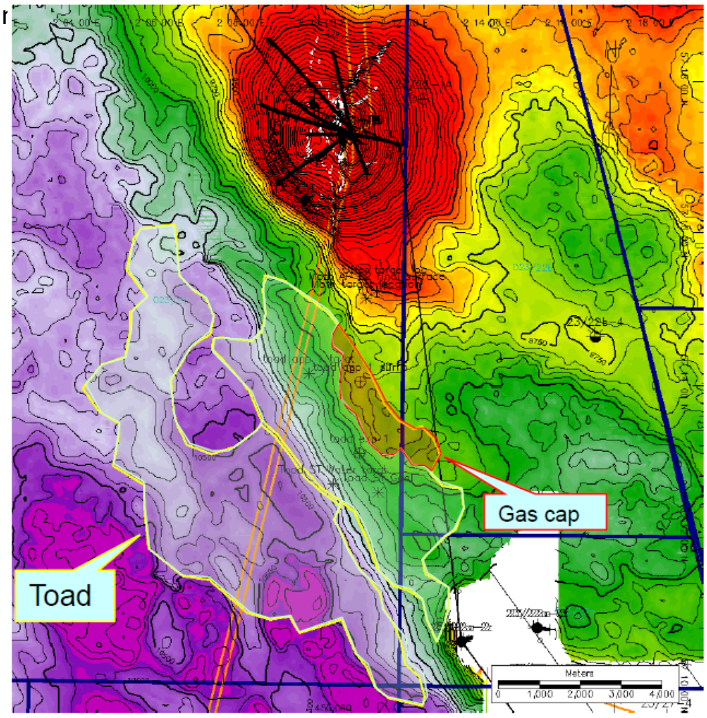


Fig.15b - Forties Formation time thickness

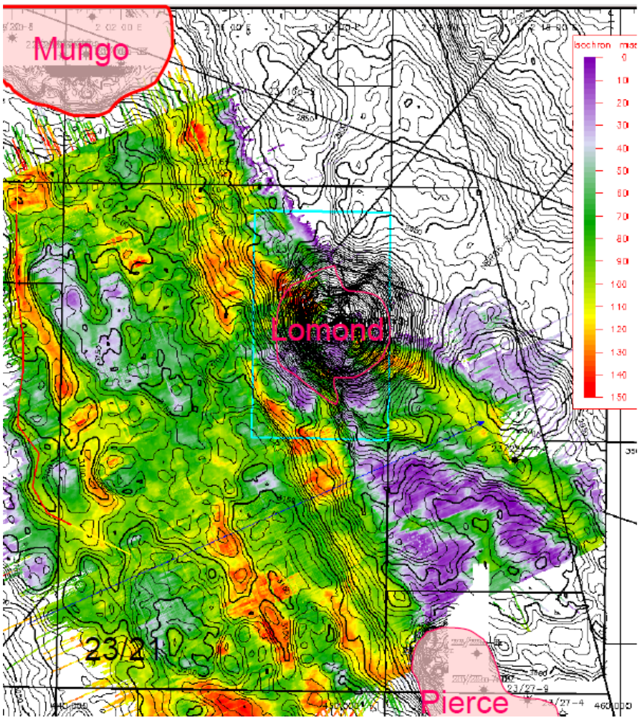
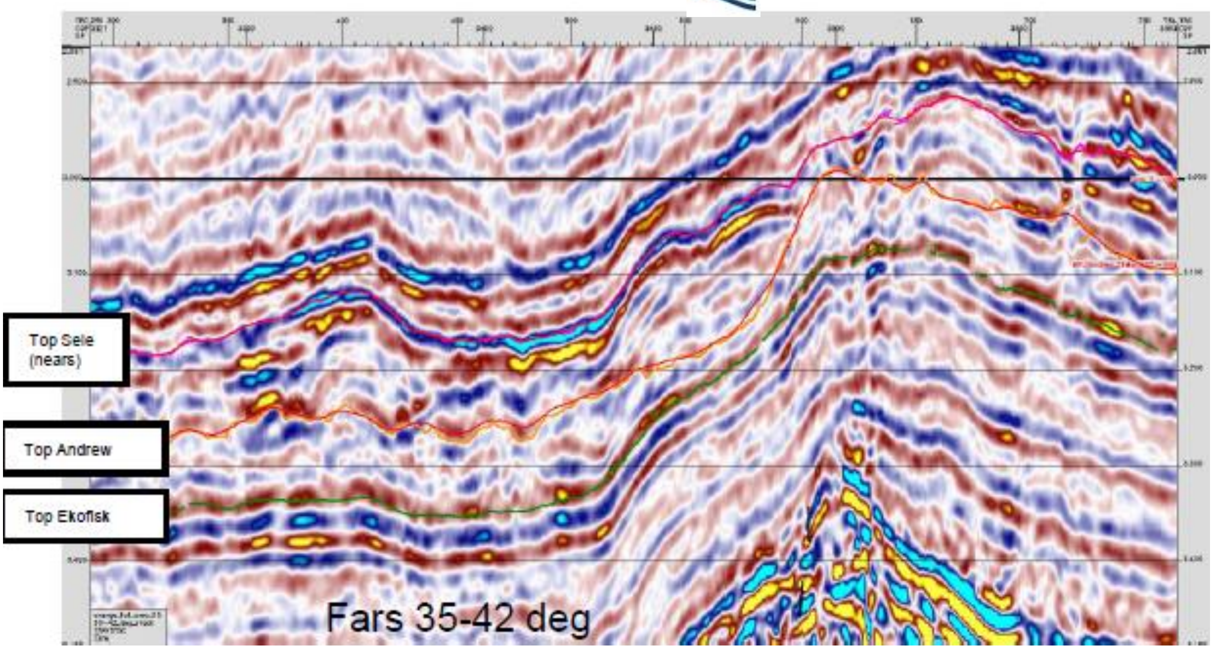


Fig. 16 – Toad prospect seismic picking **(Data courtesy of PGS)**



3.6. BG: 28/5a-7, North Channel prospect

BG farmed into Noble's equity in P213 and gained Operatorship in 2006. North Channel was a normal pressure – normal temperature (NPNT) prospect and had a commitment exploration well outstanding on the licence. Primary target was the Palaeocene Forties Sandstone deposited as a deep water turbidite channel system originating from the Western Platform and flowing WSW-ENE through an E-W oriented low resulting in an amalgamated stacked channel system (**Fig. 17**). The sand fairway extends into the Bittern and Kyle Fields and joins the main Forties fairway of the Central Graben ~25 km to the east.

The North Channel trap corresponds to the pinch-out of the Forties Sandstone to north, west and south and it is dip-closed to the east. This prospect was interpreted as a Buzzard analogue.

The North Channel prospect was up-dip from the fill-to-spill Bittern Field. The migration model showed that the Northern Channel prospect was demonstrably on the current day migration path for oil spilling up-dip from Bittern (assuming water-wet Cromarty sandstones in wells 28/5a-5 & 6 are not in communication with the Forties sands).

BG conducted rock physics and gathers analysis which concluded that a weak AVO response was observed. The lack of obvious AVO gas anomaly on prospect led to expect oil as the main fluid.

Overall CoS was set at 45%. The trap was deemed seismically well imaged but the critical risk was allocated to trap efficiency: indeed potential thief zone by thin overlying Cromarty sandstones could jeopardise the top seal. Up-dip seal of Forties channel is required for trap to work however side and bottom seal risks were considered low.

The 23-day well was drilled in September 2006. Structure and stratigraphy came in close to prognosis with Top Forties on prognosis and sand thickness and quality as prognosed. Forties section biostratigraphy analysis indicates an amalgamated section with the Bittern Sandstone Member overlying the Forties Sandstone Member.

The "Bittern / Forties" section was entirely wet:

- Trap efficiency is interpreted as the main failure mechanism for the North Channel. Failure was due to reservoir sandstones continuing beyond mapped shale-out and/or absence of bottom/side seals. For instance, the lack of Lista claystones may be indicative of a bottom seal failure.
- Another potential reason for failure is the migration pathway that may be more complex than was previously anticipated leading to prospect never receiving hydrocarbon charge.

<u>Company perspective main lessons learned:</u>

- The complexity of different sand fans (Bittern fan and Forties fan) amalgamating within the gross seismic package was not captured pre-drill. As a result, pre-drill modelling of the Cromarty / Forties / Bittern sandstones identified localised presence but failed to capture subsurface risk for complex erosional sand tracts acting as thief zones?
- Potential for base seal (Lista claystones absence), possible sandy - silty Maureen presence and possible thief zone were not identified pre-drill. Geological model did not emphasise the risk of erosion of the prognosed bottom seal.
- Absence of a convincing DHI over the prospect in the Forties suggested either a water-wet section or low-GOR oil. As a consequence, source rock effectiveness should have been risked more appropriately given down-dip full-to-spill Bittern oil and gas accumulation. Both source rock effectiveness and migration parameter may have been risked too optimistically.

<u>OGA perspective:</u>

- Interpretation and maps should not stop at the edge of the prospect (**Fig. 18**) as this does not allow properly spotting and focusing on the potential prospect weak point.
- Seismic picking should not over interpret the data: in this particular case, the interpreted Top Forties downlap (indicating the western edge of the North channel prospect) on the axial line going from well

28/5a-3 to the western outer limit of the prospect is picked in the midst of a reflection free seismic package (**Fig. 19**)

Fig. 17 – Northern Channel prospect summary: Play concept and Top Forties Depth Map

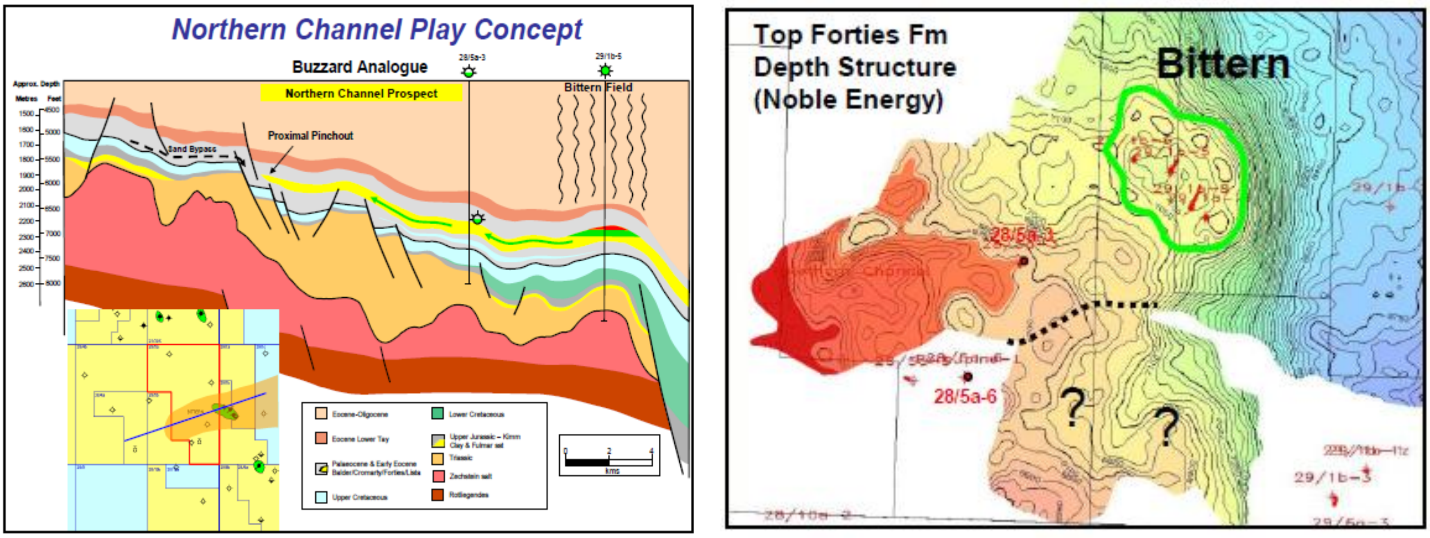


Fig. 18 – Map showing the North Channel prospect and regional setting

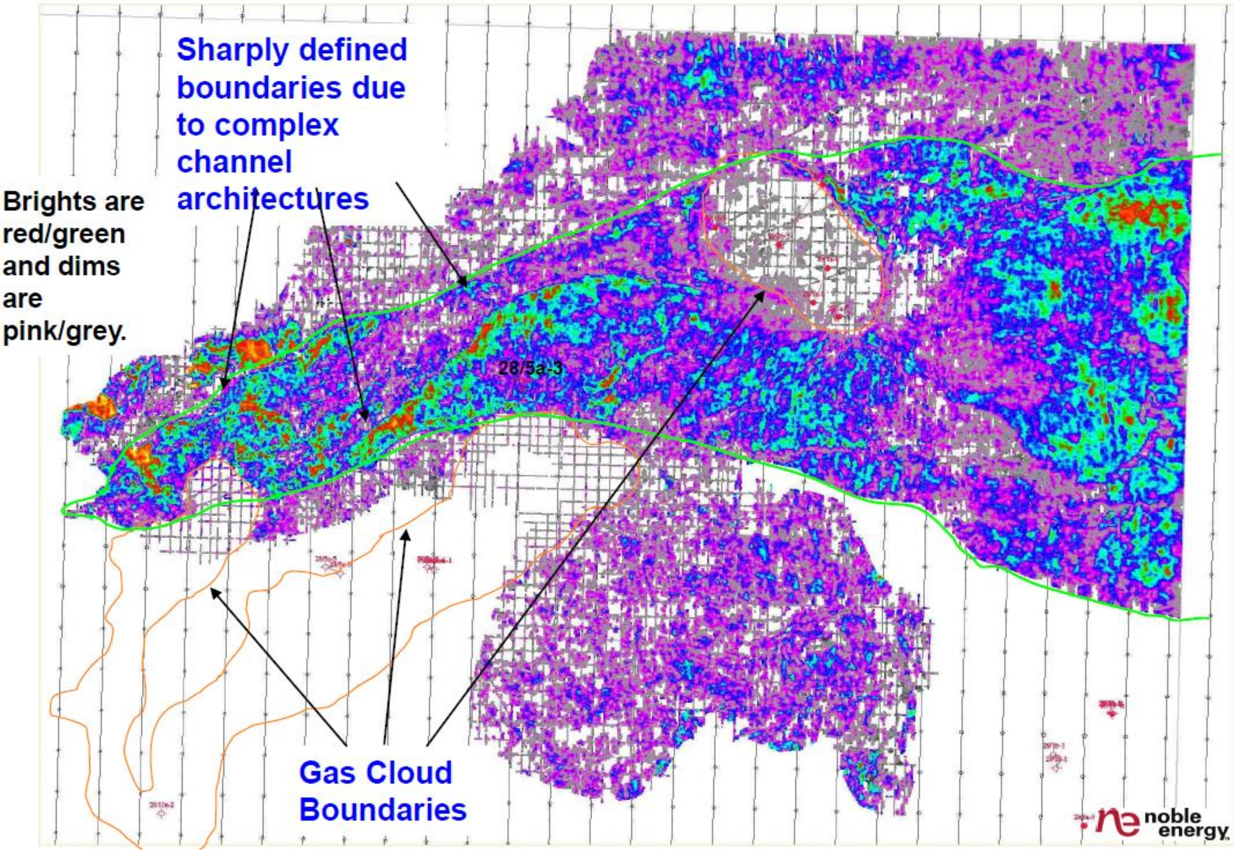
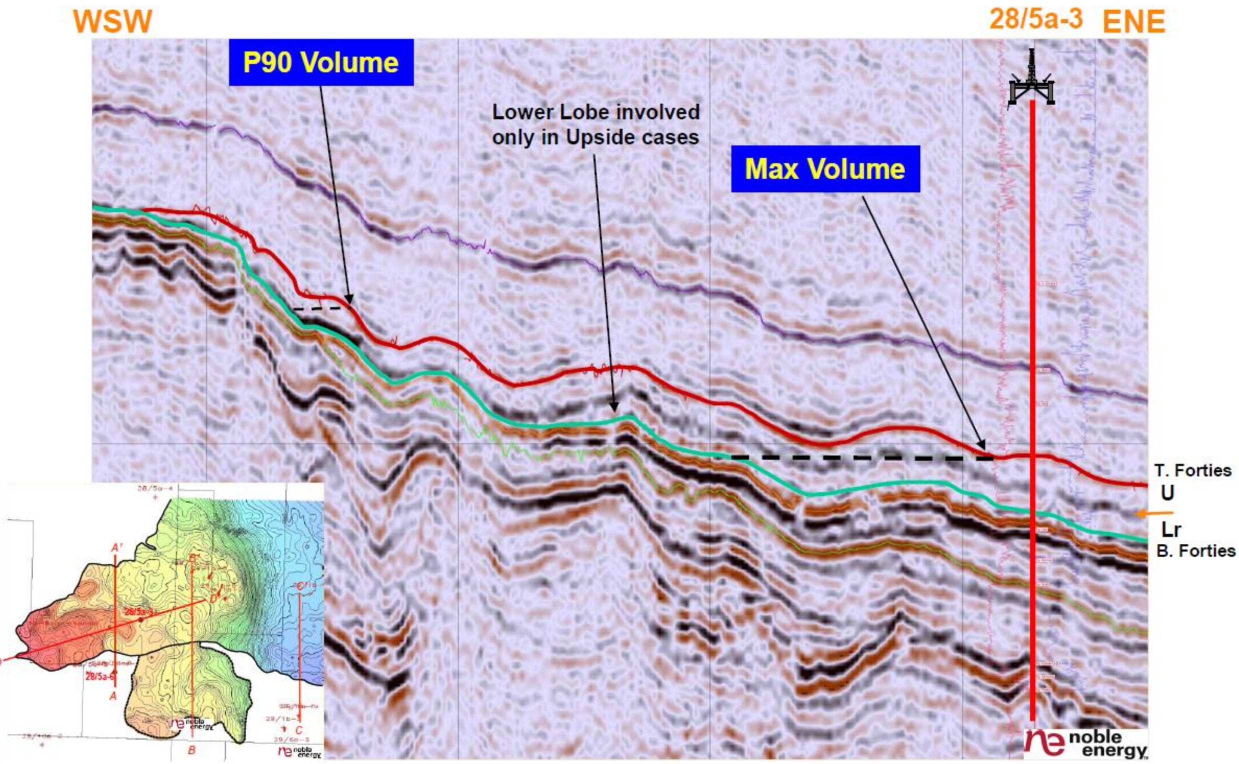


Fig. 19 - Example of seismic over picking: Top Forties (red horizon) downlap is questionable as it is defined amidst a reflection free seismic package. **(Data BG proprietary)**



3.7. BG: 30/2a-10, Thunderer prospect

This fault bounded prospect was defined on a 3D PSDM CGGV Long offset data set and further refined using the PSDM re-processing covering Jackdaw. In addition to its own perceived merits (BG chance of success -CoS- was 25%) the well was drilled partly because the 3rd Round licence expiry date was imminent and because in a success case it was planned as tandem development with the Jackdaw Field.

The primary target was the Triassic Skagerrak Sandstone Joanne Sandstone Member, a fluvial stacked channel system.

Thunderer is targeting the easternmost of four adjacent fault blocks up-dip from the 30/2a-2 Conqueror well situated 2km to the west, with an element of dip closure to the south East. Top seal is provided by the Johnathan Mudstone Member (**Fig. 20**).

Basin modelling has identified the Kimmeridge Claystone Formation shales in the east Central Graben as the source kitchen. The HC fluid is modelled as HPHT gas condensate.

Regarding the migration pathways, the eastern marginal fault on Thunderer has a large window of Pentland juxtaposed against Joanne reservoir. The Pentland is assumed to be both a source and carrier bed interval. There is no direct communication between the Joanne and the post Pentland (J54-J62) expected Sands/Heather or Lower Kimmeridge source interval.

The pre-drill risks were the source efficiency and especially the complex cross-faults migration pathway (**Fig. 21**) and the trap efficiency as pressure work suggested trap integrity risk.

A significant amount of work was done to better assess migration as it is complex and relies on fault juxtaposition and transmissibility over geologic time to migrate fluids in to the structure across 3 principle bounding faults: this consisted of capillary pressure studies to better constrain the fault behaviour and Shale Gouge Ratio assessments and allowed to build detailed juxtaposition diagrams.

Well 30/2a-10 was a 170 days well drilled in 2013. The well found tops within pre-drill seismic error range (NB: while drilling, top Joanne was re-tied seismically. It was finally encountered 61ft low to the revised prediction) and discovered a well-developed Joanne reservoir but water wet. Joanne consists of good quality (20.5% porosity, 76% NTG) sandstone interbedded with claystones. Additional reservoirs have been encountered gas condensate-bearing in Jurassic Pentland and Triassic Josephine. Gas peaks were measured within the chalk Oakley Unit but with low permeability. The obtained pressure data show Thunderer to be within predicted range but higher than expected for water-bearing case.

The main reason for failure is interpreted as a charge failure either because down flank faults are sealing preventing hydrocarbon migration out of the deep kitchen area and migration up flank into the Joanne at the crest of the structure or because Pentland is not an effective carrier bed.

The higher aquifer pressure encountered in the Joanne was suspected, immediately post-drill, as the reason why the Joanne trap failed. However, later on, fluid inclusion studies (FIS) indicated the Joanne was never charged.

Minor hydrocarbon accumulations (<< 1 mmboe) were found in the Pentland and Josephine and are interpreted as being locally sourced. These 2 accumulations are not in pressure communication.

It was noted that there was no seismic evidence for the migration of hydrocarbons into the chalk.

<u>Company perspective main lessons learned:</u>

- The Joanne Sand retains good reservoir properties at depths of up to 15,600ft.
- The Joanne Member lies in a higher overpressure cell than the overlying Pentland & Josephine: we cannot always assume the Jurassic & Triassic are in the same overpressure cell, even if offsets are.
- Although SGR and fault entry pressure studies end up on perceived precise figures, these methods still keep significant uncertainties particularly when some top Formations are found at depth significantly different than prognoses.
- It is important to collect MDT fluid samples and XPT pressure data, even in dry hole scenario.
- Fluid Inclusion analysis (FIS) indicates the Joanne has never been charged. This kind of cheap post-well study is rarely carried out which does not help understanding why a well failed.
- The Pentland Formation is probably rather a local reservoir sourced by the co-eval local coals instead of an effective carrier bed.

Fig. 20 – Thunderer prospect: post-drill depth map and cross sections **(Data Courtesy of CGG multi-client Seismic)**

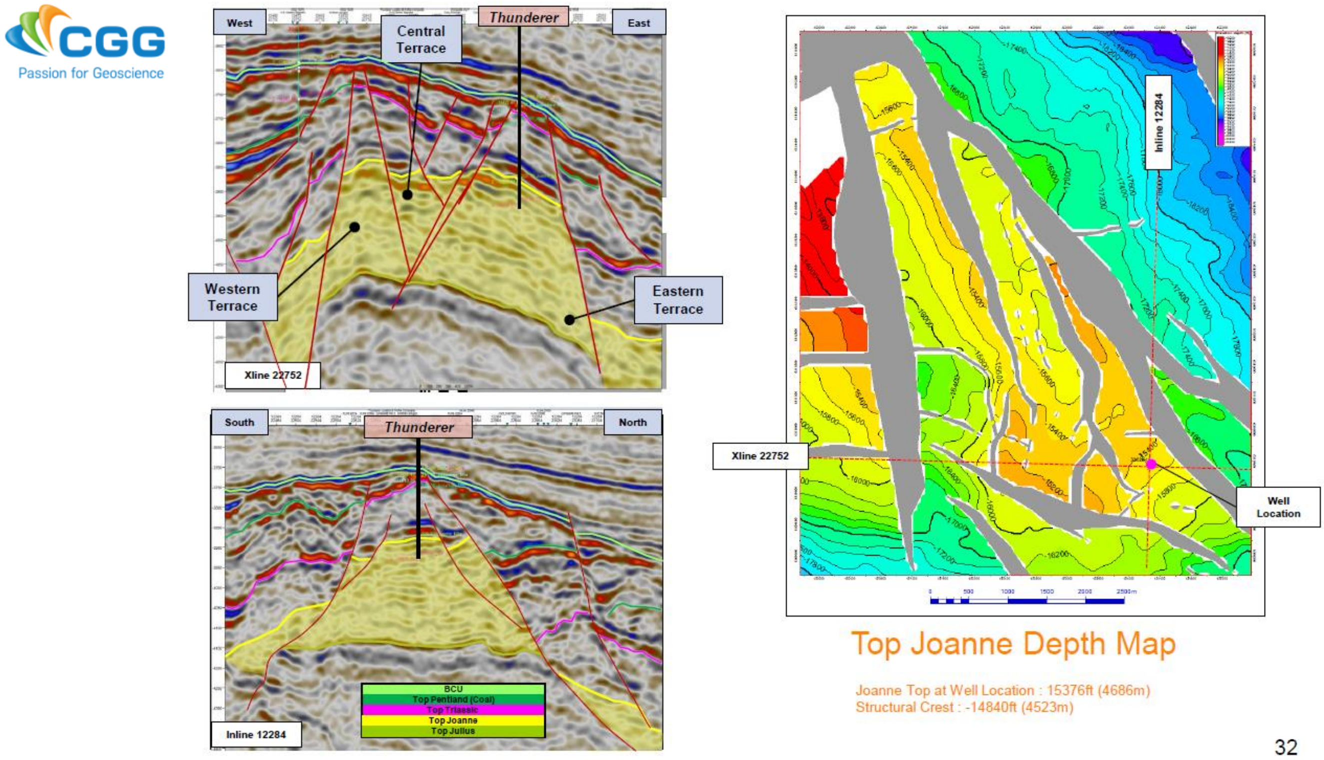
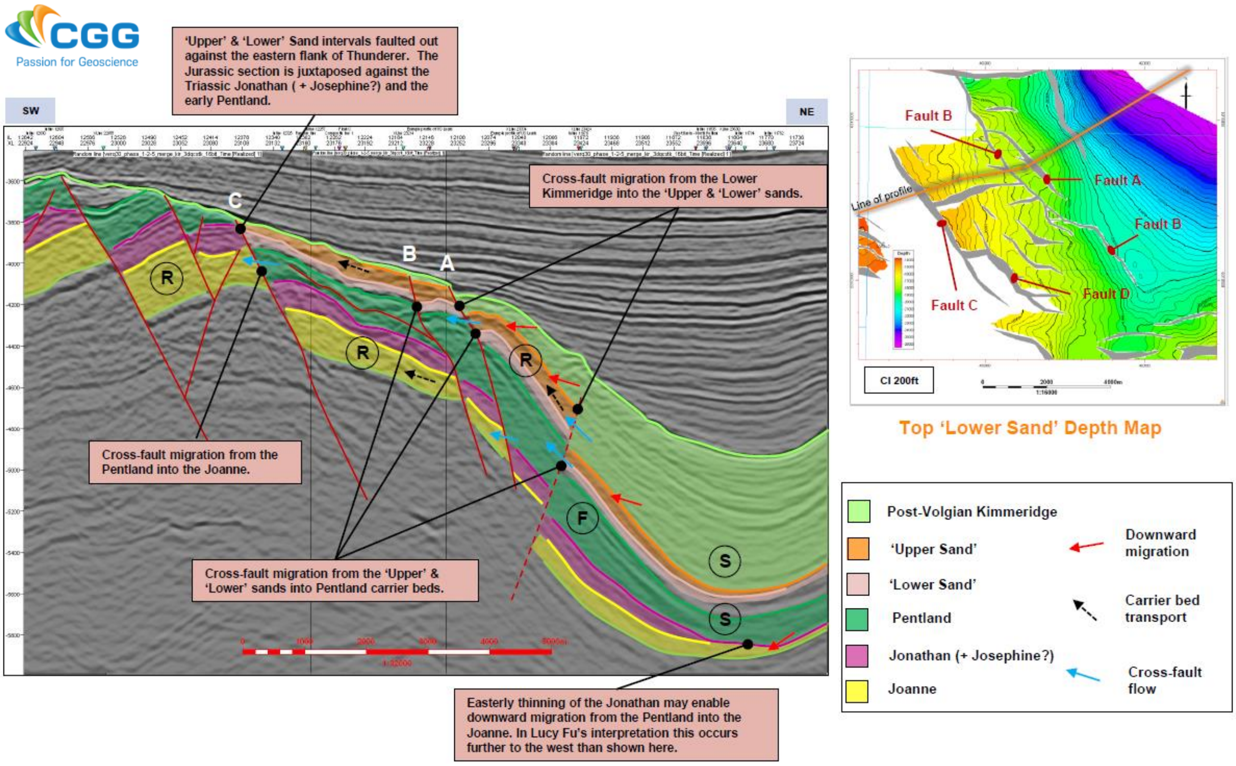


Fig. 21 – Migration pathways from the Basin to Thunderer prospect **(Data Courtesy of CGG multi-client Seismic)**



3.8. BG: 30/8-3, Calloway prospect

Calloway was an HPHT prospect located in block 30/8 in the Central North Sea. The main target was the Triassic Joanne sandstone with secondary targets in the Jurassic. Indeed there was a clear seismic tie to excellent Triassic reservoirs in Judy Field and thick (~1,200 ft). Fluvial deposits were prognosed. Excellent Triassic reservoir properties have been found at equivalent depths in the nearby Jade Field.

The trap was 3-way-dip closed and fault bounded to the south. It involved a regionally effective top seal in Jonathan Mudstone. The predicted pressure at crest of structure was below the regional fracture gradient.

The main source rocks were expected to be the mature middle Jurassic on structure and the Kimmeridge Clay Formation source kitchen in the East Central Graben. The prospect was surrounded by discoveries at multiple stratigraphic levels in adjacent blocks.

The overall CoS, updated following PSDM reprocessing, was set at 29% with the source effectiveness identified as the critical risk because analogous structures are water wet at Triassic in block 30/13.

The well 30/8-3 was a 127-day well drilled from September 2005 and found Top Joanne reservoir 204' deep to prognosis due to a mis-pick problem. Joanne thickness was correctly predicted being 32' off prognosis (1,489' actual vs 1,521' prognosed). Overburden sequence was close to prognosis, with additional early Cretaceous section. The well was deepened to test the Judy formation which was also found to be water bearing.

The Joanne reservoir was found similar to prognosis with slightly lower porosity but core plugs demonstrated effective permeabilities. Joanne pressure and temperature were on prognosis.

The Pentland, however, was found to be HC bearing and pressure was significantly higher than expected. Two light oil MDT samples were recovered showing that oil appears to exhibit 2 maturities, suggesting mixing of fluids, i.e., mostly locally (Pentland coals ?) generated hydrocarbons mixing with additional limited amount of higher maturity "off structure" generated KCF hydrocarbons.

The most likely failure mechanism for the Calloway Triassic is the lack of source effectiveness:

- Indeed, no direct migration pathway was observed on seismic data: source rock effectiveness was the key pre-drill risk @ 0.6.
- Geochemistry (oil samples and occasionally abundant fluid inclusions) showed Pentland oil to be dominantly sourced from on-structure, i.e. the off structure Kimmeridge source was not charging the Pentland.
- Fluid inclusion studies showed that the Joanne Triassic never held a hydrocarbon column as it is mostly devoid of visible inclusions.
- Fault seal and pressure data demonstrate that the Triassic is not in communication with the Jurassic at Calloway.

Company perspective main lessons learned:

- Calloway shows that, regarding the Triassic Joanne sandstones, effective porosity can be preserved with depth and very high permeabilities can be maintained, particularly within fluvial channel sands.
- Basin modelling should have focused at better understanding the pre-drill migration routes.

OGA perspective:

- In this particular case the depth issue on Top Joanne was due to a mis-pick and the depth conversion was robust. Nevertheless, it should be kept in mind that depth prognosis should not solely rely upon PSDM.

Fig. 22 – Calloway location on Joanne sandstones depth map

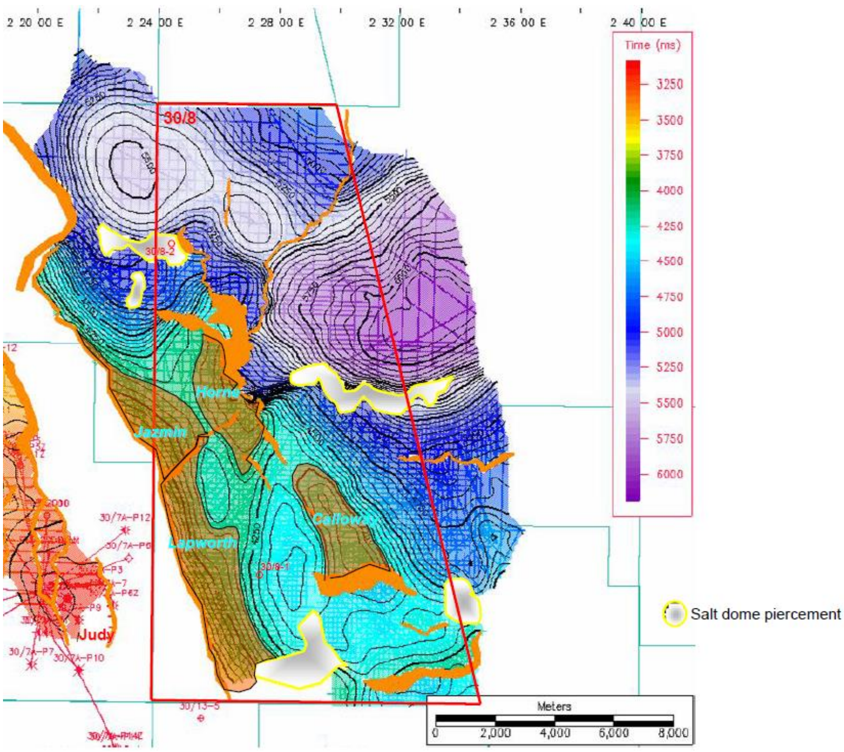
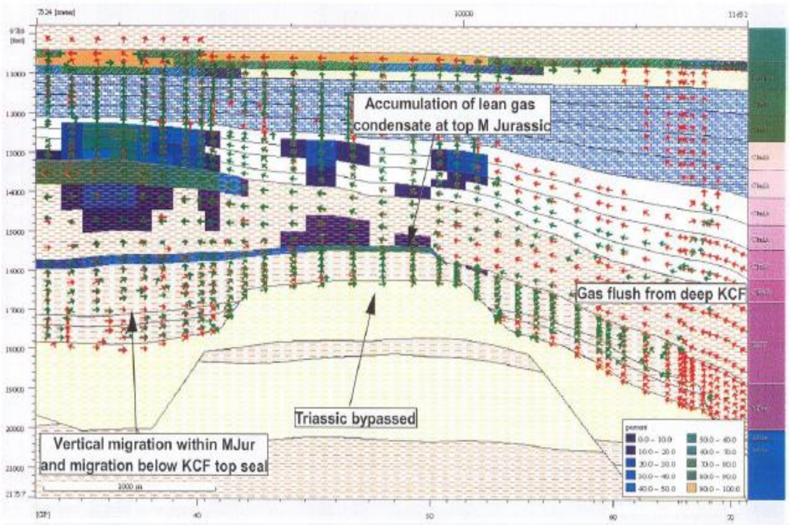


Fig.23 – Calloway post-drill modelling



Calloway base case modelled HC saturations at present day with migration vectors (red = gas, green = oil)

Triassic sits in migration shadow and is bypassed

3.9. BP: well 22/20a-7, TP1 prospect

This DHI (Direct Hydrocarbon Indicator) supported prospect was defined on a 3D PSTM contractor processing. The TP1 prospect was adjacent to the north-east of the Monan salt diapir and to the west of the DHI supported Columbus stratigraphic discovery (**Figs. 24 & 25**).

The prospect, which targeted the Forties reservoir, required a complex trap model and separation from the Monan field. This could be achieved by invoking concentric diapir relating faulting. The trap is a complex closure around the Monan salt diapir. Up-dip trap is required to separate the prospect from the Monan field itself. Multiple OWC's, pre-production pressure and production data from the Monan field suggests that the field is highly compartmentalised and not connected to a regional aquifer. Coherency illuminates a faulted zone around the diapir, which corresponds to a mapped fault penetrated by 22/20-2. Closure to the NW is difficult to define. The DHI and coherency illuminates a fault across the main axis of the structure (100m gross), caused by a small offset (30m) of the Sele and Forties Formation, related to a deep basin bounding fault. Shallow isochrons indicate this remained active during diapir formation/ salt withdrawal.

It was checked that the DHI was still valid on another 3D data set (CGGV Long Offset Q22). In addition to its own perceived merits (BP CoS was 40%) the well was drilled partly because of rig slots drive and because licence expiry date was imminent.

The Premier Oil 22/19c-6, Oates targeting similar amplitude supported feature terminated on the 26th August 2010 while the 22/20a-7 spudded on the 20th August 2010. Consequently, the potential dependency between these 2 wells could not be taken into account.

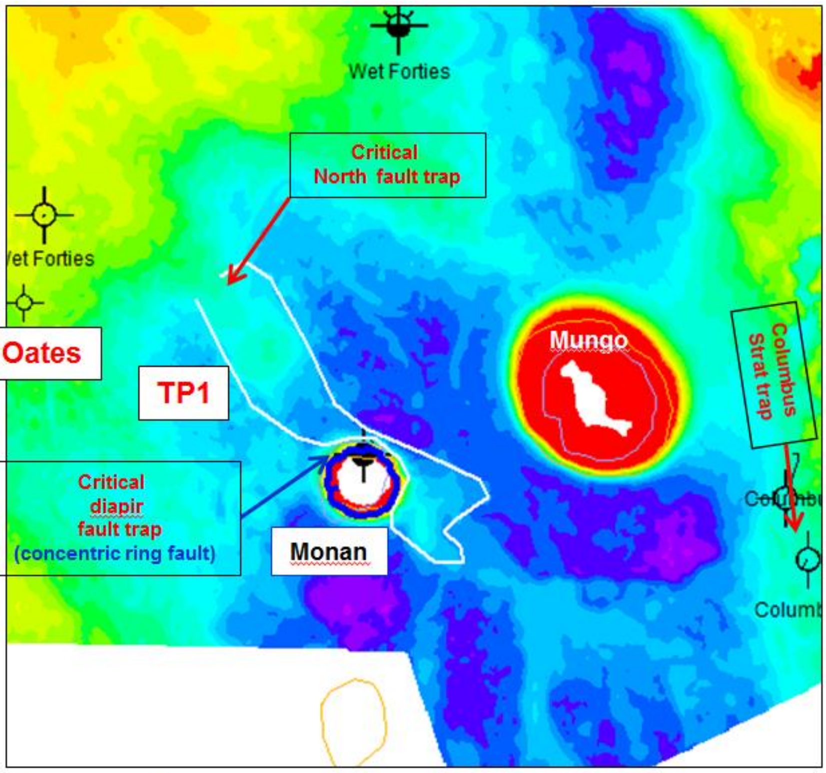
Well 22/20a-7 found the Forties reservoir as per prognosis but water wet. This well proved to be dry because of a trap failure; the DHI was a seismic artefact.

<u>Company perspective main lessons learned:</u>

- 2 different 3D data sets do not necessarily confirm DHI validity.
- PSTM exhibited a wrong velocity model in the rim syncline meaning that PSDM would have been a pre-requisite (but beware PSDM needs 12 to 18 months to create the right velocity model and to perform much iteration before it can be confidently used) (**Fig. 26**).
- Given that reservoir thickness was greater than fault throw a Shale Gouge Ratio (SGR) study should have been undertaken pre-drill.
- It looks like integration of fault sealing mechanisms in the Forties field would have been useful. However following the sale of Forties, corporate loss of knowledge was noted.
- A proprietary RTM processing which came in while the well was being drilled provided a new image with good neighbouring well ties and showed that the concentric fault did not exist.
- Overall greater geoscience integration was necessary.

<u>OGA perspective:</u> It may be of value for OGA to look 1 year in advance at the E&A drilling programme over the UKCS: OGA may use its powers to shift well timings to ensure lessons can be learned where two wells have a geological dependency. This may lead to the award of a licence extension in case the expiry date would be too close.

Fig. 24 - TP1 prospect location and critical pre-drill risk



Monan: Small producing field

- Palaeocene (Forties/Lista/Maureen) reservoirs
- Multiple OWCs
- 2 producers
- **Compartmentalised production**
- Low recovery factor

Fig. 25 - Seismic random line from well 22/19-2 to Monan salt diapir illustrating TP1 prospect

(Data courtesy of PGS)

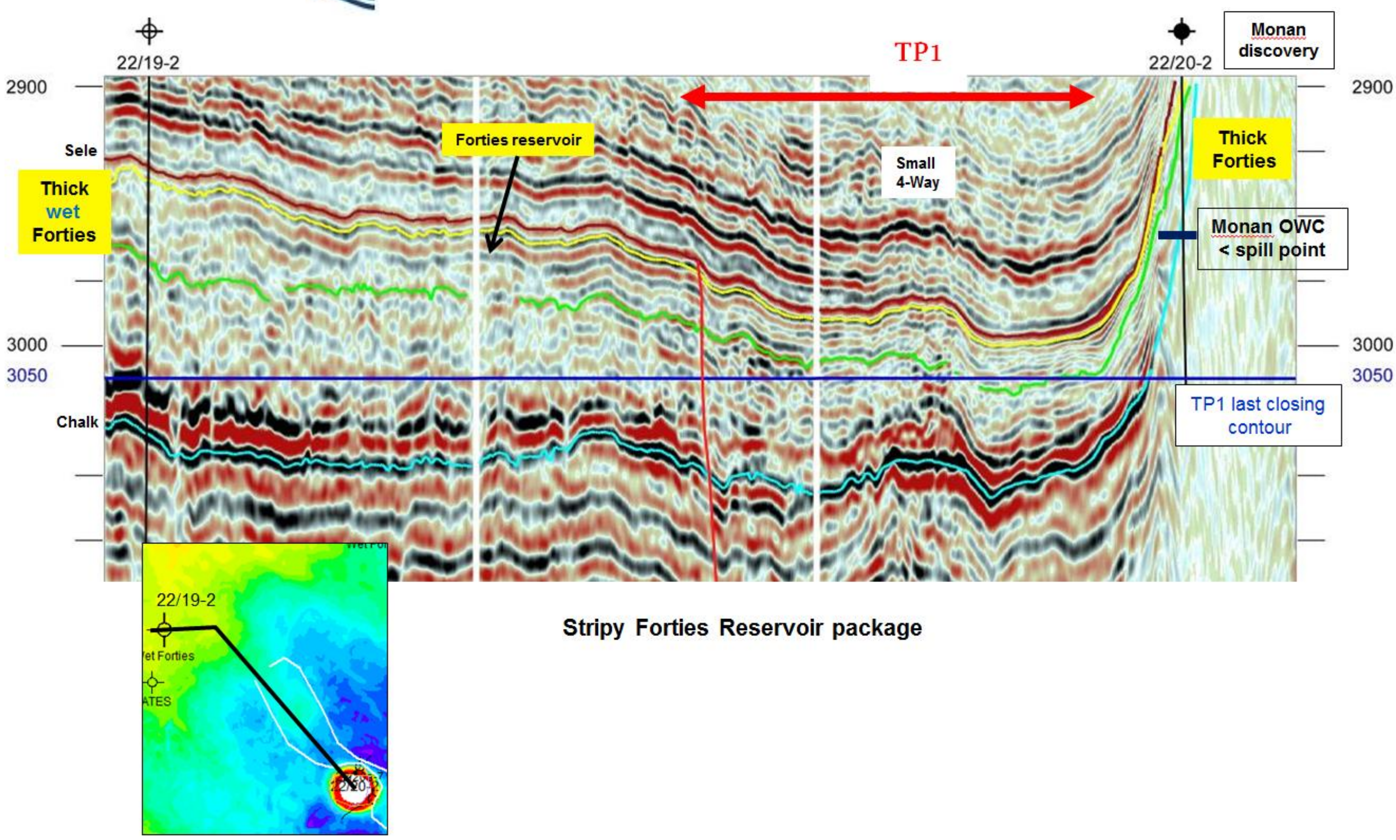
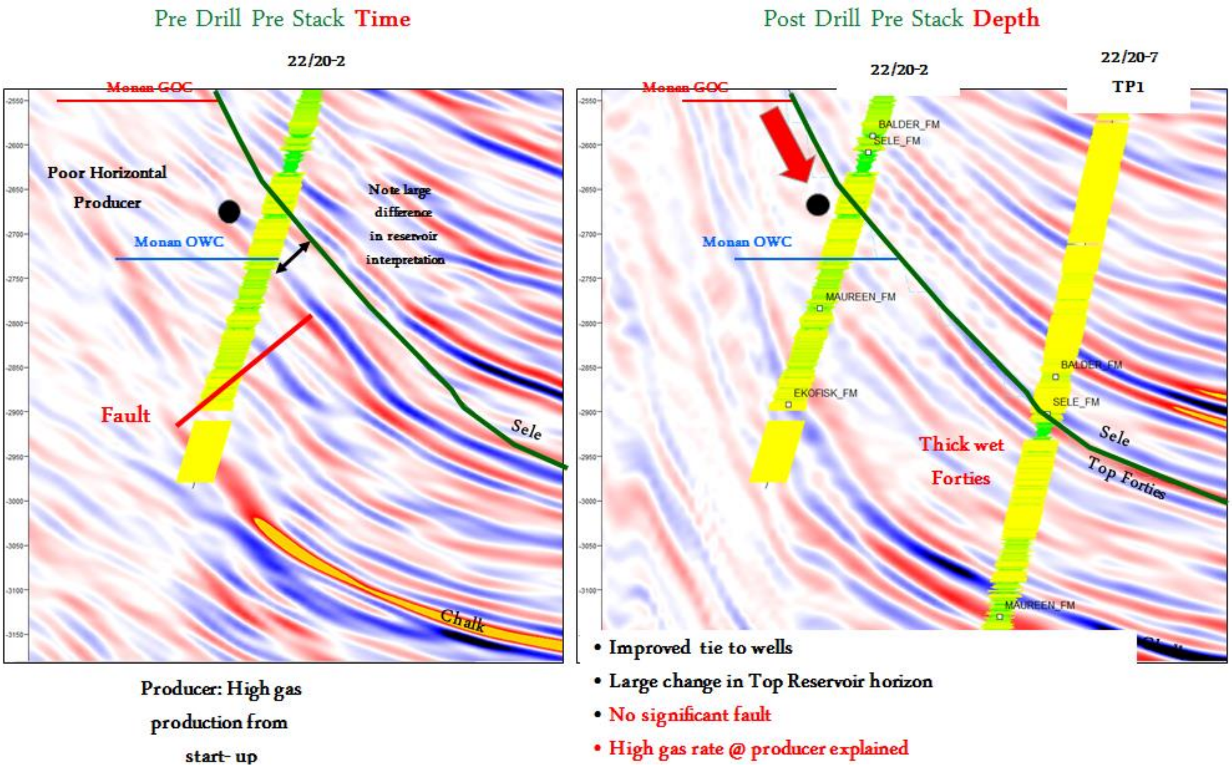


Fig. 26 - TP1 prospect: comparison pre-drill Pre-Stack Time vs post-drill Pre-Stack Depth



(Data courtesy of PGS)

3.10. Bridge Resources: well 15/11b-6, North Piper prospect

The data pertaining to well 15/11b-6 could not be accessed via CDA. Bridge North Sea left the UKCS some years ago and its present day parent company did not participate in the study. However, pre-drill information was obtained from ICENI who farmed out the North Piper prospect.

The North Piper prospect was located to the North-east of the Halibut Horst. It was a stratigraphic prospect straddling blocks 14/15b and 15/11b and targeting Upper Jurassic Piper sands. The trap was a 3-way dip closure with the target reservoir pinching out towards the west-north-west across a structural nose (**Fig. 27**). NB: The primary Jurassic target was also overlain by prospective Lower Eocene, Upper Palaeocene, and Lower Palaeocene four-way closures.

Kimmeridge Clay and Lower Cretaceous Cromer Knoll Shale would be the top seals. Sgiath and Fladden Jurassic shales should act as bottom seal. The up dip well 14/15-1 had no Piper sand: as a consequence, the overlying Kimmeridge Clay Formation shales form top and edge seals.

The source for charging the prospect was provided by immediately overlying Kimmeridge Clay Formation (KCF) shales, which are up to 500 ft. thick in the North Piper Basin to the east. Much thicker KCF source rocks are present in the Witch Ground Graben to the SW. Piper sandstones provide a direct and straightforward up dip migration pathway westwards towards the prospect. The migration route from the Witch Ground Graben is less direct. Migration from the Witch Ground Graben was perceived as a key risk (according to Hannon Westwood).

The overall CoS assessed by ICENI was 35%. No information was available concerning the overall CoS or the detailed risking breakdown from the operator (Bridge North Sea).

The Piper sand was found as per prognosis but was water bearing. Top Sgiath was found 211 ft. shallower than prognosed and was water bearing. Based on the limited amount of available G&G data it is felt that migration pathway may not be effective. The intermediate seal between the Piper and Sgiath sandstones corresponds to 42 ft. of Sgiath coals and shales and may become thinner up-dip becoming ineffective explaining a second potential reason for failure.

<u>Main lessons learned:</u>

- The seismic data quality did not allow picking the Piper target reservoir.
- A post well FIT study would have helped address the migration risk.
- OGA must get and properly store all the well data pertaining to the UKCS regardless of the CDA membership status of the company operating the well.

Fig. 27a North Piper prospect location

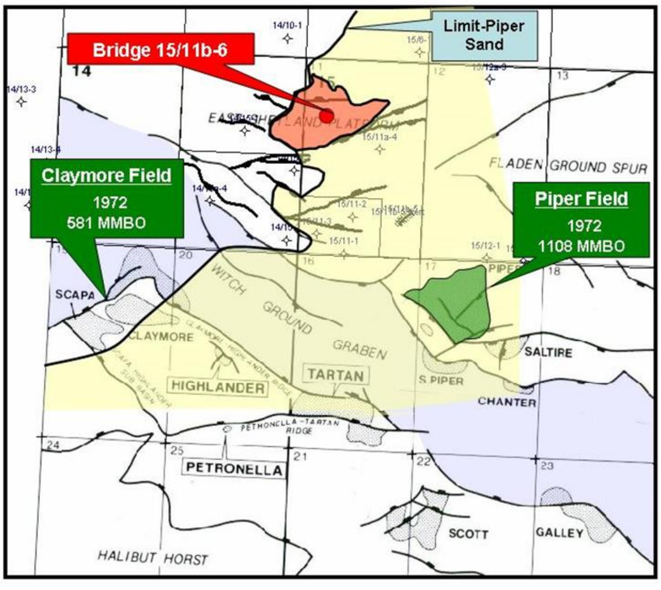
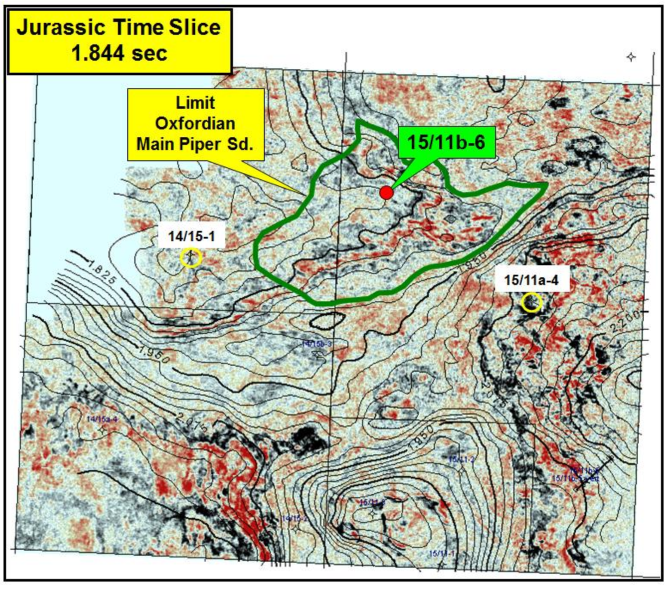


Fig. 27b Jurassic Piper pinch-out across a nose



3.11. Century Exploration UK Ltd: well 19/2-2, Dolphin prospect

Following Century's exit from the UKCS, this well was reviewed thanks to Eric King, former Century Exploration UK General Manager, and Andy Sims from Merlin Energy Resources Ltd.

Century entered a Roundstone Promote licence and had to drill this well or pay the corresponding amount to Roundstone. There was one contingent well commitment in each adjoining licenses (19/02 - P1096 and 19/01b - P1385). The well was finally drilled close to the boundary between blocks 19/1 and 19/2.

Well 19/2-2 tested as the primary target, in the deepest part of the Banff Basin, what was interpreted as a lenticular body at Lower Cretaceous level (K45 deep marine sandstone) but also tested amplitude anomalies recognised in the Punt Sandstone and Upper Jurassic Volgian formations. There was reasonable seismic evidence of rapid thinning and pinch-out in an up dip direction to south. To the west evidence can be seen for down lapping reflectors and the loss of reflectors within the K45 interval but no clear up dip edge can be mapped, but sandstones are absent from 19/1-1.

Only minor Cretaceous sandstones have been found in the immediate area at three main levels: Britannia Sandstone (K45-K50, Late Aptian), Coracle Sandstone (K20, Hauterivian) and Punt Sandstone (K12-K14, Ryazanian-Valanginian).

Only minor Cretaceous sandstones have been found in the immediate area at three main levels: Britannia Sandstone (K45-K50, Late Aptian), Coracle Sandstone (K20, Hauterivian) and Punt Sandstone (K12-K14, Ryazanian-Valanginian).

Based on well information the Kimmeridge Clay source rock near to the Banff Fault is less rich than seen to the north, the depth of burial in the Banff sub basin and the relative small size of the basin would suggest that the source and migration risk is high. However, the prolific active seepage along the Banff Fault (Fluoroscan survey) proves the existence of an active hydrocarbon system.

No significant structural closures could be mapped within the license. The most convincing stratigraphic trapping potential was deemed to be a large lens shaped body of K45 age: although Britannia Sand reservoir was unproven it was suggested by the body's morphology. The western pinch out was very poorly defined, but if sandstones were present in the lens they certainly had a western limit east of well 19/1-1.

The Dolphin prospect was considered high risk: the overall CoS of this stratigraphic trap was set at 10%, with risks about trap (40%) and reservoir (both presence and quality) at 45%, being the critical risks. As a result, an awful lot of farm-out attempts was made but with no success.

The stratigraphy penetrated was similar to that proposed in the pre-drilling prognosis. Formation tops above the BCU were at depths within the uncertainty estimates of the prognosis; however, formation tops from the BCU through the Jurassic were as much as 226 feet low to prognosis. The primary target was absent in well 19/2-2. The secondary targets, the shallower Tertiary target, the Punt Sandstone Member and the North Ettrick Sandstones were all poorly developed. No HC shows were detected in any of the secondary targets.

The main reason for failure appears to be the lack of sand sourcing in this region of the Banff Basin. It's also quite likely that all hydrocarbons leaked through the major Banff fault bounding this basin as indicated by the significant active seepage along this fault.

<u>Company perspective main lessons learned:</u>

- The seismic data quality was not good enough to define such a subtle stratigraphic trap. Some of the picked horizons seem to have been pushing the interpretation limits too far. The up dip pinch-out was defined within an area where the reflections are steeply dipping and there is a lot of noise (**Fig. 28**).
- A pre-drill Basin Modelling should have been carried out. It would likely have highlighted a much higher risk about the migration (was assessed at 70%).

- Maps should integrate all the relevant calibration points (**Fig. 29**) as it's necessary to properly assess a prospect.
- Given the poor prospect definition resulting in a very high risk prospect and the thorough attempt of farm-out which failed, a negotiation to cancel / transfer the well commitment should have been engaged with DECC.

<u>OGA perspective:</u>

- Century Exploration UK was not a CDA member. Once it ceased its UK activities, all corresponding data (8 wells and three 3D seismic surveys) have been put in Merlin Energy Resources Ltd.'s care. This is not a perennial solution and all these data should be given to CDA at no cost for Merlin.
- Given the high risk of this Dolphin prospect and as nobody agreed to farm-in, a waiver of the contingent wells commitment should have been granted. The possibility for a company to seek a waiver when some key conditions are met should be clearly stated so that all companies working on the UKCS are aware of such an option.

Fig. 28 – Dolphin prospect: South-North cross line 1960 (Data Century Exploration UK proprietary)

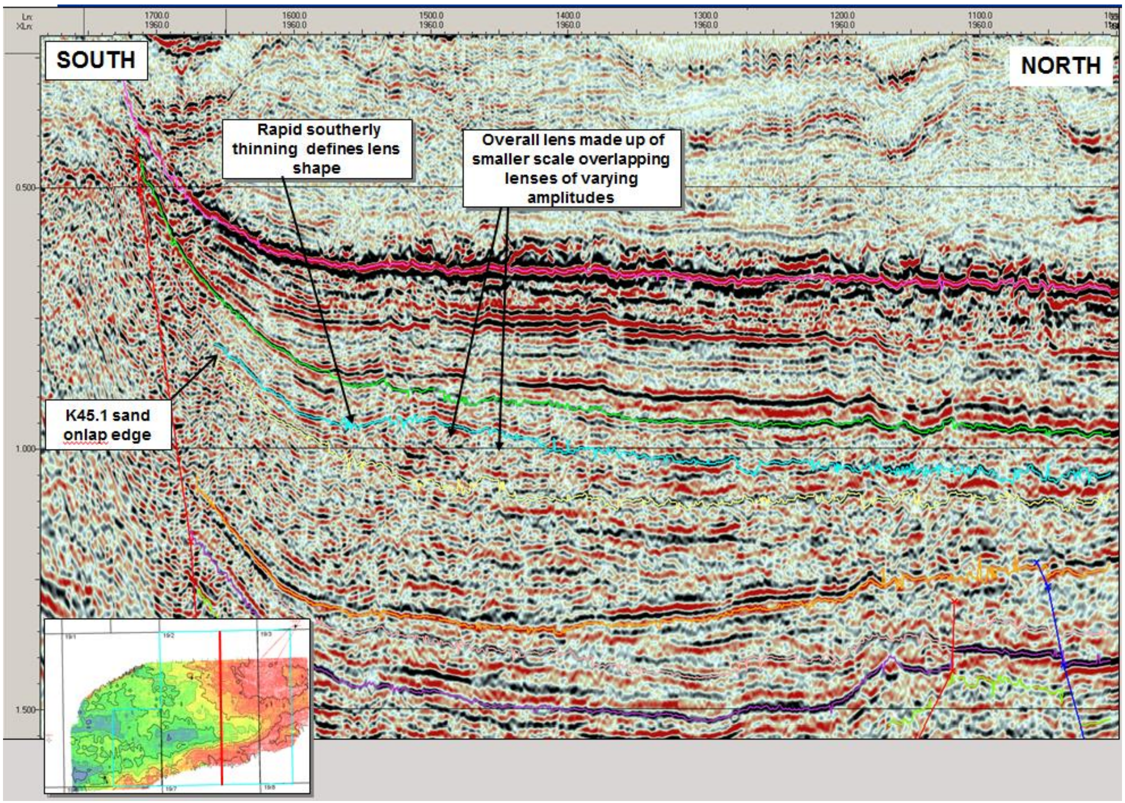
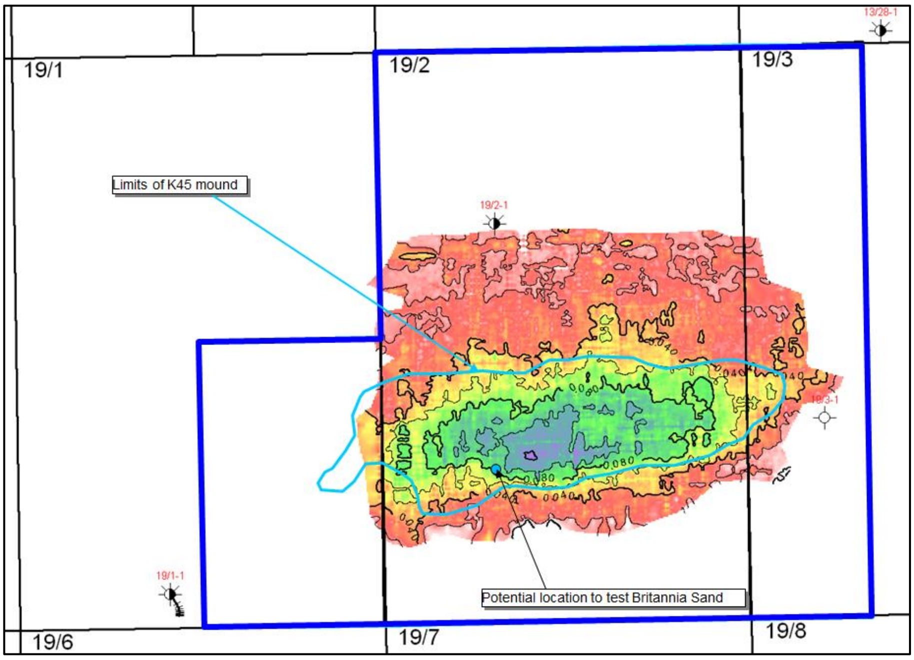


Fig. 29 – Dolphin prospect: Lower K45 Isochron



3.12. CNR International: well 22/27a-4, Deep Banff prospect

Deep Banff was a 4-way salt-induced dip closure with overhang, faulted into separate areas (**Fig. 30**). Although the seismic image under salt (Banff diapir) was poor (**Fig. 31**), data quality was deemed adequate to confirm trap presence. Well 22/27a-4 was drilled ~ 2 Km to the south-west of discovery well 22/27a-2 which found an HC down to in the Upper of two Fulmar sands. In the deep Banff prospect, the top seal should have been provided by overlying Heather Fm. and Kimmeridge Clay, Lower Cretaceous shales and Chalk. Lateral seal (up dip) to SW was against salt stock. Lateral sealing was expected via faults to the south and west. Top seal integrity risk due to gas column height and overburden strength was assessed as the critical pre-drill risk (49%). However, depending on FWL and depth to top structure this trap was estimated as being able to support column of 2-3000ft.

The overall CoS was set at 42% and the well was drilled deviated. Appraisal HPHT well 22/27a-4 and mechanical side track -4Z did not find the Jurassic Fulmar upper sand unit but only the lower sand unit. The reservoir quality was pretty good and porosity (22% average) was better than prognosis. Hydrocarbon shows were marginal to poor and only occasionally slightly above the oil based mud background and the lower sand unit was water bearing.

The reason for failure was adequately forecasted as top seal failure at crest of the structure due to overpressure from hydrocarbon column.

<u>Main lessons learned:</u>

- Being up dip from a discovery well and close to infrastructure, this prospect would very likely have been drilled. However, a better seismic image (longer offsets, OBC…?) should have allowed a better definition of the relationships between 22/27a-2 discovery well and "Segment 4", which was targeted by well 22/27a-4 and -4Z, impacting the trap definition.
- If this kind of prospect was proposed today for drilling, OGA should extend the license duration and request that a dedicated OBC / OBN seismic is acquired prior to giving any drilling consent.

Fig. 30 – Deep Banff Top Fulmar depth map

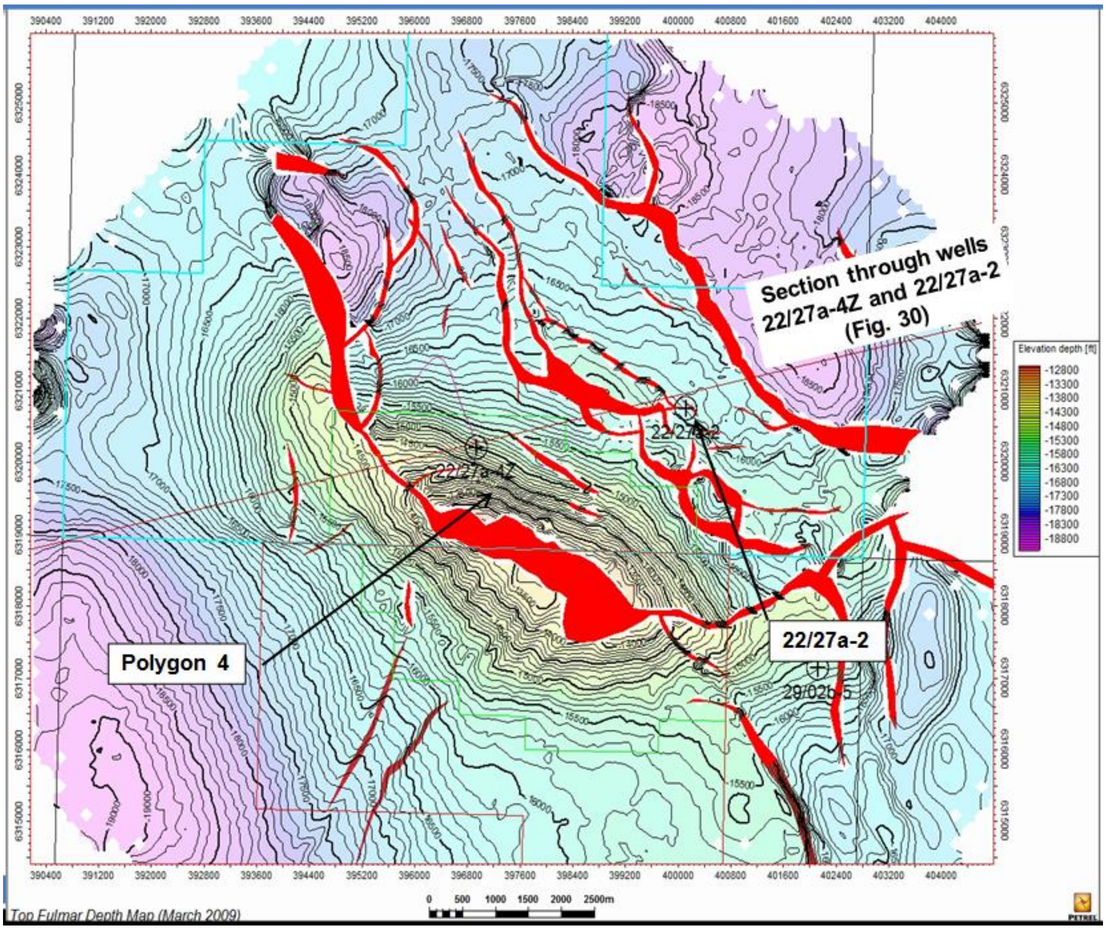
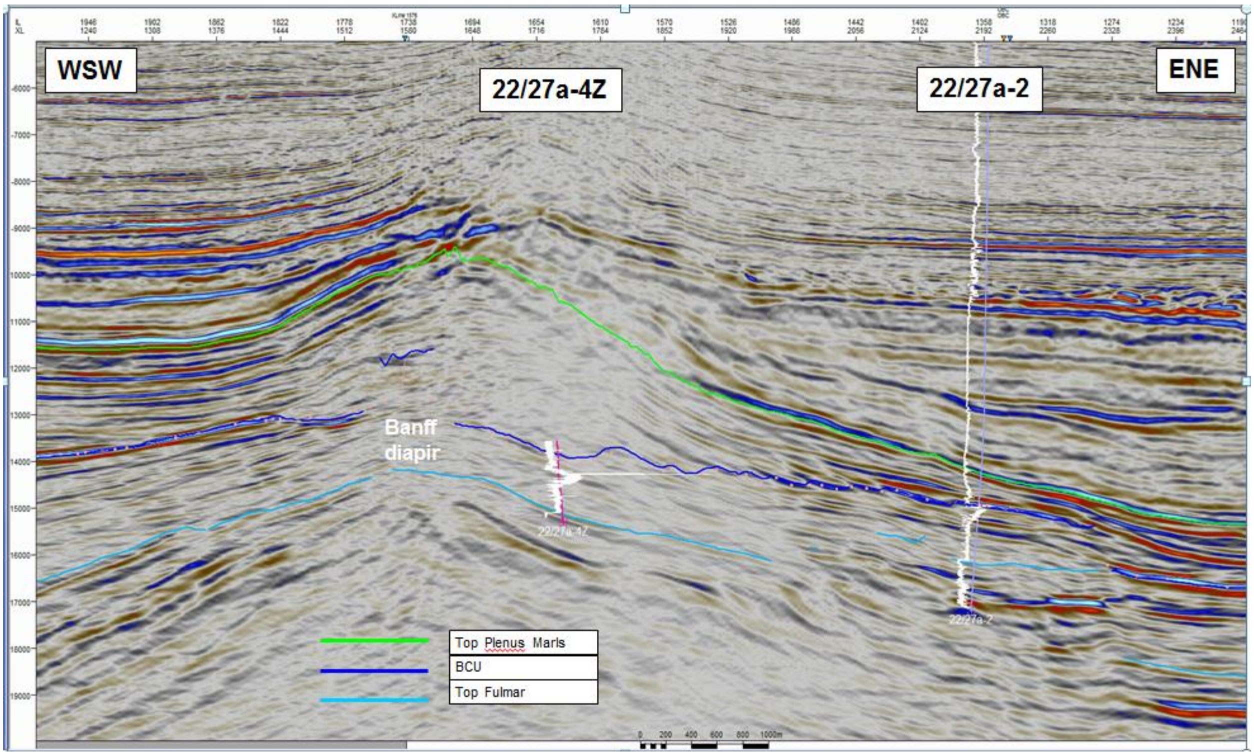


Fig.31 – Deep Banff: seismic section through wells 22/27a-4Z and 22/27a-2



(Data courtesy of WesternGeco) WesternGeco

3.13. ConocoPhillips: well 15/30-12, Macallan prospect

Following 15/30-2 well discovery, well 15/30-12 targeted the Piper sandstones in one of three clearly defined tilted fault blocks (referred to as Block 1 which was drilled too low on the structure by well 15/30-1 in 1975) located beneath the Britannia field (**Fig. 32**). A common contact was expected across these fault blocks.

Top seal was provided by Jurassic Kimmeridge Clay and Cretaceous Valhall shales which are proven top seals in the area and are effective in the 15/30-2 fault block (Block 2). One of the key uncertainties was the top seal integrity (**Fig. 33**). Indeed well 15/30-1 had only gas shows possibly due to a breached seal.

The second key uncertainty was that sand may be absent from the crest either due to erosion or by non-deposition as the Upper Jurassic interval was thinning towards the block crest.

All fault blocks moved at about the same time with the last major movement in Palaeocene (Alpine orogeny) while the main HC generation had been post Eocene. As there was large proven source kitchen overlying prospect and all adjacent fields were full to spill, no risk was assessed to the source-rock and migration parameters.

The resulting overall CoS was estimated at 33% with the seal (at 60%) and the reservoir (at 58% including quantity – 72% - and quality – 81%) being the critical risks. At the time, the level of risk involved was seen as acceptable.

Well 15/30-12 found all the main seismic horizons close to prognosis and within seismic tolerances. The Piper reservoir was found 64 ft. high to prognosis but thinner, with a lower NTG than predicted and water bearing. Some intra reservoir cemented layers were observed on the core.

The crest of the block being higher than anticipated, the primary reason for failure was clearly the lack of top seal integrity as demonstrated by the water gradient coincident with regional fracture gradient at mapped crest of targeted trap (blown trap). This was confirmed because good gas shows were observed while drilling together with Fluid Inclusion studies suggesting presence of residual hydrocarbon column in the Piper Formation.

Main lessons learned:

- This case study highlights the key value of detailed pre-drill studies not only to help describing the expected prospect size but also for HSE reason (safe well planning).
- It was noted that in this particular case there was no striking quality improvement between the original 3 Km cable seismic data (2001) and the later 6 Km long offset data (2003) as the latest data set did not allow a better reservoir thickness resolution.

Fig. 32 – Pre-drill Top Piper Structure Map

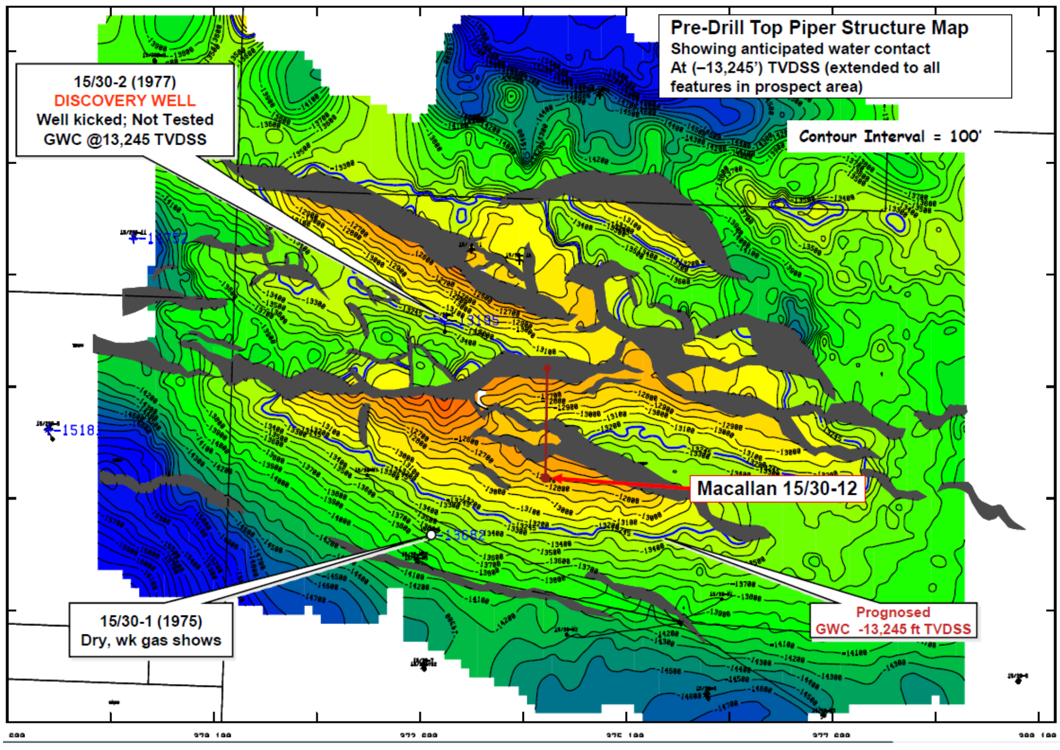
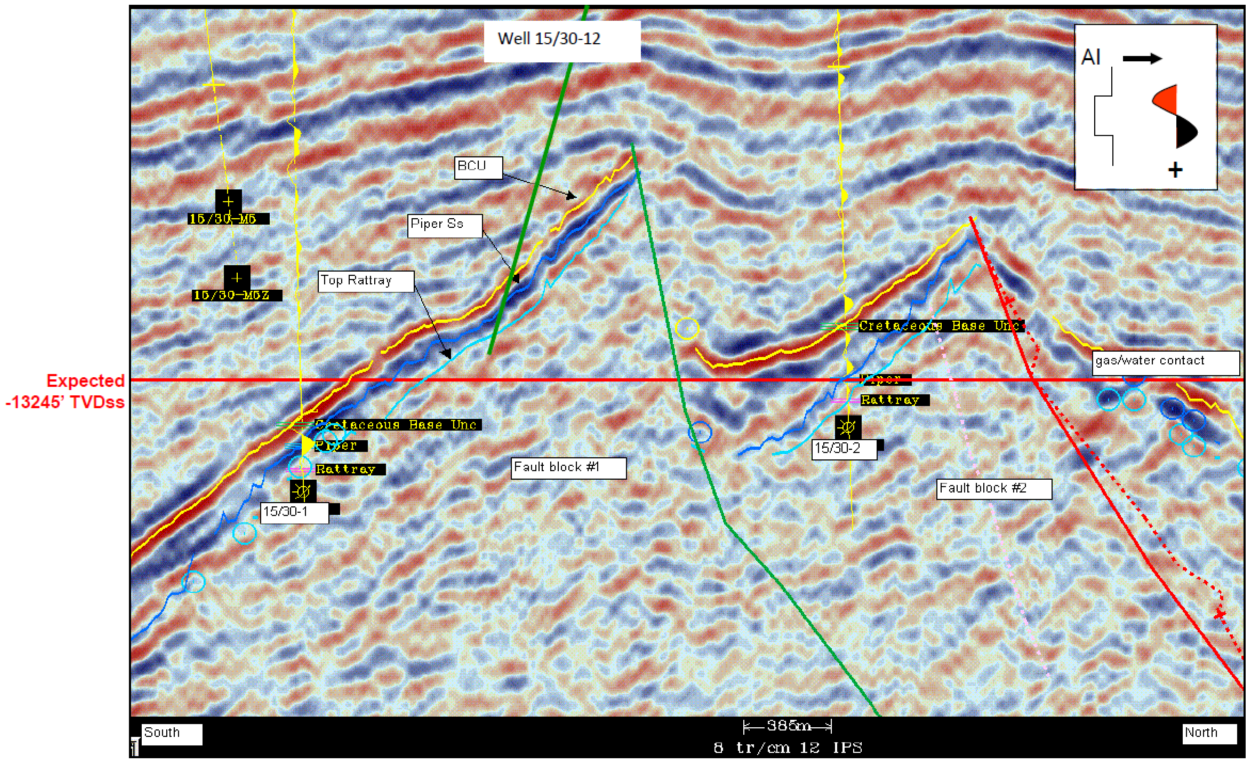


Fig. 33 – Pre-drill 2001 seismic – Line 2328 (Data ConocoPhillips proprietary)



3.14. PetroCanada well operator, (Dana Petroleum current well owner): well 12/20b-1, Gemini prospect

Well 12/20b-1 drilled by **PetroCanada** is currently owned by Dana. It targeted an elongated 3-way dip closure along the Smith Bank High and required an efficient southern fault closure against the Smith Bank Fault (**Fig. 34**). This well was optimally sited to penetrate five stacked primary exploration targets (1 - Cretaceous, Coracle Sandstone Member of the Valhall Formation; 2 and 3 - Upper Jurassic, Late Volgian + Early Volgian, Burns Sandstone Member of the Kimmeridge Clay Formation; 4 - Upper Jurassic, Oxfordian, Alness Spiculite / Ross Sandstone Member of the Heather Formation; 5 - Permian, Findhorn Formation sandstones), each with documented risks (ranging from 8% for Early Volgian to 25% for late Volgian Burns sandstones).

The primary trapping mechanism for the prospect hinged on its footwall location on the tilted fault block (three way dip and Smith Bank Fault closure to the south), but higher risk Jurassic Volgian stratigraphic plays were also interpreted with perceived wedge-out southwards towards the Smith Bank Fault.

Oil charge is proven in the area, with geochemical data supporting Late Jurassic, Mid-Jurassic and Devonian charge elements. Given the complex structural history of the area there was uncertainty over the oil volumes expelled and precise drainage vectors.

The main pre-drill risks were reservoir presence for both Burns sandstones (early and late Volgian) and intra-formational top and side seal integrity, particularly seal capability of the Smith Bank Fault for Coracle (Cretaceous), Alness (Mid-Lower Jurassic) and Findhorn (Permian) sections.

None of the Burns sandstones were present. No hydrocarbon shows were encountered in any of the sandstone reservoirs and log analysis indicates all the reservoirs were water bearing. Estimated gross reservoir thickness was always larger than that actually drilled, particularly for the Coracle Sandstone (EK3b) and the Alness Spiculite Members.

Formation tops also came in significantly shallow to prognosis for reservoirs older than Cretaceous, where present, and much deeper for reservoirs within the Cretaceous, being outside of the prognosed depth error ranges at all target level.

Fluid inclusion analyses were carried out on 171 samples by Fluid Inclusion Technologies (FIT). Poor FIS signal strength and low visual liquid petroleum inclusion abundance suggest that a migration pathway may have existed around the drilled Gemini location, with subsequent migration of petroleum into areas without trap presence or integrity.

Except for the 2 Burns objectives which were absent, the identified pre-drill critical seal risk is believed to be the main reason for failure and explain the lack of oil shows. In particular, the sealing potential of the Smith Bank Fault is questionable due to ongoing tectonic activity, with the Fault intersecting present-day seabed. As such, the Fault could have acted as a conduit for hydrocarbon migration to surface through geologic time. Furthermore, cross-fault reservoir juxtaposition could have also resulted in migration away from the drilled location.

<u>Company perspective main lessons learned:</u>

- A careful reconstruction of the structural history (incorporating estimate of the eroded Tertiary series) would have better constrained the kitchens potentially able to source this prospect.
- The top and side seals required for hydrocarbon accumulation and the integrity of the main bounding fault, in terms of cross-fault juxtaposition relationships and vertical seal integrity, are elements which should have been worked more in depth (Shale gouge ratio, Allan diagrams) as well as improved depth conversion of seismic horizons. Indeed the pre-drill geological cross section along the Smith Bank crest (**Fig. 35**) highlights 2 worrying observations: (a) the major fault bounding the prospect to the south is still active at sea bed and (b) the Cretaceous reservoirs are all subcropping at sea bed to the west of well 12/23-2.

OGA perspective:

- Most of the pre-drill prospect description was provided via a third party (thanks to TrapOil). This highlights the fact that all well data should be transferred from the well operator to the next license owner: in that respect, OGA should properly store and manage these data. OGA should also request and obtain G&G pre-drill description which at the moment is not required in any of the existing PON.

Fig. 34 – Gemini prospect: structural setting **(Seismic data courtesy of WesternGeco)**

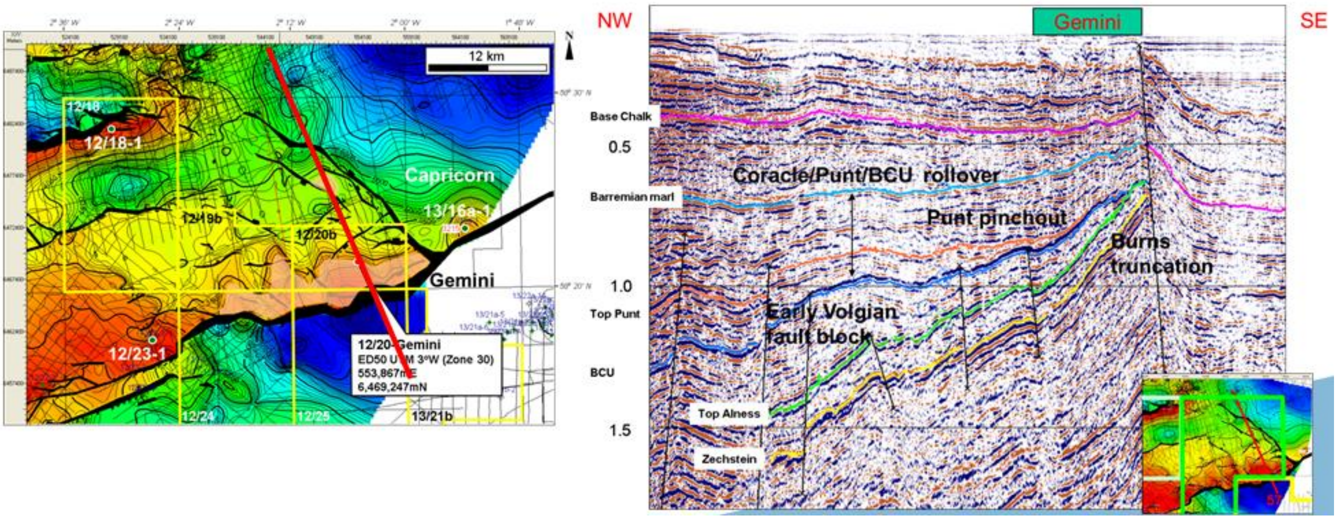
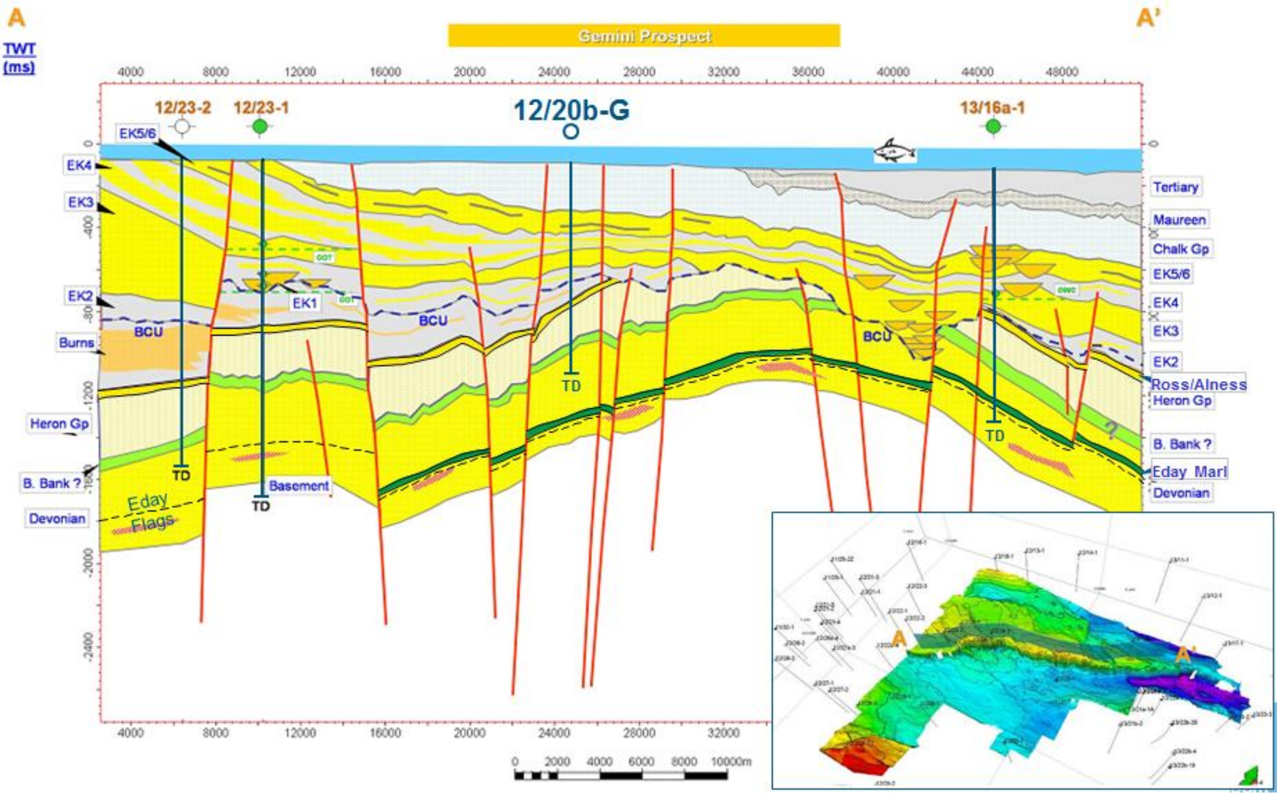


Fig. 35 – Gemini prospect: geo-seismic cross section along the Smith Bank crest



3.15. Dana Petroleum: well 13/23a-7 &-7A, Magnolia prospect

The 13/23a block with associated commitment (Minos prospect at that time) was picked up when Dana Petroleum bought **Bow Valley**. Reinterpretations of Minos led to it being discarded and replaced by Magnolia.

The trap was described as a 3-way dip closure and 1-way pinch out onto the Halibut Horst (**Fig. 36**). The structure was formed by a prominent ridge plunging southwards from the Halibut Horst into the Smith Bank Graben. Magnolia was a stratigraphic play and the well location was a long way down-dip from the pinch-out edge. The prospect was targeting Lower Cretaceous reservoirs at 3 levels: from top to bottom, Captain Sandstone (Albian/Aptian), Coracle Sandstone (Hauterivian) and Punt Sandstone (Ryazanian to Valanginian).

The proven oil kitchen for the Block lies to the south of the Halibut Horst and involves the Kimmeridge Clay Formation. Charging of the terrace within which Magnolia is located is proven in the Tain discovery to the east and the Surprise discovery to the west. The Captain Field to the north and the Jurassic Phoenix discovery to the south provide significant proof that hydrocarbon charge is unlikely to be a problem. Claystones of the Rodby and Carrack Formations should provide the top seal while the Kimmeridge Clay Formation was estimated to be thick enough (100 ft.) to provide an efficient bottom seal.

The overall CoS was set at 31% with the main risk being the seal effectiveness (50%).

All horizons came in within error bars. The Captain Sandstone reservoir came in as per prognosis while the Coracle and Punt show lower NTG and lower average porosity than predicted. All 3 targets are water bearing. The main reason for failure is interpreted as being the lack of bottom / lateral sealing against Old Red Sandstones. A secondary cause for failure may be that although the structure existed at time of migration, there was no access from the K50 sand carrier bed to any sand in Magnolia: unfortunately no post well FIS analyses was performed. In addition, both Captain and Coracle sandstones were found quite blocky at 13/23a-7A well location meaning that the expected pinch-out may either not exist or be located further up dip.

Main lessons learned:

- Pre-drill, migration was not considered as being a risk. In addition, no FIS study was performed post-well (should have been a minimum post-well study as the well was dry!) preventing any proper lesson learning from this well failure.
- The Top Coracle surface should have been more extensively mapped (**Fig. 37**): the existing map does not allow proper definition of the trap, hence it does not help focus onto the weakest parameters of this Magnolia prospect. Indeed, the prospect concept looks OK on the NS line but there is no closure shown on any map where it should be closed.

Fig. 36 – 13/23a-7A well location – Dip line 4455 **(Data provenance uncertain: Chevron proprietary, WesternGeco?)**

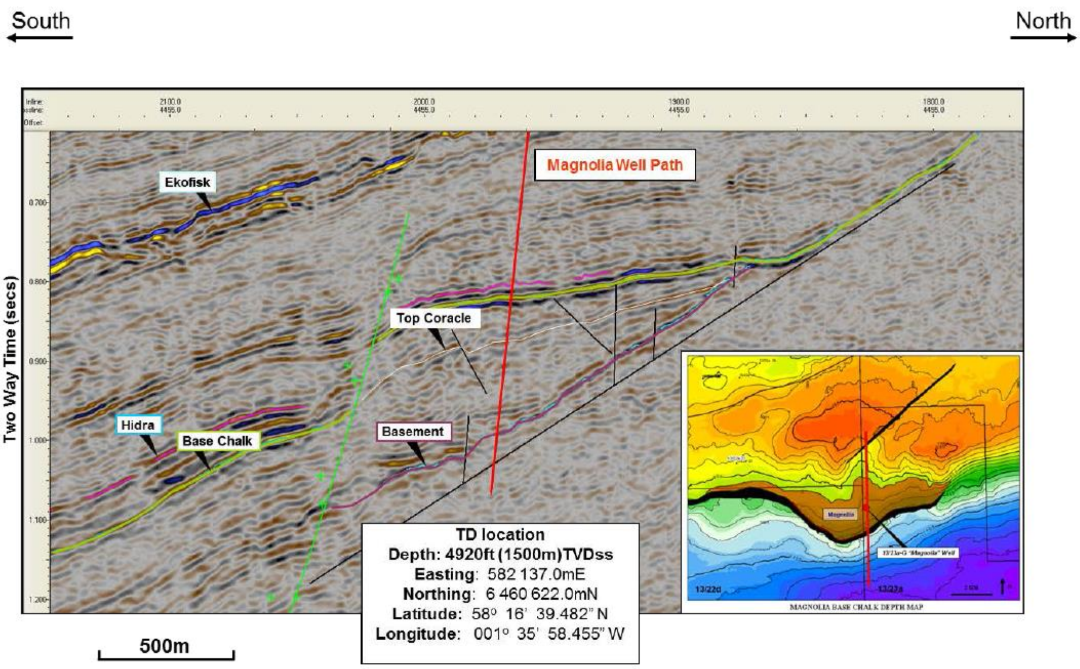
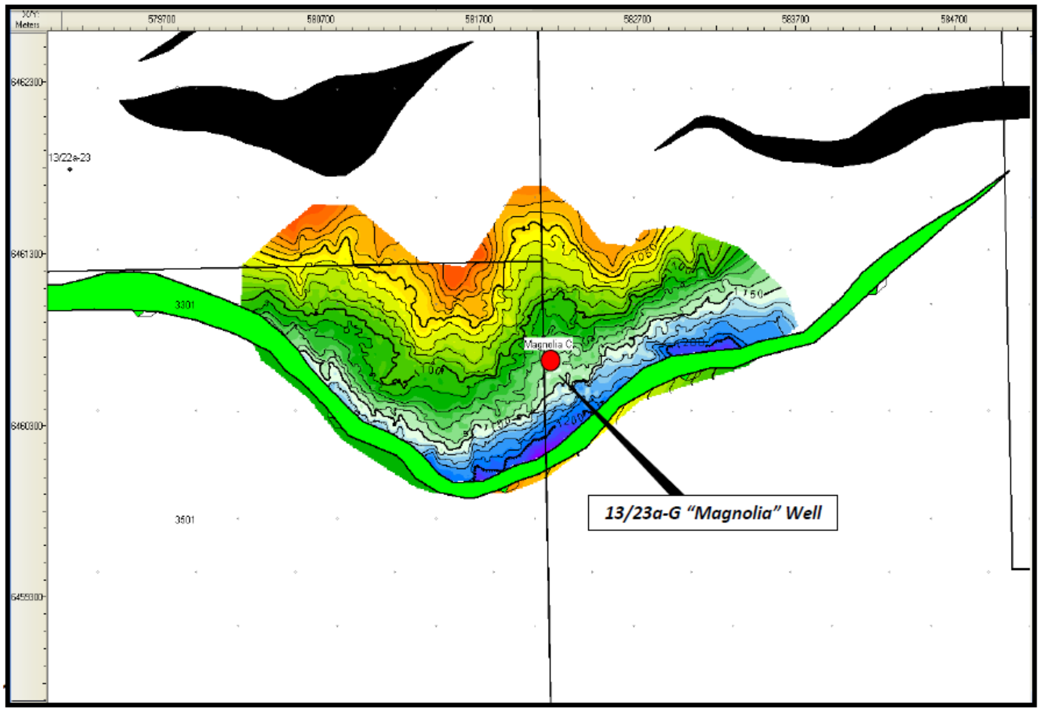


Fig. 37 – Magnolia prospect Top Coracle depth map



3.16. Dana Petroleum: well 13/23d-8, Liberator prospect

The Liberator Prospect is defined as a four-way dip closure formed by differential compaction of the Captain sandstones on the western side of the Blake channel portion of the Blake Field.

The seal is formed by the Albian shale of the Rodby Formation (the presence and effectiveness of which has been proven in nearby wells including the Blake Field and is considered certain to be present and effective over the Liberator Prospect).

Hydrocarbon charge is assessed to be proven by the location proximal to the Blake Field (of which Liberator could be considered an extension) and by the presence of residual oil columns in multiple wells in Blake, and below the spill point between the two structures.

In common with much of the Inner Moray Firth, due to the weak reflectivity contrast between sandstones and shales, direct interpretation and mapping of the presence of sand over Liberator is not possible (**Fig. 38**). Additionally, the VP/VS properties of the sand and the surrounding shale do not allow for AVO discrimination. As well as the lack of reflectivity, seismic data in this area also exhibit a poor signal to noise ratio making the interpretation process challenging.

The overall CoS was estimated at 35% with reservoir presence (50%) and trap configuration (70%) being the main risks associated with the Liberator prospect.

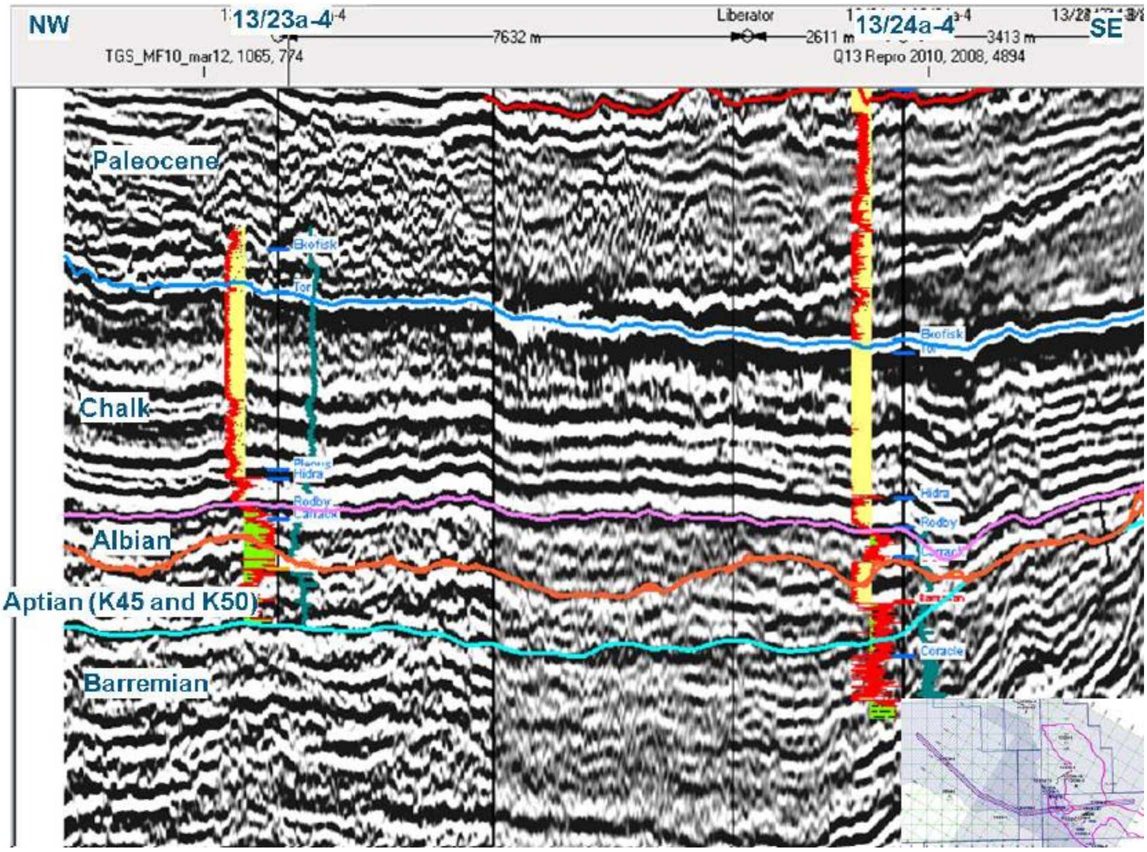
Well 13/23d-8 found the top reservoir 105 feet deeper than expected and overall petrophysic characteristics in line with prognosis. Only the top was found to be fully HC bearing.

The main reason why the trap was not filled as per expectation is thought to be linked with the trap definition. As there was only 3-6ft average difference between pre-drill time depth and post VSP one it is felt that the geometry of the trap was not found as per expectations because of seismic pick rather than the time depth conversion.

Main lessons learned:

- Acquisition of 3D broadband seismic should be done. Wider frequencies should help better discrimination between sandstones and shales in this area of the Moray Firth.

Fig. 38 – Liberator prospect: Seismic Line between 13/23a-4 well and 13/24a-4 Blake Field well **(Data provenance uncertain, please contact BG, Talisman, TGS)**



3.17. Dana Petroleum: well 21/20f-7, Morgan prospect

Dana Petroleum farmed in Noble Energy operated block 21/20f.

The Morgan prospect, located ~25 Km due west of Montrose Field, was a simple 4 way dip closure (**Fig. 39**) targeting two reservoir targets, the Balmoral Sandstone Member and the younger Forties Sandstone Member, both of Palaeocene age. In this area, the sandstones comprise channelised deep-water turbidites in the Forties and more distal fan deposits in the Balmoral Member.

These were expected to be sealed by shales of the Lista Formation and Sele Formation, respectively. No top seal risk was anticipated at the well location as the edge of the nearest Eocene sand fairway, that of the lower Tay Sandstone, lies approximately 10 Km to the south of the prospect.

Oil was expected to be sourced from the Jurassic Kimmeridge Clay, migrating in through faults in the Cretaceous Chalk and hence up dip within the Palaeocene sands. Due to its structural location, the Morgan prospect was believed to lie on a migration pathway via the Gannet D Field. Fluid properties were therefore assumed to be similar to Gannet D, rather than similar to the Forties-Nelson and Montrose-Arbroath areas.

Re-mapping of the seismic led to the recognition of a possible AVO anomaly with good fit to structure within the Balmoral, rather than the overlying Forties interval, possibly indicative of relatively thicker, better quality Balmoral Sandstone as opposed to the more thinly interbedded Forties Sandstone.

The overall CoS was estimated at 45%. The corresponding risking parameters were not available and the critical risk at time of drilling is not known.

The well 21/20f-7 found both Forties and Balmoral deep to prognosis and out of the error bars. This is either because of slight mis-pick of seismic horizons or because of potential small change in predicted overburden velocities.

The quality of both reservoirs was broadly in line with expectations despite lower Net to Gross Ratios. Forties Formation was found water bearing but Balmoral Formation was found oil bearing: however resources were below the predicted P90 volume making this discovery non-commercial.

