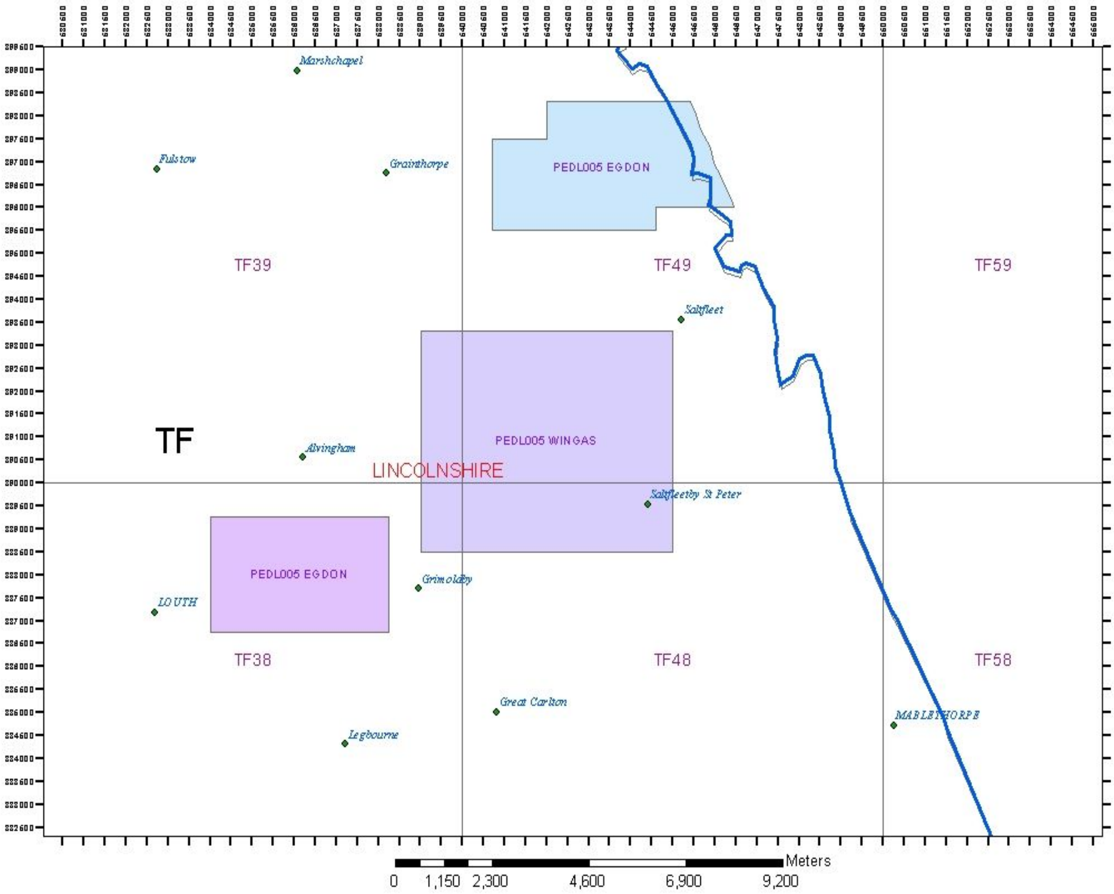
WINGAS STORAGE UK LIMITED

PRODUCTION OF SALTFLEETBY GAS FIELD (PEDL005)

AMENDED FIELD DEVELOPMENT PLAN

OCTOBER 2012

Figure 1 PEDL005 Licence area



Contents

WINGAS Storage UK Limited

Addendum to Field Development Plan

1. Executive summary

The Saltfleetby Gas Field, located at the PEDL005 Licence, was acquired by Wingas GMBH from Roc Oil UK Ltd (Roc) on the 1st of January 2005. The purchased company was renamed Wingas Storage UK Ltd. (WSUK). The acquisition was with the view of converting the Saltfleetby gas field to a gas storage facility. The economics of gas storage at the present time do not justify the required investment. WSUK's shareholders believe that circumstances will alter and have instructed the company to take all necessary steps to maintain the option to re-start the storage project but in the meantime to produce and sell gas from the field, with a target start date of 1 November 2012, to finance continuing operations.