Clearly the Morgan trap was not full to spill. The fact that the Lista shale becomes sandy to the north may possibly explain seal failure in the northern flank of the Balmoral prospect, limiting the container size. Or does the fault noted at top Sele (IL 13114, **Fig. 40**) allow reservoirs to leak? Indeed lack of charge is not a realistic explanation because both Scolty and Crathes have been discovered further west.

<u>Main lessons learned:</u>

- Acquisition of broadband 3D seismic data *may* have helped increase the resolution allowing discrimination of thin potential thief zones compared to the 2005 reprocessed Shell E91100 and Enterprise E90UK12 surveys.

Fig. 39 – Morgan prospect: Top Balmoral Sandstone Depth Structure Map

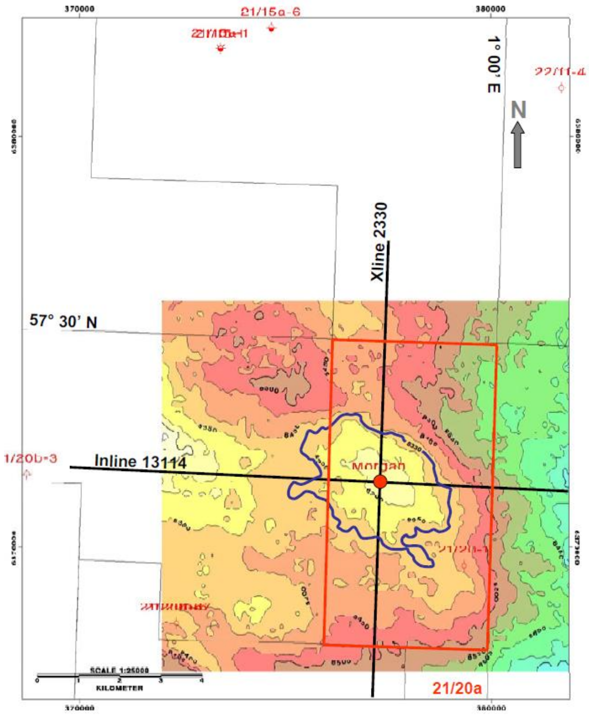
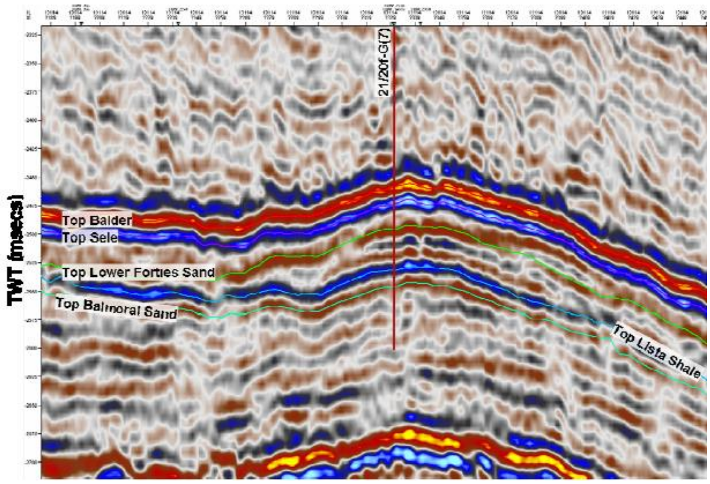


Fig. 40 – Morgan prospect – Seismic inline 13114, near offset **(Fugro data courtesy of Spectrum)**



3.18. Bow Valley Energy well operator, (Dana Petroleum current well owner): well 22/11b-13, “L” prospect

This well was drilled by Bow Valley which was subsequently purchased by Dana Petroleum.

Well 22/11b-13 targeted 3-way stratigraphic closures against Forties-Montrose Platform bounding fault on a structural terrace between the Forties-Montrose High to the NE and the West Central Graben to the SW. This was one of the flanking Fulmar prospects located to the SW of Nelson Field (**Fig. 41**): it was drilled after the Howe discovery and is considered as a Howe analogue.

Three stacked Upper Jurassic sand pods were identified, named from top to base as FN7, FN6 and FN4. The 22/18-6 Wood oil discovery was interpreted as the analogue Fulmar shoreface reservoir for the “L” prospect. Top seal was expected to be provided by the Kimmeridge Clay Formation and up dip lateral fault seal was expected. The prospective interval corresponded to high amplitude continuous seismic reflections against a reflexion free interval to the north-east.

The overall CoS was estimated at 24% with the seal (50%) and the reservoir presence and effectiveness (60%).

All the horizons above Valhall came in more than 230 feet low, while Top Triassic came in 419 feet high to prognosis. Only one (FN4) of the three stacked 'pods' contained sand: FN4 pod contained good quality water-wet “Fulmar 2” sandstones, overlain and pressure-separated by silty shale from a 10ft oil bearing “Fulmar 1” sand. The small volume of oil in the “Fulmar 1” sequence is trapped stratigraphically by the thin sandstones pinching out before the fault. By contrast, the thicker “Fulmar 2” sandstones extend to the fault and are not sealed. As a summary, it looks like there was no effective significant trap but "L" prospect was on the migration pathway towards Nelson.

<u>Main lessons learned:</u>

- The seismic interpretation was pushed too far and over interpreted (**Fig. 42**). The assessment telling that 1 Fulmar pod = 1 seismic reflection was not supported / challenged by any seismic modelling found.
- The overall thickness of the targeted interval (<100 msec TWT) was most likely too thin to provide at the same time thick reservoirs and a thick source rock, as a consequence, sourcing was expected from the West Central Graben although no basin modelling was apparently performed.

Fig. 41 - 3D schematic of Upper Jurassic sand distribution hung on Base Cretaceous surface: view from NW

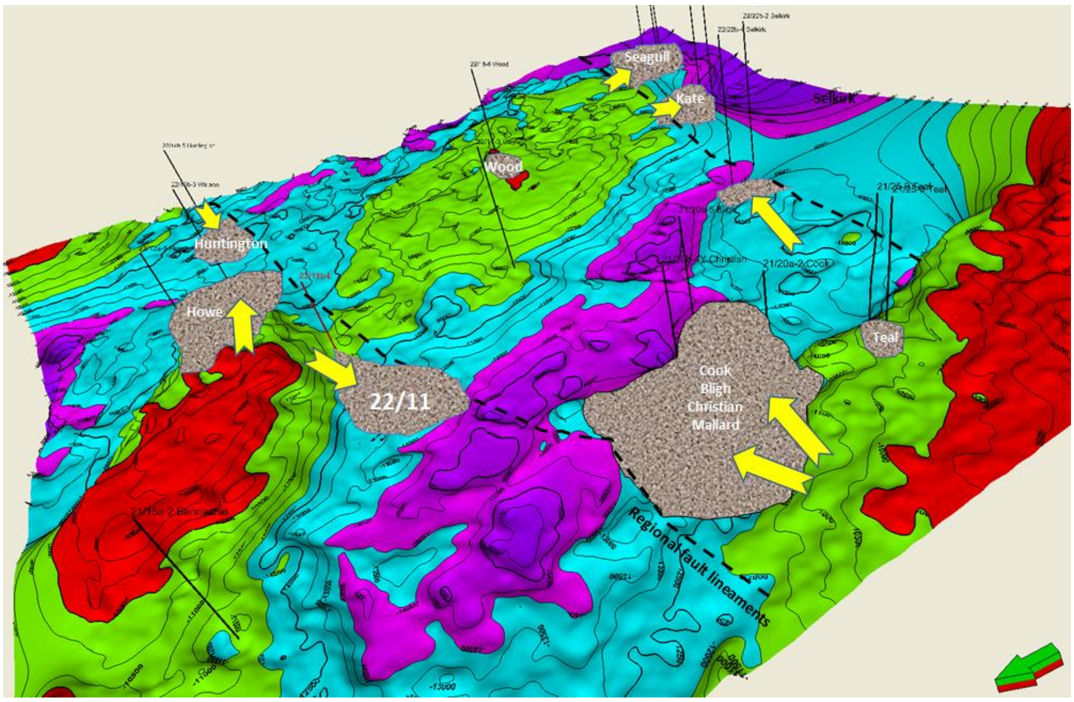
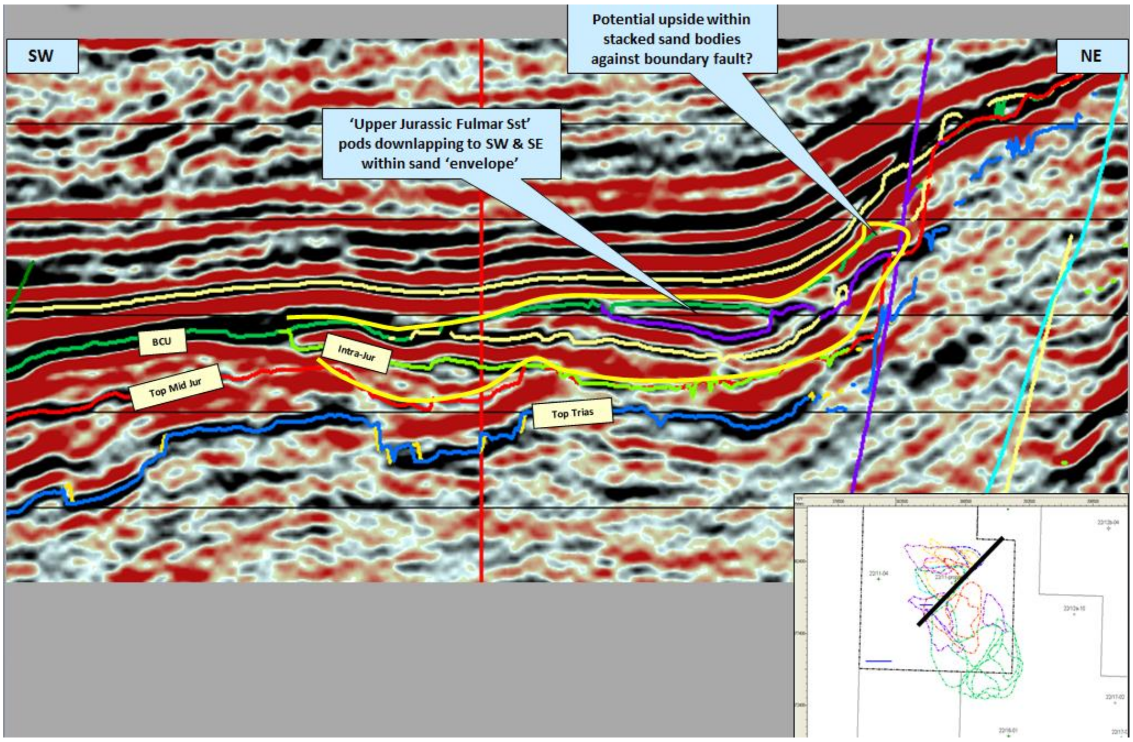


Fig. 42 – 3D Pre-STM PGS Plus: Detail of stacked, downlapping Upper Jurassic sand pods



(Data courtesy of PGS)

3.19. Dana Petroleum: well 23/11-04, Fiacre prospect

The Fiacre prospect was a Jurassic interpod targeting Ula Formation reservoir between pods of Triassic Smith Bank Formation (**Figs. 43 & 44**). The top seal was provided by the Kimmeridge Clay Formation shales and the lateral seal by the Smith Bank Formation. Sourcing was interpreted as coming from the Kimmeridge Clay Formation seated immediately above the Fulmar interpod. Here too the overall thickness of the targeted interval (<50 msec TWT) was most likely too thin to provide at the same time thick reservoirs and a thick source rock (**Fig. 45**). Apart from this downward migration pathway, there appears to be no connection to a wider (and deeper) kitchen. As a result, there should have been a greater risk attached to the migration pathway and the hydrocarbon volumes available to trap.

Indeed the overall CoS was set at 35% with the reservoir presence (65%) and seal effectiveness being the two identified critical risks.

All picked horizons with the exception of the tops below the Kimmeridge claystones (but for those horizons success was not deemed depth dependant) were encountered at depth within the bounds of the prognosis error bars. The Ula Formation petrophysical characteristics were within prognosis albeit on the lower end of the quality expectations. Ula sandstones exhibited a degree of overpressure but no oil and gas shows were observed and the logs indicate they were water bearing.

In addition, there was a thin, unexpected sequence of sandstones/siltstones at Forties level - gas bearing but with very poor reservoir quality.

The main reason for failure is interpreted as being related to source rock and particularly ineffective migration pathways, either laterally across the Smith Bank pods or downward because of the overpressure observed in the Ula Formation. However, migration and source rock maturity are also questionable. A secondary reason for failure may have been the lack of effective lateral seal due to silts in both Triassic pods.

Main lessons learned:

- If the in-situ Kimmeridge Clay is not mature enough and / or the overpressure in the reservoir prevents the downward migration, as the trap is not connected to any other kitchen, it would be impossible to source this prospect. A detailed pre-drill basin modelling would have been an absolute pre-requisite: it would likely have highlighted a much higher migration risk and the potential risk attached to the thinness of the targeted interval (i.e. <50 msec to accommodate both a thick enough mature source rock and a significant reservoir).
- The seismic interpretation (picking + map) should not be solely limited to the perceived prospect. Indeed this “postage stamp” approach does not allow proper understanding of the geological context. Hence the main risks attached to this prospect were not appropriately understood.

Fig. 43 - Fiacre prospect:

Top Ula Formation Depth Map

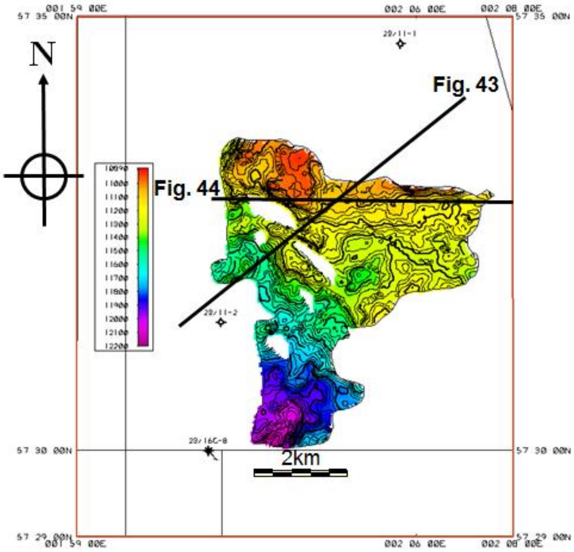


Fig. 44 – SW-NE Geological cross section

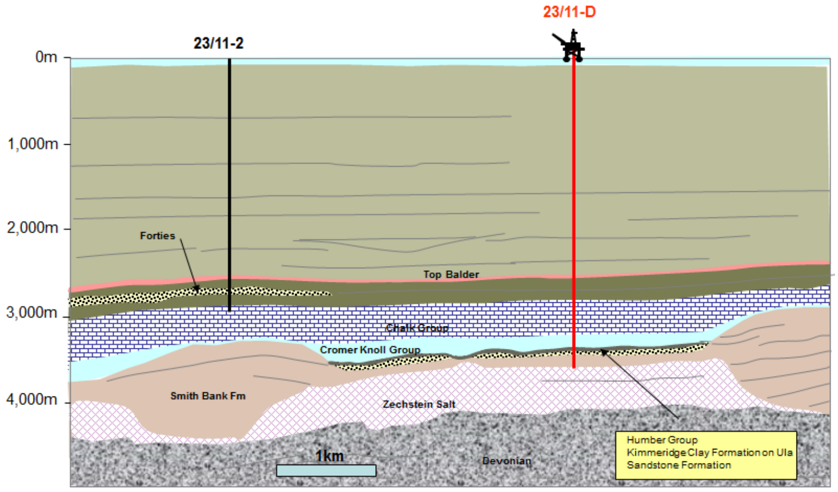
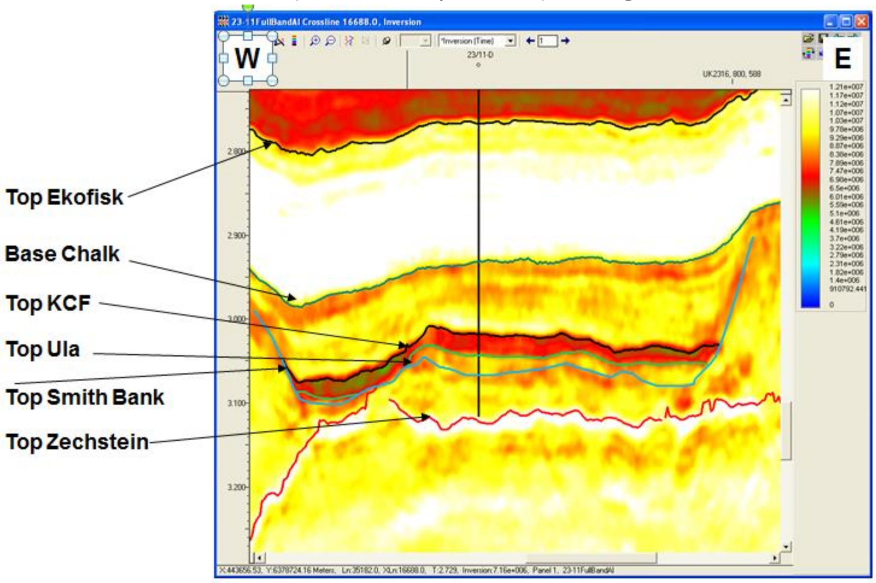


Fig. 45 – West-East seismic Cross-Line 16686 (Acoustic Impedance) through Well Location



3.20. Endeavour: well 15/27-10, Roisin prospect

Well 15/27a-10, an unsuccessful HPHT well drilled to test the Roisin prospect, was drilled by Talisman Energy UK and is now owned by Endeavour. It targeted two superimposed sand wedges - Lower Cretaceous (Scapa sandstone Member) + Upper Jurassic (Galley sandstone Member) - down dip from the Renee ridge in the South Telford sub-basin (**Fig. 46**).

Migration was considered low risk as the source rock would have been immediately below the target Scapa reservoir. The sealing mechanism was more complex as it involved Valhall claystones as top seal, Kimmeridge Clay Formation as the bottom seal, an up dip pinch-out towards the North while the lateral sealing was downthrown against the Renee ridge.

Risking was combined for Lower Cretaceous Scapa Sandstone Member and Late Jurassic Galley Sandstone Member. The reservoir presence was not seen as a major risk (70%) based on setting, seismic character and analogues and the main risk was deemed to be the reservoir quality because of the significant burial depth. The overall CoS was estimated at 24% with the reservoir quality (55% due to depth of burial) and the lateral / bottom seal (60%) seen as the critical parameters.

Four (4) pre-drill geological setting scenarios and associated pore-pressure predictions were built in order to safely plan this well which was assessed by Talisman as being an HP-HT well.

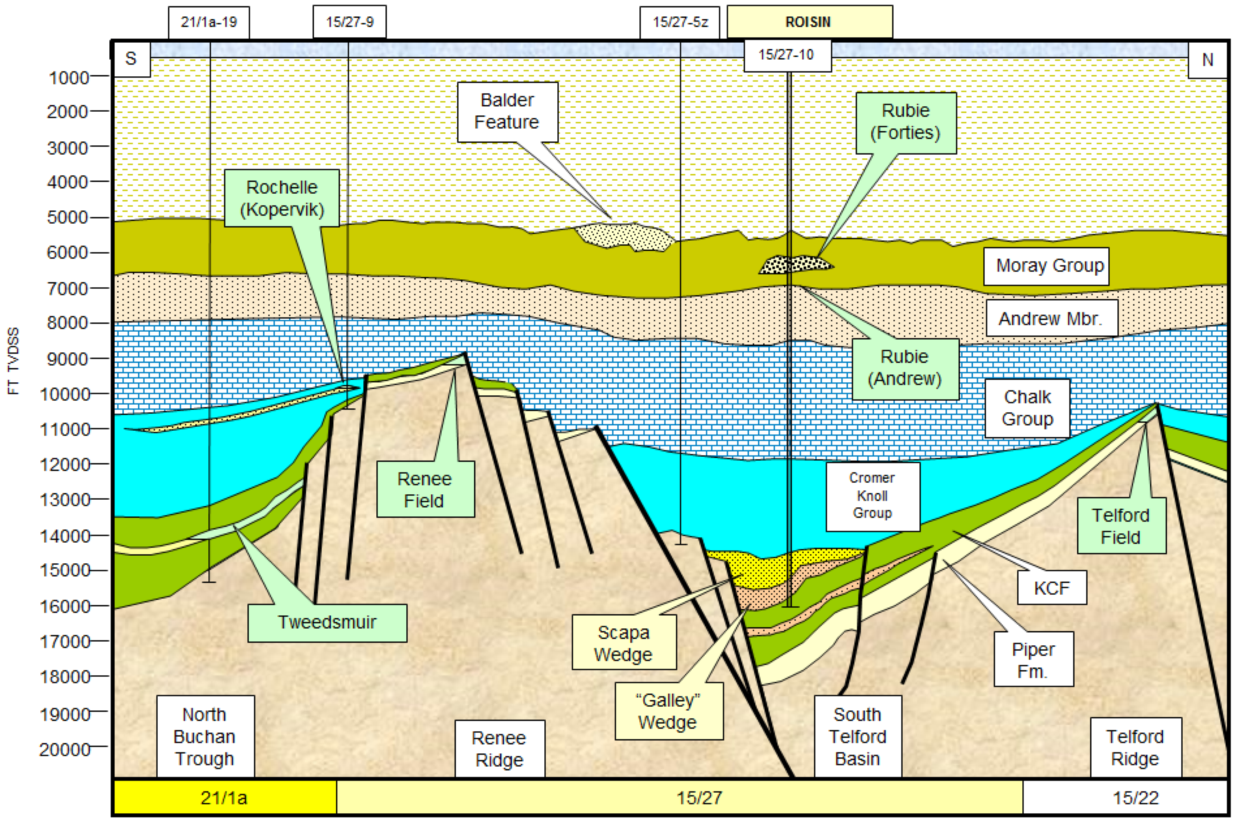
Kimmeridge Clay was encountered 656 ft higher than prognosed and the Scapa wedge was not found because the top Scapa seismic pick (pre-drill) proved to be the BCU (post-drill). The well did encounter the Upper Jurassic Galley wedge; however this had a low Net: Gross ratio. Where minor Galley Sands were encountered in rare thin sandstones stringers, these contained high pressured hydrocarbons and resulting in 3 well control incidents. The Upper Jurassic Galley wedge probably corresponds to a small locally sourced isolated accumulation. The total wedge thickness was close to expectation although all is Upper Jurassic Kimmeridge Clay Fm. Pore pressure profile was also within expectation. In line with the most common outcome, Post-drill volumes are at the very low end of pre-drill estimate (i.e. between pre-drill P95 – P99).

The well failed to find a commercial hydrocarbon accumulation due to insufficient sand supply to the local region.

<u>Main lessons learned:</u>

- The well appeared to be geophysically driven because there were not so many deep well penetrations in similar settings in the area.
- This case study highlights the key value of detailed pre-drill studies, not only to help describe the expected prospect size, but also for HSE reason (safe well planning).
- An alternative geological model with higher BCU pick was recognised pre-drill and assigned 20% chance. It is not clear, given the paucity of available data, whether this was incorporated into the final risk profile for the well.
- Explorationists tend to narrow down the geological model on one scenario when a breadth of options is possible. It's quite often difficult to get out of this state of mind and consider a range of scenarios.
- It was observed that historic data (e.g. biostratigraphy, geochemistry, subsurface temperatures…etc…) are scattered / not available / not standardised. There is scope for in-fill analyses and regional studies to help with regional picture while companies are often doing very license focused works.

Fig. 46 – Roisin Pre-drill description: geological cross section illustrating the 2 targeted wedges



3.21.Endeavour: well 30/23b-4, Balgownie prospect

Well 30/23b-4 targeted two superimposed segments. The primary objective was a 4-way dip closure involving shallow marine sandstones of the Upper Jurassic Fulmar Formation. The secondary target was a fault dependent, 3-way dip closure at top Rotliegendes level. Regarding the Fulmar target, the top seal was provided by both the Kimmeridge Clay Formation and the tight Ekofisk chalk Formation which progressively truncates the reservoir in the east. Base seal was provided by the Pentland and/or the Smith Bank Formation.

Although we don't know the maturity of Kimmeridge Clay Formation at the well location, long range migration from the east (Central Graben) is most likely required to source this prospect. Continuous carrier beds would therefore be the key requirement for a successful well. The key pre-drill risk was indeed the migration-charge although it was not severely assessed (75%) and the overall CoS was estimated at 52%.

Balder to Maureen horizons are within error bars (+/- 50 ft). All deeper horizons are outside the error bars (+/- 65 ft). The well encountered an unexpected Cromer Knoll section and the resulting thickness of the chalk section (+ velocity) was not therefore as predicted. It's difficult to say if these outcomes result from picking mistakes or time/depth conversion issue. However this raises the question: is there a valid trap? Kimmeridge Claystones have been drilled at well location (122 ft thick). The Fulmar objective was found 189 ft deeper than prognosed, on the low side regarding thickness but with good reservoir characteristics. Both the primary and secondary targets were found to be water bearing.

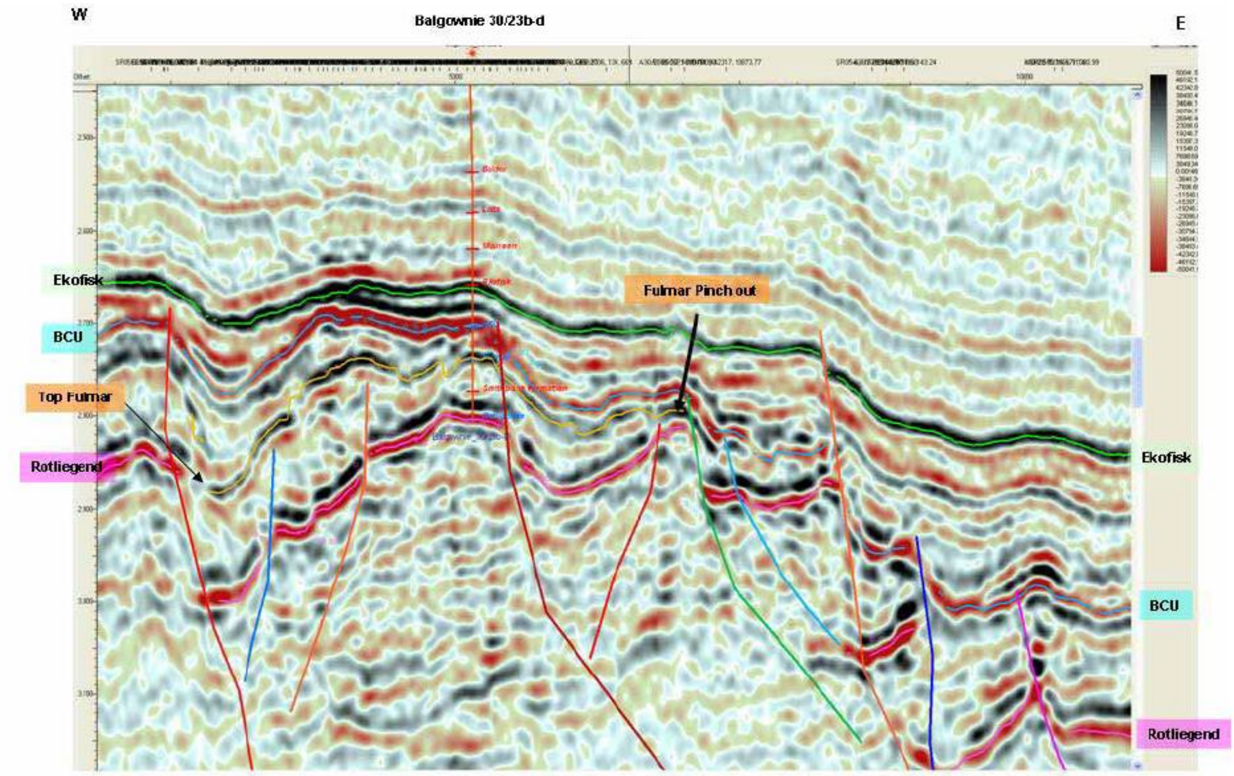
According to initial petrophysical calculation there would be residual hydrocarbons. However, "subsequent geochemical analysis by Fugro Robertson Ltd of extracts from the Fulmar Formation's cuttings, drilling mud and base oil confirmed the absence of any significant indigenous oil saturations."

As a consequence the main reason for failure is deemed to be the lack of charge and especially the lack of migration pathways (i.e. lack of continuous carrier bed connected with the Central Graben kitchen to the east, **Fig. 47**).

Main lessons learned:

- Given Balgownie structural setting, basin modelling focusing on drainage areas and migration pathways should have been performed pre-drill.
- A post well map derived from updated velocities would be required to validate that there was a valid structure in depth.

Fig. 47 - Balgownie 30/23b-d well tie to E-W seismic section (XLine 1464) (Data Shell proprietary)



3.22. Endeavour: well 31/26b-17, Turnberry prospect

The Turnberry prospect was within a large four-way dip closure at Base Cretaceous level. Its lowest closing contour (LCC) was at same depth as the OWC in the Flora Field (**Figs. 48a & b**). The Flora field is within this dip-closure and its reservoir is the Carboniferous with a thin covering of Jurassic while the Turnberry Prospect target consists in Late Kimmeridgian to Volgian Fulmar Formation shelfal sandstones where the Fife thickens was supposed to expand.

The Kimmeridge Clay Formation is the known source rock for the area although it was anticipated to be absent or very thin at the proposed well location. A fill and spill model was invoked from Flora Field into Turnberry (sharing the same OWC) and then from Turnberry into Fife.

Pre block award, the initial prospect mapping was made on the 3D PGS merge while detailed mapping and well planning used the 2003 Fife Area Reprocessed 3D data. The quality was deemed good and nobody thought the BCU pick could be wrong. The overall CoS = 66% was high but no detailed risking parameters have been provided.

In well 31/26b-17, the expected Fife sandstone target was absent and the corresponding interval turned to be Lower Cretaceous interbedded claystones and limestones. The Fulmar Formation is very thin (17 feet gross) which makes its continuity questionable. 12 feet net Upper Jurassic sandstones were deeper than Flora's OWC and water bearing.

Poor oil shows and observed gas increase in the Tor Formation demonstrate that the timing of HC generation and migration was good. Charge or migration into the pre BCU section has not been proven whereas oil migrated in Tor Formation. The lack of continuous carrier bed connecting Turnberry to a deeper active kitchen is the likely cause of failure. Another reason for failure is shown on the pre-drill North-South cross section below (**Fig. 49**) which shows that a sand to sand juxtaposition was expected immediately to the North of Fife: as a result fault sealing effectiveness should have been highlighted as a significant risk.

Main lessons learned:

- Although several companies (5 including farminees) participated in the well, the seismic picking (BCU and Top Zechstein) was not challenged as the seismic reprocessing looked good and everybody agreed with the single scenario supporting Turnberry.
- Flora production data being limited did not shed much light on potential additional oil volumes in the adjacent Turnberry prospect.
- Rock Physics modelling (inversion) and a detailed study of the bounding fault behaviour (N-S fault cutting through the overall 4 way –dip closure) may have helped open the range of geological models.
- Given the well results, alternative geological models should have been considered in order to potentially construct a different risk model, as the seismic data did not highlight the actual issues encountered.

Figs. 48a & b – Base Cretaceous depth map: Flora area (**a**) and detail over Turnberry (**b**)

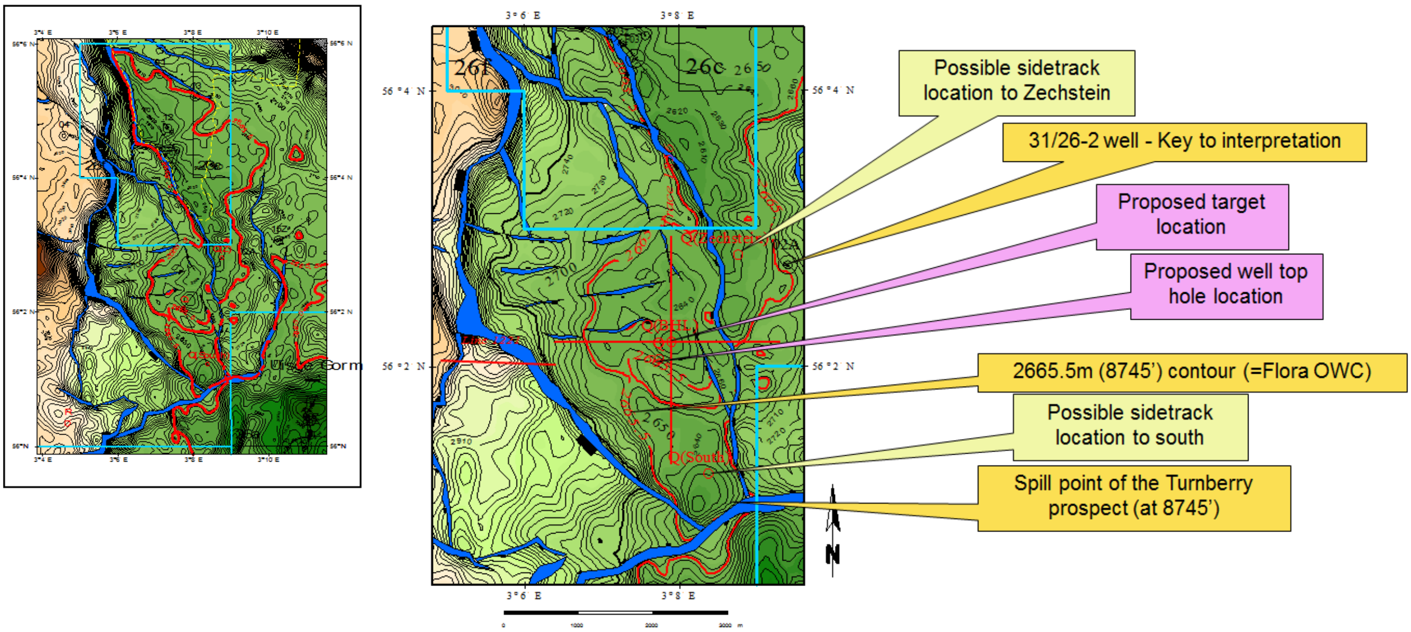
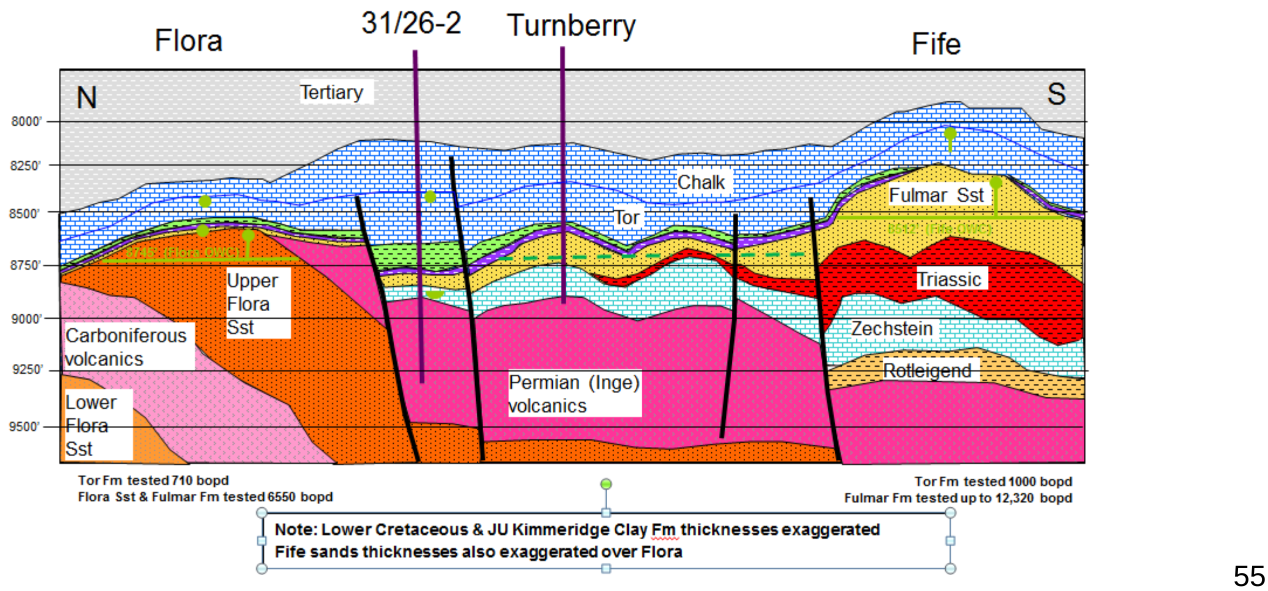


Fig. 49 - Turnberry N-S schematic geological cross section



3.23. Endeavour: well 31/26b-18, Turriff prospect

31/26b-18 was drilled as an exploration well to test the Upper Jurassic Fulmar Formation sandstones (known locally as the “Fife” sands) in the “Dead-end” Graben. The primary target was a downthrown fault closure with faults to the south and east, and dip closure to the west and north. The actual location was on a small four-way dip closure at Base Cretaceous level. Within this closure, the sandstones were interpreted as stratigraphically trapped, with a pinch out mapped to the east and north, based on amplitudes, and down thrown fault closure to the west and south (**Fig. 50**).

The Kimmeridge Clay Formation was anticipated to be around 75 ft thick at the proposed well location. The principal source was the Kimmeridge Clay Formation, from which oil migrated laterally 40-50 km from the Central Graben. Migration is thought to have taken place during the Palaeocene to Eocene.

The Kimmeridge Clay Formation acts as a seal where present together with the Cromer Knoll Group, Valhall Formation (claystones, marls, siltstones and limestones). The Smith Bank would act as bottom seal. A strong lateral seal component is required either against pre-Rotliegendes to the south or against Smith Bank Formation to the east.

The overall CoS = 20% was moderate but no detailed risking parameters have been provided.

Lithologies originally prognosed were similar to those encountered. Smith Bank was however 137 ft deep to prognosis. The Kimmeridge Clay Formation top seal was present (67 ft thick TVT). Fulmar sandstones were found 76 ft shallow to prognosis (although thinner and poorer porosity than prognosed) but water wet. No oil shows were encountered.

Geochemical analysis shows that in situ Kimmeridge Clay are marginally immature to early mature for oil and are unlikely to have generated hydrocarbons and also suggest that there is no evidence of migrant hydrocarbons in the Jurassic, suggesting that charge and migration are the key failure modes.

The other main risk element of fault seal has not been proven either way.

<u>Main lessons learned:</u>

- A detailed basin modelling carried out before drilling would likely have helped better assess the key HC migration risk of this prospect.

Fig. 50 - Base Cretaceous depth map with +10 msec to +20 msec amplitude extraction

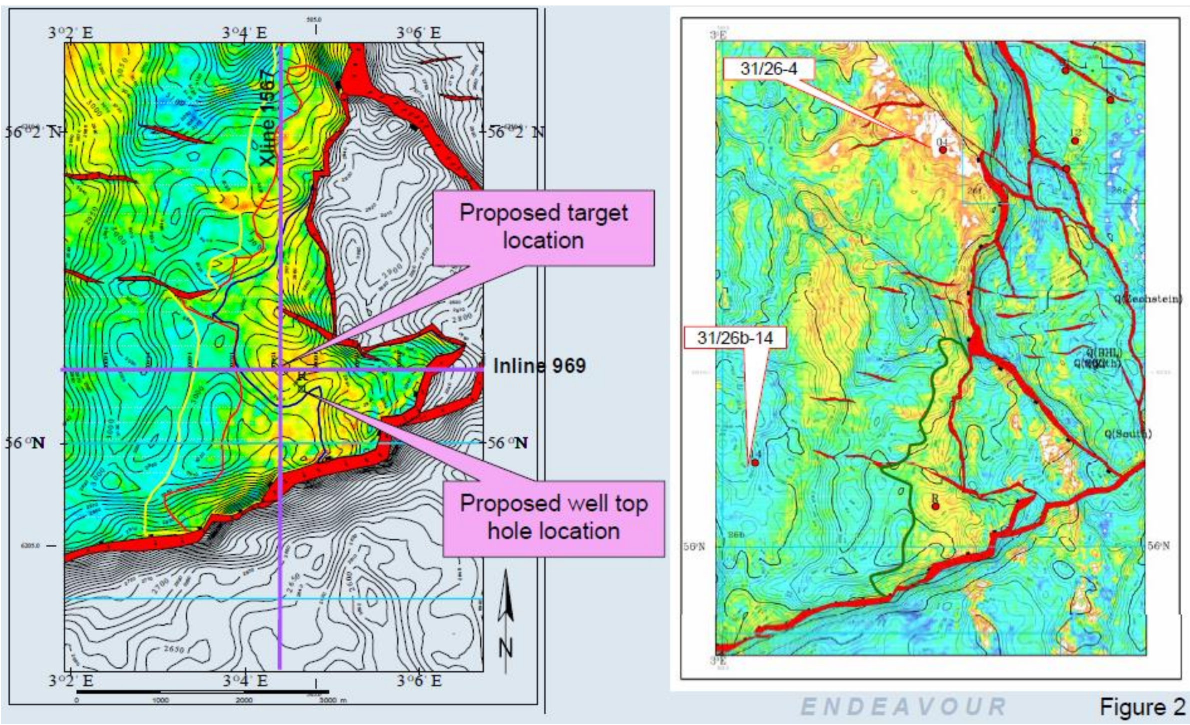
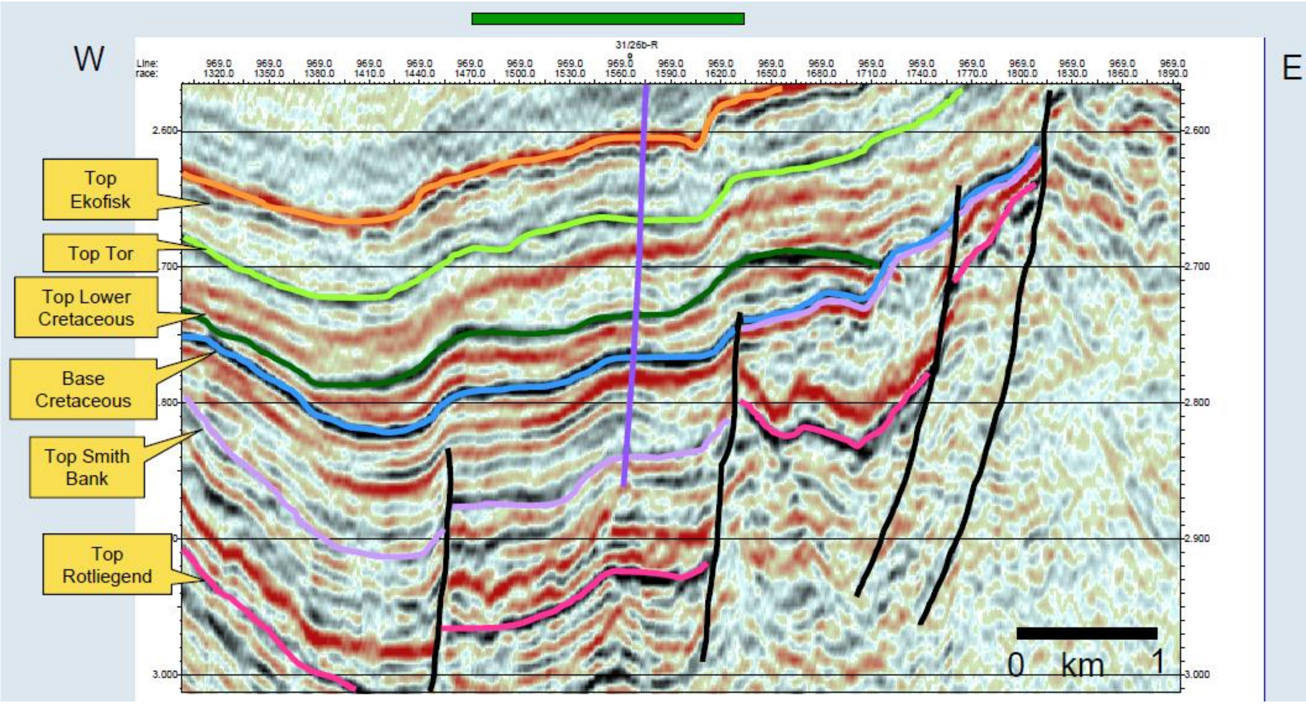


Fig. 51 - West – East Inline 969 through Turriff (Data Amerada Hess proprietary)



3.24. Lundin well operator (EnQuest current well owner): well 12/17b-1, Ridgewood prospect

Well 12/17b-1 was drilled by **Lundin** following a farm-in to Palace Exploration and Britcana's interests for a 30% interest on the 12/17b promote block. Lundin later became part of EnQuest. The Ridgewood prospect was located in block 12/17b in the Wick Basin, within the Inner Moray Firth, 22.2 miles northeast of the Beatrice Alpha platform. The well was designed to test a tilted fault block where the primary target was the Upper Jurassic sandstones of Volgian age. A secondary target, the deeper Beatrice Sandstones, would not be drilled if the Volgian was absent, or, of insufficient quality.

Ridgewood was interpreted as a four-way dip fault related roll over structure, the structure being related to a post depositional inversion of the Upper Jurassic EW basin. The Ridgewood prospect has a bounding fault to the south-west which the vertical well will cut. The basin reduces in size towards the base of the Upper Jurassic seal. At the Beatrice level it depends on the up dip fault seal. The structure was well defined with 2D seismic data. The P50 volumes were defined on the top 150 feet which are within a smaller 4 way dip closure.

The primary objective, the Volgian, was deposited as a mass flow (turbidite) deposit from a provenance area to the north. The Beatrice Sandstone is of shallow marine to deltaic facies.

The source rock is thought to be Devonian with the involvement of marginal mature Upper and Middle Jurassic shales.

The overall CoS was estimated at 18% and the main critical risk was the reservoir presence at 50%.

Well 12/17b-1 did not find a true reservoir section in the primary target objective but only several tight sandstones stringers. Although the Kimmeridge Clay was found 49 feet shallow to prognosis, the major bounding fault was not seen at well location and a time to depth conversion issue is suspected. No shows have been reported. The well TD was called early and the secondary objective was not chased.

The reason for failure is clearly the lack of target reservoir although one cannot exclude additional migration failure.

<u>Main lessons learned:</u>

- This post well analysis has been quite difficult to perform. EnQuest had no in-house data and the data stored in CDA are pretty limited: mostly logs and a so called "Geological Final Well Report" which provides very limited relevant data about the prospect as most of its 23 pages give only basic general information and listings and not a single figure! OGA / CDA must give more stringent rules about which data are requested from the operators.

3.25. Centrica well operator, (EnQuest current well owner): well 21/17a-6, Whitethroat prospect

The Whitethroat prospect was defined by Ventures production (later purchased by **Centrica who operated the well**) and Dana; it was a commitment well on the license. The Whitethroat prospect was a stratigraphic pinch-out on a salt wall ridge; it incorporated a lower risk but small structural 4 way dip closure within a typical Greater Kittiwake Area (GKA) interpod setting (**Fig. 52**). Lateral seal integrity was a significant risk and the model assumed that Fulmar Formation was onlaping and pinching out onto impermeable Smith Bank Formation or tight Skagerrak Formation. The trap was deemed to be well imaged on 3D seismic data.

The up dip Whinchat Skagerrak Formation discovery has an ODT-only and Whitethroat lies on the most likely charge fill and spill route from the deeper areas to the north. The producing Goosander Field was believed to be in communication with a large aquifer or potentially a larger volume of oil outside of closure (potentially combined Whitethroat/Whinchat).

The primary target was the Upper Ryton Member (Upper Jurassic Fulmar Formation) and reservoir characteristics and oil type were expected to be similar to those at Goosander. Simultaneous AVO seismic inversion products appeared to show a reasonable character correlation from the high quality Goosander Field reservoirs along the shared salt wall interpod; this package appeared to pinch out up dip before reaching Whinchat where no Fulmar Formation had been encountered.

Source rock was expected to be the Kimmeridge Clay shales and as Whitethroat was located between Goosander (located down dip and 4.3 Km to the NW of Whitethroat) and Whinchat, the charge risk was seen as being very low.

The overall CoS was estimated at 29% and the main risk was the reservoir presence (= 65%) and quality (=55%) meaning the overall reservoir risk was set at 36% because the observed accommodation space may be filled with Skagerrak or Heather Formations only and the Fulmar reservoir quality could be as low as in Wagtail (8mD average permeability). For upside cases to work, lateral seal was another key risk.

Top reservoir came in close to prognosis although the Fulmar Formation was absent and the Heather shales were directly underlain by approximately 200 ft of Triassic Skagerrak Formation tight continental sands, silts and shales. Gas and resistivity readings both indicated little or no hydrocarbon presence within the formation. Pressure measurement attempts confirmed a very tight formation. This point suggested that the Whitethroat interpod is at virgin pressure, thus making the connection to the Goosander Field very unlikely. The lack of hydrocarbons indicates oil may have by-passed Whitethroat and preferentially migrated through the better quality reservoir into the Whinchat accumulation up-dip, although not of sufficient quantities to allow a 'greater Whinchat / Whitethroat' accumulation.

Main lessons learned:

- The well was a technical failure, for the main risk identified pre-drill, with the primary reservoir target absent and no evidence of significant hydrocarbon saturation was measured. The prospect was at virgin pressure indicating it is not connected to the Goosander field as previously proposed.
- Although a robust seismic inversion (2008, **Fig. 53**) supported the decision to drill this prospect, it was the interpretation of the acoustic impedance character that has proved to be an incorrect stratigraphic correlation. Thus more care needs to be taken to ensure that "seismic" correlations are valid. This was recognised as a key risk and peer reviewed correctly.
- The kind of "summary" map shown below (**Fig. 52**), included in the pre-drill documentation is too focused on the prospect and is lacking all the surrounding geological setting: this does not allow to adequately understanding where the prospect weak points are and how best it can be filled with HCs. However, in this instance a thorough interpretation had been carried out that included significant regional surfaces, with deep knowledge of the play fairways and the prospect was thoroughly peer reviewed prior to approval to drill (personal communications from Andy Alexander & Ernest Robertson).
- One element that might have been missed was the importance of a potential Heather Formation waste zone forcing a shallower spill point to the one mapped.
- Once again, the current well CDA assigned well owner had no deep knowledge about this "inherited" well and the corresponding post well analysis was made easier thanks to Jeremy Lockett from Centrica, and Andy Alexander from Siccar Point. The current CDA assigned well owner, views this as a CDA administrative issue, and does not view this well as being individually that more significant more than other wells within the area. However, they do note that from a sub-regional perspective this well is anomalous in not containing Fulmar sands given the relationship between Fulmar reservoir thickness and BCU to Zechstein isopach. This lack of ownership highlights the need for much more robust data centralization with CDA / OGA and for much easier data access in order for the knowledge of the Basin to be better shared / spread across the Industry.

Fig. 52 - Top Upper Ryton time map (msec TWT)

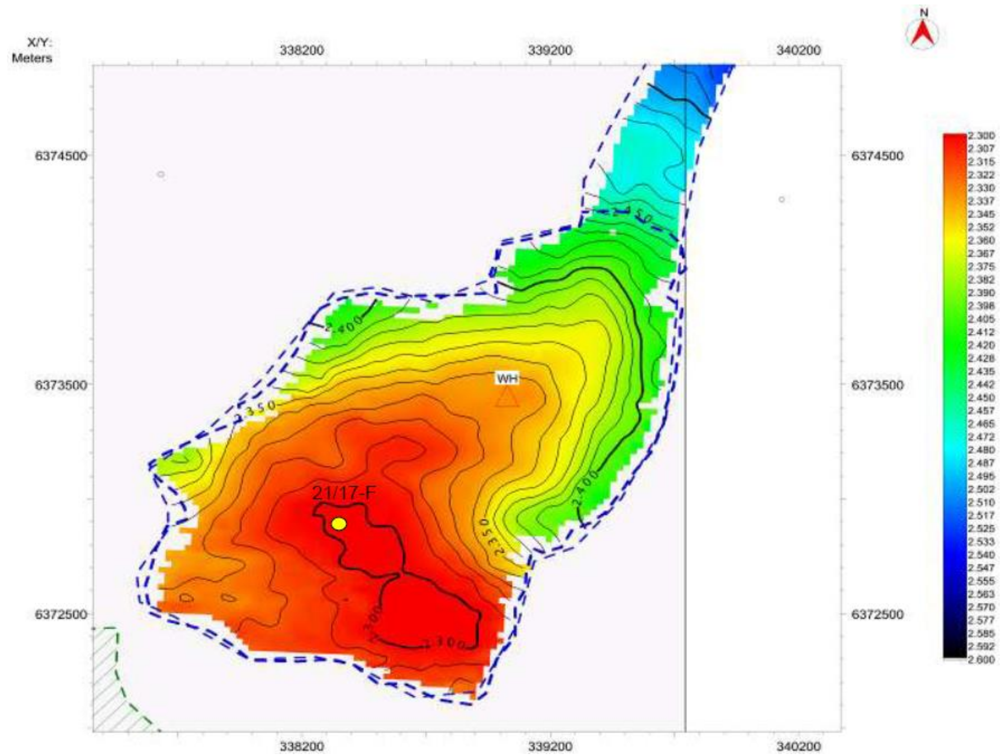
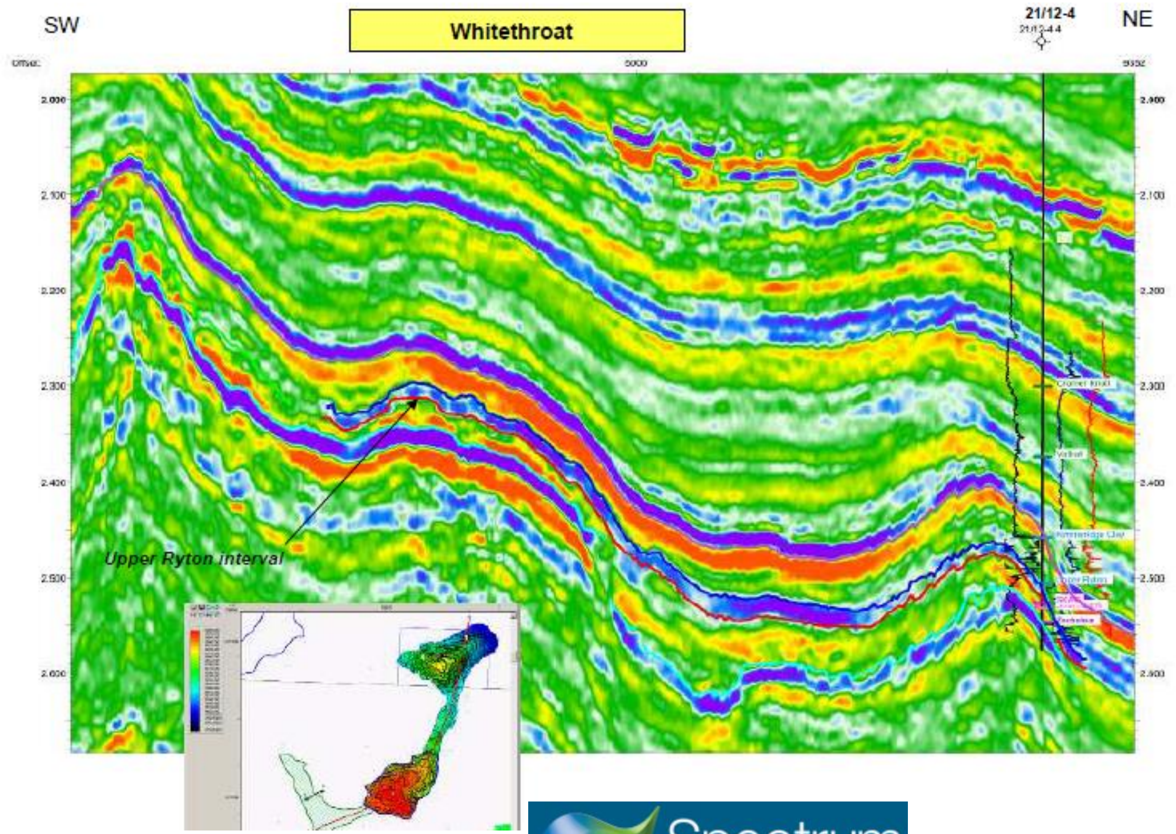


Fig. 53 - SW-NE axial line (IP) from Whinchat through Whitethroat to Goosander



(Fugro seismic data, courtesy of Spectrum)

3.26. Walter E&P UK Operator, (EnQuest current well owner): well 30/28-2, Beta prospect

Well 30/28-2 was drilled by ADTI on behalf of **Walter E&P UK** in the southern part of the Central North Sea.

The Beta prospect was 3-way dip closed to the north, east and south-east and relied upon fault closure (?) and pinch-out towards the west and SW (**Fig. 54**). The stratigraphic section below Upper Cretaceous was difficult to resolve on seismic and remained uncertain. The target reservoir was the Duncan sandstones Formation sourced by the Kimmeridge Clay Formation. The vertical seal should have been provided by Lower Cretaceous and Kimmeridge Clay and up dip fault seal against Permo-Triassic (or older) section was also required.

The CoS for this combined downthrown terrace + up dip pinch-out was set at 16%. The pre-drill critical risks were the control on Duncan Sandstone distribution (thickness & clay content, at 35%) followed by the migration (at 70%). Some partners alternatively highlighted sealing as being the second main risk.

Valhall Formation was not prognosed and turned out to be 173 feet TVT thick. This was compensated by reduction of thickness of the Kimmeridge Clay being only 15 feet TVT. The time to depth conversion was fairly good with the top chalk found 44 ft low to prognosis and the top Triassic found + 10 ft deep. Thin Duncan (Fulmar) sandstone equivalent (14 feet) was present with no reservoir quality (2 feet net sands?). No shows were observed throughout the well.

The main reasons for failure are as follows: first, the target reservoir was absent but, given the very limited sand thickness (if any, as the composite log does not exhibit convincing sands…) the migration pathways from the Central Graben is most likely ineffective, providing a second reason for failure.

<u>Main lessons learned:</u>

- Walter E&P UK having left the UKCS made access to well data difficult and the current well owner had no deep knowledge about this “inherited” well. Some useful data have been provided by Peter Gibbs.
- From a technical standpoint, in-depth semi-regional basin modelling would likely have shown that the sourcing was quite risky (particularly the migration pathways as shown on **Fig. 55** which illustrates the pretty thin Jurassic section between blue and yellow seismic horizons) and the hydrocarbon amount available to trap too small.

Fig. 54 - Beta prospect: Near top Duncan depth map

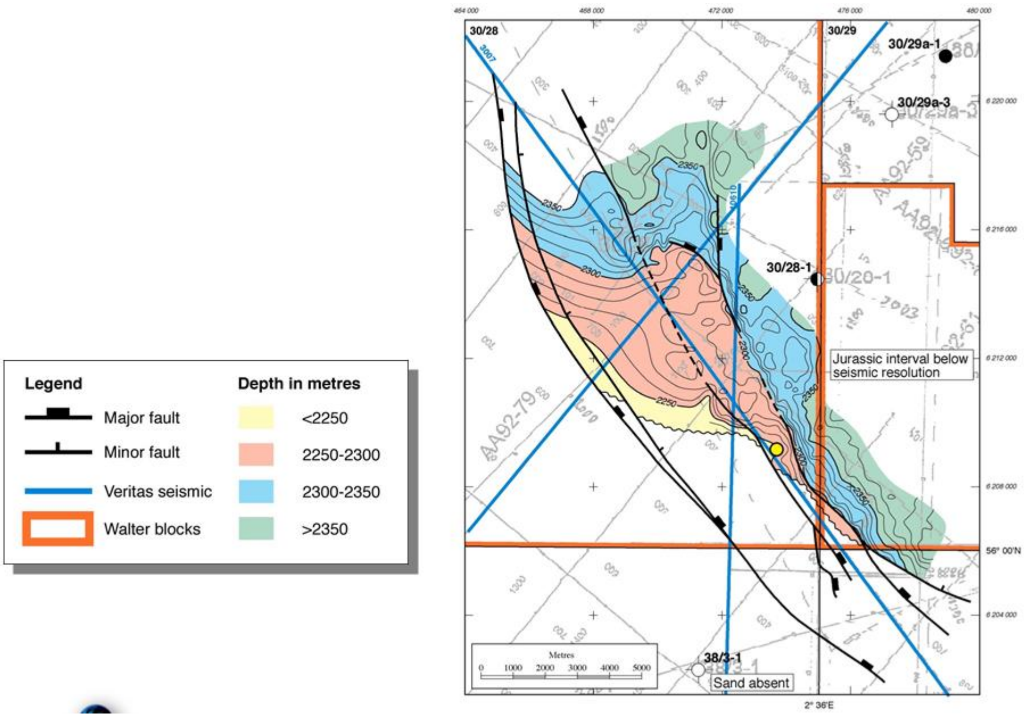
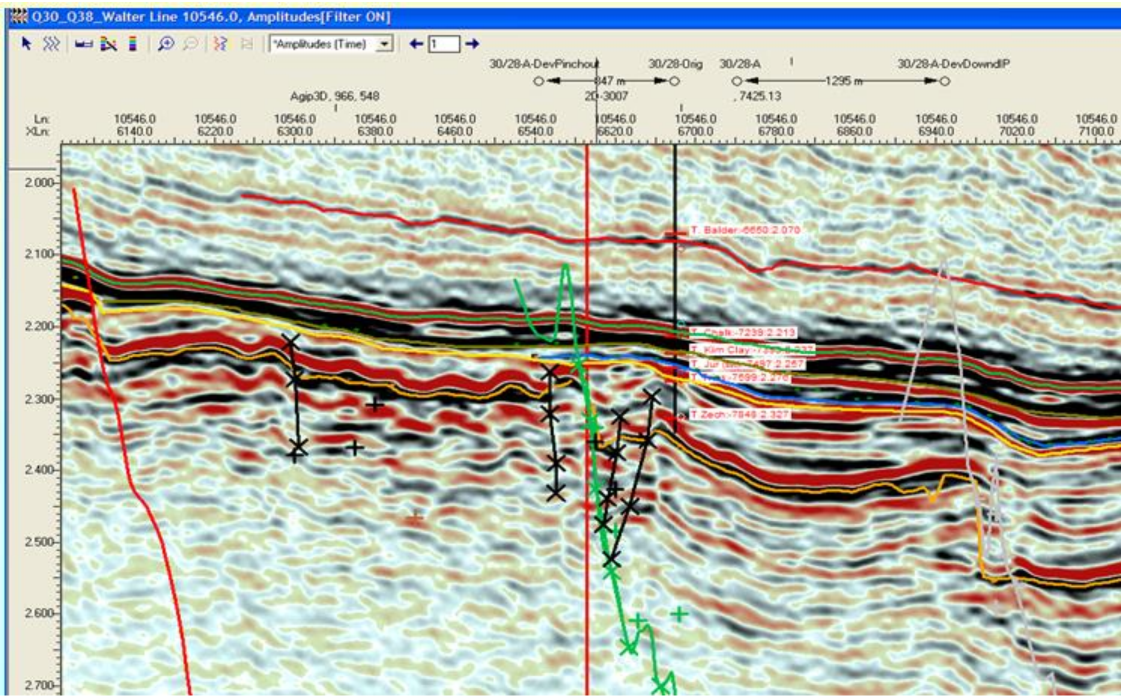


Fig. 55 – 3D Veritas North-South Inline 10546 through proposed well 30/28-2 (black line) **(Veritas seismic data courtesy of CGG)**



3.27. EOG Resources: well 15/30a-14, Dunkeld prospect

Well 15/30a-14 was a farm-in well by EOG Resources in license P103 (ConocoPhillips operator, Chevron, Gaz de France) and the data and time available before decision to drill were limited. Indeed, there was no time to reprocess the data and access to digital data from one of the 3D data sets was not granted.

The Dunkeld prospect was interpreted as an AVO supported stratigraphic play created by the pinch out of the Beauly sand, one of the youngest of the Palaeocene submarine fan sandstones that in filled the depositional lows created by differential compaction of older Palaeocene sands. Balder Formation and Sele Formation shales should act as Top and Bottom Seal. Lateral seal was not clearly described (**Fig. 56**).

Alpine uplift and tilting allowed hydrocarbons generated from the Jurassic Kimmeridge Clay source rocks in the basin depocentres to migrate via a series of faults and diapir flanks into the Palaeocene sand sequence.

The prospect was supported by an amplitude anomaly and AVO modelling was undertaken. During the data room EOG compared 2003 Long Offset Britannia 3D data (as EOG was not allowed digital copy of this survey) to 21/5 survey: they showed very similar amplitude responses.

The overall COS was set at 30% but the breakdown of the risking was not available.

Top Balder Formation was found 25 feet low to prognosis while the top Beauly was 100 feet deep to prognosis. The target reservoir was thicker and of much better quality than expected but water bearing with no shows.

The main reason for failure may have been the lack of trap as the lack of up dip seal towards the NW may have been an issue.

Although the reason for the apparent amplitude anomaly is not clear the data processing sequence (details not available) was inadequate. Indeed indications of residual move-out are still there. Tuning effects have not been properly modelled. AVO modelling should have been more comprehensive:

- If the Fars are over scaled (by 1.5 x) then a wet response can appear as a hydrocarbon response when only the gradient is considered;
- The use of Far-Near as an attribute ignores the intercept value and therefore is potentially more sensitive to errors in scaling than a two-attribute analysis such as achieved by AVO cross-plotting.

Main lessons learned:

- Seismic data should have been properly processed (**Fig. 57**) allowing for rigorous AVO modelling. Tuning effects should have been properly assessed. Post well modelling highlighted that oil bearing reservoirs should have been discriminated.
- Establishing which of the risk parameters the critical one was would have helped build a better pre-drill prospect assessment.
- If time had permitted an elastic inversion approach might have been beneficial.

Fig. 56 – Dunkeld prospect: Time thickness map Top Balder to Top Forties

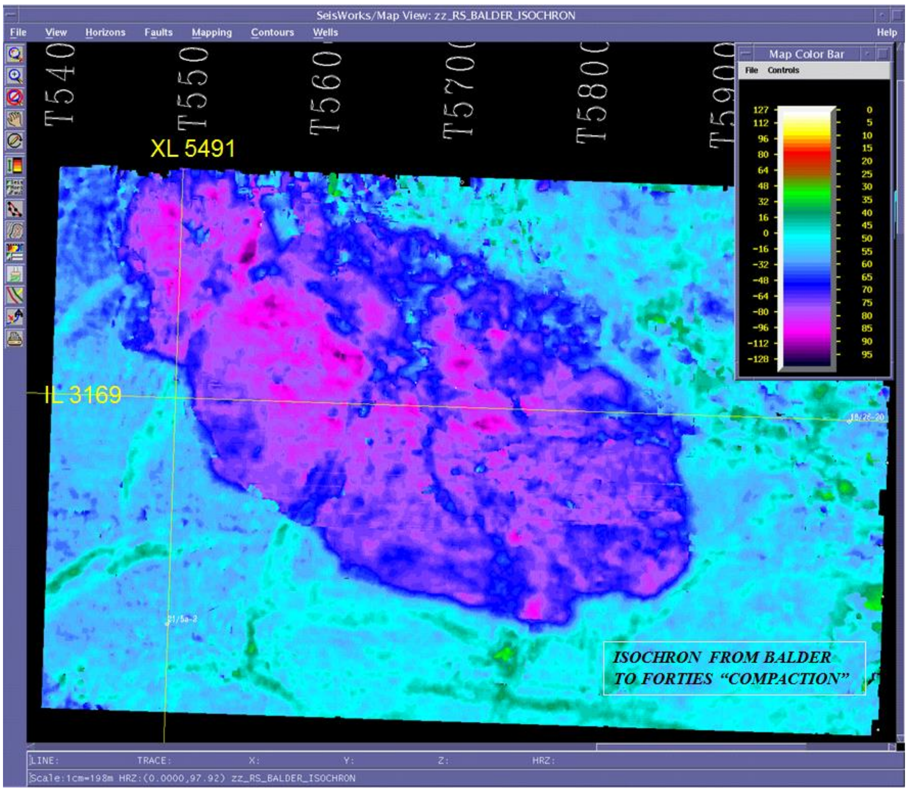
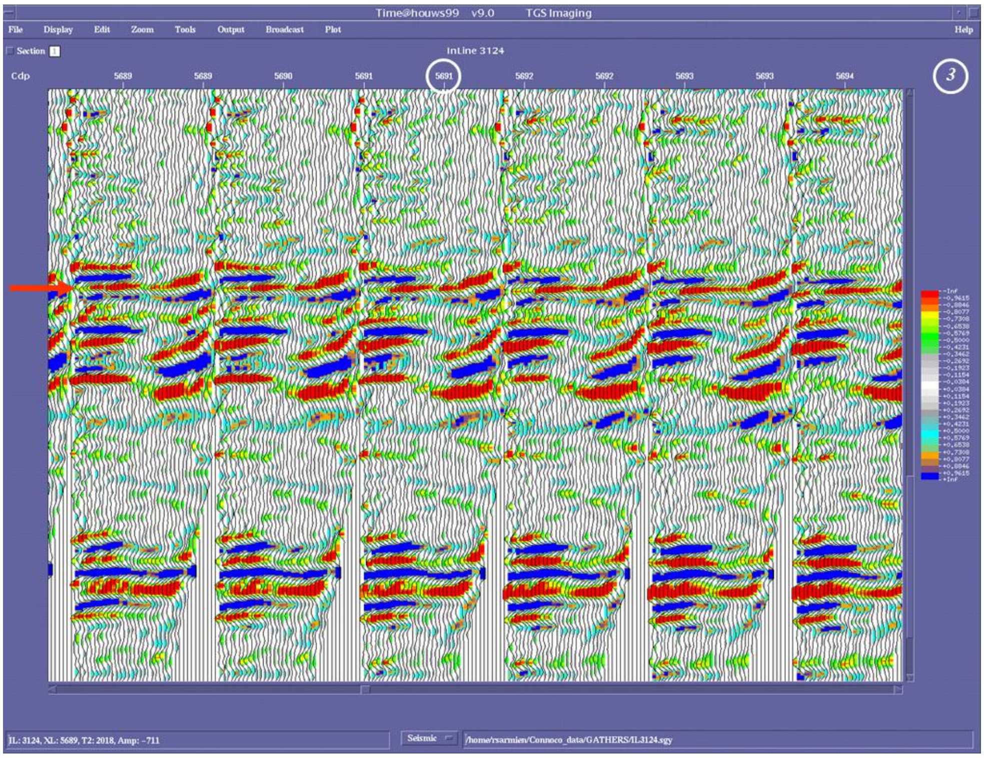


Fig. 57 - One of the very few available gathers showing room for processing improvement



3.28.EOG Resources: well 21/12b-6, "B" prospect

A four-way dip closed structure was mapped at the Cromarty Sandstone level (**Fig. 58**). The Balder tuffs and shales were expected to make the top seal. The Alpine uplift and tilting allowed hydrocarbons generated from the Jurassic Kimmeridge Clay source rocks in the basin depocentres to migrate via a series of faults and diapir flanks into the Palaeocene sand sequence. An AVO analysis was carried out, comparing "B" prospect

AVO response with the 21/8-3 Scolty discovery and another seismic anomaly located due east of the "B" prospect and straddling blocks 21/12 and 21/13 (it would later become known as the Crathes discovery by EnQuest) (**Fig. 59**): this AVO study rightly concluded that these Cromarty sands, provided they were similar to those in Scolty, should be water bearing. However regional basin modelling using the regional Sele map in Trinity Software demonstrated that prospect "A" (Crathes) should fill and spill into prospect "B".

Key geological uncertainties of the prospect were largely linked to the reservoir, its exact depth, quality, geometry and the connectivity of the sands. Yet, the well found the top reservoir very close to prognosis (17 feet low) and better than expected. However, there were no HC's as per pre-drill AVO modelling, despite a few thin (2 to 3 feet) remnant migration paths that look to contain residual oil.

The main reason for failure was thought to rely upon the bottom seal in the Crathes well (former "A" prospect) which could have prevented effective migration into the "B" prospect.

The AVO study suggested that for fluids and reservoir quality similar to Scolty a significant AVO anomaly should be present. Therefore, the water bearing nature of the "B" prospect was the most likely outcome. EOG being sole licensee tried to farm-out the block but was unsuccessful and could not find a partner. Furthermore, 21/12b-6 was a 25th Round Firm commitment well, and EOG decided to honour its commitment to drill at 100% cost.

Main lessons learned:

- When AVO analysis is correctly done using a properly processed 3D data set, and with comparable anomalies being calibrated by wells in the same seismic data set, AVO is a fairly robust tool that is able to discriminate between HC and water bearing structures.
- This well is a typical case of wells that have had low probability of success where dispensation could have been requested allowing the commitment or corresponding cost to be expensed in a different manner.

Fig. 58 - Top Sele Depth Structure Map showing the two prospects "A" and "B"

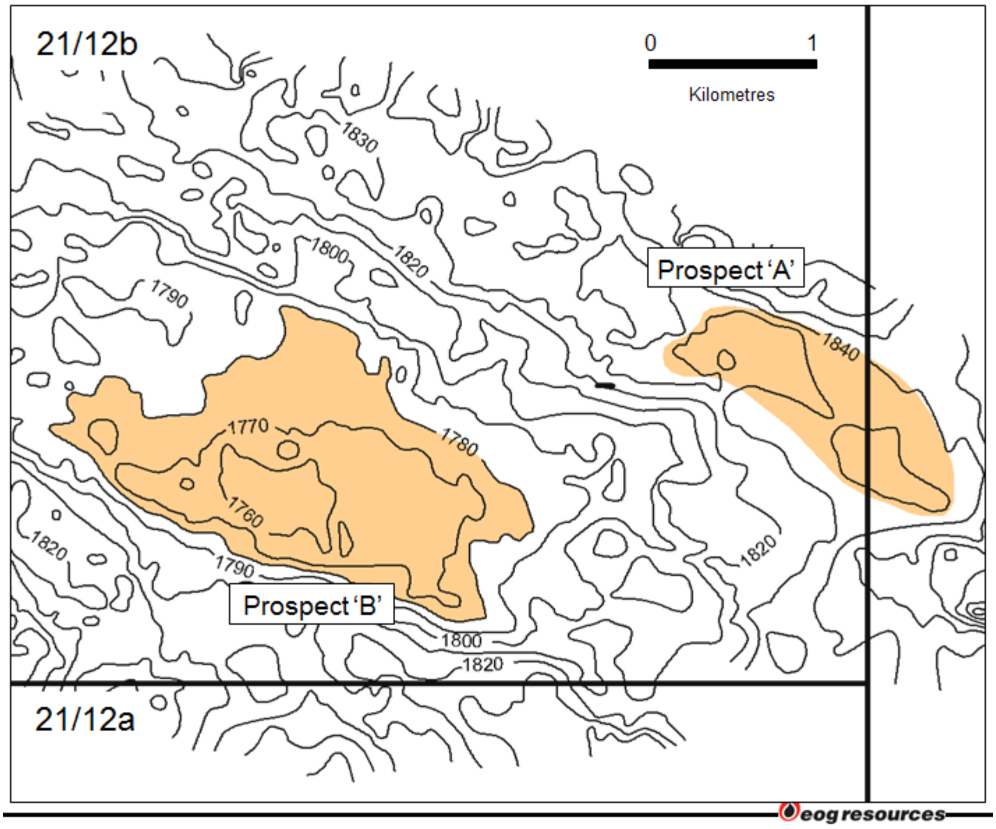
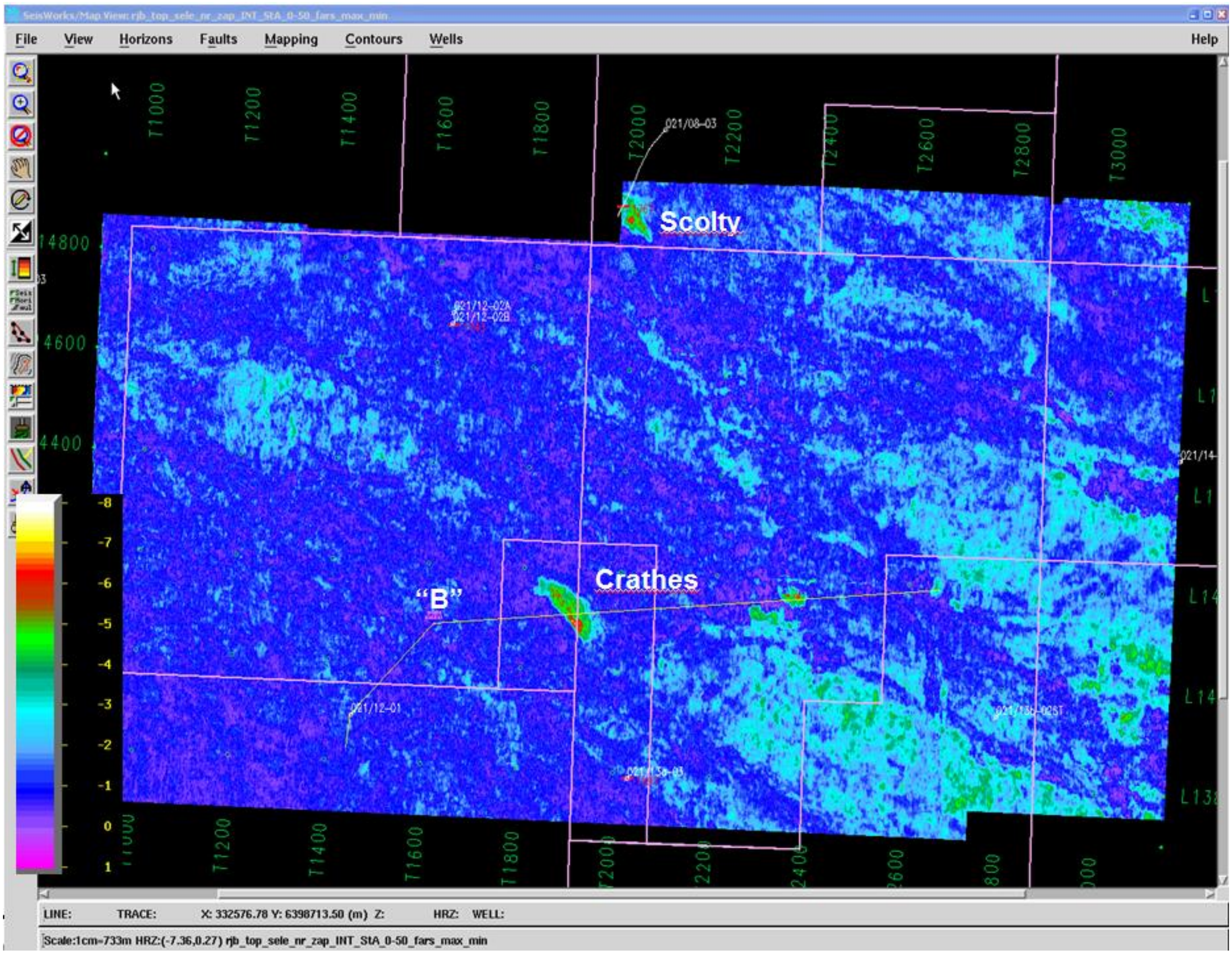


Fig. 59 – Beauly Formation – Near **-** Far Offset Amplitude extraction on a 50ms window below the top Sele horizon



3.29. EXXONMOBIL: well 37/25-1, Corbenic prospect

The 37/25-1 well tested what was perceived as a new play. Indeed, application of global geologic analogues (Western Canada, Russia Timan-Pechora…etc…) indicated a potential self-contained Devonian petroleum system with carbonate reservoir, domanic source rock and seal in very close proximity. The Corbenic prospect was one of three large structural closures on the Mid North Sea High (MNSH) structural feature (**Fig. 60**). The target was the Middle / Late Devonian Kyle Limestone Group which has been drilled in several nearby wells. Mapping of depositional environment over the MNSH suggested that Corbenic would be located such as a carbonate build-up would provide much better reservoir development and potential later fracturing.

Three potentially multi Tcf 4 way dip closures were identified in the P1259 license using magnetics, gravimetry and all 2D seismic available in the area (including TGS-NSR long offset and 514 Km reprocessed data). In addition, potential reefal development was identified on the eastern Corbenic closure thanks to seismic stratigraphy analysis (**Fig. 61**); this reservoir was adjacent to possible deeper marine sediments (thick reflection free interval interpreted as source-rock deposit). FIV gas response was also recorded in well 38/3-1 which drilled a valid 4-way closure at the Mid Devonian carbonate level but found tight carbonates.

The overall CoS = 10% corresponded to a very high risk prospect with major risks on source rock presence, timing of the migration and reservoir presence and quality (although no detailed risking parameters have been provided).

Devonian Kyle limestone was absent in well 37/25-1. Key seismic lines were mis-interpreted: what was interpreted as a "reefal" character was onlap onto basement. There was no top seal and no shows in Devonian Old Red sandstones and the well TD'ed in the Caledonian basement. The overall pre-Zechstein section is pretty similar to what was drilled by well A17-1 in the Dutch offshore. Isotube gas analysis at 2200m (ORS) showed heavier isotopic value indicating a probable coaly source but no indication of Domanic source rock.

The main reasons for failure were:

- Source / migration did not work,
- Interpreted "reefal" seismic facies was basement. This was because of a mis-interpretation of the one key strike line where the "reefal" character change was on-lap of the limestone onto basement.

Main lessons learned:

- The play searched by the Corbenic well does not exist meaning all remaining prospects at this play have been technically rejected and the licence was relinquished.
- The lack of accurate Devonian biostratigraphy prevented the geoscientists from picking the predicted top seal shale unit.
- Pre-drill integration of the geology of the Yorkshire onshore basin may have been beneficial.
- Although a 3D data set would likely have helped better assessing the "reefal" seismic facies, the cost of a 3D acquisition over such a large area (1.2 million acres) could not compete with the cost of a single vertical relatively shallow well (committed TD = 2650m).

Fig. 60 – Corbenic well location, Top Devonian Kyle Group Depth Map

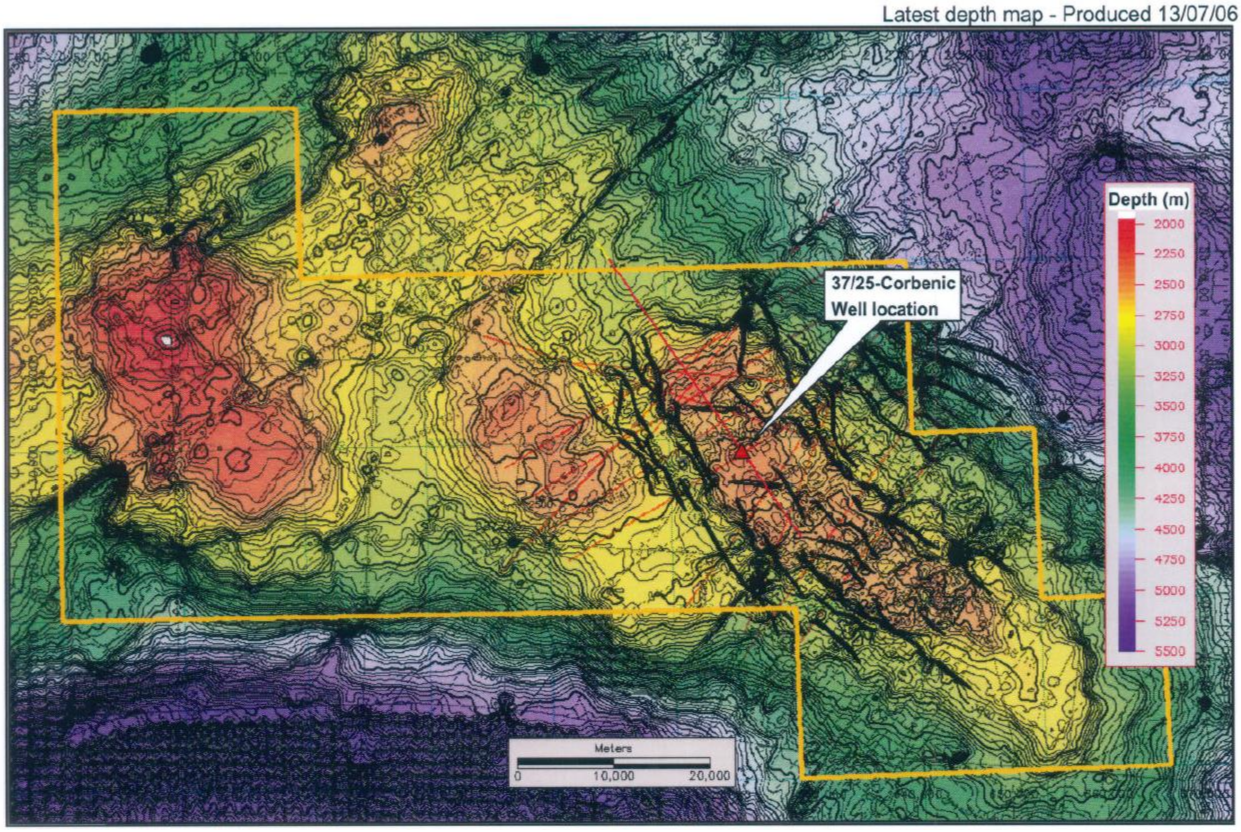
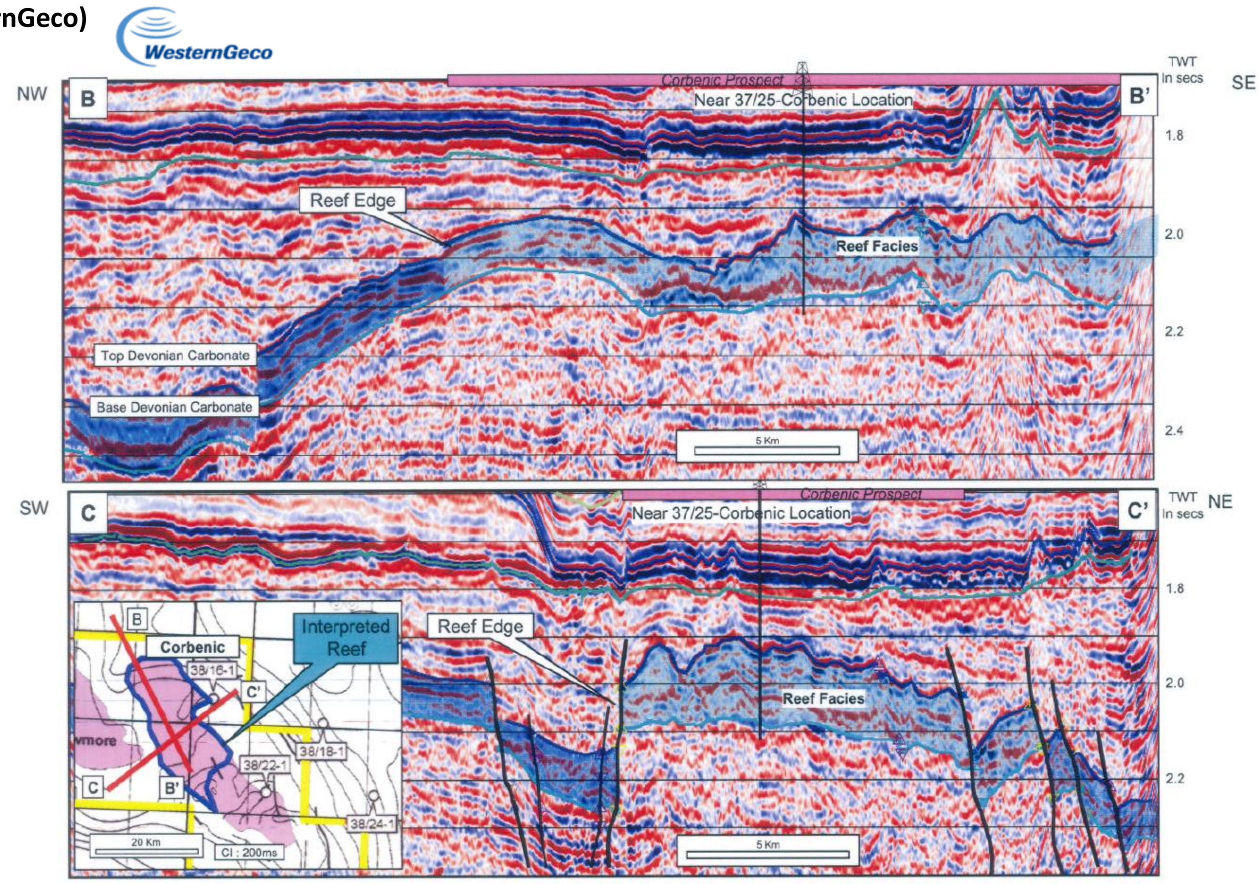


Fig. 61 - Corbenic: two orthogonal seismic lines showing the interpreted "reefal" facies **(Data courtesy of WesternGeco)**



3.30. First Oil: well 29/06a-8, Centurion South prospect

The Centurion South prospect was a large structural 3-way dip closed 'nose' extending from the WSW to the ENE from the West Central Graben bounding fault (**Fig. 62**). The Upper Jurassic Fulmar reservoir target was interpreted as being within an 'interpod' setting as per analogy to well 29/6b-2 (**Fig. 63**). Hence, stratigraphic boundaries to the reservoir extent were interpreted to exist but were poorly defined on the available seismic dataset. Depth conversion placed well 29/6a-4 deeper than the prognosed well 29/6a-8 penetration. The dominant Fulmar 'type' seismic response was however not observed/recognisable.

Kimmeridge Clay equivalent source rock is proven in the area given the adjacent oil fields and the Centurion 29/6a-3 discovery. Oil quality and migration risk were assessed via a Senergy study and recognized that Centurion oil is heavier (28 API) than adjacent lighter oils at Curlew. The kitchen area of the mega-slide complex was expected to possibly be mature but limited expulsion was expected. The most likely kitchen area was north of well 29/6a-3 and from source rock located below the mega-slide. The mega-slide occurred in the latest Jurassic/earliest Cretaceous hence reservoir, trap and seal were all in place prior to hydrocarbon migration occurring.

Top seal was the Kimmeridge Clay as seen in all offset wells whilst the base seal was Triassic Smith Bank shales. The West Central Graben bounding fault was interpreted as essentially a shale and salt dominated fault zone and was expected to seal.

The overall CoS was estimated at 30% and the key pre-drill risk was reservoir presence (60%) followed by trap geometry (70%). Seal was not seen as a risky parameter.

Well 29/6a-8 was on prognosis except for a thicker than expected Kimmeridge Clay interval which led to a deeper Fulmar pick. The Fulmar reservoir target was much thinner than expected (19 feet, with oil shows) and lay above a Triassic Gassum sandy Formation. The Fulmar average porosity was also below the P90 porosity estimate.

The main reasons for failure were, first of all, the lack of significant target reservoir development, and secondly, likely lateral seal failure. Indeed, up dip there are no Lower Cretaceous shales and Chalk is interpreted as adjacent to the Fulmar allowing for leakage. This can be inferred from seismic amplitudes and shows seen in the Chalk at well 29/6a-6 to the SW.

<u>Main lessons learned:</u>

- Presence of Fulmar to some extent proves the "pod/interpod" model applied but it is not clear if Fulmar extends to crest. Anyway, the seismic quality was far from sufficient to understand Fulmar distribution. Trap concept has been validated although precise trap definition remains very difficult.
- It is still unclear whether Fulmar potentially thickens up dip or down dip away from well.
- Greater focus could have been given to the lateral seal elements of the prospect pre-drill.

Fig. 62 – Top Fulmar depth structure map

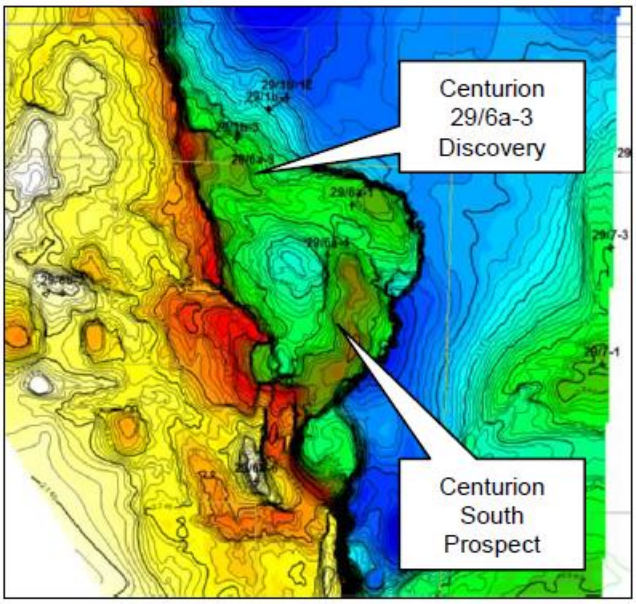
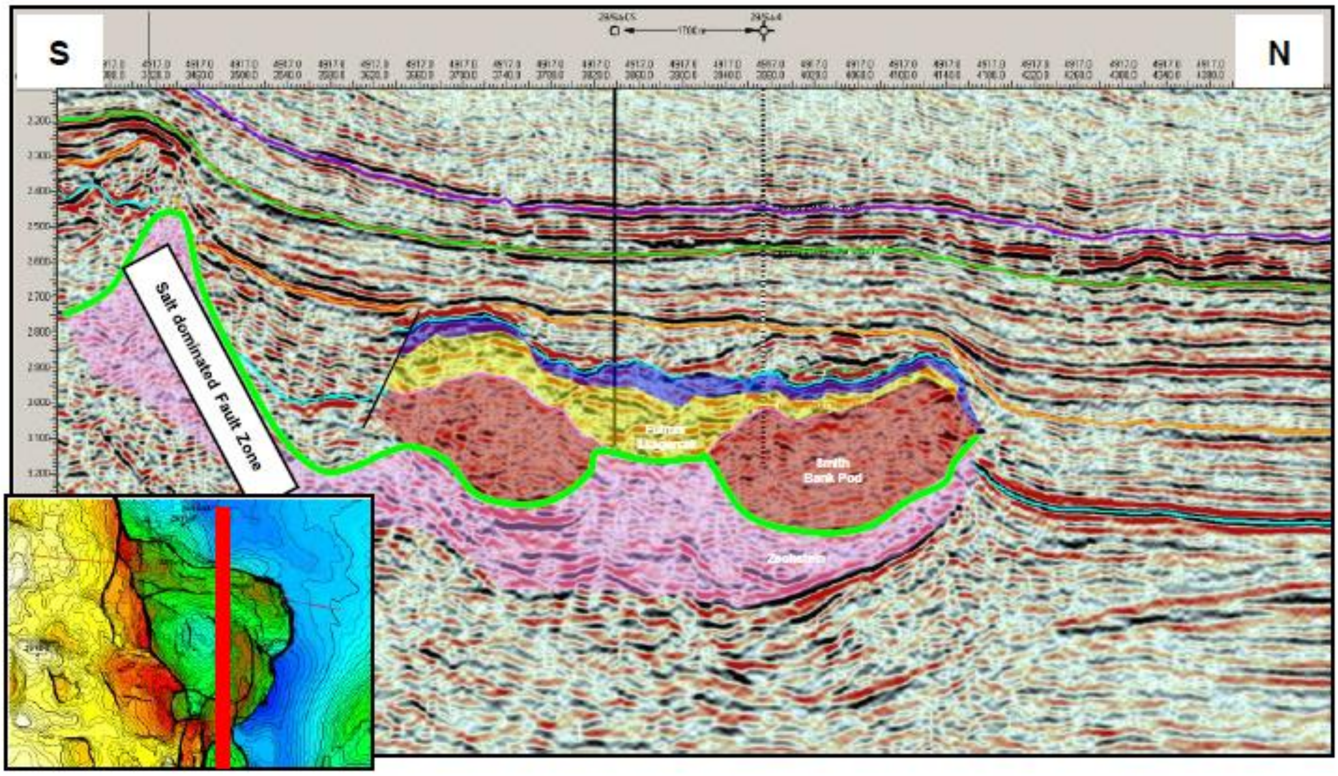


Fig. 63 – Interpreted South – North seismic line illustrating the “pod-interpod” setting



(Fugro data, courtesy of Spectrum) Spectrum

3.31. GdFSUEZ (now ENGIE): 22/23c-8X, Taggart prospect

The 'Taggart' prospect was located in block 22/23c in the UK sector of the Central North Sea. It was the primary objective of well 22/23c-8. Following mechanical side tracks, well penetration-8X managed to drill through the Taggart prospect. This block was acquired in the 26th Licensing round (October 2010). The 22/23c block is situated on the Southern platform of the Montrose/Arbroath high.

The Taggart interpod structure sits on a structural high, north of the Kate discovery (22/23b-5) (**Fig. 64**). The proposed trapping mechanism for the Taggart prospect was a 3-way stratigraphic trap, produced by the pinch-out of the sandstones to the North against the edge of the inter-pod mini-basin (**Fig. 65**). The targeted Upper Jurassic Fulmar sandstones were prognosed to be shallow marine sandstones deposited in a shoreline type setting. The sealing mechanism was expected from the Triassic Smith Bank Formation providing base seal and from the Kimmeridge Clay Formation providing the top seal. Good quality mature Kimmeridge Clay Formation was present down dip. However, the main risk was associated with timing and charge of hydrocarbons.

The overall Cos was set at 25%. Risk had been placed on the presence of effective reservoir (80%), closure (70%) and seal/retention (90%) in the Taggart structure. However, the main risk was associated with timing and charge of hydrocarbons (50%).

While drilling well 22/23c-8X, the majority of the formation tops down to the base chalk came in on prognosis within the error bar. The major difference is that a Lower Cretaceous Cromer Knoll section is present (372 feet). As a consequence the Kimmeridge Clay Formation was found 351 feet deeper than prognosis.

The Fulmar reservoir petrophysical characteristics are broadly in line with expectations. Although HC shows were weak during drilling, a representative formation fluid sample was recovered at 13248 feet MD containing uncontaminated light oil (41 API). When 155 Kppm formation water salinity is used, the Top Fulmar and top Skagerrak sandstones are computed to have residual HC saturations. This is consistent with fluid inclusions analysis provided by FIT in Tulsa: "overall data provide only sparse indications of migration and no evidence of paleo-accumulations or proximal charge." The in situ Kimmeridge Clay maturity was measured post drill and indicated the early entrance in the oil window (PRV = 0.55%). From all these observations, it is interpreted that these minor hydrocarbons have demonstrated a working migration pathway.

Skagerrak Formation (535 feet thick) shows sandstones with average N/G = 38% and average porosity = 15%, meaning that the bottom seal was not as effective as expected. There was likely no breaching of top seal as pressure was below the low case of the pre-drill pressure model. The interpreted main reason for failure is reservoir pinch-out failure to the NW.

As a summary, the Taggart prospect was likely acting as a migration route towards Shaw.

Main lessons learned:

- A fairly low risk was placed on the presence of effective reservoir, closure and seal/retention in the Taggart structure. However, the failure of the prospect was in these risk areas. Hydrocarbon timing/charge was of a lower risk than predicted as shown by the oil sample obtained.
- The Taggart pre-drill documentation provided should set the standard minimum data to be provided by any company seeking consents to drill a well.

Fig. 64 –Structural relationship between Kate, Taggart and Shaw **(Data courtesy of CGG)**

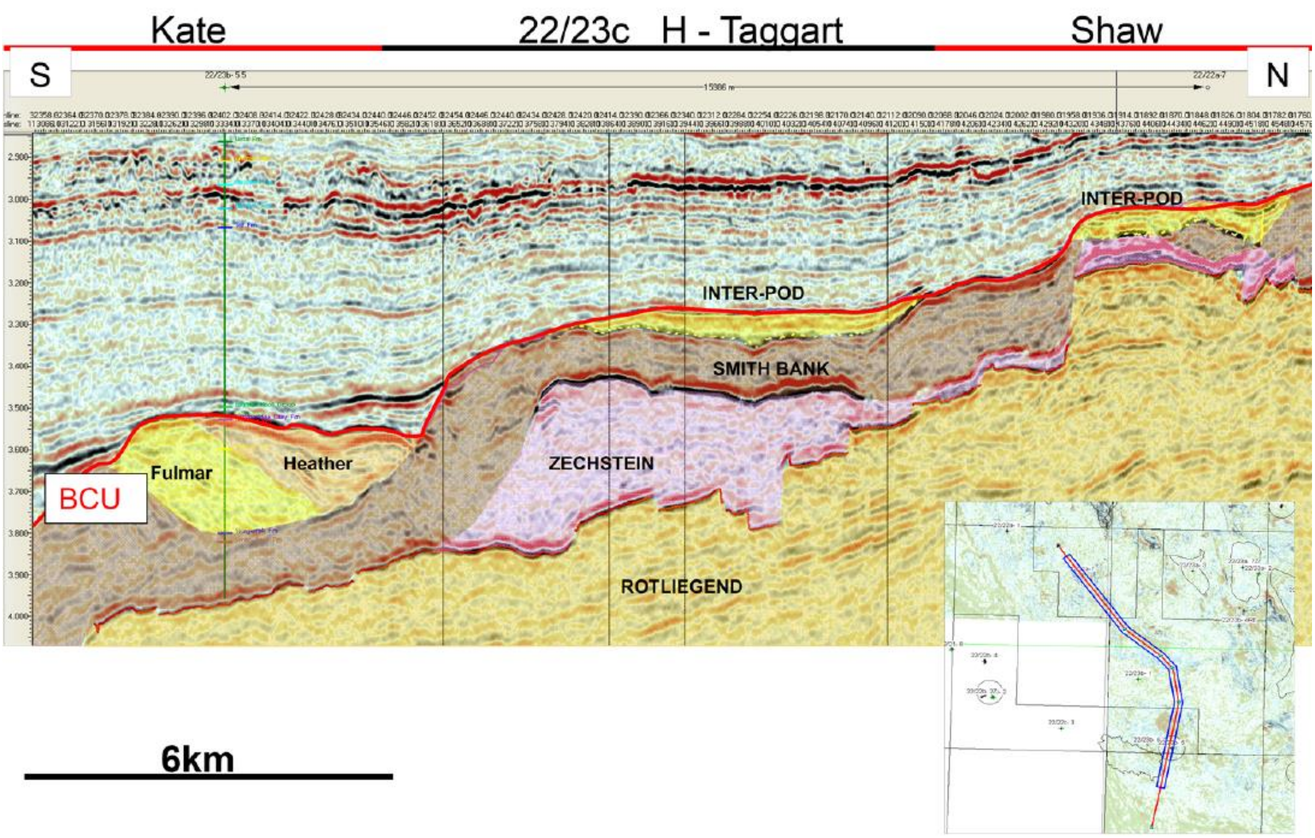
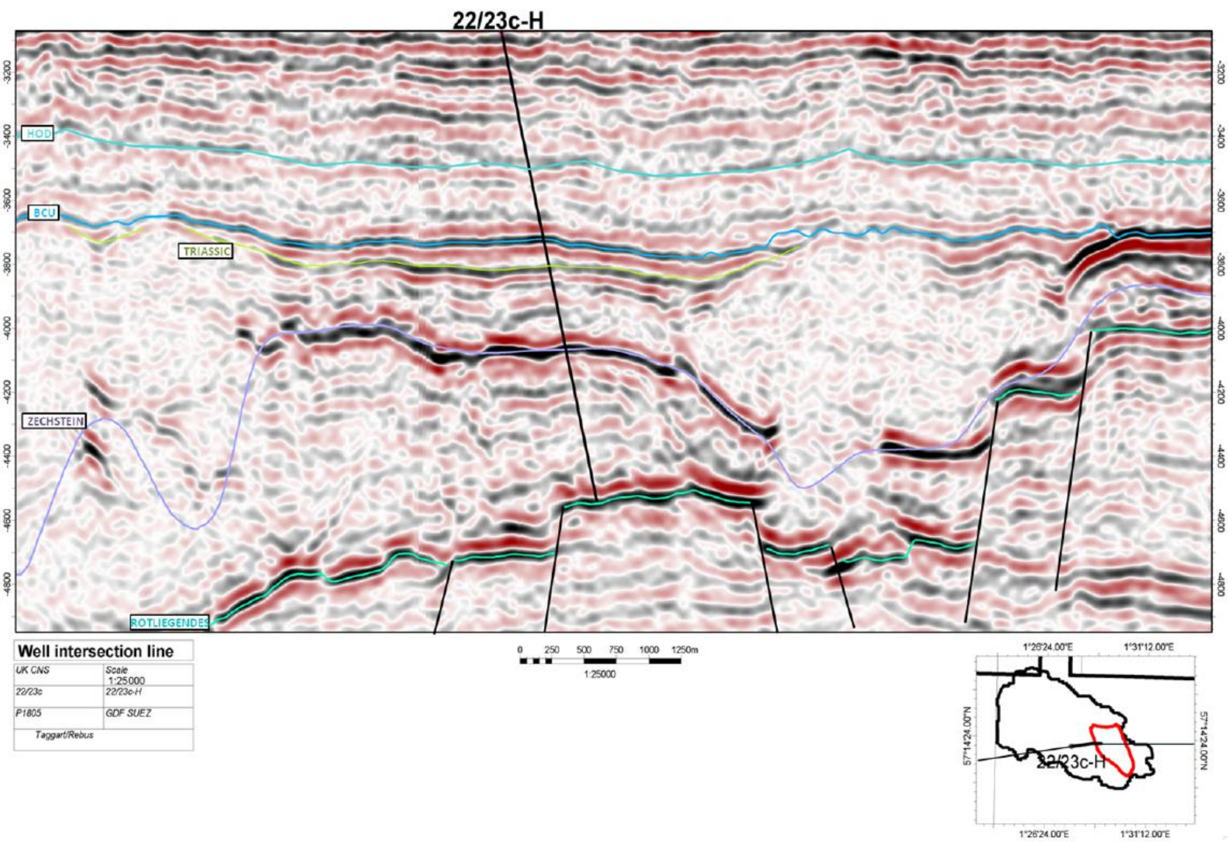


Fig. 65 - West-East seismic line across Taggart prospect though the planned well path **(Data courtesy of CGG)**



3.32.Ithaca: well 11/29-1, Manuel prospect.

The Manuel prospect was located in the inner Moray Firth, approximately 15 Km to the WSW of the Beatrice Field and ~20 Km to the SSW of the small Knockinnon 11/24a-2 discovery. Well 11/29-1 had multiple reservoir targets including from top to bottom Upper Jurassic Burns Sandstone Unit, Kimmeridgian Sandstone Unit and Upper Oxfordian Sandstone Unit as well as Middle Jurassic Brora Sandstone Formation. For each potential reservoir, traps corresponded to 4-way dip closures and significant upside was expected from stratigraphic pinch-out (**Figs. 66 & 67**).

Great Glen fault allows migration of Hydrocarbons form the Devonian and Middle Jurassic source rocks into upper reservoirs and carrier beds.

The overall combined CoS was 15% with the main critical risks being reservoir presence and HC migration / timing, both estimated at 50%.

Well 11/29-1 found most of the formation tops from the Lower Burns to TD 200 to 600ft deep to prognosis. The Lower Cretaceous section was mostly sandy. The primary Brora sandstones objective corresponded to thick blocky good quality sandstones but water wet. In the Spiculite Sandstone interval of the Brora Sandstones, subsequent wireline log and MDT testing indicated a porous but tight formation where the high resistivity readings indicate potential residual hydrocarbon. The secondary target horizons of the Upper Jurassic Burns showed porous but water-bearing sands. The Kimmeridgian sandstones corresponded to thin tight sands.

The preferable interpretation of the main failure cause is a lack of lateral (up-dip) seal. However, the significant discrepancies between prognosed versus actual depth of the main horizons make the trap geometry questionable.

<u>Main lessons learned:</u>

- A significant effort should have been made to improve the time to depth conversion in order to better define the trap (if any).
- A detailed pre-drill basin analysis should have highlighted Manuel's source rock drainage areas for each target, allowing the volumetric to take a better account of HCs available to the trap.
- It looks like this well was rig driven.

Fig. 66 - Manuel prospect: NW-SE line MF 06-205B **(Data provenance uncertain, Ithaca proprietary, TGS?)**

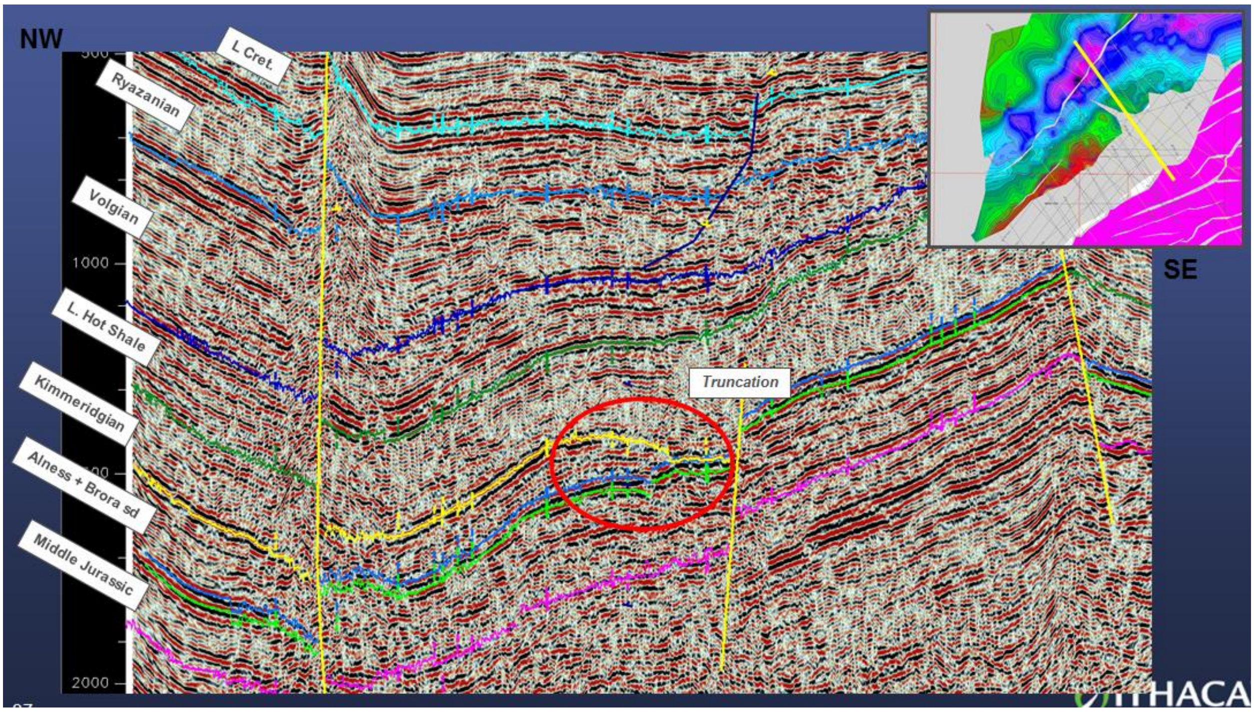
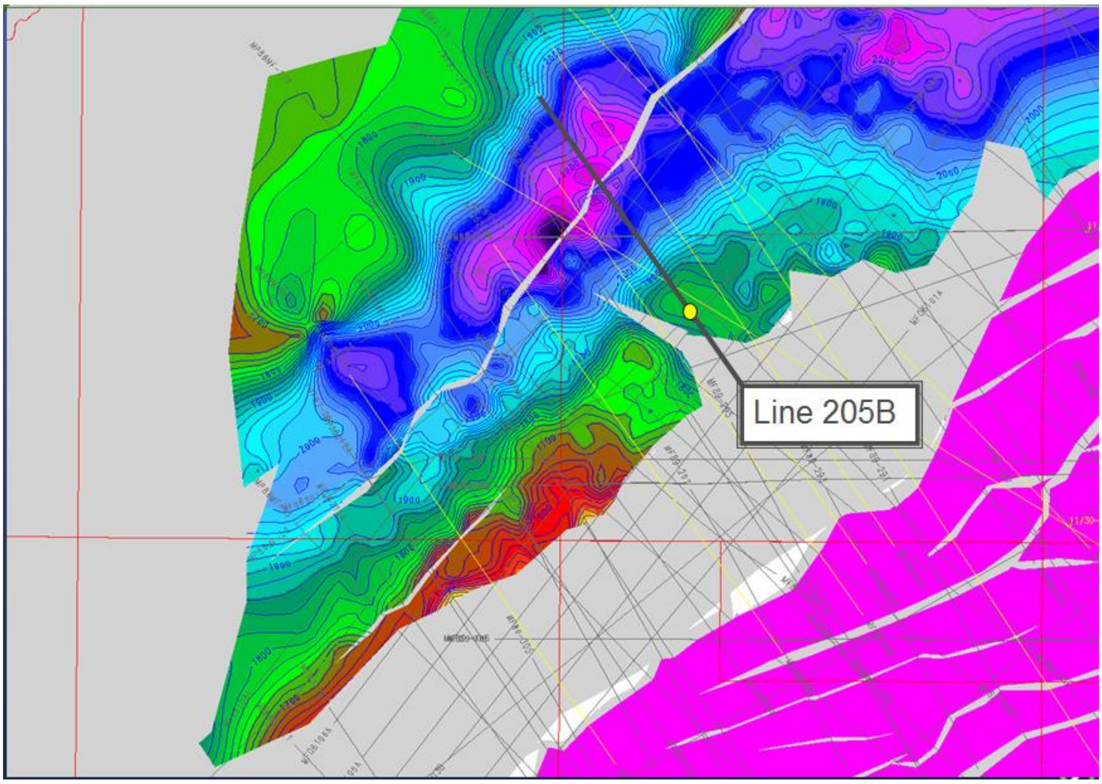


Fig. 67 - Top Brora Sand Depth Map (m tvdss; contour interval 20m)



3.33. Ithaca: well 12/26c-5, Polly prospect.

The Polly prospect, located ~2 Km south-east of the Beatrice Bravo platform, was a structural narrow, elongate, fault bounded and dip closed structure sub parallel to the main Beatrice accumulation: it was 3-way dip closed in the low case, and relied on faults to be closed on its north-eastern and south-western edges in mid and maximum cases (**Figs. 68 & 69**).

The target reservoir was the shallow marine “A” sandstones of the Callovian Beatrice Formation sourced by Kimmeridge Clay / Devonian combination source rock as demonstrated by Beatrice Field. Top seal was expected to be provided by Heather Formation shales. The key risk was seen at the low throw west-east fault bounding Polly to the north-west. In addition, major faults affecting sea bed have been observed as in Beatrice. Migration from kitchen to reservoir was interpreted via vertical fault conduits and through Beatrice Sandstones carrier bed. Oil was expected to be similar to Beatrice oil.

The trap, although defined on the original 1997 Beatrice 3D seismic data set, seemed to be robust and the overall CoS was estimated at 32%. However, despite the fact that the north-east bounding fault was recognized as critical, the main risk parameter was allocated to the trap definition (55%) and the second risky parameter was deemed to be the migration (70%).

Most of the horizons (“A” sandstones included) came in within error bars but the top reservoir was 84 feet deep to prognosis. Well 12/26c-5 found the target “A” sandstones oil bearing and the OWC was found fitting pretty well with the minimum case (3-way-dip closure) meaning that the HC column measured 21 feet instead of the 150 feet prognosed. Oil sample analysis confirmed similar parameters to Beatrice crude. The calculated resources ended below the P90 prognosis.

The main reason explaining the partial HC fill is assumed to be limited fault seal effectiveness of the bounding fault to the NW end of the Polly structure. Another possible explanation may be that charge would have been limited due to basin reconfiguration because of movement on the Great Glen Fault but this looks more speculative.

Main lessons learned:

- Although the critical bounding fault to the north-east end of the Polly prospect was clearly highlighted it did not translate into the relevant risking assessment.
- A detailed basin modelling exercise to establish / test proposed migration timing vs basin structural evolution may have indicated a charge limitation risk. However, given the near-field nature of this prospect, this would likely not have prevented the drilling of well 12/26c-5.

Fig. 68 - Beatrice "A" Sand depth structure map

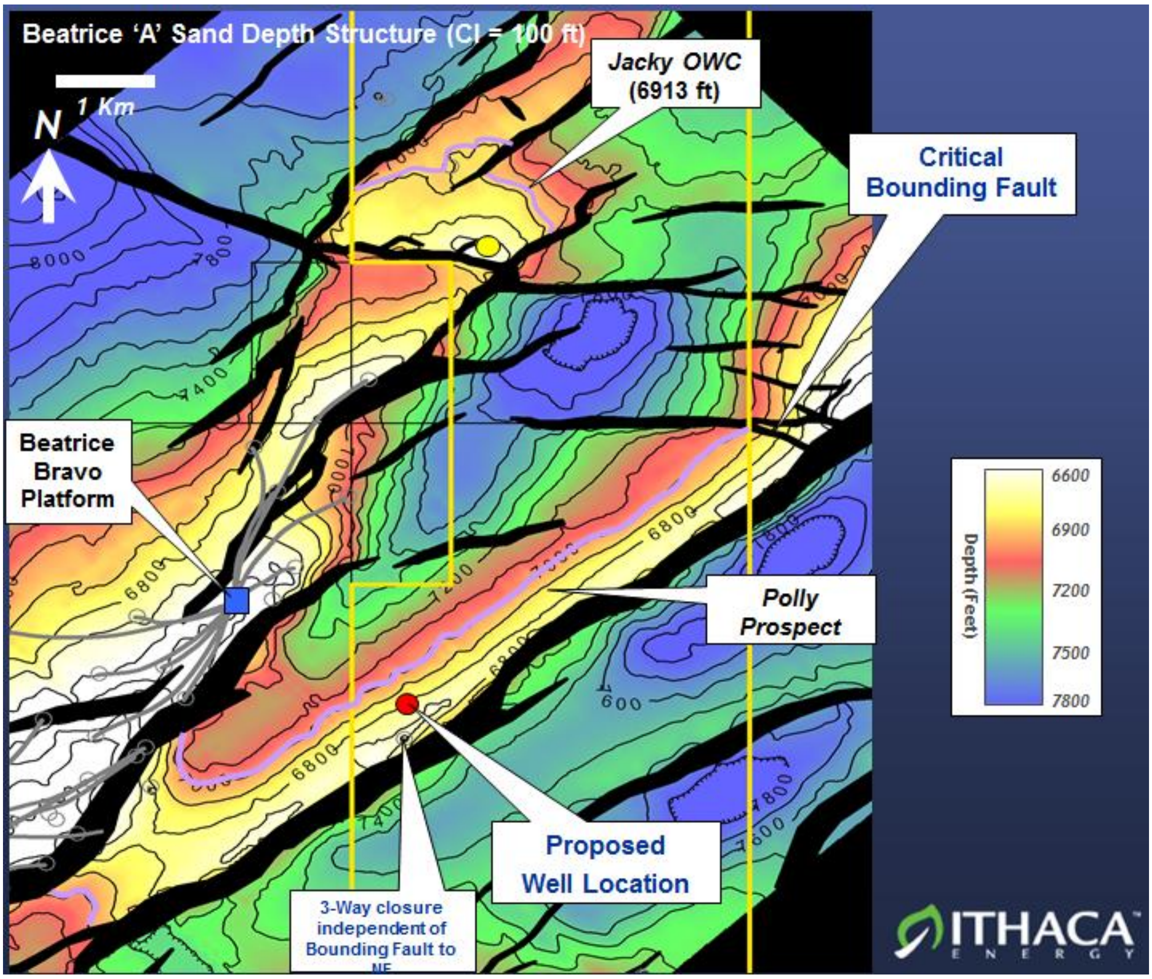
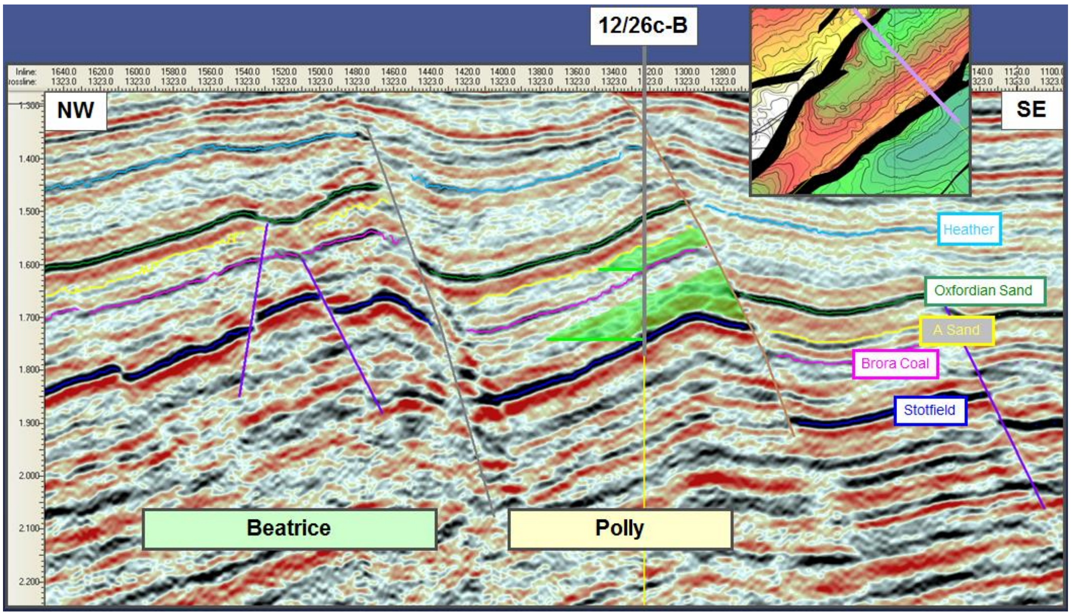


Fig. 69 - NW-SE cross line 1323 across Beatrice and Polly structures (Data Talisman proprietary)



3.34. Maersk: well 13/26a-5, Stephenson prospect

The Stephenson prospect was an Early Cretaceous Punt sandstone channel feature interpreted to sit directly on the Base Cretaceous Unconformity (BCU). The prospect was mapped on a seismic dimming associated with a small 4 way closure at BCU level (**Fig. 70**). Jurassic Burns and Ettrick sandstones were secondary targets. The southern tip of this prospect was pretty close to the available WGQ13 3D data set. Valhall Formation mudstones and Kimmeridge Clay Formation mudstones were prognosed as the top and base seal respectively.

Source rock was the Kimmeridge Clay Formation. This stratigraphic trap was supposed to be locally charged from the Banff Sub-Basin. Punt Channel was assumed to be charged by underlying Burns Sand acting as carrier-beds.

The Punt sandstones were supposed to come from the south-south-west.

Overall CoS was estimated at 26% and the critical risk was the seal both laterally and below the Punt reservoir interval. Indeed, the prospect was interpreted to stratigraphically seal beyond the seismic anomaly and pinch out up dip to the south west. Sealing the seismically mapped prospect laterally relied upon a stratigraphic pinch out of the Punt Sandstone Member within the Valhall shale. The base seal relied upon Kimmeridge Clay sealing the Punt Sandstone from the underlying Upper Jurassic sandstones.

Well 13/26a-5 found the Punt sandstones Member equivalent but it encompassed only 5.5 feet of net reservoir facies: the reservoir intersected is not true Punt. It's interpreted as thin sand within the Leek Member (**Fig. 71**). Reservoir parameters calculated pre-drill from wells on the West Bank High (true Punt fairway) were much more optimistic than observed.

The main horizons came in low due to the velocity model being poorly constrained. All reservoirs (Punt, Burns, and Ettrick) were water wet underlining the lack of charge.

A post-drill model (2014) based on a regional Outer Moray Firth maturity and migration model could not reproduce Stephenson pre-drill charge vector showing Stephenson is located in migration shadow.

A stratigraphic pinch out was mapped predrill, and a "mounded" seismic character supported presence of Punt Sand at Stephenson but the amplitude dimming had been incorrectly interpreted to be analogous to Hobby.

<u>Main lessons learned:</u>

- Post well evaluation showed that the dimming on seismic was caused by the Leek Member not being eroded by a Punt channel as had been prognosed. We must be aware of non-uniqueness of method.
- Migration and source basin modelling should be done on a more semi-regional scale and avoid being too prospect limited ('postage stamp' analysis).
- The Lower Cretaceous depositional model was over-reliant on favourable offset wells: we must take into account all available data. There was a pre-drill over estimation of Stephenson reservoir parameters due to use of an incorrect analogue.
- Rock physics may have helped to better assess the Punt Member.
- Finally, it must be highlighted that despite an unsuccessful attempt to farm-out this well, Maersk fulfilled this 26th Round firm well commitment. OGA is encouraging companies to do in depth pre-drill work as much as possible before committing to wells.

Fig. 70 - Map showing seismic extraction of maximum negative amplitude -8 to +8 around the BCU surface showing an "erosional" feature, thought to represent the location of the Punt Sandstone deposition.

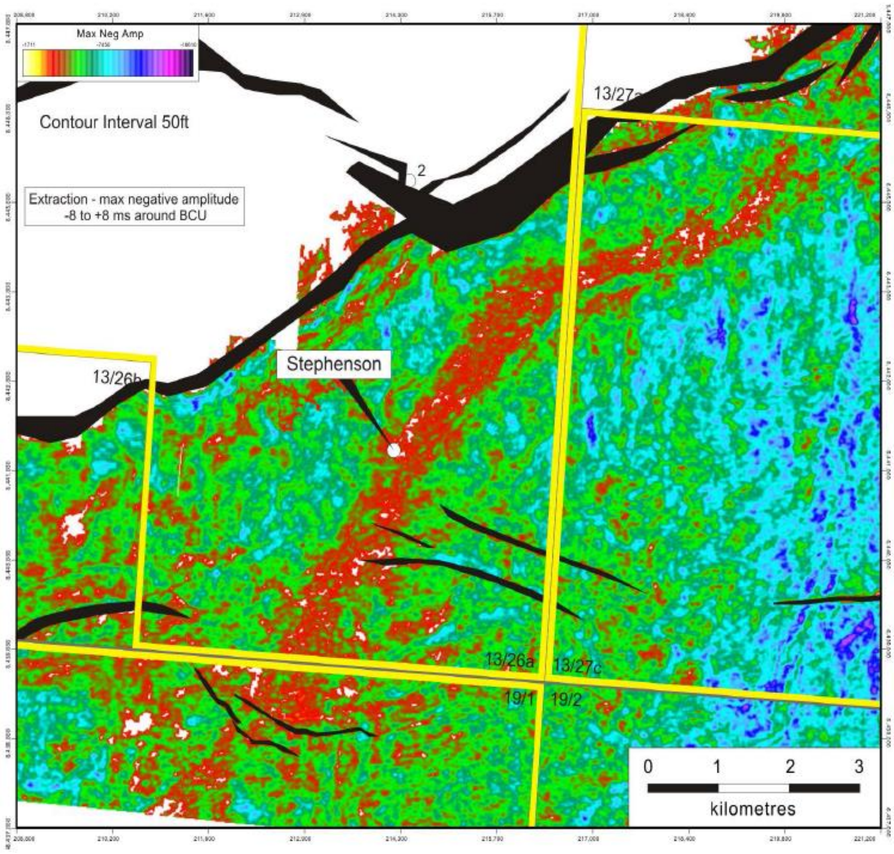
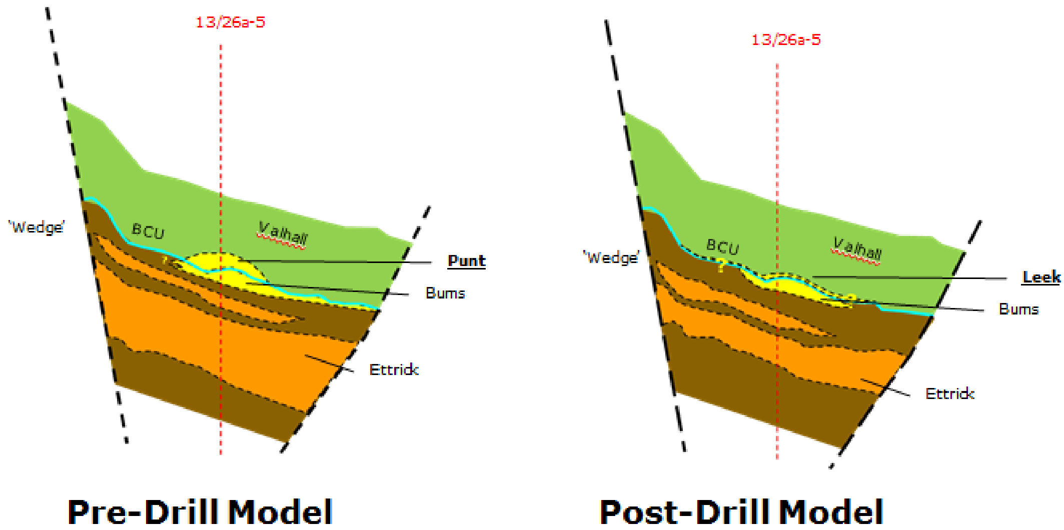


Fig. 71 - Failure mechanism: reservoir. Comparison pre- versus post-drill model



3.35. Maersk: well 15/19c-11, Dunvegan prospect

The Dunvegan prospect was interpreted as a stratigraphic trap (channel like), AVO delimited, defined at Tertiary Upper Balmoral Sand (Palaeocene) (**Fig. 72**). It was believed to sit on the same trend as Mac Culloch. Source rock was expected to be Kimmeridge Clay Formation. The kitchen area for Block 15/19c was situated down-dip to the south-west of the block. All fields in the area are believed to be filled to spill and the prospect is located in the middle of a prolific area (Tertiary to Jurassic): as a consequence no risk was attached to source rock and migration timing.

Reservoir would have been sealed by Lista and Sele formation mudstones. Seal was seen as the main pre-drill risk (80%). However, this AVO supported prospect, was considered as low risk with an overall CoS = 72%. Given its proximity to infrastructure, the building of the business case for this prospect was straightforward.

The seismically mapped top sand horizon turned out to be Top Lower Forties at the well location and not Lower Balmoral sandstone as prognosed. The Upper Balmoral reservoir was water wet with indications of residual hydrocarbons. Porosities (up to 30%) and net/gross were both high, in line with expectations.

The main reasons for failure are interpreted as the lack of trap as well as a wrong AVO interpretation, the AVO anomaly possibly being created by the wrong top reservoir pick. However, extensive post well AVO work was carried out, concluding that the anomaly is a likely false positive AVO, caused by low saturation gas.

<u>Main lessons learned:</u>

- The N-S seismic line from the prospect montage shows an artificial "mound" like picking (**Fig. 73**). This highlights the need for thorough quality control. In such case when the operator is the sole owner (100% interest), pre-drill peer review involving the OGA should help highlighting what kind of work still needs to be carried out prior to deciding to drill.
- It is often too easy to build a case when a prospect is on the same trend as an existing discovery (cognitive bias).
- Too great confidence was given to AVO. Although extensive peer review was done predrill, the chance of low saturation gas was not taken into account.

Fig. 72 - Top Upper Balmoral sand depth structure map highlighting AVO anomaly

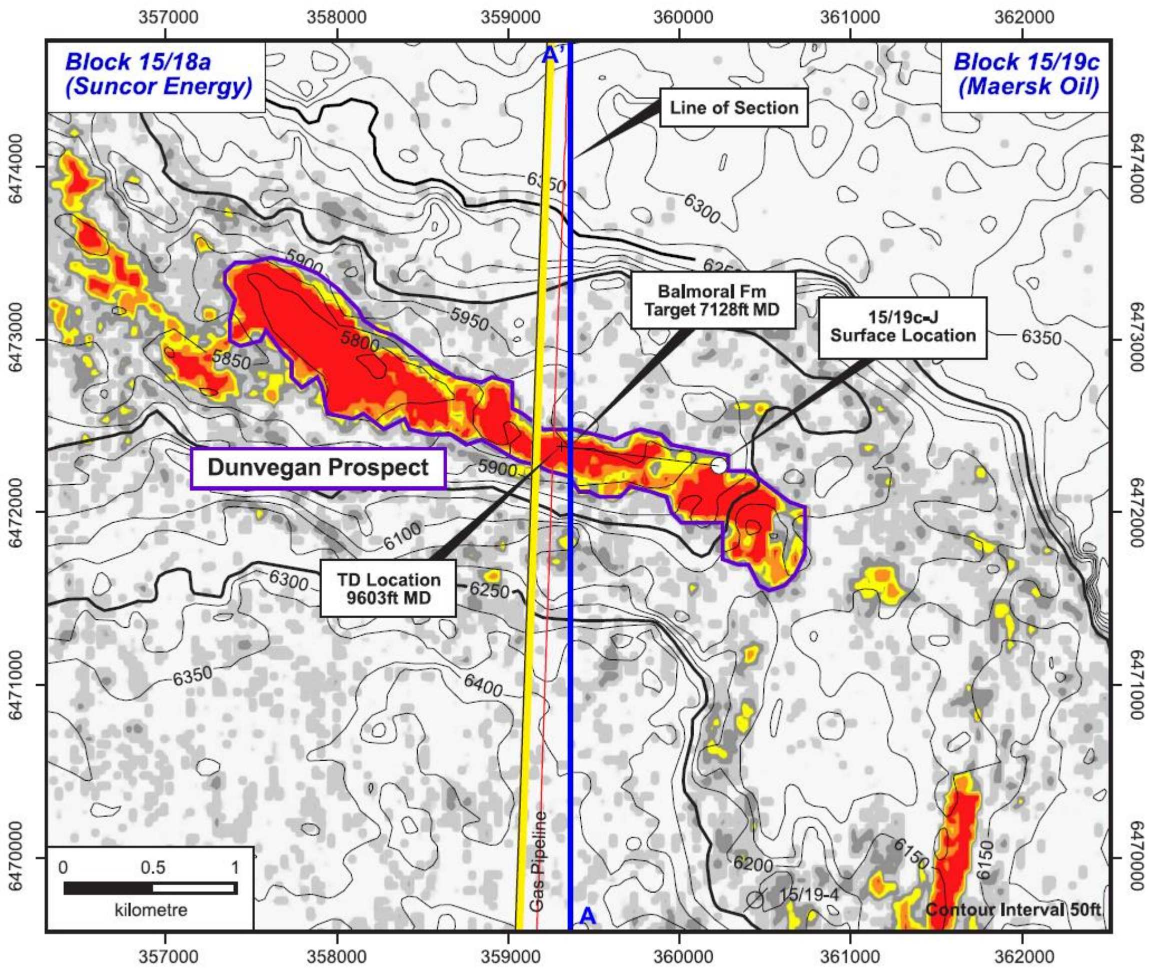
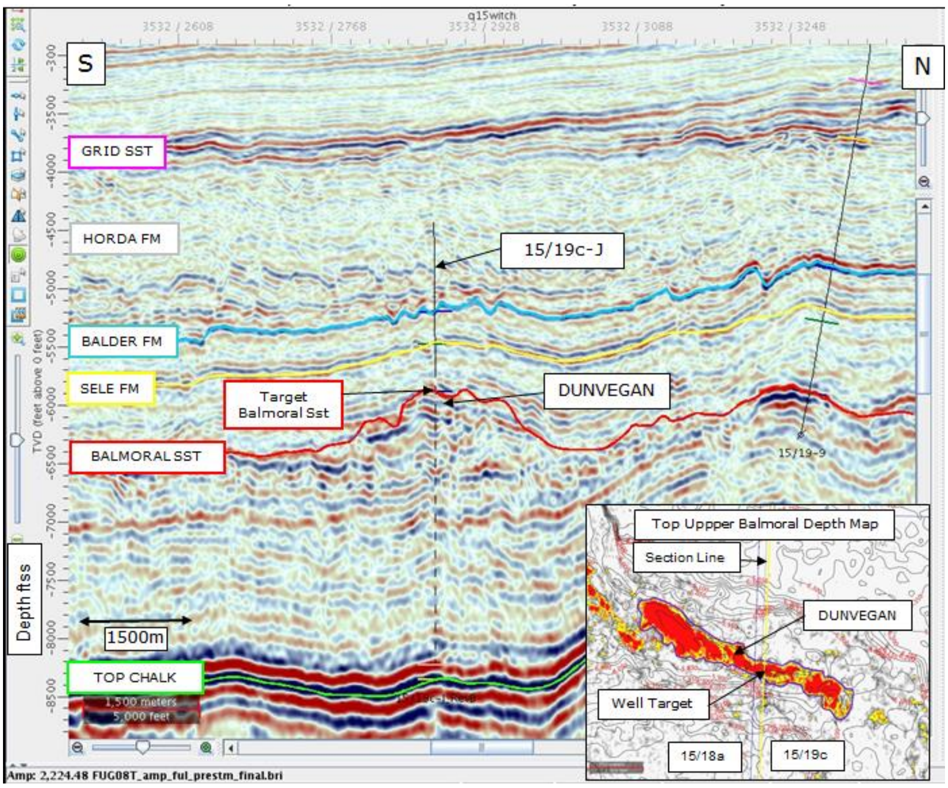


Fig. 73 – Seismic Inline Depth Full Stack Seismic Line (Strike Section along well path)



(Fugro data, courtesy of Spectrum) Spectrum

3.36.Maersk: well 15/20b-18, Dunglass prospect

Located towards the south western edge of the Fladen Ground Spur, 15/20b-18 was designed as a deviated exploration well to investigate the hydrocarbon prospectivity of the Dunglass prospect, a Jurassic Piper Formation sandstone within a fault and dip closed structure (fault closed to the west, north and east and dip closed to the SSW), with a predicted oil-water contact of -8400 ft TVDSS (**Fig. 74**). Well 15/20b-18 had to be drilled through the overlying Balmoral Sandstone which is the productive interval at the Dumbarton Field. Sourcing was expected from the Kimmeridge Clay Formation within effective kitchens to the north and south of the prospect. The Piper target reservoir was expected to be shallow marine shoreface deposits with depositional thickness variation being influenced by syn-rift late Jurassic (Kimmeridgian) faulting together with underlying eroded Carboniferous and Devonian topography. Post deposition thickness is impacted by major uplift and erosion during the late Jurassic and early Cretaceous. Top seal was prognosed to be the Cromer Knoll Group while Carboniferous and Devonian would have provided base seal.

The overall CoS was estimated at 72% with the main question mark related to reservoir presence (80%).

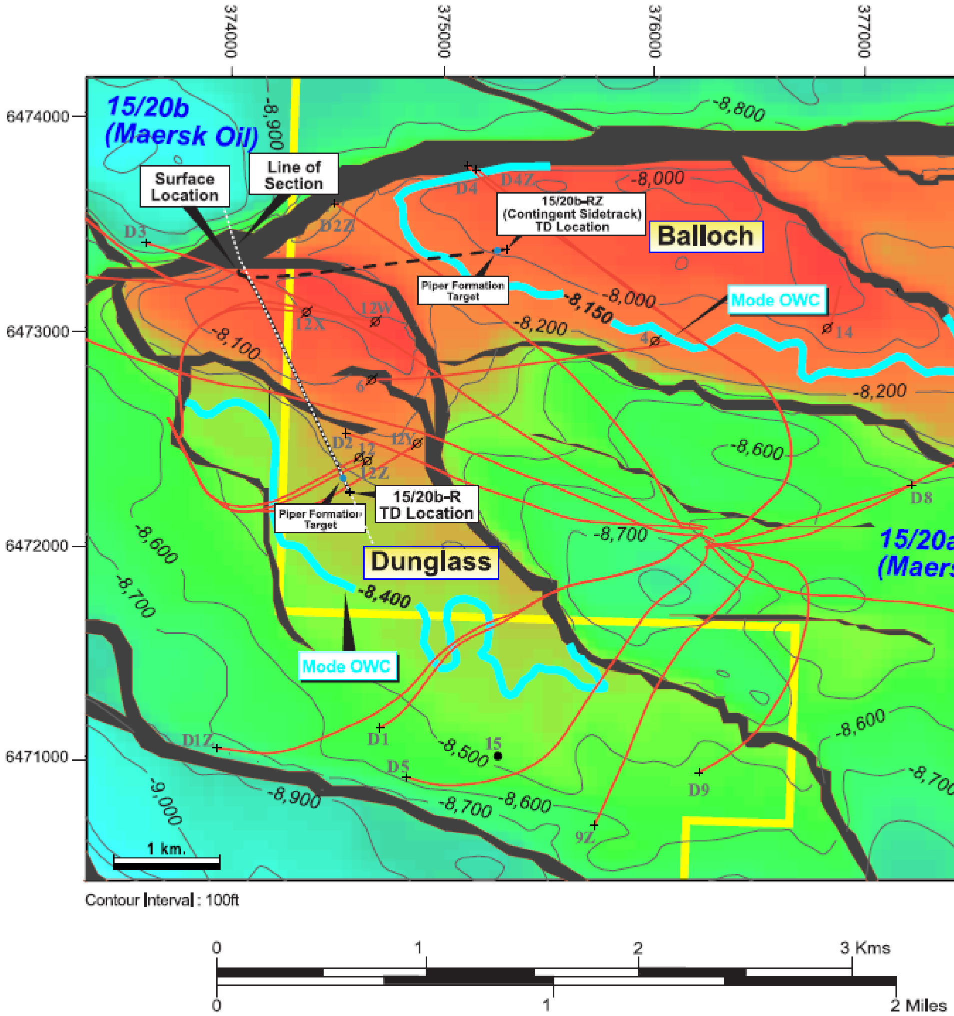
Horizons came in within prognosis down to the top chalk. Below this the prognosis was not as good; most of the horizons come in +/- 200feet deep to prognosis down to TD. The Piper reservoir was found thicker and of better reservoir characteristics than expected but water wet. All of the section is considered to be normally compacted with hydrostatic formation pressure.

The primary reason for failure is interpreted as the lack of trap at the well location: indeed, as the Piper and Devonian horizons were significantly deeper than prognosis, one can wonder if there was a valid trap. However, this fault block structure has now successfully had a Balloch producer drilled into it up dip meaning the trap is clearly present albeit smaller than initially forecasted. A secondary reason is linked to the lack of seal to allow HC down to that depth in the reservoir at the well location. The fault bounding Dunglass to the north-east is probably not sealing while the Devonian is likely too sandy to create an effective bottom seal.

Main lessons learned:

- An improved time-depth conversion coupled with a detailed fault seal analysis may have helped better assess the lateral seal risk.
- Both Geological Programme (prospect montage showing 1 map + 1 cross section over 44 pages) and Geological Well report significantly (petrophysical CPI log over 73 pages) lack figures explaining the prospect description / outcome!

Fig. 74 - Base Cretaceous Unconformity depth map



3.37. Kerr McGee Operator, (Maersk current well owner): well 22/01a-11, Brodie prospect

The Brodie prospect was located in block 22/1a to the SW of the Britannia Field. The target comprised Alba sequence sandstones within the Eocene, Horda Formation. The surface location was positioned vertically over an elongate-shaped seismic feature which was interpreted as turbidite channel sand, analogous to the Alba sand reservoir of the nearby Alba Field. The target sandstones in the Brodie prospect were probably deposited rapidly from high-density turbidity currents. Seismic sections through the main target show wing-like upward projections along the flank of the principal sand channel. These are considered to represent large-scale sand injection structures (neptunean dykes) (**Fig. 75**).

It was thought that the sandstones were preserved in pre-existing NW-SE trending channel complex. This prospect corresponded to classical injectites relying purely on a stratigraphic trapping mechanism where sandstones are encased within the shales. The prospect was also defined structurally by a broad 4-way dip closure at Top Horda depth structure and displayed on top Alba Sand Amplitude displays. Amplitude anomaly was thought to be similar to the Alba one.

It was assumed that the Brodie structure was in a favourable position to receive a Tertiary charge, either by regional migration via the Palaeocene or (less likely) by means of more direct vertical migration via faults from the Jurassic. The Jurassic in this area is deeply buried and in the case of block 22/7 and 22/8 to the southeast of Brodie, highly over pressured.

The top, base and lateral seals were the hemipelagic Horda shale as the prospect consisted of large-scale sand injection structures. Key pre-drill risk was up dip seal. Indeed the pre-drill mapping of the prospect at both Top Alba depth and Top Alba amplitude showed that there was a potential leakage to the northwest of the Brodie mound.

Kerr McGee, licence and well operator at the time of drilling estimated the overall CoS at 35%. The main critical parameters were the migration (50%) and the up dip seal (70%). No risk was attached to all other parameters including the trap definition.

Well 22/1a-11 found two sand rich sections in the Horda Formation; the upper (Alba Sequence) sand was 180ft thick with 99.4% net-to-gross. The lower Caran sandstones extended from 7288ft to 7530ft with some inter-bedded shale (total 206ft sand, 85% net-to-gross). The Alba sandstones have excellent porosity and permeability.

The Alba target was found 213ft deeper than expected. Unfortunately both sandstones (Alba and Caran) were dry with 100% water saturation and hydrostatic pressure.

Post well analysis revealed that the top sand seismic pick was shallower than the actual top sand; it is therefore likely that the mapped structural trap did not actually exist. Consequently, trap failure is the envisioned main cause for failure although charge and seal are unresolved.

<u>Main lessons learned:</u>

- Despite not showing a clear cut geological feature (**Fig. 76**), the targeted amplitude anomaly highlights sand presence, not hydrocarbons. Calibration of seismic amplitudes, rock physics modelling and AVO analysis should have been performed pre-drill.
- As the well was dry, no wireline logs were acquired once TD was reached. This does not allow post well auditing of the targeted anomaly and makes it difficult to learn any valid lesson from this well failure. OGA may consider requesting acquisition of a minimum set of wireline logs prior to P&A'ing a dry well.

Fig. 75 - SW-NE seismic line across Brodie prospect **(Fugro seismic data, courtesy of Spectrum)** Spectrum

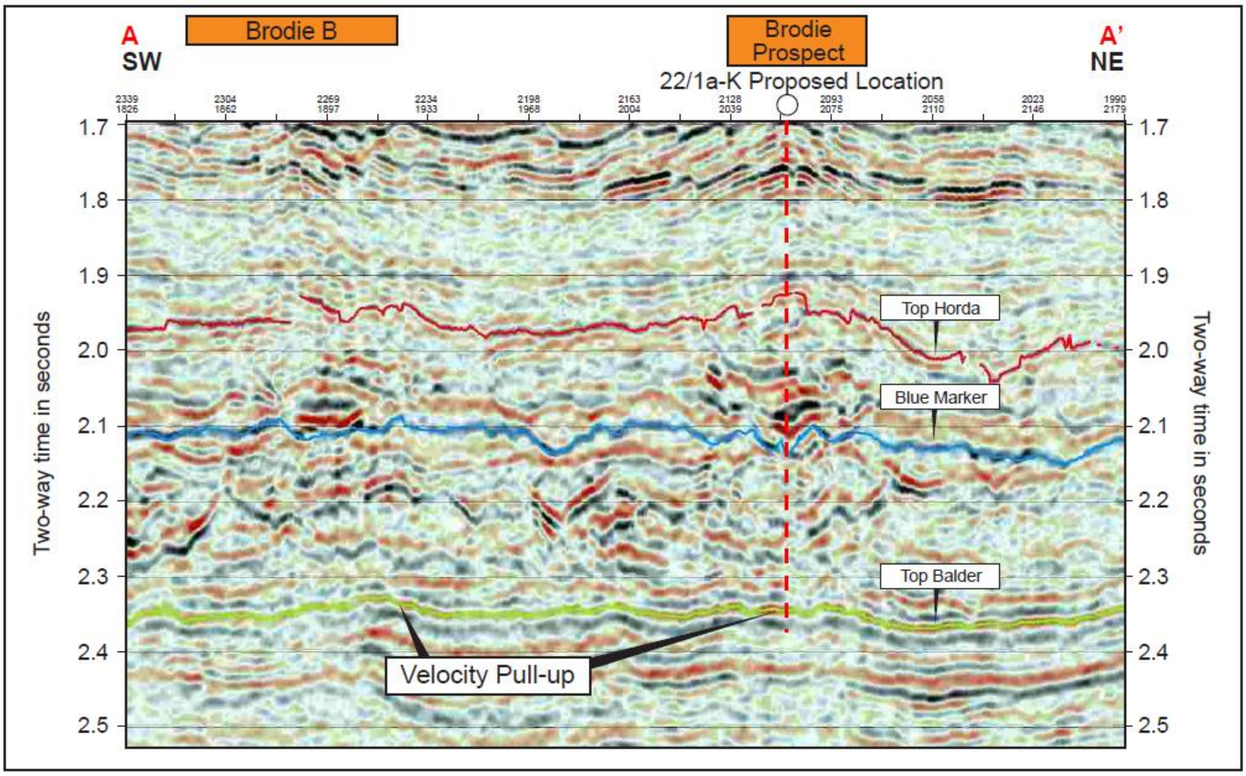
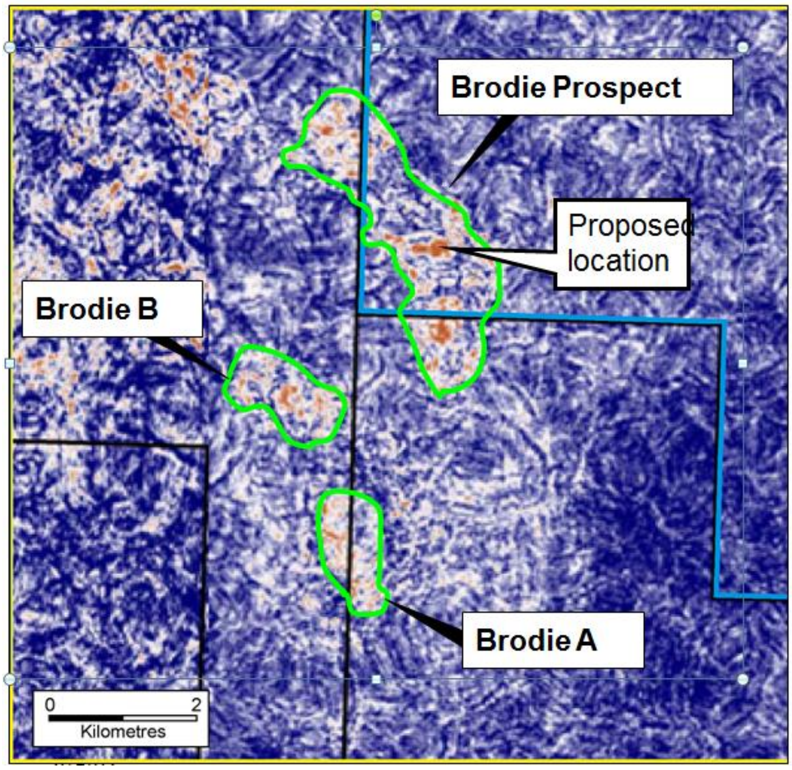


Fig. 76- Top Horda Formation amplitude map



3.38. Kerr McGee Operator, (Maersk current well owner): well 29/15-3, Fyvie prospect

The licence operator was Kerr McGee, who operated the well.

The Fyvie prospect was located ~20 Km due west of the Fulmar field. It targeted a combined stratigraphic-structural closure mapped at the top Fulmar level (**Fig. 77**). Although it had a small independent closure at its crest, it was the shale-out of Fulmar sandstone into time equivalent Kimmeridge Clay which provided the trapping geometry at deeper levels.

Sourcing from Kimmeridge Clay Formation was seen as very low risk. Fulmar shoreface sandstones were prognosed as in the Janice and Fulmar fields.

The overall CoS was estimated at 43%. The validity of the top Fulmar pick and the presence of an effective lateral seal were perceived to be the prime risk on this prospect (75%) as well as the overall trap geometry (70%).

Well 29/15-3 was prognosed to encounter up to 800 feet gross Fulmar Sand below a thin chalk interval. In fact it drilled directly from the chalk into a thin Cromer Knoll interval followed by a 170 feet gross column of Triassic Skagerrak shales and sands. There was no Kimmeridge Clay and no Fulmar Sand present. The Skagerrak was water bearing.

Obviously the main reason for failure is the lack of target reservoir because of a wrong interpretation of the seismic facies below BCU (Kimmeridge Clay was also over confidently expected down dip to the north) leading to absence of trap (**Fig. 78**). In addition as there is no clear Kimmeridge Clay Formation apparent down dip on the provided seismic lines the migration is likely not effective.

The risk assessment failed to address the key risk of reservoir presence (reservoir risk was set at 90%) as it was assumed that all wells in the area would encounter at least 20 feet of Fulmar Sand. The key risk was assumed to be that the Top Fulmar had been picked too high and that the trap was not as seismically well defined as mapped.

Main lessons learned:

- The seismic facies below BCU was almost reflection free making the pre-drill Top fulmar picking quite bold.
- This particular well illustrates several cognitive biases: a human tendency to “anchor” an evaluation on a reference analogue as well as the tendency to overestimate the accuracy of one’s own interpretation.
- Multiple hypotheses during pre-drill interpretation should lead to a more widely opened range of different scenarios.

Fig. 77 - Fyvie prospect: pre-drill Top Fulmar Sand Depth Map

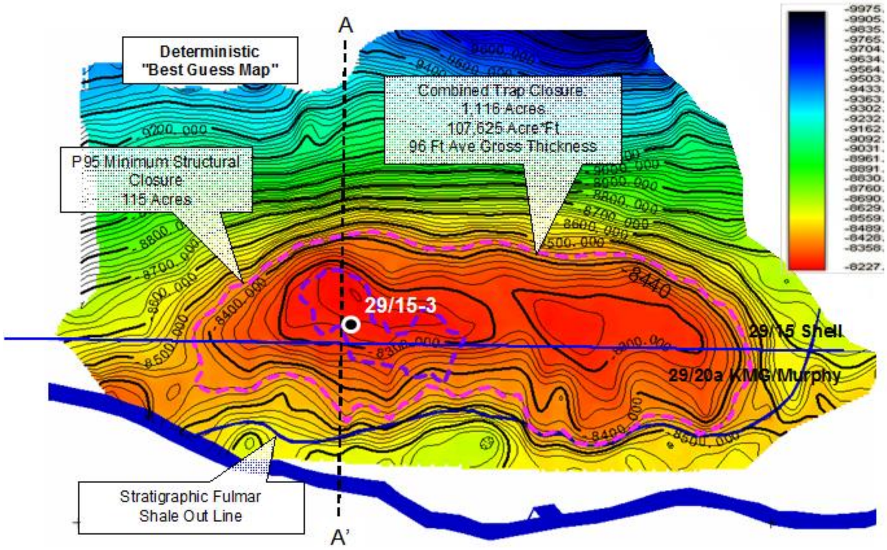
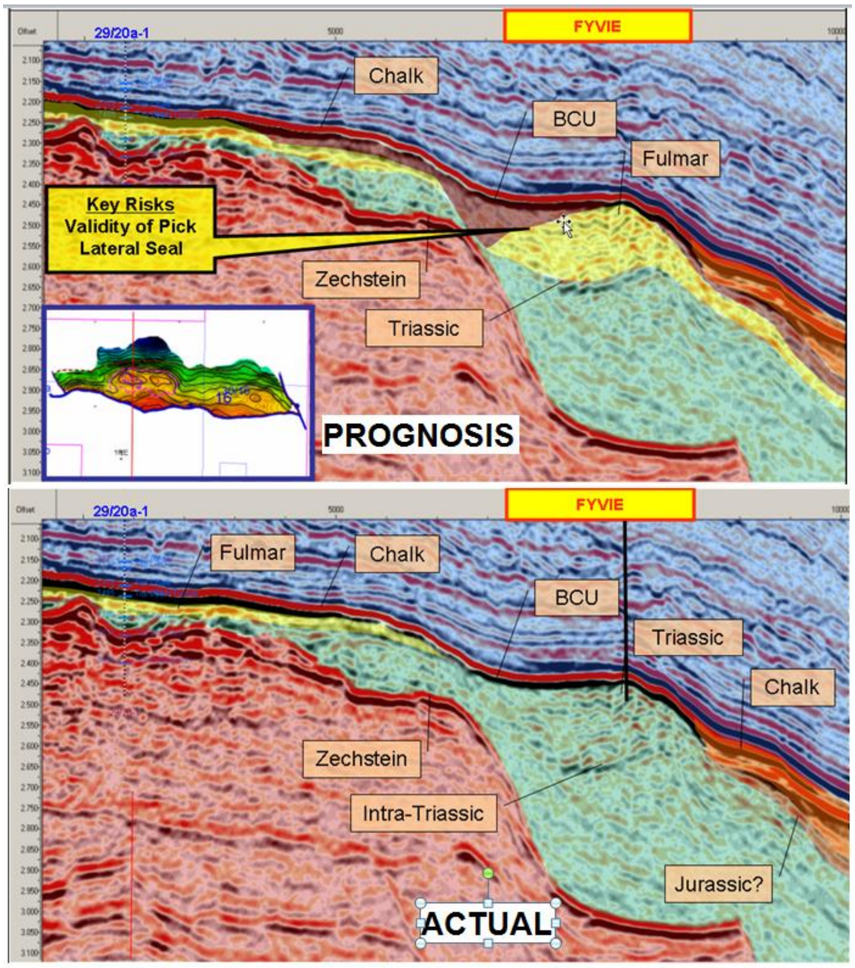


Fig. 78 - Comparison pre-post-drill along a N-S line across Fyvie prospect **(Veritas seismic data courtesy of CGG)**



3.39. Kerr McGee Operator, (Maersk current well owner): well 30/16-14, Western Terrace prospect

The Western Terrace prospect was located ~ 2.5 Km due west from the Janice field. Western Terrace was a 4-way-dip closure which straddled blocks 30/16t and 30/17a: the small closure was mapped over the crest of the structure, with a larger closure of shallower relief surrounding it over a much wider area. It was difficult to map the SW edge of the prospect (**Fig. 79**) and there was no 4-way-dip closure at BCU level.

The target reservoir was the Fulmar as in the neighbouring Janice Field and reservoir quality was a bit risky (85%).

Sourcing was expected either from adjacent Kimmeridge Clay or via contribution from the Kimmeridge Clay sitting on Janice Terrace. Results of previously drilled well 30/17a-4 were interpreted as follows: breaching of the fault seal was thought to have led to the further westward migration of the oil and to the charging of the Auk field. The remaining oil was subsequently trapped within the 4-way dip structure that was recognised as the Western Terrace prospect. None of these parameters were deemed risky. Seal was not seen as risky (100%). The overall CoS was set at 64% with the trap being the main pre-drill risk (75%).

Well 30/16-14 was drilled further up dip of well 30/17a-4 in 2005 and encountered thick good quality Fulmar sandstones which were dry. Breaching of the trap was most likely caused by a lack of closure within the SW quadrant of the prospect: it is likely that the original 2005 mapped structural closure to the SW does not exist (lack of trap, **Fig. 80**)

<u>Main lessons learned:</u>

- Minor oil saturations identified from CPI implies that the prospect lies on a migration fairway.
- Although Explorationists should use analogues and geological models, they should be careful when it comes to the seismic picking. Seismic interpretation should pay attention to noise / multiples and should not cut across valid seismic reflections (**Fig. 80**).
- Maps should be larger than the described prospect. In this particular case the map is cut off too soon towards the south west making it difficult to give any pre-drill focus on the prospect weak point (**Fig. 79**).

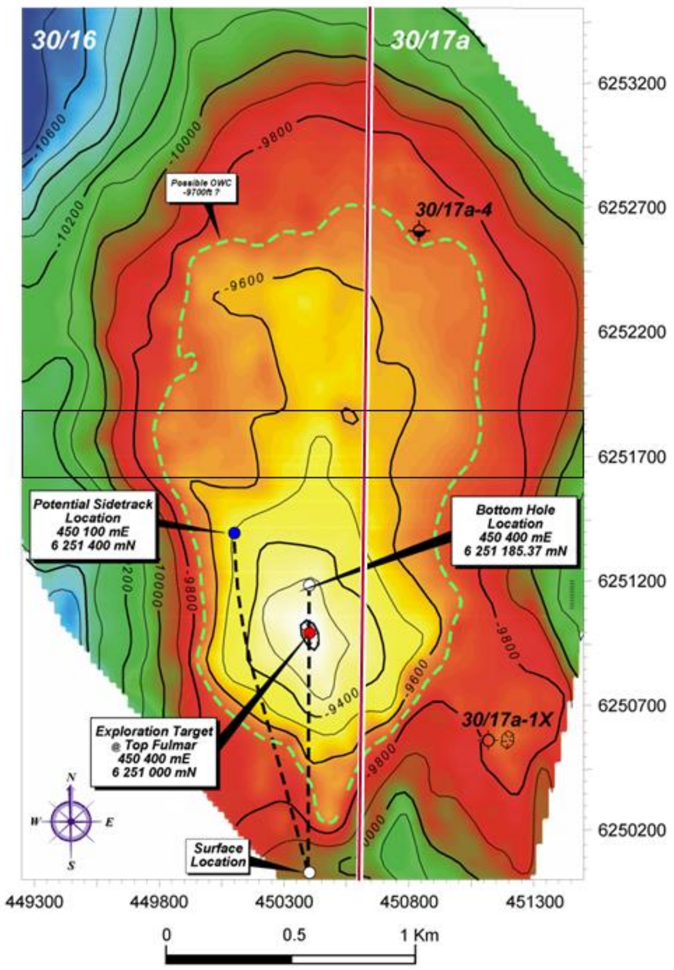
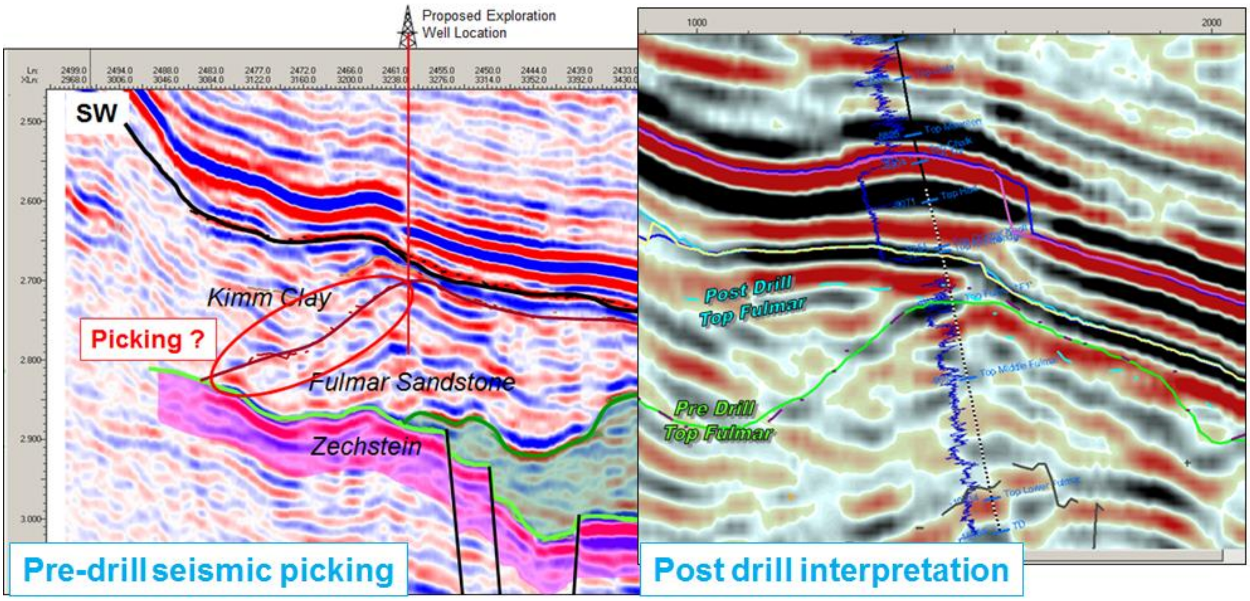


Fig. 79 - Western Terrace:

Top Fulmar depth map

Fig. 80 – Western terrace: pre- versus post-drill comparison along a SW-NE line **(Veritas seismic data courtesy of CGG)**



3.40. Nexen-CNOOC: well 12/14-2, Zanzibar prospect

The Zanzibar prospect was located on the western margin of the Wick Graben, sloping down to the northeast towards the basin bounding ENE-WSW Wick Fault. The structure was controlled by Late Jurassic faulting and flexure on the Wick Fault, with movement during the early Cretaceous creating significant throw at Base Cretaceous level. Discrete sand bodies pinch out against the flanks of the Graben, creating stratigraphic traps which are encased within the anoxic marine claystones of the Kimmeridge Clay Formation. Well 12/14-2 tested the Zanzibar prospect defined as a combined structural and stratigraphic trap at Top Burns Sandstone level (Late Volgian/Early Ryazanian). 12/14-2 had been located on a 4-way dip closure and the upside of the prospect was considered as a stratigraphic trap formed by the pinch-out of the Burns Sandstone to the west of well 12/14-1 (**Fig. 81**).

The Kimmeridge Clay Formation source rock is mature for oil generation and expulsion in the deepest part of the Wick Basin (>10,750ft), adjacent to the Wick Fault. The mature hydrocarbon subsequently migrated up-dip, to the south and west and oil shows are present in well 12/14-1.

The Burns Sandstone reservoir was interpreted as being fully encased in marine shale of the Kimmeridge Clay Formation which would provide top, base and lateral seals. However, petrophysical analysis on well 12/13-1 shows 13 feet of Late Volgian sandstone with 30% porosity and no shows; the up-dip location of this well increased the risk on the seal. Faults mapped east of well 12/13-1 were believed to offset this 13 feet sandstone and isolate it from the Zanzibar Prospect.

Zanzibar was evaluated as a risky prospect with an overall CoS set at 10%. The critical risks were the trap geometry (40%) and the seal (50%). Reservoir presence (70%) and source rock presence and quality (80%) were deemed less risky.

Well 12/14-2 failed because the Burns Sandstone reservoir target was absent. Instead it founds cemented sand stingers and no shows. The Kimmeridge Clay Formation was present and thick. However, no shows have been recorded in any sand from Alness (Callovian) to Oxfordian and top Triassic all being more than 365 feet deep to prognosis. Lack of charge is interpreted as the secondary reason for failure.

<u>Main lessons learned:</u>

- Sand source (ref well 12/14-1) was not as well developed as expected in the Wick Graben.
- Well 12/14-2 proved the lack of effective migration pathway from the deep part of the Wick Graben.
- The 3D seismic seems to be of poor quality (**Fig. 82**: lack of character, multiples…etc…): would a new 3D have better imaged the area and provided the basis for a more accurate sand / shale discrimination?

Fig. 81 - Zanzibar Prospect - Base Cretaceous Depth Map

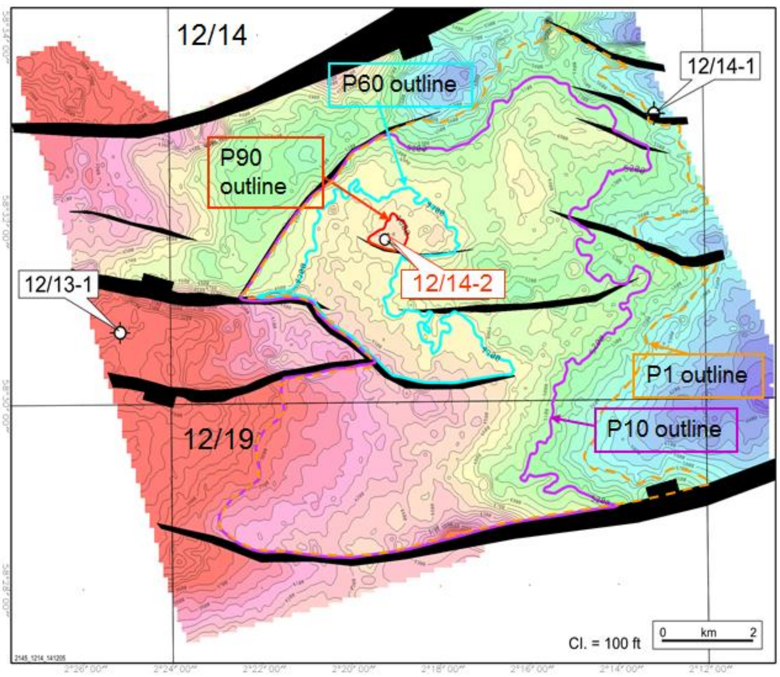
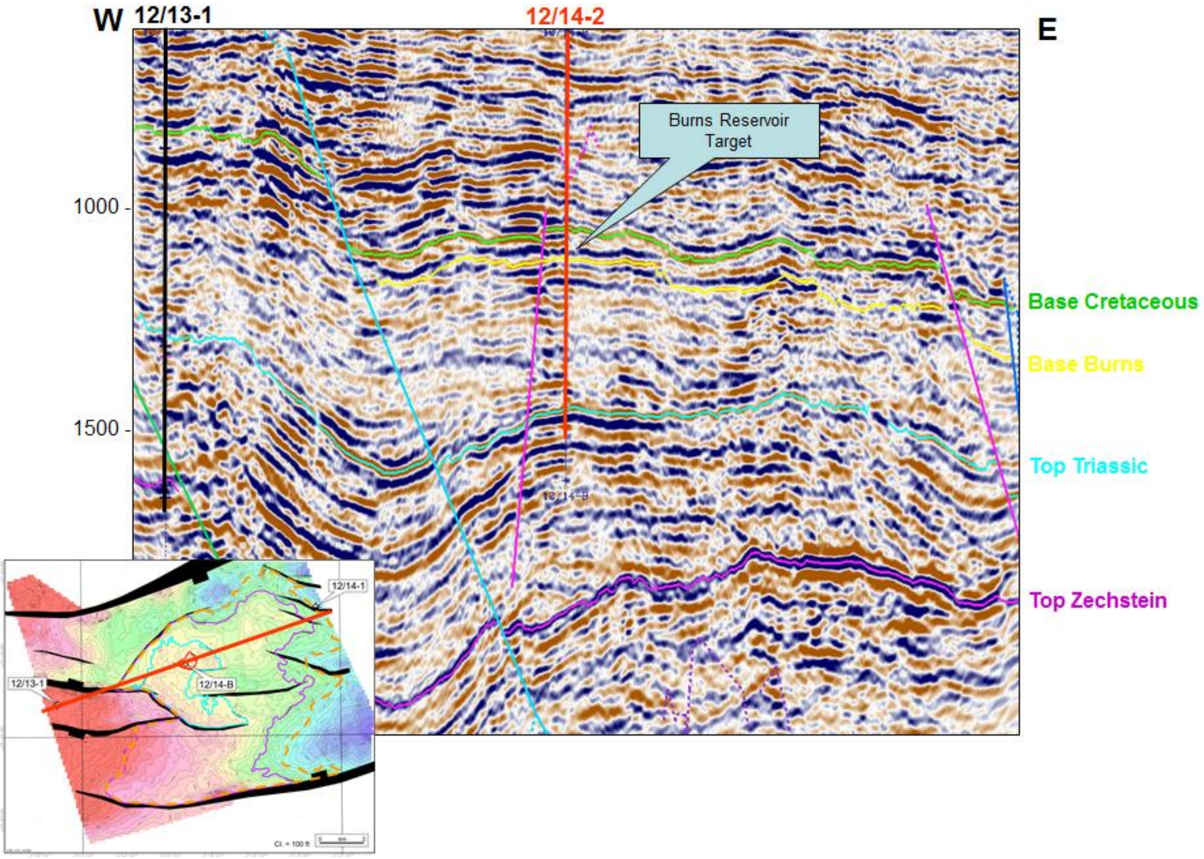


Fig. 82 - Zanzibar: West - East Line through wells 12/13-1 and 12/14-2 (Data Amerada Hess proprietary)



3.41. Oilexco well operator, (NEXEN-CNOOC current well owner): well 13/30b-7, Oddjob prospect

The Oddjob prospect was located ~7 Km due east of the Cromarty Field and straddled blocks 13/30b and 14/26a. **At the time of drilling, BG was license operator and decided to farm-out. Oilexco paid 100% of the well costs (and operated it) to obtain a 70% interest in both blocks**. Nexen-CNOOC is the current well owner.

Well 13/30b-7 targeted a 4-way dip closure corresponding to Tertiary inversion structure (**Fig. 83**). Possible spill to the North was identified due to poor imaging in Cretaceous and Jurassic levels. The primary target reservoir was Lower Cretaceous Captain C Sandstones, also referred to as the Kopervik Sandstones. Secondary objective were units A-D of Ettrick Sandstones from the Upper Jurassic Kimmeridge Clay Formation.

Valhall Formation (Cromer Knoll Group) limestones and chalks as well as Lower Cretaceous Rodby Formation were interpreted as top-seal for the primary Captain sandstones while the Kimmeridge Clay Formation was the bottom seal. Fault seal to the west could limit column height. Sourcing by the Kimmeridge Clay Formation was not seen as a risk.

The overall CoS was estimated at 49% with trap geometry and seal set at 80% and being the main risks while reservoir presence was interpreted as a secondary risk (85%). Gas was expected in Captain sandstones while oil was prognosed in Ettrick sandstones.

Well 13/30b-7 found top chalk 406 feet high to prognosis and chalk was thicker than prognosed (1843 feet vs 1280 feet prognosed): this error very likely impacted on target time to depth conversion. Kimmeridge Clay shales were present but very thin (24 feet). Captain reservoir was in line with expectations but water wet. The secondary target Ettrick D and C Sandstones were encountered at 6958 feet and 7765 feet tvdss respectively but both zones were water wet.

Main reasons for failure are likely to be the lack of trapping geometry and additionally, as no shows of any kind were observed, a lack of charge. Although the prospect was located amidst a prolific basin, could it be within a shadow zone? Captain most likely leaked to the North, because the closure is so slight, small variations in the depth conversion could change the 4-way dip closure. Ettrick most likely leaked to the North, because there is a spur that continues from the well location up towards the Halibut Horst fault. Also, as there is a relatively high N/G in the Ettrick D & C, there may be no top seals individually for the sandstones.

Main lessons learned:

- The Captain Sandstone closures typically have very low relief in the Atlantic Cromarty area complicated by the Top Captain sandstone being a poor seismic event of variable character (**Fig. 84**). Given the difficult Top Captain pick, the Top Rodby (circa 200 feet above the Captain) is often used as a proxy for the Captain sandstone, isopachs being added to the Top Rodby. For Oddjob, both direct mapping and isopach methods were used for sensitivities. There was greater relief at Top Captain (poor event) than at Top Rodby in the Depth volume but both had more relief that the Top Rodby in the time volume.
- For the Captain and Ettrick D, the closure on the depth volume of the PSDM is much larger than in the time volume. For the Captain, the reason for this seems to be related to low velocity trends in the velocity model. At Ettrick D, the uncertainty was correctly identified as being due to low relief closure and risk of spill to north.
- Interpretation should ideally be performed on the time converted version of the PSDM and depth converted in a conventional manner. Alternatively, if the PSDM depth volume is used for a prognosis, ascertain that it does tie neighbouring wells at the relevant levels.
- Understanding any differences in closure between time and depth in PSDM volumes is critical in areas of low-relief. Indeed pre-drill comparison of the time and depth volumes of the PSDM may have highlighted the depth 'mistie' at Top Chalk.

Fig. 83 – Oddjob prospect: pre-drill top Captain Depth map tied to nearest wells – ft TVDss

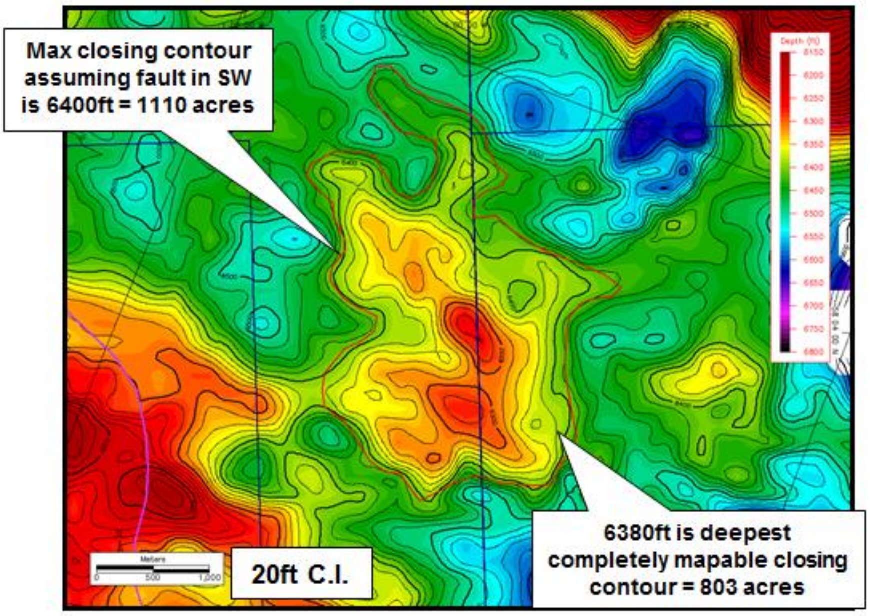
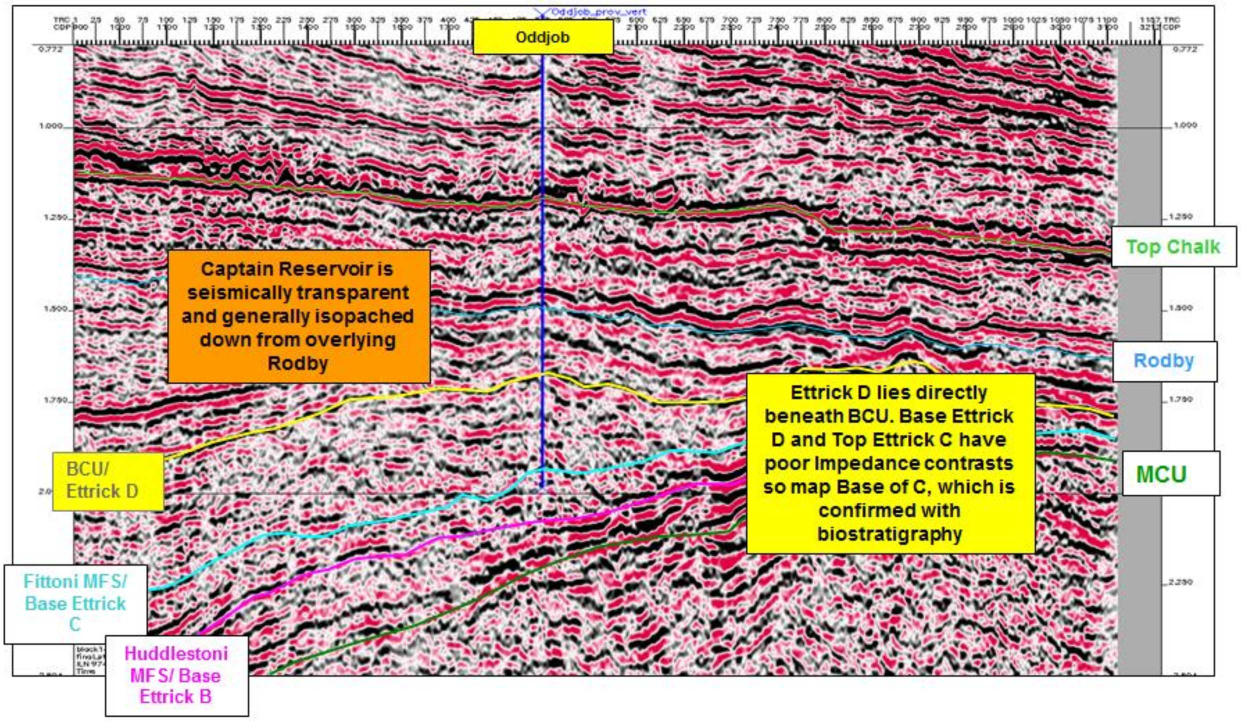


Fig. 84 - 4-way dip closure at Base Chalk & BCU Structure observed on 2003 PreSDM dataset (NW-SE Seismic In-Line 974) (Data Amerada Hess proprietary)



3.42. Nexen-CNOOC: well 14/26a-9, Hobby North prospect

The Hobby North prospect was located to the north of the Hobby discovery in block 14/26. The target reservoir was the Late Ryazanian / Early Hauterivian Punt sandstones (same as Hobby reservoir) sourced by the underlying Kimmeridge Clay Formation.

A secondary objective was the Buzzard sandstone (Late Kimmeridgian / Early Volgian) reservoir which was oil bearing in Samedi well 13/30-2.

Migration pathway analysis suggested that the Hobby North area was connected via the Golden Eagle (Punt) fairway to the source kitchen from Golden Eagle to the east, which provided a direct migration pathway. As the northern extent of the narrow Golden Eagle (Punt) fairway has been found to be oil bearing, this migration pathway had been well tested.

Top and lateral seal for the Punt sandstones were the overlying Valhall Formation claystones. The Punt sandstone pinches out and downlaps on to the BCU. The Kimmeridge Clay Formation was the base seal for the prospect (and is successful in the nearby Golden Eagle and Pink discoveries). The P10 resources had been calculated using a common OWC with Golden Eagle.

Two time-to-depth conversion methodologies had been carried out respectively called “hybrid” and “SeismicVint” resulting in two different depth maps. There was no independent closure in time. A stratigraphic pinch-out was defined to the east onto a local high; dip closures were observed to the north and west; the key critical risk to the Hobby North prospect was up dip sealing (50%) in the northwest due to continuation of the depositional system without dip closure meaning success required up-dip seal (**Figs. 85a & 85b**).

All other risking parameters were deemed certain; hence the overall CoS was estimated at 50%.

Well 14/26a-9 found the top Punt significantly deeper than prognosis due to shale prone upper section. Although Punt sandstones are both at high end of pre-drill estimate (223ft net Punt sandstone with average porosity 22% and 78% N: G), the top sand ties a seismic loop deeper and being below the Golden Eagle OWC, are entirely water bearing.

The Valhall claystones were thick, providing an effective top seal but the Kimmeridge Clay was thin (3feet) jeopardizing the bottom seal effectiveness.

The full Upper Jurassic section was penetrated and further reservoir intervals encountered in Kopervik, Coracle, Burns, Ettrick, Buzzard and Sgiath: all were water bearing. The secondary objective Buzzard-aged sandstone was encountered above Samedi ODT but water bearing which means that both sand bodies are disconnected.

Well 14/26a-9 failed because the up-dip sealing to the north-west was lacking: it is likely that sandstones at Hobby North and Oddjob (**see chapter 3.41**) are connected and that any hydrocarbons passing through this reservoir leak to the northwest. It is also possible that the failure was due to a lack of trap with the sands coming in deep to prognosis and below the established FWL.

<u>Main lessons learned:</u>

- We cannot assume Top Sand will follow the same reflector onset type when correlating from Golden Eagle to Hobby North along Punt channel depositional axis (**Fig. 86**).
- Anchoring interpretation on successful offset wells can result in over confidence in knowledge levels.
- Alternate Top Sand seismic event should have been mapped but it's fair to highlight that Nexen had 10 consistent seismic well calibrations to the south.
- Isopaching up methodology for generating Top Punt depth map should be compared with direct depth conversion within the 3D velocity model.
- PSDM gathers should be looked at for velocity variation analysis
- Post-well Fluid Inclusion Study would have helped checking the effectiveness of the migration pathway.

Fig. 85a - Hobby North: south- north schematic geological cross section along Punt depositional axis volume

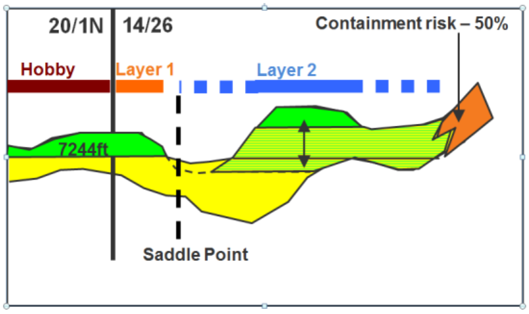


Fig. 85b – Hobby North: volume scenarios (Top Punt 2 Depth (ft) using Seismic Vint. depth conversion map)

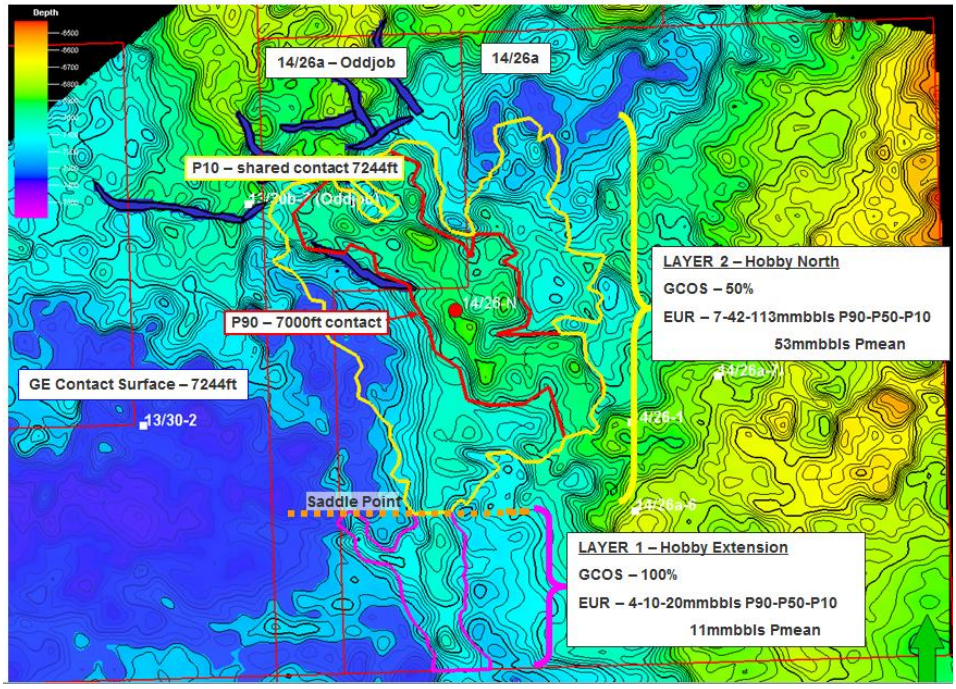
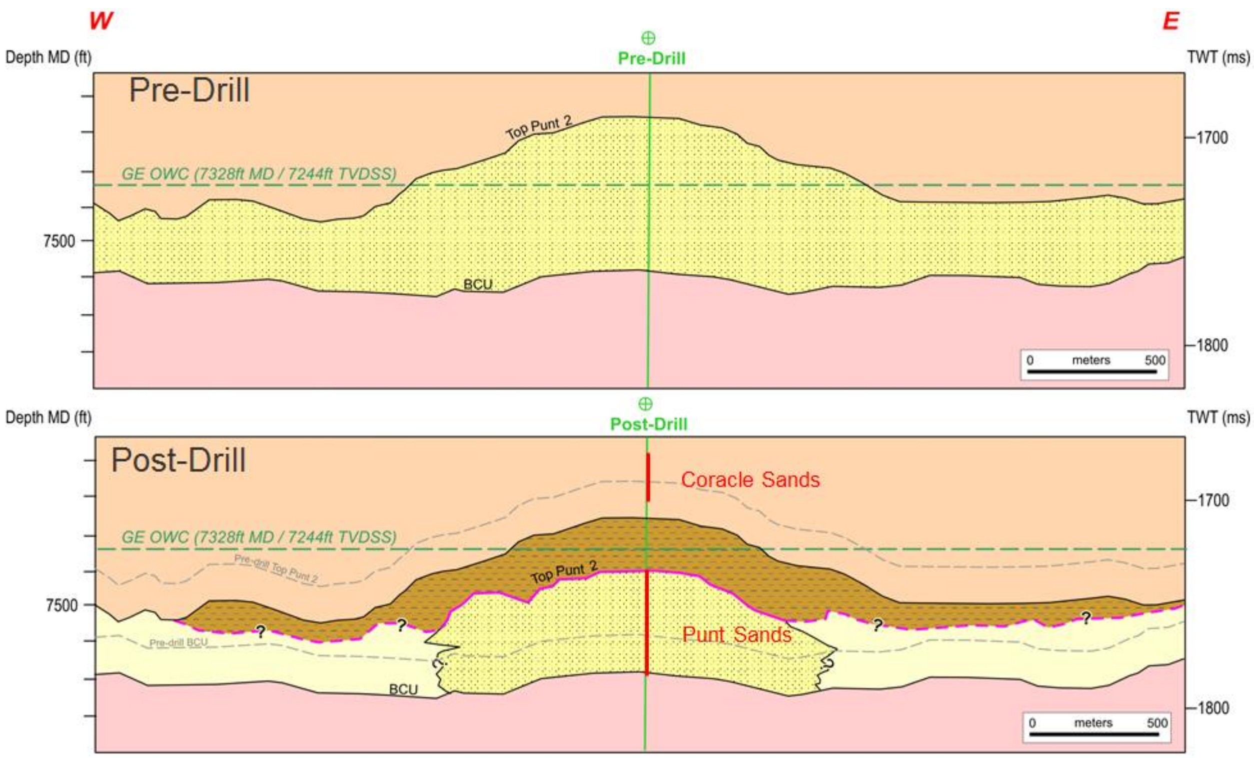


Fig. 86 - Hobby North: geoseismic line: pre-drill vs post-drill comparison



3.43. BG well Operator, (Nexen-CNOOC current well owner): well 14/27a-2, Octopus prospect

At the time of drilling, **this block was operated by BG International Limited** (83.33%) with partner Amerada Hess Limited (16.67%). Nexen-CNOOC is the current well owner.

Octopus prospect was located adjacent to the south of Halibut Terrace and consisted of a series of N-S trending Lower Cretaceous confined slope channels sourced from the Halibut Horst which were interpreted as extending into the main Apto-Albian (Captain / Kopervik Sandstone) fairway (**Fig. 87**). The trapping mechanism was either up-dip fault closure (against one of the main horst-bounding faults) or up-dip pinch-out onto the slope. This prospect was defined on final migration data (uncertain phase and polarity).

No local direct analogues are known, although feeder channels trending south from the Halibut Horst have long been postulated. Evidence of differential compaction identified in the Lower Cretaceous overburden above each channel suggested a sandy / conglomeratic fill. Reservoirs were expected to be Captain, Coracle or Punt sands.

Top seal was to be provided by the Plenus marl and Chalk Formations. Inter-channel overbank facies could provide lateral communication and potential thin bedded thief zones between these channels. Base-Seal was interpreted as Kimmeridge Clay Formation which was also expected to be the source rock. Octopus prospect depended on up dip and channel margin sand pinch out.

Overall CoS was estimated at 27%: the main critical risk was the seal effectiveness (50%). Reservoir presence (75%) and quality (90%) were secondary risks.

Well 14/27a-2 found no sandstones in the Lower Cretaceous or Upper Jurassic Ettrick.

Obviously the main reason for failure was the lack of reservoirs at the target location. For this reason, the proposed trapping and sourcing were not actually evaluated.

Main lessons learned:

- Considerable weight was placed on the compaction / lenses geometry as an indicator of sand presence although the well was drilled at a location without clear compaction indicator (**Fig. 88**).
- Indeed, the overall small size of prospect meant the well was located for economic volumes, not necessarily geological optimum.

Fig. 87 – Octopus prospect definition: superimposed Top Captain to BCU Isopach and Top Captain Depth maps

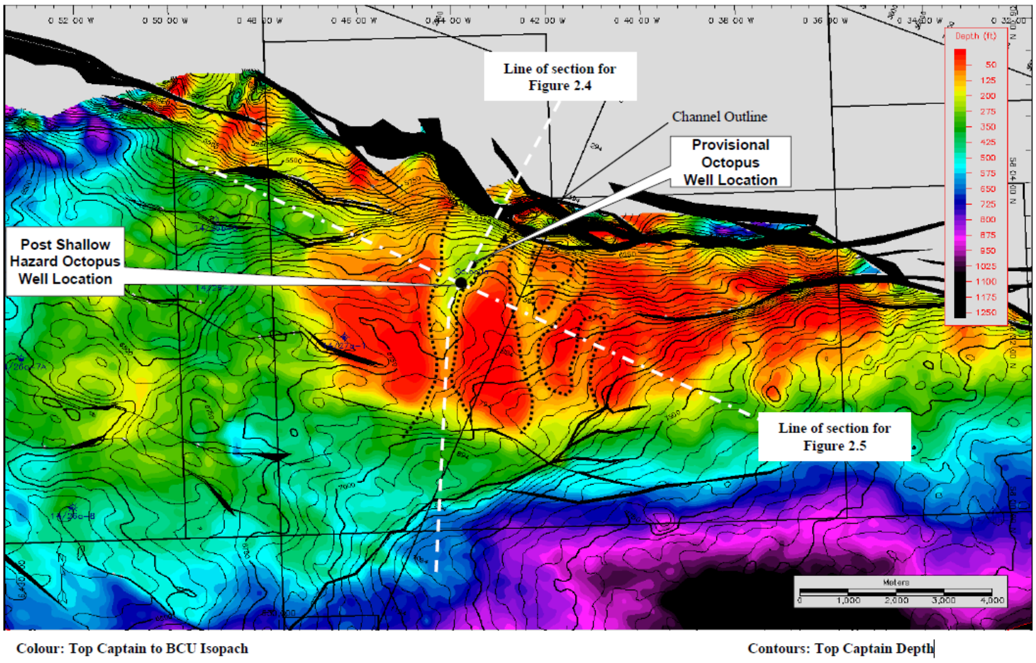
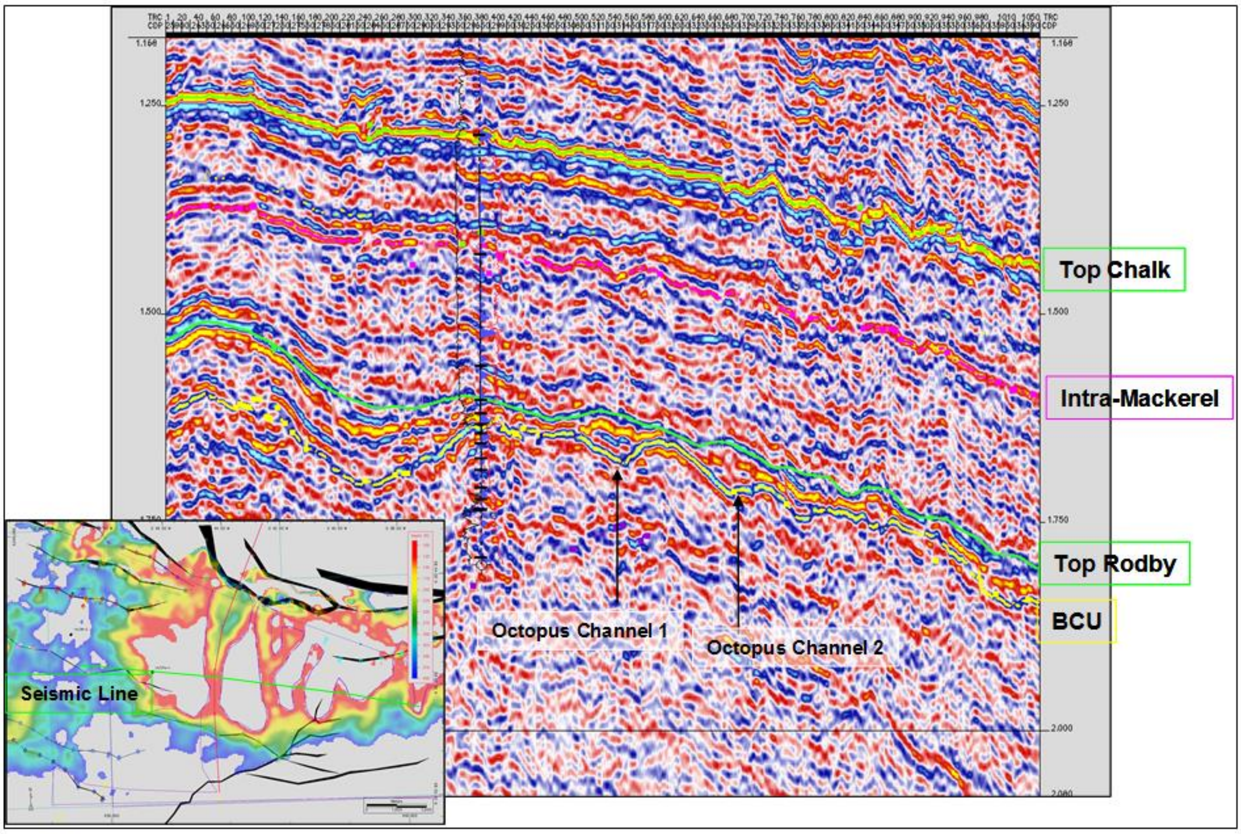


Fig. 88 - West – East seismic section across Octopus prospect **(Data courtesy of TGS)**



3.44. Nexen-CNOOC: well 15/13b-11, Stingray prospect

The Stingray prospect was located ~26 km to the north-east of the Piper Field. The Stingray structure was a southward dipping seismic package whose up dip extent to the North was defined by an east-west trending fault, which ceased movement in the Late Cretaceous, and its cross-fault juxtaposition against Carboniferous aged mudstones and silts (**Fig. 89**). Spillage to the east was thought unlikely and assigned a low risk due to the pinch-out or erosion of the mapped sand unit based on regional well penetrations.

Although being immature for oil generation at prospect location, the Kimmeridge Clay Formation was the expected source rock. As a result, long distance migration of ~50 km from the Witch Ground Graben was required. Oil was encountered in the 15/13b-6 well, 4 km from the proposed location, indicating good charge potential. Timing of potential tilting and migration were the main risk for charge, however the overall source / migration was not seen as a key risk (90%).

Upper Jurassic Shoreface "Fulmar" J70 Sandstones were the target reservoir at Stingray. The 15/13b-11 well was located so that it would test the thickest part of the fairway in the structure. However, target sandstones were too thin to be mapped on seismic (**Fig. 90**). Quality may be reduced due to fault proximity. TD was planned in Triassic Smith Bank Formation to penetrate all Upper Jurassic intervals.

Kimmeridge Clay Formation top seal (20 - 60 ft thick) with downthrown fault seal were interpreted as necessary sealing components. The fault seal to the north was required to be an effective seal to hydrocarbon migration in the Jurassic sands. Limited well penetrations to the north of the fault (wells 15/07-1 and 15/08-1) as well as fault seal analysis studies, supported the sealing capacity of the fault, but this risk could not be eliminated.

The overall CoS was estimated at 50% with the seal (70%) and the reservoir (80%) being the main identified risks.

The well 15/13b-11 failed to encounter oil in the Jurassic primary target of the Stingray Prospect. However, Upper Jurassic Fulmar (J64-J63) reservoir was present within the forecast range for thickness and porosity while permeability was at the high end of expectations. Regarding the deeper secondary objectives, Late Jurassic aged (J62-J52) Piper and Sgiath sandstones were present below the Fulmar equivalent (J64-J63) sandstones, with good reservoir quality, but no shows. Oil shows were described in the Tertiary Balmoral Formation.

The main reasons for failure are interpreted to be the lack of fault seal effectiveness of the E-W bounding fault: the pre-drill Shale Gouge Ratio (SGR) modelled less shale than was found and used much greater permeability than encountered in the region resulting in overestimating the SGR.

<u>Main lessons learned:</u>

- Although Nexen assesses the charge model as unproven, one may wonder if absence of shows in Jurassic reservoir target but oil show in Balmoral is showing that there was no effective migration pathway to source the Fulmar. The Jurassic section (interval between BCU and near Base Jurassic) is pretty thin (~20 ms TWT, **Fig. 90**) and many faults are cutting through the BCU making the Jurassic carrier beds potentially ineffective.

- Although pre-drill basin modelling was undertaken, a more detailed charge evaluation is needed for edge of basin plays to better assess detailed migration pathways and potential HC volumes.

- Quality LWD logging can replace wireline runs

- New analysis of old biostratigraphy data results in better paleo-geographic models.

- Again, despite an extensive fault seal analysis being carried out pre-drill, wider variation in critical parameters needs to be used.