A draft Field Development Plan for storage operations dated March 2011 was submitted to DECC. Key technical data from that draft is included in this Addendum, either in the body of the text and as Appendices, for the sake of completeness and clarity.

The field is located in the License Sub-area PEDL005 (Saltfleetby) (Fig. 1). The License Sub- area is operated 100% by WSUK.

The field has been developed by Candecca Resources (pre 2000), Roc Oil (2000 - 2006) and WSUK (post 2006). Eight horizontal and sub-horizontal wells and multiple re-entries have been drilled. It is a field that produces lean-gas-condensate from the early Westphalian sandstones at ~2300 mss. The field is split into a 4 km x 1.5 km main structure and a 1 km² southern satellite. The permeability defined by core measurements ranges from 1 to 5 mD and the porosity from 6 to 12%. The total GIIP is 3.35 bscm (118.3 bscf). The drive mechanism is gas expansion, with a small aquifer entrance. The GWC is unchanged at 2338 m compared to the 2005 study, Units 1 and 2 are connected, and the Namurian section is not included.

The cumulative raw gas production at the 1st July 2009 is 1.683 bscm (59.4 bscf) and the cumulative condensate production is 156,000 m^3 (981,000 stb). A three phase 10" – 8 km pipeline exported the products to the Theddlethorpe Gas Terminal (TGT).
The current field production potential is 0.6 mmscm/d (21.2 mmscf/d) with a condensate production of 9.54 m^3/d (60 bbl/d). Two wells on the Western part of the field and one on the southern structure are able to produce. Due to the production of free water, the remaining wells are shut-in. The available information indicates this water is produced from the Namurian sandstones in the wells that have entered this layer.

A field description and data on geological interpretation and reservoir description are set out in Appendix 1

2. Technical status of existing wells

In this section DECC well-numbering has been used, followed by WSUK's own well designations. Elsewhere, for brevity, we have used WSUK's designations alone

Wells L47/16-2U (SF01), L47/16-6Z (SF03), L47/16-9 (SF05), L47/16-10Y (SF06) and L47/17-11Y (SF07) are subject to long-term suspension and the detailed well diagrams reflecting this status are contained in Appendix 2A.

Wells L47/16-5 (SF02), L47/16-7 (SF04) and L47/16-12X (SF08) have recently undergone an inspection programme with measurements to ensure integrity prior to the start of gas production. Detailed well diagrams are contained in Appendix 2B.

The status of the wells and WSUK's well integrity assurance programme are set out in Appendix 3.

3. Planned changes to the wells

No further changes are planned for the three production wells with regard to additional workovers, side-tracks or facilities upgrades. The possibility of drilling an additional well is currently under consideration with a final decision expected to be made in Q1 2013 after completion of design, costing and economic evaluation.

4. Investment plan

As indicated in 3 above no additional work is required or intended in respect of the production wells and there is therefore no current investment plan. If an additional well is commercially justified as a result of work now being undertaken an investment plan will be prepared and information provided to DECC.

5. Expected production profile

The expected production profiles for gas and condensate are shown in Appendix 4

Produced hydrocarbons are exported to ConocoPhillips' Theddlethorpe Terminal for processing and redelivery as gas and condensate. We have been informed by ConocoPhillips that there may be a capacity constraint for a period of between one and two years from August 2013. We are in discussion with them on the detail of the constraint and a working on potential solutions. Because of the uncertainty of both the extent and timing we have not reflected it in our expected production profile. Should circumstances change we will inform DECC

6. Ultimate recovery

The 1P reserve case was calculated with the condition of producing to the existing compressor at Theddlethorpe Gas Terminal allowing the well head pressure to be a minimum of 32 bar.