Fig. 89 - Stingray pre-drill BCU depth map and volumetric hypotheses

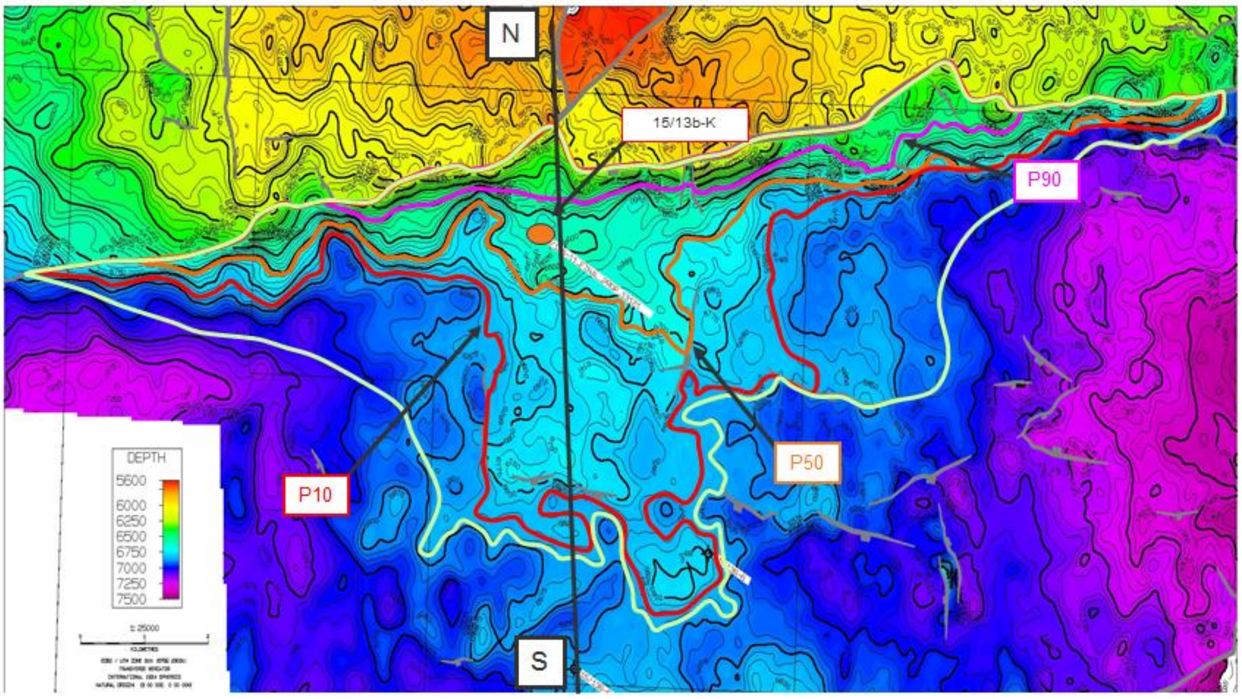
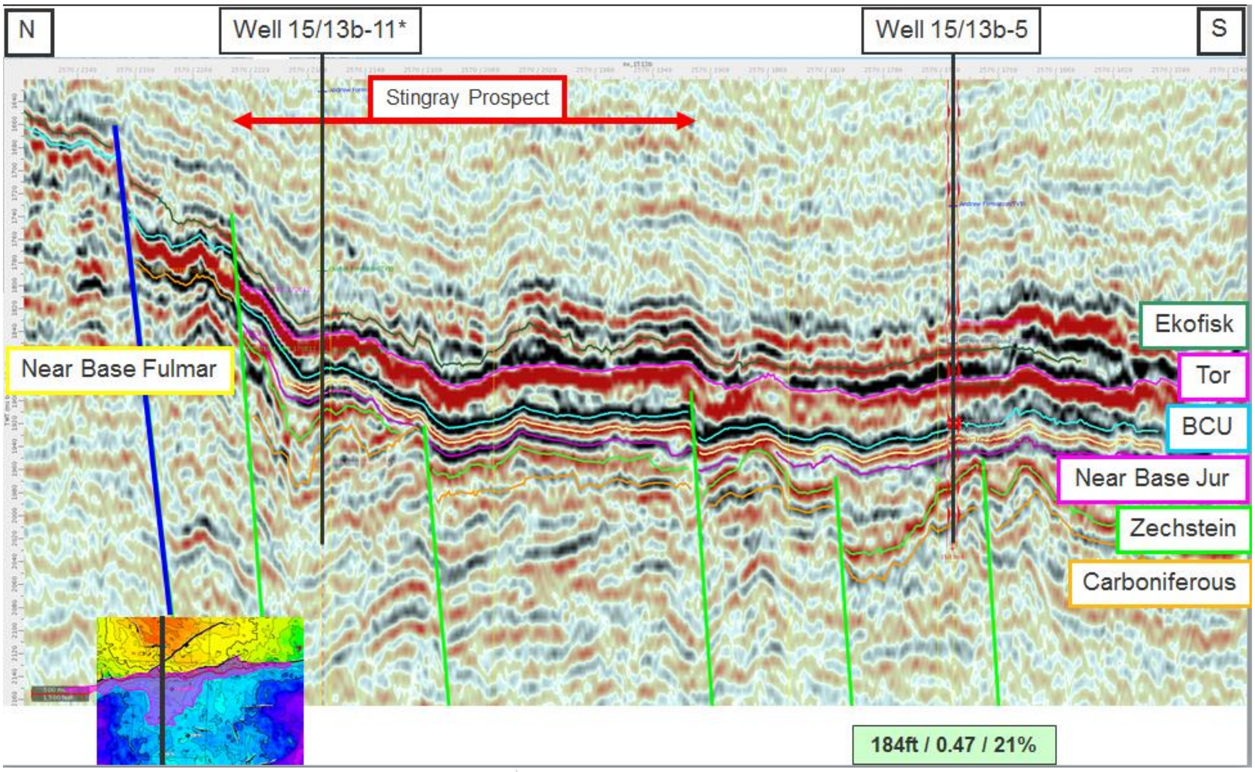


Fig. 90 – North-South seismic In-line 2570 (location shown on map Fig. 89)



(Polarcus data, courtesy of TGS) TGS

3.45. Nexen-CNOOC/ Granby: well 15/13b-8, Guinea prospect

The discovery of the Yeoman 15/18b-11 in July 2005 prompted further work looking at further prospects along the continuation of the Yeoman trend in an ESE direction. The Guinea prospect was a four-way dip closed structure defined at the Top Balmoral Sandstone marker analogous to Yeoman at equivalent depth (**Fig. 91**). The prospect was located mainly in block 15/13b. It was located over an inversion anticline at Top Chalk level and was associated with relative amplitude brightening. Volumes were sensitive to depth conversion, but structure was considered to be robust in time and depth.

The target reservoir was the Balmoral Sandstone, a deep marine gravity flow deposit which forms part of the Palaeocene Lista Formation. The top seal was expected to be the deep marine claystones of the Lista Formation, proven effective in the Balmoral and MacCulloch fields, the 15/19-9 discovery and the Yeoman discovery.

The source were the anoxic claystones of the deep marine Kimmeridge Clay Formation, which is mature for oil and gas generation at present-day burial depths in the Witch Ground Graben to the south. Hydrocarbon migration was interpreted from the Witch Ground Graben to the south. The primary risk was considered to be hydrocarbon migration as the Guinea prospect required long distance migration with the risk of a possible migration shadow. Migration should have taken place through faults from the Graben into the Tertiary sandstone systems.

Oil was prognosed to be in the Balmoral Sandstone but there was a risk over oil gravity (biodegradation was expected by analogy with Yeoman).

The overall CoS was estimated at 34% with migration (60%) and seal, mostly top seal because there was some evidence of overlying Eocene channels to west of prospect (70%) being the main pre-drill risks.

Top Balmoral came in 296 ft high to prognosis while error bar was + / - 50 ft. The top 200 ft of the Balmoral reservoir consisted of medium to coarse-grained sand with 100% net to gross with average porosity of 30%. Lista cap rock appears to be sufficiently thick as a competent seal and had just a few very thin stringers within it.

There were no oil shows in this well and gas levels were at background throughout the well. The main reason for failure was probably the lack of trap. However, only two small fluid inclusions were found (one in the Lower Dornoch and another within the Balmoral) and it’s felt that neither of these represent migration pathways. The Guinea structure is possibly sitting in a migration shadow so charge is another potential failure mechanism.

Main lessons learned:

- Top reservoir was found significantly shallower compare to prognosis casting a doubt about the trap presence as it was deemed sensitive to time/depth conversion. Although picking issue cannot be ruled out, the preferred interpretation is a time/depth conversion problem (**Fig. 92**).
- A fluid Inclusion analysis was carried out and hydrocarbons bearing fluid inclusions (HCFI) were recognised in inter- and intra-granular trails in two samples (4570 ft, 5230 ft). These inclusions were trapped after cementation and reflect oil migration pathways. Lack of charge does not seem to explain the 15/13b-11 failure.

Fig. 91 - 15/13b Guinea Prospect: Balmoral Depth Structure Map

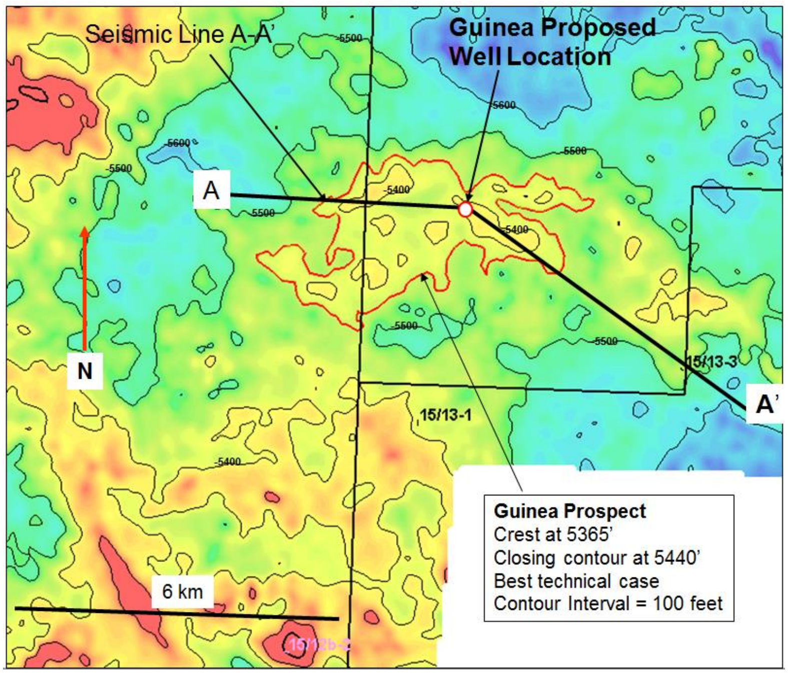
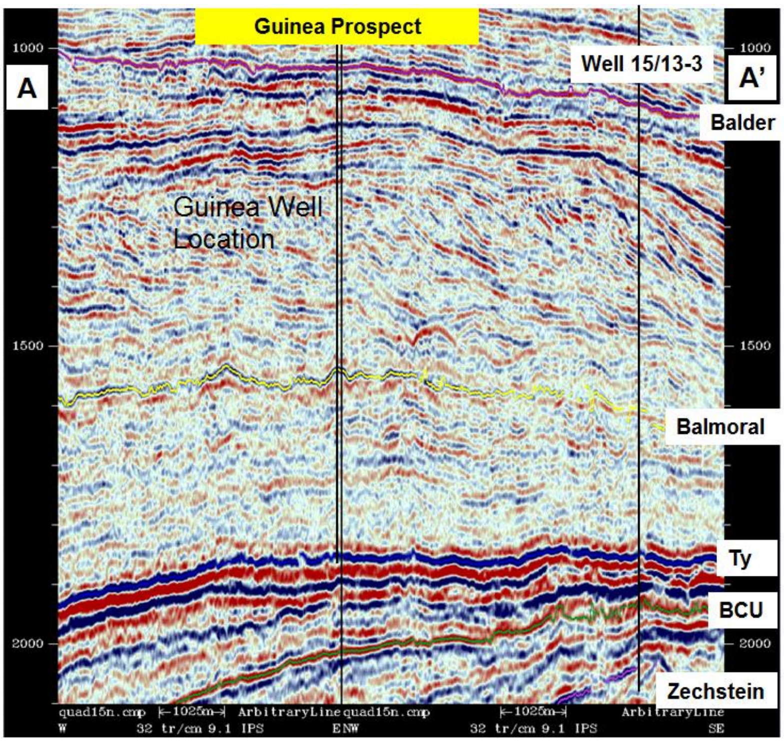


Fig. 92 - EW-NWSE Seismic Line A-A' From Guinea to Well 15/13-3



(Data courtesy of PGS)

3.46. Nexen-CNOOC: well 15/18b-10, Fox prospect

The Fox prospect located in block 15/18b was a 4-way dip closure mapped at Base Cretaceous Unconformity level. The structure was formed by Late Jurassic faulting on the margin of the Witch Ground Graben, although the bounding faults were not well constrained on seismic data. It is likely that the margins of the structure were defined by faults to the south west and east, and by dip to the north.

There were 2 different picking hypotheses at BCU level (so called “Conservative” and “Upside” picks) (**Fig. 93**). The depth map based on a conservative pick shows a complex maximum closure. The depth map based on the “upside” version shown a much simpler 4-way dip closure (**Figs. 94a & b**). However the seismic quality was not that good and the picking was made amidst a mostly reflection free area.

The target reservoir consisted of stacked shallow marine deltaic sandstones from the Piper Formation. Top seal was provided by marls and limestones of the Chalk Group, shales of the Lower Cretaceous Cromer Knoll and the Upper Jurassic Kimmeridge Clay Formation, if present. Chalk is known to form a good seal over part of the Piper field. The Pentland shales would have provided the bottom seal.

This prospect was not deemed very risky: its overall CoS was estimated at 72% with the trap being the main pre-drill risk at 80%.

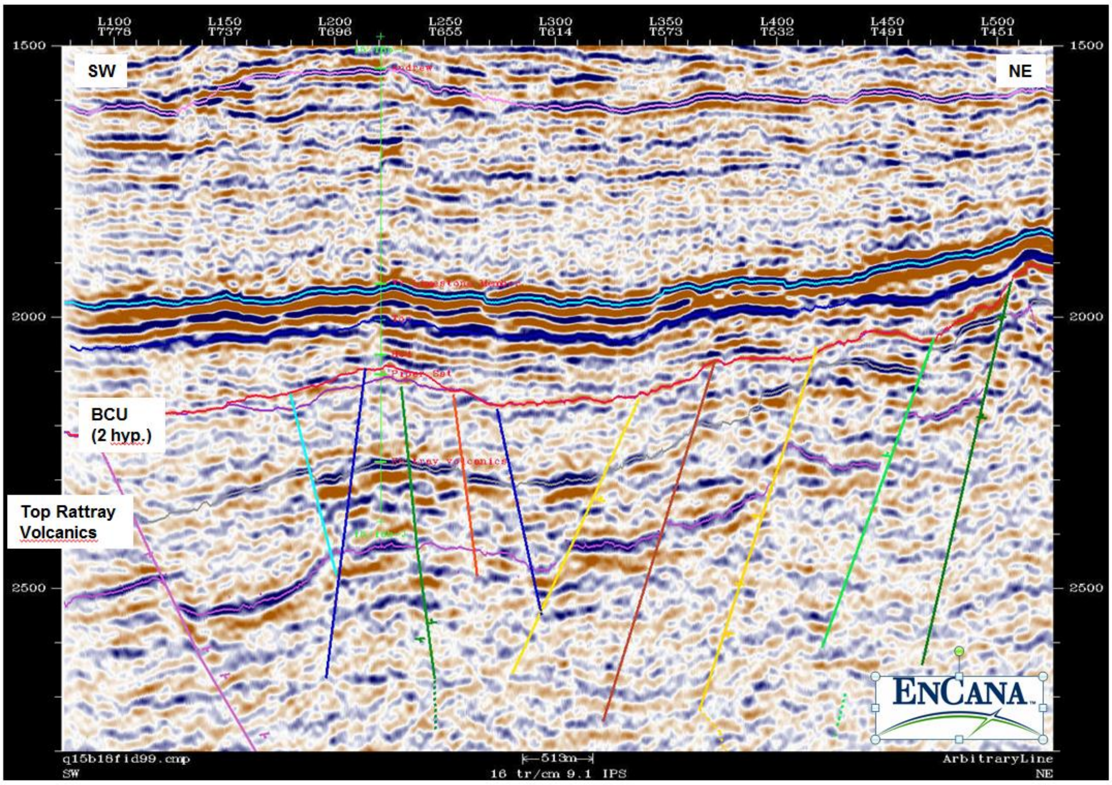
Well 15/18b-10 found the top reservoir 314 ft deep to prognosis casting a doubt on trap presence. Reservoir was within the range of expectations with 279 ft gross thickness, excellent quality sandstones present as a single, continuous sand body but water bearing. Top seal was provided by Cromer Knoll calcareous claystones to argillaceous limestone.

The main reason for failure was likely the lack of trap; although one cannot entirely rule out the lack of charge.

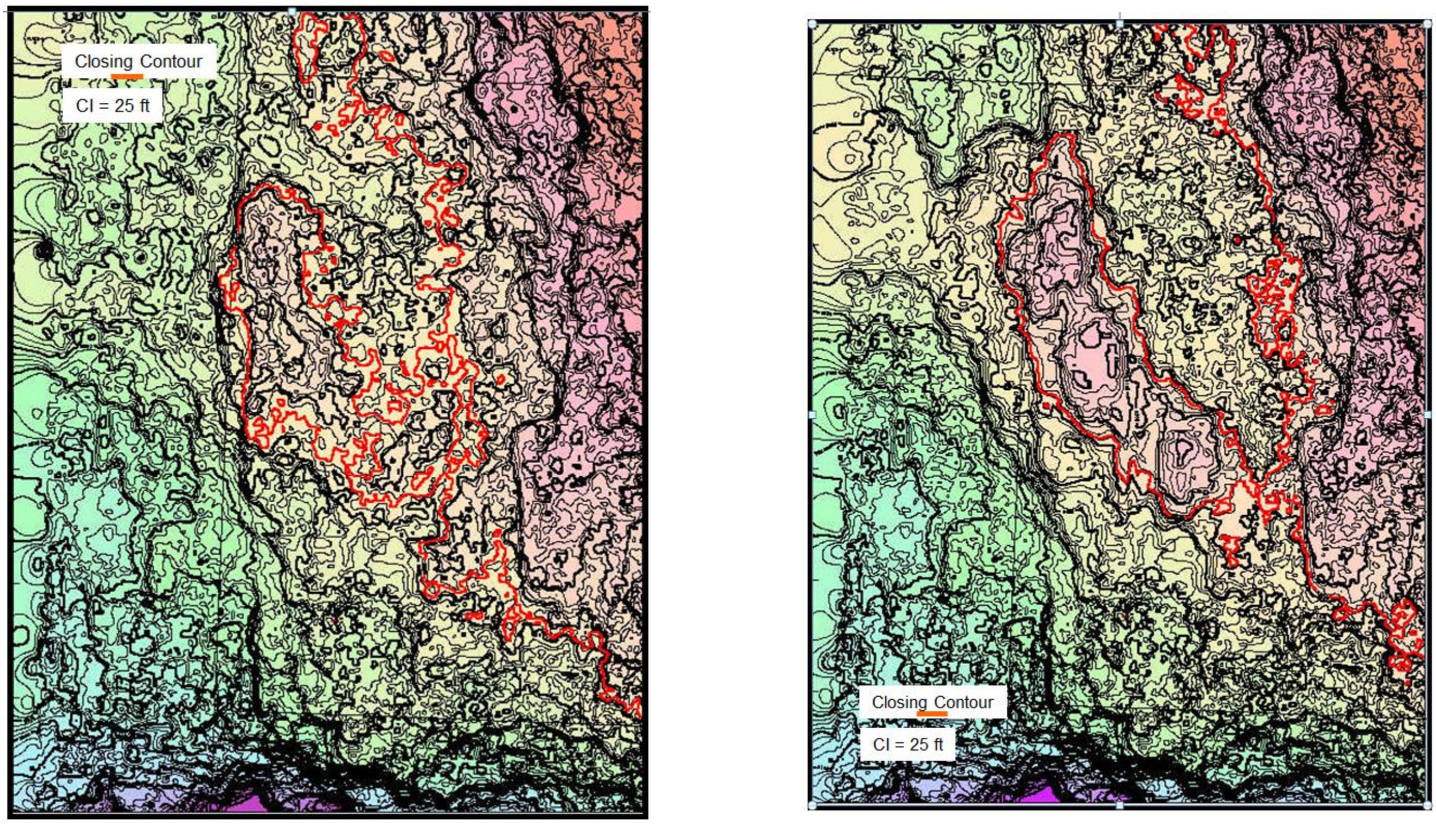
<u>Main lessons learned:</u>

- The poor quality 3D data made the picking questionable (BCU included): this should have rung an alarm bell and drawn attention to the prospect risking. This prospect risking assessment shows evidence of overestimation / overconfidence and or lack of interpretation quality control.
- In this particular case, 3D reprocessing or a new 3D acquisition before drilling the well may have provided a much better image of this prospect.

Fig. 93 - SW-NE Line across proposed location on Fox prospect (Data Nexen proprietary)



Figs. 94a & b - **a:** BCU Conservative Pick Depth Map **b:** BCU Upside Pick Depth Map



3.47.Nexen-CNOOC: well 15/22-18Z, Stareek prospect

The 15/22-18Z side-track targeted a 4-way dip closure encompassing a thickened Forties package which was interpreted to be a sand-filled channel (**Fig. 95**). The Stareek location did not allow drilling a simple vertical dual objective well (Stareek Forties segment + Galley sandstones of the Blackhorse segment) and had to be drilled with a dedicated side-track. Expected thickness of the Forties sandstones was 150 ft.

This prospect was located within a prolific basin and was surrounded by several fields: Scott, Telford and Galley. It was overlying the Blackhorse discovery. All those fields are sourced by the Kimmeridge Clay Formation. Migration was expected to occur through faults across the Cretaceous and base Palaeocene.

Top seal was prognosed as the Sele Formation shales as in wells 15/22-14 and -16. In addition to the 4-way-dip closure base case, a much bigger stratigraphic upside was defined. In this scenario, the Forties channel may erode into sandy Lista Formation creating a significant lateral and bottom seal risk (**Fig. 96**).

The overall CoS for the 4 way-dip base case was estimated at 22% while the stratigraphic upside was risked at 8.5%. The main pre-drill risk was interpreted as the seal risk (40%). Trap (80%), reservoir (85%) and migration (85%) were all seen as less risky.

Well 15/22-18Z found top Forties 55 ft shallow to prognosis but much thinner than expected (59 ft) and water bearing. Indeed no oil or gas shows were recorded during the drilling of the Stareek side-track.

The main reason for failure is probably a combination of lack of trap and charge. Indeed, Top Forties is a nice pick while top Lista Formation which makes the base of the interpreted “channel” is an envelope cutting through valid seismic reflections: this seismic picking is not supported by the neighbouring well calibrations or by the seismic data. Although Nexen-CNOOC interpret Stareek prospect as a channel, OGA’s interpretation is more in favour of an injectite feature. As no major faults are observed below the Stareek feature on the available seismic line one can also wonder if migration pathway failure occurred.

<u>Main lessons learned:</u>

- Although geoscientists must use analogues to support their interpretations, they must honour the existing data. This is particularly true in mature areas where wells are available in the immediate prospect vicinity.
- Would a detailed pre-drill basin modelling have deterred drilling Stareek? Although given its location immediatly above the Blackhorse discovery, it may still have been drilled.

Fig. 95 - Random seismic line across wells 15/22-14, 15/22-16 and Stareek proposed location **(Data provenance uncertain: Talisman proprietary or PGS)**

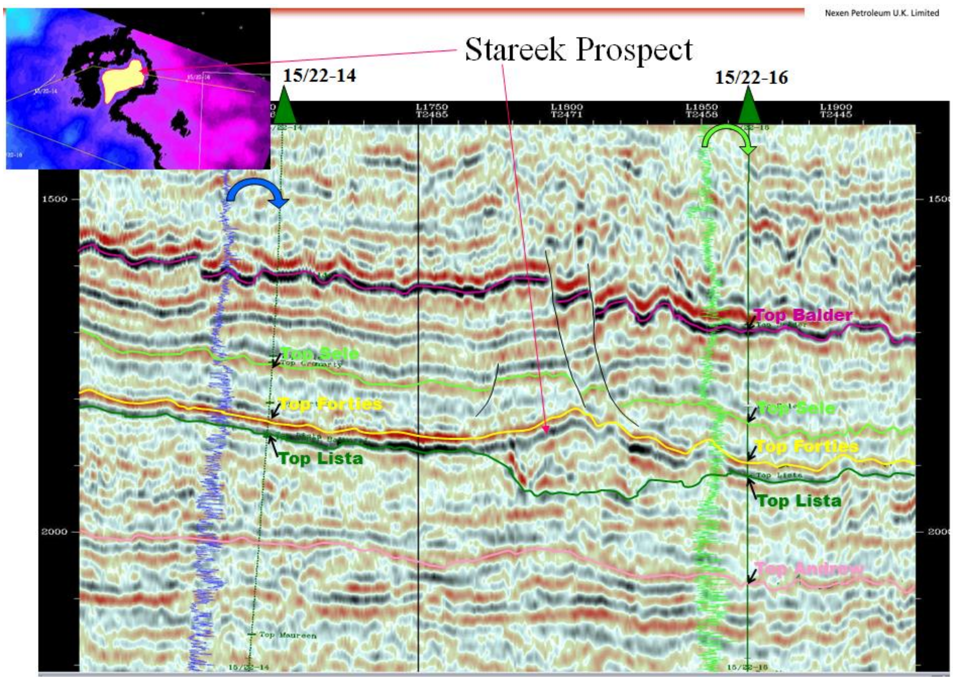
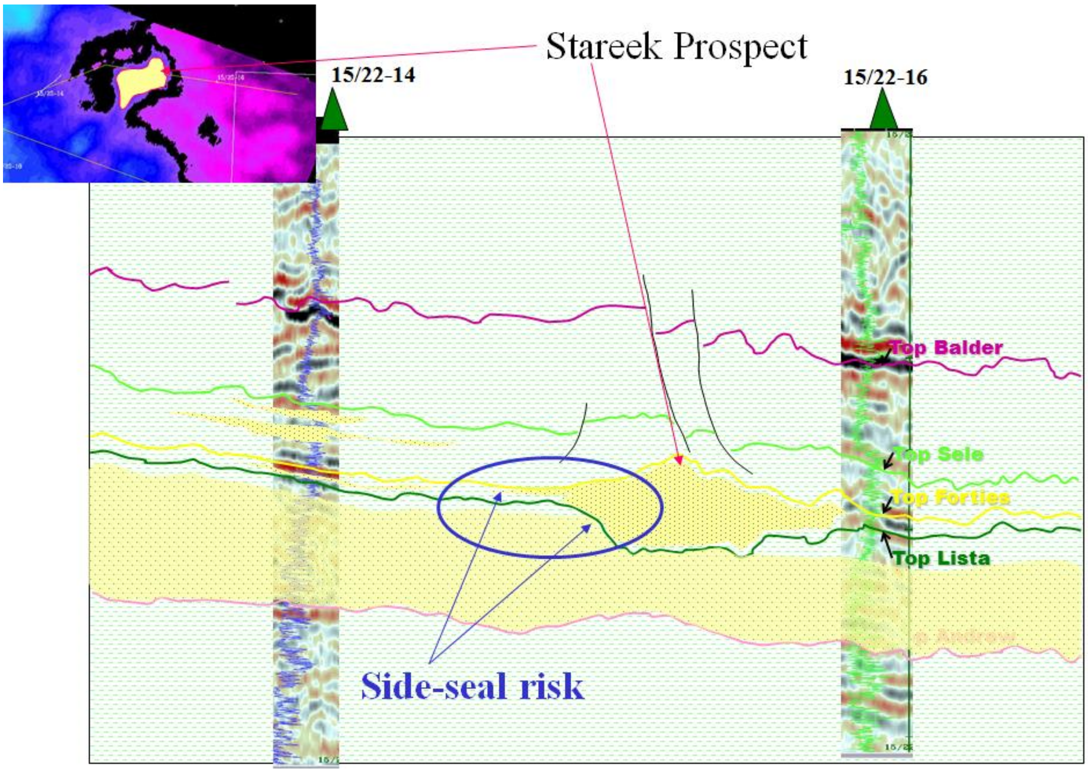


Fig. 96 - Stareek prospect cross section along the line shown above (ref. **Fig. 95**)



3.48.Nexen-CNOOC: well 15/28c-9, Deacon prospect

Deacon was situated in the north-eastern edge of the Buchan Graben, to the south of the Renee Ridge and north of the Rattray High. The Deacon prospect was a combination of stratigraphic pinch out to the north, east and west, and structural dip closure to the south (**Figs. 97 & 98**). The target reservoir consisted of Upper Jurassic stacked Lower Volgian sandstones shed locally from the Renee ridge according to high acoustic impedance response. Trap geometry and volume cases were indeed purely defined on amplitude variations (**Fig. 99**).

The source rock was the organic rich Upper Jurassic Kimmeridge Clay Formation, which is mature for oil generation in the Buchan Graben in the areas surrounding the Deacon prospect. Although the Lower Volgian sandstone were encased in the Kimmeridge Clay, providing a direct migration pathway for hydrocarbons, migration was seen a bit risky (80%).

The Kimmeridge Clay Formation was expected to act as both top and lateral seal for the Deacon prospect, as the Lower Volgian sandstone was interpreted to pinch out to the north, east and west. The Lower Volgian sandstone pinch out to the north is established by well 15/28c-6 and 15/28-2.

The overall CoS was estimated at 27%. Main risk was associated with reservoir presence and quality (60%) as the amplitudes seen at Deacon were brighter than those corresponding to the sandstones at Tweedsmuir and viewed as possible carbonate cemented sand risk. Risk was also associated with both seal (70%) and trap (80%), as trap delineation was based mainly on the amplitude response corresponding to sand. Additionally there was uncertainty associated with the western trapping mechanism (assumed to be pinch-out).

Well 15/28c-9 found no target reservoir rock in the Volgian section which mostly contains cemented limestone with no net pay. RCI sampling had been attempted, but reservoir was too tight to allow a pressure reading. Surprisingly at the time, the well 15/28c-9 encountered Kopervik sandstones, which were 227 ft TVT.

Top Balder was found 253 ft shallow, while all horizons below BCU are 187 to 300 ft shallow to prognosis. It is not clear if this is because of picking or time/depth conversion issues, but the trap definition may be inadequate. Lack of migration pathway cannot be a valid explanation as reservoir, albeit of poor quality, is encased within the source rock. As a consequence one shall ask “is there a Lower Volgian up dip pinch-out”?

Main reason for failure is obviously the lack of effective reservoir.

<u>Main lessons learned:</u>

- Amplitudes / inversion need to be calibrated against a wider range of possible lithofacies end member outcomes, before they can be used to delineate prospects confidently.
- In restricted basins, local sources can dominate the sediment fill.
- The interaction between predicted sediment pathways and potential barriers need to be recognised as a significant risk when the reservoir cannot be mapped in detail.
- Would a post well FIT study have clarified the migration / timing aspect?

Fig. 97 - Lower Volgian depth map

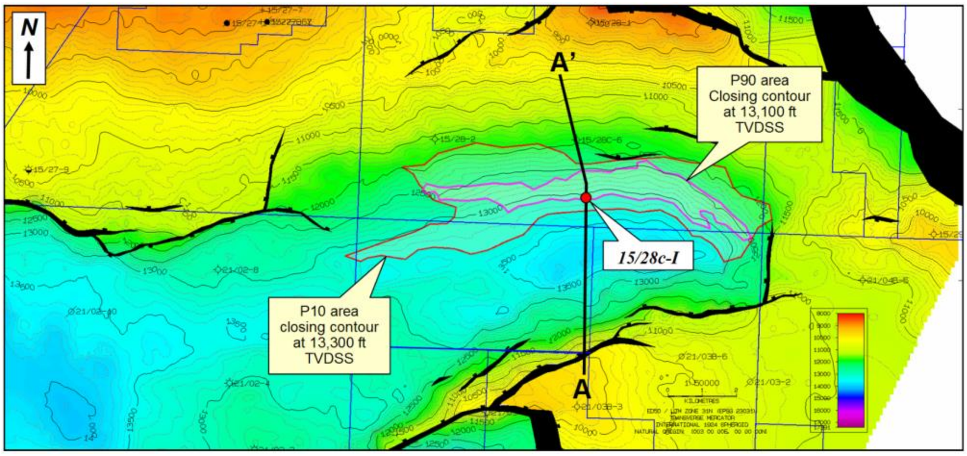


Fig. 98 - North-South seismic line through the Deacon prospect (see location on **Fig.97** above) **(Veritas seismic data courtesy of CGG)**

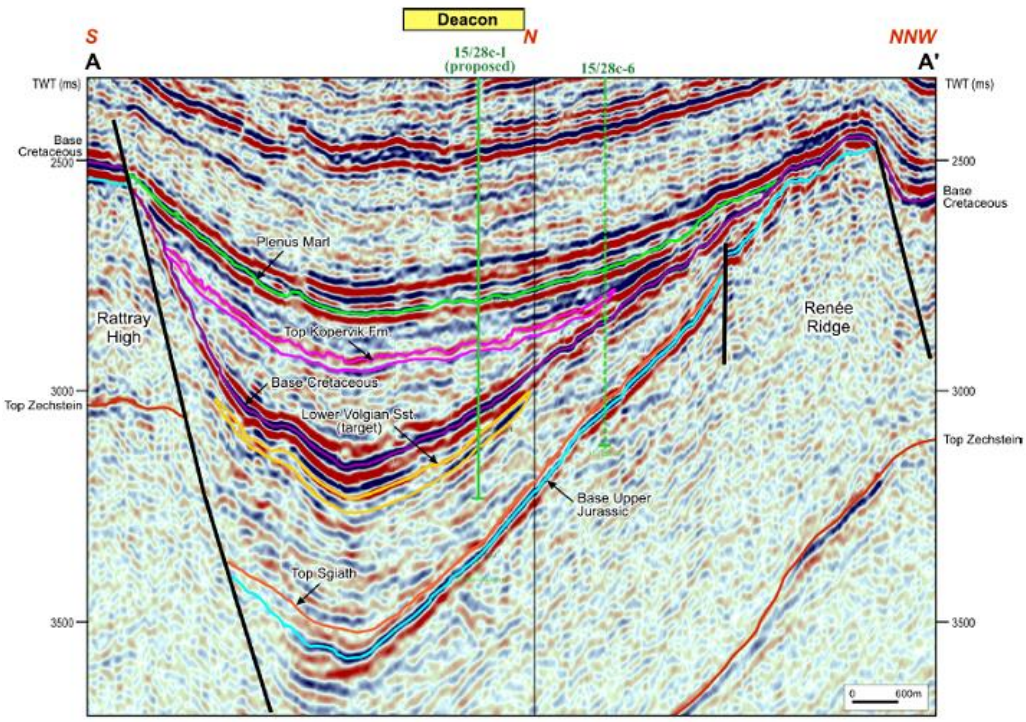
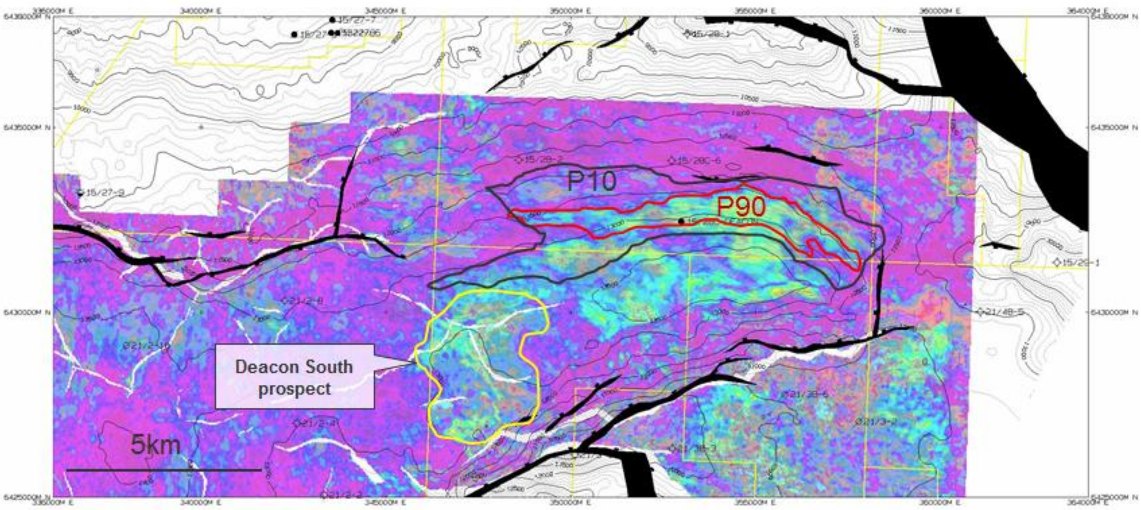


Fig. 99 – Deacon Prospect: Amplitude extraction combined with AI



3.49. Nexen-CNOOC: well 19/3-1, Pineapple prospect

The Pineapple Prospect was a downthrown, structural/stratigraphic trap defined at the Base Cretaceous Unconformity. The structure was a northward plunging nose in front of the main east-west trending Banff Fault (**Fig. 100**). The nose was thought to be partially created by differential compaction over Burns Unit Sandstone (**Fig. 101**). The prospect was dip closed to the north, a saddle point present in Block 19/2 separating the structure from Well 19/2-1 which encountered 320 ft of water-wet Burns Sandstone. To the south the prospect was a downthrown closure against basement rocks across the Banff Fault. To the east and west the structure did ultimately close against the Banff Fault in Blocks 19/2 and 19/4, however, it was interpreted to be an element of stratigraphic closure in these directions.

The Upper Jurassic Burns Sandstone, shed off the Grampian Spur to the south, was the main reservoir target. Additional prospectivity had been recognised in the Upper Jurassic Alness Sandstone. The reservoir properties were expected to be similar to Burns 19/2-1 sandstones which are of moderate to good quality with 20% average porosity.

Kimmeridge Clay Formation was immature or early mature on block but mature in Banff basin 20 km north. As a consequence, charging of the trap required long distance migration from the northeast and migration modelling indicated flow pathways into prospect providing a carrier bed was present.

The overall CoS was estimated at 23% with the key risk identified as seal, primarily due to potential late movement on Banff Fault. Two additional risks consisted of the reservoir presence and quality (70%) and the migration (70%).

The well 19/3-1 encountered Upper Jurassic sandstone 69 ft high to the prognosed top of the primary target Burns Sandstone. Initially identified as Burns Sandstone, subsequent biostratigraphical analysis indicated that this is of Ettrick age. The section consisted of a 570 ft gross vertical thickness of sandstones variably cemented with locally poor porosities and interbedded with siltstones, compared to the predicted 615 ft of reservoir section. The secondary target, the Alness Sandstone was encountered 461 ft high to prognosis. These sandstones consisted of a 94 ft vertical thickness of sandstone with minor silty claystones stringers, compared to the predicted 103 ft of reservoir section. No hydrocarbon shows were observed while drilling and both of the sandstones were water wet.

The main reason for failure is interpreted as lack of charge. Indeed, lack of shows and absence of hydrocarbons in fluid inclusion work suggests no migration. This may be related to the absence or very limited span of carrier beds (absence of Ettrick reservoir in 19/2-1) able to connect reservoir to the mature kitchen therefore a lack of a migration pathway from a mature source.

Although this interpretation is not shared by NEXEN-CNOOC, OGA considers that another potential cause for failure may be the lack of Banff fault sealing effectiveness as no conglomeratic material had been observed. However, cementation seen may be fault related and provide up dip seal.

Main lessons learned:

- Biostratigraphy was instrumental in confirming different ages of reservoir.
- The migration issue was assessed post-drill through a dedicated Fluid Inclusion Screening.

Fig. 100 – Pineapple Prospect: BCU depth map

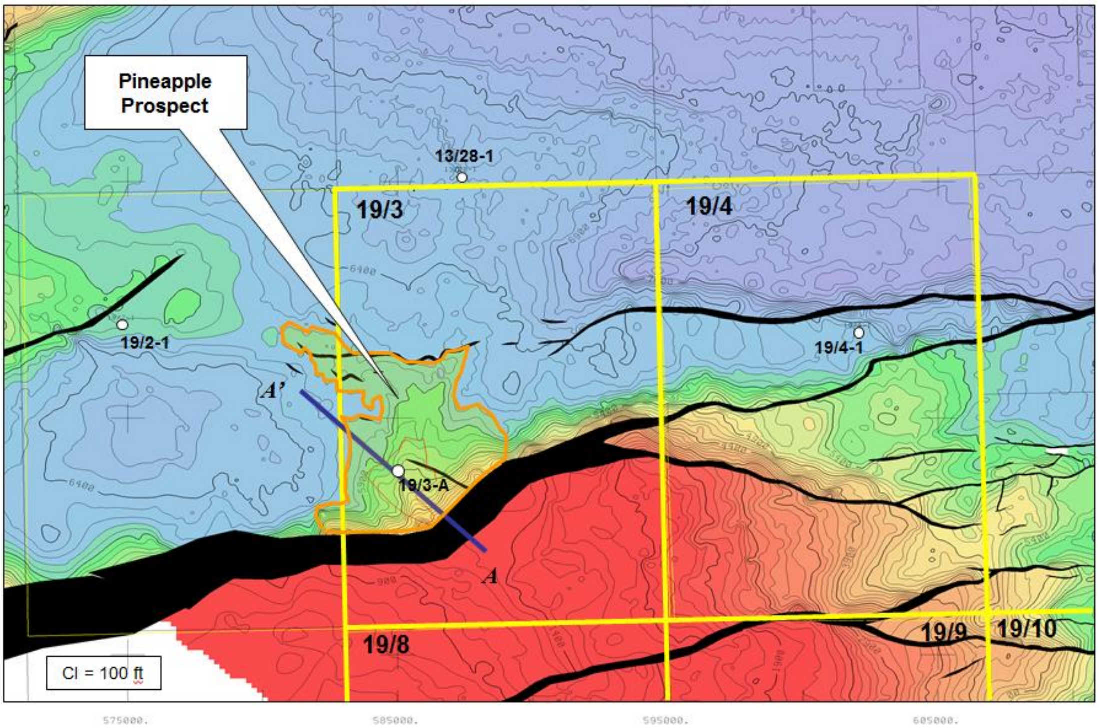
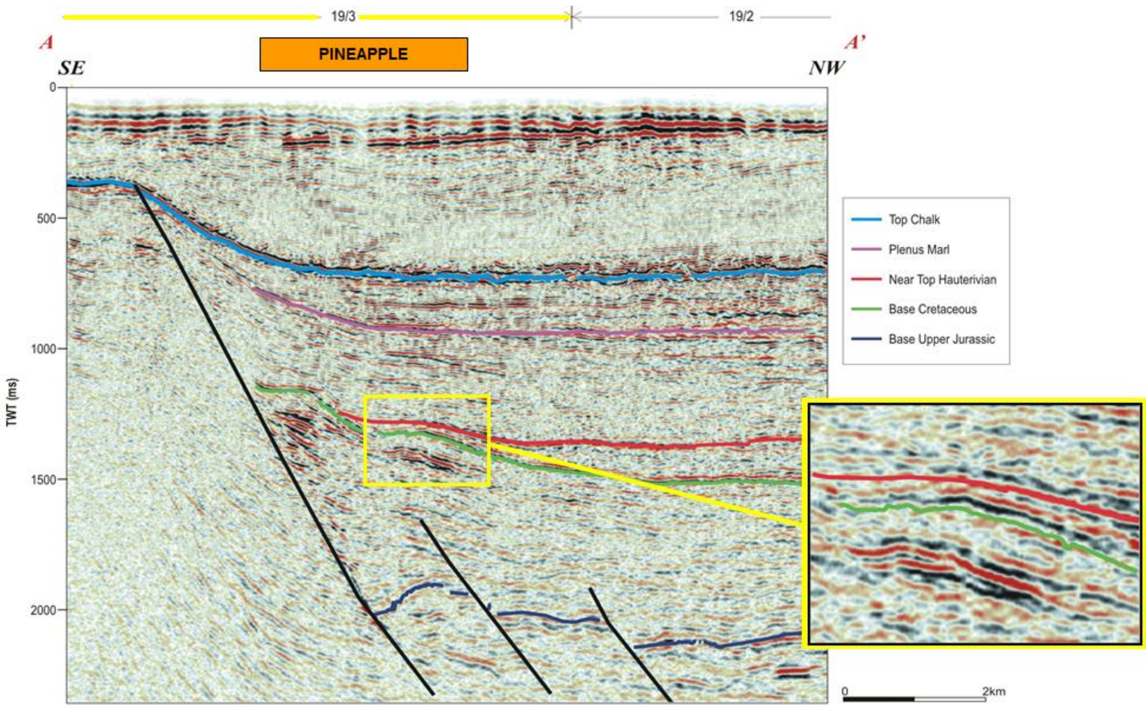


Fig. 101 - Block 19/3 Pineapple Prospect: SE - NW Seismic Line (Data Nexen proprietary)



3.50. Nexen-CNOOC: well 19/4-2, Full Moon prospect

The Full Moon Prospect at the Ettrick level was a downthrown, structural/stratigraphic trap defined at the Base Cretaceous Unconformity (**Fig. 102**). The reservoir was interpreted to be within Upper Jurassic age turbidite sandstones shed off the Grampian Spur to the west. This reservoir was modelled as a continuation of the main sand system which deposited the Ettrick aged sand package found in the 19/3-1 well (Pineapple prospect) drilled by EnCana in 2005.

The structure was an eastward dipping seismic package whose up dip extent to the west was defined by an erosive feature at BCU level (**Fig. 103**). This erosive truncation would have allowed a significant oil column (300 ft) to be possible without the need to invoke fault seal against the main Banff fault down throwing to the north. It was however interpreted that the risk of cross fault seal required to trap a 300 ft+ column was moderate due to the lack of evidence for sandstones in the juxtaposed Lower Cretaceous interval. To the south, cross fault seal was important as only smaller volumes can be accounted for otherwise. From seismic it was interpreted that along most of the strike of this fault the primary reservoir target of the Full Moon prospect was downthrown against Permian or older sediments and/or Silurian granite and as such fault seal was again assigned only a moderate risk. Top seal to the structure was provided by the marine claystones of the Lower Cretaceous Cromer Knoll Group.

The prospect was interpreted to be sourced from either of 2 separate kitchens. The most likely was to the north and was interpreted to be the same source as the Ross field (38ºAPI Oil). The secondary kitchen lies to the east and was the kitchen for the Buzzard field (32-34ºAPI Oil).

The overall CoS was set at 12%. The main pre-drill risk was the migration (40%) followed by seal (60%). Source rock, reservoir and trap were all estimated moderate risks at 80%.

The well 19/4-2 found the objective Ettrick Sandstone to be absent at this location. No shows were observed in the occasional thin sandstone stringers encased in the Kimmeridge Clay Formation.

The main reason for failure is clearly the lack of target reservoir while the lack of charge is also a problem.

<u>Main lessons learned:</u>

- This well results confirm the issue about migration pathway which had been flagged following the 19/3-1 Pineapple well results.
- Would a better 3D data set + seismic inversion have helped being more predictive about sand presence? (recognising the lack of wells of calibrate too)

Fig. 102 - Full Moon Prospect: Base Cretaceous Depth Structure Map with location of line A-A' (**Fig. 103**)

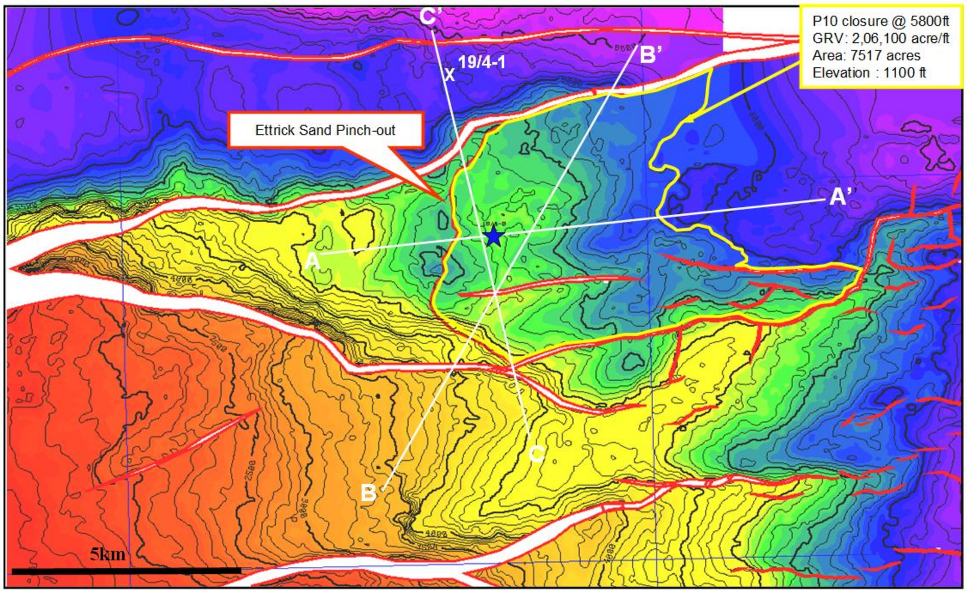
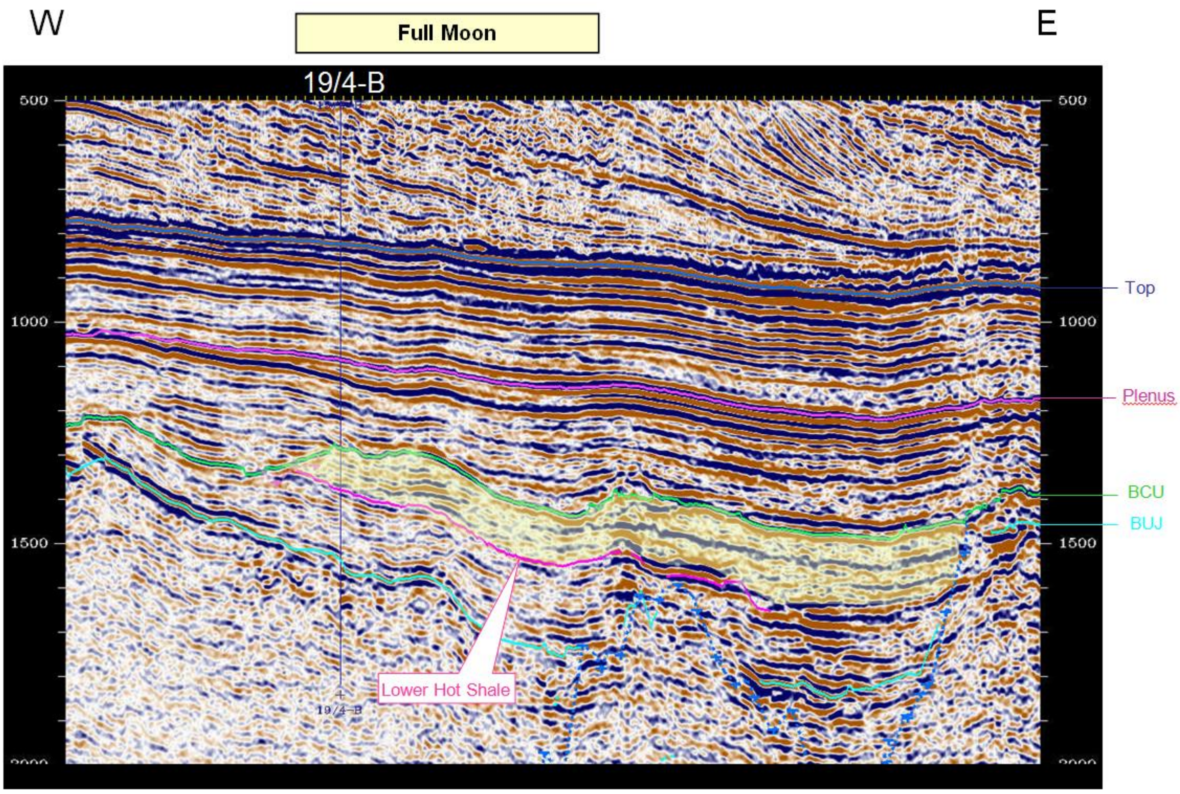


Fig. 103 - 3D Seismic Line A-A' through 19/4-B (**Data provenance uncertain: Nexen proprietary or TGS)**



3.51.Nexen-CNOOC: well 19/5b-2, Griffon prospect

The Griffon prospect, located 20 km east of Golden Eagle and 19 km northeast of Buzzard, targeted a stratigraphic trap in Lower Cretaceous (Late Ryazanian to Early Hauterivian) Punt Sandstone, analogous to the nearby Golden Eagle Discovery with similar depositional model & reservoir facies and similar positive seismic indicators. The turbidite sand was predicted to have been shed off the Grampian Spur towards the NNE (**Fig. 104**).

The well 19/5b-2 was located to drill a feature interpreted as strongly mounded with differential compaction and marine downlap (**Fig. 105**). This feature appeared channelised. Amplitude dimming along the BCU was observed along this elongated feature similar to the one observed at Golden Eagle. This dimming was interpreted as resulting from a decrease in acoustic impedance from Lower Cretaceous sandstones into the underlying Jurassic section.

Top and lateral seals for the Punt reservoirs were prognosed as the overlying Valhall Formation claystones. These low permeable claystones are an effective seal in the nearby Golden Eagle Field. The Griffon prospect was a stratigraphic trap that required up-dip facies change (Seismic character changes supports this facies change) and/or fault seal towards the south.

Organic rich Kimmeridge Clay Formation in the Cromarty sub-basin to the north was the expected source rock. Two 2D line basin model sections completed from the basin to prospect area suggested the source rocks were mature for oil generation in the areas north of the prospect. Griffon was interpreted as being charged through migration path from north to south across the basin margin fault and/or via ramp to the east. Fault plan transmissibility was considered key to charging Griffon.

The overall CoS was estimated at 30% with seal (60%) and migration (70%) interpreted as the main pre-drill risks. It must be highlighted that pre-drill detailed seismic stratigraphy study and basin modelling had been carried out.

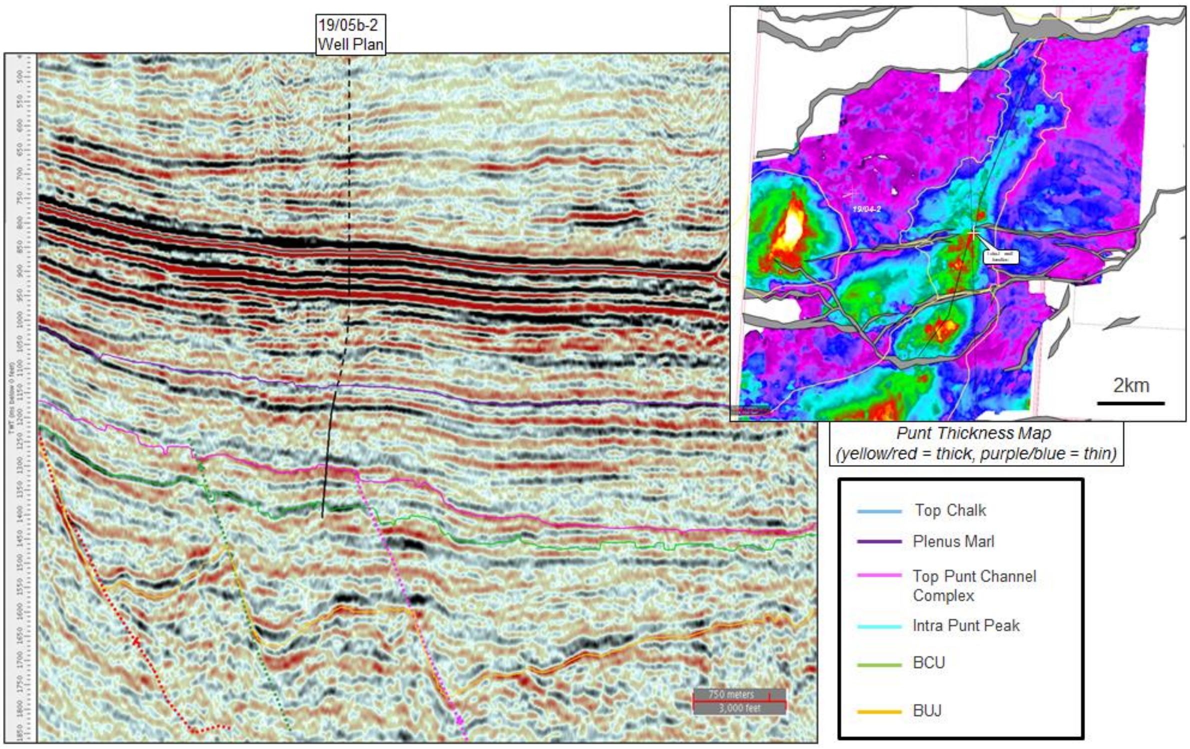
Targets depths were on prognosis and ~ within pre-drill error margins. The 19/5b-2 well log analysis confirmed that no sandstones were present within the target Punt interval and shown that the Upper Burns Sandstone contained no significant accumulations of oil.

No evidence of hydrocarbons in the underlying Burns Sandstones shows that migration shadow is also a potential failure mechanism.

<u>Main lessons learned:</u>

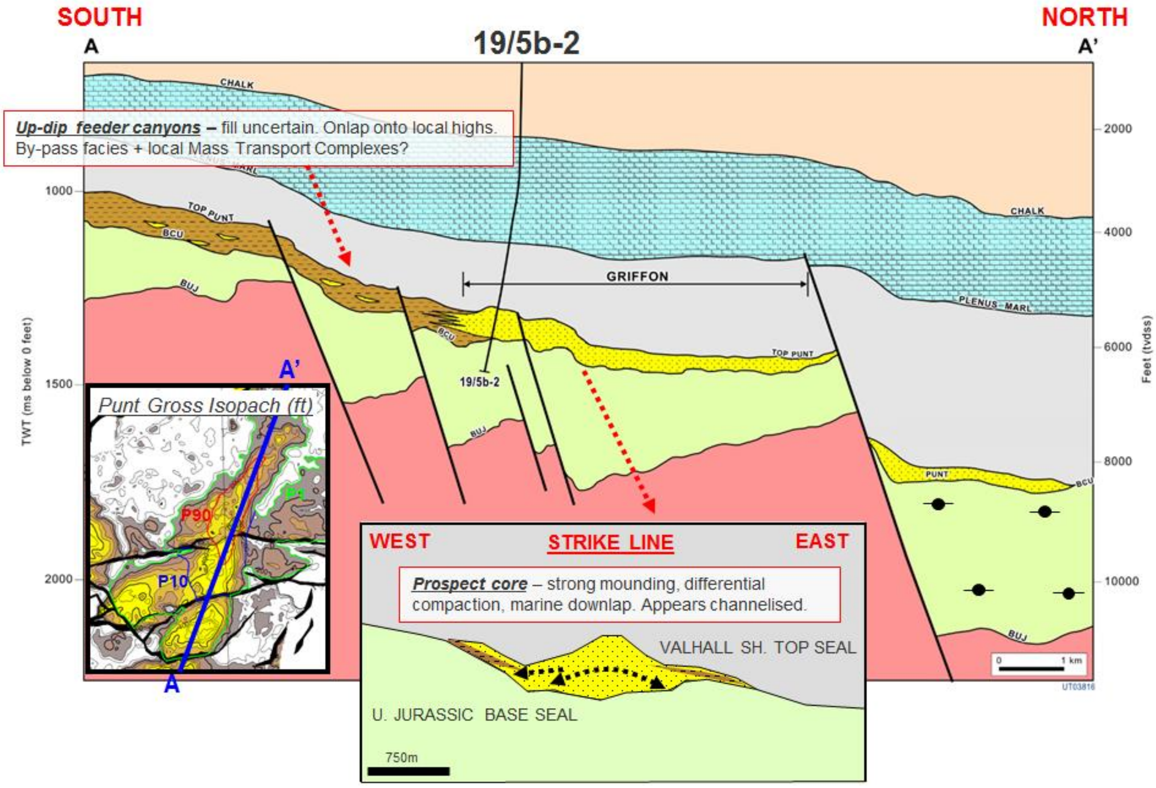
- Differential compaction and seismic attributes (BCU dimming) are not always Punt sandstone indicators.
- Stratigraphic traps are inherently more risky and, therefore, drilled at lower chance of success. Although the 30% estimated chance of success was deemed high (post drill…), other stratigraphic traps such as Buzzard have been drilled on a low CoS (11%), so Griffon may still have been drilled had the CoS been lower.
- One can wonder if the very large multi-client 3D data set (2500 km^2) used to define this prospect was good enough to assess such subtle traps?
- Waiting for reprocessed seismic (required to confidently run the EEI inversion) may have helped defining the shale-sand facies (trap limits) and better locating the well, indeed the BCU character was poorly defined on the original 3D.

Fig. 104 - SSW-NNE random seismic section showing planned 19/5b-2 well bore trajectory



(Data courtesy of TGS) TGS

Fig. 105 - Pre-drill Griffon geoseismic interpretation



3.52. Nexen-CNOOC: well 19/8-1, Peacock prospect

The Peacock Prospect was a downthrown, stratigraphic trap defined at the Base Cretaceous Unconformity (BCU) (**Fig. 106**) which was located at the western limit of the West Buzzard Graben. The BCU steeply dips from west to east and the prospect was dip closed towards the east. To the south the prospect was potentially downthrown against the southern bounding fault of the West Buzzard Graben juxtaposing the reservoir against Rotliegend or older sediments (**Fig. 107**). To the west the prospect was downthrown against the western bounding fault to the West Buzzard Graben, juxtaposing the reservoir against Rotliegend or older sediments, or locally the Jurassic section thins to give rise to stratigraphic pinch out. To the north, the closure was more difficult to accurately define on the current 2D dataset. The Jurassic interval progressively thins up the dip slope of the half-Graben.

The reservoirs were interpreted to be within Upper Jurassic Burns and Buzzard age turbidite sandstones shed off the Grampian Spur to the west. It was interpreted that turbiditic sandstones being fed axially into the Graben from the west would pinch out on the dip slope of the Graben creating a stratigraphic closure to the north. The position of this pinch out could not be confidently mapped on the 2D dataset however; analogies had been taken from numerous wells on the Buzzard Field. <u>Numerous seismic attribute analyses had been attempted to predict sand thickness, the best of these was simply the gross Jurassic Isopach where sandstones were predicted to pinch out where the Jurassic was less than 1,100 ft thick</u>. This piece of empirical evidence, along with seismic reflectivity, had been used to guide the position of the stratigraphic pinch out for Peacock.

The shales of the Kimmeridge Clay Formation provided top and lateral stratigraphic seal for the reservoir. An important risk to the prospect was cross fault seal against the footwall of the southern and western bounding faults to the West Buzzard Graben where the reservoir was possibly juxtaposed against Rotliegend or Devonian Old Red Sandstones.

Oil trapped at Buzzard implied that no migration could occur up dip to the west. Consequently, oil charge had to rely on leakage up dip of Buzzard and later sealing. Long distance migration was an additional requirement.

The overall CoS was characteristic of a very high risk prospect (4%) and the key risk was identified as migration (20%). Trap geometry and seal were both seen as unknown (50%) while reservoir was not perceived as a major risk (80%).

Well 19/8-1 found the top of the Buzzard Sandstone 564 ft high to the prognosis and the top of the Triassic 926 ft high to the prognosis. This was caused by depth conversion errors caused by the chalk being thinner (394 ft TVT vs 648 ft prognosed) and its velocity being faster than expected. Both Burns and Buzzard sandstones were present as massive units but no hydrocarbon shows were observed.

Top seal was pretty thin (Devils Hole Formation siltstones, 12 ft TVT). There was no intermediate seal between the 2 objectives as the prognosed Ettrick shale were absent: the stratigraphical subdivision was provided by biostratigraphy.

The main reason for failure is very likely the lack of seal: the Upper Jurassic interval is so sand rich (thickness was in line with prognosis but N:G was much higher averaging ~96%) that lateral seal presence and up dip pinch-out are very unlikely. As a result, the predicted trap geometry was wrong. The absence of any HC show also demonstrates that there is no leakage up dip from the Buzzard field.

Main lessons learned:

- All depth conversion errors (picking BCU and BUJ; chalk thickness and velocity) have been cumulative as a layer cake method was used. Given the sparse well data available in the Peacock vicinity, it was likely not easy to test another time-depth conversion methodology.
- The empirical evidence using the Upper Jurassic thickness as a threshold to define the sand pinch-out was far reaching and illustrate pretty accurately at the same time the “anchoring bias” (i.e. the tendency to anchor our interpretations on a reference value) and the “confirmation bias” (i.e. tendency to favour an information which confirms our preconceptions).
- The map used to describe the prospect (Fig. 104) did not properly describe the expected trapping mechanism to the south.

Fig. 106 - Peacock Prospect BCU depth map

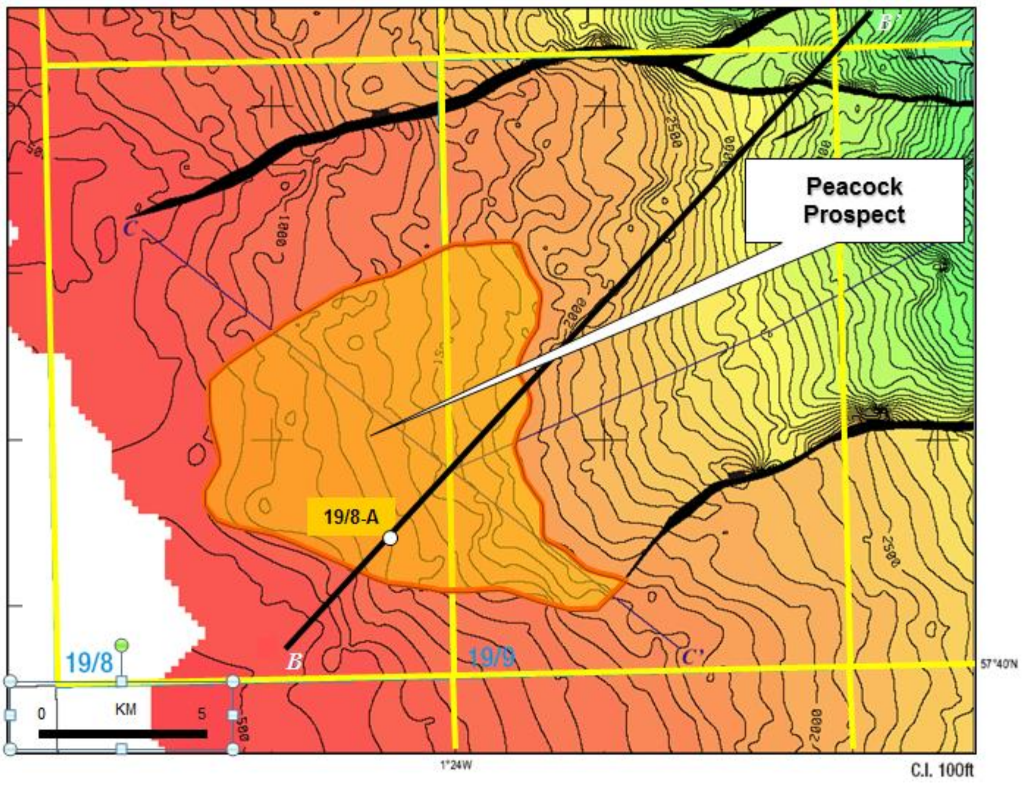
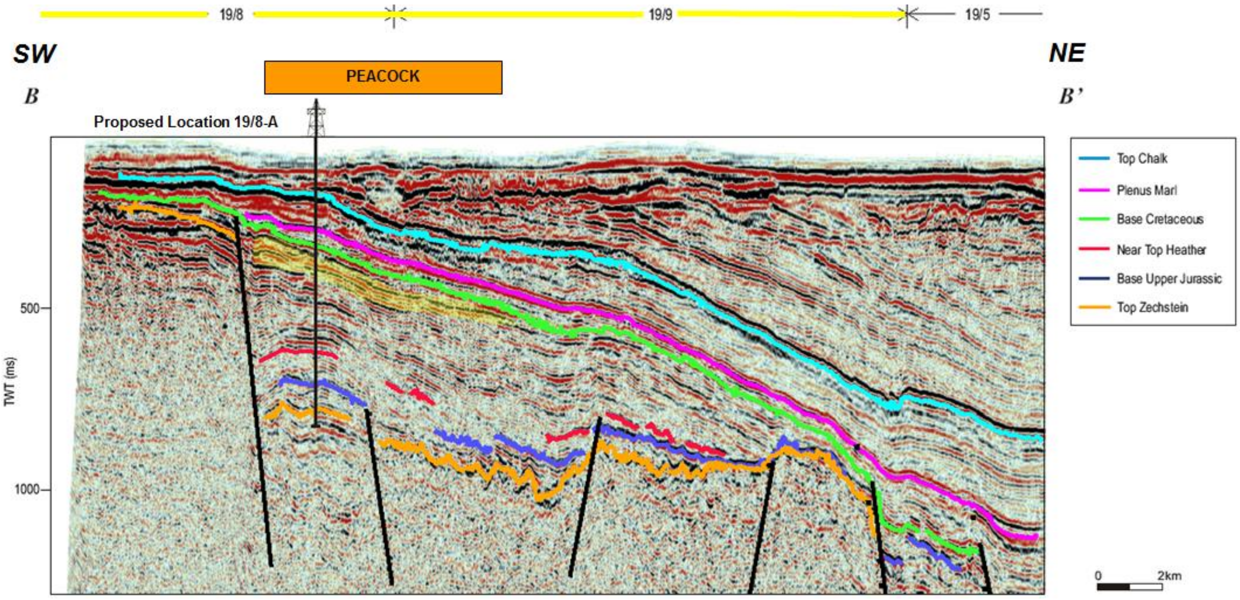


Fig. 107 – SW –NE seismic line through Peacock prospect (Data Nexen proprietary)



3.53. Nexen-CNOOC: well 19/15-1, Firefly prospect

The Firefly prospect was located 12 miles south of Buzzard at the western end of the Peterhead Graben. This Graben is different from the Buzzard one but was interpreted as having similar depositional and tectonic history.

The Firefly prospect is a downthrown, structural/stratigraphic trap (**Fig. 108**). The Base Cretaceous Unconformity steeply dips from west to east and the prospect is dip closed towards the east. To the west and south the prospect is generally downthrown against the northwest to southeast trending fault separating the Firefly Terrace from the French Horn Terrace. This juxtaposes the reservoir against Heather shales, Smith Bank shales and older sediments. The Jurassic interval progressively thins up the dip slope of the half-graben (**Fig. 109**). The target reservoirs were stacked submarine channel sandstones within the Buzzard or Ettrick age Sandstone unit underlying the BCU. Source rock was expected to be the Kimmeridge Clay Formation but likely immature at the well location making long distance migration necessary. The shales of the Kimmeridge Clay Formation provided top and lateral stratigraphic seal for the reservoir. An important risk to the prospect was cross fault seal against the footwall of the western bounding faults to the French Horn Terrace where the reservoir was likely to be juxtaposed against dominantly Triassic, Smith Bank Shales.

The overall CoS was estimated at 11% and main pre drill risks were reservoir presence (50%, primarily due to lack of reservoir previously seen in Peterhead Graben), trap geometry (50%) and seal (60%).

All seismic markers came in significantly shallow to prognosis (> 224 ft, up to 1046 ft) and the top of the 1st reservoir, the Burns sandstones, was found 661 ft higher than prognosed with sand thickness on the high side highlighting a much higher lateral seal risk. Valhall Claystone (136 ft) were present and provided an effective top seal while Heather Formation claystones were thick enough to act as the bottom seal (157 ft TVT). No shows were seen in well 19/15-1 illustrating the lack of migration pathway from a mature source.

The main reason for failure are therefore interpreted as the lack of trap, the lack of up dip seal (as there is too much sand to ensure an effective cross fault seal), meaning well 19/15-1 is probably too close to a sand rich source and the lack of migration pathway.

Main lessons learned:

- Even though there were no wells in the close vicinity of 19/15-1 and in the Peterhead Graben, more detailed time depth conversion involving different scenarios would likely have helped at better defining the trap and, as a result, better assessing the risks attached to the Firefly prospect.

Fig. 108 - Firefly prospect: Base Cretaceous Depth Structure Map

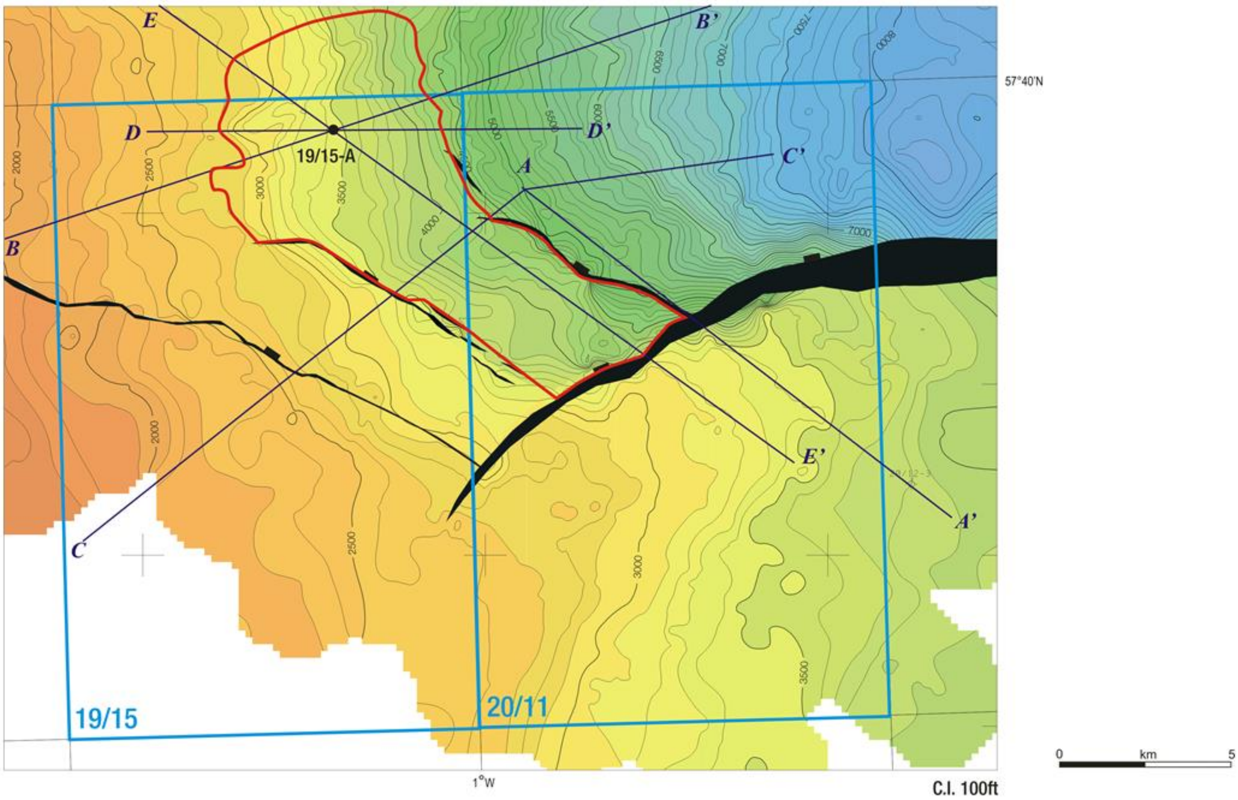
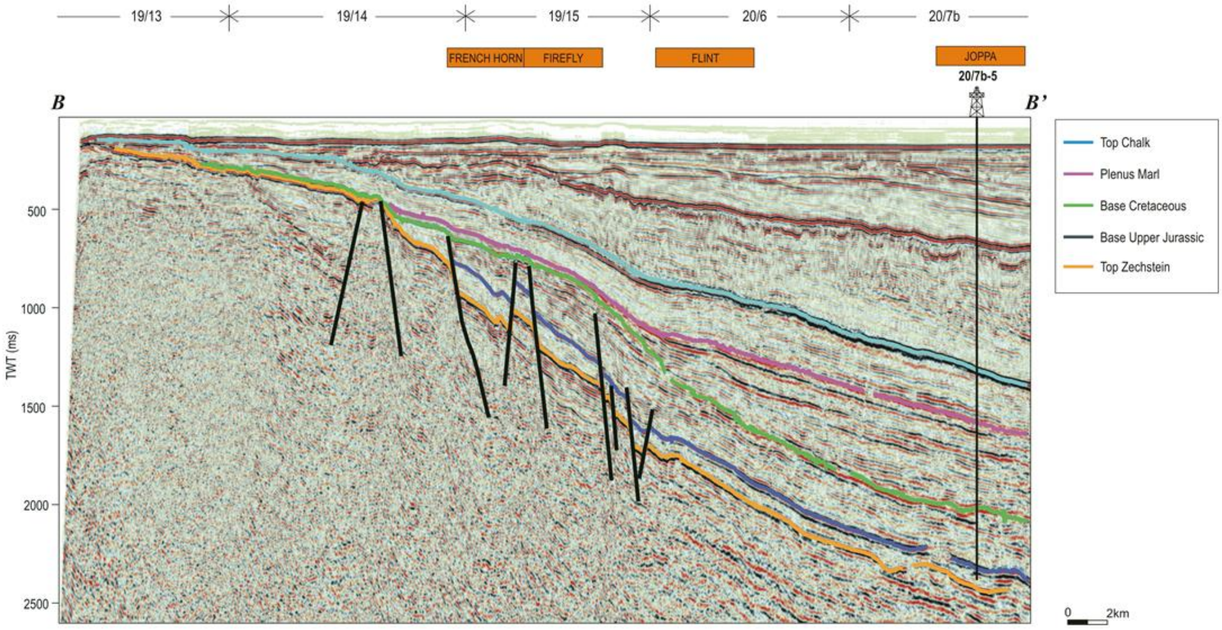


Fig. 109 - West-East B-B' seismic line showing the Jurassic interval (green to blue) pinching out to the north and west creating the trap **(Aker seismic data, courtesy of TGS)**



3.54. Nexen-CNOOC: well 20/1-5, Buzzard North Terrace East prospect

Well 20/1-5 successfully tested the Buzzard North Terrace East prospect which will be part of "BUZZARD phase II" development. The Buzzard North Terrace structure is an up thrown terrace to the north of the Buzzard Field but, downthrown from the Lily Terrace to the north (**Fig.110**). The bounding fault to the north is a major east – west trending fault that defines the northern margin of the Buzzard Graben. Target reservoir was the Buzzard Sandstone sourced by the Kimmeridge Clay Formation thanks to relatively long range migration from the east.

Top seal to the structure is provided by the marine claystones of the Kimmeridge Clay Formation. Up thrown cross fault seal is required to the south where the reservoir is juxtaposed against Kimmeridge Clay Formation or Lower Cretaceous shales. Downthrown cross fault seal is required to the north where the reservoir is juxtaposed against Kimmeridge Clay Formation, Heather Formation, Smith Bank Formation and Silurian granite.

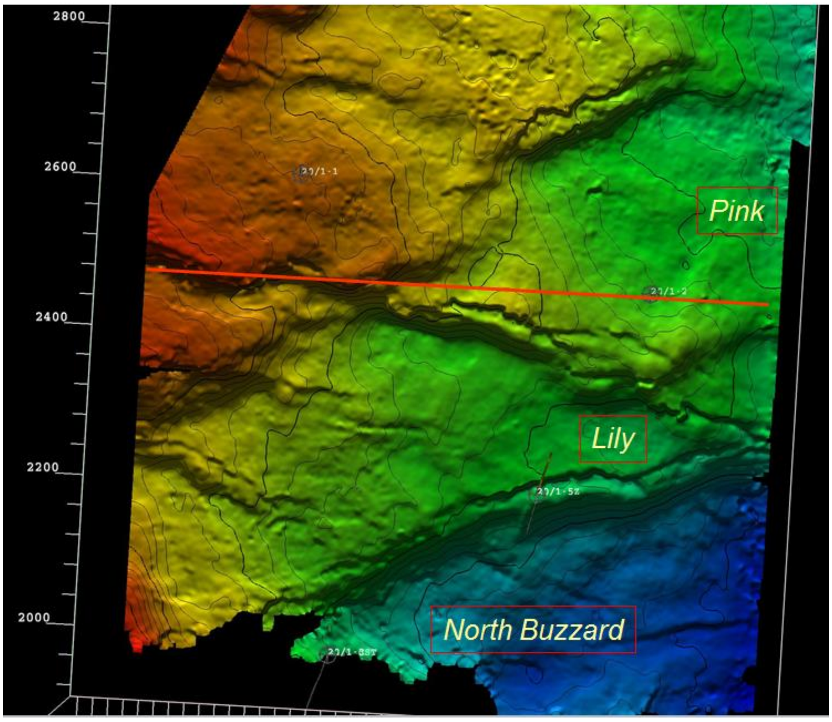
The overall CoS was estimated at 20% with main pre-drill risks interpreted as seal (50%) followed by trap and reservoir (70% each).

All the markers came in within error bars and well 20/1-5 found the Buzzard sandstone oil bearing although its reservoir characteristics are on the lower end of the range expectations.

<u>Main lessons learned:</u>

- Not much can be learned from this positive well as everything but the reservoir characteristics was in line with prognosis.
- Buzzard sandstones are of poorer quality than expected which may be explained by local diagenesis?

Fig. 110 – Block 20/1S, North Buzzard and Lily Terraces on BCU depth structure map



3.55. Nexen-CNOOC: well 20/1-5Z, Lily prospect

The Lily Terrace structure was an up thrown terrace to the Buzzard Field but, downthrown from the Pink Terrace to the north (**Fig. 110**). The bounding fault to the south was a major east – west trending fault that defined the northern margin of the Buzzard Graben. The Upper Jurassic Buzzard / Burns

Sandstones were the target reservoir. Top seal to the structure was expected to be provided by the marine claystones of the Kimmeridge Clay Formation. Up thrown cross fault seal was required to the south where the reservoir was interpreted as being juxtaposed against Kimmeridge Clay Formation or Lower Cretaceous shales. Downthrown cross fault seal was required to the north where the reservoir was assumed to be juxtaposed against Kimmeridge Clay Formation, Heather Formation, Smith Bank Formation and Silurian granite (**Fig. 111**). The source rock was expected to be the Kimmeridge Clay Formation with similar migration mechanism as for the Buzzard field.

The overall CoS was set at 11% with main risks being the reservoir presence (40%) and seal effectiveness (50%).

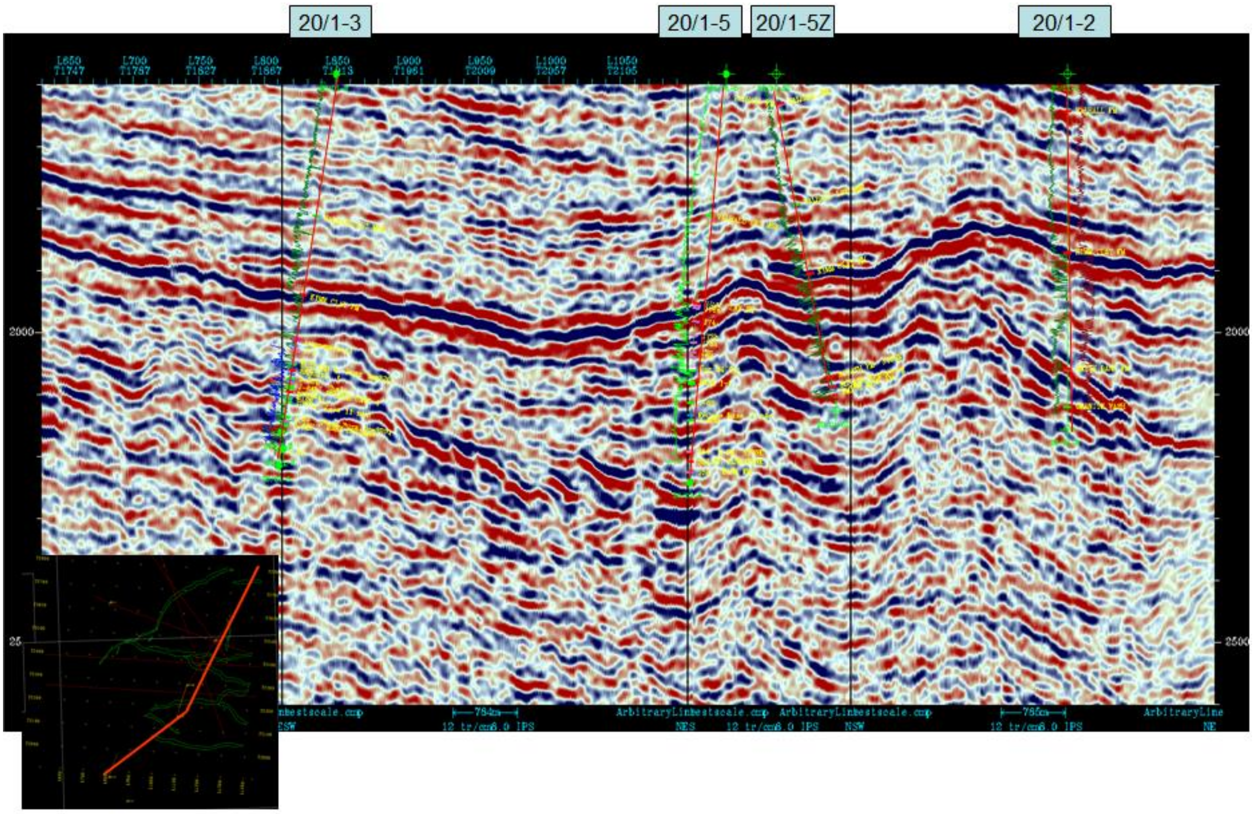
All markers came in quite well within the error bars. The Buzzard equivalent interval contained interbedded claystones and rare, thin, variably cemented sandstones showing that well 20/1-5Z had been drilled outside of the Buzzard turbidite fairway. The Burns sandstones show gross = 201 ft, N/G = 76%, porosity average = 16,8 % but are water wet.

The main reasons for failure are clearly the lack of Buzzard reservoir section as well as the lack of lateral up dip seal. Indeed a post well Fluid Inclusion study shows that HC migration occurred in the younger Burn sandstones, meaning a lack of effective lateral seal, hence no containment: the Lily terrace was a migration route.

<u>Main lessons learned:</u>

- Although the pre-drill risking was pretty well assessed, the target of this side-track was the extension of northern boundary of the Buzzard Field towards the north. As such 20/1-5Z penetration had to be drilled.

Fig. 111 - SW-NE seismic random line through the Buzzard North terraces **(Data provenance uncertain: PGS or WesternGeco?)**



3.56. Nexen-CNOOC: well 20/4a-8 and -8Z, Polecat prospect

The Polecat Prospect was a stratigraphic trap defined at the Near Top Buzzard Unconformity. The structure lies in the southern part of Block 20/4a in the hanging wall of the 20/4a horst, and is delimited by fault to the north, pinch-out to the east and south, and dip to the west (**Fig. 110**). This is a prominent late Jurassic horst in the central part of Block 20/4a (**Fig.112**). The Jurassic and pre-Jurassic isopachs implied that the horst was forced up during the late Kimmeridgian – early Ryazanian, but that little movement took place either before or after this interval. On the south side of the fault was a Jurassic embayment with a generally thickened section. This formed the Polecat prospect (**Fig. 113**). As no late reactivation of the horst bounding faults was seen it was interpreted that effective fault sealing had a high probability.
The target reservoir was the Buzzard sandstone unit, with P50 gross thickness expected at 240 ft, sourced by the Kimmeridge Clay Formation which was also expected to act as the top and bottom seals.
The overall CoS was estimated at 24%: seal was perceived as the main risk (50%) while the reservoir and trap geometry were significant additional risks (70% each).

Well 20/04a-8 penetrated the top of the upper Buzzard Sandstone 241 ft deep to the prognosed top. The upper Buzzard Sandstone had a Gross thickness of 26 ft, while the lower Buzzard Sandstone had a gross thickness of 9 ft. The combined lower and upper Buzzard Sandstone intervals gave a Gross vertical thickness of 35 ft. Buzzard Sandstones were present but good quality reservoir was much thinner than expected.

Oil samples were obtained utilizing the RCI, oil gravity of the upper Buzzard Sandstone is 32° API and the lower Buzzard Sandstone 29° API but both are of sour nature.

After running a wireline log suite, the 20/4a-8 well was plugged back and subsequently side-tracked.

Side track well 20/4A-8Z found the top of the Buzzard Sandstone 91 ft high to prognosis. Two distinct sand bodies were seen, “upper” Buzzard Sandstone (Gross 16 ft), and “lower” Buzzard Sandstone (Gross 25 ft), both being water bearing. So the reservoir was similar in thickness and quality to mother well -8 but water wet. The RCI was used to obtain a water sample. The formation pressure profile indicated the OWC to be at (- 10023 ft TVDSS). After running a wireline logging suite at TD in the Heather Formation, the well was plugged and abandoned.

The main reason for failure of the side-track is that well drilled too far down dip and that the trapping mechanism is more stratigraphic in nature with a shallower FWL.

Company perspective main lessons learned:

- The accommodation space for sand deposition was not as large as expected.
- It is very challenging to predict sand facies and presence when reservoirs are below seismic resolution
- The sour nature of the oil discovered in well 20/4a-8 means that bigger volumes are needed to pass the economic threshold.
- Unfortunately, as shown by the resources calculation carried out after side-track 20/4a-8Z results have been integrated, this oil discovery sits on the lower end of the prognosed range of volumetrics.

OGA perspective:

- It is possible that only the 3-way dip (i.e. the P90 pre-drill case) closure works while the lateral seal may not be as effective as prognosed. This would result in the effective trap being smaller than prognosed.

Fig. 112 - Polecat Prospect, Top Buzzard Depth Structure

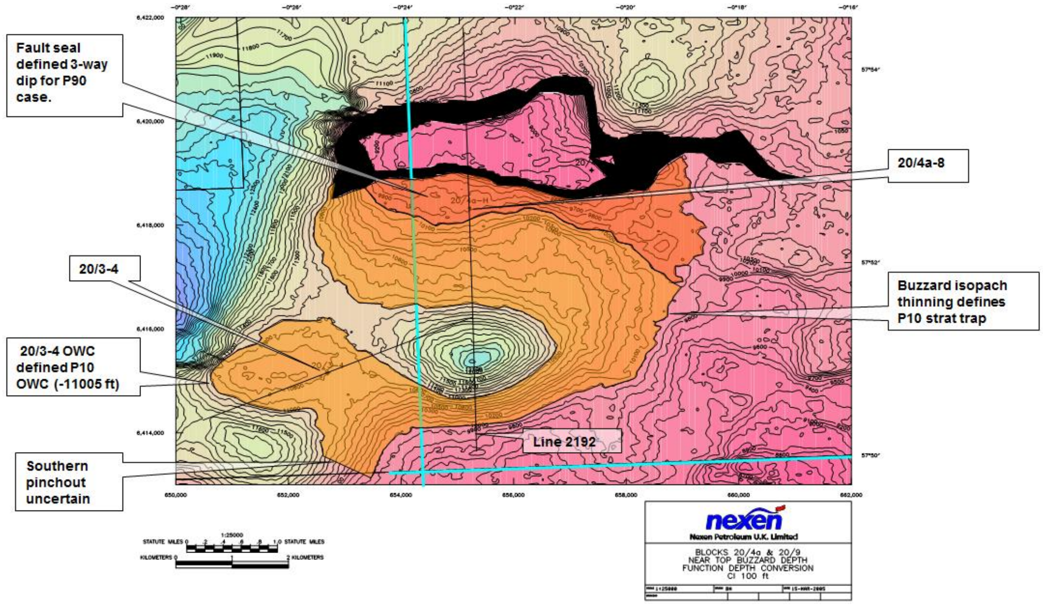
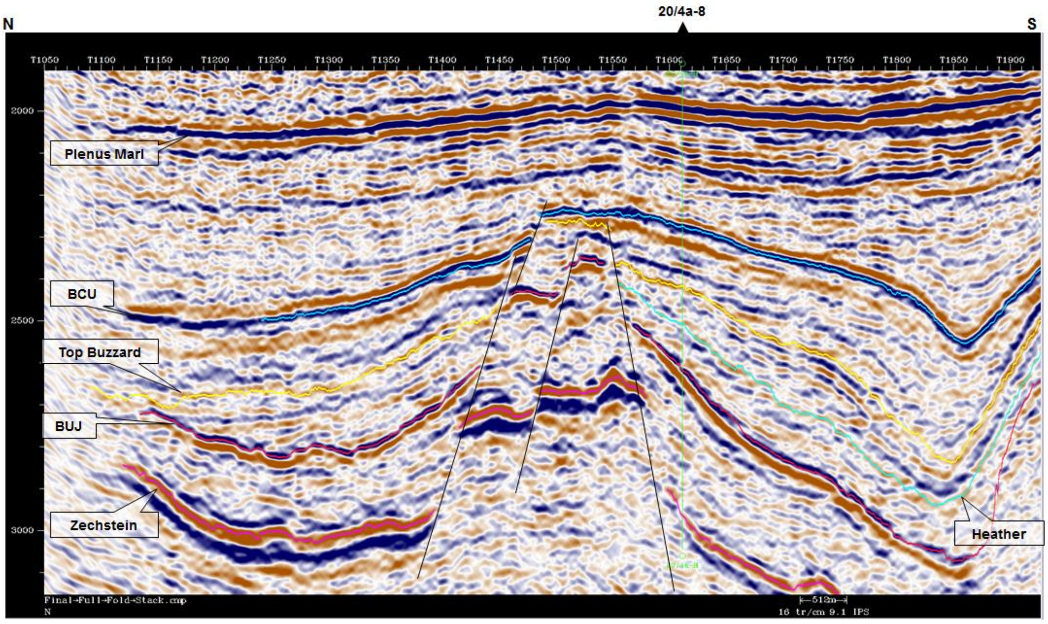


Fig. 113 – N-S seismic line 2192 across Polecat Prospect (Data Nexen proprietary)



3.57. Nexen-CNOOC: well 20/6a-7, Bluebell prospect

Well 20/6a-7 was an appraisal well to test the southernmost extension of the Buzzard field (**Fig. 114**). The trap was a combination trap and relied on depositional pinch out to the west and fault seal to the south. The terrace opened up and connected with the main Buzzard Field further to the east through a relay ramp. As a consequence, the Bluebell prospect was believed to have a common oil-water contact with the Buzzard Field and charge connection was postulated either through the carrier beds up the ramp from Buzzard into Bluebell or through face charge across the E-W fault.

The target reservoir was the Buzzard Sandstone, Early Volgian gravity flow sandstones, encased in the Kimmeridge Clay Formation which was expected to act as the top and bottom seals.

The overall CoS was set at 48% with the reservoir presence being the main risk (60%) and the migration a secondary risk (60%).

Well 20/6a-7 found no target reservoir although a condensed Buzzard equivalent section may be present. The only reservoir found was the Middle Jurassic Sgiath which was water wet (**Fig. 115**).

The main reason for failure is clearly the absence of target reservoir (as was rightly assessed pre-drill) although lack of charge is a potential additional cause.

<u>Main lessons learned:</u>

- The seismic quality over this southernmost Bluebell terrace was significantly reduced compared to the existing Buzzard field. There was considerable uncertainty in the picks themselves and a new 3D data set or a new reprocessing may have helped better assessing the Bluebell terrace geometry, hence its prospectivity.
- Pre-drill alternate seismic correlations across the fault (jump correlations) would have been beneficial to help better understand the risk.
- The limited available space suggests that Bluebell Terrace fault was syn-depositional implying the terrace was acting as a positive structural high at time of Buzzard sandstone deposition. Terrace therefore likely had no accommodation space for Buzzard sandstones and acted as barrier to sediment dispersal patterns.
- The target of this side-track was pushing the southern boundary of the Buzzard Field towards the south. As such 20/6a-7 penetration would have been drilled.

Fig. 114 – Bluebell Terrace location map

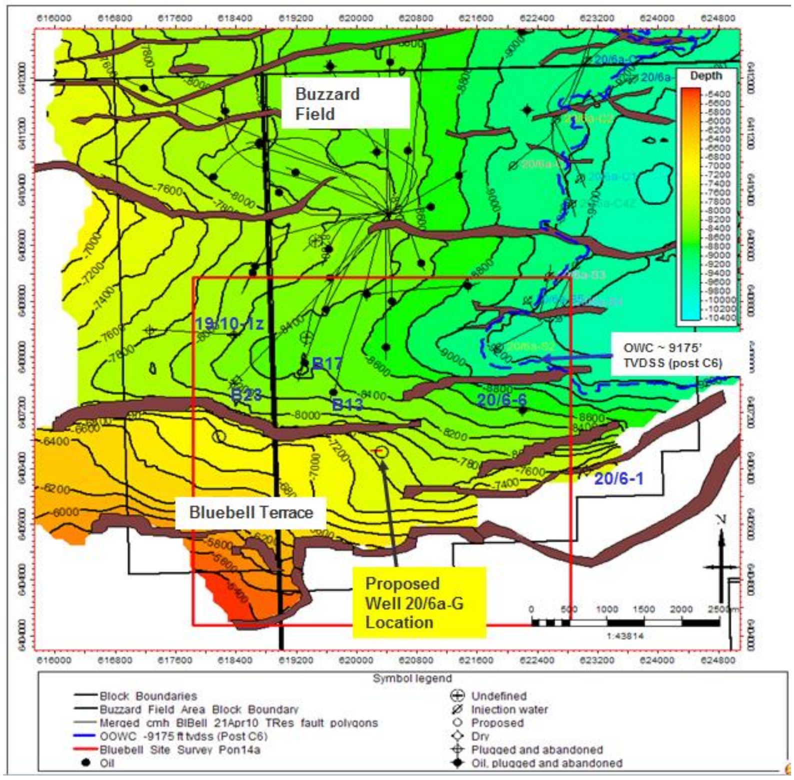
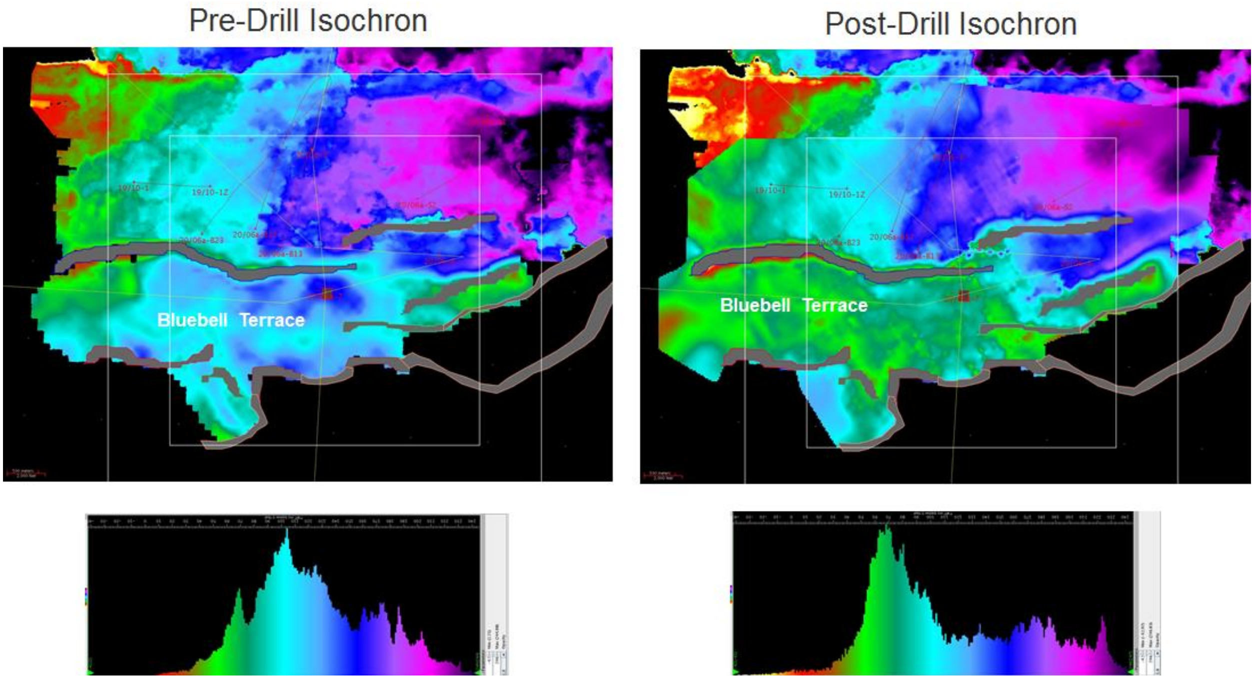


Fig. 115 - Comparison pre- vs post-drill BCU-Base Upper Jurassic time thickness maps



3.58.Nexen-CNOOC: well 20/7-7, Bardolph prospect

Bardolph prospect was located on fault terraces that separate the Peterhead and Buzzard Grabens. The Bardolph prospect was a combination trap with both hanging wall and footwall elements. The proposed exploration well was designed to target the hanging wall side and in the event of a success, possible side-track could be considered to test the upside potential on the footwall side. The P90 of the prospect was defined as the footwall component of a stratigraphic trap. Stratigraphic pinch-out or facies change was required to the west, east and south whereas the northern limit was defined by the fault. The P10 of the prospect involved the hanging wall component and required stratigraphic limit to south and east with dip closure to the north (**Fig. 116**).

The target reservoir was Volgian submarine gravity flow sandstones “Ettrick Sandstones” of the same age as in Ettrick & Blackbird Fields. Amplitude was used to delineate lithology (channel). The source rock was the organic rich Upper Jurassic Kimmeridge Clay Formation, which is mature for oil generation in the areas north of the prospect, in the Ettrick sub-Basin. Block 20/7 lies within the Peterhead Graben and previous workers believed that most of the charge from the Ettrick sub-Basin migrated towards Buzzard to the west leaving the southern flank charge-starved. However more recent successes on the Blackbird Terrace and evidence of shows from some of the offset wells provided encouragement that the Bardolph prospect could receive charge.

Both the Ettrick and Buzzard age equivalent sandstones were fully encased in marine shales which provided top and base seals. Most of the faults in the area had moderate to significant amount of throws and side seal was not expected to be a major concern. However, some of these major faults had evidence of later reactivation in the shallower section and that might indeed be one of the bigger containment risks. Lateral facies seal was required.

The overall CoS was estimated at 36% with the seal risk being the key pre-drill risk (60%).

Targets depths were on prognosis and within pre-drill error margins. The target reservoir was present and thicker than prognosed (gross thickness = 562 ft versus P10 Gross = 260 ft) but water wet. The pre-drill depositional model had been validated. The Lower Cretaceous Punt Sandstones were not encountered as per expectations and Upper Jurassic Late Volgian Burns Sandstones were not found.

No oil or gas shows were recorded asking if there was either no charge or limited charge and up-dip leakage?

The main reason for failure appears to be the lack of seal. Indeed, sandstones and canyon possibly extend significantly further south than previously thought and leak up-dip (**Fig. 117**). It is also possible that the Bardolph prospect is in a migration shadow as there is no evidence of shows and fluid inclusion work was also negative. There may also be potential top seal failure from erosive Punt Channel located to the south.

<u>Main lessons learned:</u>

- With hindsight, the well was too aggressively located down-dip and a location in the footwall may have been more appropriate.
- Understanding where and how the reservoir fill of canyon systems terminate up-dip and better assessment of associated uncertainty levels should be given greater consideration in future canyon play prospects.
- This case study highlights the fact that New Ventures team have a limited amount of time to assess a prospect (3 to 4 months in this particular case) which prevents assessing alternate seismic interpretations and their impact on prospectivity.
- In addition, objectives for the New Ventures (NV) team and the well delivery & prospect maturation team must be fully aligned.

Fig. 116 - Bardolph: gross reservoir interval thickness map

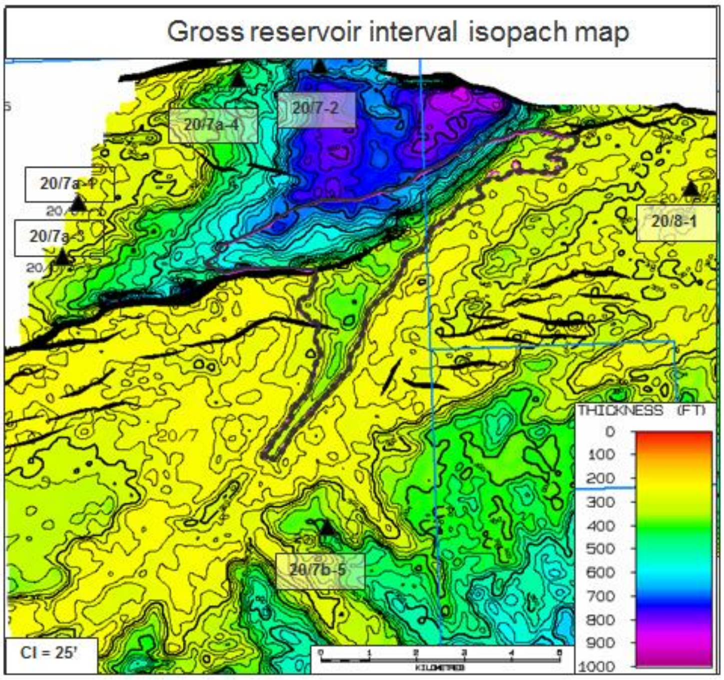
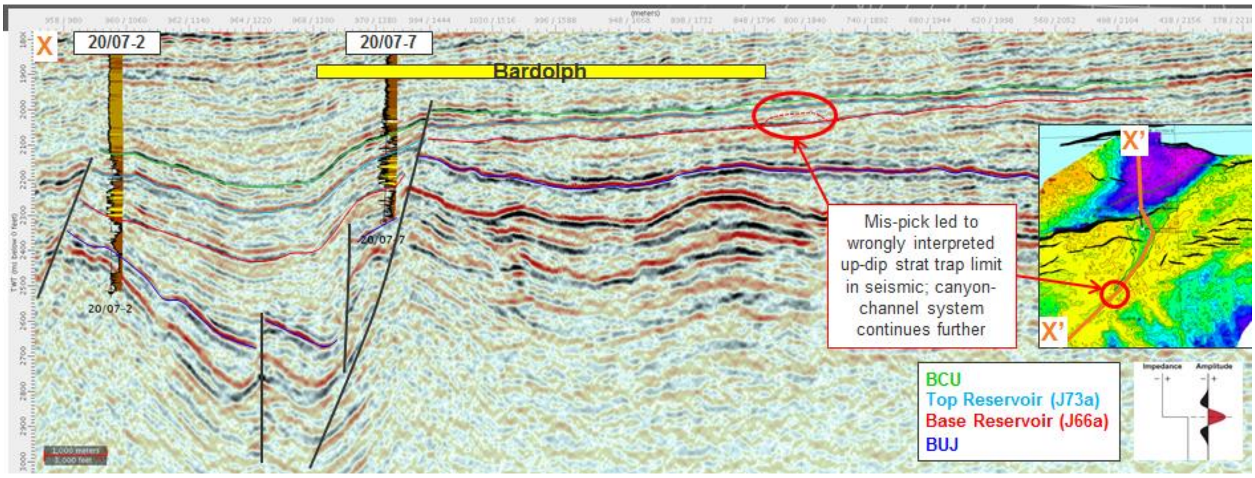


Fig. 117 - North-South composite seismic line along canyon axis **(Data provenance uncertain: Nexen proprietary or WesternGeco?)**



3.59. Nexen-CNOOC: well 20/7a-4, Squirrel prospect

The Squirrel Structure was located ~5 km to the south of the Ettrick field. It was a stratigraphic pinch out in Upper Jurassic Ettrick and Buzzard Sandstones towards the crest of a major east-west fault (**Figs. 118 & 119**). Pinch out was also required towards the south. Pinch out was defined based on amplitude extraction across Upper Jurassic section. Top and lateral seal to the structure was provided by the marine claystones of the Kimmeridge Clay Formation. Up thrown cross fault seal was required to the north where the reservoir was expected to be juxtaposed against Lower Cretaceous shales. The target reservoirs were the Upper Jurassic Buzzard and Ettrick Sandstones encased within Kimmeridge source rock which were prognosed as being mature in the Squirrel Fault Panel.

The overall CoS was set at 38% and the main pre-drill risks were interpreted as the seal (60%) and the reservoir presence and quality (70%).

The main markers came in within error bars and Buzzard gross thickness was accurately prognosed with N:G at the high end of expectations. All reservoirs were water wet and no hydrocarbon shows were observed while drilling. Kimmeridge Clay as well as Heather shales were present and thick respectively acting as effective top and base seal.

The main reason for failure is interpreted as the lack of lateral / up dip seal. Although the Upper Jurassic thickness map shows considerable thinning to west and sandstones are absent in wells 20/7-1 and 20/7a-3, sandstones are sourced from west and thickness map never guarantees sand presence or absence. There may also be no cross-fault seal, but this seems unlikely as Cromer Knoll Group seals elsewhere and there are no obvious sandstones in the Ettrick Graben. Another potential cause for failure may be lack of migration into the structure as initial extraction from cuttings indicates low maturity hydrocarbons are present.

<u>Main lessons learned:</u>

- Even though the reason for failure is uncertain, thickness maps (isopachs) cannot be taken as a guarantee that no sandstones at all will extend further up dip.
- More detailed Basin Modelling may have shown that the fetch area was much more limited than anticipated and that long range migration pathways were not that simple?

Fig. 118 - Top Ettrick depth map showing pinch-out hypotheses: Squirrel location is 20/07a-D

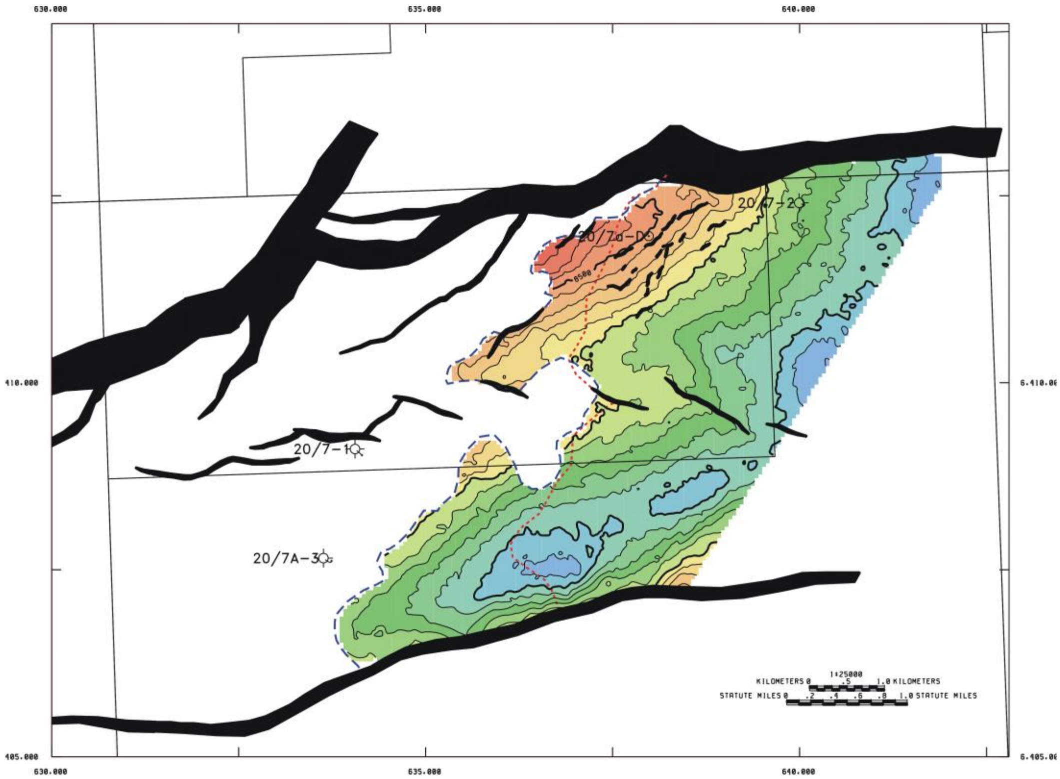
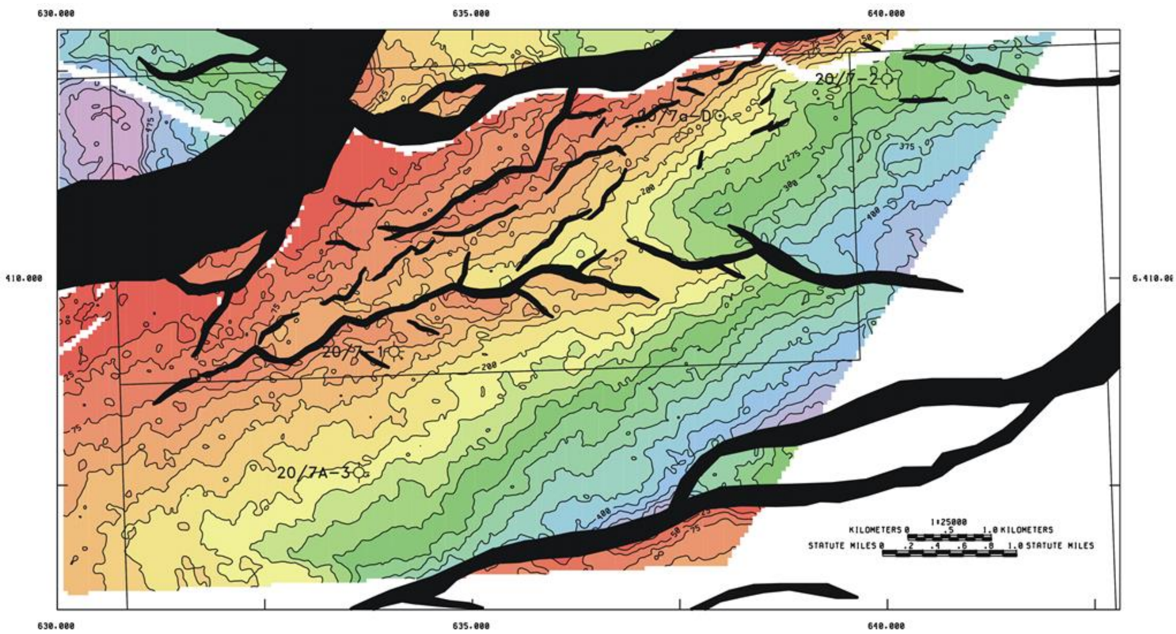


Fig. 119 - Upper Jurassic thickness map: Squirrel location is 20/07a-D



3.60. Nexen-CNOOC: well 20/7a-6, Black Cat prospect

Black Cat was located half way between Buzzard and Ettrick fields. The trap for the Black Cat prospect at Ettrick Sandstone was a combined structural and stratigraphic trap, with dip closure to the north, downthrown closure against basement rocks to the south and east, and stratigraphic pinch out to the west. The trap for the Buzzard Sandstone was structural only, with dip closure to the west and fault closure to the south, north and east (**Figs. 120 & 121**). The target reservoirs were Upper Jurassic Ettrick and Buzzard gravity flow sandstones. Reservoir presence was not supported by an acoustic impedance / AVO study as the target reservoirs were expected to be too thin to be detectable.

The source rock was interpreted as the Kimmeridge Clay Formation which was mature for oil generation and expulsion in the centre of the Ettrick Basin. The kitchen area was located south of the Ettrick Field and was believed to have charged the Ettrick and Buzzard Fields. Both reservoirs are fully encased in marine shales which provided top and base seal, and were reliant on fault seal on the main bounding fault that separated the Peterhead Graben from the Buzzard/Ettrick Graben.

The CoS was set at 40% and the main pre-drill risks were interpreted as the seal (70%) and the trap and reservoir presence both being assessed at 80%.

All markers down to Heather came in within error bars (+/- 200 ft) even though top Ettrick came in 169 feet shallow to prognosis. Both Ettrick and Buzzard exhibited poor net sand thickness with reduced N:G (respectively 4% and 16%) and porosity on the low end of the expectations. In addition, Lower Buzzard and Sgiath seem to be cemented. Both top and base seal were encountered and thick enough to provide effective such seals. However, no significant gas or oil shows were recorded.

OGA believe the main reason for failure is the lack of lateral seal: indeed conclusions of a post well Fluid Inclusion study were that “the HC bearing fluid inclusions were trapped after cementation and mark oil migration pathways". However, Nexen-CNOOC’s technical position acknowledges that cementation occurred early, prior to the migration of small quantities of oil. This indicates that the Black Cat structure is not a breached trap. Charge of the structure was probably not possible because of the early cementation of the reservoir and carrier beds. Also, the kitchen is located east in the Ettrick Graben and from the top Ettrick depth map, it is possible that the structure is located in a migration shadow, providing a possible failure cause for the well.

Main lessons learned:

- Timing of migration and reservoir quality preservation needs to be considered on basin margin prospects.
- Acoustic impedance (AI) separates sandstones from shales reasonably well but does not discriminate fluid saturation very successfully.
- Post well full stack AI inversion provides a high resolution result which shows considerable lateral and thickness variation. The majority of thin-bed sandstones (Ettrick sands) are not suitably resolvable and the inversion results provide more of an average zonal response.

Fig. 120 - Top Ettrick reservoir depth map and Ettrick + Buzzard targets closure outlines.

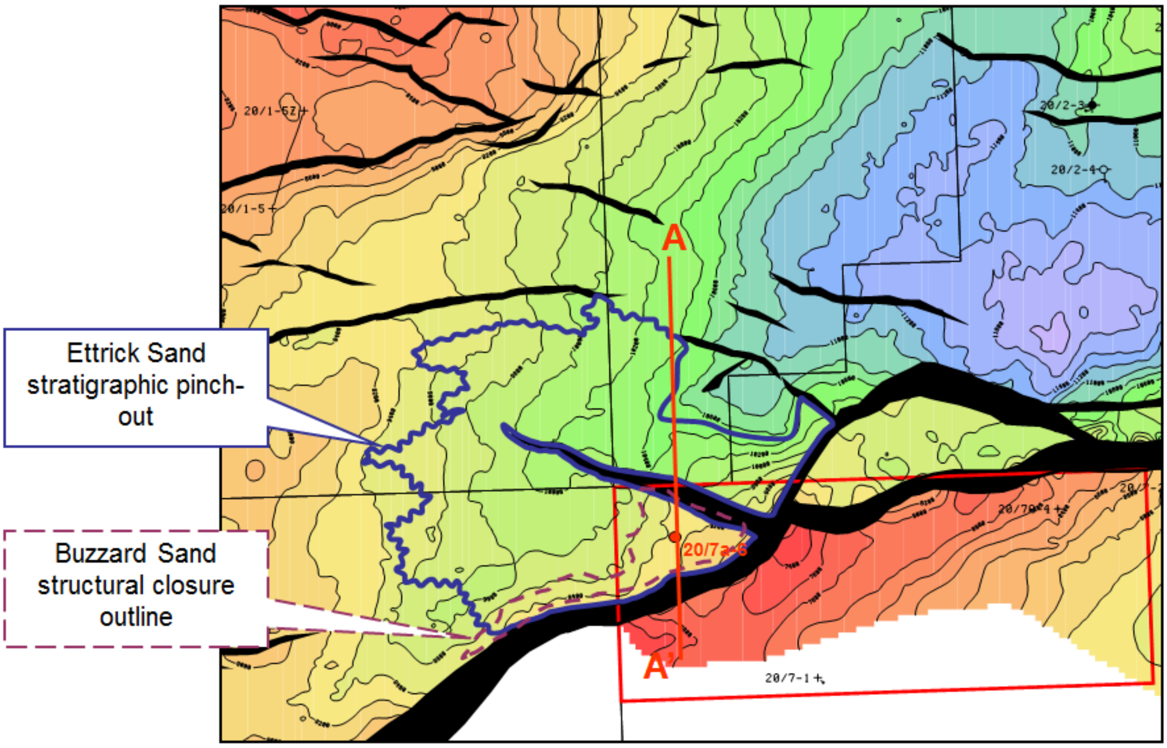
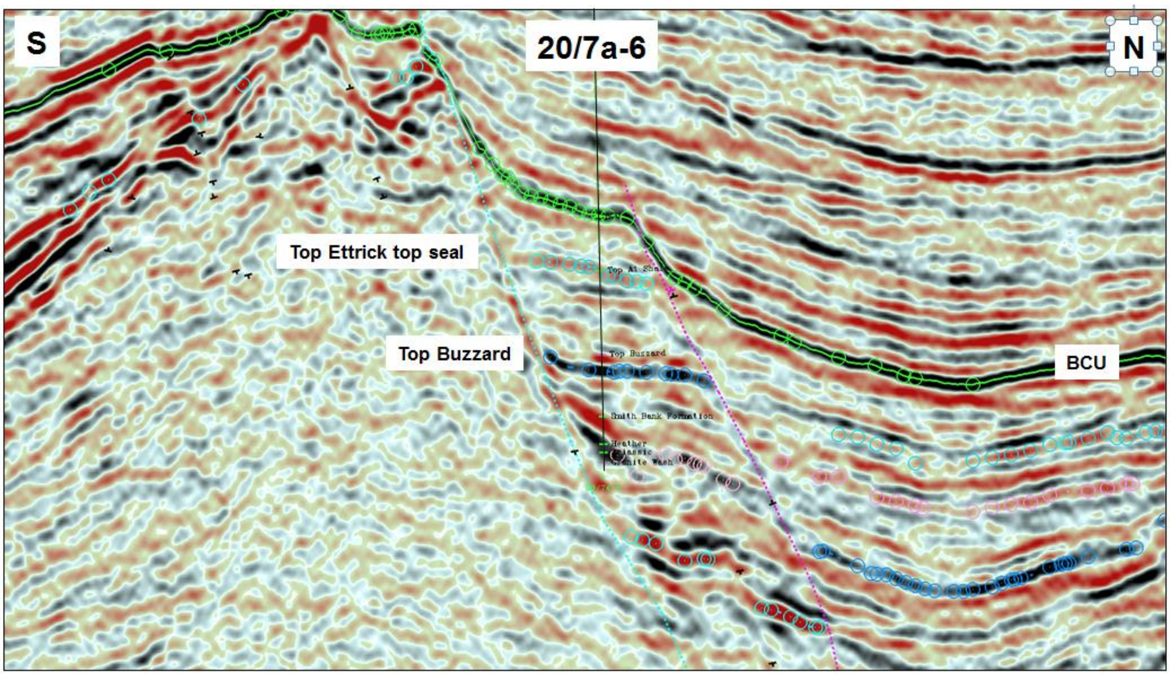


Fig 121 - North-South seismic line across the Black Cat prospect **(Aker seismic data, courtesy of TGS)**



3.61. EDC well operator, (Nexen-CNOOC current well owner): well 20/7b-5, Joppa prospect

The well was located in the Outer Moray Firth in block 20/7b approximately 20 km south east of the Buzzard Field, and 20 km south of the Ettrick Field.

The 20/7b-5 exploration well was drilled by EDC (a subsidiary of Noble Energy Inc.) to evaluate the reservoir and hydrocarbon-bearing potential of the “Joppa Prospect”, at top Jurassic Peterhead Sandstone Member level. Secondary prospectivity was also recognised at the slightly shallower Upper Jurassic Ettrick Sandstone Member level. The prospect was interpreted as a purely stratigraphic trap in the form of a large detached basin floor fan pinching out to the north, west and south west, with dip closure to the east and south east. Reservoir was predicted to be in the form of mass debris flows such as seen in the nearby Buzzard field, sealed by the Kimmeridge Clay (top) and the intra Upper Jurassic mudstones (lateral and base seals). The source rock was the Kimmeridge Clay Formation, predicted to be locally mature within the Peterhead basin, implying short migration pathway as KCF interbedded with the predicted Peterhead sandstones with possible additional longer-distance migration from the Ettrick sub basin. However in the Peterhead Basin, the ability of the Upper Jurassic sediments to generate and expel significant volumes of oil was interpreted as a key risk.

The Joppa analogue was seen as the Buzzard Field located in the adjacent Graben to the north. The overall CoS as well as the individual risking parameters are not known. However, it was made clear that “reservoir presence and quality were key risks”.

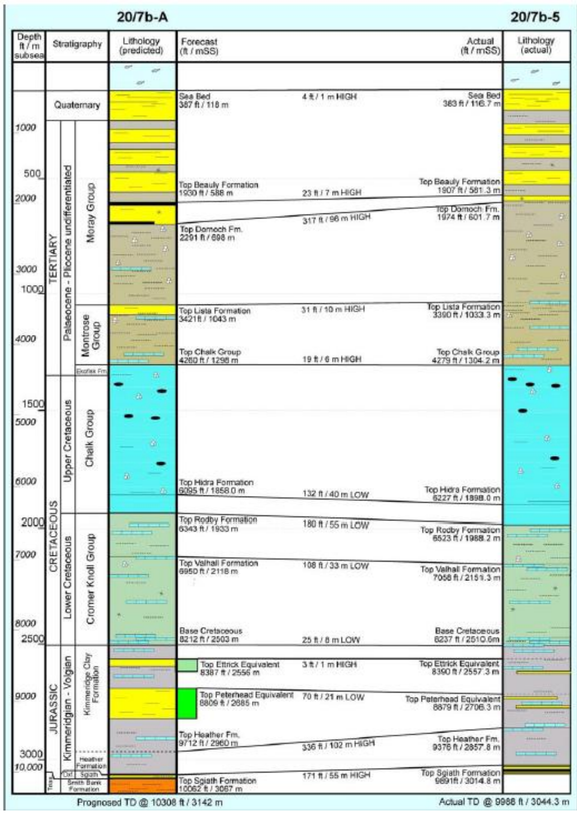
All main Formation tops came in deep to prognosis but base Peterhead sandstones (-182 ft high). The 20/7b-5 well penetrated only thin sandstone stringers and siltstone in the Middle Volgian Ettrick Formation and tight sandstone stringers in Early Volgian Buzzard Formation (**Fig. 122**). Minor oil shows were seen in both formations, comprising dull to bright yellow fluorescence and rare light brown oil staining was observed.

<u>Main lessons learned:</u>

- Effective clastic source is lacking in the Peterhead Graben for this play.

- Once Nexen farmed-in into the EDC P1047 license, they undertook a major reprocessing project incorporating several of the legacy 3D datasets to produce a seamless 1300 km^2 regional dataset. Then Nexen carried out a 1D Basin Modelling using all neighbouring available data. It showed that in the Peterhead Graben, the Kimmeridge Clay Upper Hot Shale is in the early mature window and has not expelled hydrocarbons while the Heather Formation is not considered a source rock in the area. As a summary, the Peterhead Graben is not considered mature enough to have sourced any significant accumulation.

Fig. 122 – Joppa well 20/07b-5: Prognosis versus Actual



3.62.Nexen-CNOOC: well 20/11-1, Flint prospect

The Flint prospect located in the Peterhead Graben was stratigraphically defined by “hummocky” architecture at the Base Cretaceous which was interpreted to be the result of differential compaction over an Upper Jurassic sand body (**Fig. 123**). The architectural form narrowed to the west and was inferred to pinch out at the base of a significant increase in dip of the Base Cretaceous Unconformity (**Fig. 124**).

The reservoir targets were the Upper Jurassic Middle-Late Volgian sandstones base of slope/proximal (Burns and Ettrick) sourced and sealed by Upper Jurassic Kimmeridge Clay Formation. Indeed shales of the Kimmeridge Clay Formation provided the top seal for the prospect. The up dip seal relied on either clay plugging of the feeder channel system, or a sand bypass zone associated with a break in slope. The latter was considered the most likely up dip seal in the Buzzard Field, but both mechanisms were deemed possible. The lateral seal relied on the sand bodies being confined to the channel feature, shaling out rapidly into sealing shales at the margins of the channel.

Flint was again interpreted as analogue to the Buzzard Field located in the adjacent Graben to the north.

The overall CoS was estimated at 16% with the key pre-drill risk being the reservoir presence and quality (35%). Additional risks were also interpreted, albeit to a lesser degree, regarding seal (70%) and trap and migration (80% each).

None of the target Burns or Ettrick reservoirs were found by well 20/11-1, it found only thin sandstone stringers either tightly cemented or water wet. The Flint "hummocky" feature is not a result of differential compaction but more likely the flank of a late Jurassic/Early Cretaceous erosive event. Lack of shows was observed throughout this well therefore potential migration problem was an additional cause for failure.

Post well basin modelling concluded that Buzzard equivalent is an excellent Type II source-rock. However both the Kimmeridge Clay and leaner Heather source rock intervals are immature for oil generation.

Main lessons learned:

- The Peterhead Graben is sand starved for this play.
- Potential for oil generation/migration into block is now considered high risk in the Peterhead Graben. Could pre-drill basin modelling have reached this conclusion?
- Would any rock physics modelling / acoustic inversion have helped better defining the lithological nature of this Graben infill?

Fig. 123 - Seismic Inline 1700 across Flint Prospect (Aker AGEA99, **Data courtesy of TGS)**

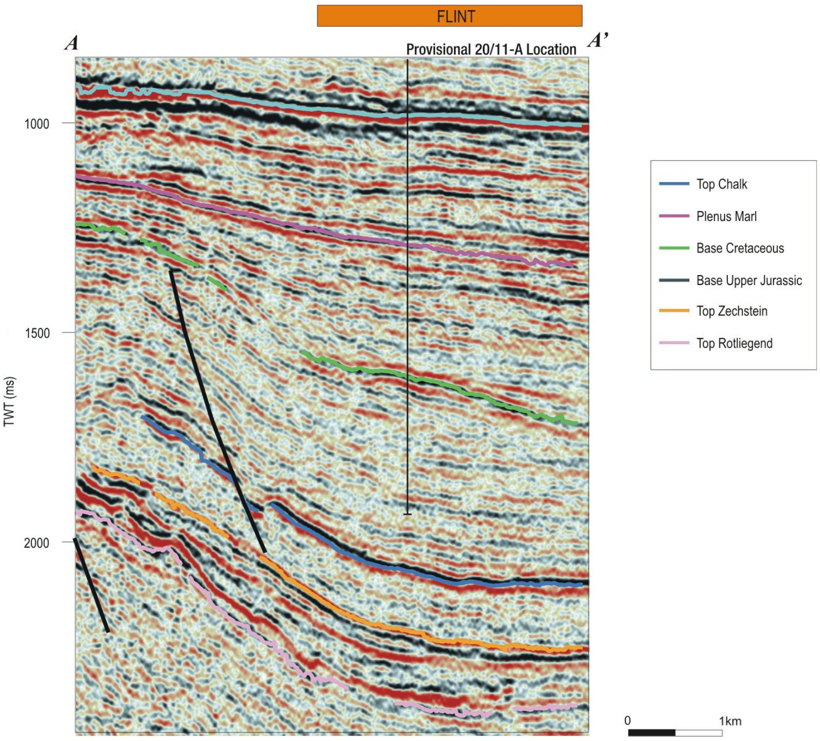
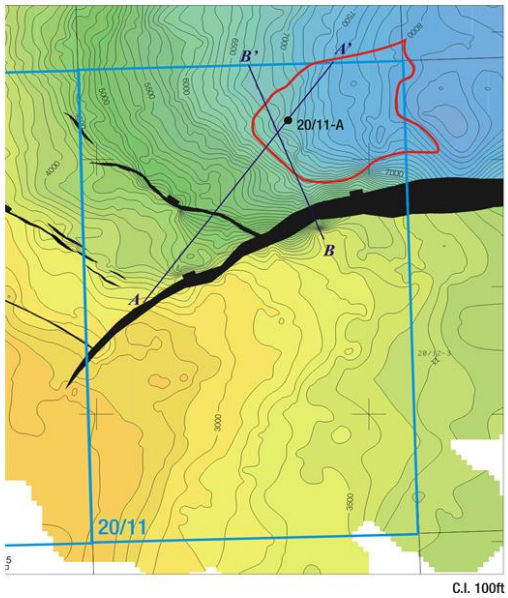


Fig. 124 - Flint prospect BCU depth structure map



3.63. Nexen-CNOOC: well 21/2-10, Saracen prospect

The Saracen prospect was a Jurassic terrace area separated from the Tweedsmuir Field by a north-south trending fault. The entire Jurassic interval thins rapidly to the north on the back of the Renee Ridge. Here the sandstones were interpreted to either pinch-out giving the stratigraphic trap or being downthrown against Middle Jurassic Rattray Formation volcanics. To the east the interval also thins, and significant sandstones are absent from well 21/2-8. It was interpreted that the sandstones pinched-out in this direction. To the south and west the trap was dip closed (**Fig. 125**). The target reservoir was a submarine fan from the Early to Middle Volgian sourced by the Kimmeridge Clay Formation. In the most likely scenario, the Prospect was considered to be in communication with the 21/1a-12 BP 1985 discovery which contained an OWC at 14,138 ft TVDSS (**Fig. 126**). Shales of the Kimmeridge Clay Formation provided the top, base and lateral seal for the prospect. To the north the prospect was potentially fault closed with the reservoir juxtaposed against Middle Jurassic volcanics.

The overall CoS was estimated at 41% with the reservoir presence and quality being the main pre-drill risk (50%).

Well 21/2-10 confirmed seismic picks as all horizons came in within error bars but Sola Formation and base Kopervik sands. The objective reservoir was close to prediction, providing confirmation of the seismic horizon identification, mapping, depth conversion and geological model for the presence of sand. Reservoir was wet despite being higher than at well 21/1a-12. The sandstones in Saracen and Tweedsmuir North are the same, Buzzard 4 equivalent according to Biostratigraphy. No hydrocarbon shows have been recorded whilst drilling. Reservoir pressures indicate separation from Tweedsmuir North well 21/1a-12.

The main reason for failure is interpreted as the lack of lateral seal as a result of either a) leakage of the predicted downthrown fault-seal to the north or b) leakage through an extension of the sand up-structure, to the east. In addition, no hydrocarbon bearing fluid inclusions have been recorded in samples from the Upper Sandstones suggesting that no hydrocarbons were present during the cementation of these samples and that these horizons did not act as oil migration pathways, meaning that the target reservoir was likely in a migration shadow and the N-S fault bounding Tweedsmuir to the east is likely sealing. On the other hand, Lower sandstones had HC Fluid Inclusions (indicative of residual hydrocarbons) showing that migration occurred via these lower sandstones but there was either no effective trap or no effective seal at this level too.

Main lessons learned:

- Given adjacent Tweedsmuir Field and the similar geological context, it was worth testing this prospect. However, the geological model of the sandstones extending further to the east and the 21/2-10 location not being within closure was not considered possible and the seal - closure uncertainties were under-estimated. This illustrates the "anchoring" bias, tendency to anchor evaluation on the 21/1a-12 OWC and the "overconfidence" bias, the tendency to overestimate one's own interpretation.

Fig. 125 - Saracen Prospect and Tweedsmuir Field outlines (Base Early Volgian Sst Depth Structure)

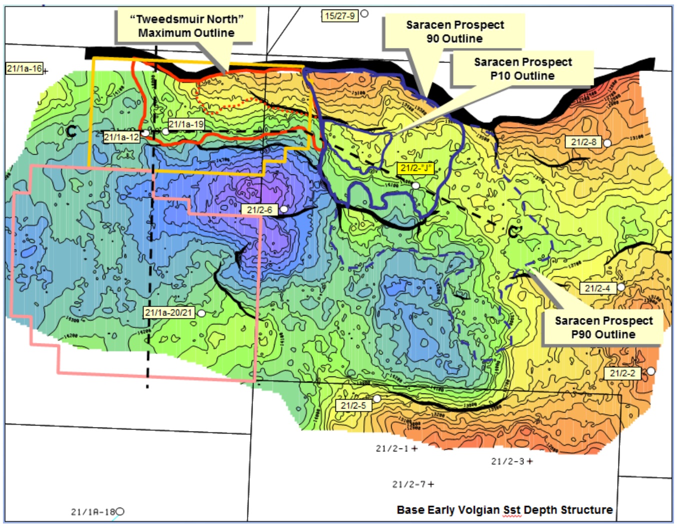
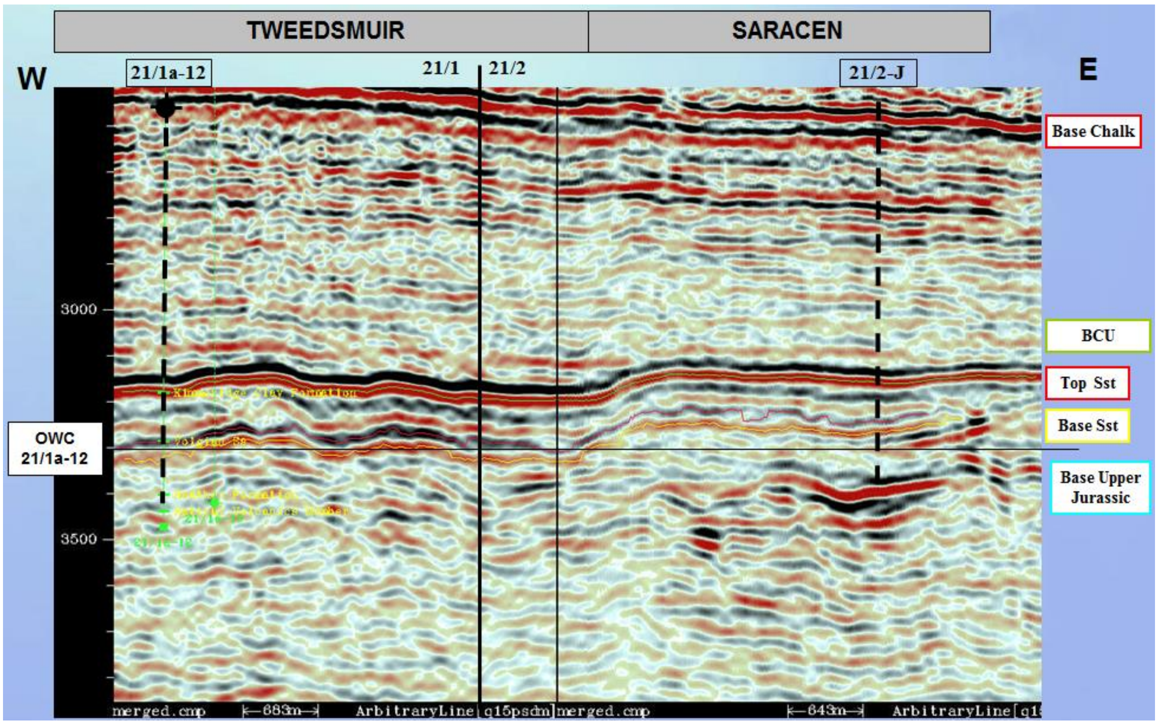


Fig. 126 – West-East seismic line C-C' across Saracen **(Data provenance uncertain: Nexen proprietary or SSL-WesternGeco?)**



3.64.Nexen-CNOOC: well 28/5a-6, Porcupine prospect

The Porcupine prospect was located ~8 km to the south-west of the Bittern Field. This large Palaeocene accumulation lies beneath a prominent gas chimney which obscures and depresses the seismic reflectors above and below it. The Bittern and South Arne successes suggested that the gas cloud should be regarded as a strong Direct Hydrocarbon Indicator (DHI). It was believed that the Porcupine gas anomaly represented a Direct Hydrocarbon Indicator analogous to Bittern. Both Eocene Tay and Palaeocene Forties targets were geologically plausible. As inadequate seismic data within the gas cloud prevented a definitive analysis of the reservoir horizon it was felt that only by drilling could the question of up dip Bittern prospectivity be answered (**Figs. 127 & 128**).

The Porcupine stratigraphic trap was purely defined by the gas anomaly at Balder level. Therefore well 28/5a-6 objectives were:

- To penetrate the gas cloud in an area of maximum gas effect, such that the presence of either Palaeocene or Eocene hydrocarbons will be fully assessed,

- To penetrate the Palaeocene section in an isopach sufficiently thick for there to be good Forties sand development.

The expected seismically transparent nature of the Eocene sandstones made the mapping of the reservoir horizon problematic. The Tay structure was a stratigraphic trap created by a depositional submarine channel trending south-west to north-east from the shelf to the west downslope to the basin to the east as per high amplitudes outlining Lower Tay depositional system. The Tay channel would have been mud-plugged at its up dip (south-western) end, laterally sealed by clay drape and dip closed to the north-east. The Forties trap definition was not detailed as it only relied on the existence of a thick enough section allowing good sandstones to be present! Sourcing of these reservoirs was expected via vertical migration from the Kimmeridge Clay Formation similarly to Bittern sourcing.

Both overall CoS and pre-drill risking parameters are unknown.

Well 28/5a-6 found top Cromarty (Forties) found 307 ft deeper than prognosis as well as top chalk (+214 ft) and Top Triassic (+200 ft) showing the picking uncertainty and that the presence of the gas cloud added considerable uncertainty concerning the depth conversion. Neither Upper nor Lower Tay was present; thin (19 ft) good quality water wet Cromarty sandstones (Forties) have been found. No shows were seen in well 28/5a-6 except elevated ditch gas readings throughout the interval 4100 ft to 5400 ft MDBRT likely corresponding to the gas cloud penetration.

The primary reason for failure is the lack of significant reservoir development, Tay sandstones being absent and Cromarty sandstones being quite limited showing that the interpretation of the gas cloud as a DHI was lacking geophysical grounds and grossly overestimated. In addition, one can wonder if there were any effective migration pathways.

<u>Main lessons learned:</u>

- Would a comparative CSEM study over Bittern and Porcupine have been helpful to decide to drill or not to drill Porcupine?
- Given the relatively low cost of the 28/5a-6 well (£4 M), it is likely that a multi-azimuth seismic acquisition would not have been cost competitive. However from a technical standpoint, acquisition of a new 3D seismic data set along an azimuth different from the existing one followed by suitable processing should have improved the horizons definition and the trap definitions.

Fig. 127 - Porcupine Prospect: Palaeocene Volumetrics

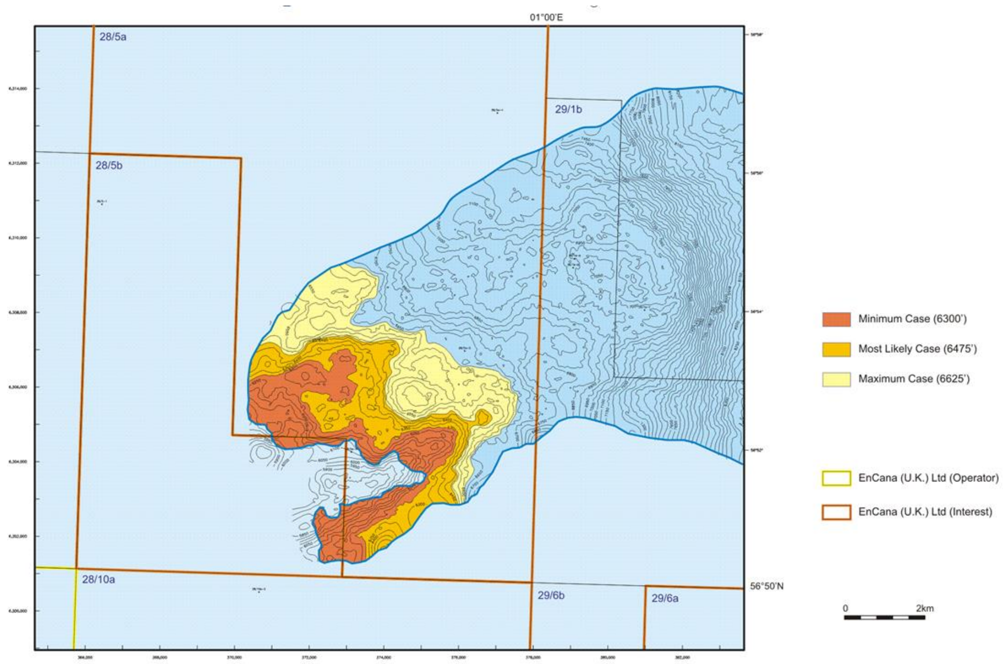
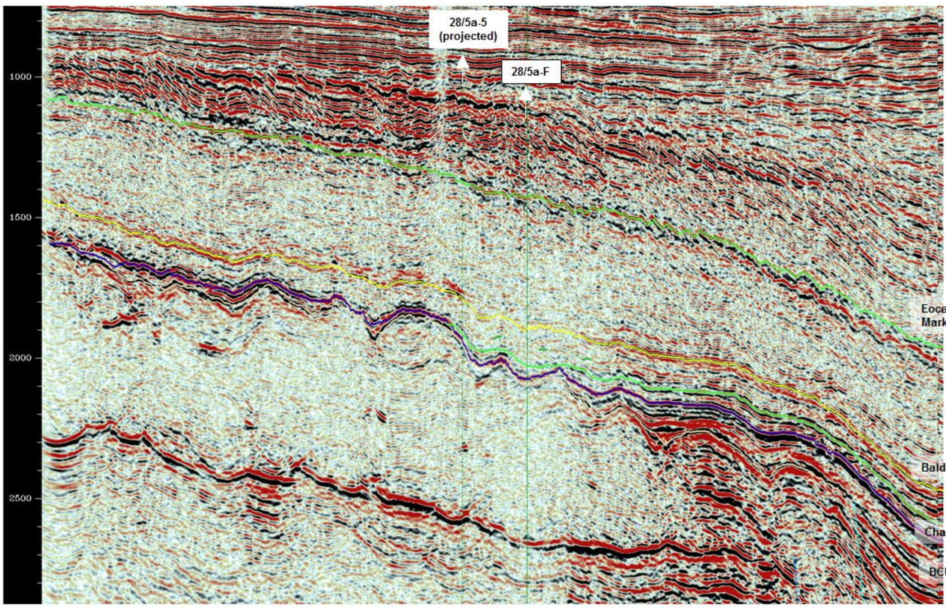


Fig. 128 - WSW – ENE seismic section through Porcupine prospect (Data BG proprietary)



3.65. Nexen-CNOOC: well 39/1b-3, Edgware prospect

The target of the well was the shallow marine/shore face Fife Sandstone, of Fulmar age, and was a commitment in the 26th License Round. The 39/01b-3 Edgware tested Upper Jurassic sediments deposited in a series of north-south oriented embayments with expected shoreface facies belts oriented west-east along the flanks of the embayments. The development of accommodation space was expected to control the Fulmar spatial distribution and the reservoir thickness prognosis was directly related to isopach.

Well 39/01b-3 tested a combined structural/stratigraphic closure on a shoreward extension of the Argyll Ridge. This 3-way dip combined stratigraphic pinch out closure was part of a greater overall structure that encompassed significant upside potential on and flanking the Grensen nose, bounded to the east by the Fife Embayment and to the west by the Aldgate (38/5) Embayment. The structure map showed the stratigraphic trap concept with two crests (**Fig. 129**). As a consequence of this fairly complicated structure there were several potential well locations. The chosen location was deemed to be less risky as it was contained within a larger 4-way dip closure, was closer to the main kitchen area in the Central Graben and had what was deemed to be good seismic support for sand presence.

A considerable amount of work was done to evaluate the seismic data (**Fig. 130**). The bulk of the seismic used to define Edgware was acquired in two tranches in Q4 2003 and Q1 2004 and it was then combined with newer (2007-08 acquisition) data to the East. The Edgware location was at the intersection of these two vintages which also raised doubts on the quality of the data. The seismic vintage was relatively old for pre-stack work (>5 year sold). The resulting merged seismic data set was from 2010 and was not broadband but the quality was deemed good. Both amplitude and inversion work indicated that the chosen structural location exhibited a seismic response consistent with proven sand in offset wells. The Maximum Shear Impedance Attribute was Nexen strongest confidence builder as it seemed to fit with the known sand penetrations at 31/26b-18 Turiff well and Fife field and no sand at wells 39/2c-5 Peveril and 31/26b-17 Turnberry.

Top and lateral seals were supposed to be provided by Kimmeridge Clay Formation while base and lateral seals were interpreted to be the Triassic Smith Bank Formation. Chalk serves as effective seal where KCF not present as demonstrated on Fife field. Kimmeridge Clay was immature at prospect location and Edgware required long distance migration to find oil mature kitchens. There were hopes that Fife (early mature) and 38/5 (immature) embayments would contribute. Pre-drill Basin Modelling demonstrated two potentially effective pathways while API distribution maps supported charge from deep kitchens of the Central Graben.

The overall CoS was set at 35% with reservoir presence and seal were deemed as the main pre-drill risks (70% each).

The 39/1b-3 well penetrated a thick Upper Jurassic section including anomalously “hot” shale, 400ft of Upper Jurassic, of which 352ft was a mudstone equivalent of the Fulmar (Fife) Sandstone. Due to thinner Kimmeridge Clay and deeper BUJ pick, the Fulmar section was 128ft thicker than prognosed, but did not contain reservoir quality sand (**Fig. 131**). Very rare oil stains in Balder Formation and in fractures at Tor-Ekofisk Formation have been observed. However, the key surfaces came in close to their prognosed depths therefore the timing model is still valid.

The main reason for failure is the lack of target reservoir: no sandstones have reached the Edgware location by progradation / reworking from the south or west or more proximally from the Grensen Nose to the east. As this prospect was attribute led, the wrong interpretation of the amplitude and inversion works was another reason for failure: indeed the Upper Jurassic shale section has similar rock physics characteristics to other non-reservoir wells. Offset wells weren't calibrated to local rock conditions – and the seismic data was trusted too much. Last but not least, given the scarcity of shows, one cannot rule out the lack of migration pathways.

<u>Main lessons learned:</u>

- The prestack relative inversion has been assessed as representing trends within the well, but low frequency model was incorrect due to the anomalous geology.
- The AVO effect observed on gathers and far stack has since been determined to be related to significant multiple energy in the original dataset.

- The seismic attributes / inversion need to be treated with more caution when there is a relative lack of calibration from a limited number of neighbouring wells.
- Indeed wells 39/02c-5 and 31/26b-14 have no shear logs: this highlights the need to acquire more data even though the well is dry as it would help a better understanding of the area.
- Although a detailed Basin Modelling study was carried out pre-drill, and assuming Fulmar would be present, one can wonder if there are continuous enough potential carrier beds connecting the two main kitchens to the prospect.

Fig. 129 - Edgware prospect: trap definition. Depth to Top Reservoir (base hot shale) Structure Map

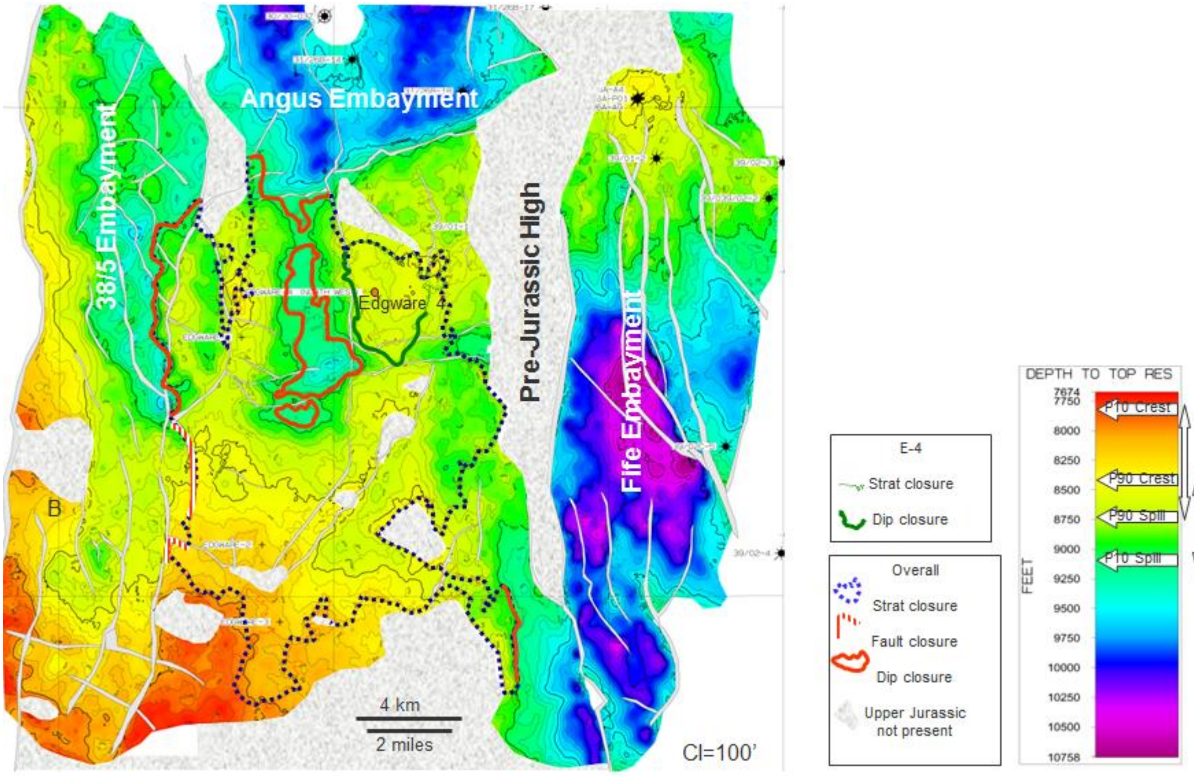


Fig. 130 - SW-NE seismic line across the Edgware prospect illustrating well 39/1b-3 location**(Data courtesy of CGG)**

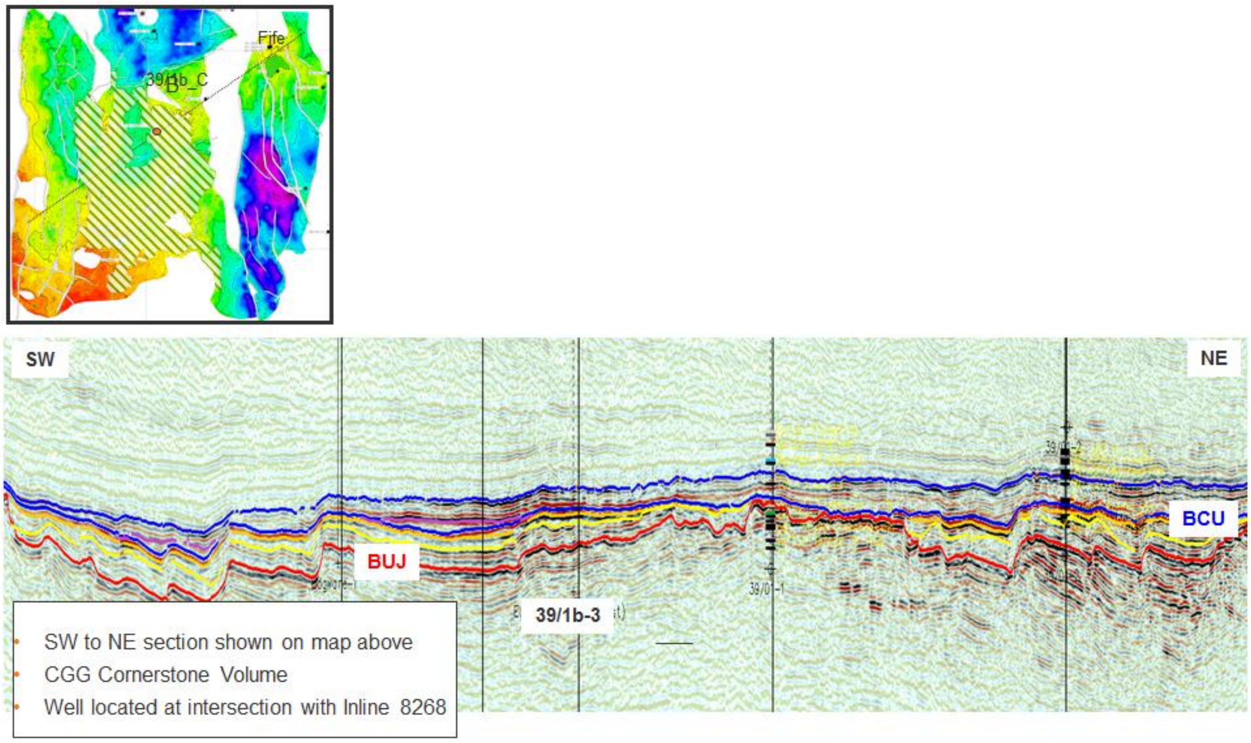
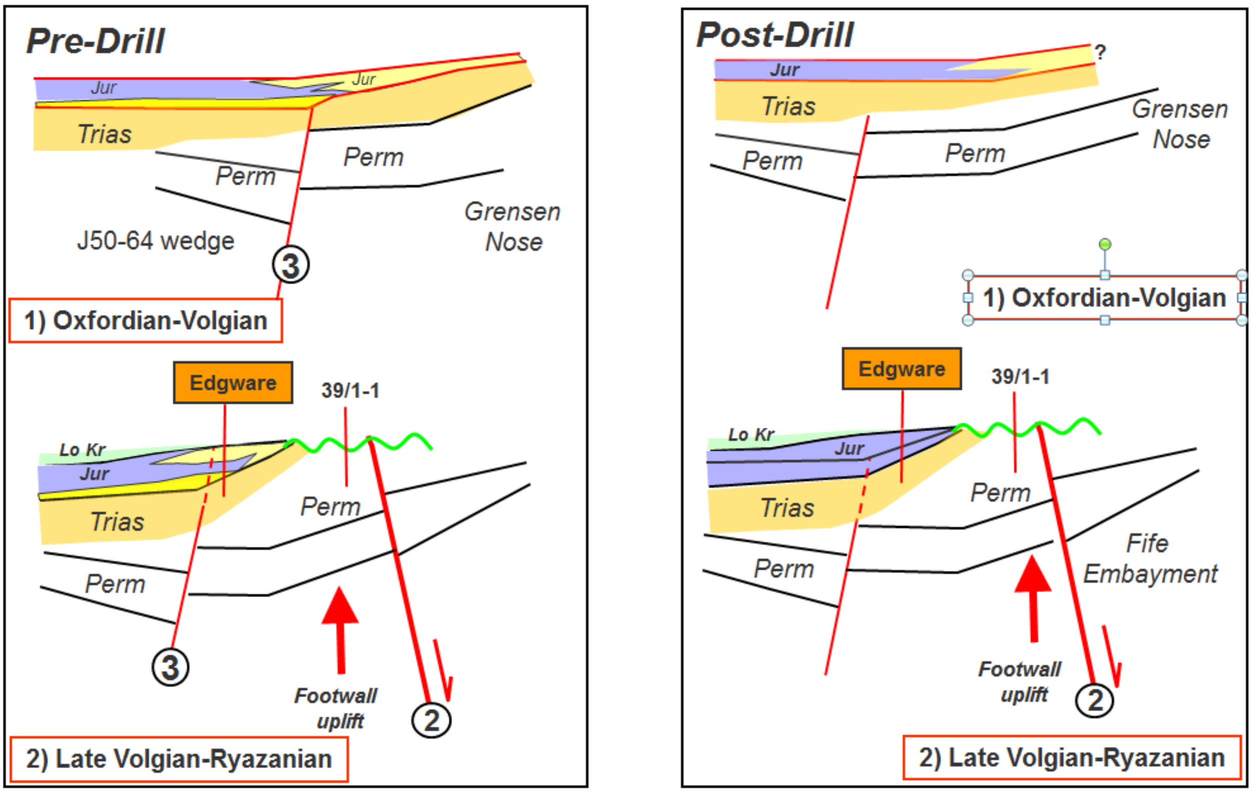


Fig. 131 – Edgware pre- versus post-drill comparison



3.66. Perenco: well 21/30-25, Spitfire prospect

The Spitfire prospect was targeting a stratigraphic trap in the Upper Tay Sandstone Member located between 2 non-economic discoveries (as per 2008) Evelyn and Belinda. This was formed by a detached sand body that was interpreted as shaling-out up-dip to where the Upper Tay interval is shale in Evelyn wells 21/30-12 and 21/30-16 to the west. There was a small 4-way dip closure where the sandstones appeared to be “mounded” in the seismic trace data, interpreted to be caused by a combination of depositional shape and post-depositional differential compaction (**Figs. 132 & 133**).

The Eocene (Tay Sand Formation was interpreted as an inter-salt dome ponded submarine channel and fan sandstones encased in shales from the Balder and Horda Formations and sourced from the Kimmeridge Clay Formation. Regionally, oil and gas charging occurred mainly by upward or long distance lateral migration. Extensive distribution of underlying Palaeocene sandstones has provided excellent regional lateral migration conduits. Migration from the Palaeocene into the Eocene is thought to have been facilitated via Miocene age faulting.

Pre-drill rock physics modelling on 4 neighbouring wells showed that oil and water signatures were similar; hence it was not used for pre-drill de-risking. A detailed pre-drill seismic stratigraphy study was done. Finally, the range of pre-drill resources was estimated using a single OWC scenario (= ODT in Belinda discovery) and all reservoir properties and hydrocarbon saturation were kept constant (except Net/Gross) in all P90, P50 and P10 scenarios.
The overall CoS was estimated at 25% with the trap geometry (45%) and the reservoir presence and quality (65% because Upper Tay was not present in Evelyn and Belinda) being the main pre-drill risks.
Well 21/30-25 found Tay Sandstone 39 feet low to prognosis and within expected error. Reservoir quality was at the high end of pre-drill expectation. It confirmed 12 feet oil leg seen on LWD but the contact was 196 feet shallow to prognosis.
The discovered resources were lower than the P90 pre-drill estimate showing that the trap was not as efficient as forecasted. The likely reason explaining this trap under filling is an imperfect bottom and/or lateral seal (**Fig. 134**). In addition it was incorrect to assume that Upper Tay sandstones in Spitfire were connected to Middle Tay sandstones in Belinda.

<u>Main lessons learned:</u>

- Given the petroleum context, this well could easily have been drilled again.
- The seismic stratigraphic approach, although interesting, lead to loss of the overall picture therefore to overestimating the pre-drill volumes.
- It is unclear whether improved seismic data would have been beneficial.
- This prospect description was too deterministic. Increased consideration of alternative scenarios should be the norm and each parameter should be given P90, P50, P10 values. There must also be several contact scenarios. It is also likely that there was a proper DHI which would have deserved a detailed analysis.
- Subject to cost reductions, both Evelyn and Belinda may become economic for the operator / production hub owner but for third party partners the big issue remains the cost of offtake.

Fig. 132 - Spitfire Prospect Montage **(Data courtesy of WesternGeco)**

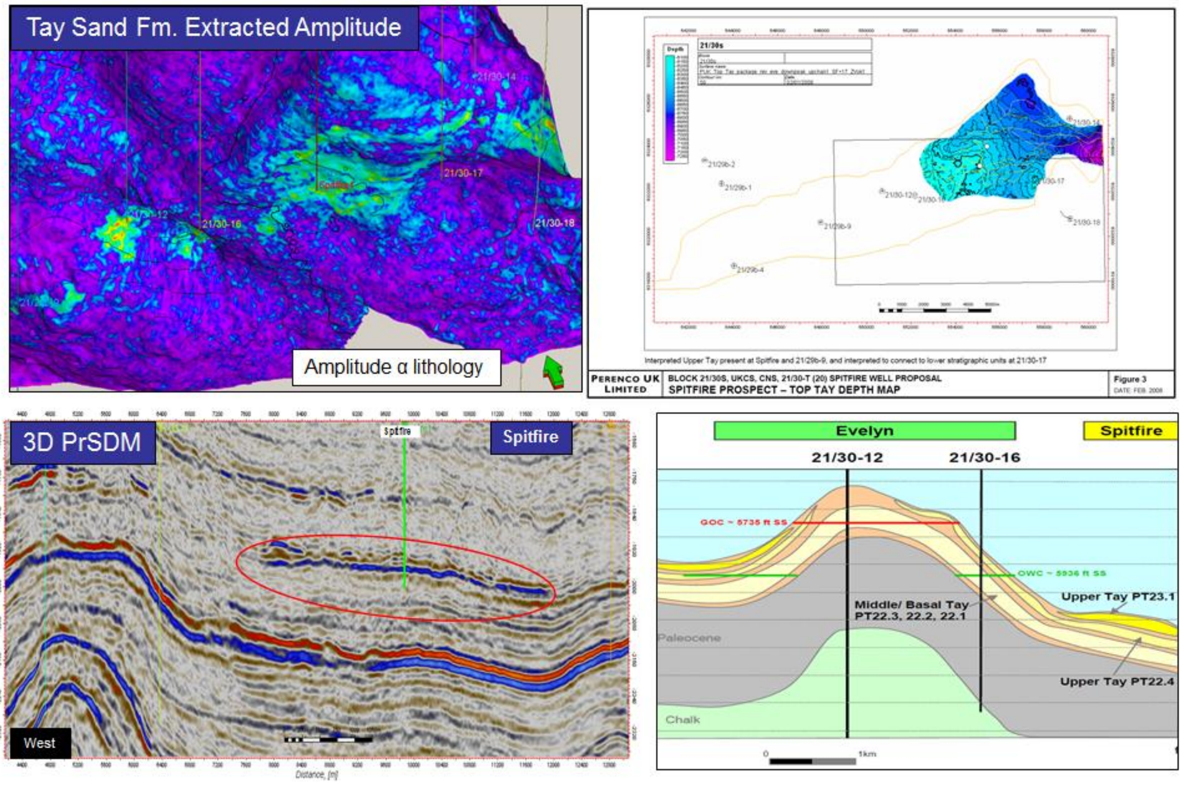


Fig. 133 – Arbitrary seismic lines connecting offset discovery wells **(Data courtesy of WesternGeco)**

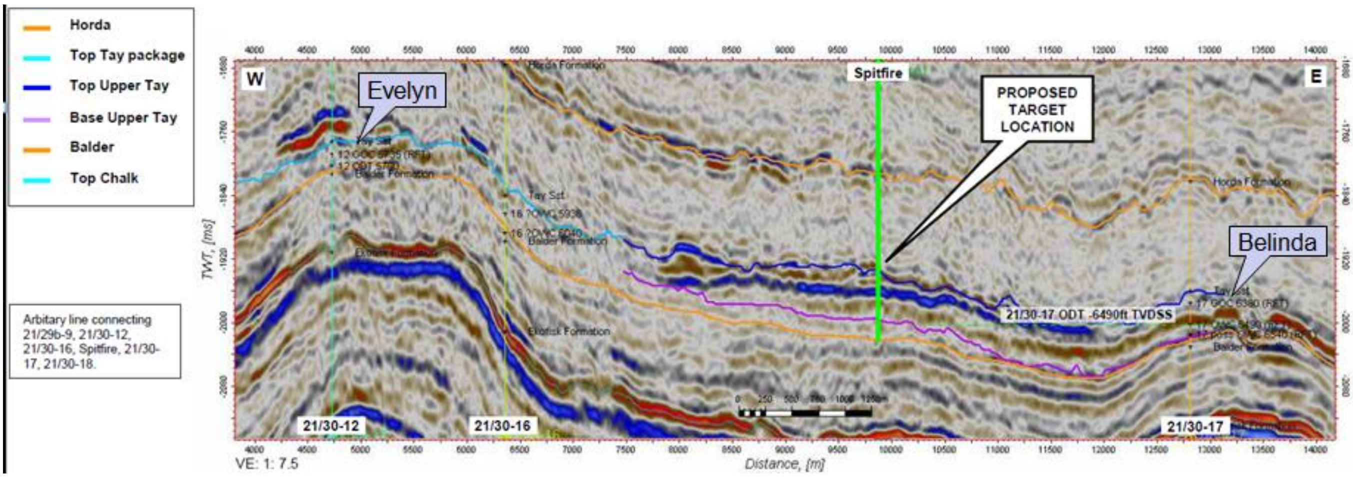
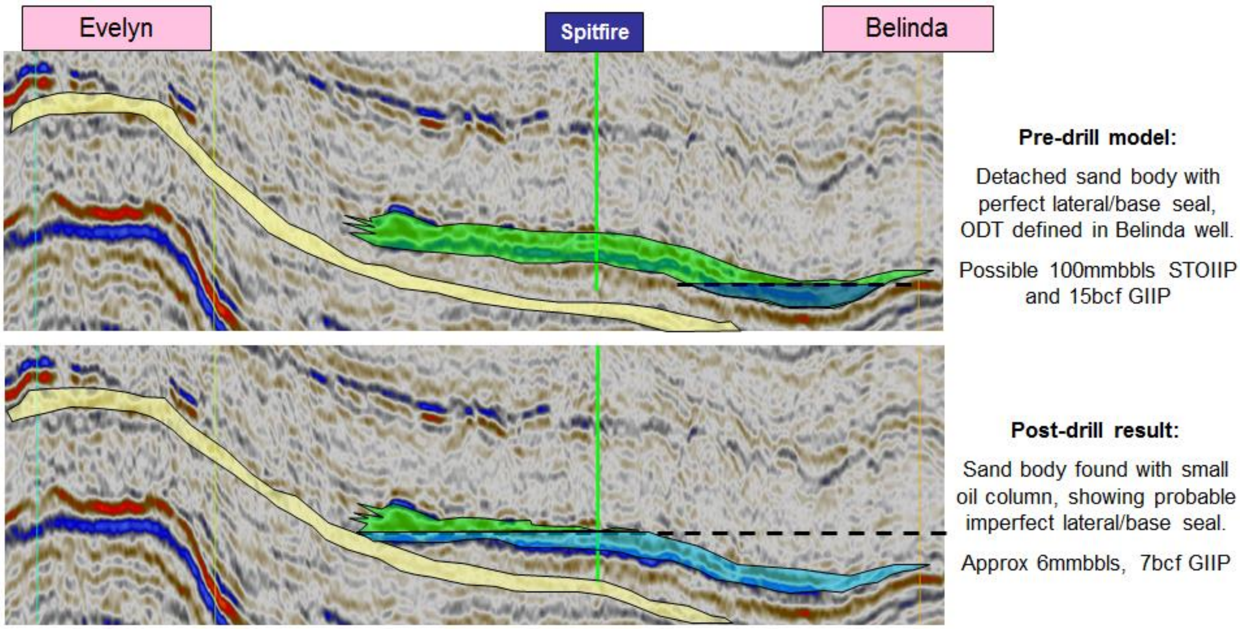


Fig. 134 – Spitfire: comparison pre-drill model versus post-drill results **(Data courtesy of WesternGeco)**



3.67. OilExco Operator, (Premier Oil current well owner): well 14/21a-1, Halibut prospect

The Halibut prospect was located in block 14/21a, adjacent to the north of the Halibut Horst. Faroe Petroleum farmed-out part of its interest to **OilExco North Sea** which drilled the well. Premier Oil is the current well owner. Most of the data reports have been provided thanks to Phil Ware from Faroe Petroleum.

The trap was a downthrown nose to the north of the Halibut Horst, with fault closure on the south flank and dip to the north. At Jurassic level, the structure is an E-W anticline with easterly plunge, and fault closure on the SW flank (**Figs. 135 & 136**). The primary objectives were the Upper Jurassic Piper and Claymore sandstones (seen at well 14/23-1) while Lower Cretaceous Scapa and Britannia sandstones (described at wells 13/19-3 and 13/24a-3 and -4) were secondary objectives. The Kimmeridge Clay was expected to seal the Jurassic sandstones while Lower Cretaceous shales and marls were supposed to seal the Britannia and Scapa sands. The mature Jurassic Kimmeridge Clay present within the Smith Bank Graben, some 19 miles (30 km) to the southwest across the Halibut Horst would have provided the source via long range migration. However, numerous gas effects were deemed present on seismic and related either to Carboniferous Coal Measures to the north or to Dinantian coals.

We could not find the overall CoS and the individual risking parameters. However, there appeared to be a high risk associated with migration of hydrocarbons, which were assumed to come for the most part from the mature Jurassic Kimmeridge Clay within the Smith Bank Graben. The overall risk was estimated as “moderate” by Faroe Petroleum in their farm-out presentation.

All tops below Chalk came in low to prognosis but within acceptable error margin. Thick good quality Upper Jurassic sandstones were present but no Lower Cretaceous sands. Upper Jurassic sandstones were thicker and had better porosity than expected but were water wet. 53 ft thick (TVT) Kimmeridge Clay Formation was encountered providing the top seal. However, the TOC and pyrolysis results are not typical of the Kimmeridge Clay Formation “Hot Shale”: the analysed interval is early mature for oil generation but has not reached the main oil stage. This suggests that samples have at best only fair hydrocarbon source potential to be realised at a higher level of maturity.

The main reason for failure is therefore interpreted as related to source rock maturity and migration. Indeed in situ source-rock seems to be not mature enough for oil generation. Long distance migration does not seem to be effective. In addition, it seems that lateral sealing to the south (Halibut horst granite) failed. As a matter of fact, Halibut Horst is a richer clastic source during Jurassic time which would likely increase the lateral seal issue to the south. By contrast, Halibut Horst does not appear to act as an effective clastic source during Lower Cretaceous times.

<u>Main lessons learned:</u>

- This well drilled in an under explored basin of the UKCS was supported by classical pre-drill G&G studies. As you would expect from such an under explored area, the well data were scarce and the seismic data, although being 3D was of fair quality.

Fig. 135 – Prospect "A"-Halibut, top Jurassic depth map

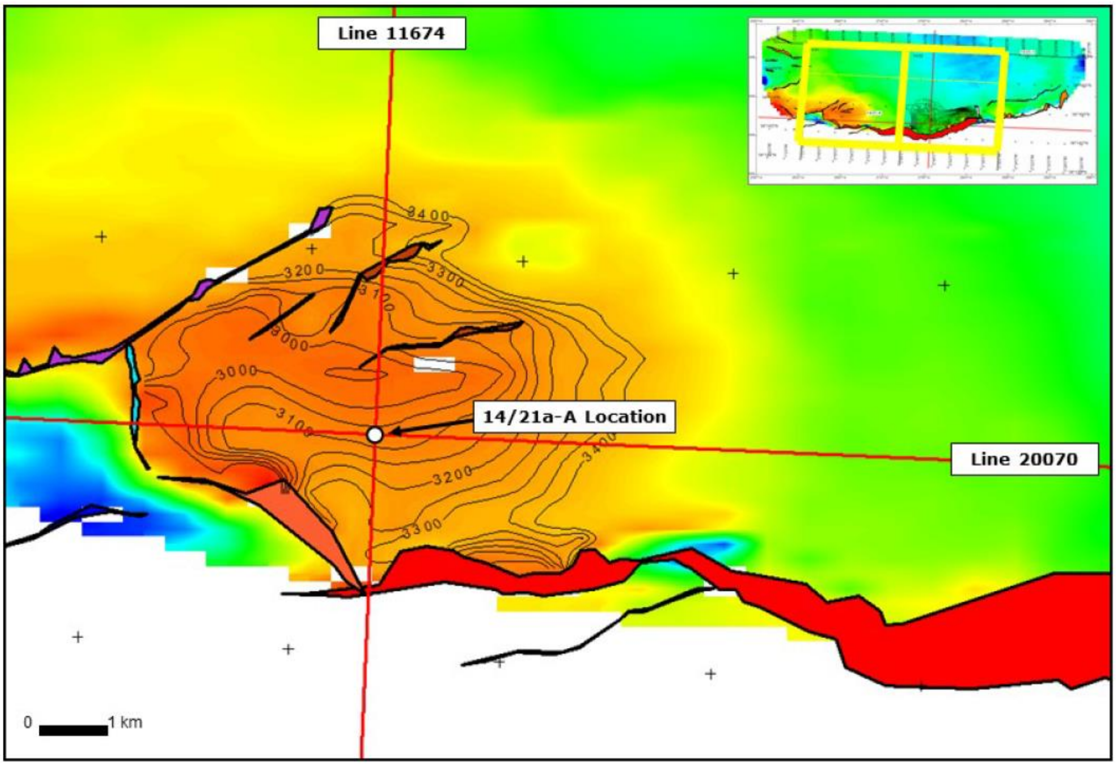
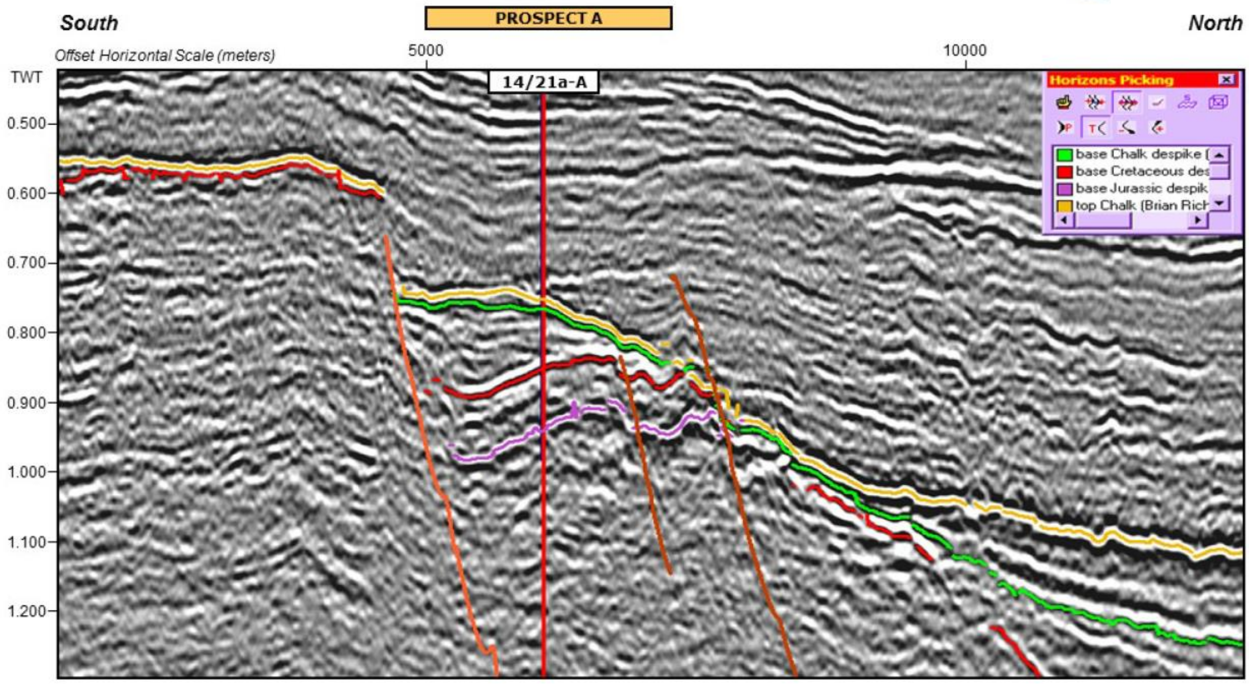


Fig. 136 - Prospect "A"-Halibut: north-south seismic line 11674 **(Data courtesy of PGS)**



3.68. OilExco Operator, (Premier Oil current well owner): well 14/28a-5 & -5Z, Laurel Valley prospect

This prospect located on 23rd and 24th Round licenses operated by Challenger Minerals was subsequently farmed into in 2006 by OilExco which drilled it prior to Premier's acquisition of their UKCS assets.

The Laurel Valley prospect was located in the Renee Graben in the Outer Moray Firth Basin in Block 14/28a. There were three targets identified at the planned well location: Kopervik, Birch and Piper Sands. The Lower Cretaceous Kopervik was expected to be a gas and condensate bearing sand. A second target was the Birch Sandstone in the Upper Jurassic prognosed oil bearing. The final target was the Lower Jurassic Piper sand.

The trap was a steep turbidite feeder paleo-canyon emanating from the SE corner of the Halibut Horst (**Fig. 137**). Deepwater sandstones of Lower Cretaceous age (Kopervik Formation) and Upper Jurassic age (Birch Formation) and shallow marine sandstones of Upper Jurassic age (Piper) were thought to pinch out northwards into the canyon head (**Fig. 138**). A stratigraphic trap at these three levels was thus set up with Upper Jurassic Kimmeridge clay acting as the source bed for oil into this trapping configuration. Each objective relied on its own top seal. There was no evident DHI; the OilExco model was simply that sandstones encountered by down dip wells must pinch out somewhere up dip.

The overall CoS was set at 6% for the Kopervik sandstones with the main pre-drill risks being seal, source and migration, all at 50%. For the Piper objective, the overall CoS was estimated at 18% and the main risk was the seal at 60%; however, none of the other risking parameters was estimated as certain and the risk was spread “all over the place”.

All main markers (Andrew sandstones and Piper sandstones) came in within reasonable error margin. The Kopervik Sandstone was not present but wet Scapa equivalent sandstone was encountered. Wet Birch and Piper sandstones were also encountered. Birch and Piper were found much thicker than expected with good petrophysical characteristics. Kimmeridge Clay at the well location (474 ft TVT), exhibiting excellent source potential but being very early mature (PRV = 0.5% ~ 8500ft).

The main reason for failure at Kopervik is clearly the lack of target reservoir. However, all 3 targets failed because either, there was no mature kitchen within the prospect fetch area and/or lateral sealing up dip towards the Halibut Horst was ineffective. A post-drill fluid inclusion study indicated that no significant HC have passed through this well.

<u>Main lessons learned:</u>

- A semi-regional basin modelling study would likely have highlighted a much higher risk regarding source and migration of this prospect. Reliable calibration points could have been brought into the overall assessment of the southern flank of the Halibut Horst.

Fig. 137 - Laurel Valley prospect: BCU (top Birch) depth map

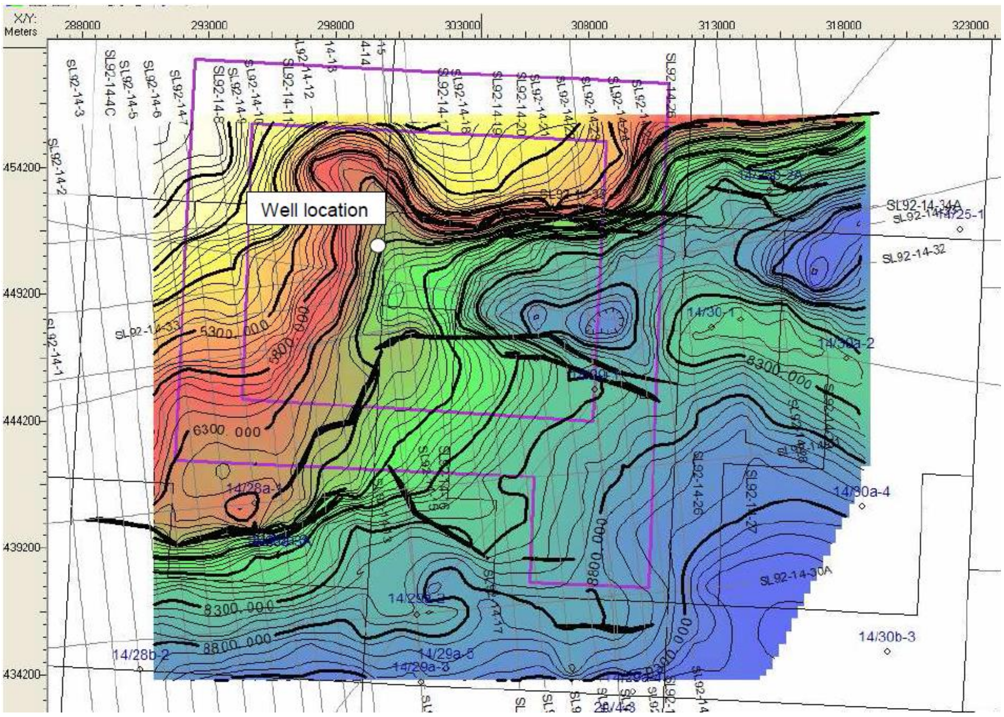
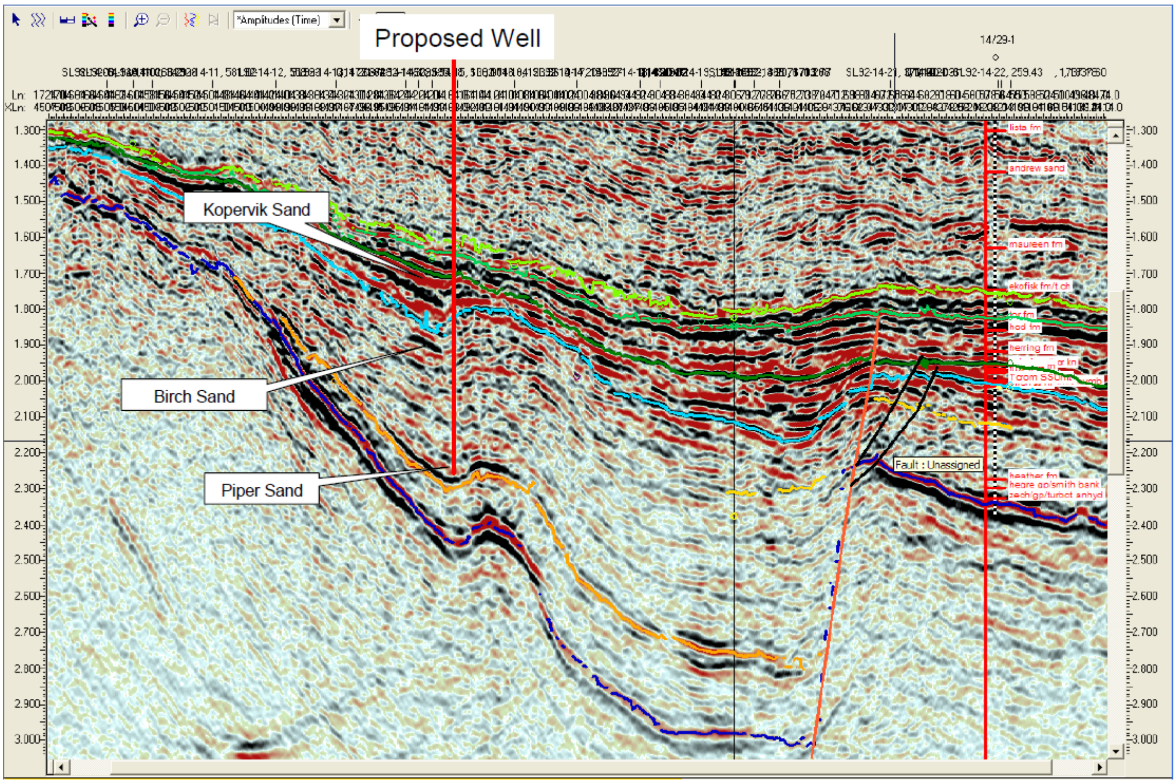


Fig. 138 - W-E seismic cross section across Laurel Valley prospect **(Data provenance uncertain: Nexen proprietary or Veritas i.e. CGG?)**



3.69. Premier Oil: well 15/24c-10, Bluebell prospect

The trap had both stratigraphic and structural elements, relying on facies variation to create a bird's foot anomaly which broadly conformed to the structure. However, apart from inconsequential tiny 4-way-dip closures due to minor top surface undulations there was no overall 4-way-dip component to the trap and Bluebell was drilled as a stratigraphic trap.

The target reservoir was a crevasse splay off the Forties sand fairway and had a far stack amplitude response that appeared anomalous. This was attributed to be due to hydrocarbon fluid by OilExco (due to the MuRho inversion). Premier's evaluation did not use the inversion as it found inputs and results to be suspicious compared to the observations from reflectivity and attributes. Compared to nearby producing fields that response at Bluebell on Premier's attributes was not the same as the observations from those producing fields; hence attributes were thought to represent lithology rather than hydrocarbons at Bluebell (**Fig. 139**). In fact, geophysical attributes and AVO modelling suggested that the 15/25a-4 well penetrated the lateral down-dip shale equivalent of a Forties sandstone crevasse splay with thin sandstones and potential oil shows.

A mud filled channel was interpreted to flank Bluebell to the west (**Fig. 140**). Both degradation of sand quality going westwards and mud filled channel system were expected to act as lateral seal setting up the stratigraphic trap. Forties Formation crevasse splay/channel sandstones were encased by Sele Formation claystones which provided both top and base seals. Production from similar aged sands, deposited in the same or parallel fairways with comparable geophysical signatures, is seen locally in the Brenda, McCulloch and Nicol Fields all being sourced by Kimmeridge Clay Formation.

The overall CoS was estimated at 34% with the key pre-drill geological risk on trapping mechanism.

All the key horizons came in within the error bars. Forties sand thickness is close to prognosis (45m versus P50 = 40m). Seismic attribute indicating sand presence appears valid. However, the reservoir is channelised with overbank rather than “true” crevasse splay, shows a much higher N:G (97% versus P50 = 65%) and is water wet. The Sele shales and Sele + Lista shales provided effective top and bottom seals.

The main reason for failure is interpreted as lack of lateral seal making the trapping mechanism ineffective: this was the critical risk and expected, given the ambiguous seismic attribute support. In addition, let’s keep in mind that Bluebell prospect had little geophysical support because of ambiguities between different DHI techniques which were reflected in Premier Oil internal seismic anomaly evaluation.

<u>Main lessons learned:</u>

- Similar MuRho seismic response to nearby Ptarmigan and Brenda fields was observed. However, reflectivity data did not show AVO behaviour comparable to rock physics modelling results, which suggested a brine filled reservoir. Given the difficulty to geologically explain the trap and the ambiguous seismic attribute support, Premier Oil decided to farm-out the 15/24c-10 contingent well. Without farm in from Canadian Overseas Petroleum UK Ltd (COPL), Premier would not have drilled this prospect.
- The MuRho anomaly was generated in the inversion process by the background model, possibly resulting of interpolating sparse well data across large areas.
- Another important learning is that the variation in overburden shale properties is equally important as reservoir properties when trying to understand AVO behavior.

Fig. 139 - Top Forties Mu-Rho Extraction showing well 15/25a-4 may not have tested the Bluebell prospect

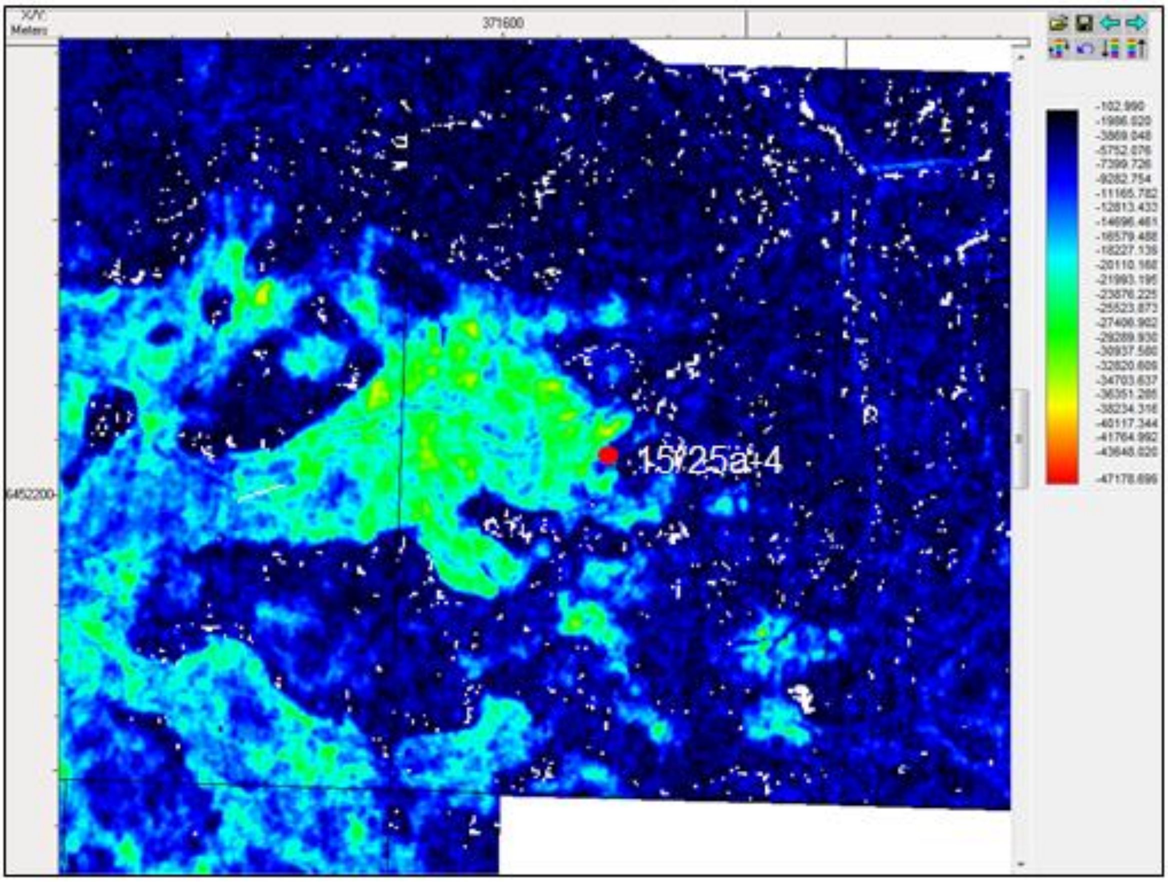
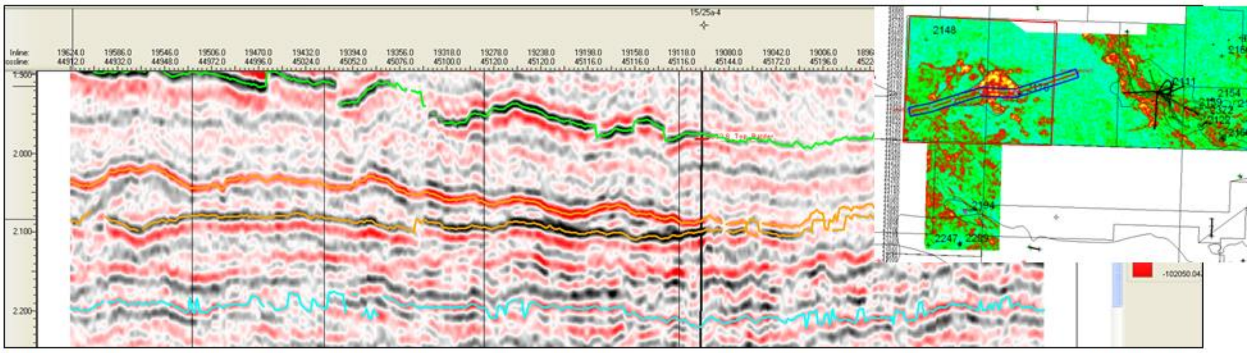
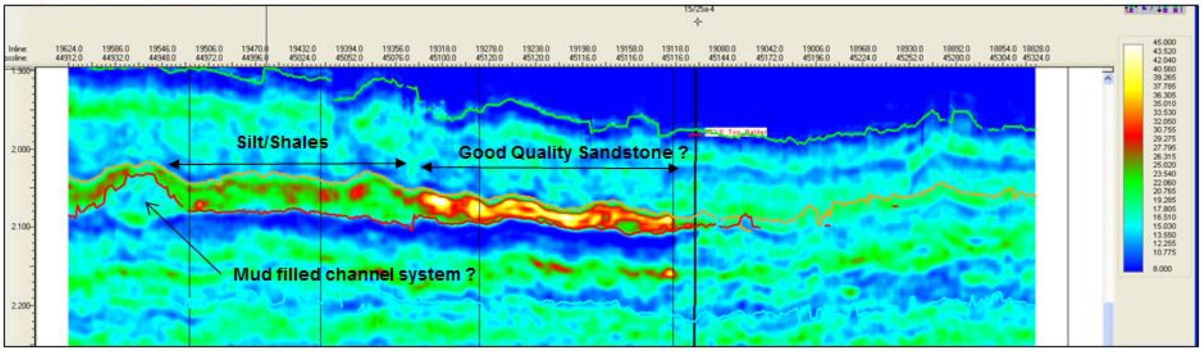


Fig. 140 – Bluebell trap definition. **(Veritas seismic data courtesy of CGG)**



Final migrated data, the base is picked along yellow reflector. If using the base channel system picked on final migrated data as base of the Bluebell prospect do not seal towards the NW.



MuRho data, the base picked along red reflector. Notice mud filled channel seperating Bluebell to the West. Both degradation of sand quality as going westwards and mudfilled channel system act as lateral seal setting up the stratigraphic trap

3.70. OilExco Operator, (Premier Oil current well owner): well 15/25b-7, Sheryl prospect

Firm commitment well 15/25b-7 was drilled by OilExco prior to Premier's acquisition of their UKCS assets to assess the potential of a well-defined small structural 4-way closure located immediately north of the Brenda field (**Fig. 141**). The target reservoirs were Forties sandstones (1st objective) and Balmoral (2nd objective) sandstones sourced by the Kimmeridge Clay Formation. Top seal was provided by Lista and Sele shales.

It was quite difficult to find all the necessary information to perform an in depth post well analysis as limited data are available via CDA and Premier Oil doesn't have OilExco background material from the prospect.

It seems that the Sheryl prospect was defined on a Veritas 3D which was pre-processed to preserve amplitudes allowing for AVO and SRME. The final product was Pre-Stack Depth Migration. In addition, a rock physics modelling (elastic inversion) may have been carried out (**Fig. 142**). OilExco highlights an "impedance indicator" supporting the prospect but no more data were found about it.

No information was available about the overall CoS and the Sheryl prospect risking.

All main markers came in within + / - 60 ft error bars and it is likely that the 4-way dip closure is valid in time. Thick Balmoral reservoir was present, but water wet and an effective top seal was found corresponding to more than 1000 ft of shales belonging to Sele Formation, Balder Formation and Belton Member. Given the 3.3 ft oil column discovered in side-track 15/25b-7Z, it is assumed that source rock and migration / timing would also be effective for the Sheryl prospect.

As a consequence, the main reason for failure is interpreted to be related to the closure in depth: is the 4-way dip area still closed in depth? Or was the drilled just outside the closure in depth? Oilexco has a different interpretation stating that oil escaped during Miocene, but as they did not perform any fluid inclusion study it's impossible to prove it.

Main lessons learned:

- Both pre-drill and post-drill well data should have been requested in due times and safely stored so that it could be shared amidst the UK geoscientists community.

Fig. 141 - Sheryl prospect Top "Sand 1" time map

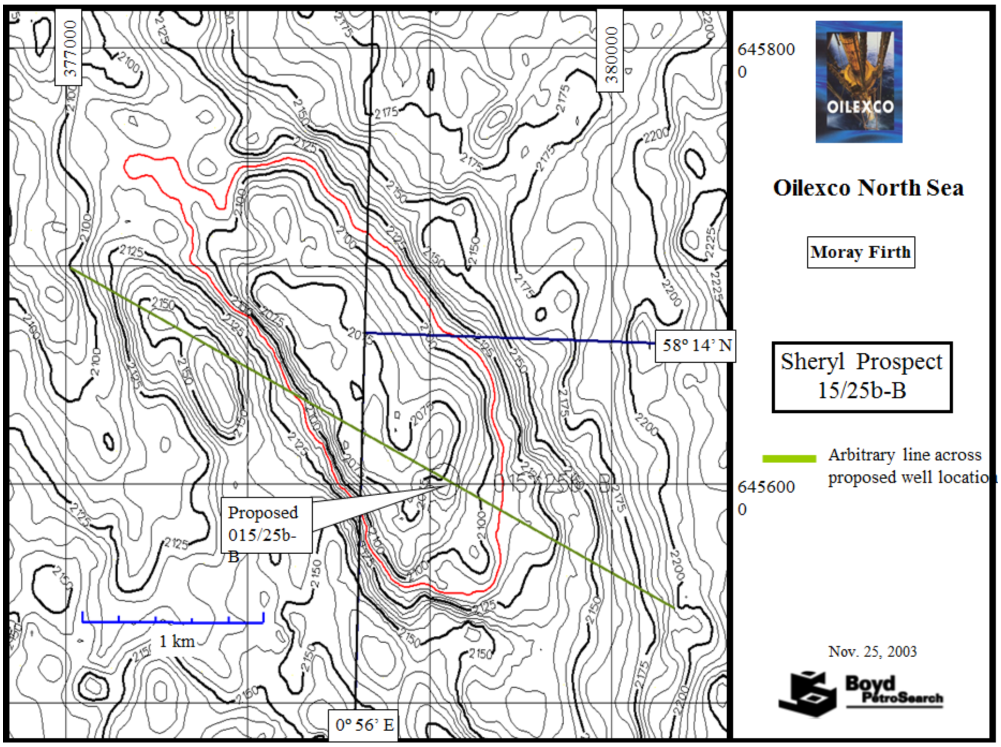
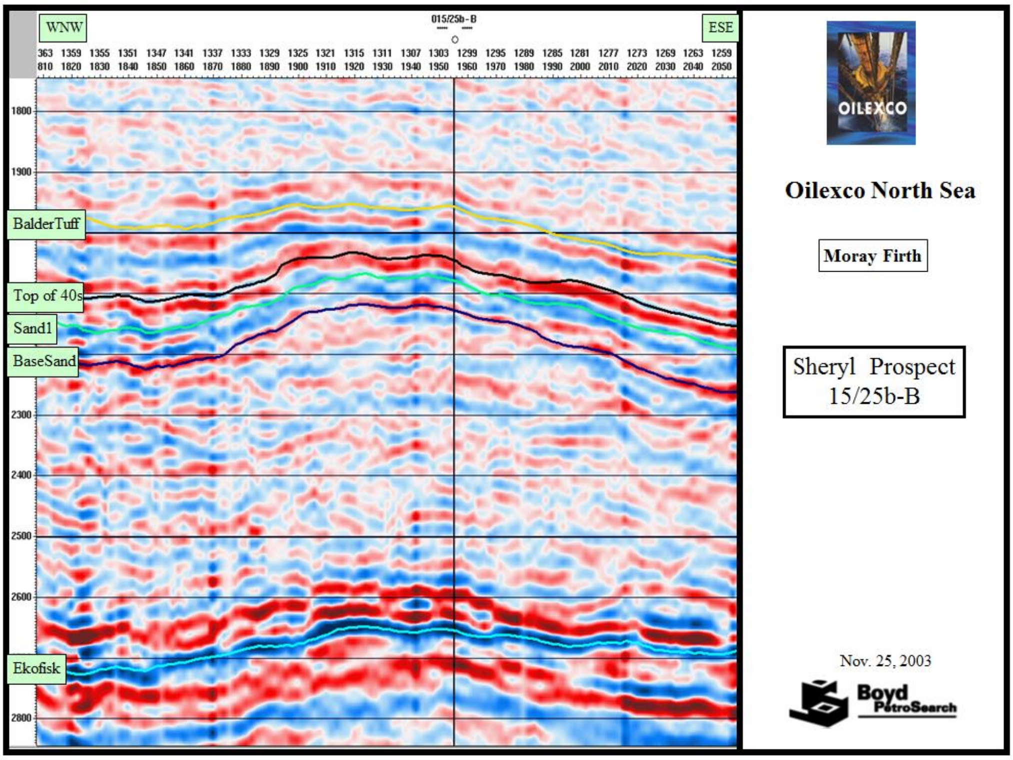


Fig. 142 - WNW-ESE arbitrary seismic line across Sheryl **(Data courtesy of CGG)**



3.71. OilExco Operator, (Premier Oil current well owner): well 15/25b-7Z, "Sheryl 2nd target"

This well was a side-track from mother well 15/25b-7 described above. Despite being also called Sheryl, it was in fact targeting a nearby seismic 'bright spot' on the northeast edge of the Brenda discovery: indeed OilExco tended to name wells rather than prospects so #6 was Brenda, # 7 was Sheryl…etc….