Remaining 1P reserves from 1 November 2012 are calculated as: Gas 1.32 bscm (48.8 bscf) and Condensate 91300m³ (574210 stb)

7. Assumptions made

The expected production profile described in Section 5 above and in Appendix 4 is based on the following assumptions:

7.1 SF02, SF04 and SF08 remain in their existing configuration.
7.2 The Theddlethorpe Gas Terminal has the capacity to receive, process and redeliver all production.
7.3 The wells will produce to 32bar WHP as dictated by the compressor at Theddlethorpe.
7.4 The 6.5 year production life of SF08 is considered to the best case scenario. The P80 case is calculated by taking 100% of SF08's production in the first 12 months, 66% in the second 12 months and 33% in the third 12 months with no further production thereafter.
7.5 As gas velocity in the wells drops it will no longer be able to carry the water out of the wells requiring periodic shut-ins to allow down hole pressure to build up before re-opening. This process is expected to start after about 4-5 years and has been included in 7.6 below
7.6 Down time for maintenance, repairs and pressure recovery is estimated at 10%
7.7 Any well will stop producing once 45bar down hole pressure has been reached.

8. Flaring volumes

No flaring is planned during production operations.

9. Venting volumes

No venting is planned during production operations; there may be a requirement to vent during maintenance and an application will be made at the appropriate time via the DECC portal.

Appendix 1

Field description, geological interpretation and reservoir description

1. Field Description

The Saltfleetby Gas Field is located onshore in UK at the western extent of the Humber Basin in the PEDL005 license. The commercial discovery was made in 1996 after re-entering an exploration well drilled in 1986. The field was put on stream in December 1999 producing from the Early Westphalian sandstones in the Carboniferous Formation at a depth of 2300 mss. In 2000 the Late Namurian sandstones were produced by well SF05. Eight wells and several sidetracks have been drilled. The production is exported as a mixed phase in an 8 km pipeline to the Theddlethorpe Gas Terminal (TGT). The incoming field gas is compressed to national transmission system (NTS) pressure using the shared facilities of the Pickerill compressor. Table 1 summarises the main field data.

2. Geological Interpretation and Reservoir Description

Tectonic History, Structure and Seal

The depocentre was initiated during Late Devonian – Early Carboniferous time. In the Saltfleetby area, Dinantian limestones were deposited and syn-sedimentary normal faulting is well-known. During early Namurian (post Dinantian, pre late Namurian) times, a regional erosion event has led to the karstification of Dinantian limestones and formed a paleo-topography of probably low relief. The basal sands of the Namurian - Westphalian units are unconformably overlying the Dinantian limestones.

Namurian to Early Westphalian extension led to regional syntectonic progradational systems of deltas and channel sands - the main reservoir units in the field. Higher sedimentation rates are detected north of the field in the Scupholme 1 well, whereas subtler reservoir variations in the field itself are identified from west (SF04) to east (SF03, SF05, SF07) pointing towards a smooth paleo-relief (see Fig. 3). Core evaluations of well SF03 (Fig. 4) and well log analysis of all penetrations indicate a proximal fluvial-deltaic depositional setting for the amalgamated channel sands in the main reservoir units of the Westphalian. Intercalated shalier sections within the main reservoir section are either related to crevasses and overbank deposits or marine bands.

The Saltfleetby structure is a complex faulted anticlinal (4-way dip closure) inversion structure with a crest close to the wells SF01x and SF05. A much more gentle satellite structure with similar structural evolution is located towards the south and has been investigated with the wells SF06 and SF08. The encountered water contact drilled at 2338 mss in well SF06, assumed valid as the regional field GWC, even if this is not proven in the north, would create a total gas column of around 93 meters in the main structure (see Fig. 5).

The structural evolution is mainly related to Late Westphalian - Stephanian compression and structural inversion during the Variscan orogeny. Former extensional normal faults were reactivated with compressional and/or strike-slip movements.