This well targeted a stratigraphic trap corresponding to a channel sand feature "whose prospectivity was indicated by an anomalously low elastic impedance response on the far offset stack". It was an appraisal to the north of the Brenda field. All other prospect characteristics were the same as for Sheryl prospect proper. The available data was in the same poor and limited state as Sheryl: according to Premier Oil operations geologist, "the -6 and -7 wells were drilled when Oilexco was a couple of people, so as far as I know, there is no real Subsurface data available…"

Well 15/25b-7Z found a 3 feet HC column and was P&A. Thick Balmoral reservoir was present with clear OWC and according to a detailed mapping exercise (courtesy of Ron Parr, BP) it seems to strike right on the OWC of Brenda. It is unclear if the aim of this side-track was to determine Brenda's OWC (hence this was successful) or if OilExco was searching for additional resources. In the second scenario, the well probably failed because of a limited lateral seal.

3.72. OilExco Operator, (Premier Oil current well owner): well 15/25c-14, Joy prospect

The post well analysis of well 15/25c-14 could not be performed because of an even greater lack of data compare to the above described 15/25b-7 and -7Z penetrations.

3.73. Apache Operator, (Premier Oil current well owner): well 18/5-2, Golden Arrow prospect

Well 18/5-2 was drilled by **Apache North Sea** and most of the information was kindly provided by Ron Roberts. This well is currently owned by Premier Oil.

The Golden Arrow prospect was a compaction mounded feature at the stratigraphic pinch-out margin of the Upper Jurassic Burns Sandstone i.e. at the up dip pinch out of turbidite channel system (**Fig. 143**). When A. Booth and G. Dore set up their new company ENCORE they defined the prospect as the "Buzzard look-alike in the Banff Basin". The sequence pinch-out was well defined but it was on 2D data. The target reservoir was the Burns intra Kimmeridge Clay turbidite sandstones within a well-defined compaction drape (**Fig. 144**). Burns reservoir is present with reasonable quality down dip.

Golden arrow sealing mechanism was complex. Detachment of a channel to the SW was critical to success and regarded as moderate risk on moderate data. There was also some risk on base seal if the channel was erosive and cut into older systems that connect back to the SW. Top seal may also have been compromised by overlying Cretaceous Punt sandstones.

Kimmeridge clay was the assumed source rock and no risk was seen on timing. Moderate risk was interpreted for an effective migration pathway due to light brown oil stains in intra-Kimmeridge sandstones having been observed in well 19/2-1 (85%).

Overall CoS was estimated at 17%, seal being by far and large the main pre-drill risk (35%) followed by the trap reliability (70%).

Stratigraphic succession came in close to prognosis below base Chalk but all main markers came in between 78 and 286m deep to prognosis. It remains difficult to say whether this was due to a wrong time-depth conversion or poor picking? Burns sandstones came in 94m deep to prognosis, much thicker than expected (115m vs P50 = 17m) and water wet. No hydrocarbon shows were observed in either Burns or Punt Sandstones. Top seal were respectively Valhall claystones for Punt and 26m thick Kimmeridge Clay Formation for Burns. Regarding the base seal, Kimmeridge Clay was as expected for the Punt sandstones but Middle siltstone Unit (126 m thick) provided a poor quality sealing for Burns.

The main reason for failure is interpreted as a lack of seal: given Burns thickness at well 18/5-2 the pinch-out may be far up dip? There is also very likely an up dip seal failure with thief sandstones bleeding oil to surface making the trap ineffective.

<u>Main lessons learned:</u>

- Would a 3D acquisition + rock physics have prevented drilling this well?
- The secondary target Punt Sandstone was poorly imaged on seismic, hence the seal risk and reserves estimates were poorly constrained.
- No wireline logging programme was carried out at TD.
- A fluid inclusion study would have ascertained the migration effectiveness.

Fig. 143 – Golden Arrow prospect definition

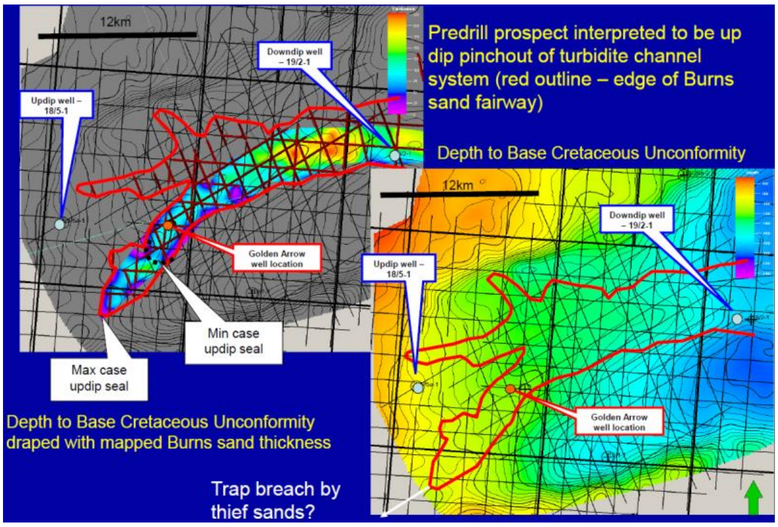
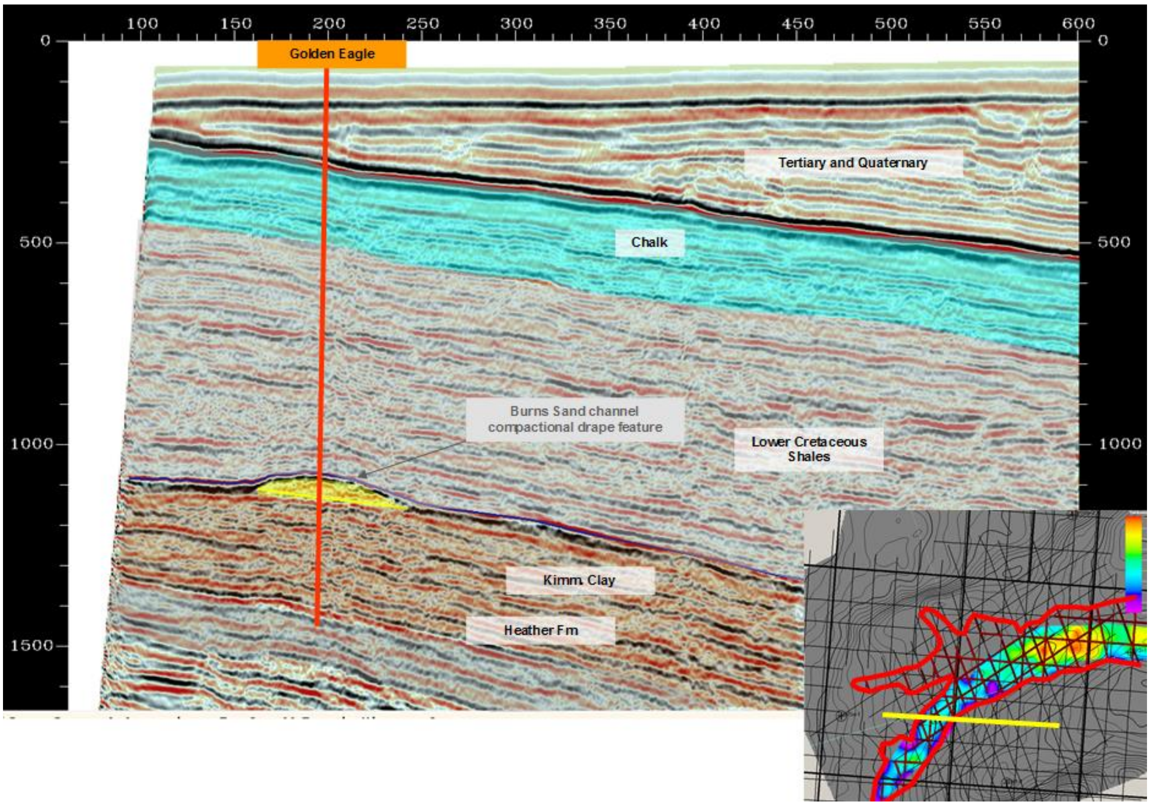


Fig. 144 - E-W seismic line A-18-19-82-25 through Golden Arrow well location **(Data provenance uncertain: BP or WesternGeco?)**



3.74. Premier Oil: well 20/10b-5, Criollo prospect

The Criollo prospect was a stratigraphic trap in the Esk Trough, with structural dip to the east and pinch-out of sandstones to the north, west and south (**Fig. 145**). The Jurassic/Cretaceous package pinched out up dip (westwards), giving the potential for stratigraphic trapping. The analogue was Buzzard, 55 Km to the northwest (**Fig. 146**).

The target was Volgian Peterhead Formation sandstones, sourced from the Peterhead Ridge; these sandstones were not encountered in the up dip 20/10-2 well. The reservoirs were expected to have been deep water turbidite and grain flow sandstones forming amalgamated submarine channels and lobe complexes. These sandstones were believed to pinch-out on the western flank of the Esk Trough. High magnitude seismic amplitude trend supported sands presence in the Volgian section: amplitudes were calibrated to represent the greater impedance contrast between sandstones and shales within the Humber Group (**Fig. 147**).

The secondary objective reservoirs were shallow marine Fulmar Formation sandstones and, if present, were expected to be of Upper Oxfordian age. Over 600 feet of Volgian to Lower Ryazanian age shales of the Kimmeridge Clay Formation were expected to provide a good top seal at the Criollo prospect. Lateral seal was expected to be provided by juxtaposition of the reservoir against Heather shales or directly against shales of the Triassic Smith Bank Formation. Geochemical study indicated very rich Kimmeridge Clay and the volume of mature source rock was deemed large enough within trap drainage area. Maturity and migration were deemed favourable even though a moderate risk of Criollo being in a "shadow zone" was interpreted because of uncertain pathway along carrier beds from mature source rock to trap.

The overall CoS was set at 18% and the key pre-drill geological risks were the seal (48%, especially the base and lateral seals) and the reservoir (mostly presence = 55% and quality = 90%).

The 20/10b-5 well did not encounter any Volgian sandstones proving the pre-drill amplitude interpretation was wrong. It did encounter an 82 feet water-bearing Fulmar section directly overlying Triassic Skagerrak sandstones. Both Fulmar and Skagerrak sandstones were water wet and no HC shows have been recorded.

The main reason for failure was clearly the absence of target reservoir. The amplitude interpretation supporting sand presence was wrong. As no shows have been observed in the sandy intervals, one can also wonder if there was a lack of migration pathway up to this end of the Esk Trough.

<u>Main lessons learned:</u>

- There was likely no sand sourced from the Peterhead Ridge into the Esk trough during Volgian.

Fig. 145 – West-East geological cross section illustrating the Criollo prospect

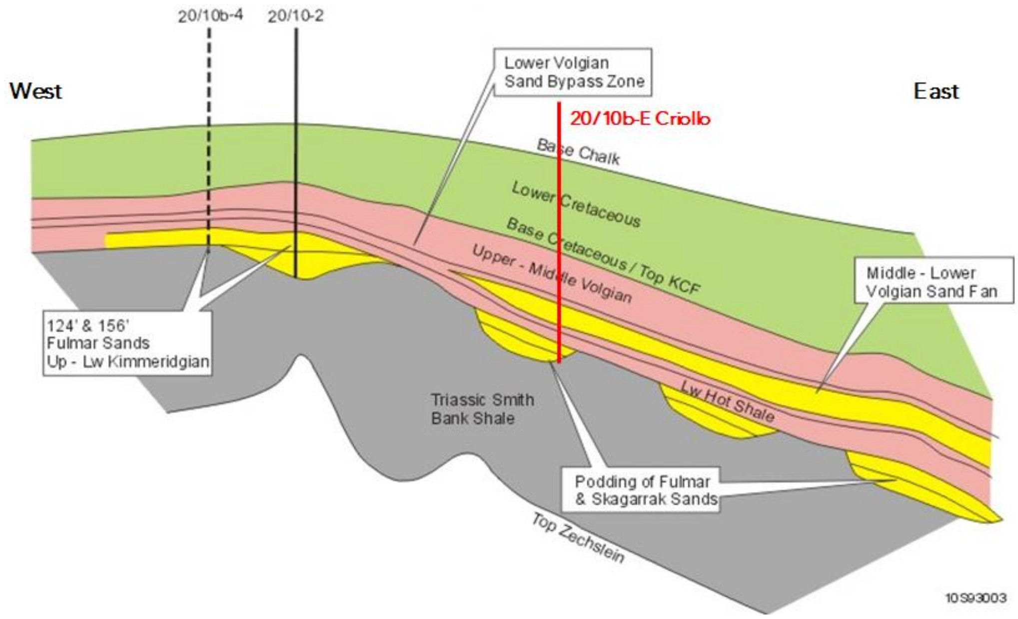


Fig. 146 – Top Volgian fan depth map

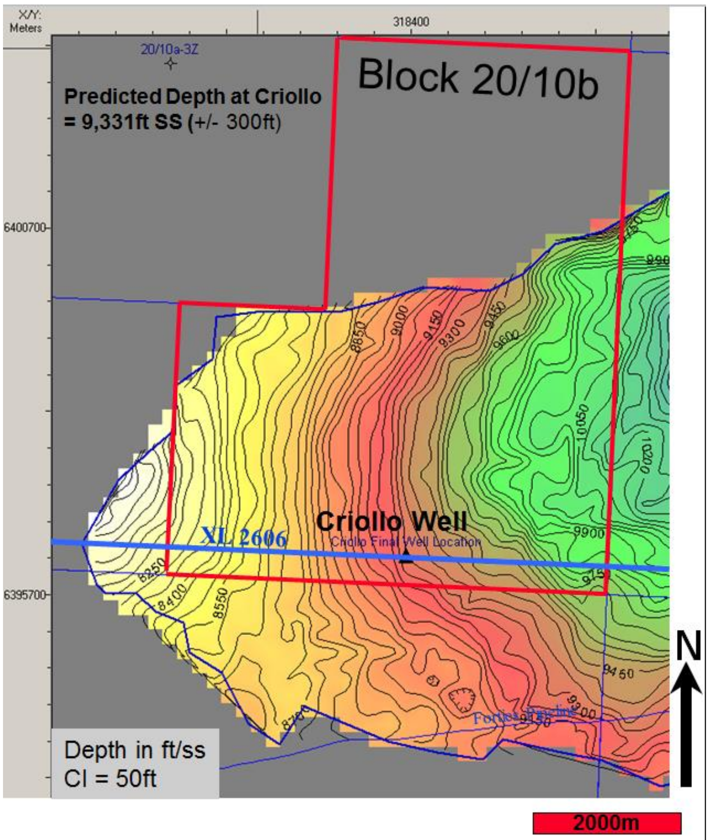
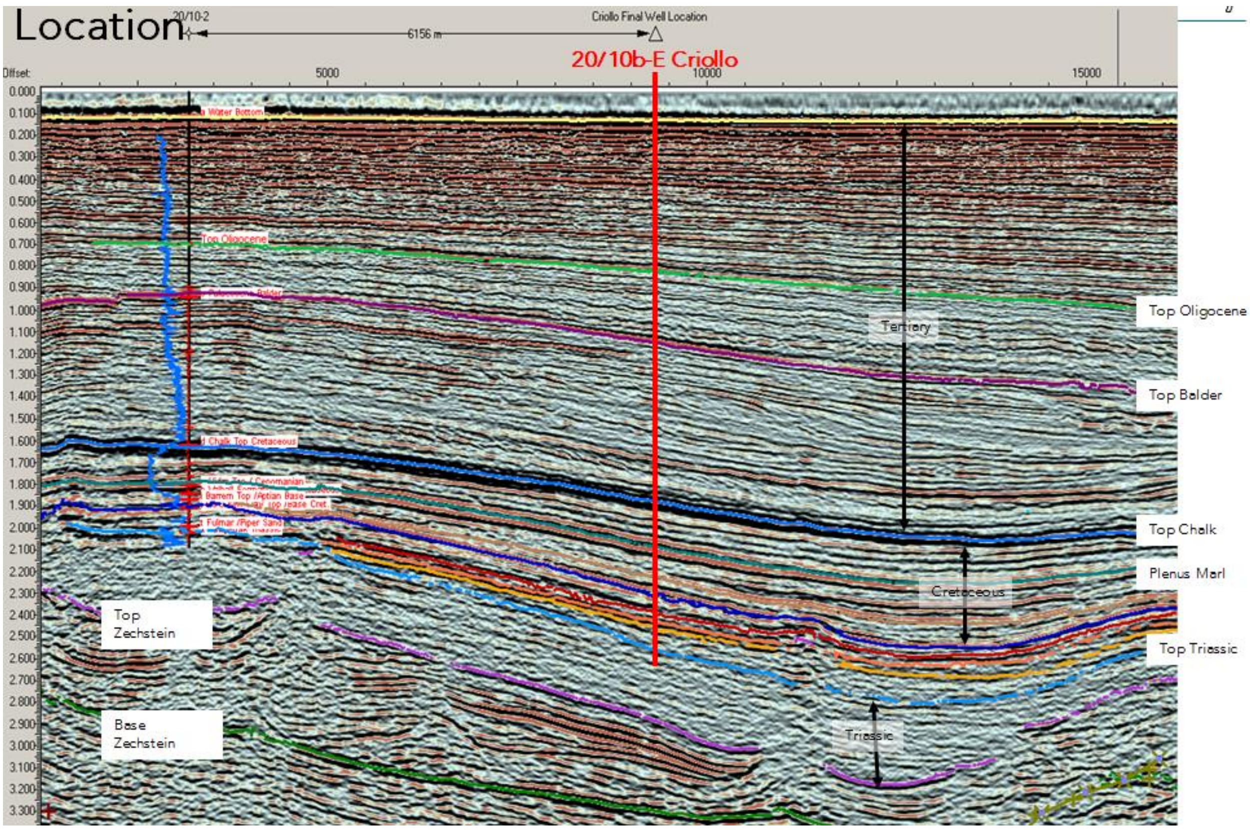


Fig. 147 – 20/10b-5 Criollo: Crossline 2606 through well (Data Amerada Hess proprietary)



3.75. OilExco Operator, (Premier Oil current well owner): well 21/4b-6, Muness prospect

The aim of well 21/4b-6 was to explore the proven Kopervik trend, a ribbon of high quality sand largely sourced from west in Aptian-Albian times, and extending the fairway 1 block east from the Brodgar discovery. This play is difficult to explore for directly due to interference from base Chalk and lack of acoustic impedance (AI) contrast.

Well 21/4b-06 was drilled by **OilExco farminee and well operator** on **license P1104 operated by Kerr McGee** which, later on, had been purchased by Maersk Oil. The current well owner is Premier Oil. Most of the prospect information had been provided by John Colleran from Maersk Oil, while a useful workshop with Ron Parr (BP) discussed the reason for failure.

Muness was a large stratigraphic trap with similarities to other Kopervik fields with a stratigraphic component, i.e. pinch-out edges to the north, west and south (onlaps on Rattray volcanics). It was dip closed to the south-east (**Fig. 148**). Uncertainty existed regarding the extent of the intervening structural high between Brodgar and Muness.

Top and bottom seals corresponded to Lower Cretaceous mud rocks. It was interpreted that there was high chance of lateral seal to north on Rattray based on several Lower Cretaceous analogue fields. The main risk was lateral seal especially onto the structural high to the west. Source rock was expected to be Kimmeridge Clay Formation belonging to a separate source kitchen from adjacent accumulations. The expected fluid was very likely gas or gas / condensate. Wells 21/4-1 & -2 were believed to be on migration route.

The overall CoS was estimated at 27% and the main pre-drill risk was the lateral seal (at 45%). A secondary risk was the reservoir presence (75%). HC migration was interpreted as certain (100%).

Well 21/4b-6 found Kopervik sandstones at -11,328 feet TVDSS versus prognosed depth at -11,443 feet TVDSS). Gross Kopervik interval was 372feet (prognosed 576 feet) with good characteristics (N:G of 64% , average porosity of 16% but no shows & no flow. Top seal was provided by 520 feet TVT claystones from Rodby + Sola Fms while base seal corresponded to more than 180 feet of claystones from Valhall Formation (> 180 feet TVT as TD in Valhall Formation).

The main reason for failure is interpreted to be the lack of lateral seal as seismic shows sandy fairway all the way up to Brodgar: we can wonder where is the pinch-out edge to the west? In addition, migration pathways seem more complicated than expected: Muness should mostly rely on the eastern kitchen but is located at the very end of a shallower and narrow syncline. It should also be noted that it was drilled on a pre-drill small 4-way dip closure which does not exist anymore on the post drill mapping (Maersk, Top Apto-Albian sandstones depth map, May 2007).

<u>Main lessons learned:</u>

- The pre-drill picking of base target reservoir looks questionable: the ultimate onlap may be right onto the BCU (**Fig. 149**), changing the bottom seal prognosis at the very edge of the interpreted pinch-out.
- A pre-drill detailed basin analysis may have helped understanding if Muness is in a shadow migration route.
- A post-drill FIS study would have ascertain if there was HC migrating through Muness.

Fig. 148 - Muness Prospect: Kopervik Gross Sand Isochore with Top Kopervik Contour Overlay

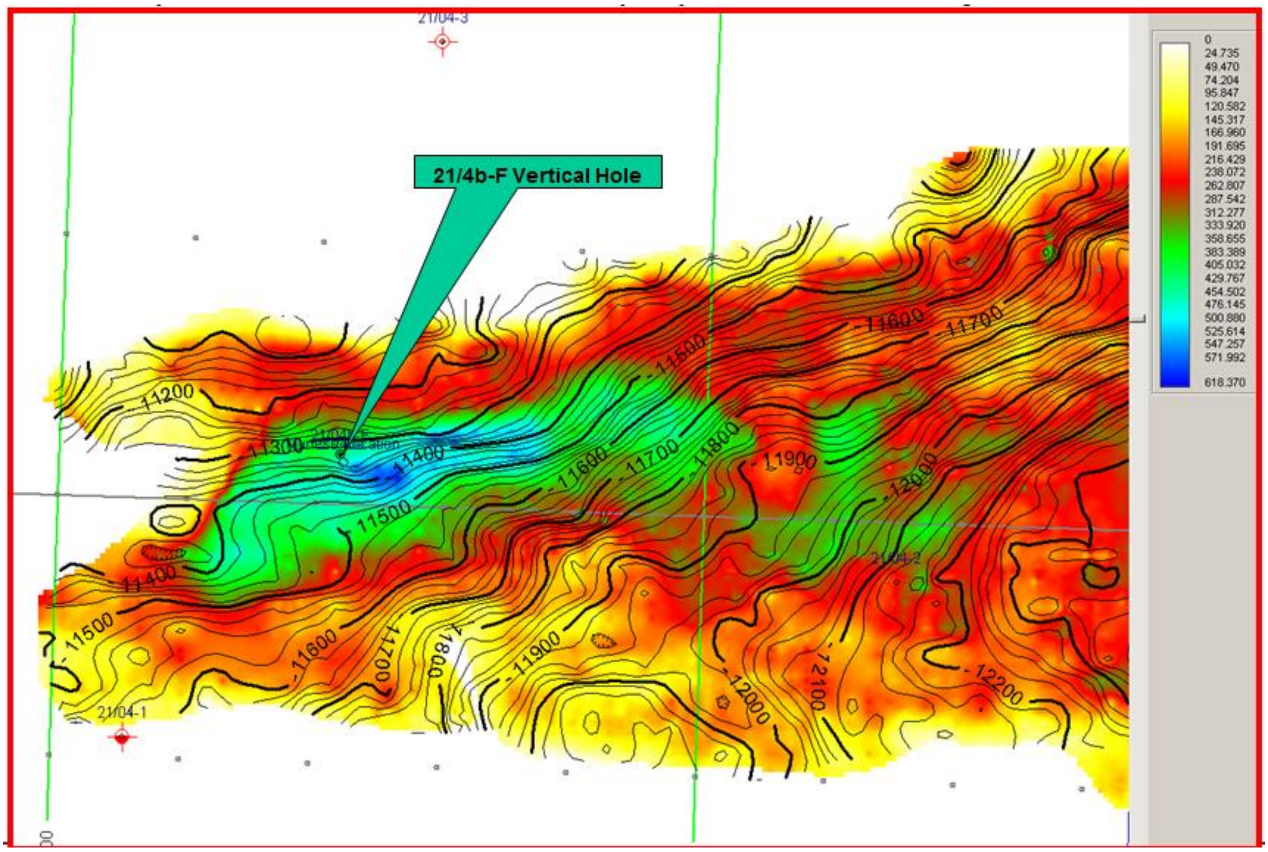
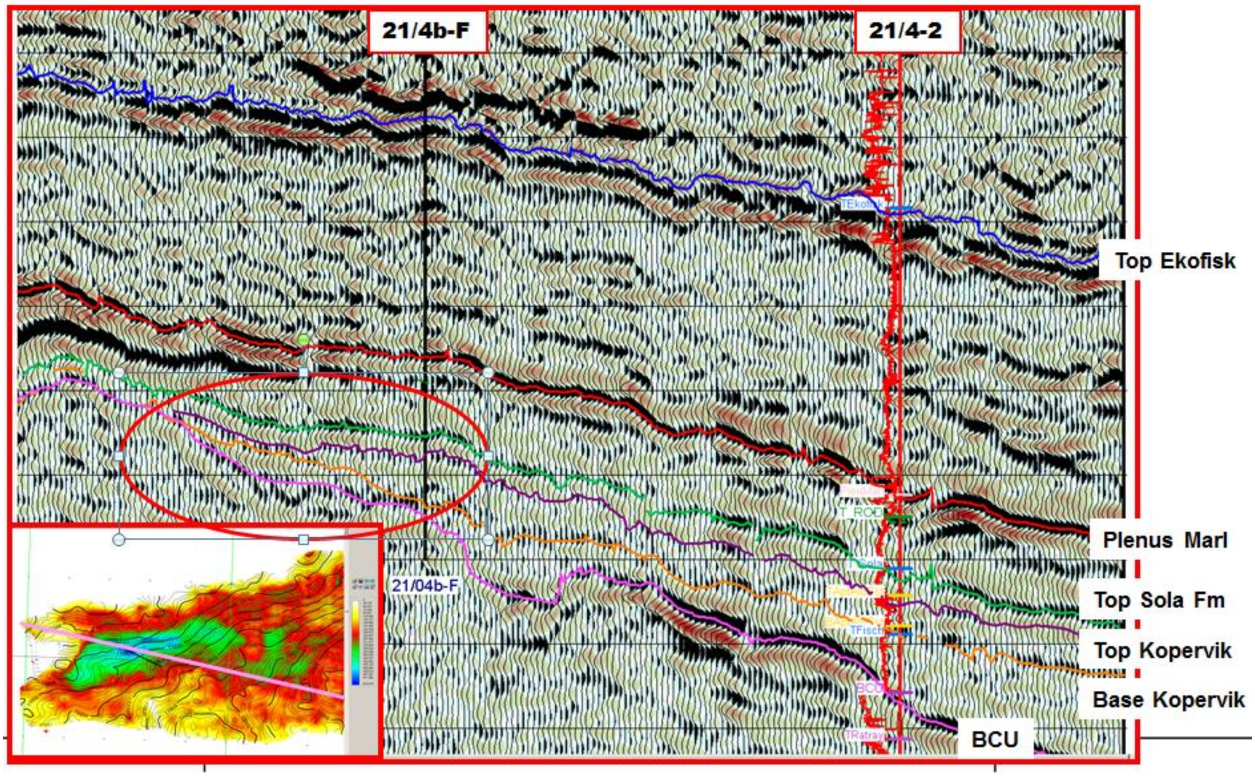


Fig. 149 - Seismic Traverse from proposed exploration well 21/4b-F to well 21/4b-2 **(Data provenance uncertain: Nexen, ConocoPhillips or PGS?)**



3.76. Premier Oil: well 21/6a-7, Palomino prospect

Oilexco North Sea Ltd farmed in to Palomino (21/6a-7) via 2:1 carry on Premier's interest. Palomino lies at the eastern end of the Esk trough. Palomino was a 4 way dip-closed structure with stratigraphic upside targeting reservoir objectives in Jurassic Fulmar and Triassic Skagerrak sandstones draped over a salt diapir. The interpretation envisaged Fulmar sandstones draped over the Palomino salt high, pinching out to the north (**Fig. 150**). Thin (8 feet) Piper Sandstones had oil shows in well 21/6b-4 only a couple of kilometres to the north, so migration could have occurred if carrier sands had been present. The southern culmination (Palomino South) was deemed higher risk (**Figs. 151 & 152**).

Kimmeridge Clay Formation was the inferred source rock as well as the top seal which was unlikely to be breached. Triassic Smith Bank Formation was interpreted to be the bottom seal. A risk of older thief sandstones up dip (= 80%) was identified. Pre-drill geochemical study indicated very rich Kimmeridge Clay Formation. Top oil window was estimated at 9000ft and no problem with volume of mature source rock within trap fetch area was forecast. Sourcing being from east and west kitchen areas favourable migration pathways and timing had been anticipated.

The overall CoS was set at 25% and the main pre-drill risks were the reservoir presence (50%) followed to a lesser degree by the trap geometry (70%) and the seal (80%).

Well 21/6a-7 found tops of Balder, Chalk, Kimmeridge Clay and Triassic Smith Bank within error bars. However, Fulmar and Skagerrak sandstones were absent. Instead there was a thin and wet sandstone unit of approximately 15 to 20 feet in thickness belonging to the Heather Formation. The Smith Bank strata were encountered higher than anticipated, maybe because of early salt movements. The Fulmar may not have been deposited on this paleo high. Despite a thick Kimmeridge Clay being present at well location (458 feet TVT), there was no show at all in the Heather sand.

The main reason for failure is clearly the lack of target reservoir. However as there are no shows in the thin Heather sands, migration may have been an additional issue.

<u>Main lessons learned:</u>

- The absence of Fulmar sandstones may be because of early salt movements (paleo-high and / or erosion) but possibly also, because no sandstones were sourced into the Esk Trough at Upper Jurassic times in this particular location.
- According to Oilexco and Premier Oil seismic well tie and remapping, Palomino would have been drilled off structure but the migration pathways may be an issue.

Fig. 150 - Palomino prospect model

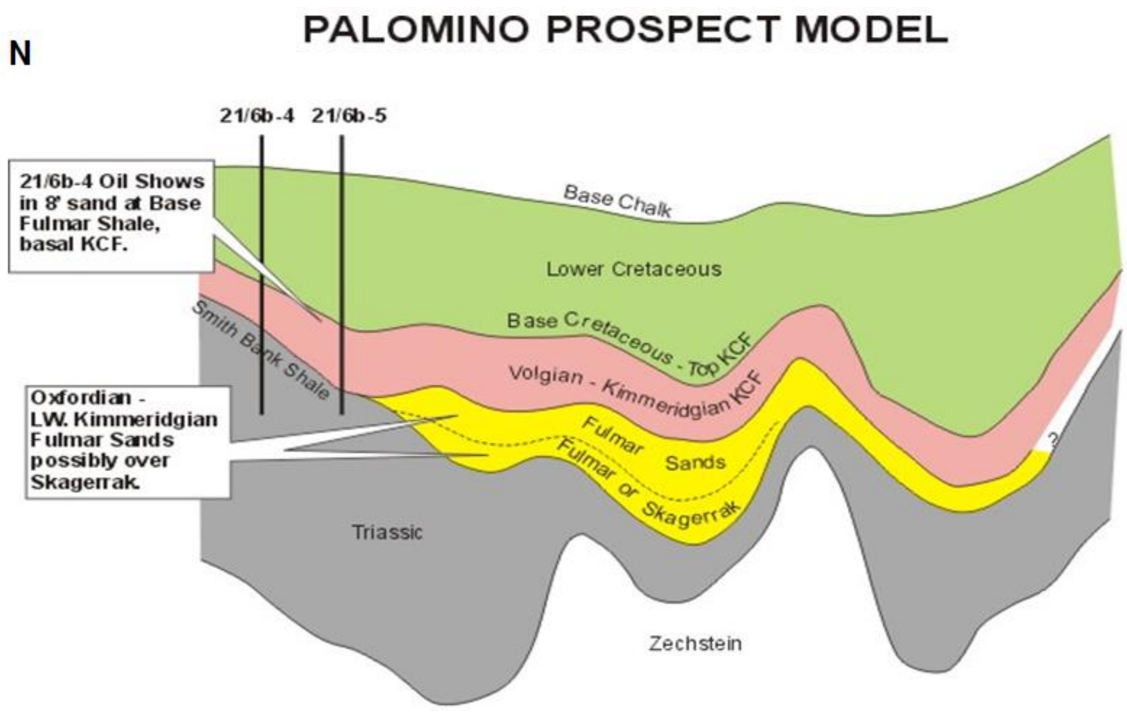


Fig. 151 – North-South random seismic line through Palomino prospect **(Data provenance uncertain: Amerada Hess proprietary, BP or WesternGeco)**

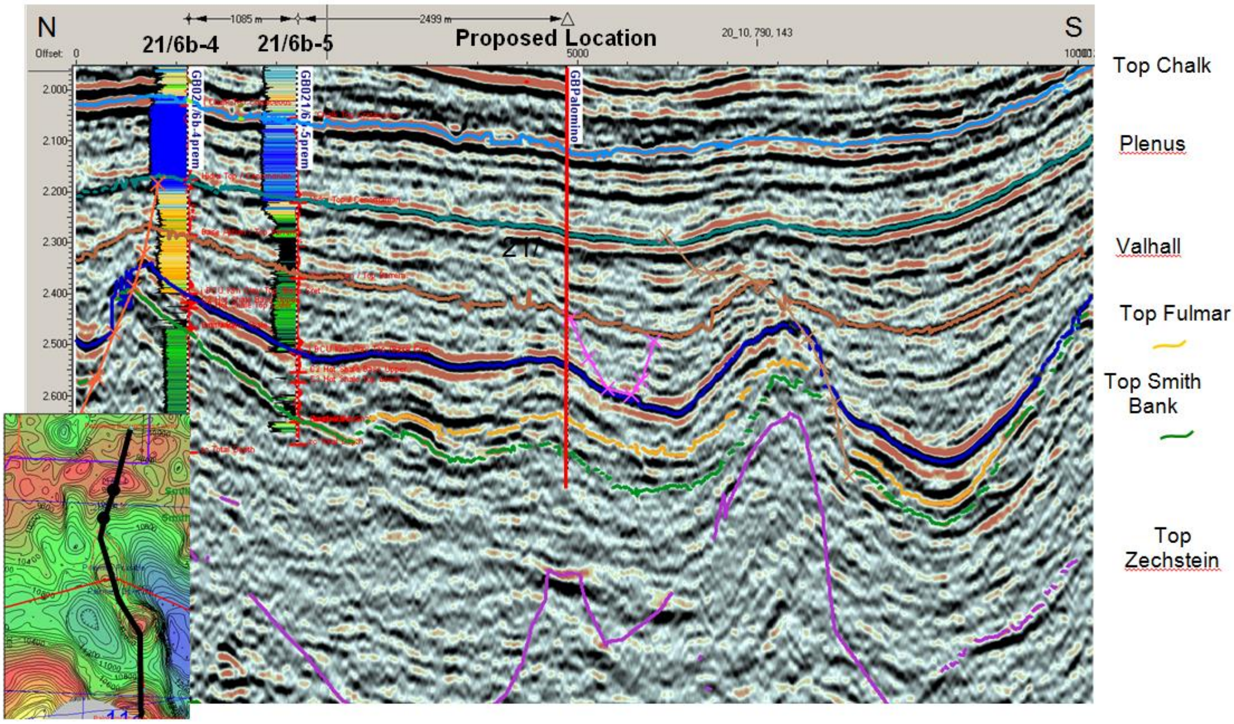
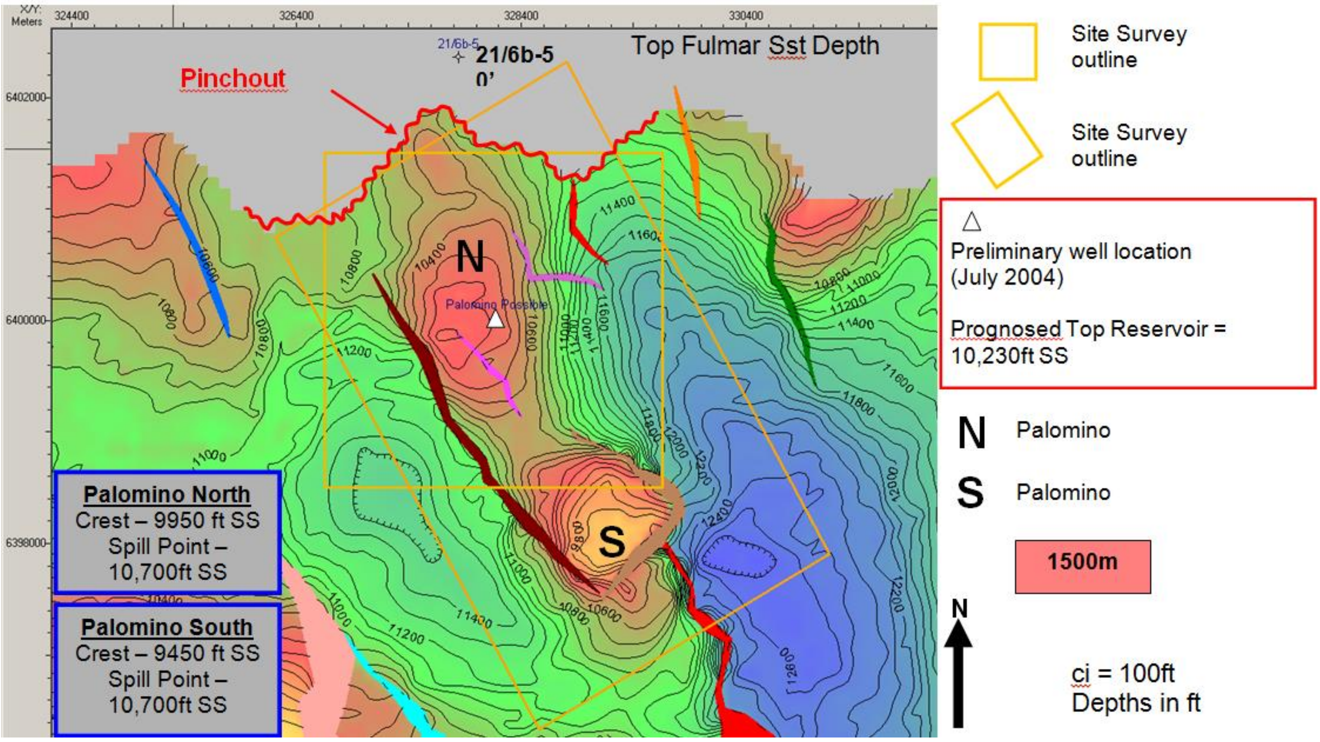


Fig. 152 - Block 21/6a Top Fulmar Reservoir Depth Map



3.77. Premier Oil: well 21/7b-4, Cyclone prospect

The Cyclone prospect was located in Central North Sea immediately to the west of the 21/8 block where two discoveries have been made in the Palaeocene (Scolty and Torphins) and lies 38km west of the Forties Field. The reservoir consisted of Late Palaeocene Cromarty aged sandstone, and was thought to be a series of fan apron lobes which were ponded into an area of accommodation space on the slope. It was interpreted that these sediments ponded via a spill-fill mechanism during a period of increased sedimentation during the Late Palaeocene regression (**Fig. 153**). These sandstones eventually filled the accommodation space and spilled over the paleo-relief, sourcing the down dip isolated turbidite system, now recognised as Torphins. Reservoir quality was prognosed to be good, as demonstrated by the Torphins wells, with well sorted, high porosity sandstones expected.

Trapping configuration was purely stratigraphic along a structural nose with differential compaction. The seismic architecture suggested that there was both an up dip and down dip bypass zone which not only trapped sandstones at the time of deposition, but also effectively acted as the seal for hydrocarbons. The top and bottom seals were mappable on seismic and thought to represent Sele/Balder shales, and slumped/reworked Sele material respectively. Migration was proven at Torphins indicating the timing of migration post-dates deposition and differential compaction.

Comparable geophysical signatures (AVO class III) were seen at Torphins (21/8-4 & 4z), Scolty (21/8a-3) and Crathes (21/13a-5). The gas/oil contact was interpreted as being clearly defined, whilst the oil water contact was partially conformable with a consistent contour. There was a very clear bright at the crest, off block, which could either have been gas with an oil rim, or oil, or gas with a down dip oil leg. The model that an oil leg might exist was adopted even though conformance was not perfect.The DHI gave CoS a nominal 20% uplift for the oil case.

The overall CoS was estimated at 20% when ignoring seismic anomaly while a nominal 20% uplift was added resulting from AVO support. Indeed, Cromarty was drilled to test a high risk stratigraphic trap based primarily on an AVO response that could be modelled as representing an oil response (**Fig. 154**). However, it was difficult, geologically, to see how the prospect could seal, and the "trap" element (which included the "seal" aspects) was risked at 30%. There was no proof that lateral seals can retain charge without citing seismic amplitude support. Secondary risks were assessed for migration (80%) and reservoir (85%).

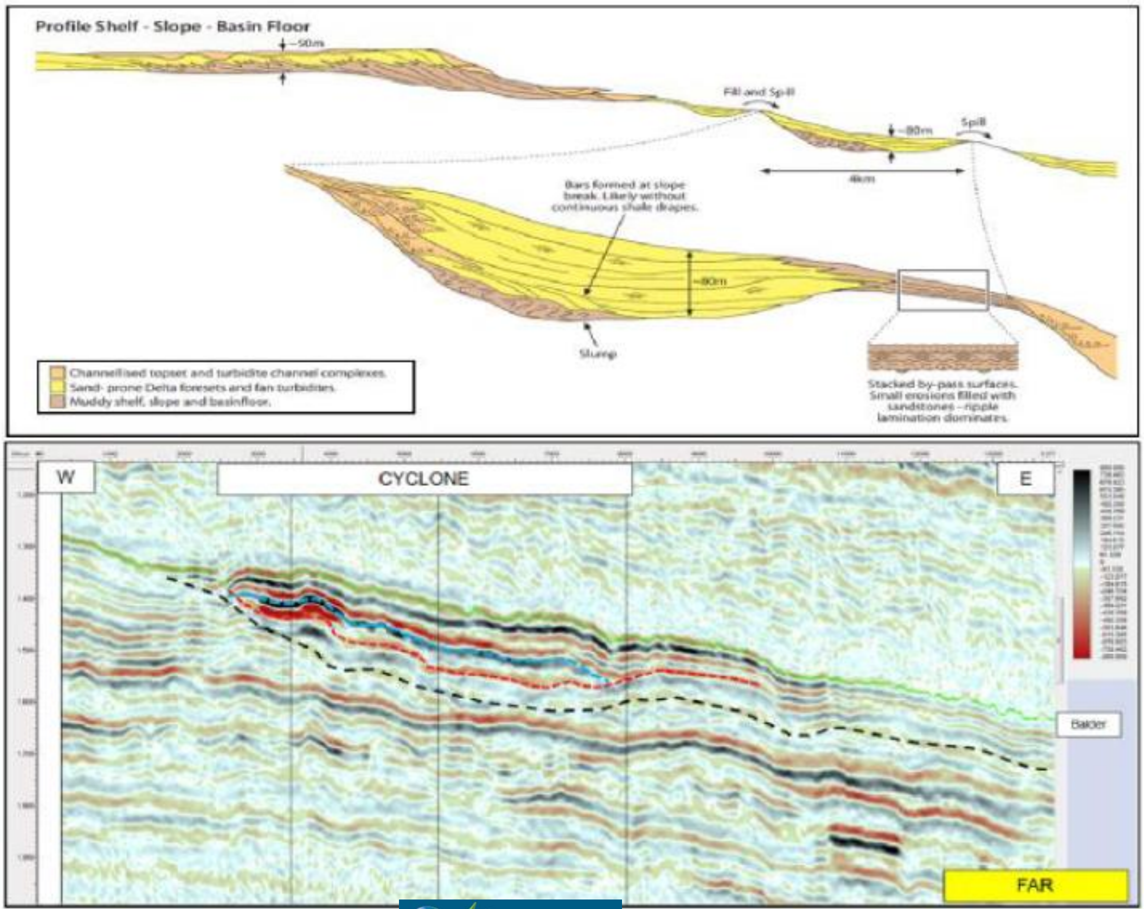
Well 21/7b-4 found top reservoir 33 feet high to prognosis. The depositional model was proven to be robust, with 136 feet (thicker than prognosed) of high porosity amalgamated slope sandstones found by the well. All sandstones were water wet (Cromarty, Bittern, Forties and Balmoral) without shows but common brown staining and specks of black "residual tar" were observed.

The main reason for failure is therefore interpreted to be the failing of the trapping mechanism: as a matter of fact, as Balder Claystones and tuffs as well as Sele shales acted as top seal and Sele claystones acted as bottom seal, it is very likely that the lateral sealing failed. This was identified as the main pre-drill risk. In addition, the AVO behaviour failed.

<u>Main lessons learned:</u>

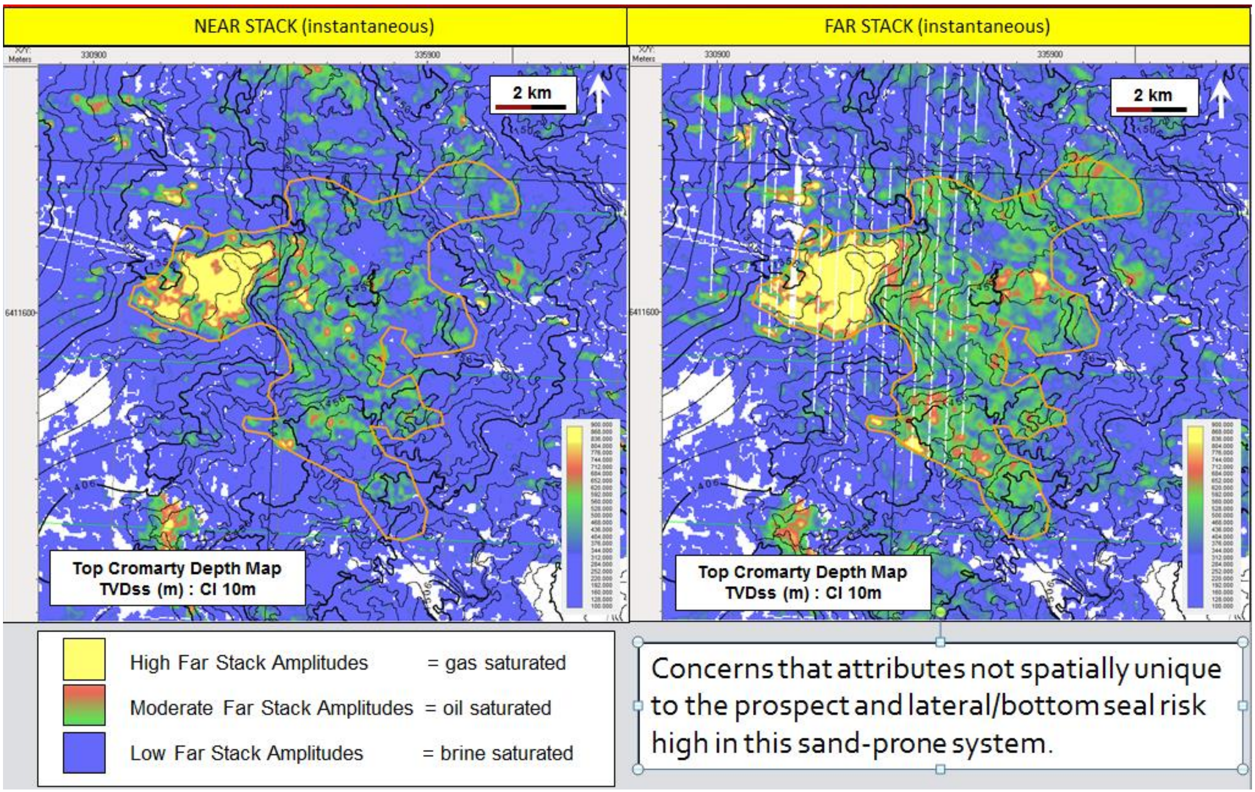
- The up dip portion of Cyclone, which lies in the adjacent licence, was modelled as a gas cap. Subsequently it has been drilled by well 21/6b-8 (EnQuest) which found an oil column. As a result, recalibration of the Cyclone so called DHI should have been performed post-drill.
- The initial CoS, i.e. the geological probability of finding hydrocarbons was revised upward following in depth amplitude analysis (Premier Oil SAAM process): this is the right way to assess any DHI supported prospect making sure the prospect makes sense on its own petroleum geology grounds before considering any impact from any kind of DHI.

Fig. 153 - Depositional model of Cromarty sand accumulation at Cyclone location



(Fugro data, courtesy of Spectrum) Spectrum

Fig. 154 - Cyclone amplitude response - pre-drill evaluation



3.78. OilExco Operator, (Premier Oil current well owner): wells 21/23a-10 & -10Z, Constance prospect

Premier Oil is the current well owner but at time of drilling Sterling Resources were the 100% owners. **Oilexco North Sea Limited operated this well** as part of a farm in agreement with the licence holder for part block 21/23a. Volumetrics and risking have been kindly provided by Ikon Science via Sterling Resources and a workshop on seismic with Ron Parr and Kathleen Nolan (BP) was held to better understand the wells results.

Well 21/23a-10 was drilled on a high amplitude seismic event interpreted to represent a part of the Tay high density channelised turbidity complex pervasive throughout this area as demonstrated by adjacent Sheryl discovery wells 21/23a-8 & -9 (**Fig. 155**). The anomaly to be appraised was bounded to the north and west by the limitation of the "LMR" anomaly and to the south east by dip closure. Well -10Z was located at the edge of a small canyon. It was in the centre of the LMR anomaly and was interpreted as being filled with sandstone. Well -10 was located in the centre of a large channel system and in the centre of a significant amplitude anomaly down dip from well -10Z (**Fig. 156**).

Overlying Stronsay Group (Horda Formation) claystones provided the seal. Up dip seal was interpreted as being either by pinch-out or by channel shale plugs. Top seal breaching was deemed possible as sand injectites may exist in the Constance overburden. Lateral shale out was needed to ensure containment. Kimmeridge Clay Formation source rock was proven in all surrounding acreage and mature for oil and gas. Gas chimneys were interpreted on seismic making the migration / timing parameter low risk (81%).

The overall CoS was estimated at 12% by Ikon (which carried out the G&G works for OilExco) and their main pre-drill risk was the seal (35%, with lateral seal being highlighted) followed by reservoir presence (63%). Sterling had a less risky assessment at 25% overall.

Both well penetrations found the top Tay reservoir significantly deeper than prognosed. Well 21/23a-10 found the Tay sandstones to be cemented and tight which was causing the seismic anomaly. The up dip -10Z penetration found thick blocky water wet soft sandstones and no shows at all. In both wells, top seal and bottom seal have been in line with expectations with respectively Horda shales and Balder Formation.

The main reason for failure is probably a lack of up dip seal towards the Saxon 23/21b-1 field. This trap failure was "supported" by a misinterpreted polarity of soft sandstones. Indeed, Pict field is soft sandstones while well 21/23a-10 targeted an anomaly with the opposite polarity, hence hard sandstones. As a consequence the perceived DHI turned out to become a lithology indicator.

<u>Main lessons learned:</u>

- A proper pre-drill QC should have highlighted the wrong polarity. As a result, the whole interpretation should have been questioned.
- The down dip target was drilled first (in the heart of the so called "LMR anomaly") before drilling up dip. The up dip location would have been drilled first, the clear water wet sandstones would have been found and there would have been no reason to go down dip. Pict is soft sands and 21/23a-10Z is a carbon copy of Pict while -10 targeted an anomaly with the opposite polarity (hence hard sandstones).
- A fluid inclusion study would have helped understanding if HC migrated through the Tay sandstones. Could tight Tay sandstones in well -10 prevent up dip migration?

Fig. 155 - Block 21/23a Constance prospect Middle Tay acoustic amplitude and time structure

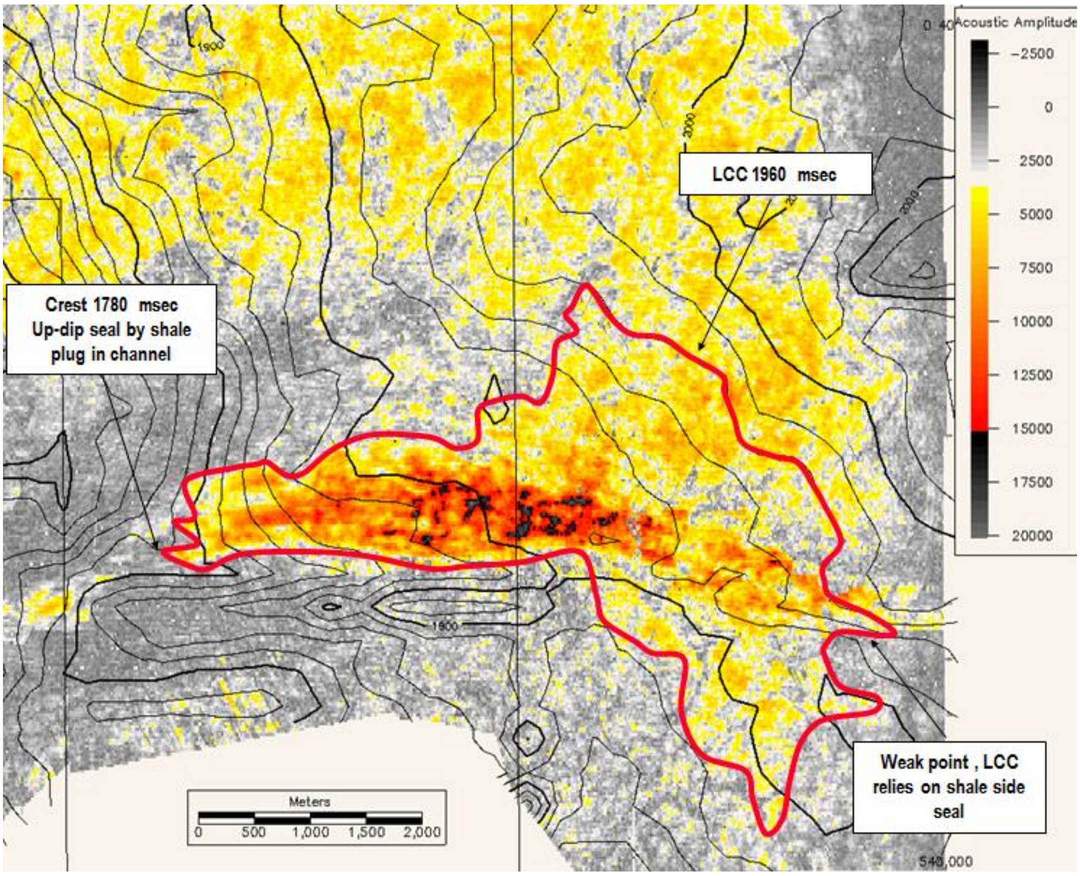
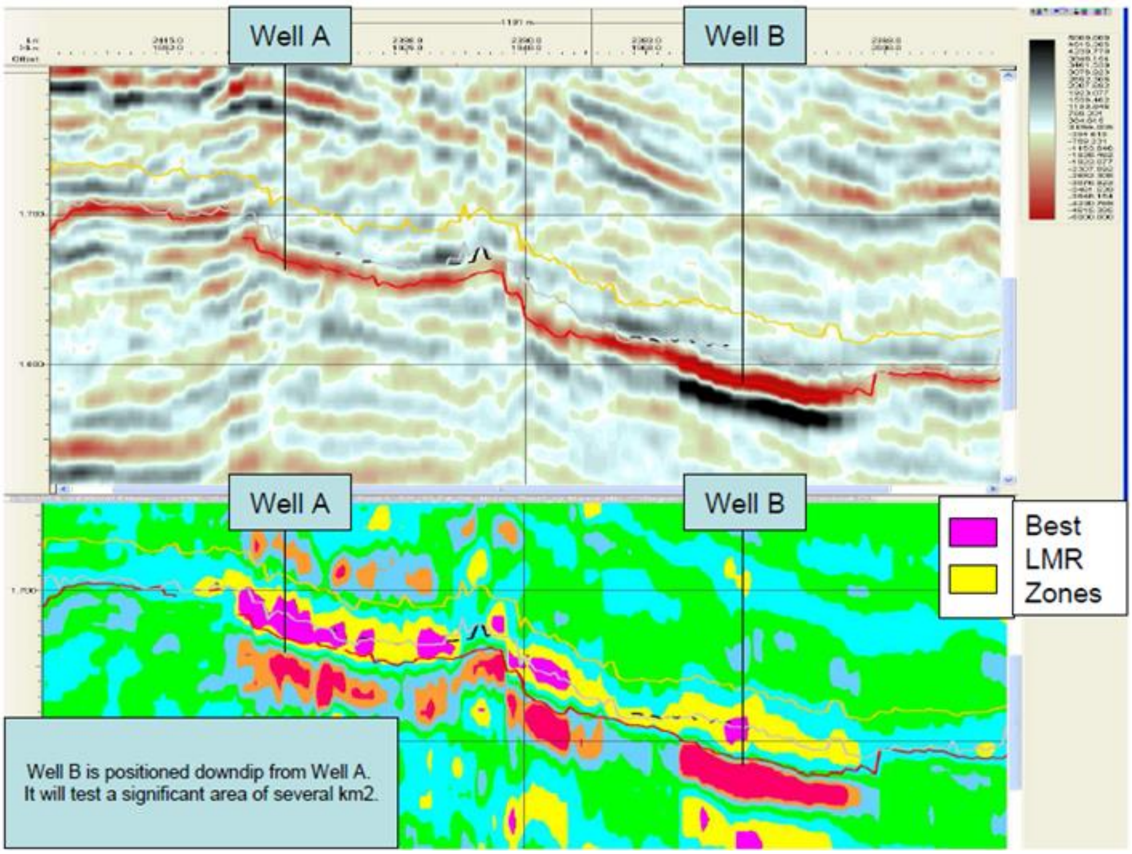


Fig. 156 - Strike seismic random line across 21/23a-10Z (Well A) and 21/23a-10 (Well B) locations



(Seismic Data courtesy of PGS)

3.79. OilExco Operator, (Premier Oil current well owner): wells 22/13b-7, Coronado prospect & 22/13b-7Z, Morro prospect

Wells 22/13b-7 and -7Z have been drilled by OilExco and are now owned by Premier Oil. In July 2007, Oilexco along with E.ON, Noreco and Carrizo discovered the Huntington Field with the 22/14-5 well. The Forties reservoir event at Huntington exhibits a subtle AVO response. Following the discovery Oilexco and Carrizo licenced the PGS 3D Megasurvey and undertook proprietary 3D reprocessing Pre-STM data to conduct the geophysical evaluation. Most of the data was kindly provided by Jim Hollywood from Carrizo and a workshop with Ron Parr (BP) was carried out to better understand the reasons for failure.

Two small, low-relief structures were identified in the southern part of block 22/13b (**Fig. 157**). The western structure, drilled by the 22/13-7 well named Coronado, exhibited four way dip closure in time and depth and had about 45 feet maximum relief according to Carrizo's mapping. The eastern closure drilled by the 22/13-7Z well named Morro had about 35 feet maximum relief consisting of two culminations separated by a saddle. A complicating factor was that the time to depth conversion at Morro was challenging due to the presence of shallow Mid Pliocene features which were observed to alternately pull-up and push down the Forties event in surrounding areas.

A key aspect of the geophysical interpretation was the AVO evaluation. There seemed to be a far offset amplitude increase at both Coronado and Morro. A similar response was also seen at the nearby 22/13-6 well where no shows but good quality sandstones were encountered in the Forties interval. Also, the far offset anomaly seen at Moro and Coronado did not conform to structure but seemed to extend across most of the area. As a result, Carrizo interpreted the offset anomaly to indicate the presence of excellent quality reservoir and not hydrocarbons. Oilexco meanwhile interpreted the offset anomaly to represent hydrocarbons and remained keen to drill the well.

Top seal consisted of overlying Sele shales and Balder volcanics. Source rock was interpreted to be the Kimmeridge Clay Formation and migration was seen as the key risk: this risk assessment was not based on geological considerations but resulted from the question "is AVO anomaly present?"

The overall CoS was estimated at 29% for both culminations with the main pre-drill risks being in both cases migration / timing at 55% and trap geometry at 65%.

22/13b-7 Coronado found the Forties 16 feet low to prognosis. The target reservoir was much thicker than expected and wet, exhibiting at best a transition zone across poor quality rock and the upper 10 feet potentially with residual HC. As long as the reservoir upper 10 feet are impregnated by residual HCs, this would indicate an effective source rock and the prospect to be within an effective migration path.

22/13b-7Z Morro found the Forties 52 feet deep to prognosis. The target reservoir was also much thicker than expected and clearly wet, as was the second objective, Andrews.

The main reasons for failure are interpreted in both cases, as a trap failure and a DHI failure. As a matter of fact, as was correctly analysed by Carrizo, the far offset anomaly indicates presence of excellent thick sand package. At Coronado, the map at top Sele (referred to as the map used to define the prospect in OilExco pre-drill document) shows 20ms TWT closure while at Forties (which is the true objective), closure is reduced to only 15ms TWT. Although the trap exists in time, what about the depth conversion? It may only preserve a limited 10 feet closure fitting with the 10 feet residual HCs.

At Morro, it's even worse as the map at top Sele (referred to as the map used to define the prospect in OilExco pre-drill document) shows 15ms TWT closure while at Forties (which is the true objective), closure is reduced to only 10ms TWT (**Fig. 158**).

Main lessons learned:

- Picking should be made as close as possible to the top objective. In these particular cases, although the Forties was a clear marker both prospects have been defined thanks to top Sele picking (trough). Mapping of the Top Forties seismic marker (instead of Sele) would have shown a reduced vertical closure hence higher risk.
- The absence of a clear, hydrocarbon-related AVO response at the prospect locations in conjunction with the small reserves potential should have prompted a re-think about the value of drilling these 2 penetrations. Eventually Carrizo declined participating in these wells which had been 100% funded by OilExco.
- Would a proper basin modelling have better highlighted the migration risk?

Fig. 157 - Top Sele depth map showing Coronado & Morro targets

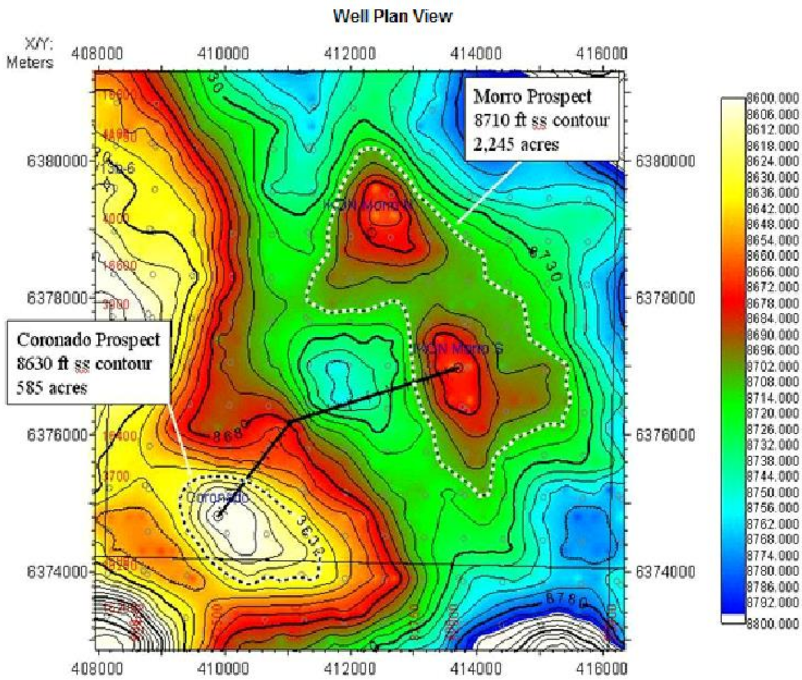
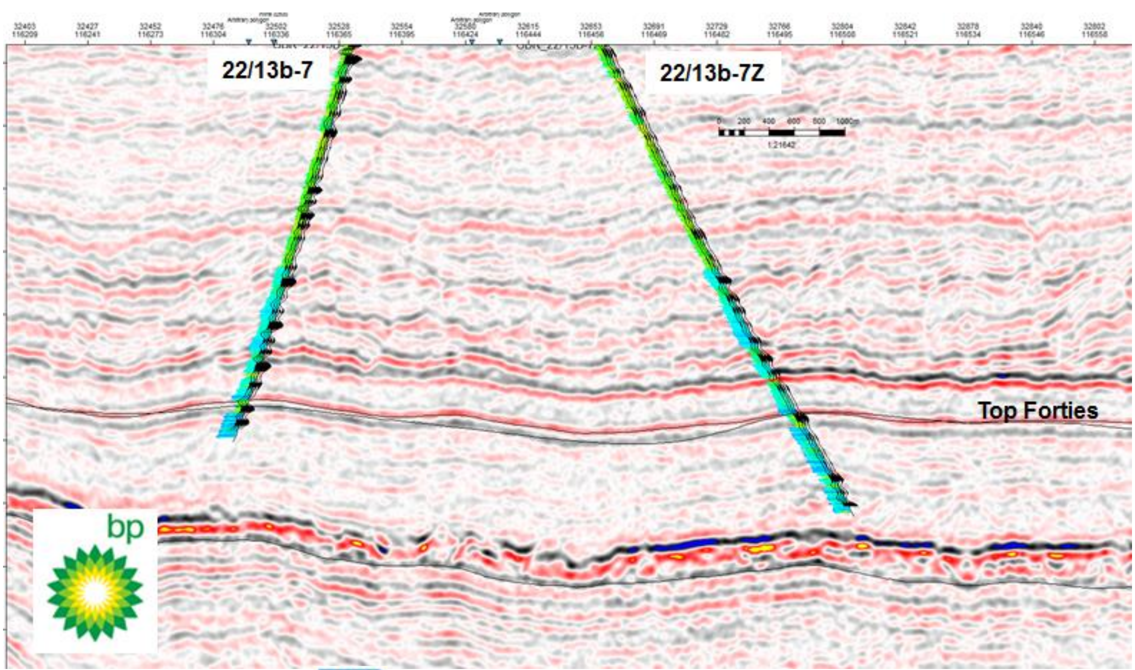


Fig. 158 – SW-NE seismic random line along the well paths (Courtesy of BP)



(Data courtesy of PGS)

3.80. Premier Oil: well 22/19c-6, Oates prospect

Block 22/19c is located in the heart of the Forties fairway. Oates was seen on seismic as a depositional thick, into a low area, of Forties-age (Palaeocene) sand (**Fig. 159**) that was seen to pinch out in an up dip direction. The top Forties showed a bump along SW-NE direction. However the picking of intra Forties F4 seemed subjective (**Fig. 160**). The existence of a trap was supported by a seismic anomaly that rock physics modelling indicated could be a DHI, although this interpretation was not unique. Brightening of the far offsets was observed within the anomaly area as is usually the case regionally where it correlates with the presence of hydrocarbons. Source rock was the Kimmeridge Clay Formation as in several neighbouring fields / discoveries (Mungo, Monan, Mirren, Fiddich…etc…). No detailed study of the migration was made pre-drill: it was deemed a no risk parameter.

Reservoir and charge risk were interpreted as extremely low in this area. The main risk was on the robustness of the stratigraphic trap which relied on a perfect pinch out, passing up dip into sealing facies.

The overall CoS was set at 40% and the main pre-drill risk was interpreted as the trap geometry (which included the seal risk).

All main markers came in within error bars. The well penetrated 702ft (351ft net) of Forties sand, interbedded with claystones and calcareous beds exhibiting neither shows over OBM or oil staining.

The main reason for failure is interpreted to be the lack of lateral and bottom seals: given the sand distribution all over the Forties Formation (the F4 sequence is sandier than expected) lateral sealing may be as problematic as bottom seal. In addition, as no shows were recorded, it is also possible that the trap was not charged, possibly due to issues with migration pathways. For most of the Forties highs in the area the migration pathway is along the Andrew Sandstone and then up faults. Possibly the Oates area is in a migration shadow/bypass zone, due to the lack of faulting. Amplitude anomalies (AVO included) interpreted as possible hydrocarbon indicators may be due to calcite stringers giving rise to hard and soft event effects.

<u>Main lessons learned:</u>

- When looking at prospects that are solely dependent on AVO it is necessary to examine the pre-conditioned gathers (not just the conditioned angle gathers) and to use properly processed seismic cubes.
- It needs to be extra diligent when dealing with merged or purchased data sets.
- AVO responses are modelled outcomes, not unique solutions which means they do not eliminate risk
- “When looking at prospects that are solely dependent on AVO, it is necessary to produce and risk the geological model unsupported by AVO. Does the prospect make sense without AVO support?”
- When dealing with prospects requiring lateral seal, produce a lateral seal map. In addition, it makes sense to clearly identify the various seal parameters (top, lateral and bottom) and take it into accounting when making the overall risk assessment.
- An extensive post drill study with the gathers was made to understand the AVO. Firstly the AVO behavior was not really an anomaly – brightening on the fars could be seen all over the area, not just on the prospect. Secondly it was found that, on closer inspection of the gathers, tuning on the far stack had caused a mis-interpretation of the response. When this was accounted for it was clear that there was no DHI observable for this prospect.

Fig. 159 – SW-NE seismic line across the so called "Forties channel" **(Data courtesy of CGG)**

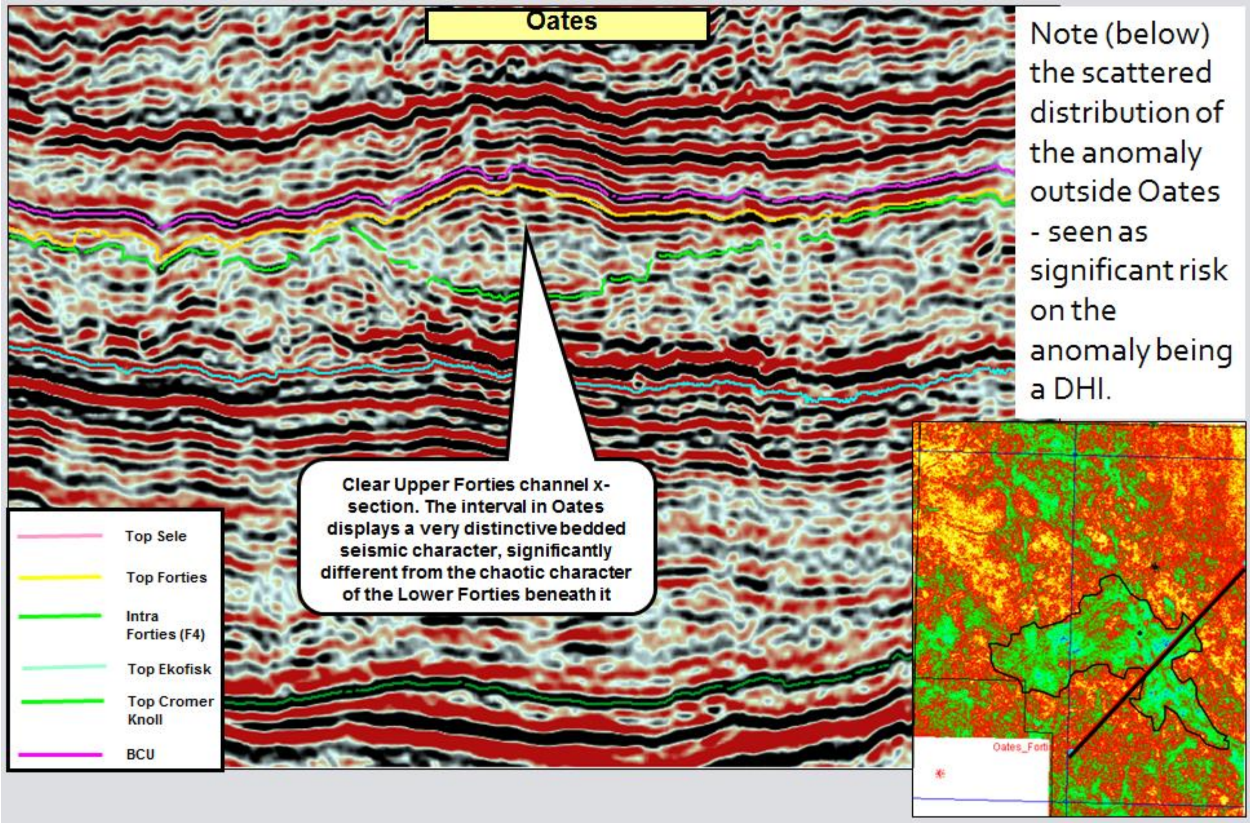
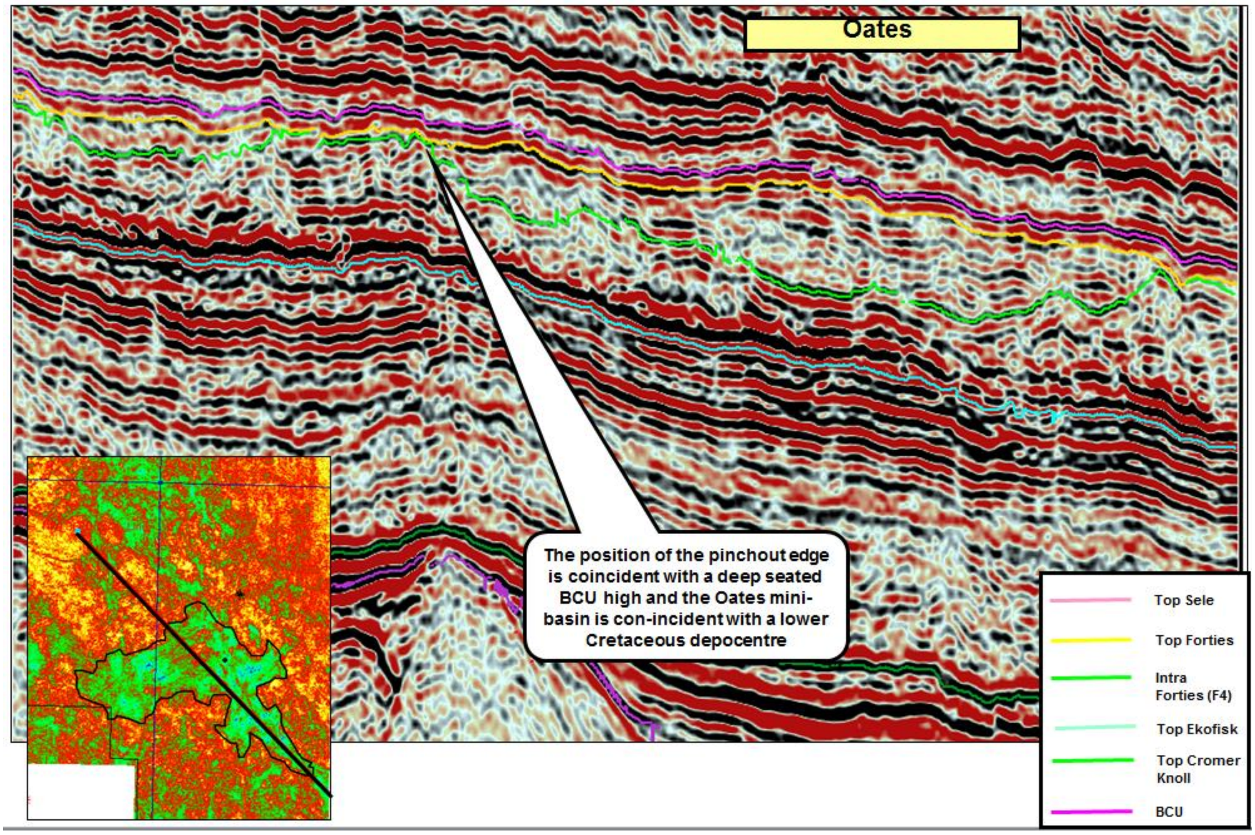


Fig. 160 – SE-NE seismic section showing interpretation of the pinch-out **(Data courtesy of CGG)**



3.81. Premier Oil: well 28/10a-3, Coaster prospect

This prospect, originally defined by Encore Oil, was turned down by Premier Oil when Encore was looking for partners. Later on Premier Oil "inherited" the Coaster commitment well when they purchased Encore Oil.

28/10a-3 targeted a stratigraphic trap heavily reliant on AVO behaviour (**Figs. 161 & 162**): without AVO, it was not possible to define sandstones architecture and the prospect. In addition there was no conformance with structure but the size of the anomaly made it worth to drill it in the Catcher catchment area.

The Coaster prospect was a large scale stratigraphic trap with pinch out to the west associated with a current induced tidal bar system. However, the supposed trapping mechanism was not supported by the attribute analysis. The target reservoir consisted of injected or depositional Tay sandstones sourced via long distance migration from mature Kimmeridge Clay Formation in Central Graben. Seal would have been provided by Eocene Tay mudstones and Balder Tuff Formation.

The overall CoS was estimated at 8%. Although detailed risking parameters were not available, trap presence and charge were interpreted as the critical risk factors. The Coaster class IV anomaly was quite different from the Catcher / Varadero classical Class III ones: as a result there was no nominal uplift to the geological CoS and the prospect was not AVO supported.

Sandstones were not present in the Lower Tay interval. In addition, Cromarty sandstones, a secondary objective were water wet. Initially it was concluded that limestone stringers had contributed in some way to the apparent anomaly. However, further post well analysis indicated soft shale throughout the Lower Tay interval. This shale, which is softer than the shale trend which has been shown to extend across much of the Catcher area, was able to cause the soft AVO response. The difference between soft shale and soft oil filled sandstone is the AVO behaviour; pseudo Class IV in the case of the shale, and Class III in the case of an oil filled sandstone.

The main reason for failure is clearly the lack of Tay sandstones as absence of any Tay reservoir was not expected. The lack of charge is also likely as the Cromarty sandstones had no shows.

<u>Main lessons learned:</u>

- Although from a technical perspective the well should not have been drilled, it was a commitment well and there had also been commercial reasons for drilling. The lack of a clear process to get out of a well commitment may be addressed by OGA.
- Applying Premier Oil understanding and experience from nearby analogues was key to de-risking the Coaster prospect. Indeed, detailed forward modelling combined with systematic amplitude risking helped Premier Oil to make the correct pre-drill assessment.
- This well provided a useful soft shale data point which has been integrated in the Greater Catcher prospectivity assessment. Even in the dry hole case, especially if the dry well is in a good neighbourhood, it is worthwhile acquiring wireline logs (DT, DTS and Rhob).
- In the Coaster case, neither the reservoir absence nor the shale softness had been predicted: during pre-drill evaluations we should try to think of, and be open to, alternative models and interpretations.
- Shale properties are highly variable and can introduce uncertainty into AVO behaviour. As a consequence, understanding the range of possible shale properties is important for AVO analysis.
- This case study shows that for solely AVO dependent prospects it is compulsory to produce and risk the geological model unsupported by AVO and check if the prospect makes sense without AVO support? In this particular case, the Coaster CoS was downgraded to 8% following the detailed AVO analysis.
- Last but not least, without AVO support there is little chance of hydrocarbons in the Tertiary.

Fig. 161 - Coaster anomaly: RMS amplitude extractions from near and far angle stacks with TWT contours overlaid

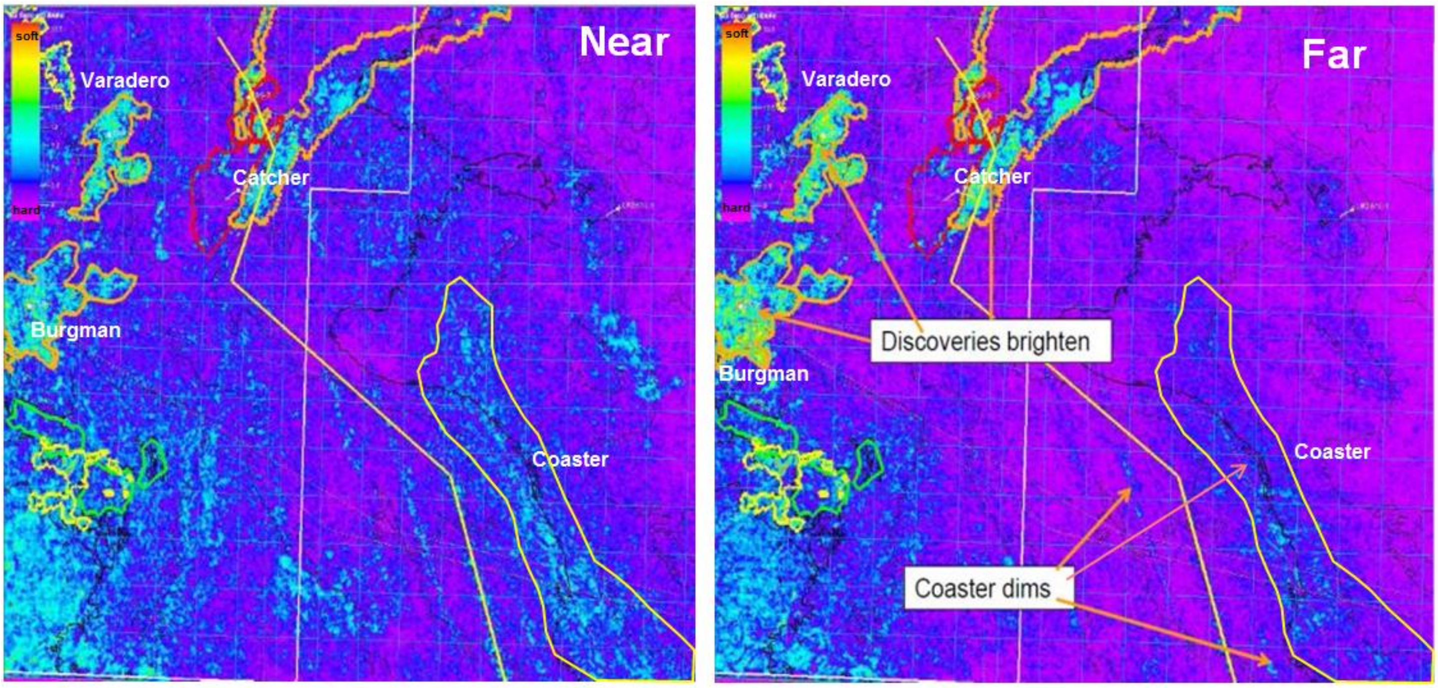
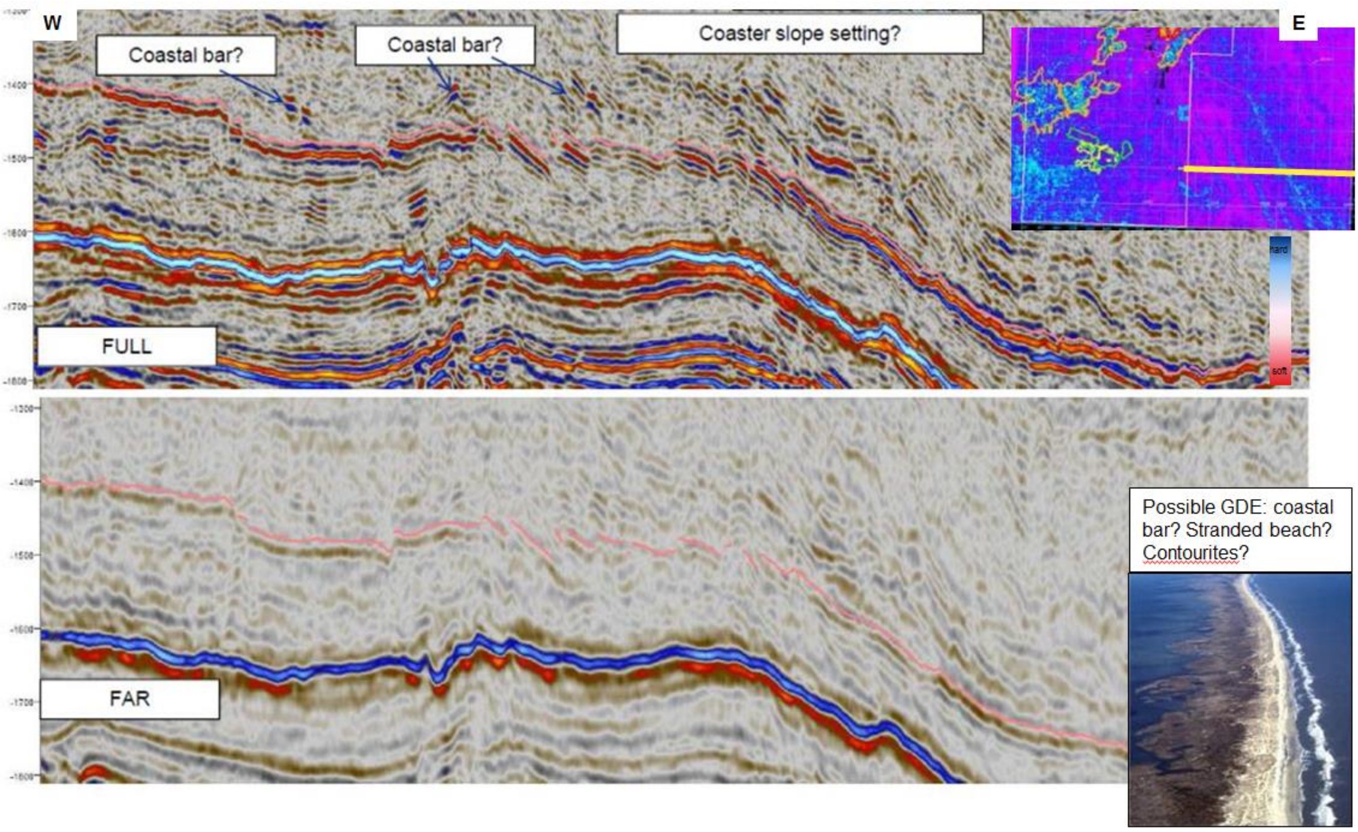


Fig. 162 – East-West seismic line across Coaster **(Veritas seismic data courtesy of CGG)**



3.82. OilExco Operator, (Premier Oil current well owner): wells 29/6b-7 & -7Z, Danica prospect

The prospect was drilled by OilExco prior to Premier's acquisition of their UKCS assets. The Danica prospect exhibited wings emanating from the edge of a "mother" bed of turbidite sandstones and cross cutting the Eocene shale stratigraphy forming a bowl shaped structure in three dimensions (**Fig. 163**). This was interpreted to be large scale high net to gross sandstone intrusion complex in the Palaeocene at Balder Formation level similar to the Alba and Chestnut fields. There was no apparent dip closure on the structure and, depending on the interpretation of the trap, ultimate seal relying either on lateral enveloping seal within the tuffaceous shales of the Balder, or on an up-dip pinch-out of the sand within the Lower Eocene.

Hydrocarbon generation from the Upper Jurassic Kimmeridge clay occurred from the late Cretaceous to present day. Oil migration within the basin had obviously punched up through the Jurassic to form shows and oilfields by faulting and salt diapirism within the Jurassic, fractured Chalk and Palaeocene and Eocene turbidite sands.

Mother well 29/6b-7 appears to have been targeting a Balder Channel, while the side-track -7Z was planned to test the amplitude anomaly to the NW, interpreted as a wing of the sand intrusion complex.

OilExco stated that Danica was seen on amplitude extractions (**Fig. 164**), in impedance volumes. Although dedicated AVO study was not reported, it's clear that OilExco recognised some sort of seismic attribute.

The overall CoS was estimated at 18% but no detailed risking analysis was found. According to Hannon Westwood "the two main risks were reservoir presence and trap".

Well 29/6b-7 found thin and heavily cemented sandstone stringer (20 ft gross) in lower Horda and no associated shows. While 29/6b-7Z side-track found 17 ft good porosity water wet sandstones Balder age in the lower Horda Formation. The sandstones in 29/6b-7 are interpreted to be in-situ channel sands, whereas those in 29/6b-7z are inferred to be injectites. Top and base seal are provided by the Horda shales. Given the thinness of the sands, lateral sealing appears very likely.

The main reasons for failure are the lack of effective reservoir in the -7 well as well as a potential charge failure: could HC migration have been prevented by the lack of porous and thicker sands? In addition, the DHI was not valid: indeed, Premier has looked at the post well data and recognised no valid DHI attribute.

Main lessons learned:

- A regional basin modelling exercise would likely have highlighted the gas prone nature of the Kimmeridge Clay Formation.
- An accurate AVO study and a seismic comparison with well 29/11a-1 soft sandstones would likely have increased the reservoir risk.

Fig. 163 - Seismic over the eastern extension of the Danica injectites package in adjacent Block 29/6a *(image courtesy of Encore Oil)*

(Veritas seismic data courtesy of CGG)

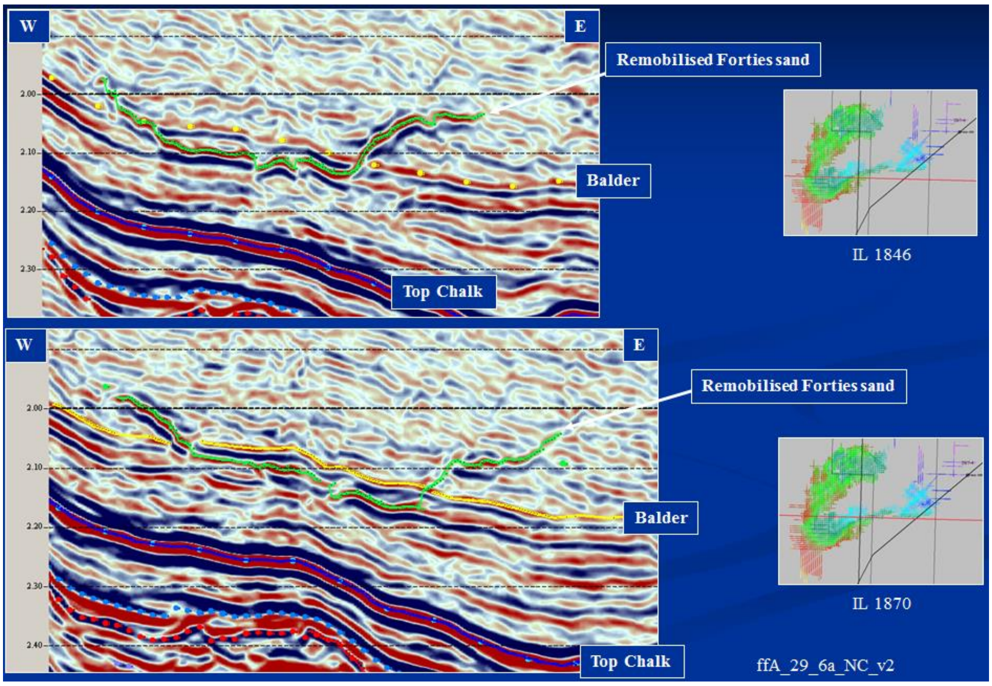
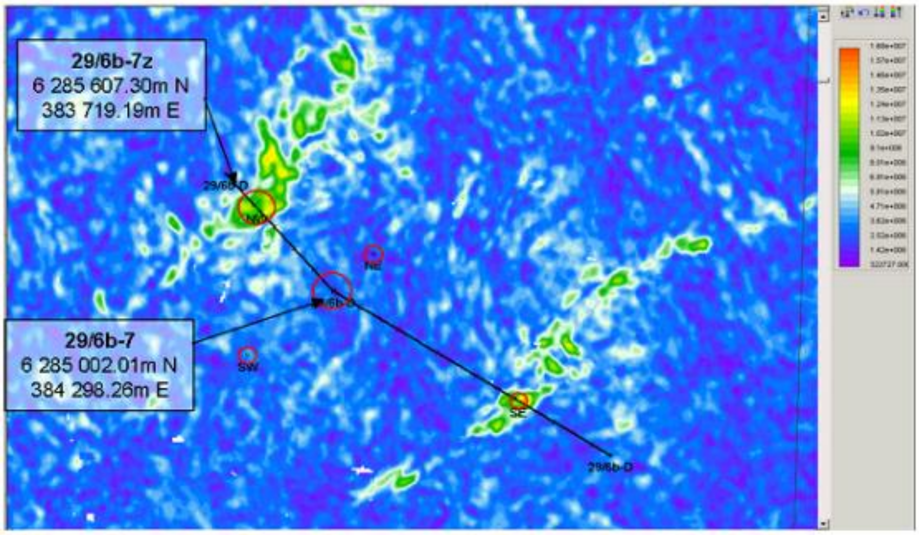


Fig. 164 – Danica Amplitude map (undefined horizon!) showing both well penetrations



3.83. Premier Oil: well 39/2c-5, Peveril prospect

The Peveril prospect was located to the south of Premier's Fife and Fergus oil fields and the well targeted Lower to Middle Volgian sandstones as found at Fife. Fife has thick sandstones, piled up against the boundary fault to the Grensen Nose and Peveril being within a structurally controlled embayment was seen as a possible analogue. This complex stratigraphic trap relied upon a combination of subcrop, erosion and pinch-out to the south of Fife sandstones defined by subcrop of Triassic Smith Bank Formation shales against Lower Cretaceous shales (**Fig. 165**). The targeted reservoir was interpreted as being sourced locally (from a point source hence there was some risk on reservoir presence at Peveril) from the southern area of the Grensen Nose to the south and east of the prospect thought to be sub aerially exposed during the Volgian. In addition, regional work had shown that Upper Jurassic sandstones and Kimmeridge clays were indistinguishable in the area.

Top seal was assumed to be provided by the overlying Kimmeridge Clay Formation while base seal would have been provided by the Triassic Smith Bank shales. Regarding upside cases, lateral fault juxtaposition against tight Permian Rotliegend volcanics was interpreted. The mature Kimmeridge Clay of Upper Jurassic age being buried at depths greater than 9,000 feet would have provided the hydrocarbon source for the Peveril prospect. Charge was seen as having some risk because of its distance to a mature Jurassic kitchen, but it was felt that migration through the syncline between Fife and Peveril was possible given the overpressure regime.

The overall CoS was set at 24% with the migration timing (50%) and the trap geometry, which included the seal risk (60%), being the critical pre-drill risks.

No reservoir quality sandstones were encountered in well 39/2c-5. The obvious reason for failure is the absence of targeted reservoir. As a result, one can ask the question whether the Fife clastic source is different or did Peveril correspond to the distal end of this system. In addition, in situ source rocks are marginally mature and one can wonder if there is an additional lack of carrier beds?

<u>Main lessons learned:</u>

- The seismic correlation with Fife appears quite questionable (**Fig. 166**) making the resulting geological model optimistic. Pre-drill peer review or a more in depth QC would likely have been pretty useful.
- A pre-drill rock physics study and associated modelling may have highlighted the risk on reservoir presence.
-

Fig. 165 - 39/2c-Peveril prospect location Map shown on BCU depth map

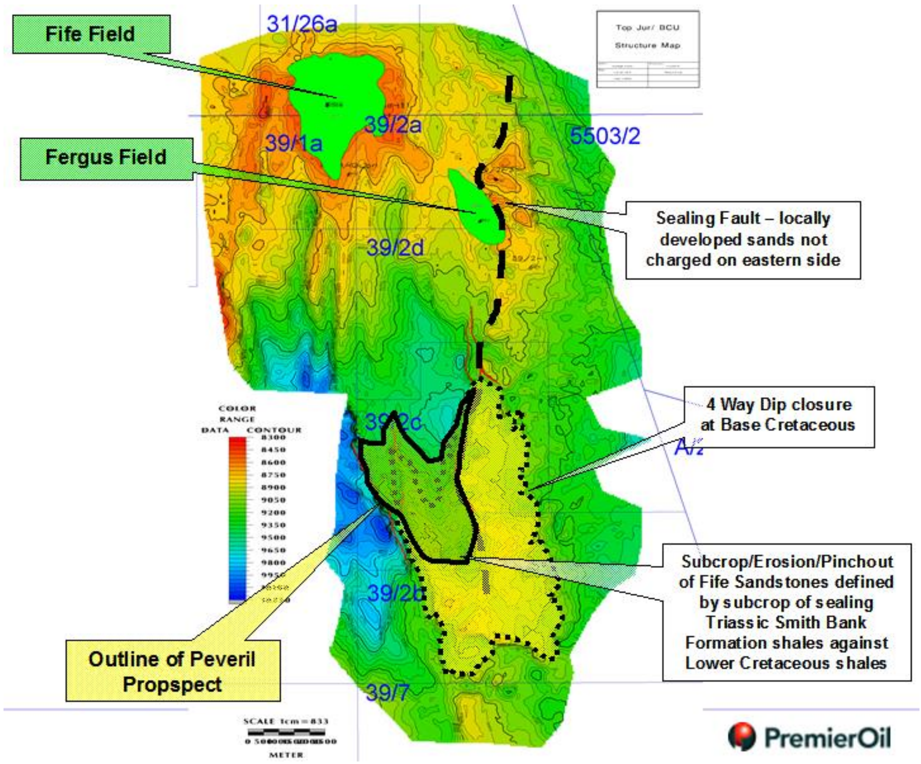
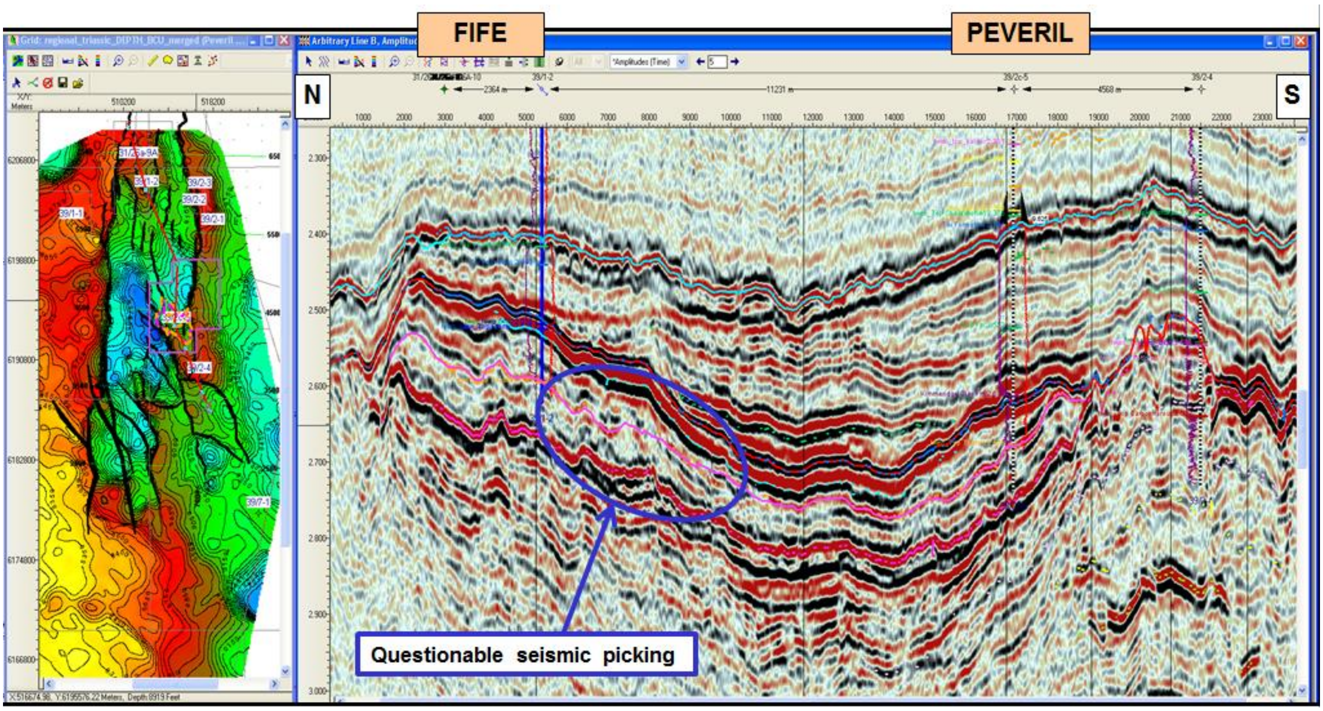


Fig. 166 - North-South seismic section from Fife field to Peveril prospect (Data Amerada Hess proprietary)



3.84. Shell: well 22/12a-11, Stavro prospect

The Stavro prospect was located ~5 Km to the north west of the Howe field (**Fig. 167**). It was an interpod 3-way closure above a Zechstein dome sealed laterally by Smith Bank shale pods atop Zechstein lows. The target reservoir was the Upper Jurassic Fulmar sandstones. A secondary objective was located in the Hugin sandstones. Three top sandstones scenarios had been interpreted and the structure was confidently mapped on seismic for all 3 scenarios.

Top seal (Kimmeridge Clay) was proven at numerous analogues such as Howe and Bardolino while lateral seal was effective at nearby fields and inferred from amplitude extraction at BCU.

Charge was expected from the Kimmeridge Clay Formation and was considered certain because all valid tests on Fulmar Play have seen charge; Stavro was interpreted as being favourably located on flanks of oil-mature kitchen and continuous carrier beds (underlying Fulmar or Pentland sands) from Stavro to source rock down dip had been "demonstrated" (**Fig. 168**).

The overall CoS was estimated at 58%. The main pre-drill risks were reservoir presence (80%) and delivery (90%) as well as seal (80%).

All formations apart from Lark were encountered within prognosis. Top Fulmar was found 11 feet shallow to most likely "Scenario 2" prognosis but water bearing. Multiple cemented stringers occurred in reservoir section and TD was called before encountering Zechstein. Pressure was within range of expectations albeit closer to the high end.

The Kimmeridge Clay was encountered in the well and acted as top seal. Triassic Skagerrak claystones were drilled at well TD, providing bottom seal. Lateral seal is unproven, however elevated pressures in the reservoir do suggest all sealing elements are likely present; elevated pressures would be unlikely if there is an absence of seal.

The main reason for failure is very likely the lack of viable migration pathways to connect the mature kitchen to the prospect. In support of that interpretation, post-drill geochemical analyses of the traces of oil in recovered core suggest that the immediately local source rock is immature and not sourced from the Kimmeridge Clay (local Pentland?).

<u>Main lessons learned:</u>

- Well 22/12a-11 was drilled immediately after the Howe and Bardolino discoveries: was there some cognitive bias allowing a too quick assessment of Stavro and full acknowledgment of the geological risks may not have been taken into account.

- The charge risk was not fully recognized at the time and not adequately represented in the risking. Interpod prospects require a detailed migration study in order to understand the potential migration pathways: continuous carrier beds may not be compatible with lateral sealing.

- Pressures in interpod sandstones may be isolated from nearby pressure points and can therefore be difficult to predict. A wide range of pressures are possible and mitigations against these need to be considered pre-drill.

Fig. 167 - Map of the regional Top Fulmar (interpretation from multiple datasets): nearby field outlines, offset wells and infrastructure. Red outline is the core area of the Stavro Prospect

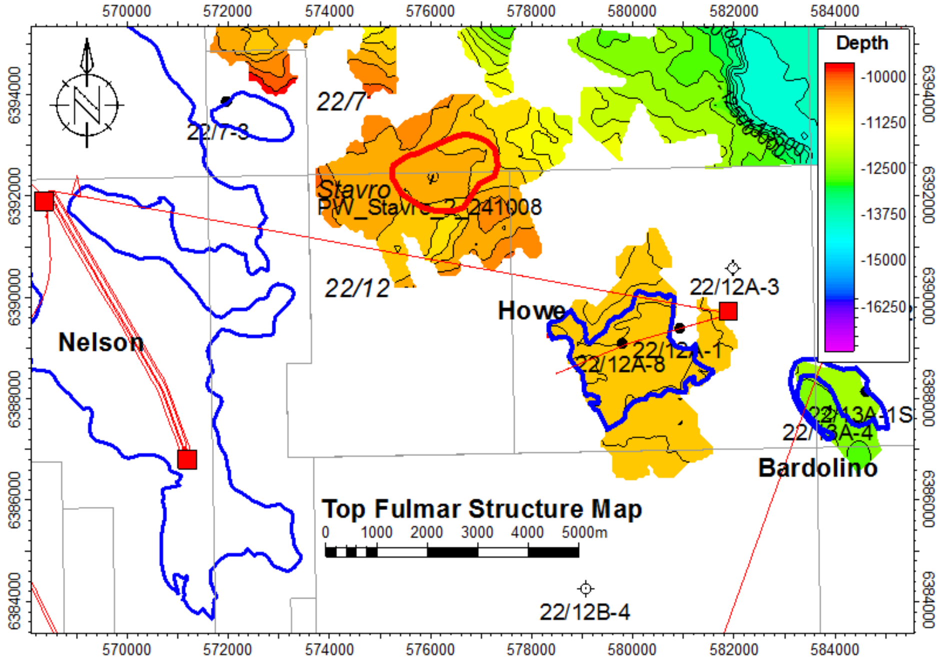
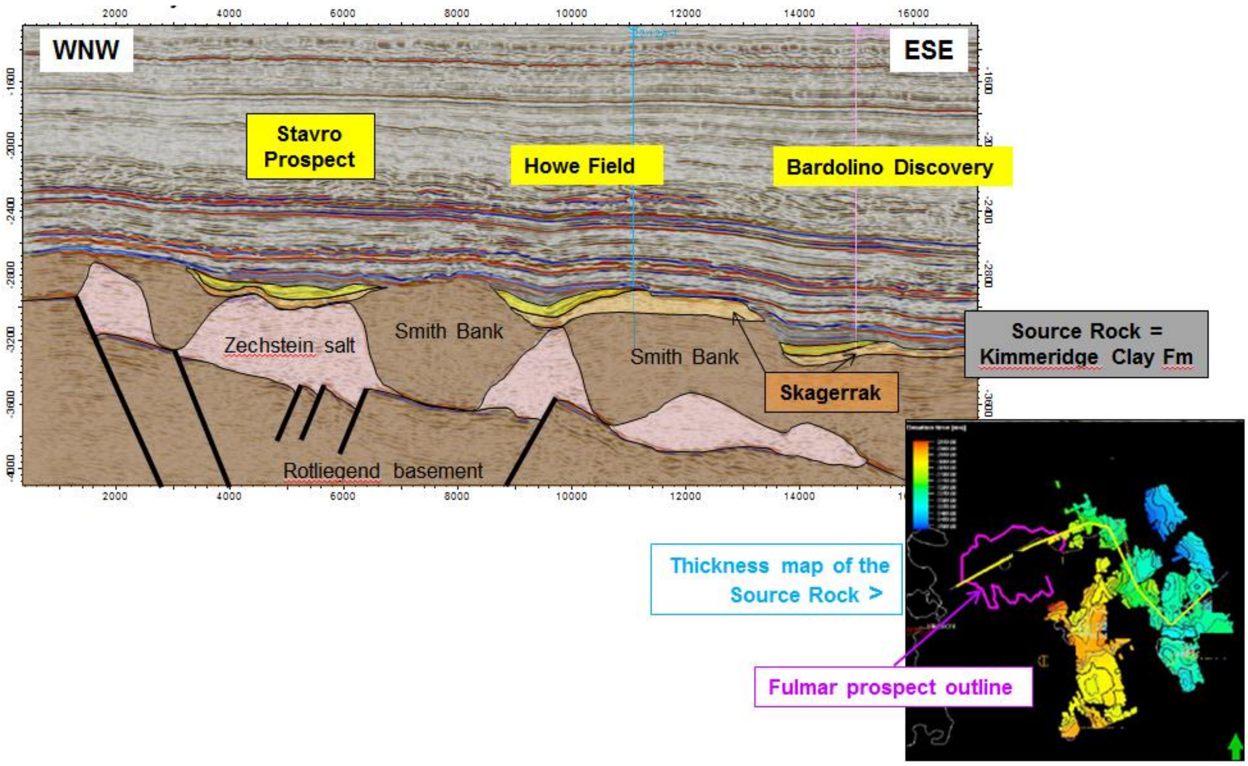


Fig. 168 – Composite seismic line illustrating the migration pathway (Data Shell proprietary)



3.85. Shell: well 29/10-7, Quasimodo prospect

Quasimodo prospect was a significant tilted Rotliegend fault block with 68 km^2 of structural closure and 1200m vertical relief. It was confidently mapped on 3D seismic (**Fig. 169**). The target reservoir was Rotliegend 310 m thick aeolian sand reservoir which was split into two formations, Rotliegend A and Rotliegend B. Rotliegend A was expected to overly Rotliegend B and was expected to be waste zone. Top Seal was interpreted to be provided by Zechstein Halite or Smith Bank shales. Despite the significant vertical closure, the risk of a blown trap was deemed insignificant. The Quasimodo fault block was juxtaposed against Smith Bank shale to the south. The possibility of thief sandstones in the hanging walls of bounding fault to south was recognized.

The Quasimodo prospect was expected to be charged from the Kimmeridge Clay Formation and Heather Formation across the bounding fault to the south of the prospect (**Fig. 170**). The chance that charge would be insufficient to fill structure was carried in spill point statement.

Overall this prospect was deemed high risk – high reward, with a wide range of volumes that reflected the uncertainty in the calculated spill point definition. The overall CoS was set at 15%. The critical pre-drill risks were the reservoir presence (85%) and quality (60%) corresponding to a global reservoir risk = 51%; the seal and especially the lateral seal (50%) and the migration across faults at 60%.

Although Horda Formation, Herring and Plenus Marls had not been prognosed, the main horizons came in within their respective uncertainty range. Jurassic and Upper Triassic were not encountered. Instead Smith Bank shale was encountered beneath the BCU. Rotliegend corresponded to water wet reservoir showing higher pressures than expected and was drilled without incident. The well successfully tested the stratigraphic zoning of the Rotliegend encountering the tight upper Unit A and the better quality, but still low permeability, Unit B as prognosed

The main reasons for failure are interpreted as being the possible absence of effective migration pathway and the potential lateral seal failure. One can also wonder if the accessible volume of expelled hydrocarbons was big enough to source such a huge structure. Anyway, none of the charge, seal and reservoir quality issues has been proven.

<u>Main lessons learned:</u>

- It would have been useful to check the charging issue via a fluid inclusion study.
- As Quasimodo was a high risk, high reward prospect close to infrastructures, it made sense to drill it.
- In such cases when the trap volume is significant, it would be worth to check how much HC could be generated by the available mature kitchens and to pay careful attention to the way kitchens are dipping versus the prospect entry points. It is recognised that the kitchens are located in asymmetrical synclines and Quasimodo is in perhaps a migration shadow: much of the generated HC would have migrated away from this structure (**Fig. 171**).

Fig. 169 – Quasimodo prospect concept (Data Shell proprietary)

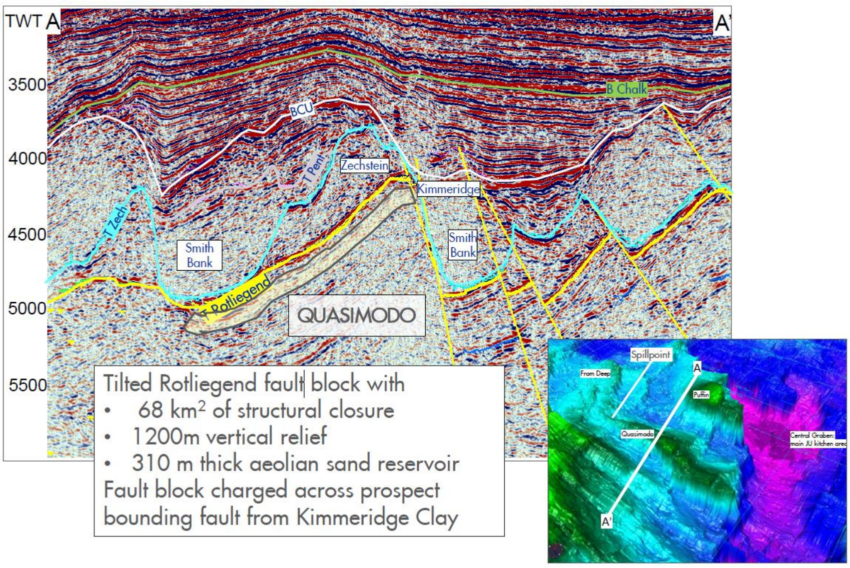


Fig. 170 - Quasimodo Outline Geology on E-W Sketch

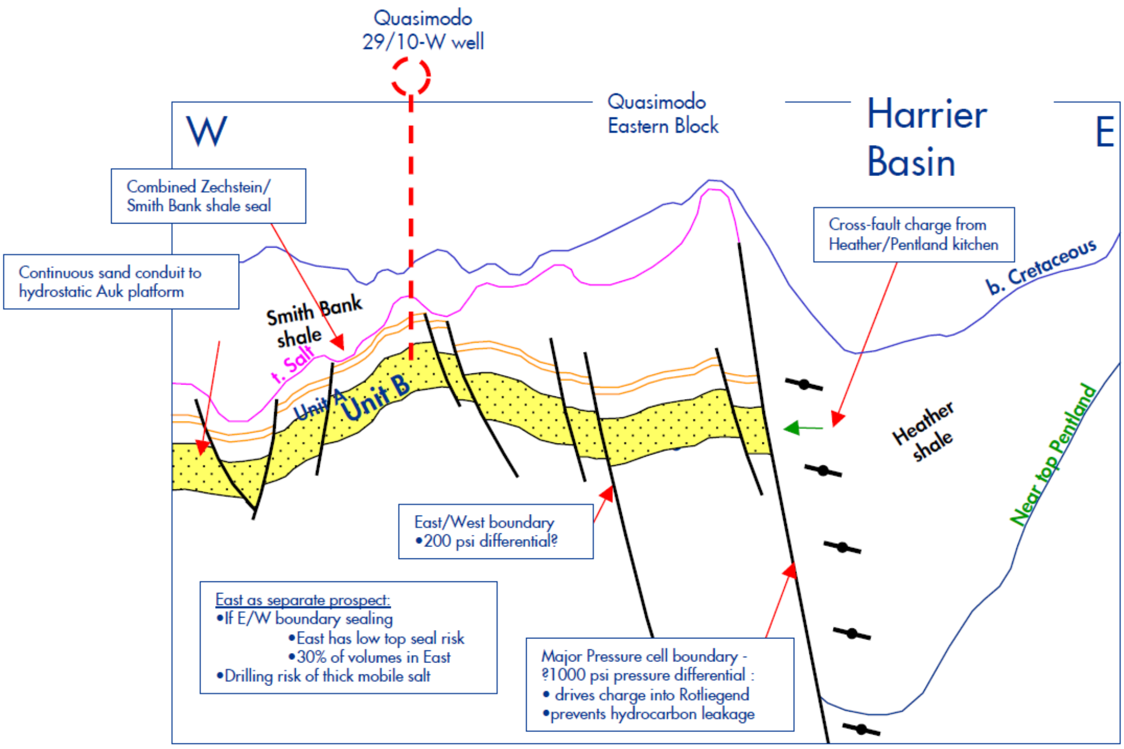
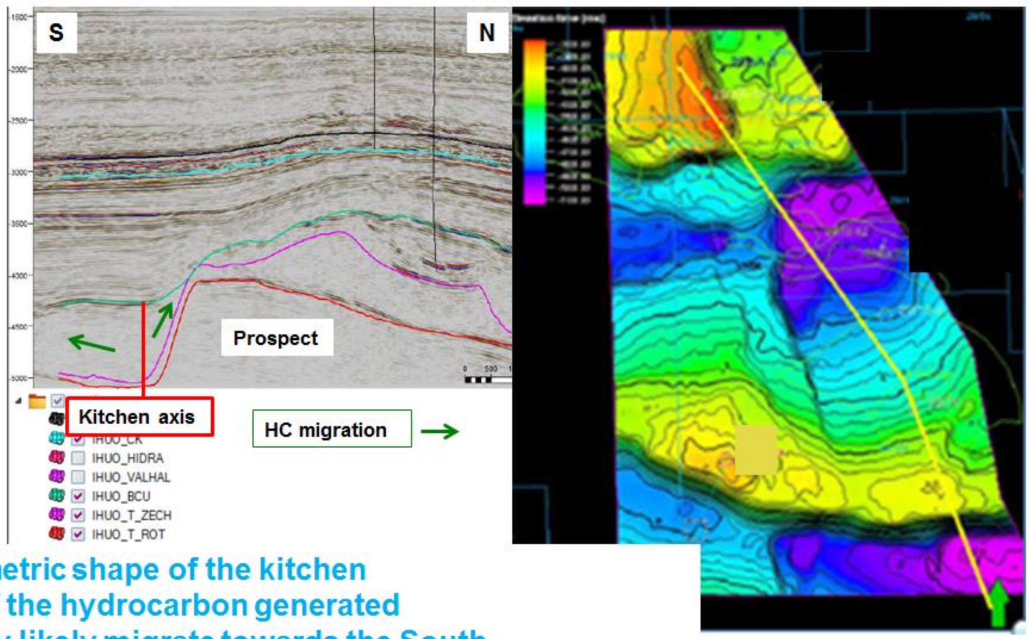


Fig. 171 – Quasimodo prospect: Drainage area vs trap size and location (Data Shell proprietary)



- Asymmetric shape of the kitchen
- Most of the hydrocarbon generated
would very likely migrate towards the South
- As a consequence high chance of underfilling the trap

3.86. OilExco Operator, (Sterling Resources current well owner): well 21/23a-8, prospect Disraeli, Eocene Tay segment

Well 21/23a-8 Disraeli was operated by **OilExco** and appraised the Tertiary Disraeli discovery now known as “Sheryl”. Most of the data that could be accessed were provided by Sterling Resources. The G&G analyses had been subcontracted to Ikon Science by OilExco. Well 21/23a-8 was a deviated well targeting 2 superimposed segments, the upper one at Eocene Tay Formation and the deeper one at Upper Jurassic Fulmar Formation. (**ref. chapter 3.87**).

The Disraeli Tay segment was a stratigraphic trap encompassing a limited 4-way-dip closure (**Fig. 172**). This Eocene segment was described as a mounded sequence. The 21/23a-8 well was the first of several penetrations drilled by Oilexco with only -8Z and -9V landing in sands, with -9V effectively twinning -8Z. According to Ikon Science, it was “poorly defined on seismic but there was some evidence of DHI." The target reservoir was Tay sandstones turbidites (deep water channel), proximal to Pict field but showing a much thinner section. Top seal consisted of Upper Tay shales and was risky as it showed polygonal faulting in Eocene. Bottom seal was interpreted as being the Lista shales while Middle Tay sandstones were interpreted as shaling out towards the east.

Risks on source rock and migration/timing was deemed moderate (81% each) because a mature source rock was proven by Saxon and Pict fields. Timing was risked at 90% as Disraeli was up dip of 21/23b-7 Gladstone discovery well. Fetch and pathways had been risked at 90% because "HC migration was evident on seismic".

Overall CoS was estimated at 10% by Ikon. Their main pre-drill risks were seal (35%) primarily because of the top Eocene was polygonally faulted, reservoir (63%) and trap geometry (70%) as it was “seismically poorly defined”. OilExco risking assessment could not be found.

Well 21/23a-8 found the Tay sandstones 185 feet deeper than prognosed (and out of the error bar). It was also thicker and water wet. Horda Shales drilled at well location, provided an effective top seal. The Sele Formation was partly sandy but Lista Shales was good enough to provide base seal.

Well 21/23a-8 likely failed at Tay level because it was drilled off structure. In addition lateral sealing is likely not effective over the whole thickness of the Tay Member. However the following side tracks -8Z (oil discovery in thick sands) and -8Y (gas discovery in thin sands) proved that the petroleum system was effective.

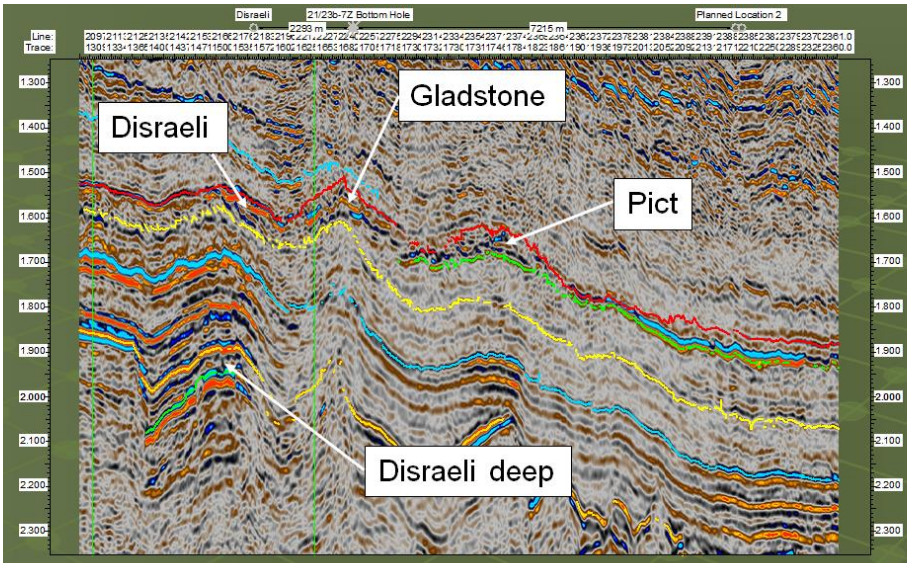
It is difficult to understand what the technical driver was allowing to drill so many penetrations (10 in total, including mother wells 8 and 9). Indeed, according to Ikon Science, “Disraeli was difficult to demonstrate since it was near impossible to map”. When taking all 10 penetrations into account, Sheryl is a non-economic discovery smaller than the P90 pre-drill estimate.

<u>Main lessons learned:</u>

- Recovering data from this OilExco well proved, once again, painful and it was finally thanks to Sterling Resources that we could find relevant data and interpretations made by Ikon Science. OGA must improve the way it collects, stores and protects all well data information belonging to the UKCS so that it could better steer future exploration and share more widely the UKCS G&G data. OGA must obtain all well data as soon as possible after well completion in order to avoid potential data losses following company bankruptcy or exit from UKCS.
- The risking assessment provided by Ikon Science was spread over all the individual parameters. For instance even the source rock was not assessed as certain (100%) although block 21/23a is in close proximity to Pict, Saxon…etc… discoveries. As a consequence it’s difficult to focus interpretation efforts on the real prospect weak points.
- Thick oil bearing Tay sand should have produced a DHI. As long as the seismic data was adequately processed, more confidence should have been put on the pre-drill rock physics modelling studies.

- Better integration between Geology and Geophysics is a must!
- In order to prevent this type of drilling burst, OGA needs to access the licence data and monitor the progress of interpretation during the licence life, early enough prior to any decision to drill a well: this could be done either via access to a JV SharePoint or via participation to QC Peer review.

Fig. 172 – Arbitrary seismic line through Disraeli Tay and Fulmar objectives, Gladstone and Pict



(Data courtesy of WesternGeco) WesternGeco

3.87. OilExco Operator, (Sterling Resources current well owner): well 21/23a-8, prospect Disraeli, Upper Jurassic Fulmar segment

This chapter will deal with the deeper Upper Jurassic Fulmar targeted by well 21/23a-8. Disraeli Deep was a 3-way-dip feature mapped in 3D, with uncertain fault sealing capability and mapping. The target reservoir was the Fulmar sandstones which Isochore shown syn-depositional thickening illustrating potential for locally derived sediment supply (re-worked Triassic sands?) and/or localised ponding of shelfal marine sands. Kimmeridge Clay Formation is an excellent top seal. As this prospect was fault closed to the east, fault seal was an absolute requirement. Here too mature source rock was demonstrated by Saxon and Pict fields. Seismic showed evidence of hydrocarbon migration along the eastern bounding fault zone. Trap was present prior to HC generation. OilExco noted evidence for HC migration at adjacent fault but the so called gas cloud seems questionable.

Overall CoS was estimated at 11% by Ikon Science. Their main pre-drill risks were seal (48%), reservoir (56%) and migration / timing (64%). OilExco risking assessment could not be found. Once again the risks were spread over all the parameters making focus on the real prospect weak points more difficult.

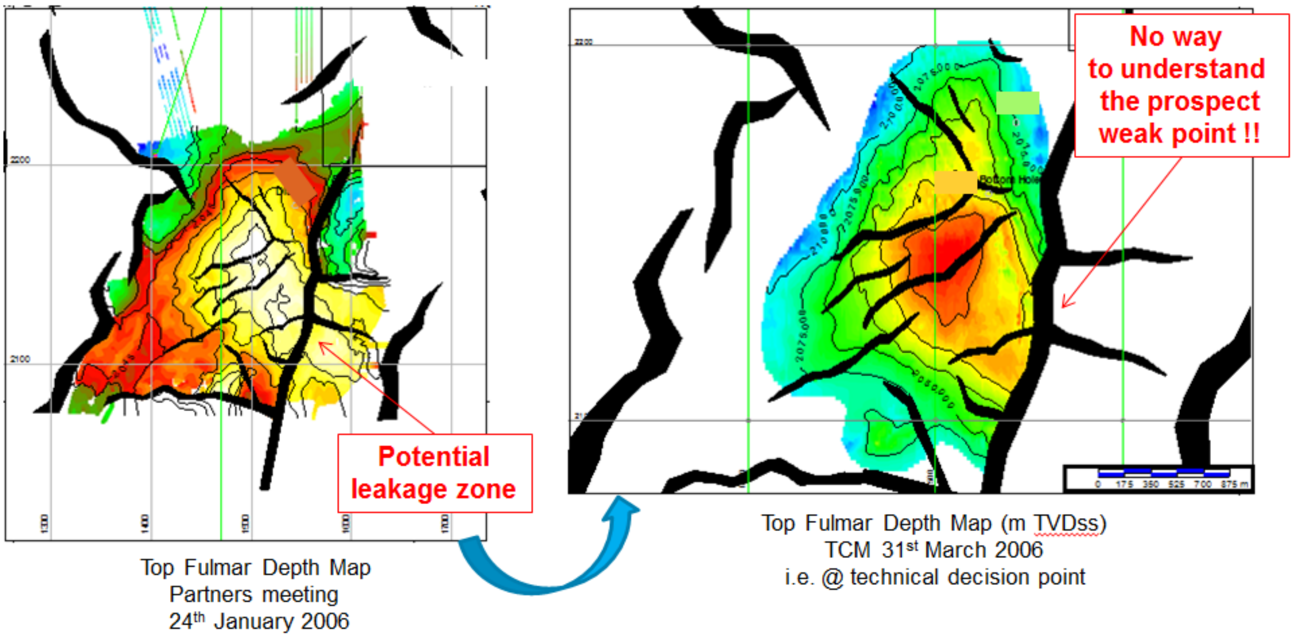
Top Fulmar was well spotted and came in 35 feet deeper than prognosed as well as Top Zechstein (+49 feet deep). Fulmar was water wet and rested directly over sandy Skagerrak Fm. 153 feet TVT thick Kimmeridge Clay Formation have been drilled providing an effective top seal. There were no shows in this deep segment but HC have been proven by side tracks -8Z (oil discovery in Tertiary thick sands) and -8Y (gas discovery in Tertiary thin sands) meaning the timing should be working and there is probably a migration pathway issue preventing HC sourcing of the deeper objectives.

The main reason for Disraeli Deep failure is very likely the lateral sealing which is not effective along the bounding fault. This potential issue was clearly illustrated on the map shown on the 24th January. On the contrary, 2 months later, on the very day of the Technical Committee Meeting, the map was truncated to the east and it was impossible to spot this weak point (**Fig. 173**).

Main lessons learned:

- Given the 3-way-dip nature of the trap, the fault sealing efficiency should have been studied in detail.
- Map should not have been truncated allowing partners to raise the potential lateral seal issue and giving time to study more in detail this particular weak point.
- An FIS should have been carried post well to check if there was some migration pathway issue regarding this pre-BCU Play.

Fig. 173 – Disraeli Deep: target maps comparison



3.88. Talisman-Sinopec: well 13/29b-9, Skate prospect

The Skate prospect was located between the Ross and Blake fields on the margin of the Kipper High with sandstones sourced either from the Blake area or, from the Halibut Horst.. This prospect was mainly identified on seismic as a mounded feature (**Fig. 174**). The reservoir was Aptian - Albian (Lower Cretaceous) and corresponds to submarine channel complex within the overall Captain Fairway. The Captain Sandstones seismic response is not unique as reflection strength and polarity are determined by presence of gas cap and the acoustic impedance contrast between variable overburden lithology and Captain Sandstone. The mounded form seen on Blake Field was interpreted as identical with that over Skate. Mounding and differential compaction were seen as proof of continuation of channelised Captain sand facies over Skate prospect although the seismic data quality was average and the Captain as well as the base Aptian pickings were, in places, voluntaristic (**Fig. 175**).

The Kimmeridge Clay Formation, as for Blake and Cromarty fields, was the expected source rock and migration was interpreted as coming locally from the Skate Basin and up the sand fairway to the NW.

At the time of drilling, the overall CoS was estimated at 32%, and given the poor seismic quality, the 80% CoS given to closure was, in retrospect, very optimistic. The key critical risk was trap definition (which included the seal risk) at 50%. Up dip separation from the Blake field was not straightforward. Additional pre-drill risks were attached to reservoir and petroleum system on an equal footing at 80%.

Well 13/29b-9 found excellent quality reservoir with net to gross and porosity in the high end of expectation and 7 ft (TVT) hydrocarbon column at the top of the Captain sandstones (gas? Paleo-column?). All significant pre-drill depth prognoses were within range. Rodby & Sola Formation claystones were drilled and would act as an effective top seal. The bottom seal was not reached as the Valhall Formation is sandy.

The main reason for failure is very likely the lack of valid trap and the absence of effective seal separating Skate from the up dip Blake field. Skate is another example where prediction of low-side volumes was inaccurate and below P99 estimate.

<u>Main lessons learned:</u>

- In retrospect, seismic picking of the mounded feature appears questionable. A detailed set of thickness maps across the whole Lower Cretaceous section may have been useful pre-drill.
- The interpretation may have been completed towards the SW allowing a better understanding of the trap (blank map to the SW were the prospect was assumed to close).
- There could have been a number of smaller closures as opposed to one elongated single closure.
- In this particular case, a pre-drill peer review would likely have highlighted the very high risk attached to the up dip sealing, hence the trap effectiveness.
- Prediction of low-side volumes was inaccurate because the net pay range was too narrow. Consequently, pre-drill volumes were over-estimated.
- Last but not least, no post drill map was found: this illustrates the lack of post well audit. Hence the difficulty in drawing meaningful lessons and increase corporate knowledge from well failures.

Fig. 174 – Skate prospect: Captain Sandstone depth structure map

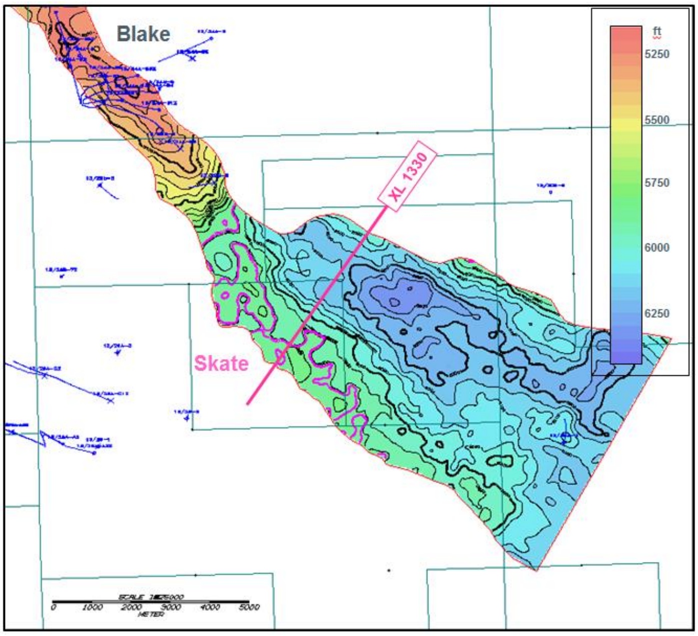
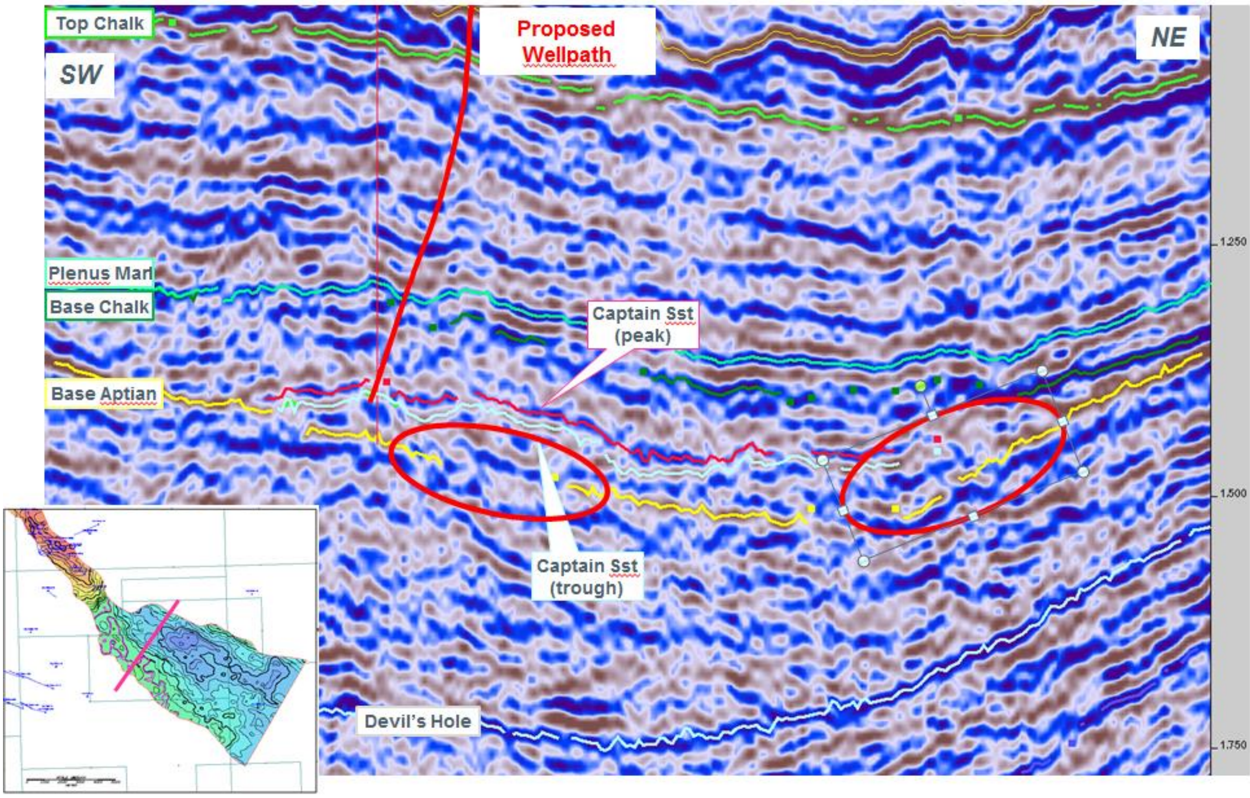


Fig. 175 – Seismic cross Line 1330 through along Skate proposed well path (Data Amerada Hess proprietary)



3.89. Talisman-Sinopec: well 14/18a-14, Dunnottar prospect

The Dunnottar prospect was located 3 km west of the Scapa Field. It was a stratigraphic play, dip closed to the east, with reservoir pinch out required to the north and reservoir cementation to the south along the Halibut Horst fault scarp (**Fig. 176)**. Reservoir was predicted to be stacked Lower Cretaceous Scapa sandstones corresponding to 3 reservoir units (from bottom to top: Leek sands, SA and SD sands) separated by intermediate seals. At the time of drilling, it was felt that acoustic impedance could not be used to discriminate lithology or fluids (**Fig. 177**). Presence of mature oil prone Kimmeridge Clay Formation source in communication with the prospect was considered certain. The basal seal had two components; at the pinch out edge the Scapa SA package was interpreted as onlaping the KCF, whereas towards the basin centre the basal seal was provided by the Scapa SA shale. Dunnottar was interpreted as being the mirror image of the 14/18b-7 Ardvreck discovery on the opposite side of the Bordeaux High.

The overall CoS was estimated at 27%. The main pre-drill risks were the trap geometry (which included the seal risk) at 50%. A critical trap element was closure to the south-west against the Bordeaux Nose – if the SA sandstones did not onlap and terminated against this feature there was nothing to close Dunnottar in this direction. Equally important was the reservoir presence and quality risk (50%).

The tops below the Chalk show significant departure from the prognosis, with some (Plenus Marl, Rodby, Sola and Leek Sandstone) falling outside the predicted error bars. The quality of the seismic picks was highly variable: the Rodby, Sola and SD sandstones were extremely difficult to map away from well control. Well 14/18a-14 found all 3 reservoirs water bearing, SA sandstones being 126 ft shallow to prognosis (but within error bar) and Leek sandstones being 360 ft deep to prognosis and thinner than expected. Net to Gross and porosity were near the high end of expectations. “SC” claystones and limestones provided an effective top seal while Leek shales provided the base seal.

The resistivity suite indicated some residual oil at the top of the SA sandstone. Some very poor, patchy shows were also encountered lower down within the SA sandstone indicating that the charge had been working.

As a consequence, trap appears to have failed because of a lateral seal failure (**Fig. 178**). The most likely reason is lateral communication of the SA sandstone with another sandstone body parallel to the basin axis or lack of SA sandstone pinch-out onto the BCU.

<u>Main lessons learned:</u>

- Primary target parameters were found within predicted range. Trap failure was identified as the key pre-drill risk meaning that this well, close to infrastructure, could easily be drilled again if the same data were available.
- The quality of the seismic picks was highly variable: the Rodby, Sola and SD sandstone were extremely difficult to map away from well control. Would a seismic reprocessing or a new 3D acquisition have changed the decision to drill Dunnottar?
- A more refined method should be applied to sub-chalk depth conversion for future well prognoses.
- Post well, the lack of dipmeter log was noted. Such a log acquisition should be compulsory for any stratigraphic trap.

Fig. 176 - Scapa “SA” sandstone depth structure map

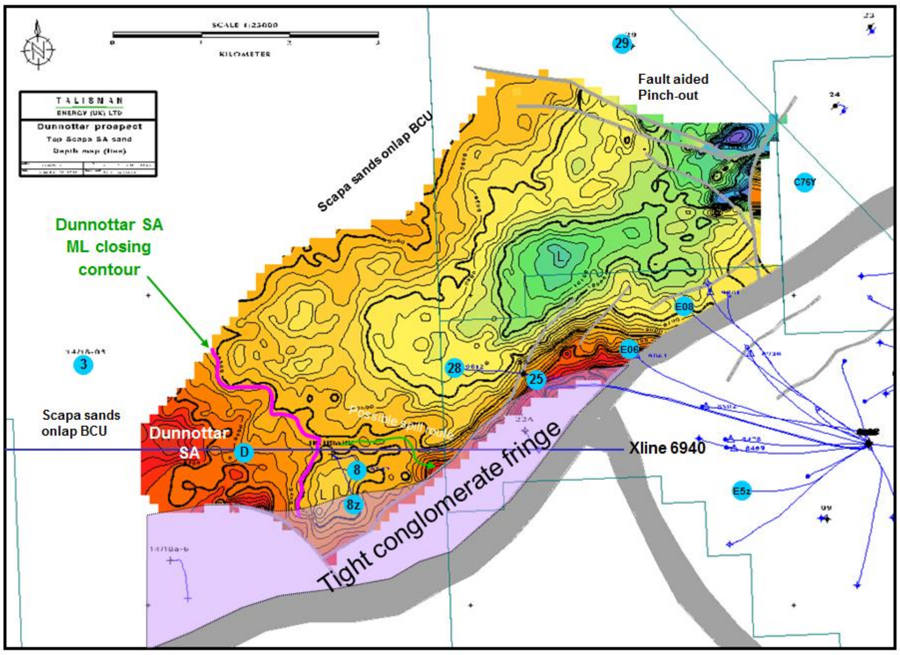


Fig. 177 - Pre-drill interpretation absolute Acoustic Impedance through Dunnottar location

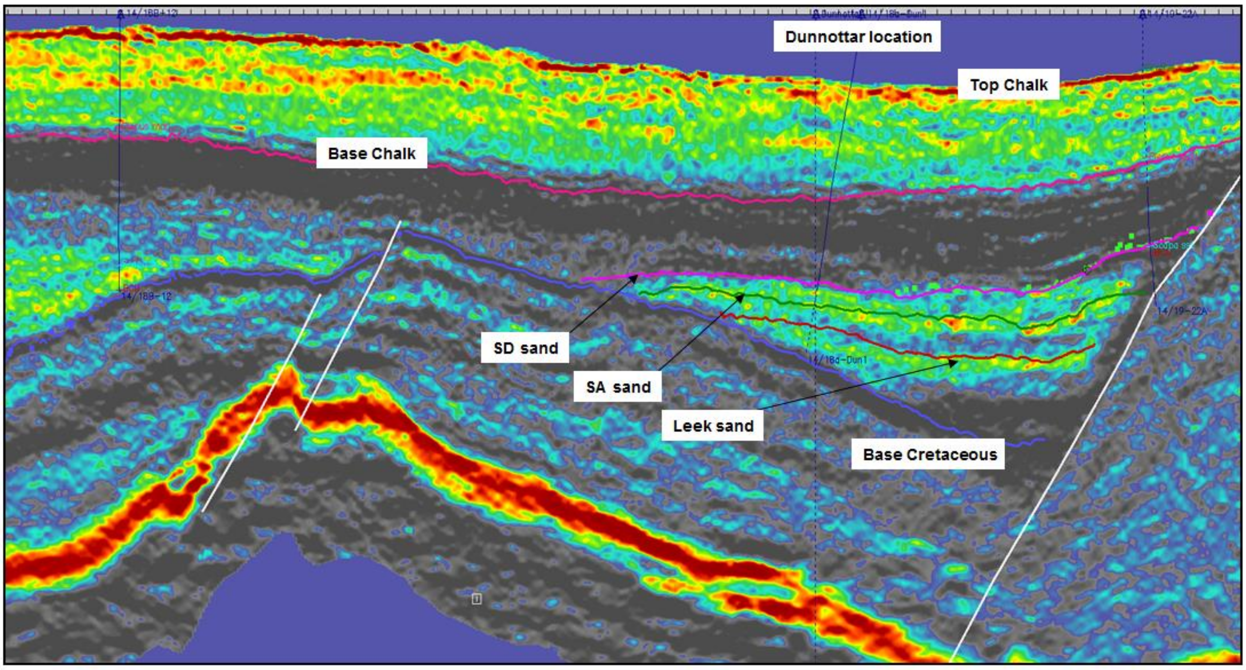
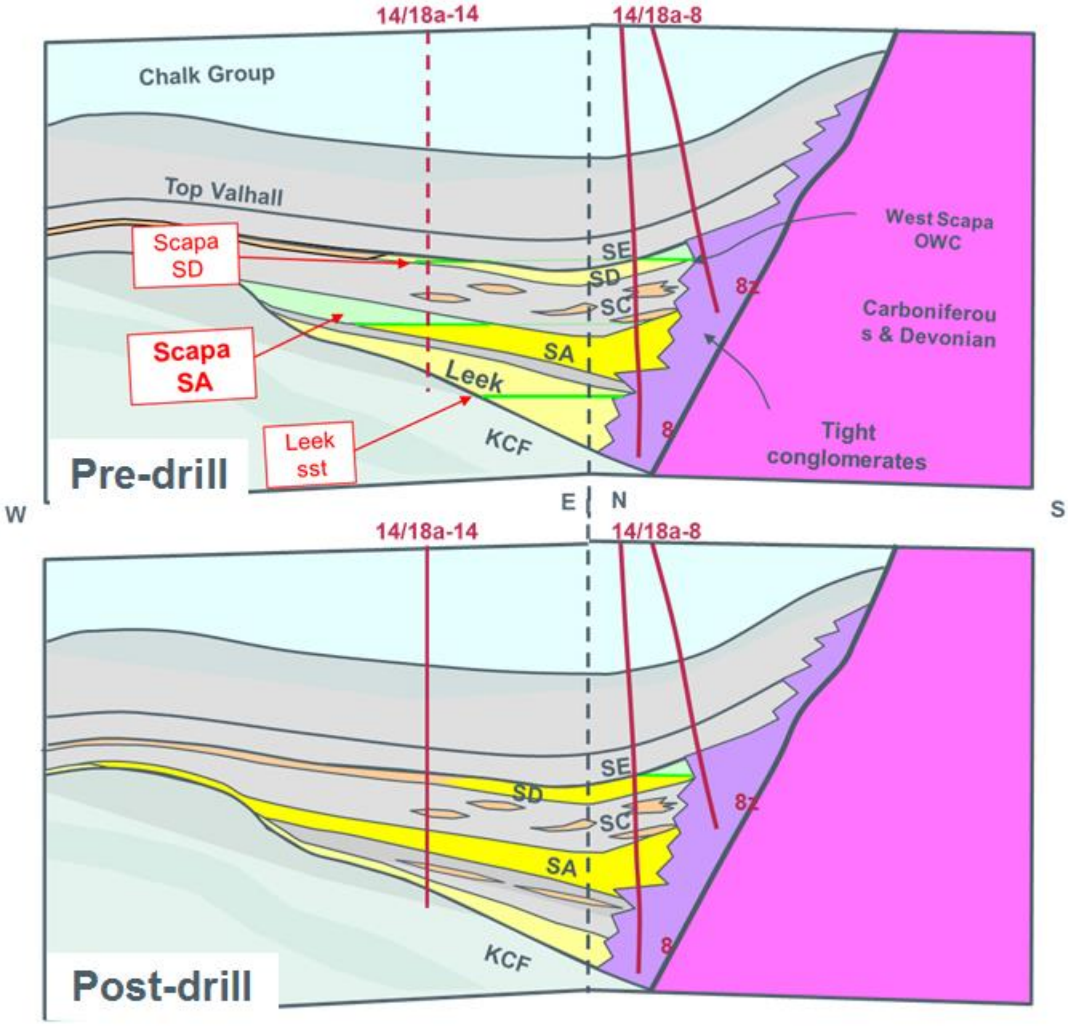


Fig. 178 - Schematic pre-drill vs post-drill cross sections



3.90. Talisman-Sinopec: well 14/20b-32, Cardhu prospect

The Cardhu prospect was located in a prolific Basin, between the Tartan and Highlander Fields. It was made of a southward-dipping terrace, downthrown against a major NW-SE trending fault system, the Highlander bounding fault (**Fig. 179**). The north-eastern boundary of the prospect was formed by a second, sub parallel fault which separated Cardhu in the footwall from the Witch Ground Graben in the hanging wall (**Fig. 180**). The target reservoir was shallow marine Upper Jurassic Piper sandstones. The Scapa-Highlander Sub-basin, contains thick, mature organic-rich Kimmeridge Clay Formation and has acted as a major source kitchen for hydrocarbon generation. There was thought to be little risk of Cardhu not being in communication with the KCF source.

Top seal was expected to be the Kimmeridge Clay Formation and base seal was interpreted to be the Triassic Smith Bank claystones. Two faults separated the Cardhu prospect from the 14/20-8 well and appeared to completely offset the reservoir section. Fault seal along this system was the key risk element for the prospect and had been analysed in detail using fault-plane (‘Allen’) diagrams.

The overall CoS was estimated at 50%. The main pre-drill geological risks were the lateral seal (65%) and the reservoir presence and quality at 85%.

The prognosed Formation tops for the lower part of the well were significantly different to the observed Formation tops. Indeed, well 14/20b-32 found the top Piper reservoir 301 ft shallow to prognosis and water bearing. Kimmeridge Clay was only 8 ft thick but Cromer Knoll claystones would have provided an effective top seal. Sourcing would likely still be efficient from the adjacent kitchens. Triassic Smith Bank was drilled as per expectations.

The likely main reason for failure was the breaching of the lateral seal: if the reservoir section is 300 ft higher across the whole fault block, it would enable leakage into the 14/20-8 block to the north-west. As there were no shows, one can wonder if the migration pathways had been effective. Unfortunately no fluid inclusion study was carried out post well allowing checking this possible additional issue.

<u>Main lessons learned:</u>

- The depth error may be caused by the low acoustic impedance contrast which existed at both the top and base of the reservoir. Top and base Piper events in the Cardhu area had been "ghosted".
- In addition, depth conversion was carried out in a single layer from seabed to Top Piper using all of the available wells in the Highlander field and the surrounding acreage (single linear regression). Additional time to depth conversion scenarios may have been useful in this particular setting.
- However, given the nearby production facilities and the overall fair to good quality 3D seismic data this well would likely have been drilled anyway. The key critical pre-drill risk turned to be the very likely reason of the well failure.
- Cardhu may also leak vertically because of the thin KCF (no top seal?).

Fig. 179 - Cardhu prospect: Top Piper Depth Structure Map

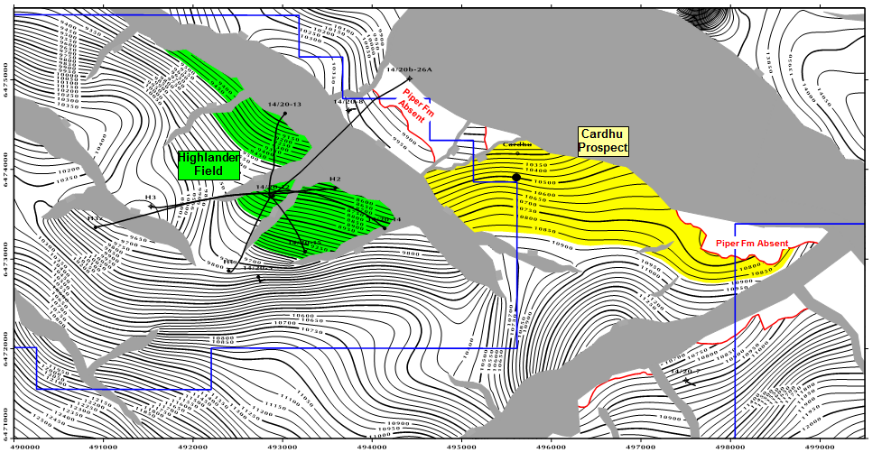
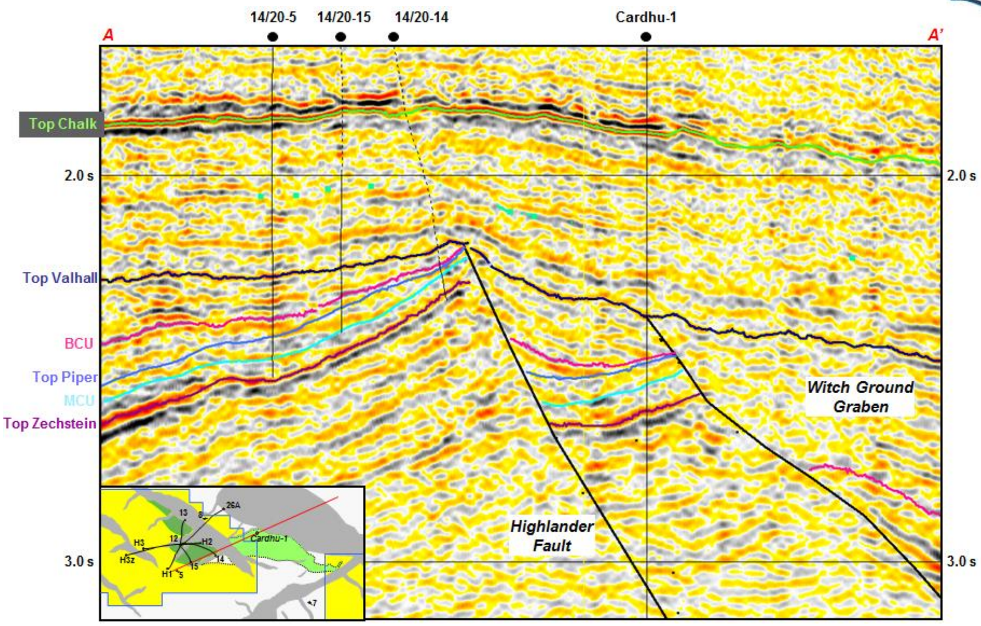


Fig. 180 - Seismic Traverse from Highlander to Cardhu **(Data courtesy of PGS)**



3.91. Talisman-Sinopec: well 14/25a-6A, MacDonald prospect

MacDonald was another near field prospect, located ~15 km to the south-west of the Tartan field. Well 14/25a-6A primary target was a seismically mapped fault bounded closure at the Upper Jurassic Piper level i.e. a downthrown 3-way dip closure against basement (**Fig. 181**). Secondary objectives consisted of structural / stratigraphic traps at the Scapa and Claymore levels. The area was covered by new PSDM seismic data. This helped firm-up the structural closure and better define the position of the boundary fault. However, picking of the Top Piper remained a step-up from MCU. The main target reservoir was Upper Jurassic shallow marine Piper sandstones. MacDonald is within a very prolific basin and this location was favourable for migration from regional Kimmeridge Clay Formation source proven in the area.

The structure being a high relief, 3-way dip and fault closure against the basement lateral seal was absolute requirement (**Fig. 182**). Statistics for downthrown traps in the region were presented showing a 50% -60% success rate. In addition, the top seal was required to be intact and able to hold an oil column of several hundred ft even in the P90 case.

The overall CoS was estimated at 29% with the critical pre-drill geological risks being the seal (59%) followed by the reservoir quality (because of the significant burial) and the trap geometry on an equal footing (~70%).

Top Piper was found 145 ft deep to prognosis but within error bar. The Kimmeridge Clay Formation was 448 ft high to prognosis and this discrepancy was attributed to the BCU being picked two legs deep on the seismic profile. Piper was found very hard and well indurated according to core analyses. The Claymore Sandstones had much more sandstone than anticipated while the Scapa had no significant sandstone developed. In the Piper Formation weak oil shows were observed while there were no shows at all in Scapa and Claymore sands. There was no top seal between Claymore & Piper sandstones. Pentland shales and Triassic Smith Bank provided effective base seal.

Three main reasons for failure are interpreted.

- The Piper sandstones had no top seal because Claymore sandstones were much thicker than expected
- The Piper and Scapa sandstones are pervasively cemented. Preliminary core analysis suggests early cement meaning this is fault-related rather than caused by hydrocarbon migration. (Note that Claymore sandstones are not cemented!).

- The very weak shows observed raise the question whether significant oil migrated through this structure?

Main lessons learned:

- Is the Piper early cementation related to the fault?
- Is the Kimmeridge Clay Formation located too far from the Piper target? Significant downward migration would be required to source the Piper sandstones, crossing through the Claymore sandstones…

Fig. 181 - MacDonald prospect: top Piper depth structure map

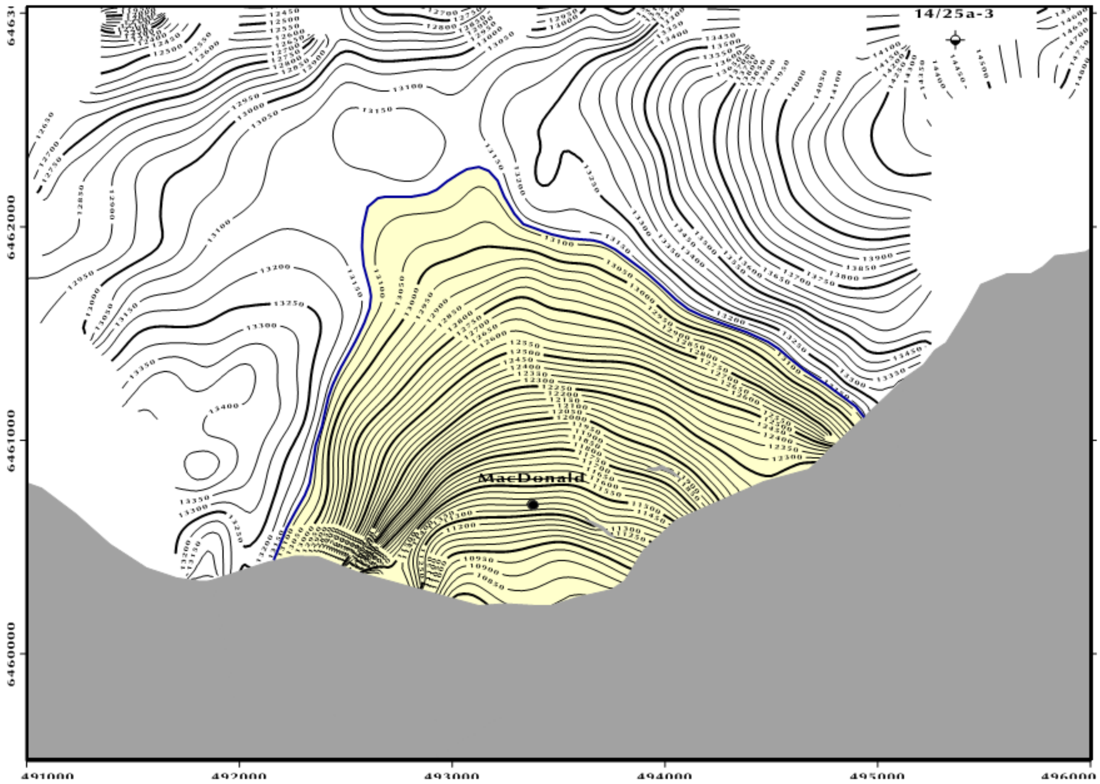
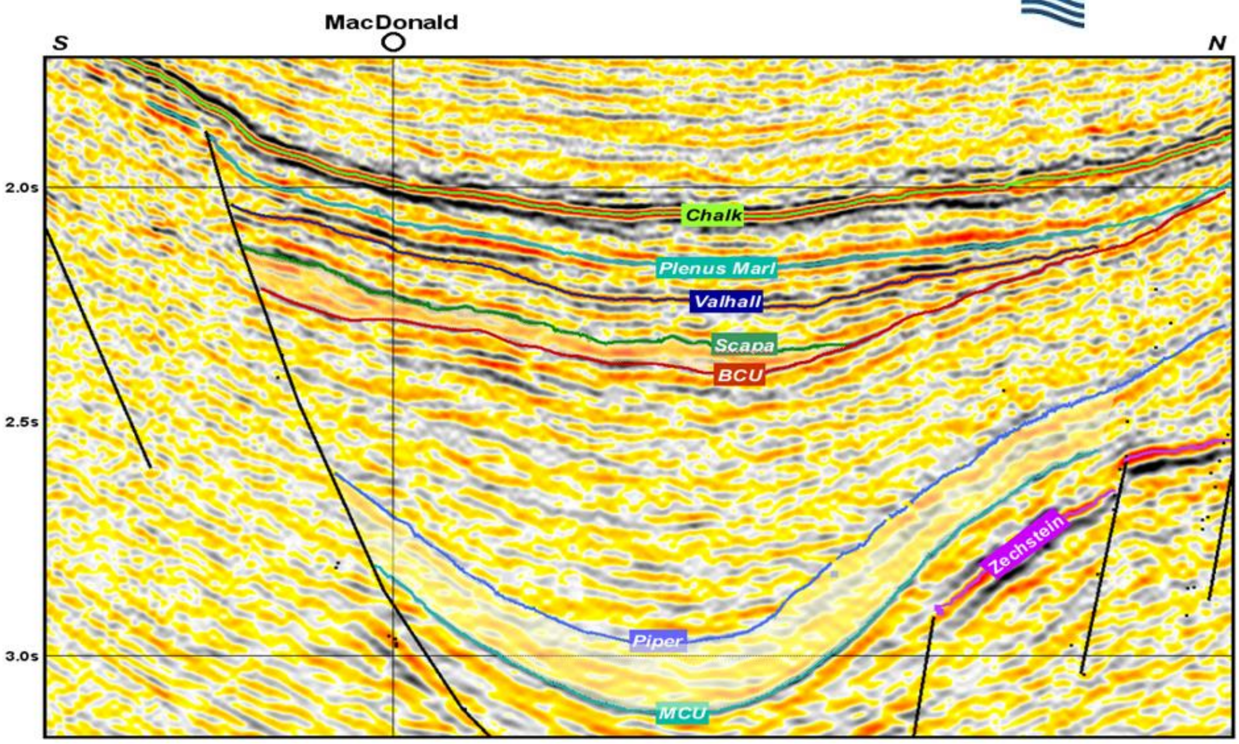


Fig. 182 - Seismic cross section showing MacDonald well path **(Data courtesy of PGS)**



3.92. Talisman-Sinopec: well 15/17-27, North Saltire prospect

The North Saltire prospect, located approximately 8 km southeast of the Piper Bravo platform, was a fault bounded terrace, up thrown to the developed Saltire field, with which it was considered closely analogous (**Fig. 183**). The prospect was a south-easterly dipping terrace, bounded on all sides by faults. The range of depth residuals, the uncertainty in gross reservoir thickness and the lack of a direct seismic tie into the prospect area indicated a depth uncertainty of +300 /-250 ft at top reservoir. The reservoir objectives for the North Saltire prospect were the Upper Jurassic Piper and Lower Galley sandstone members. Syn-sedimentary movements on bounding faults were critical to the distribution and preservation of reservoir in Saltire and it was anticipated to have had a major influence in North Saltire (**Fig. 184**). The oil was sourced from the Kimmeridge Shale in the Witch Ground Graben that lies directly to the south-west of the Saltire Field and North Saltire prospect. Prospect communication with mature source rock was considered highly probable; however fill relied on cross-fault breakdown with the Saltire field. The western boundary was considered to present the highest risk of cross fault leakage. Strata offset were potentially small and the fracture density potentially high. There was also scope for overlap of reservoir against Carboniferous, and therefore leakage through potentially permeable Carboniferous Forth Formation sandstones.

The overall CoS was estimated at 30%. The main pre-drill geological risk was the seal (43%) and particularly the lateral seal with the western boundary defined as highest risk. The reservoir risk was set at 89% because a small risk was applied to the possibility of bypass. Reservoir quality may also have been slightly degraded due to the presence of pore occluding calcite. Migration into North Saltire trap was assessed at 89%.

Formation tops were all within tolerance of their prognosed depths down to the BCU. Well 15/17-27 found base reservoir on depth. Sandstones encountered were both of probable Piper and Galley age. Total gross reservoir interval penetrated was 672 ft versus prognosed interval of 400 ft. Significantly thickened Galley aged sandstone interval meant that the Kimmeridge Clay Formation was thin (45 ft). High quality sandstones have been encountered but they were wet with no evidence for hydrocarbons. Top seal was thinner than expected (45 ft KCF). Tuffaceous claystones from the Rattray Formation provided the base seal (**Fig. 185**).

Thickened reservoir interval resulted in the probable juxtaposition of sand on footwall and hanging wall of Northern bounding fault. This is the most likely reason for North Saltire failure. In addition as there were no shows while drilling, there may have been an additional issue regarding migration pathways?

<u>Main lessons learned:</u>

- Given the nearby production facilities and the overall fair to good quality 3D seismic data this well would likely have been drilled anyway. The key critical pre-drill risk turned to be the likely reason of the well failure.
- A post well fluid Inclusion study would have helped confirming there was no migration issue.

Fig. 183 - North Saltire: top Lower Galley/Piper depth structure map

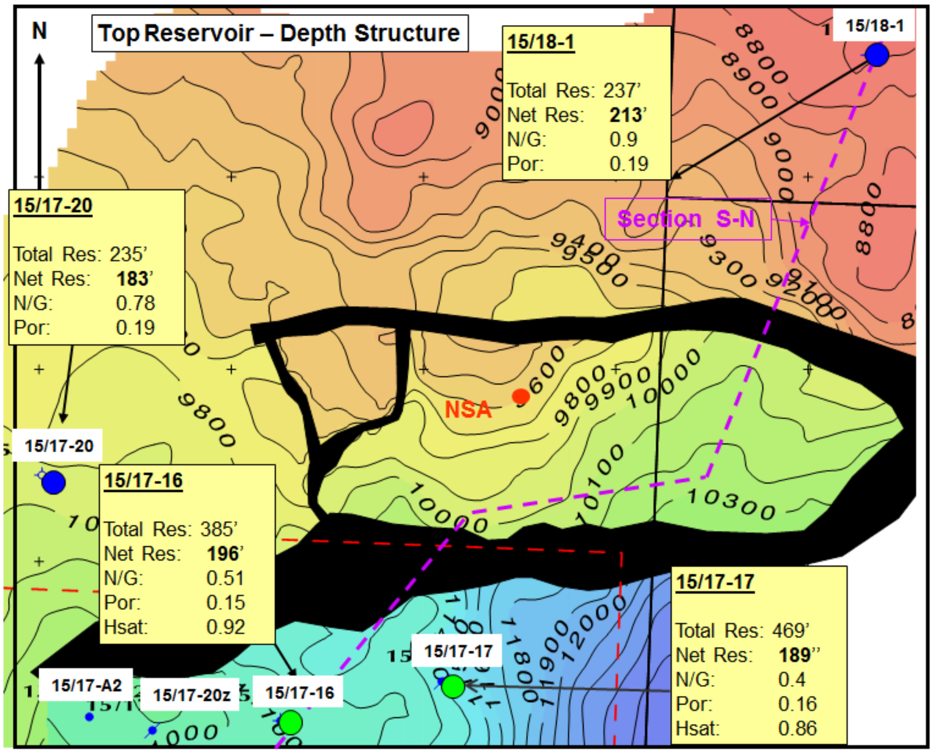


Fig. 184 - S-N Seismic line through Egilsay, Chanter, Saltire, North Saltire and 15/18-1 **(Data courtesy of PGS)**

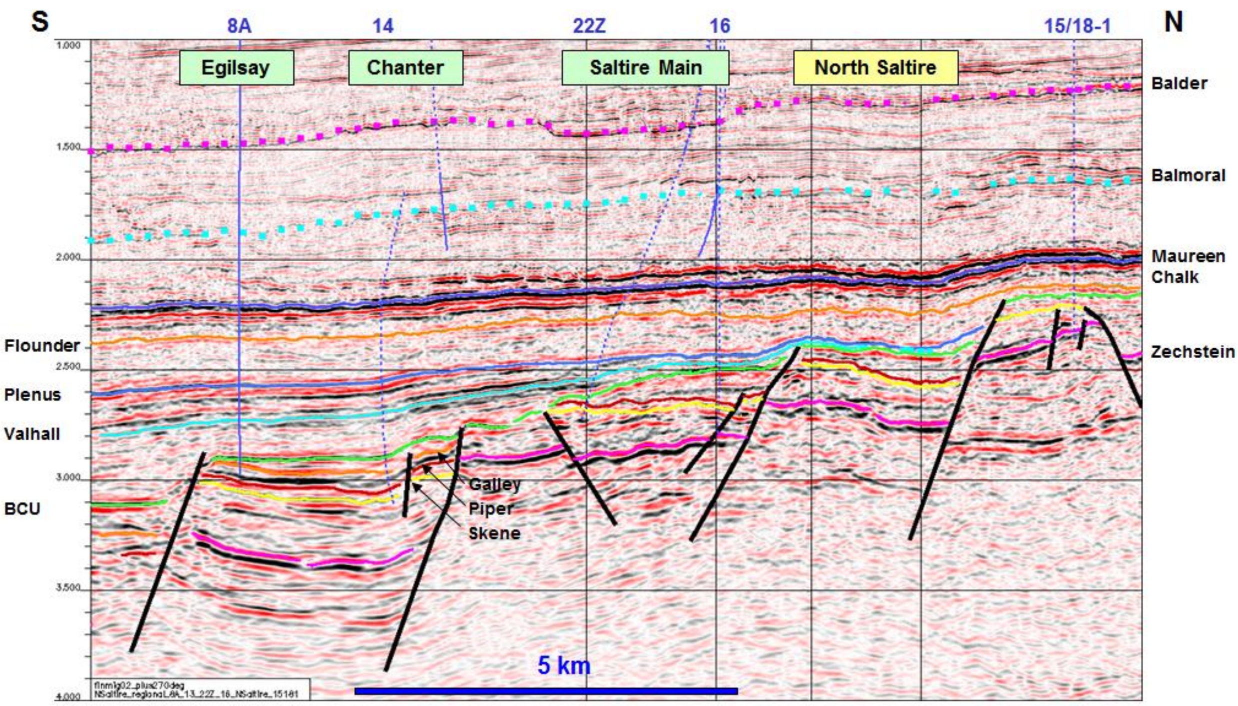
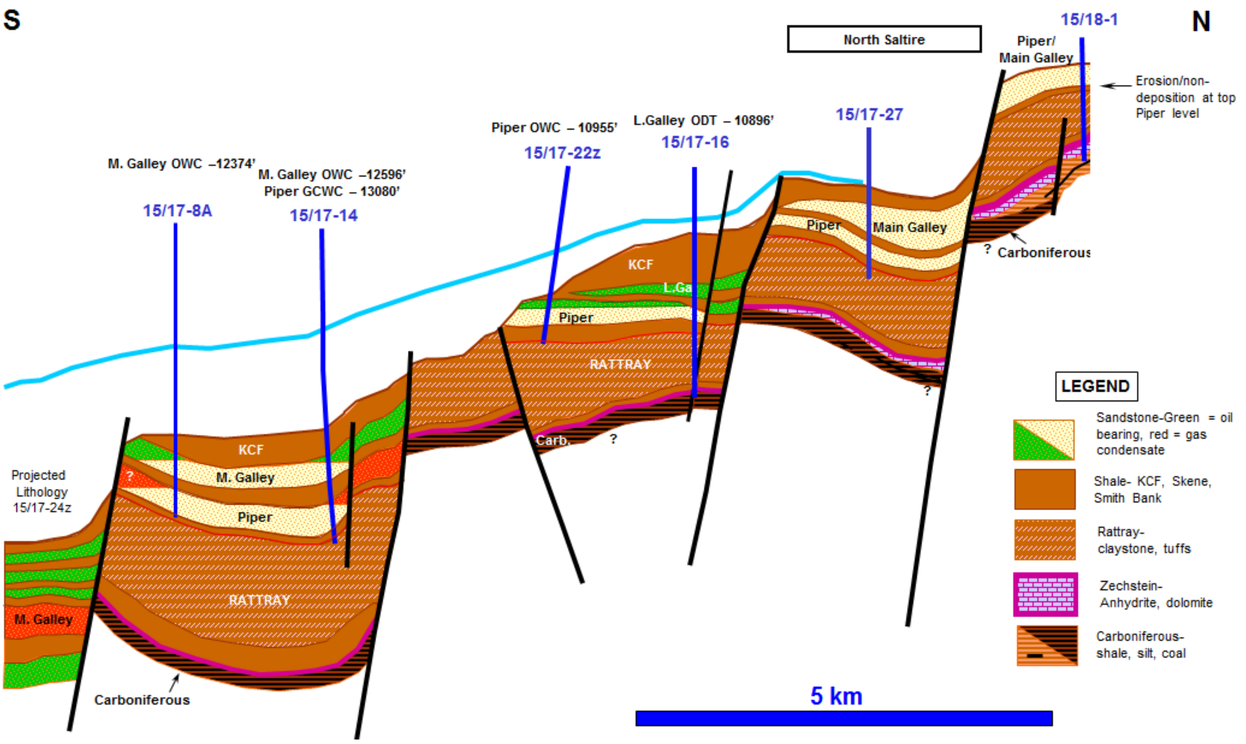


Fig. **185** - 15/17-27 – North Saltire post-drill south-north geoseismic cross-section



3.93. Talisman-Sinopec: well 20/05c-11, Sligachan prospect

The 20/5a-Sligachan Prospect was located on the western edge of the North Buchan Trough. It lay immediately east of the Cretaceous Hannay field, 13 km west of the upper Jurassic Tweedsmuir and Tweedsmuir South fields, and 7 km north of the Devonian Buchan field. The 20/5a-Sligachan well was an exploration well designed to test Intra-Kimmeridge Clay Formation sandstone, mostly dependent on stratigraphic closure, with potential fault seal closure to the west, dependant on how far the sand continues beyond the amplitude response (**Fig. 186**). Sligachan was defined by a seismic amplitude event interpreted at or near the "J72" chronostratigraphic level, within the deep-water claystones of the Kimmeridge Clay Formation (KCF, **Fig. 187**). The brightening was analogous to that seen at Tweedsmuir and Tweedsmuir South, which defines the sand limits of a high porosity basin floor fan deposited at the "J65" Burns level of the KCF. Although there was a geological model to support the existence of a basin floor fan system, reservoir presence at Sligachan was largely based on a seismic amplitude correlation. Seismic modelling showed a minimal fluid response and, therefore, the bright amplitudes were interpreted to be due to lithology.
The organic-rich shales of the Kimmeridge Clay are the sole source for the hydrocarbons in the proven North Buchan Basin. Risk on migration was deemed to be low as the sandstones were expected to be stratigraphically encased within the Kimmeridge Clay Formation and were proximal to the generating source kitchen. These Kimmeridge shales were expected to provide the top, bottom and lateral seals The overall CoS was estimated at 27%. The main pre-drill geologic risks were the reservoir (53%) followed by the seal (60%) and the trap geometry (73%).

Well 20/05c-11 found no reservoir at all within the Kimmeridge Clay Formation. This is obviously the key reason for well failure. In such a case both the trap geometry and migration parameters stay unresolved. Seismic amplitude anomaly neither corresponds to lithology nor to hydrocarbon content.

<u>Main lessons learned:</u>

- "During the reprocessing, attention was paid to multiple removal and final temporal resolution, which included the use of inverse Q and spectral balancing. There was some remnant multiple contaminations that have proved difficult to remove without suppressing signal. It is likely that some of this contamination was due to internal multiples generated in the Tertiary section as well as remnant seabed multiples." Would a new better 3D dataset have help resolving the target interval??

Fig. 186 - Intra KCF sand (ca. Top J72) Isochron RMS Amp - 30 ms window on Coloured Inversion

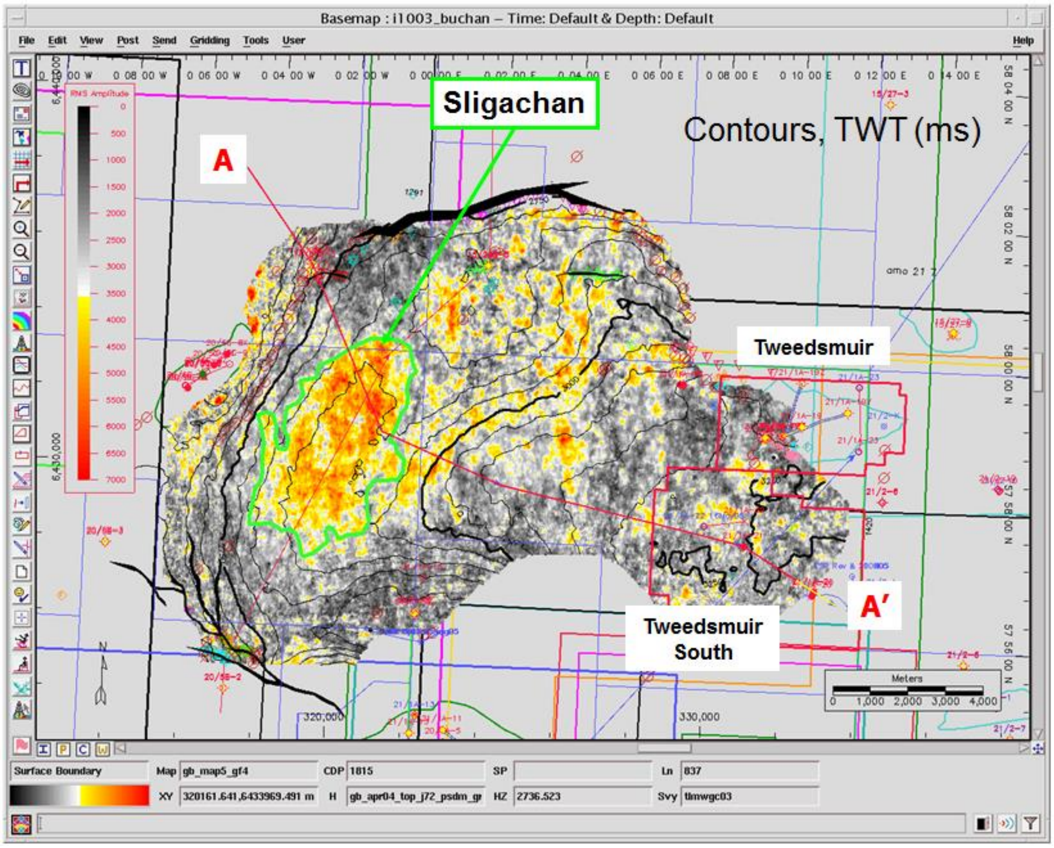
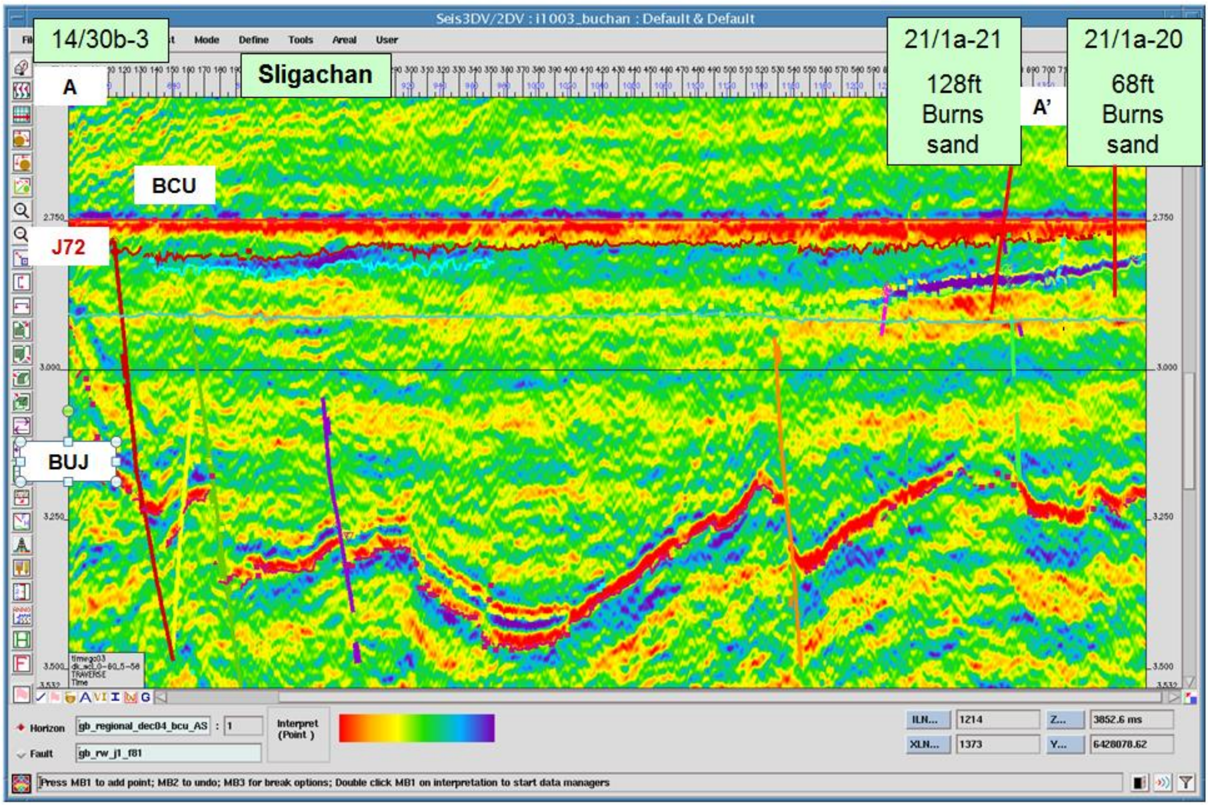


Fig. 187 - Traverse A – A' Sligachan to Tweedsmuir South: acoustic impedance flattened at BCU



3.94. Talisman-Sinopec: well 30/13-8, Jenny prospect

The Jenny prospect was located 14 km northeast of the Clyde platform in the southern part of the Central North Sea. It encompassed a stacked series of reservoirs comprising the Palaeocene Mey Sandstone Formation and the allochthonous chalk turbidite parts of the underlying Ekofisk and Tor Formations. The prospect was a steep sided dip closure on the flanks of a deep-seated salt diapir (**Fig. 188**), where the up-dip lateral seal was provided by the salt. The Mey Sandstone is present regionally, varying in thickness from 13-78 ft, with a top seal provided by the Lista and Sele Shale Formations. The Ekofisk and Tor Chalk Formations are regionally extensive units of variable thickness (200-900 ft) with overlying Palaeocene shales and claystones providing a top seal for the Ekofisk reservoir, and non-porous basal Ekofisk chalk providing a top seal for the Tor reservoir.

The source rock for both Palaeocene sand and Cretaceous Chalk reservoirs was expected to be the Kimmeridge Clay Formation (KCF) of the Upper Jurassic. Migration of the hydrocarbons is primarily in a vertical direction up the basin bounding faults and those that also breach the Chalk Group. Lateral migration within the chalk was thought to be limited to the allochthonous zones due to the very low permeabilities of the autochthonous chalk. Effective migration within the 30/13c area is proven by the hydrocarbons encountered in wells 30/13-1 and 2 Josephine discovery together with the Orion, Affleck and Flyndre accumulations in adjacent blocks.

The overall CoS was estimated at 37% for the primary Tor Formation objective. The two main geological pre-drill risks were the seal and migration on an equal footing (72%). In fact, the two key risks identified were the effectiveness of migration pathway into the Chalk reservoirs and the ability of the trap to retain hydrocarbons during later stages of salt movement. A further risk identified for the Tor was top seal i.e. possible vertical communication with overlying Ekofisk unit.

All the Formation tops came in as prognosed within the given error margin even though Top Tor came in 401 ft shallow to prognosis. Well 30/13c-8 did not encounter hydrocarbons in reservoir quality rock in either Palaeocene or Chalk. Mey sandstones were not developed. Thick slumped Upper Tor section was drilled but no porous uppermost Tor Formation was present. There was no evidence of reworked chalk debris flows. Unexpected diagenesis in fracture system was observed with fractures and macro pores cemented by ferroan dolomite and halite. Top seals are present for both chalk and Palaeocene intervals (Maureen Formation claystones). There were rare patchy oil stains on cuttings associated with fracture systems in chalk.

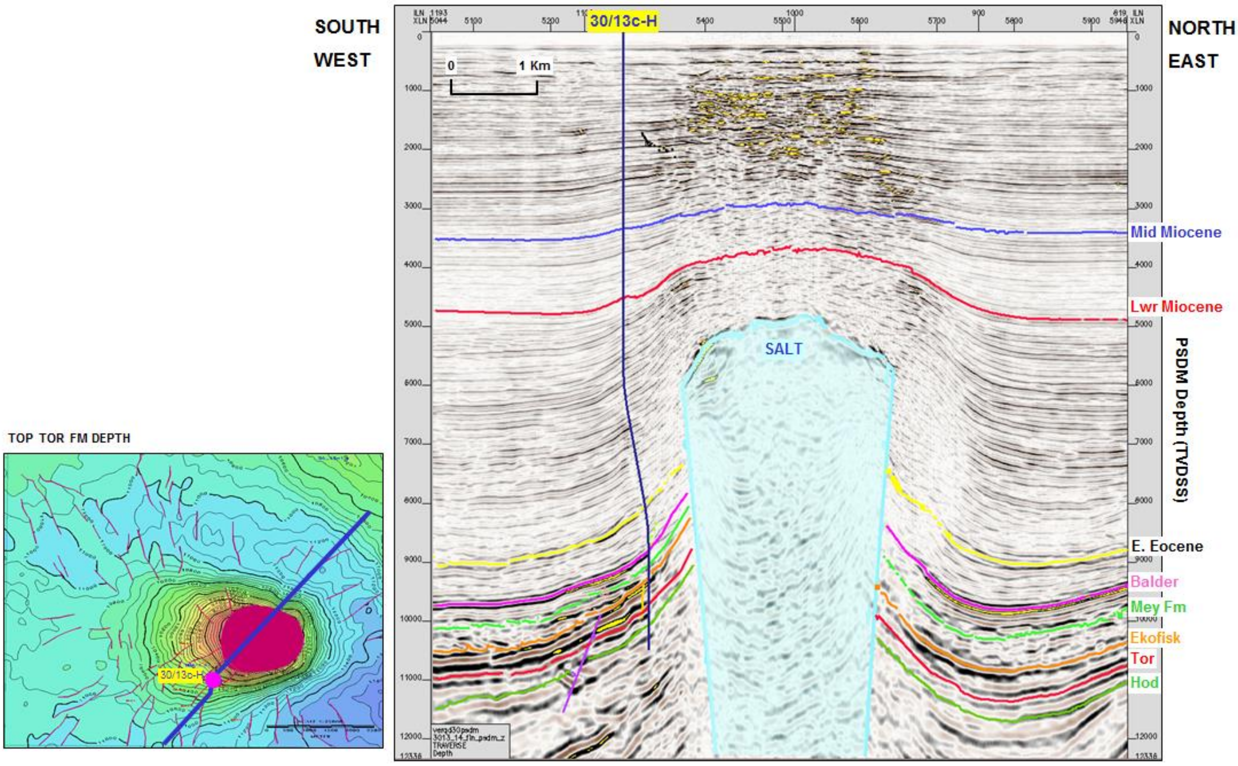
The main reason for failure is interpreted to be the tightness of the reservoir. In addition it is possible that lateral seal and HC migration also failed. Lateral seal against the diapir may be compromised by fracture systems. Is the SW side of the Jenny diapir in a migration shadow? Was the formation tight before onset of hydrocarbon generation and migration?

<u>Main lessons learned:</u>

- It is difficult to discern a single reason for 30/13c-8 failure given the atypical sequence that the well encountered combined with limited seismic resolution in the vicinity of the well location.
- The atypical chalk sequence may be caused by the well path being too close to the salt diapir (halite was described in fractures). If this is the case, remaining potential with a stratigraphic trapping mechanism may exist away from salt.
- Also when looking at seismic (**Fig. 188**) one may wonder if the overall top seal was breached?
- Any further look at prospectivity around / below salt diapirs should now rely on OBC / OBN 3D seismic data. This recently developed technology was not available 10 years ago.

Fig. 188 - 30/13c-H (Jenny): SW-NE seismic tie line

(Veritas data, courtesy of CGG)



3.95. Talisman-Sinopec: well 30/17b-16, Eta 2 prospect

The 30/17b-16 vertical exploration well targeted a Rotliegendes tilted fault block (**Fig. 189**) which had not been fully assessed by 2 previous deviated wells (30/17b-A34 and -34Z) drilled from the Clyde platform located ~ 4 km to the south-west. The ETA1-A34 well failed (stuck in Zechstein) and was subsequently abandoned. The well was revisited in 2000 with a side-track (-34Z) which also became stuck in the Zechstein.

The targeted reservoir was the Rotliegendes sandstones like in the Auk field. Mature Kimmeridge Clay Formation kitchens lie adjacent to the prospect, and small areas of close juxtaposition between source rock and reservoir had been mapped seismically. Oil shows in the 30/17b-8 well proved that migration via this mechanism works in the block. Sealing was seen as almost certain (90%).

Risking (pre-30/17b-34Z) concluded that the main risk was set on the migration pathways and overall CoS was 25%. However, during subsequent milling operations in well 30/17b-34Z gas pulses of up to 3% were recorded with C1-C4 components: this gave more confidence regarding the sourcing aspect and the overall CoS rose to 65%. Sticking to the pre-34Z CoS, the critical pre-drill geological risk was hydrocarbon charge (set at 35%), which relied on the juxtaposition of Kimmeridge Clay and Rotliegend sandstones on the flank of the Eta 2 structure.

All picks came in as per prognosis. 636 ft of Rotliegendes reservoir section was drilled by well 30/17b-16 and found with good properties (N/G = 100%; average porosity = 15%) but was water bearing. Zechstein claystones and halite provided the top seal.

A series of dip oriented seismic lines from the CGG Cornerstone 3D data set (which was not available at the time of drilling) clearly illustrate that the failure to find hydrocarbons in Eta-2 is almost certainly due to the lack of an effective migration pathway from the Kimmeridge Clay into the Rotliegendes reservoir (**Fig. 190**).

Main lessons learned:

- With hindsight, the correlation of close juxtaposition of Kimmeridge Clay and Rotliegendes with a low migration risk was too simplistic: migration pathways need to be worked in detail.
- The low migration risk was coloured by the optimistic interpretation of hydrocarbon presence at TD in well 30/17b-34Z. The moderate gas increase seen on the 30/17b-34Z mud log started before entering the Rotliegendes: could it be related to the thin but rich Kupferschiefer (Zechstein) overlying the Rotliegendes?
- However, such a well-defined structural trap located close to production facilities would probably have been drilled in any case.

Fig. 189 - Eta 2 prospect: Top Rotliegendes depth structure map (ft)

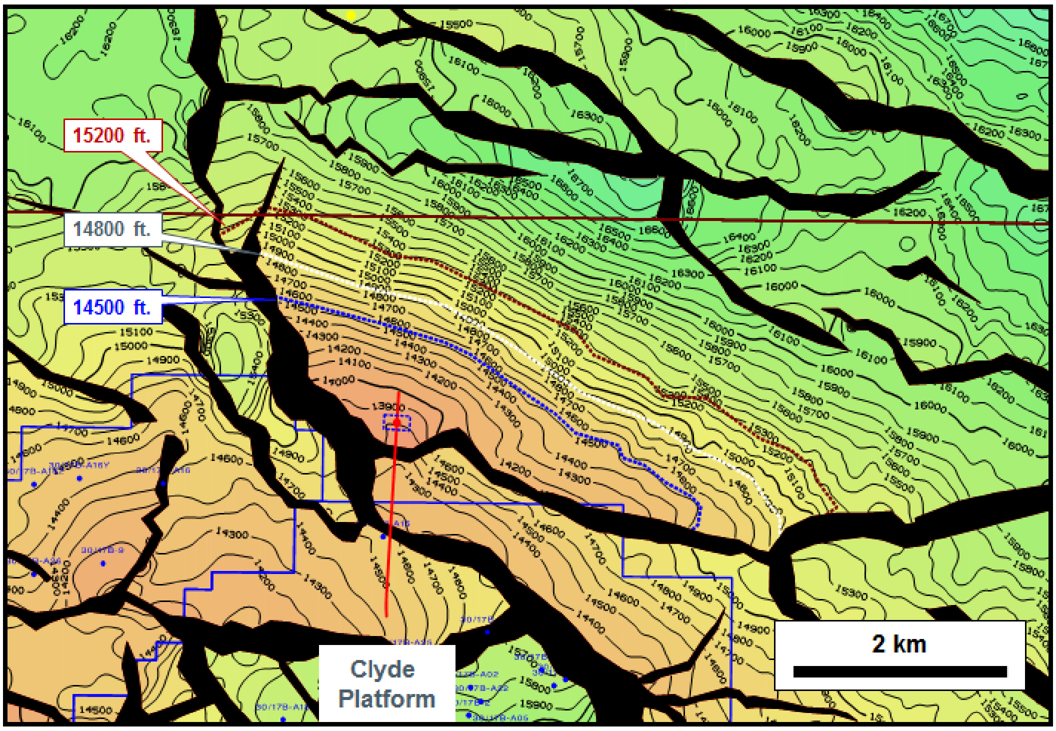
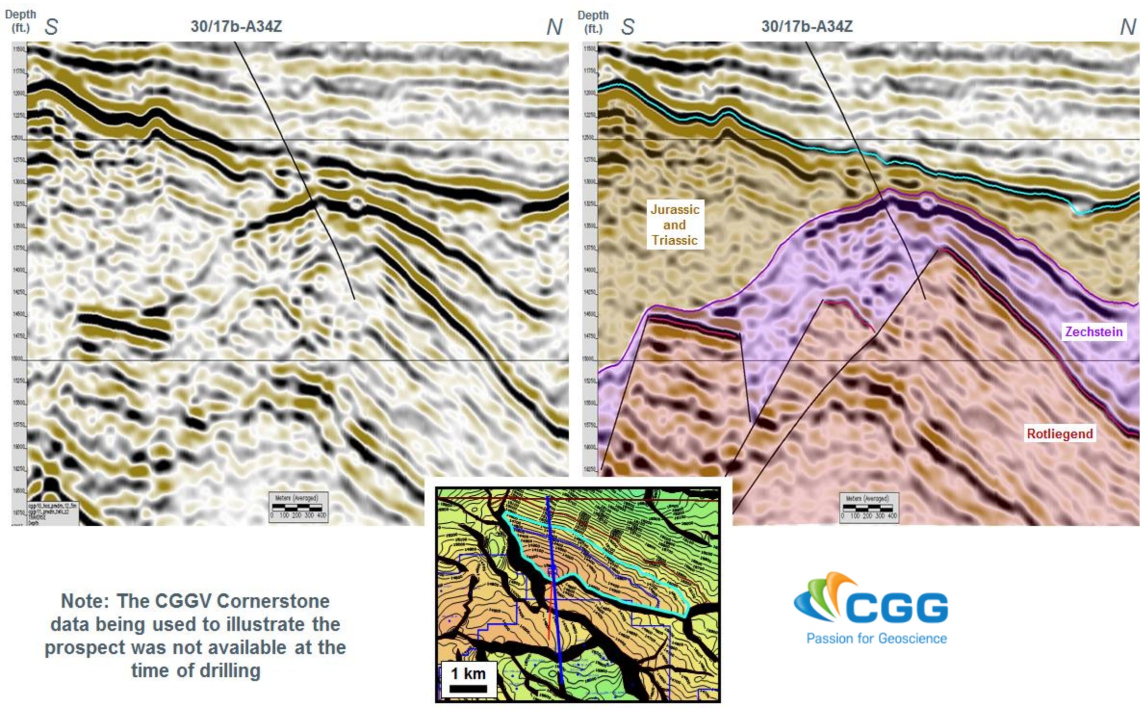


Fig. 190 - North-South seismic random line through Eta 2 prospect **(Data courtesy of CGG)**



3.96. Total: well 30/1c-9, Kessog discovery

The 30/01c-9 well was designed to appraise the un-developed Kessog discovery made by BP in the 1980s (**Fig. 191**). The HP-HT Kessog discovery made by BP in 1985-1987 was the largest undeveloped discovery in the Central North Sea and located only 25 km from the Elgin platform. Kessog is a NW-SE trending structure; the accumulation is located within a complex tilted fault block that has been subjected to erosion and affected by salt withdrawal from its core (**Fig. 192**). Top seal is the Heather Formation (for the Pentland reservoirs) and lateral sealing across faults is provided by Basal Mudstone. Most of the hydrocarbon is trapped within meandering fluvial channels from the Pentland Formation. The existing DST tests were too short to assess if economic volumes could be accessed. The hydrocarbon contacts seemed to be segmented even though all contacts were “hydrocarbon down to” (HCDT).

Between 2002 and 2003 a joint subsurface study was undertaken by TOTAL and BP in order to better understand the main uncertainty which concerns the reservoir bodies’ connectivity and, consequently, the potential recovery factor. The overall aim was to transform this stranded discovery into a producing field.

In 2006 a new appraisal well was drilled in order to define the OWC, carry out an Extended Well Test (EWT) proving 65 mmboe of connected volume and be kept as a future producer. Well 30/1c-9 found the ODT deeper than the 2P case and the OWC was constrained by a WUT 11m deeper. The water head pressure plot already showed lateral disconnection between different wells and vertical disconnection between reservoirs (**Fig. 193**). The EWT showed that the connected volume was much smaller (~5 mmboe) than expected (65 mmboe) and results were far from what was expected in terms of background permeability and sand bodies’ connectivity (**Fig. 194**).

Thanks to the new cores, it was understood that the low sinuosity channel (in Pentland main sandstone) was responsible for poor lateral and vertical connectivity. Although the in place volume was still in line with predrill evaluation, the EWT interpretation highlighted that a very high number of wells would be required to economically produce Kessog. The results led Total EPUK and its partner BP to relinquish the license.

<u>Main lessons learned:</u>

- The information brought by the 30/1c-9 was crucial; it invalidated the development strategy and led to license relinquishment.
- Prior to any DST, modelling should be performed to define the duration required to address the key uncertainty. When this is the nature and quality of fluid, a relatively short duration maybe sufficient. If knowing the connected volume is vital to understand if a development can be economic longer tests are required. OGA must adapt accordingly the test duration and volume of hydrocarbon produced and grant the relevant dispensation.
- Generally speaking, these results also show how difficult it is to find economically producible HP/HT hydrocarbons in such poorly connected continental reservoirs.