More than 2 km thickness of overburden was deposited during a sag phase ranging from Triassic to Cretaceous. The Alpine Orogeny at Miocene/Pliocene times resulted mainly in regional tilt of the field in the range of 5 degrees towards east. This probably caused a reduction in field closure with regard to the westerly spill point and re-migration of hydrocarbons.

The effective seal is provided by more than 25 meters of regional developed Carboniferous shales and mudstones above the sand Unit 2 (see reservoir section under Fig. 7). There is no closure at top Carboniferous or base Zechstein level.

Reservoir and Diagenesis

The main reservoir section of Westphalian Unit 1 and the Upper Namurian sand have been cored in the well Saltfleetby 3 (Fig. 4). The Carboniferous consists of massive coarse to conglomeratic channel systems with lateral distribution and connectivity between 10 and 24 meters. The depositional environment is marine (Namurian) and changes to fluvial (Westphalian), with distinct marine bands. Thickness increase or variations are related to paleo- relief infill towards east as seen in the wells SF03, SF05 and SF07, or fault cut outs as proven in SF01z (approx. 20 m).

Average porosity for net sand from log and core data is in the range from 6 - 12%, permeabilities ranging between 0.1 and 5 mD. The net to gross ratio of unit 1 C/D is very high (stacked channels) and demonstrates a homogeneous development across the field.

The rock composition contains 60-95% quartz, some feldspar, mica and coal fragments. Diagenetic cements comprise mostly of quartz, dolomite and kaolinite and minor detrital matrix. The porosity is predominantly of secondary origin due to leaching of feldspars and rock fragments during inversion phase

3. Seismic Interpretation – Structure and Attributes

The initial 3D data set acquired by Roc in 1997 was used for a re-interpretation check of most relevant horizons as (see Fig. 6A):

- ☐ Sherwood Sandstone (Mid Triassic)
- ☐ Brotherton (Permian Limestone)
- ☐ Base Permian
- ☐ Dinantian Limestone

Additional data is shown in Figures 6B and 6C.

Further structural interpretation was based on prestack time migration (Western, 2003), impedance cubes (Odegaard, 2003) and variance cube (Geoframe, 2005) to establish a detailed and consistent fault framework / structural model. As the former interpretation of Roc provide fair location of fault intersections, the use of inherence cubes improved significantly the fault allocations with regard to top reservoir and Unit 1C/D. However the vertical seismic resolution is limited (around 20 – 30 m) and sub-seismic faults can have a throw of up to 30 m without the possibility to detect them in the seismic data. This is a major uncertainty in planning horizontal wells within the around 20 m thick main reservoir unit 1C/D.

The new depth conversion carried out by WSUK confirmed the previous done by the former operator. Simple interval velocities with negligible velocity depth gradient together with the well penetrations indicate the robustness of this approach.

The extensive work carried out on seismic attributes, forward modelling, coherence analysis, amplitude analysis, spectral decomposition and geobody tracking has not yet resulted in the anticipated result of reservoir sweet-spot identification due to marginal reservoir properties.

4. Petrophysics and Reservoir Fluids

Full log coverage exists for the reservoir interval for the wells SF01z, SF03, SF06, SF06y, SF07, SF07z, SF08, SF08x. The well SF05 has a full suite of logs that only covers part of the reservoir section. The remainder of the reservoir section was only logged through casing where only the gamma ray log can be used. In SF01 gamma ray and sonic data are available, in SF01x gamma ray and resistivity and in all other wells there is a gamma ray log only present.

Table 2 summarises the log derived petrophysical parameters for the wells which have not been abandoned. A cutoff of 8% porosity and 40% shale content has been used in defining the net intervals. A more detailed interpretation for a 17 layer zonation has been performed to construct the geologic model.

Several gas and condensate samples have been analysed to determine the phase behaviour in the reservoir. Table 3 summarises the main parameters determined in the different tests.

The SF05 (09/09/00) separator sample shows similar parameters to the SF01u (18/11/98 - 3rd flow) sample. The parameters obtained from these two PVT studies are considered representative.

5. Hydrocarbons in Place

The GIIP values corresponding to the different sand units as well as the main and southern structures are given in Table 4. A most likely value is given as well as the range of uncertainty in terms of a maximum and minimum value. These uncertainties are caused by reservoir quality distribution (facies and diagenesis) and uncertainties of the extent and shape of the closure. Additionally the GWC is defined by on well (SF06) drilled in southern structure. There is also still a risk left if the GWC may vary throughout the field (deeper and or higher than 2338 m).

The estimates are the result of detailed geological reservoir modelling and the most likely values for the gas storage, mainly within Unit 1 C/D of the main structure, are used for further planning.

The dynamic GIIP of 3.35 bscm (118.5 bscf) is derived from the dynamic reservoir model. This value is in agreement with the volume allocated in the Wesphalian Unit 1 in the main structure where most of the cumulative production came from.

The Namurian and the Unit 2 sands and the southern structure are considered to have less contribution to the pressure dynamic of the field.

6. Well Performance

The field started production in December 1999 with wells SF01u, SF02, SF03z and SF04. A summary of the well data is presented in Table 5.

All wells produced from the Westphalian Unit 1. The well SF05 produced also from the Namurian until its re-completion in August 2002. The only well producing from Unit 2 (commingled with Unit 1) is the SF03z. All wells are completed horizontal with intervals between

120 and 612 metres with slotted liners (except for the open hole completion of SF02) and perforations in some wells towards the heel of the completion. See Table 7 for more details on well status and completed intervals.

Wells SF 01 and SF04 were drilled from the site A wellhead location, 1 km away from the site B where all other wells have been drilled from. Fig. 10 shows the production history of each well. The three phase production was exported via a 10” – 8 km pipeline to the TGT where condensate was mixed with other streams and cooled. A back allocation algorithm based on the gas density was used to calculate the stabilised condensate production corresponding to Saltfleetby. The total cumulative condensate production was 156,000 m^3 (981,000 stb) (01/07/2009).

Free Water Production

During the depletion phase of the field some wells produced free water that affected gas productivity. From seven wells completed for production three became unable to produce due to this problem.

Investigations based on water composition, simulation modelling and fault interpretation in seismic and logs lead to the conclusion that water is produced from the Namurian sandstones in the areas where wells have penetrated the Subcrenatum sealing layer between the Westphalian and the Namurian sandstones.
The “U” shaped well SF05 penetrated the Westphalian and the Subcrenatum, entered the Namurian and then finally went back up through the Subcrenatum into the Westphalian layer. This well produced free water three months after production start. The well was re-completed to produce only from the Westphalian at the heel of the well but water ingress was still possible from the Namurian to the Westphalian at the toe of the well and production had to be abandoned.

The well SF03z started to produce free water from August 2002 when completed on the Westphalian Unit 1 and 2 after depleting the reservoir from the initial pressure of 246 bar (3566 psi) to 138 bar (2000 psi). The timing of this water production indicates that the water is coming from the well SF05.

The well SF07y produced free water during the initial test in December 2003. The reservoir pressure was 116 bar(1680 psi)

Formation	Carboniferous
Depth	2300 mss
Net thickness	20 m (Unit 1c/d Westphalian)
Porosity	6 – 12 %
Permeability	1 – 5 mD
Gas initially in Place	3.35 bscm (118.5 bscf)
Gas Produced (1-7-2009)	1.683 bscm (59.4 bscf)
Condensate Produced (1-7-2009)	156 10^3 m^3 (981 10^3 stb)
Initial Reservoir Pressure	246 bar (3566 psia)
Average Reservoir Pressure (2009)	125 bar (1813 psia)
Initial Gas-Condensate-Ratio	6140 scm/scm (CGR= 29 stb/mmscf)
Reservoir Temperature	83°C (183°F)