Fig. 191 - Kessog discovery: Top Pentland depth map; seismic and geological cross sections

(Data courtesy of CGG)

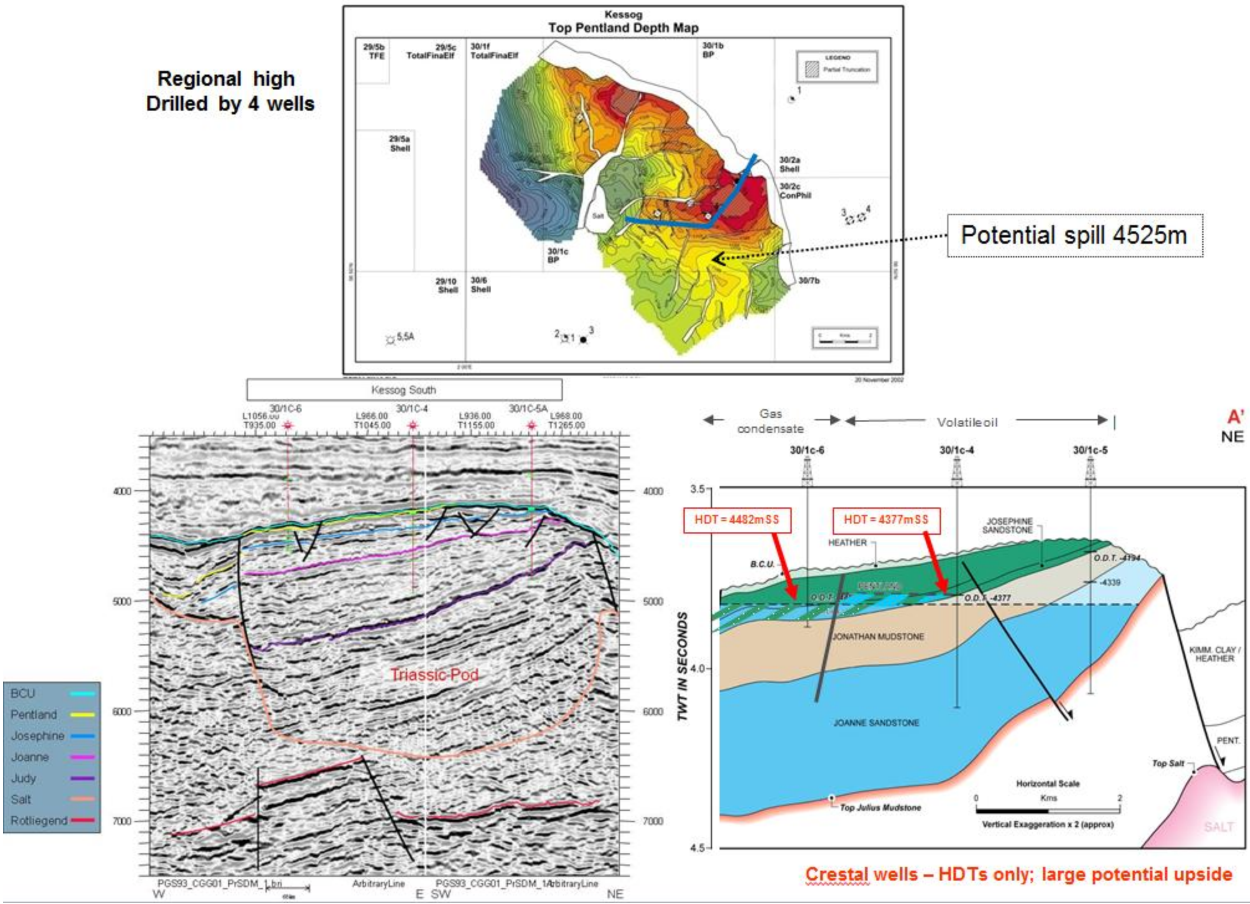


Fig. 192 - Post well interpretation on CGGV Pre-SDM 2008 **(Data courtesy of CGG)**

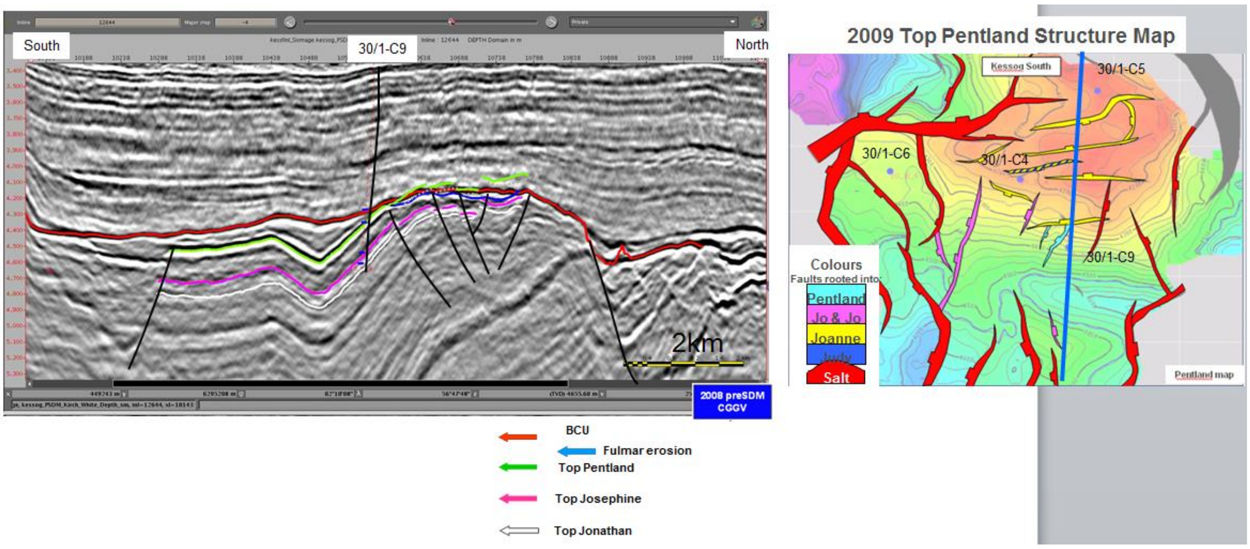


Fig. 193 - Kessog water head pressure plot including well 30/1c-9

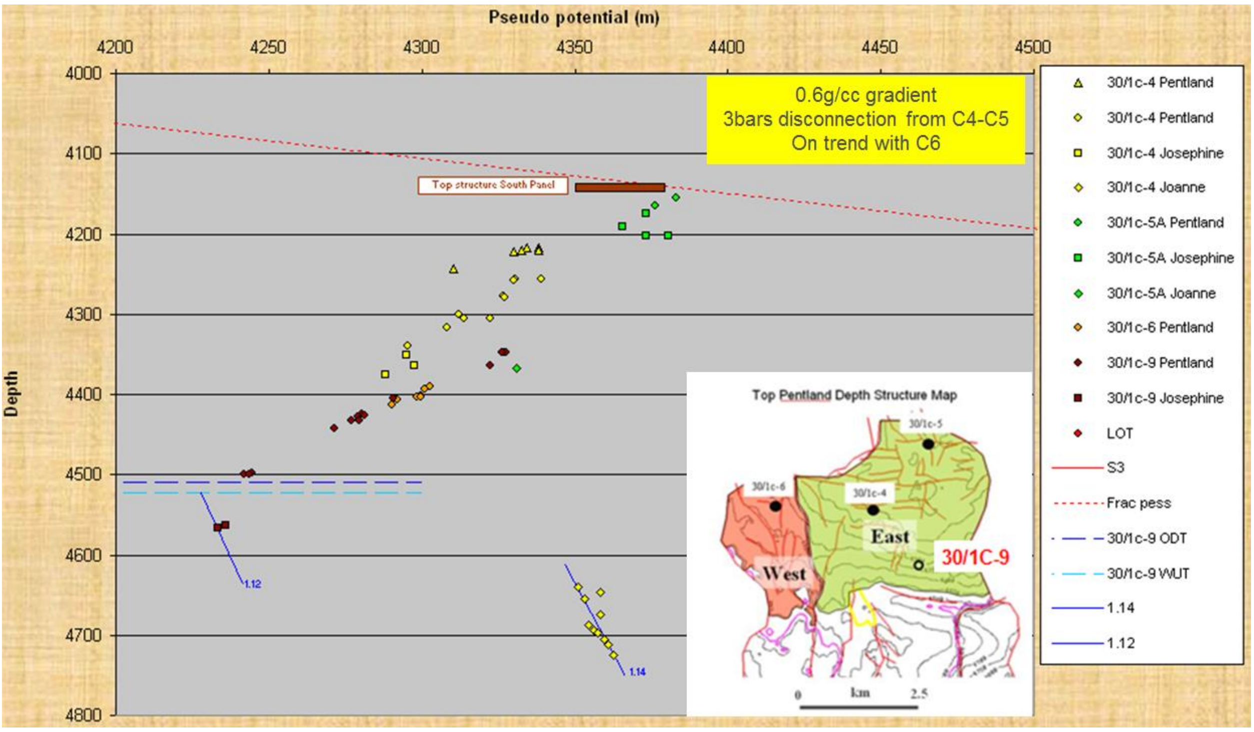
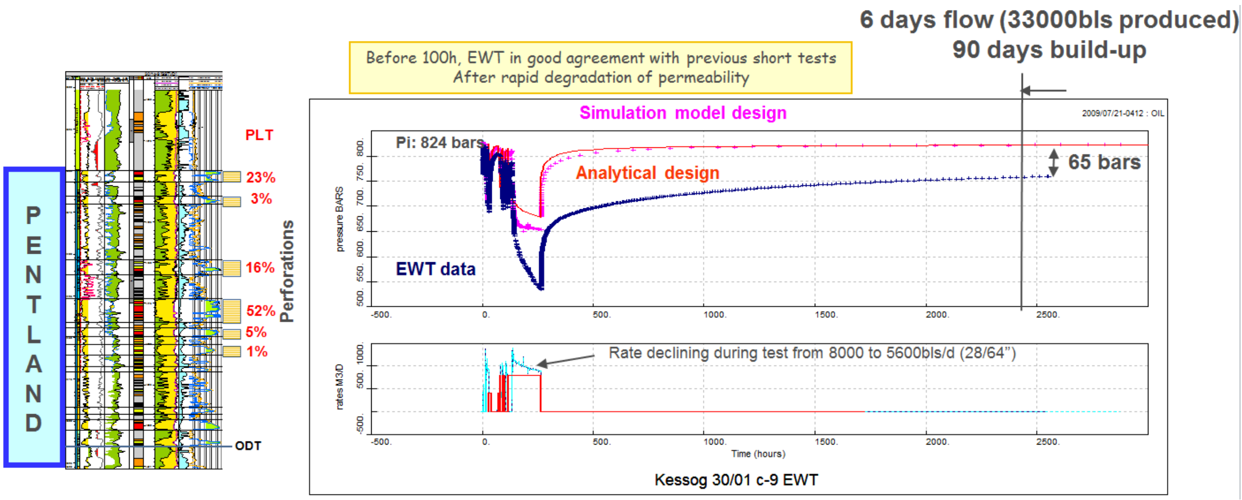


Fig. 194 - Well 30/1c-9 Extended Well Test results



3.97. Wintershall: well 20/2b-10, Volante prospect

The Volante prospect was located in UK Blocks 20/2b and 20/3d in the Outer Moray Firth geological province, due north from the Ettrick Field and ~12 Km due east from the Golden Eagle and Atlantic Fields. Volante was a medium risk stratigraphic prospect consisting of a Lower Cretaceous basin floor fan with Punt Sandstones as the reservoir. The predominant feature of Volante was a fan shaped amplitude anomaly stretching from NW to SE (**Fig. 195**). This anomaly was interpreted as probably corresponding to very good quality reservoir sandstones belonging to a point-sourced turbiditic basin floor fan with the main axis and sediment transport direction from NW to SE. The vertical exploration well might also penetrate an additional secondary target, the Lower Cretaceous Captain sandstones. Valhall Formation was considered to be a very reliable top seal. Base seal was the same as the source rock but the Kimmeridge Shale as a seal poses more risk than the top seal in this area because it can be quite sandy at places. The Upper Jurassic Kimmeridge shale, directly underneath the prospect was interpreted as the source rock.

The overall geological CoS was estimated at 23% and the main risk was the trap geometry (32%) as the seal risk was estimated as a certainty (100%). Indeed, the main risk was described as the trap integrity caused by a possible up dip connection of sandstones of the Punt fan to sandstones in its feeder channel or by juxtaposition of Punt sandstones with Upper Jurassic Ettrick sandstone on the shelf. The second key geological risk was interpreted to be the reservoir effectiveness (72%).

The majority of formation tops were encountered within acceptable tolerances. The Punt Sandstone which represented the primary target for Volante was encountered 63 ft TVD high to prognosis and had a gross thickness of 242 ft and N:G of 63% in line with expectations. Porosity was higher than the prognosed maxi case. No shows were encountered in the sandstone and the reservoir was water wet. Top and bottom seals were made of claystones with interbedded sandstones.

The most likely main reason for failure is the lack of trap integrity with up dip seal being not effective (**Fig. 196**) but also doubts about top and bottom seal effectiveness. In addition, although amplitude anomaly (AA) was accurately explained by forward modelling, it shows high quality reservoir but strong amplitude does not prove presence of HC's.

<u>Main lessons learned:</u>

- The (post stack time-migrated) seismic data received from the previous block operator had been carved out from a much larger reprocessed seismic cube based on the Jebco Ross/Ettrick and Shell Ettrick 3D survey. This carved out cube extended exactly over the license and left the most critical apex-area of the Volante fan uncovered (**Figs. 197 & 198**) Obtaining a much better 3D merged data set before drilling might have changed the risking, hence the decision.
- Following a properly made 3D merge and reprocessing, amplitude modelling should have been carried out.
- The lack of HC shows was stated as being either due to overbalance and use of OBM or lack of trapping effectiveness. A cheap post-drill Fluid Inclusion study would most likely have answered this question.

Fig. 195 - Volante was characterized by seismic anomaly. Black arrows indicate sediment transport direction

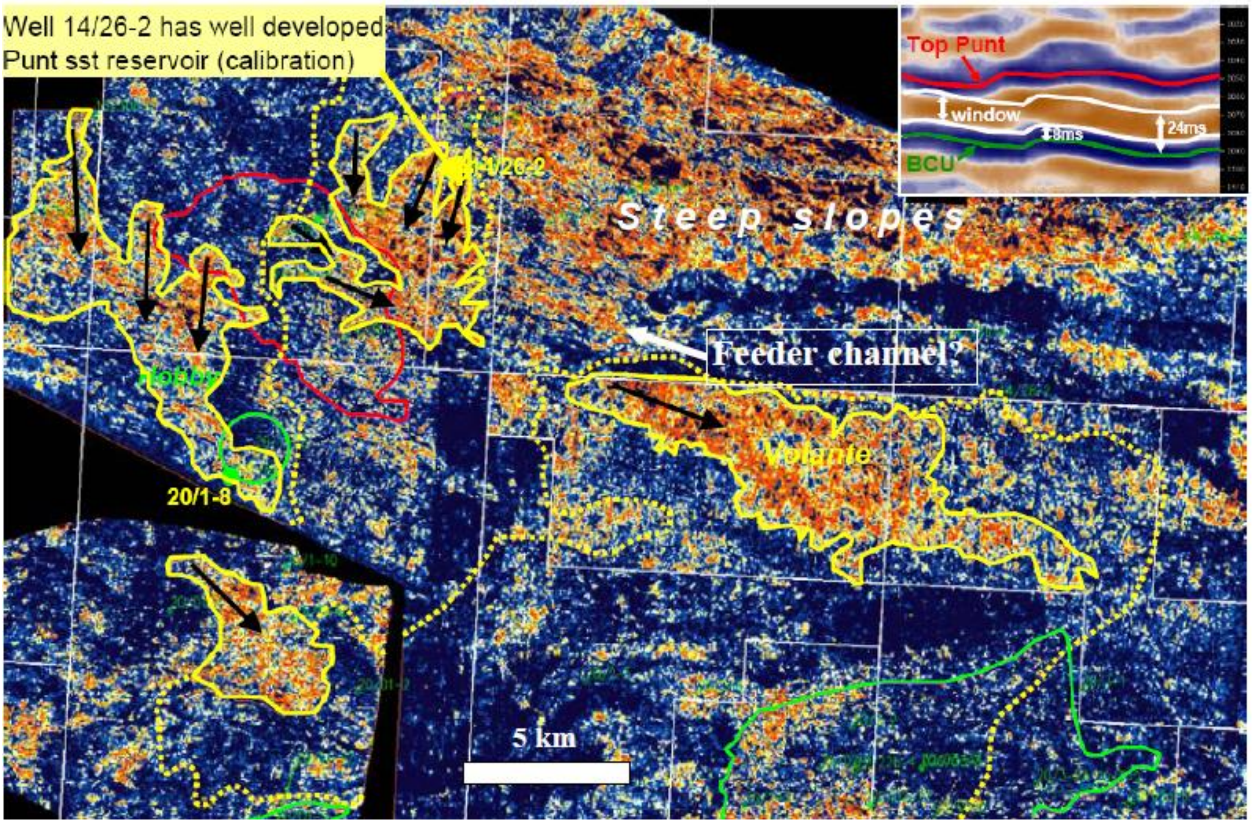


Fig. 196 - Volante Top Punt depth map: purples lines indicate location of seismic sections shown below. Red square is area of interest around the well

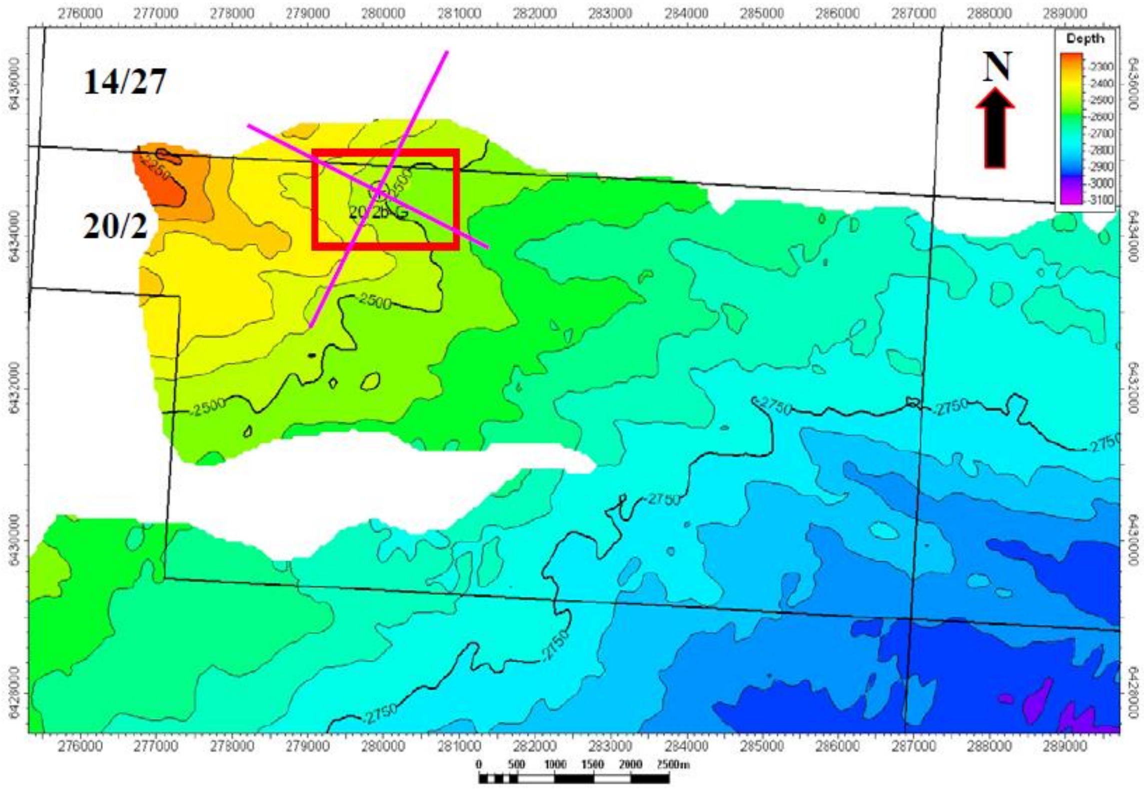


Fig. 197 – Volante prospect: axial inline 1420 through well location **(Data provenance uncertain: Shell proprietary, Jebco, WesternGeco?)**

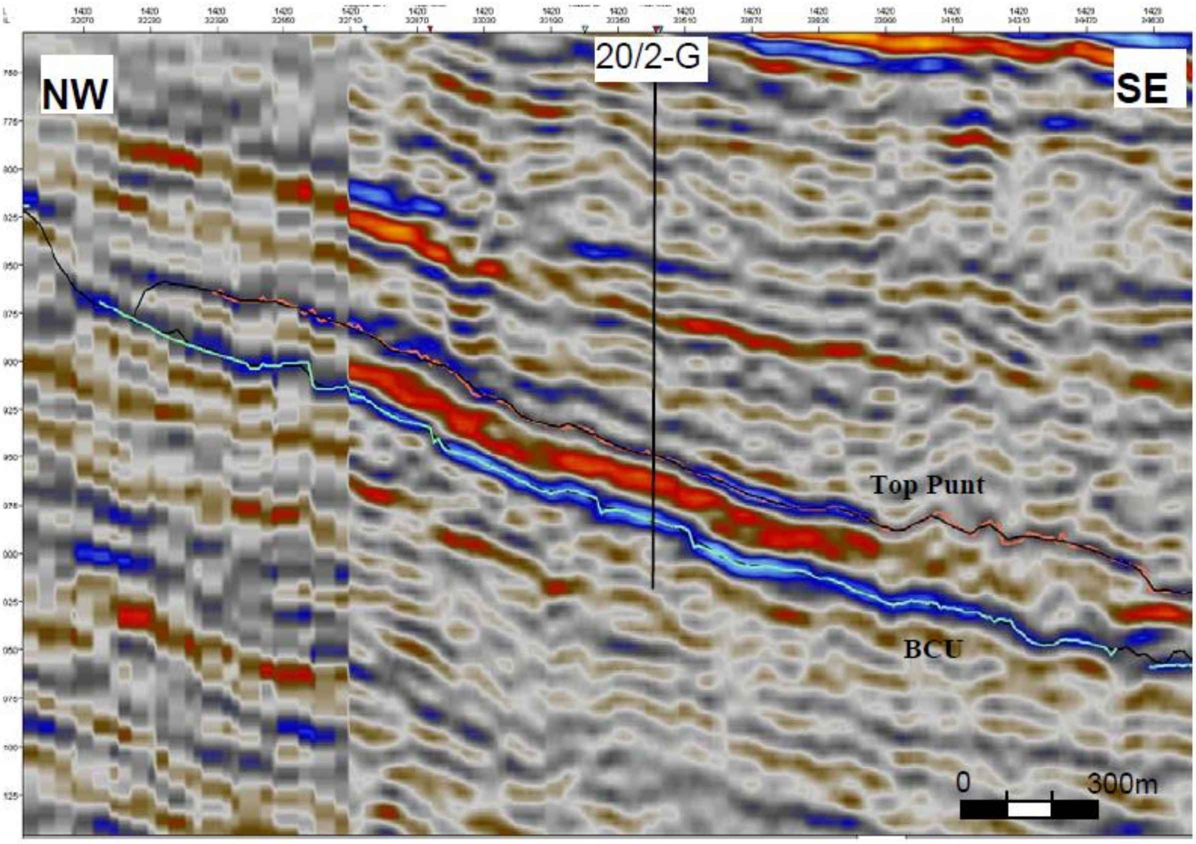
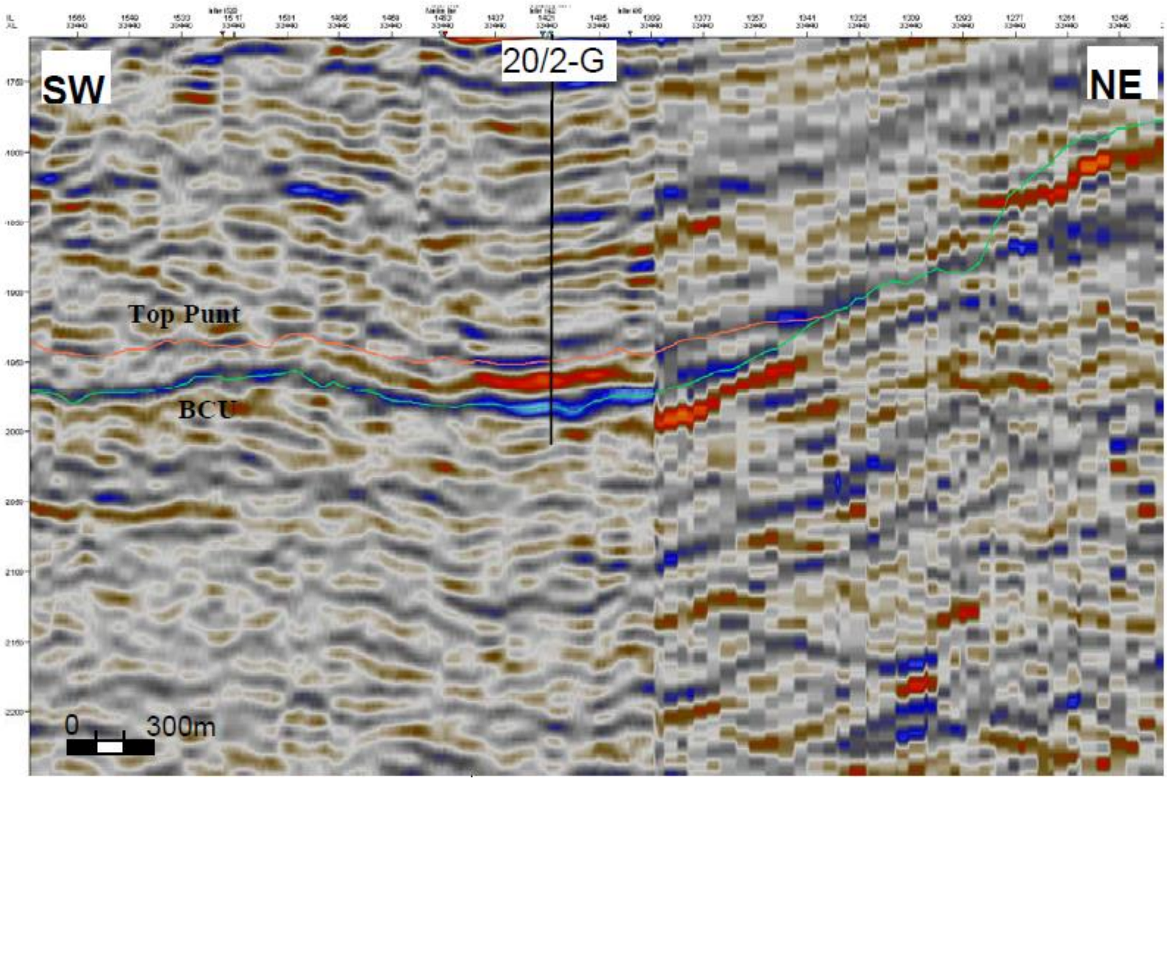


Fig. 198 - Volante prospect: Cross-line 33440 through well-location **(Data provenance uncertain: Shell proprietary, Jebco, WesternGeco?)**



4. Reasons for failure

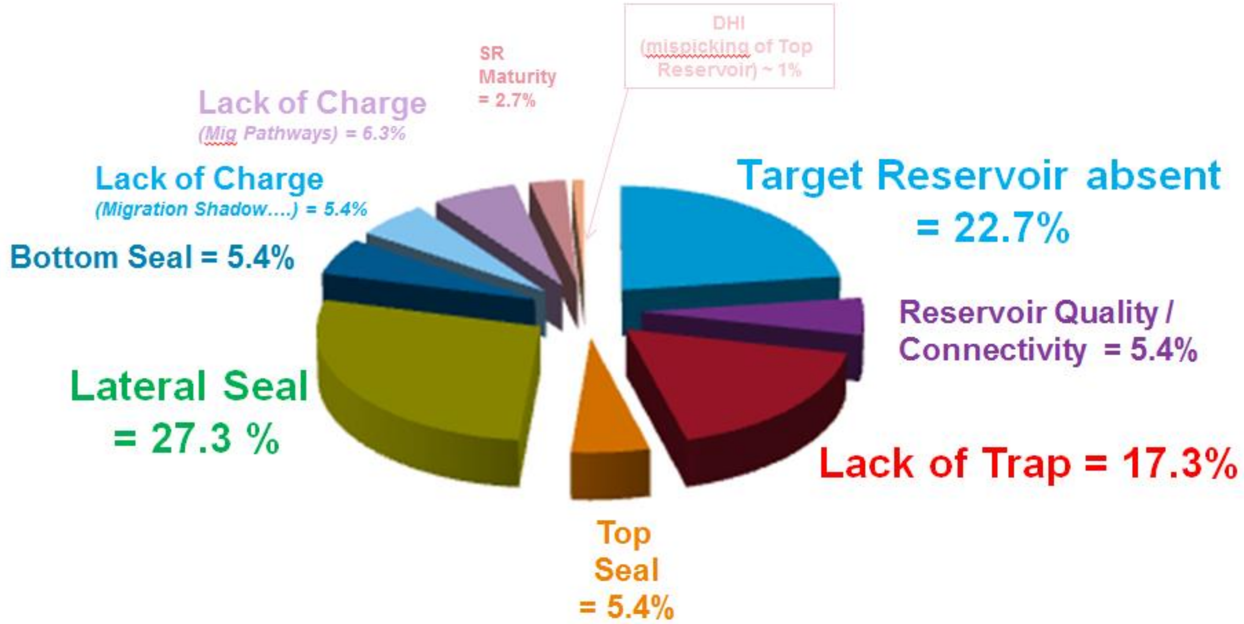
It is striking to see that 38.8 % of the wells failed because of three clear causes. This means that either these prospects were not ready to drill and more in depth technical evaluations should have been carried out before going with the drill bit, or, that, in such a mature basin, these prospects should not have been drilled at all.

Only 12.6% of the analysed wells failed because of a single clear reason: in these cases, drilling was the only valid option to check if the prospect was hydrocarbon bearing.

The reasons for failure are distributed as follows: Seal # 38%, Trap # 28 %, Reservoir # 17%, Charge # 14%. In more details, the overall main reason for failure (**Fig. 199)** is the lack of lateral seal (27.3%) followed by the absence of target reservoir (22.7%) and the lack of trap (17.3%).

Absence of target reservoir and top seal failure both act as “killing parameters”: indeed, in cases where one of these risks fails, it’s pointless to search for other failure causes. Generally speaking it was observed that top seal efficiency is well assessed even when it fails (having been clearly identified as the critical pre-drill geological risk). Similarly, source rock maturity is fairly well assessed apart from prospects located on basin margins, at the edge of the known mature kitchens.

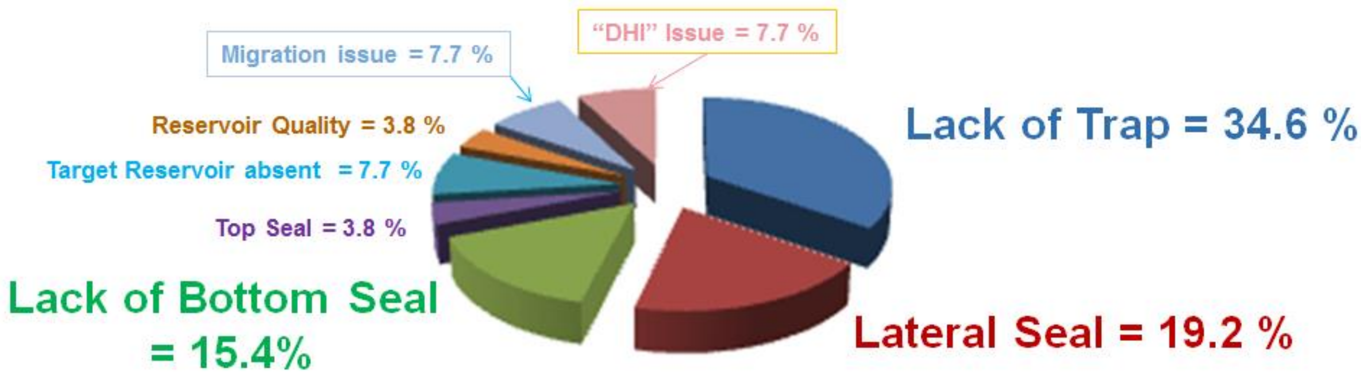
Fig. 199 - Overall main reasons for failure



4.1. Tertiary Plays

Regarding the Tertiary Plays (Eocene and Palaeocene, **Fig. 200**), the main reason for failure is the lack of trap (34.6%) followed by the lack of lateral seal (19.2%) and the lack of bottom seal (15.4%).

Fig. 200 – Main reasons for failure: Eocene and Palaeocene Plays



The sample size amounts to 24 segments and it is well worth noting that 20 have been drilled because some sort of Direct Hydrocarbon Indicators (DHI) had been interpreted: these perceived DHIs included AVO anomalies, amplitude anomalies, “impedance indicators”, gas cloud, etc… Another 2 wells have been drilled despite AVO analysis indicating that the sandstones would be water wet. So all together, 92% of the Tertiary segments have been DHI driven.

- Two key lessons must be drawn from these results: the first one relates to the seismic processing, while the second deals with geological interpretation and full integration with the outcomes from seismic data.
- When looking at prospects that are solely dependent on AVO it is necessary to examine the pre-conditioned gathers and to match amplitude response to shear log recorded in nearby wells. We must always keep in mind that AVO responses are modelled outcomes, not unique solutions. They do not eliminate risk! This is the reason why we must produce and risk the geological model unsupported by AVO. Do the prospect / segment make sense without AVO support? Some companies are performing in parallel a DHI analysis (using either their proprietary methodology or commercial software such as SAAM from Rose & Associates) and the classical prospect geological assessment. Each route leads to a Probability of Success: the DHI one is used to weight the geological one in order to reach an integrated overall CoS.

4.2. Upper Jurassic Plays – Interpod settings

Concerning the Upper Jurassic Fulmar Formation in interpod setting (**Fig. 201**), the main reason for failure is the absence of target reservoir (#43%) followed by the lack of charge (28.5%: especially the lack of effective migration pathways) and the failure of a lateral seal (28.5%) (**Fig. 202**).

Fig. 201 - Fulmar in Interpod setting

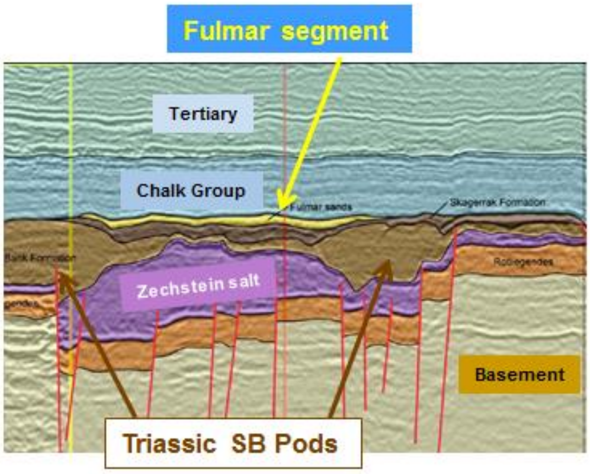
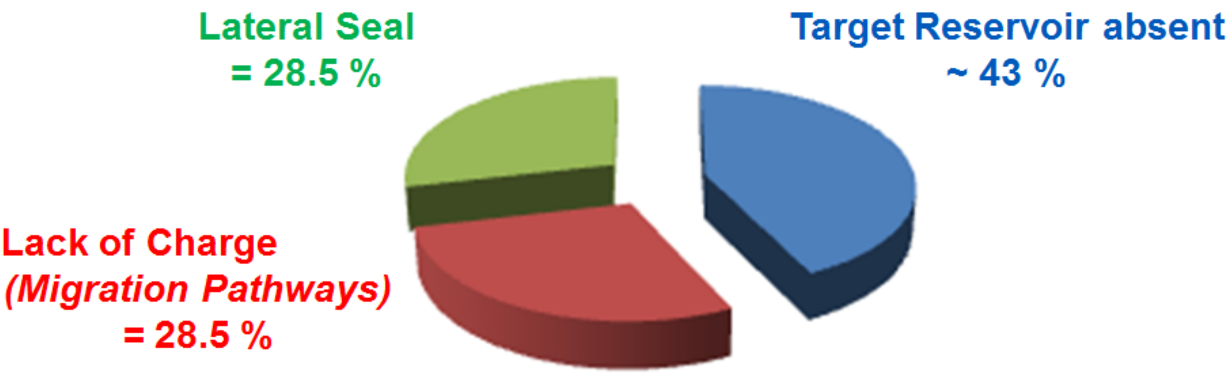


Fig. 202 - Fulmar interpod main reasons for failure



This is no surprise as quite often geologists hope to find both well-developed reservoir target and source rock in a setting where the available space is limited. In addition, lateral seal and migration pathways are rarely effective at the same time.

- ➢ Despite the limited size of the studied sample (7 segments), migration effectiveness is the 2nd reason for failure in 5 out of 7 cases. This means that detailed pre-drill basin modelling should be carried out when dealing with upper Jurassic interpod type prospects.

4.3. Upper Jurassic Plays turbidites

Regarding Upper Jurassic deep water turbidite such as Buzzard, Ettrick, and Peterhead sandstones (**Fig. 203**), the lack of lateral seal is the main reason for failure (38.7%) while the absence of target reservoir (29%) and the lack of top seal (12.9%) complete the podium (**Fig. 204**).

Fig. 203 - Upper Jurassic deep water turbidites stratigraphic trap

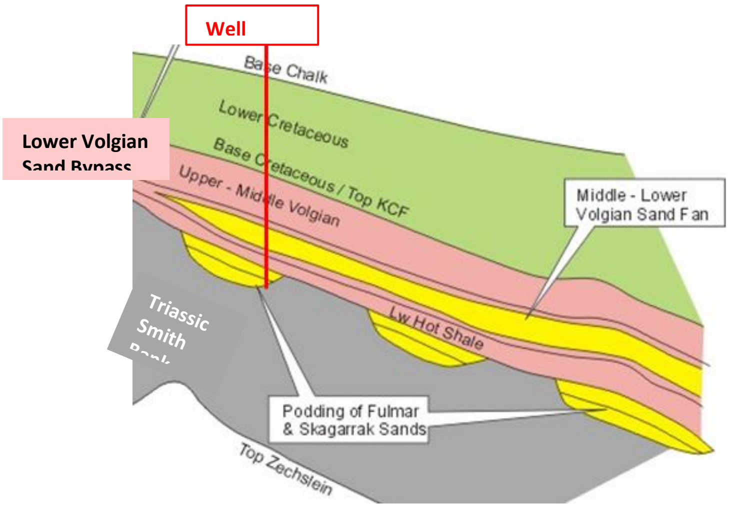
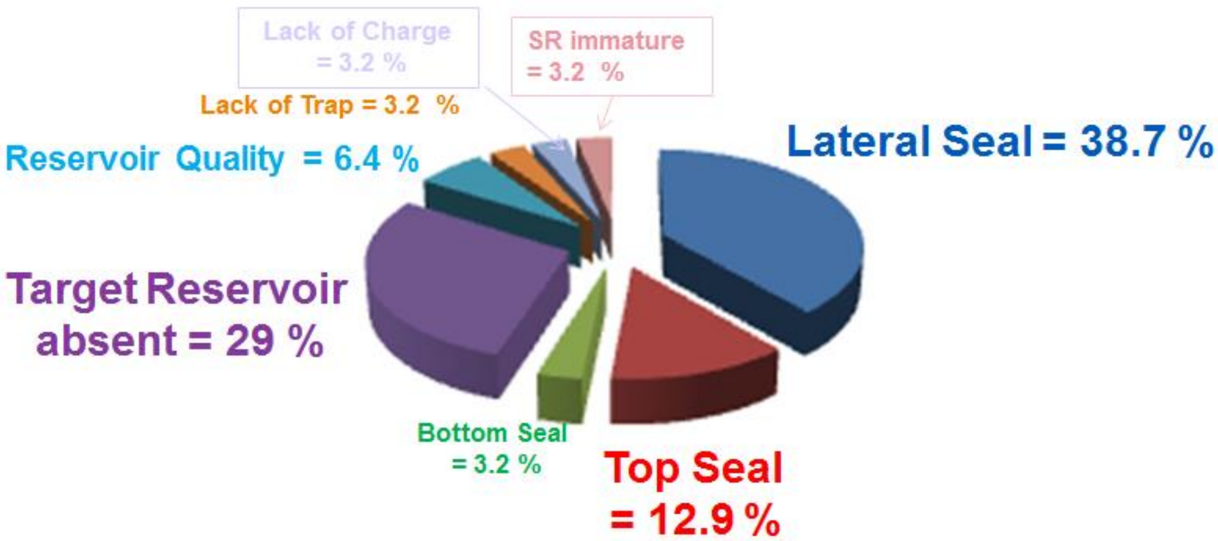


Fig. 204 - Upper Jurassic deep water turbidites: main reasons for failure



The sample size is bigger with 27 analysed segments. 76.7% were interpreted as stratigraphic traps. The search for Buzzard look alike was mostly driven by conceptual analogy, “rule of thumb” assessments and “notional prospects”. As Glen Cayley (Shell UK) rightly stated “we tend to put a significant weight on previous events, believing that they will somehow influence future outcomes. The classic example is the

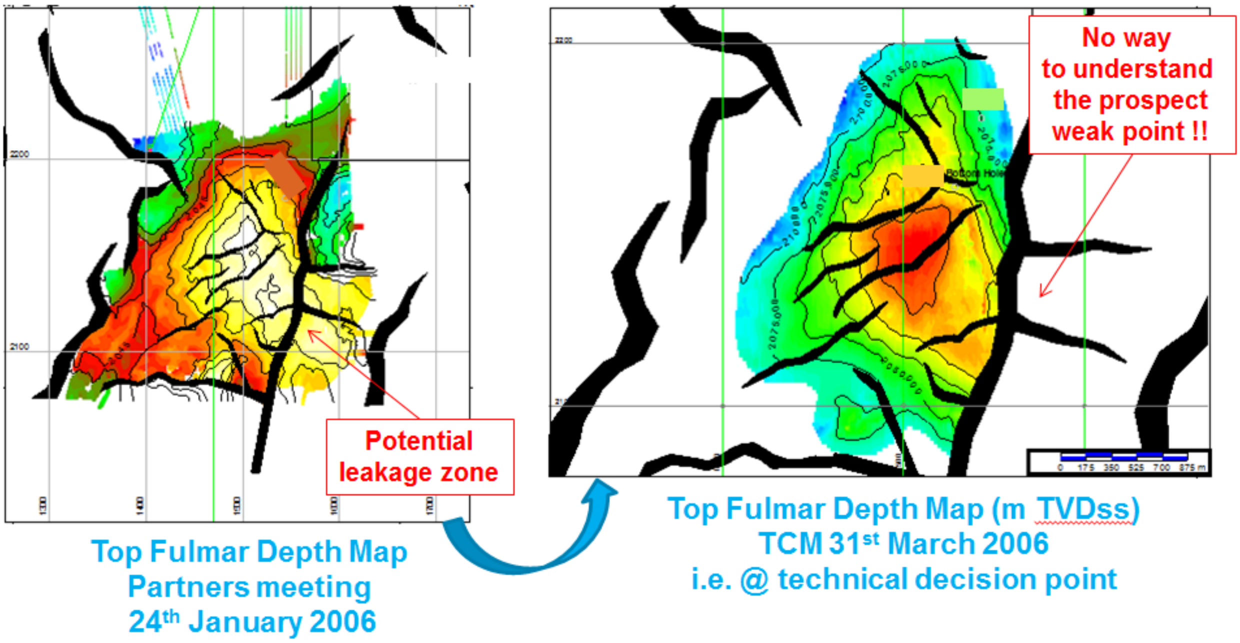
Buzzard discovery follow-up. After that large discovery the next seven consecutive exploration wells, targeting look-alikes, failed to find economic volumes. Our inclination is to predict an increase in likelihood of the next well working — that the odds must certainly be in the favour of a strike. But in reality, the odds are blind to history as with coin tossing! Relatedly, there's also the positive expectation bias, which often fuels gambling addictions. It's the sense that our luck has to eventually change and that good fortune is on the way."

5. Interpretation Pitfalls

Some of the encountered most common interpretation pitfalls are outlined below:

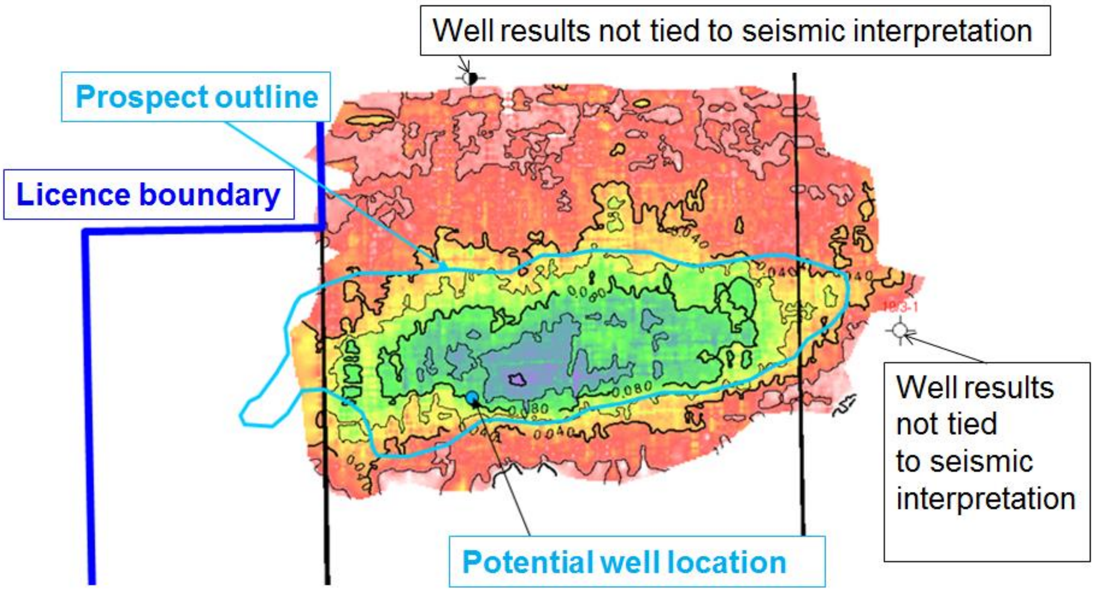
- Maps maybe cut short, excluding vital information: this does not allow an optimal understanding of the trap and a proper focus on the main weak points of a prospect (**Fig. 205**).

Fig. 205 - Example of map cut too short around the so called prospect



- Maps are not tied to the closest wells: this raises the key question of the integration between well and seismic data (**Fig. 206**). Well to seismic ties must be properly done as this impacts choice of the relevant horizon to be picked and / or on reservoir polarity.

Fig. 206 - Example of well results not tied to seismic mapping



- Questionable seismic picking: this highlights the need to improve the Quality Control of the interpretations. Seismic picks must not cut through valid seismic reflectors (**Figs. 207:** in this particular case, we must keep using analogues, but respect the data; **Figs. 208 to 211**). Dual polarity commonly displayed by the work stations should help more rigorous picking particularly when interpreting Tertiary or relatively shallow Plays.

Fig. 207 - Example of questionable seismic picking **(Data courtesy of CGG)**

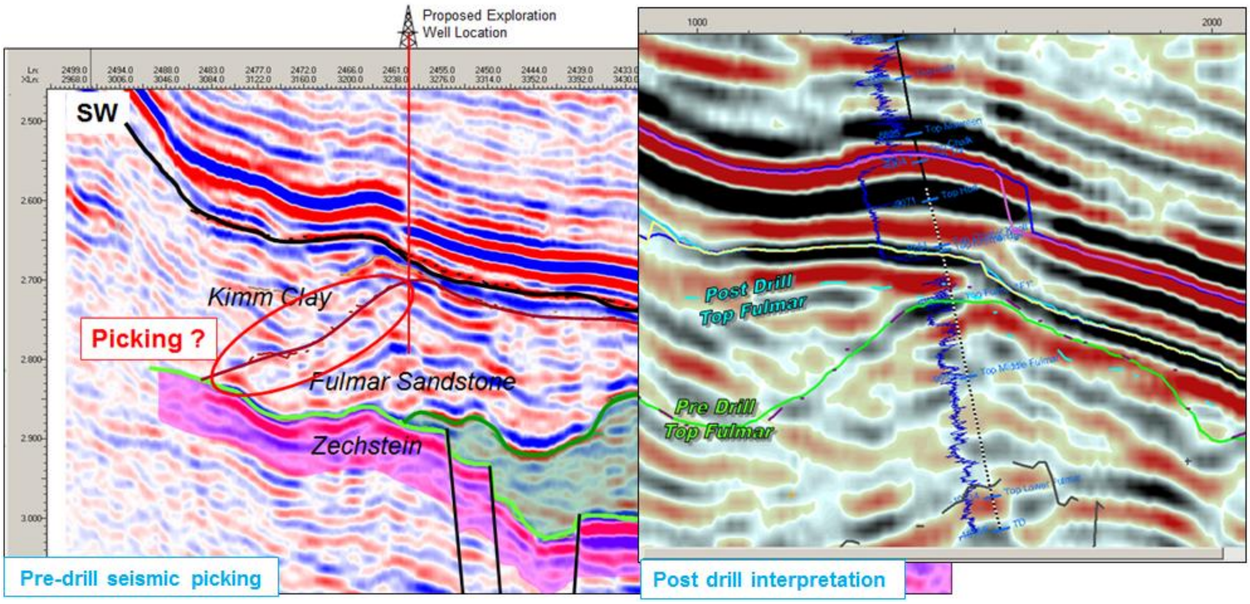


Fig. 208 - Example of wrong seismic picking **(Fugro data courtesy of Spectrum)**

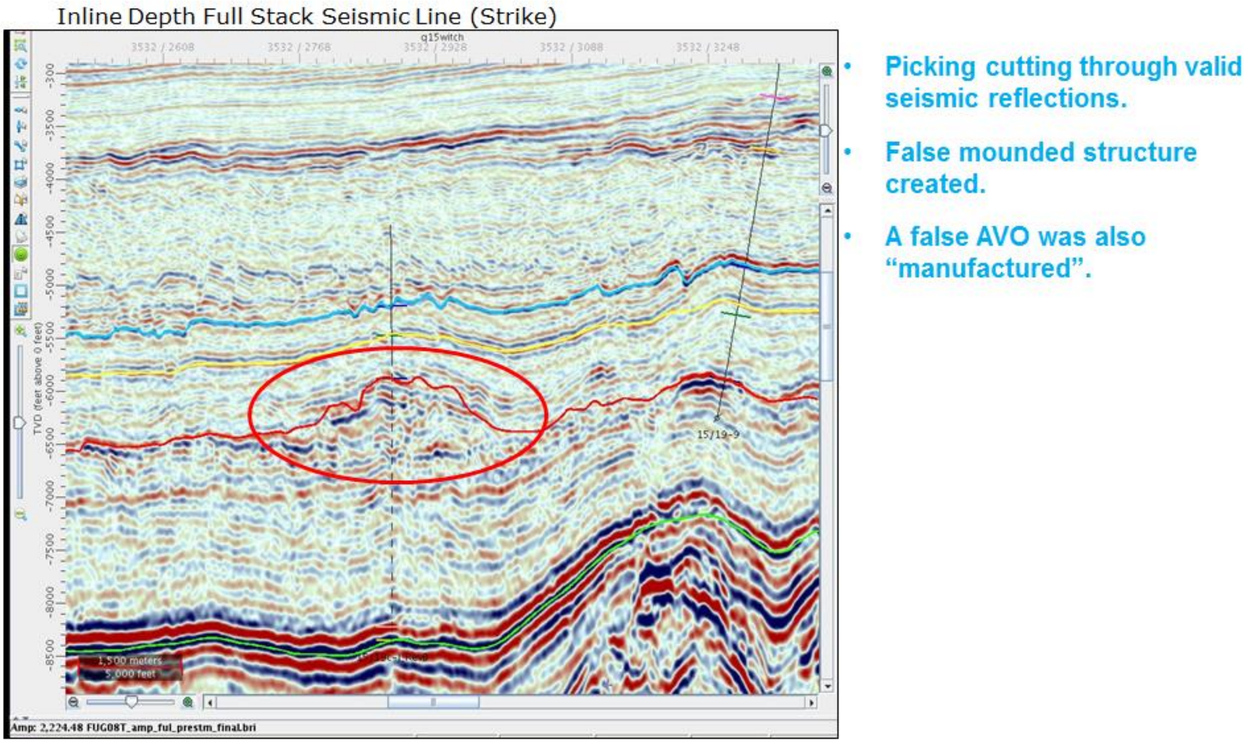
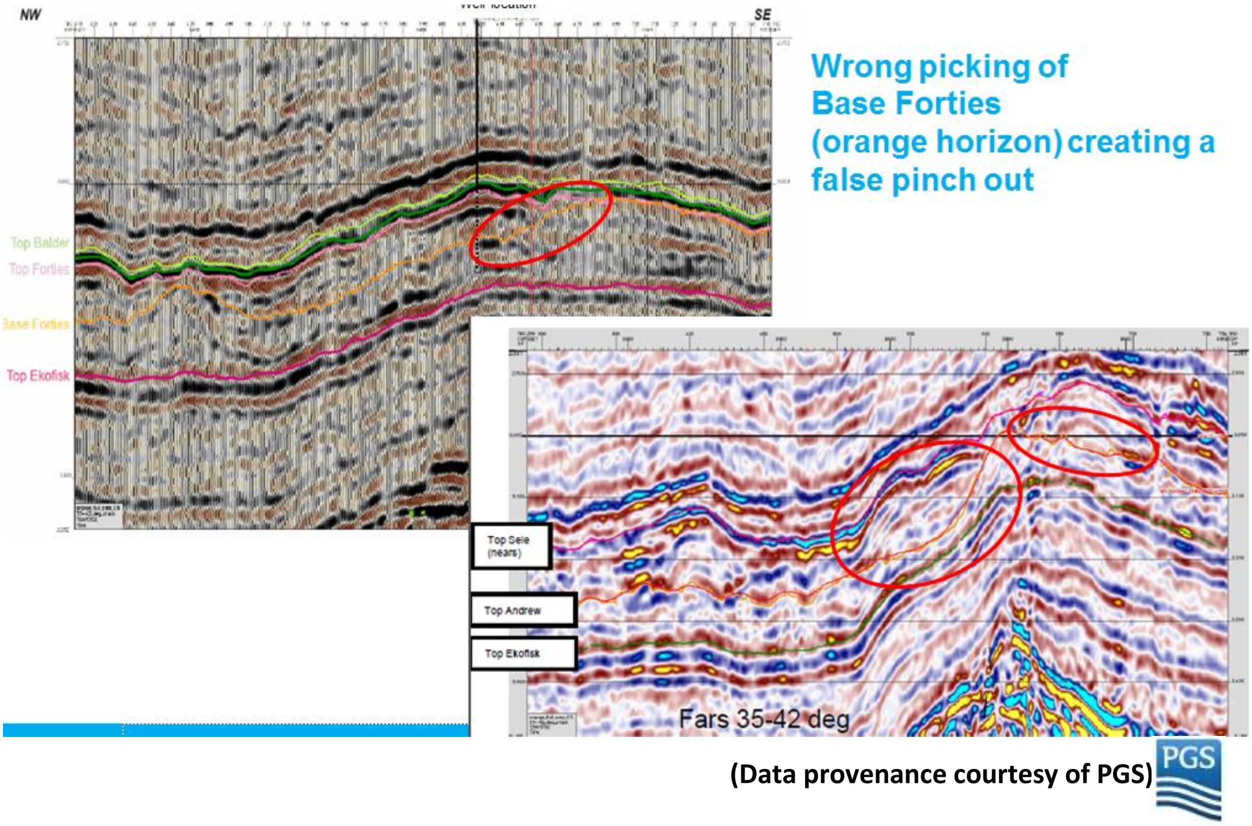


Fig. 209 - Another example of wrong seismic picking



(Data provenance courtesy of PGS)

Fig. 210 - Example of questionable picking in a reflexion free seismic area
(Operator proprietary data)

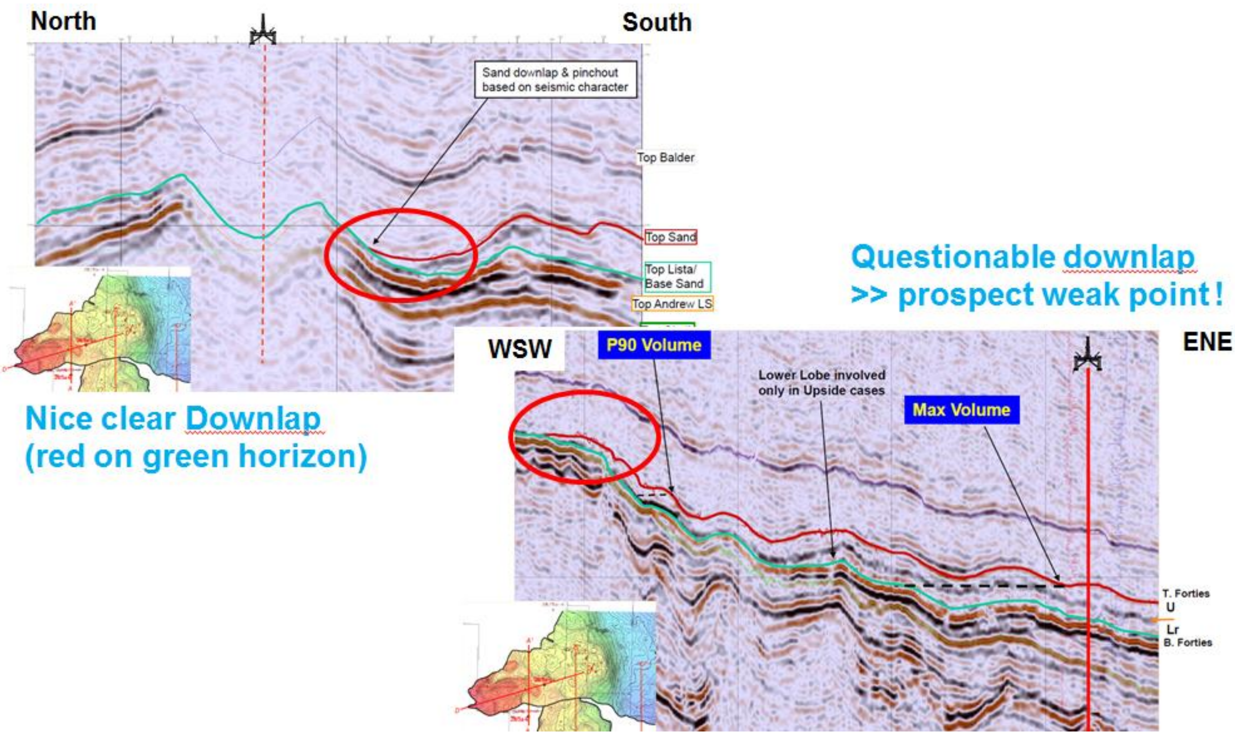
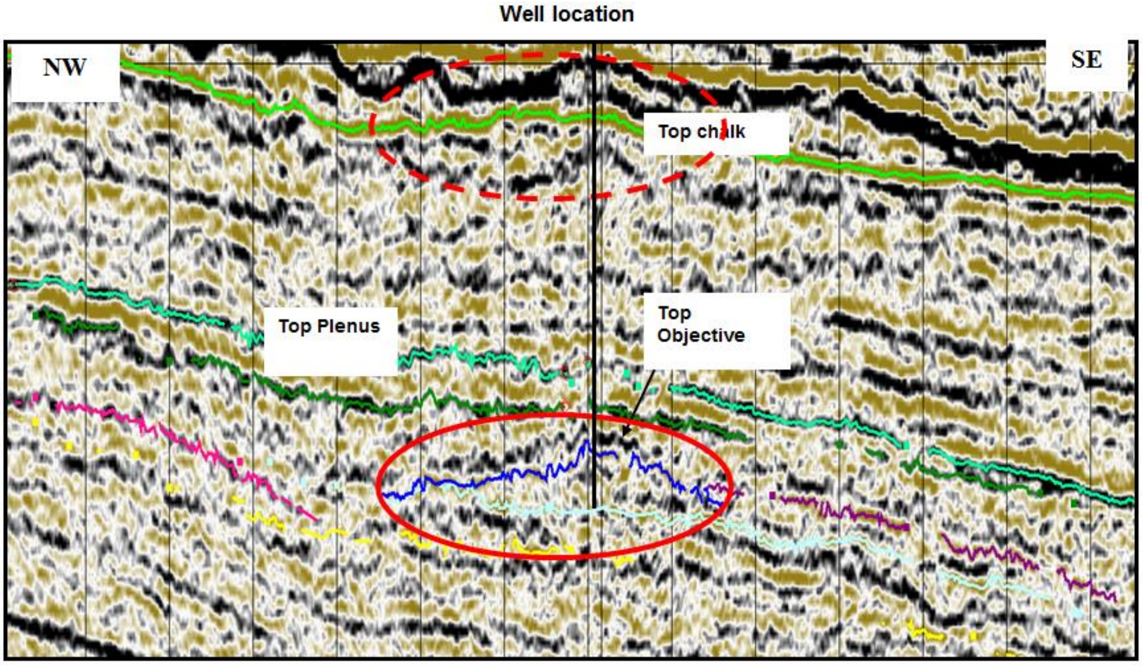


Fig. 211 - Trap interpreted as a mound while it is more likely a multiple **(Operator proprietary data)**



- <u>Underestimation / over interpretation of the physical content of the seismic response</u>. Any seismic amplitude anomaly or brightening is not synonymous with hydrocarbon bearing sandstones (**Figs. 212 to 214**): a detailed rock physics modelling must be carried out to check initial hypotheses. In other cases, the absence of a convincing DHI over the prospect should have suggested either a water-wet section or low-GOR oil and may have led to a different decision. In any case seismic data must be properly processed in order to be fit for AVO study.

Fig. 212 – Anomaly interpreted as a close analogue to a neighbouring discovery

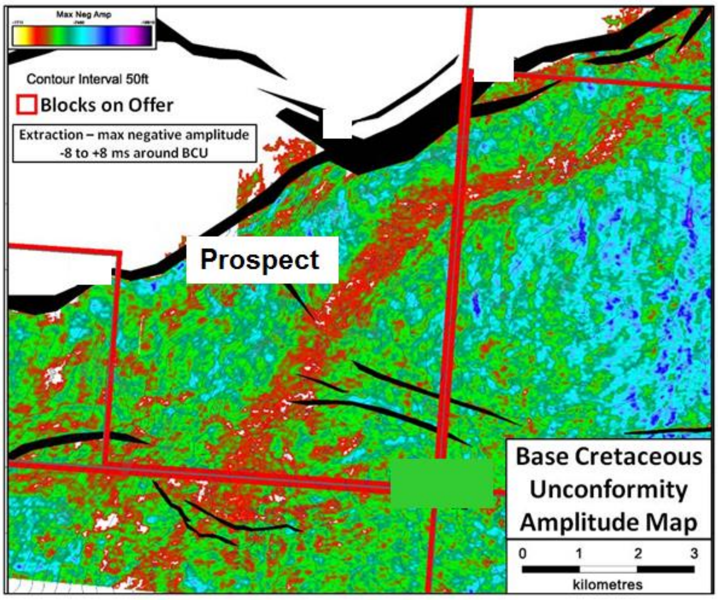


Fig. 213 - Example of “random” anomaly which does not show any particular geological feature

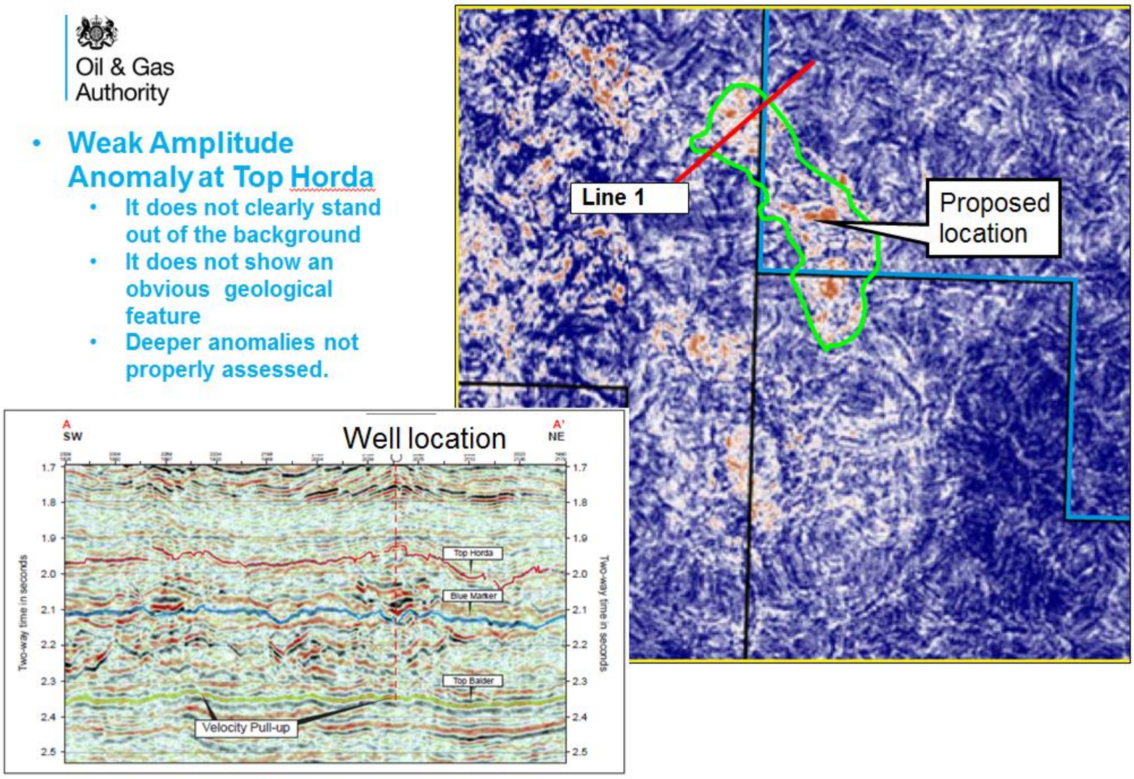
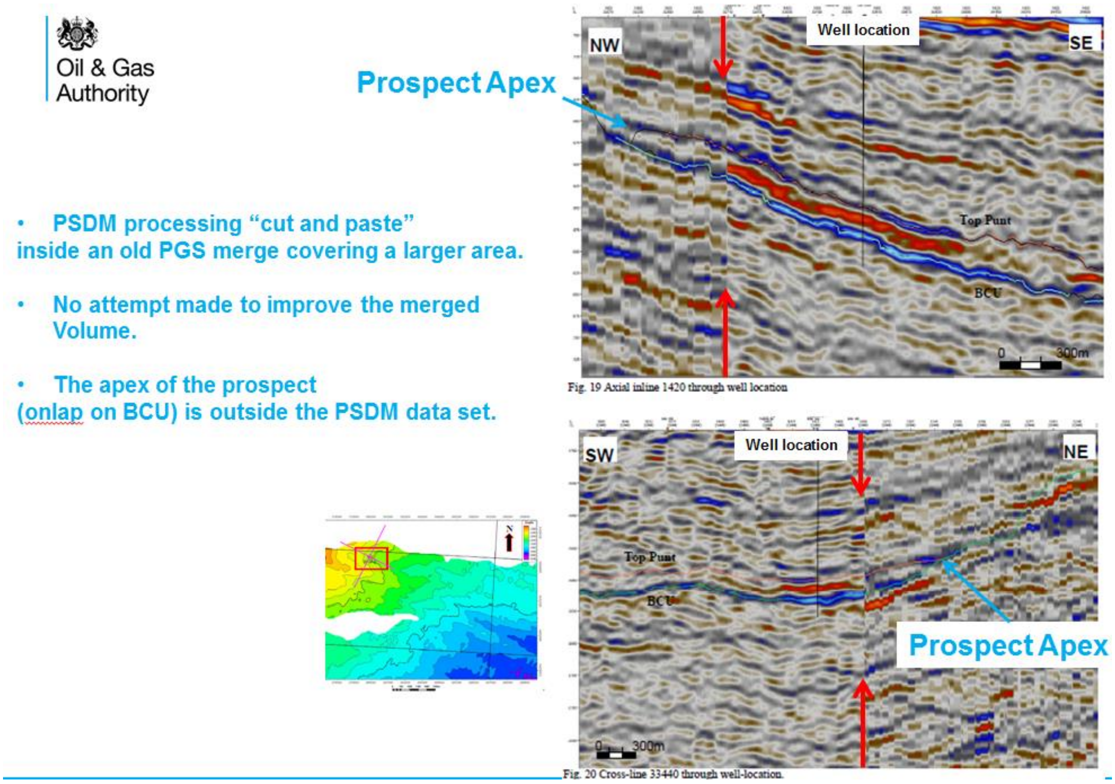


Fig. 214 - Example of prospect definition based on an inappropriate seismic data set



(Data provenance uncertain)

- <u>Charge issues</u> are involved in almost 1 in 5 well failures, neglecting the nature of the inferred carrier beds, overlooking the potential sourcing pathways and sometimes downplaying the effect the kitchen geometry will have on effective drainage towards the prospect (**Figs. 215 to 217**).

Fig. 215 - The dilemma: effective side seal vs effective migration pathway **(Operator proprietary data)**

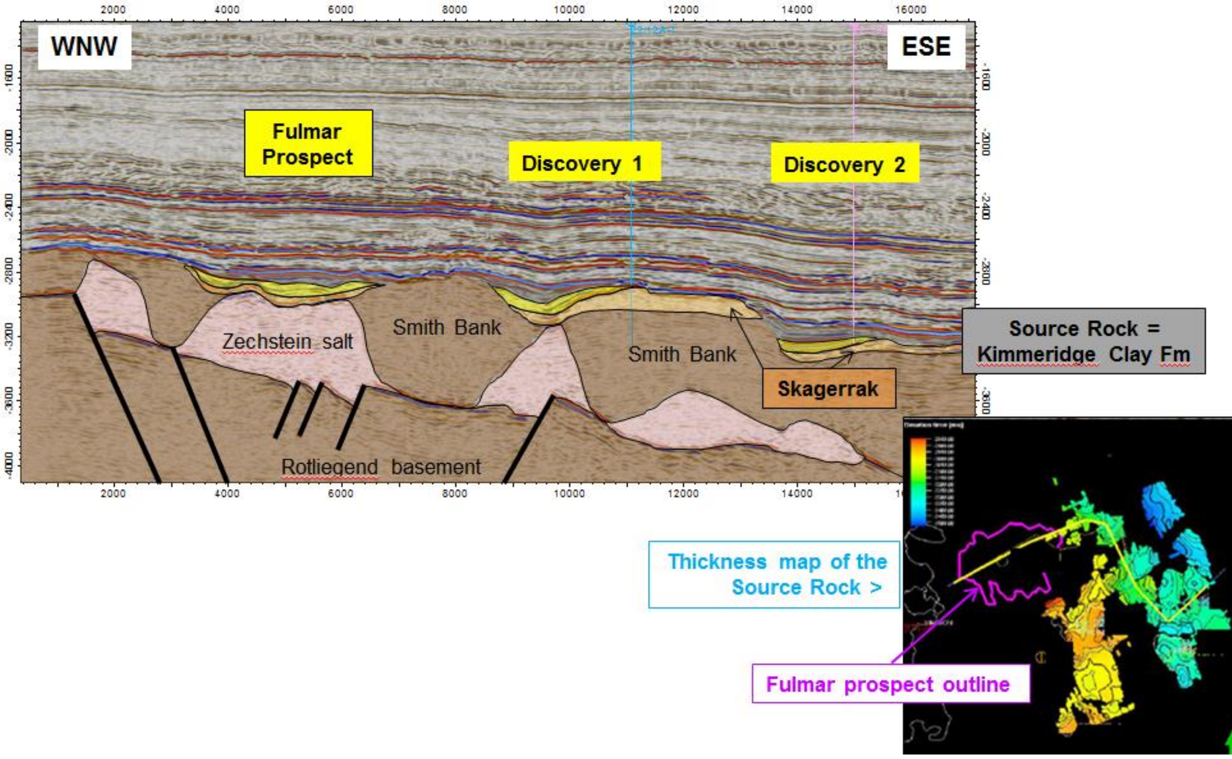
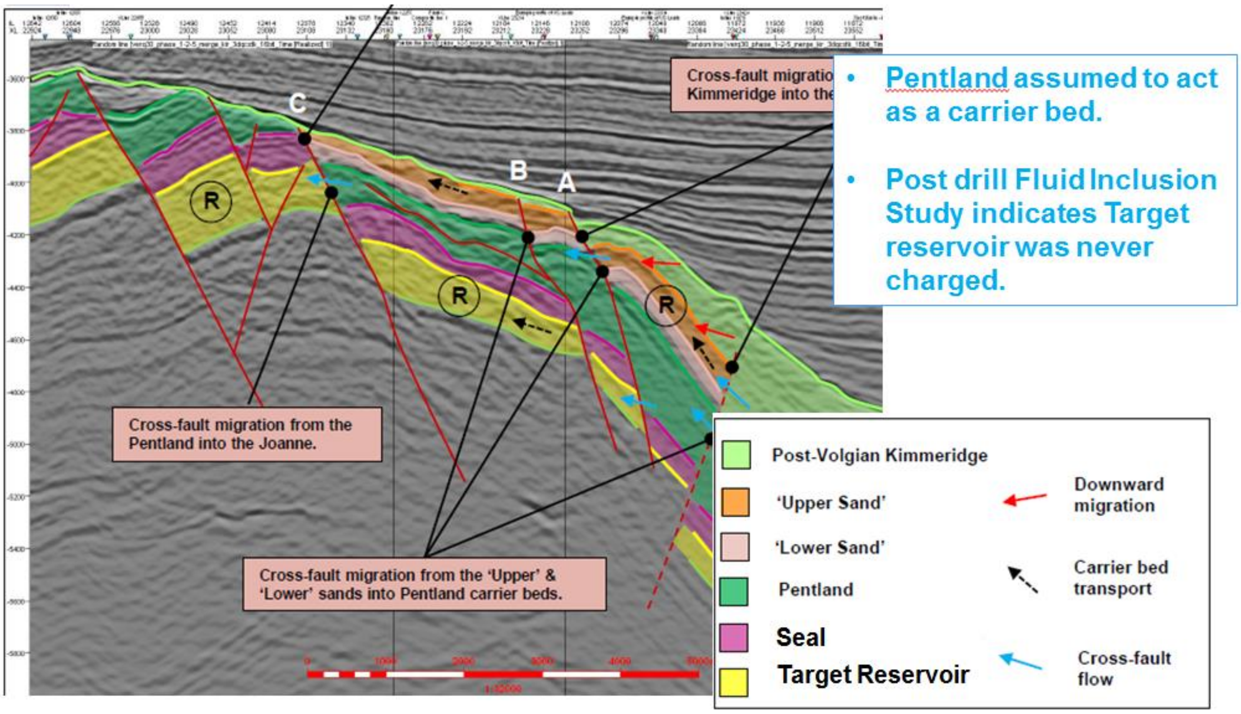
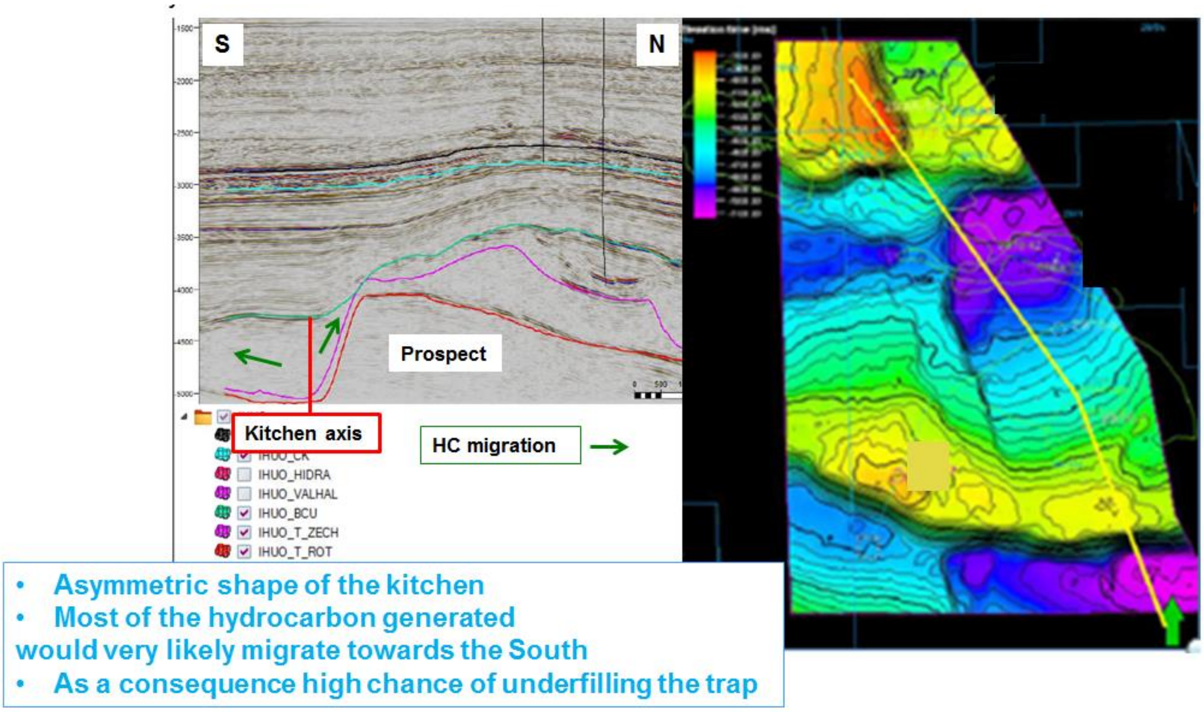


Fig. 216 - Migration pathways based on questionable assumption about inferred carrier beds



(Data courtesy of CGG)

Fig. 217 - Comparison drainage area vs trap size. Impact of kitchen geometry **(Operator proprietary data)**



- Cognitive biases have led to a flurry of dry exploration wells being drilled immediately after a discovery was made. This translated into a too fast move to drill what was deemed to be an analogue amplitude feature / an analogue stratigraphic trap without carrying out a detailed prospect assessment… Amongst these cognitive biases, one can think about the "Representative Bias" which assumes that what we know is more probable than something else (via choice of analogue, interpretation of discovery well as typical of a Play…etc..); the "Confirmation Bias" where we prefer data/ interpretations that confirm our own preconceived ideas and finally the "Overconfidence Bias" which corresponds to the fact that we tend to overvalue our own interpretations.

6. Conclusions

Common themes across the Moray-Firth / Central North Sea Post Well Analysis project and corresponding workshops are listed here below:

<u>Companies perspective:</u>

- The lack of quality G&G work, ineffective peer review, and inconsistent de-risking were key points in a number of well failures.

- The importance of doing more regional play based work for setting and context were repeatedly missed. Regional paleogeography, reservoir mapping, sand provenance and unconformities subcrop map, regional isopachs of reservoir, seals and source rocks, geochemical analysis and regional analysis of sequence stratigraphy were all lacking. The importance of correctly identifying the source rock and working out the final migration routes or at least a plausible charge story was highlighted.

- Fully linking the geophysicists and geologists was highlighted, as well as better collaboration / communication with other key functions: drilling and development and ultimately management. Actually, several of the prospects relied too heavily on geophysical analysis, missing the geological picture.

- Several of the prospects relied too heavily on seismic anomalies: indeed, it was observed that only one geological map had been presented during the 3 workshops with operators! AVOs or other DHIs were highlighted as key tools when used correctly. However, when dealing with prospects solely relying on AVO make sure the data is properly processed and is fit for purpose to properly evaluate what you see, then make sure the prospect makes sense without AVO support. Risking with and without DHI support is a key step which is often missed. Many of the wells were amplitude or seismic driven. Access to new seismic is not the silver bullet, it is necessary to get the right people looking at the right data. Depth conversion and seismic imaging challenges were common themes; more bespoke time to depth conversion should be carried out.

- Regarding the Moray Firth it was observed that the quality of seismic was generally poor, causing challenges in picking the top Captain and Top Punt reservoirs. A great deal of rock physics and other analysis is therefore required to counteract this challenge as even newer expensive seismic still bears similar problems. What can the Industry do to improve the seismic data quality in this region?

- It was observed that the pre-drill analyses often excluded the full range of possible outcomes: when describing a prospect, we should take on-board a wide range of parameters; during the interpretation process we shall stay open minded and consider different scenarios. The human behaviour is such that we are too centred about a single geological model: is it because it’s too difficult to present to the management and / or to pass on to the other functions the wider business?

- It’s easy to become convinced that the single geological model we have in mind is the right one when a lot of science may have been done (Shale Gouge Ratio studies, fault entry pressure studies, basin modelling…etc…). However we must keep in mind that the grounds for these techniques take into account several key hypotheses. For instance, SGR are calculated given defined fault throw assumptions and depth hypothesis of the geological sequence on each side of the fault: if the time-depth conversion proves to be inaccurate, the whole SGR study falls apart. This highlights the need that need to stay open minded during the interpretation process and consider different scenarios / geological models.

- Seal integrity and a better understanding of base seals were discussed. It was observed that the industry has a poor understanding of shales, seals and how to map them. In mature basins, assumptions about fault sealing effectiveness should be grounded by incorporating reservoir and fluid data from analogous producing fields.

- Overall, firm well commitments were drivers for one third of the analysed wells. As a consequence, one must ask the key question "how rigorous is the bid work and what is the data quality to hang a commitment on"? A related question mark concerns the round duration: is 90 days a sufficiently long period, firstly, to screen a huge number of available blocks, then to work in details a few areas of interest and, finally, to undergo the internal company's approval process which is lengthy in most of the big Exploration players?

- The need to keep a fresh view of the UKCS /NCS was highlighted: it is still worth looking at gaps and where is yet to be explored and understanding the exploration significance of finds such as Johan Sverdrup right across the UK-Norwegian border.

- All the companies which participate in the 3 workshops agreed that "systematic tracking of exploration results relative to pre-drill predictions is critical for improving both assessment performance and exploration decisions. All efforts that can assist in delivering accurate, un-biased and consistent assessment will ultimately enhance company exploration performance."(*Charles Stabell, formerly GeoKnowledge A.S*.): Post Well Analysis is a key element of Exploration Quality Insurance process.

<u>OGA perspective:</u>

- The poor storage of historical well data has been a recurring theme all through this study. This data issue is highlighting the questions about how companies store information, companies' ability to retrieve information post staff movements (knowledge management is a real concern during company take overs), transfer of information from asset sales to purchasing companies and the balance between documentation of regional studies versus well justification documentation. As soon as the new Energy Bill is passed into Law (which is expected during first half 2016) OGA will improve the data storage and the way it is made available to the Industry. It should then be compulsory to submit more analysis such as biostratigraphy or geochemical analysis to CDA for storage: these data would become "basic data".

- Many companies suggested that Post Well Analyses (PWA) should be regularly published and should complement more comprehensive relinquishment reports. This would be part of OGA's strategy to continue and expand sharing of data and corresponding G&G knowledge across the Industry.

- More PWA workshops should be held to avoid moving on too quickly from dry wells without learning from them. The importance of ensuring that the presenter was closely involved in the technical work (both pre and post well studies) was highlighted. It was suggested that the OGA continue to carry out PWAs of unsuccessful wells around two years post-well in order to shorten the lag time between the well completion and the PWA.

- Once the Energy Bill is passed into Law, OGA may be involved throughout the "life" of a license being able to monitor the progress of the interpretation. That may help re-orientating some piece of works and / or preventing some ill-defined prospects being drilled.

- Peer reviews involving the JV partnership and the regulator have been flagged by several companies as a significant action capable of improving the quality of the drilled prospects. Indeed, having a team in place to provide independent evaluation and challenge is fundamental to an efficient exploration process. Such peer review team should help teams:
  - question all estimations and examine justifications,
  - avoid narrow uncertainty ranges,
  - play the devil's advocate role to help considering what could go wrong and why it could fail,
  - help to take into account alternative scenarios.

  Given that there is currently less E&A activity on the UKCS, the opportunity for collaboration is increased.

- For the time being, the OGA, via BGS, carry out their own risking of wells post-drill. The OGA acknowledged that a decision must be made to decide whether the OGA should carry out pre-drill risking. This would likely be part of the new assessment of the UKCS Yet to Find (YTF) planned to be carried out before 2018.

- The value of end of well / post well information acquired even though the well is dry (pressure data, shear sonic logs / Fluid Inclusion studies…etc…) can be key both to learn why a well failed and to better understand the Basin. The OGA acknowledged that a decision must be made to decide whether the OGA should ask for a minimum standard set of logs / data to be acquired. Current regulations are that minimum information should be logged but no further guidance is provided.

- Firm well commitments were drivers for 1/3 of the wells presented. During some of the workshops it was questioned whether the usual 90 day period during which a Round is formally open is too short to allow a detailed prospect assessment to be carried out. It was also questioned whether the licence award should rely on the highest committed programme (i.e. the most expensive one) or on the best technical programme.

- Within companies large enough to have a New Ventures (NV) Team and a Licence Team, objectives for the NV team and the Well Delivery & Prospect Maturation team must be fully aligned. For instance if the KPI of the NV team consist in signing as many deals as possible (or a defined number of risked prospective resources) this may lead to a less rigorous risk assessment.

- Last but not least, OGA noted that quite often, people move on to another posting / company so that they don't see the whole history from prospect maturing to post well analysis. This too fast turn-over is detrimental not only to build individual in-depth knowledge of the basin but also to keep this knowledge within companies as it can lead to disconnects in prospect generation, post well analysis and regional integration.

To sum up the main outcomes of this Moray Firth - Central North Sea Post well Analysis,the main way to avoid drilling dry wells is by applying sound Geology & Geophysics & Reservoir science allowing prospects to be defined within a Play based understanding with adequate robust challenge. And to ask the akward question: what else could it be?

List of Figures

Fig. 1 - Moray Firth E&A wells analysed

Fig. 2 - Central North Sea E&A wells analysed

Fig. 3 - Project time line

Fig. 4 - Distribution of Objectives

Fig. 5 - Trap types Distribution

Fig. 6 - Prospect TEP3 Top Forties Depth Structure Map

Fig. 7 - Line 11792 and Trace 19124 from the PGS megamerge detailing approximate planned position of the 22/7_TEP3 exploration well.

Fig.8 - Hermes prospect, Top Ettrick "B" depth structure map

Fig. 9 - Hermes prospect schematic geological cross section

Fig. 10 a & b - Moonraker Prospect definition: map + NNW-SSE seismic section through well 14/28b-2

Fig. 11 - Evidence for fault seal (?) according to seismic inversion

Fig 12 a & b - Mallory prospect summary: Top Fulmar depth map and SW-NE seismic line through well 22/14a-2

Fig 13 - 22/14a Mallory Prospect: NW-SE Seismic random line

Fig 14 - Mallory: Trap effectiveness - Complex configuration

Fig. 15a - Top Forties Fm. Depth Map

Fig.15b - Forties Fm. time thickness map

Fig. 16 - Seismic picking should not cross valid seismic reflections (**ref. Top Andrew** and to a lesser degree **Top Sele**).

Fig. 17 - Northern Channel prospect summary: Play concept and Top Forties Depth Map

Fig. 18 - Example of interpretation / map stopping at the edge of the prospect apex

Fig. 19 - Example of seismic over picking: Top Forties (red horizon) downlap is questionable as it is defined amidst a reflection free seismic package.

Fig. 20 - Thunderer prospect: post-drill depth map and cross sections

Fig. 21 - Migration pathways from the Basin to Thunderer prospect

Fig. 22 - Calloway location on Joanne sandstones depth map

Fig.23 - Calloway post-drill modelling

Fig. 24 - TP1 prospect location and critical pre-drill risk

Fig. 25 - Seismic random line from well 22/19-2 to Monan salt diapir illustrating TP1 prospect

Fig. 26 - TP1 prospect: comparison pre-drill Pre-Stack Time vs post-drill Pre-Stack Depth

Fig. 27a - North Piper prospect location

Fig. 27b - Jurassic Piper pinch-out across a nose

Fig. 28 - Dolphin prospect: South-North cross line 1960

Fig. 29 - Dolphin prospect: Lower K45 Isochron

Fig. 30 -Deep Banff Top Fulmar depth map

Fig. 31 - Deep Banff: seismic section through wells 22/27a-4Z and 22/27a-2

Fig. 32 - Pre-drill Top Piper Structure Map

Fig. 33 - Pre-drill 2001 seismic – Line 2328

Fig. 34 - Gemini prospect: structural setting

Fig. 35 - Gemini prospect: geo-seismic cross section along the Smith Bank crest

Fig. 36 - 13/23a-7A well location – Dip line 4455

Fig. 37 - Magnolia prospect Top Coracle depth map

Fig. 38 - Liberator prospect: Seismic Line between 13/23a-4 well and 13/24a-4 Blake Field well

Fig. 39 - Morgan prospect: Top Balmoral Sandstone Depth Structure M

Fig. 40 - Morgan prospect – Seismic inline 13114, near offset

Fig. 41 - 3D schematic of Upper Jurassic sand distribution hung on Base Cretaceous surface: view from NW

Fig. 42 - 3D Pre-STM PGS Plus: Detail of stacked, down lapping Upper Jurassic sand pods

Fig. 43 - Fiacre prospect: Top Ula Formation Depth Map

Fig. 44 - SW-NE Geological cross section

Fig. 45 - West-East seismic Cross-Line 16686 (Acoustic Impedance) through Well Location

Fig. 46 - Roisin Pre-drill description: geological cross section illustrating the 2 targeted wedges

Fig. 47 - Balgownie 30/23b-d well tie to E-W seismic section (XLine 1464)

Figs. 48 a & b - Base Cretaceous depth map: Flora area (**a**) and detail over Turnberry (**b**)

Fig. 49 - Turnberry N-S schematic geological cross section

Fig. 50 - Base Cretaceous depth map with +10 msec to +20 msec amplitude extraction

Fig. 51 - West – East Inline 969 through Turriff

Fig. 52 - Top Upper Ryton time map (msec TWT)

Fig. 53 - SW-NE axial line (IP) from Whinchat through Whitethroat to Goosander

Fig. 54 - Beta prospect: Near top Duncan depth map

Fig. 55 - 3D Veritas North-South Inline 10546 through proposed well 30/28-2 (black line)

Fig. 56 - Dunkeld prospect: Time thickness map Top Balder to Top Forties

Fig. 57 - One of the very few available gathers showing room for processing improvement

Fig. 58 - Top Sele Depth Structure Map showing the two prospects “A” and “B”

Fig. 59 - Beauly Formation – Near **-** Far Offset Amplitude extraction on a 50ms window below the top Sele horizon

Fig. 60 - Corbenic well location, Top Devonian Kyle Group Depth Map

Fig. 61 - Corbenic: two orthogonal seismic lines showing the interpreted “reefal” facies

Fig. 62 - Top Fulmar depth structure map

Fig. 63 - Interpreted South – North seismic line illustrating the “pod-interpod” setting

Fig. 64 - Structural relationship between Kate, Taggart and Shaw

Fig. 65 - West-East seismic line across Taggart prospect though the planned well path

Fig. 66 - Manuel prospect: NW-SE line MF 06-205B

Fig. 67 - Top Brora Sand Depth Map (m tvdss; contour interval 20m)

Fig. 68 - Beatrice “A” Sand depth structure map

Fig. 69 - NW-SE cross line 1323 across Beatrice and Polly structures

Fig. 70 - Map showing seismic extraction of maximum negative amplitude -8 to +8 around the BCU surface showing an "erosional" feature, thought to represent the location of the Punt Sandstone deposition.

Fig. 71 - Failure mechanism: reservoir. Comparison pre- versus post-drill model

Fig. 72 - Top Upper Balmoral sand depth structure map highlighting AVO anomaly

Fig. 73 - Seismic Inline Depth Full Stack Seismic Line (Strike Section along well path)

Fig. 74 - Base Cretaceous Unconformity depth map

Fig. 75 - SW-NE seismic line across Brodie prospect

Fig. 76 - Top Horda Fm. amplitude map

Fig. 77 - Fyvie prospect: pre-drill Top Fulmar Sand Depth Map

Fig. 78 - Comparison pre-post-drill along a N-S line across Fyvie prospect

Fig. 79 - Western Terrace: Top Fulmar depth map

Fig. 80 - Western terrace: pre- versus post-drill comparison along a SW-NE line

Fig. 81 - Zanzibar Prospect - Base Cretaceous Depth Map

Fig. 82 - Zanzibar: West - East Line through wells 12/13-1 and 12/14-2

Fig. 83 - Oddjob prospect: pre-drill top Captain depth map tied to nearest wells – feet TVDss

Fig. 84 - 4-way dip closure at Base Chalk & BCU Structure observed on 2003 PreSDM dataset (NW-SE Seismic In-Line 974)

Fig. 85a - Hobby North: south- north schematic geological cross section along Punt depositional axis volume

Fig. 85b - Hobby North: volume scenarios (Top Punt 2 Depth (feet) using Seismic Vint depth conversion map)

Fig. 86 - Hobby North: geoseismic line: pre-drill vs post-drill comparison

Fig. 87 - Octopus prospect definition: superimposed Top Captain to BCU Isopach and Top Captain Depth map

Fig. 88 - West - East seismic section across Octopus prospect

Fig. 89 - Stingray pre-drill BCU depth map and volumetric hypotheses

Fig. 90 - North-South seismic In-line 2570 (location shown on map Fig. 89)

Fig. 91 - 15/13b Guinea Prospect: Balmoral Depth Structure Map

Fig. 92 - EW-NWSE Seismic Line A-A' From Guinea to Well 15/13-3

Fig. 93 - SW-NE Line across proposed location on Fox prospect

Figs. 94 a & b - BCU Conservative Pick Depth Map (**a**) and BCU Upside Pick Depth Map (**b**)

Fig. 95 - Random seismic line across wells 15/22-14, 15/22-16 and Stareek proposed location

Fig. 96 - Stareek prospect cross section along the line shown above (ref. Fig. 97)

Fig. 97 - Lower Volgian depth map

Fig. 98 - North-South seismic line through the Deacon prospect (see location on Fig.97 above)

Fig. 99 - Deacon Prospect: Amplitude extraction combined with AI

Fig. 100 - Pineapple Prospect: BCU depth map

Fig. 101 - Block 19/3 Pineapple Prospect: SE - NW Seismic Line

Fig. 102 - Full Moon Prospect: Base Cretaceous Depth Structure Map with location of line A-A' (Fig. 103)

Fig. 103 - 3D Seismic Line A-A' through 19/4-B

Fig. 104 - SSW-NNE random seismic section showing planned 19/5b-2 well bore trajectory

Fig. 105 - Pre-drill Griffon geoseismic interpretation

Fig. 106 - Peacock Prospect BCU depth map

Fig. 107 - SW –NE seismic line through Peacock prospect

Fig. 108 - Firefly prospect: Base Cretaceous Depth Structure Map

Fig. 109 - West-East B-B' seismic line showing the Jurassic interval (green to blue) pinching out to the north and west creating the trap

Fig. 110 - Block 20/1S, North Buzzard and Lily Terraces on BCU depth structure map

Fig. 111 - SW-NE seismic random line through the Buzzard North terraces

Fig. 112 - Polecat Prospect, Top Buzzard Depth Structure

Fig. 113 - N-S seismic line 2192 across Polecat Prospect

Fig. 114 - Bluebell Terrace location map

Fig. 115 - Comparison pre- vs post-drill BCU-Base Upper Jurassic time thickness maps

Fig. 116 - Bardolph: gross reservoir interval thickness map

Fig. 117 - North-South composite seismic line along canyon axis

Fig. 118 - Top Ettrick depth map showing pinch-out hypotheses: Squirrel location is 20/07a-D

Fig. 119 - Upper Jurassic thickness map: Squirrel location is 20/07a-D

Fig. 120 - Top Ettrick reservoir depth map and Ettrick + Buzzard targets closure outlines

Fig 121 - North-South seismic line across the Black Cat prospect

Fig. 122 - Joppa well 20/07b-5: Prognosis versus Actual

Fig. 123 - Seismic Inline 1700 across Flint Prospect (Aker AGEA99)

Fig. 124 - Flint prospect BCU depth structure map

Fig. 125 - Saracen Prospect and Tweedsmuir Field outlines (Base Early Volgian Sst Depth Structure)

Fig. 126 - West-East seismic line C-C' across Saracen

Fig. 127 - Porcupine Prospect: Palaeocene Volumetrics

Fig. 128 - WSW – ENE seismic section through Porcupine prospect

Fig. 129 - Edgware prospect: trap definition. Depth to Top Reservoir (base hot shale) Structure Map

Fig. 130 - SW-NE seismic line across the Edgware prospect illustrating well 39/1b-3 location

Fig. 131 - Edgware pre- versus post-drill comparison

Fig. 132 - Spitfire Prospect Montage

Fig. 133 - Arbitrary seismic lines connecting offset discovery wells

Fig. 134 - Spitfire: comparison pre-drill model versus post-drill results

Fig. 135 - Prospect "A"-Halibut, top Jurassic depth map

Fig. 136 - Prospect "A"-Halibut: north-south seismic line 11674

Fig. 137 - Laurel Valley prospect: BCU (top Birch) depth map

Fig. 138 - W-E seismic cross section across Laurel Valley prospect

Fig. 139 - Top Forties Mu-Rho Extraction showing well 15/25a-4 may not have tested the Bluebell prospect

Fig. 140 - Bluebell trap definition

Fig. 141 - Sheryl prospect Top "Sand 1" time map

Fig. 142 - WNW-ESE arbitrary seismic line across Sheryl

Fig. 143 - Golden Arrow prospect definition

Fig. 144 - E-W seismic line A-18-19-82-25 through Golden Arrow well location

Fig. 145 - West-East geological cross section illustrating the Criollo prospect

Fig. 146 - Top Volgian fan depth map

Fig. 147 - 20/10b-5 Criollo: Crossline 2606 through well

Fig. 148 - Muness Prospect: Kopervik Gross Sand Isochore with Top Kopervik Contour Overlay

Fig. 149 - Seismic Traverse from proposed exploration well 21/4b-F to well 21/4b-2

Fig. 150 - Palomino prospect model

Fig. 151 - North-South random seismic line through Palomino prospect

Fig. 152 - Block 21/6a Top Fulmar Reservoir Depth Map

Fig. 153 - Depositional model of Cromarty sand accumulation at Cyclone location

Fig. 154 - Cyclone amplitude response - pre-drill evaluation

Fig. 155 - Block 21/23a Constance prospect Middle Tay acoustic amplitude and time structure

Fig. 156 - Strike seismic random line across 21/23a-10Z (Well A) and 21/23a-10 (Well B) locations

Fig. 157 - Top Sele depth map showing Coronado & Morro targets

Fig. 158 - SW-NE seismic random line along the well paths (Courtesy of BP)

Fig. 159 - SW-NE seismic line across the so called "Forties channel"

Fig. 160 - SE-NE seismic section showing interpretation of the pinch-out

Fig. 161 - Coaster anomaly: RMS amplitude extractions from near and far angle stacks with TWT contours overlaid

Fig. 162 - East-West seismic line across Coaster

Fig. 163 - Seismic over the eastern extension of the Danica injectites package in adjacent Block 29/6a (*courtesy of Encore Oil*)

Fig. 164 - Danica Amplitude map (undefined horizon!) showing both well penetrations

Fig. 165 - 39/2c-Peveril prospect location Map shown on BCU depth map

Fig. 166 - North-South seismic section from Fife field to Peveril prospect

Fig. 167 - Map of the regional Top Fulmar (interpretation from multiple datasets): nearby field outlines, offset wells and infrastructure. Red outline is the core area of the Stavro Prospect

Fig. 168 - Composite seismic line illustrating the migration pathway

Fig. 169 - Quasimodo prospect concept

Fig. 170 - Quasimodo Outline Geology on E-W Sketch

Fig. 171 - Quasimodo prospect: Drainage area vs trap size and location

Fig. 172 - Arbitrary seismic line through Disraeli Tay and Fulmar objectives, Gladstone and Pict

Fig. 173 - Disraeli Deep: target maps comparison

Fig. 174 - Skate prospect: Captain Sandstone depth structure map

Fig. 175 - Seismic cross Line 1330 through along Skate proposed well path

Fig. 176 - Scapa "SA" sands depth structure map

Fig. 177 - Pre-drill interpretation absolute Acoustic Impedance through Dunnottar location

Fig. 178 - Schematic pre-drill vs post-drill cross sections

Fig. 179 - Cardhu prospect: Top Piper Depth Structure Map

Fig. 180 - Seismic Traverse from Highlander to Cardhu

Fig. 181 - MacDonald prospect: top Piper depth structure map

Fig. 182 - Seismic cross section showing MacDonald well path

Fig. 183 - North Saltire: top Lower Galley/Piper depth structure map

Fig. 184 - S-N Seismic line through Egilsay, Chanter, Saltire, North Saltire and 15/18-1

Fig. 185 - 15/17-27 – North Saltire post-drill south-north geoseismic cross-section

Fig. 186 - Intra KCF sand (ca. Top J72) Isochron RMS Amp - 30 ms window on Coloured Inversion

Fig. 187 - Traverse A – A' Sligachan to Tweedsmuir South: acoustic impedance flattened at BC

Fig. 188 - 30/13c-H (Jenny): SW-NE seismic tie line

Fig. 189 - Eta 2 prospect: Top Rotliegend depth structure map (feet)

Fig. 190 - North-South seismic random line through Eta 2 prospect

Fig. 191 - Kessog discovery: Top Pentland depth map; seismic and geological cross section

Fig. 192 - Post well interpretation on CGGV Pre-SDM 2008

Fig. 193 - Kessog water head pressure plot including well 30/1c-9

Fig. 194 - Well 30/1c-9 Extended Well Test results

Fig. 195 - Volante was characterized by seismic anomaly. Black arrows indicate sediment transport direction

Fig. 196 - Volante Top Punt depth map: purples lines indicate location of seismic sections shown below. Red square is area of interest around the well

Fig. 197 - Volante prospect: axial inline 1420 through well location

Fig. 198 - Volante prospect: Cross-line 33440 through well-location

Fig. 199 - Overall main reasons for failure

Fig. 200 - Main reasons for failure: Eocene and Palaeocene Plays

Fig. 201 - Fulmar in Interpod setting

Fig. 202 - Fulmar interpod main reasons for failure

Fig. 203 - Upper Jurassic deep water turbidites stratigraphic trap

Fig. 204 - Upper Jurassic deep water turbidites: main reasons for failure

Fig. 205 - Example of map cut too short around the so called prospect

Fig. 206 - Example of well results not tied to seismic mapping

Fig. 207 - Example of questionable seismic picking

Fig. 208 - Example of wrong seismic picking

Fig. 209 - Another example of wrong seismic picking

Fig. 210 - Example of questionable picking in a reflexion free seismic area

Fig. 211 - Trap interpreted as a mound while it is more likely a multiple

Fig. 212 - Anomaly interpreted as a close analogue to a neighbouring discovery

Fig. 213 - Example of “random” anomaly which does not show any particular geological feature

Fig. 214 - Example of prospect definition based on an inappropriate seismic data set

Fig. 215 - The dilemma: effective side seal vs effective migration pathway

Fig. 216 - Migration pathways based on questionable assumption about inferred carrier beds

Fig. 217 - Comparison drainage area vs trap size. Impact of kitchen geometry

List of Appendices

Appendix 1 - Post Well Analysis sheet: template

Appendix 2 - Invited Companies

Appendix 3 - Listing of studied wells

Appendix 4 - Agendas of the 3 workshops held from 16th June to 09th July 2015

Appendix 5 - Workshops attendees

Appendix 6 - All completed PWAs ranked by well owner alphabetical order then by increasing numerical order

Oil & Gas Authority
AB 1
48, Huntly Street
Aberdeen AB110 1SH
www.gov.uk/oga
URN --/----