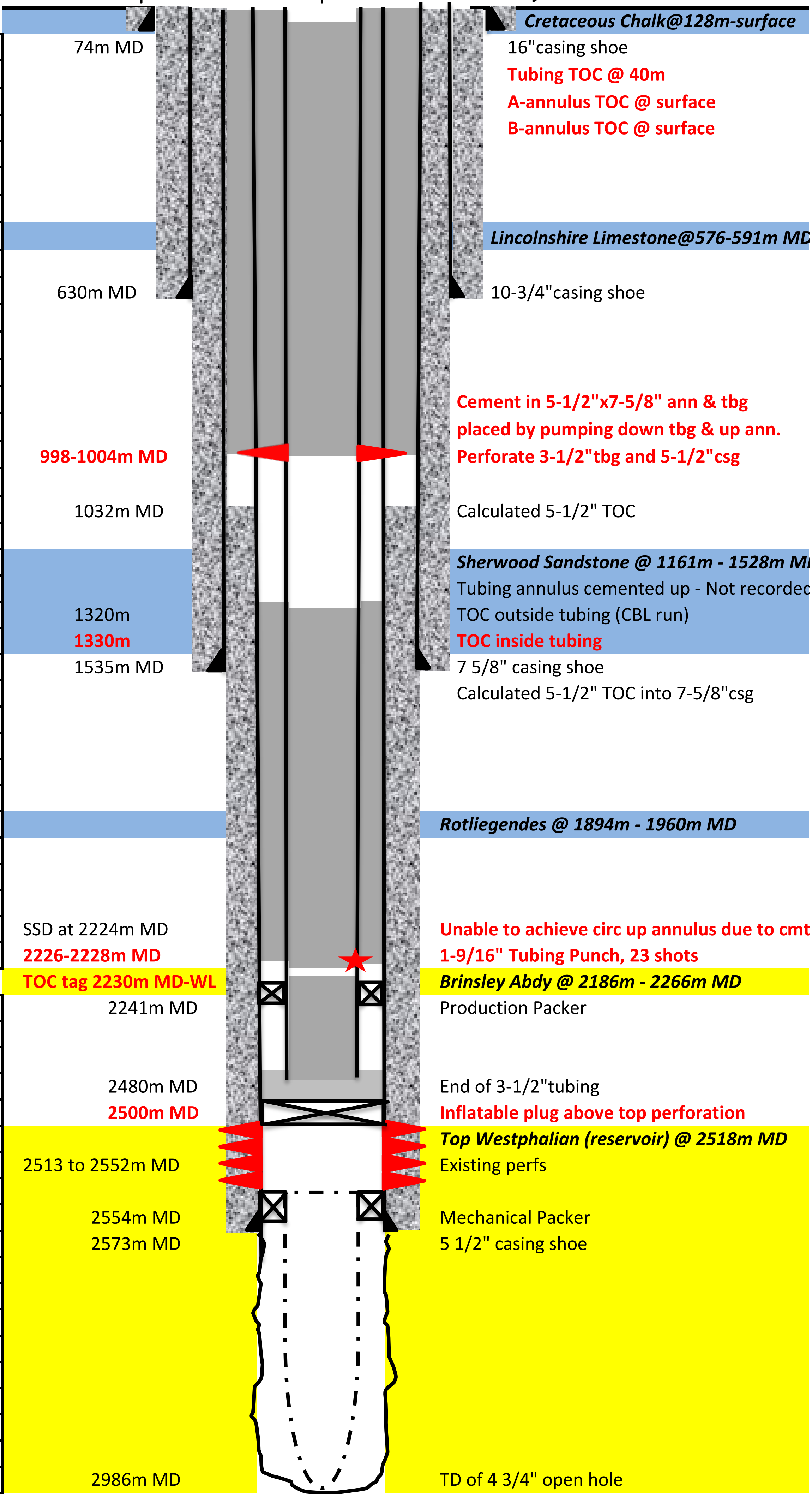
Table1. Summary of main field data

Appendix 2A

Status of existing wells (suspended)

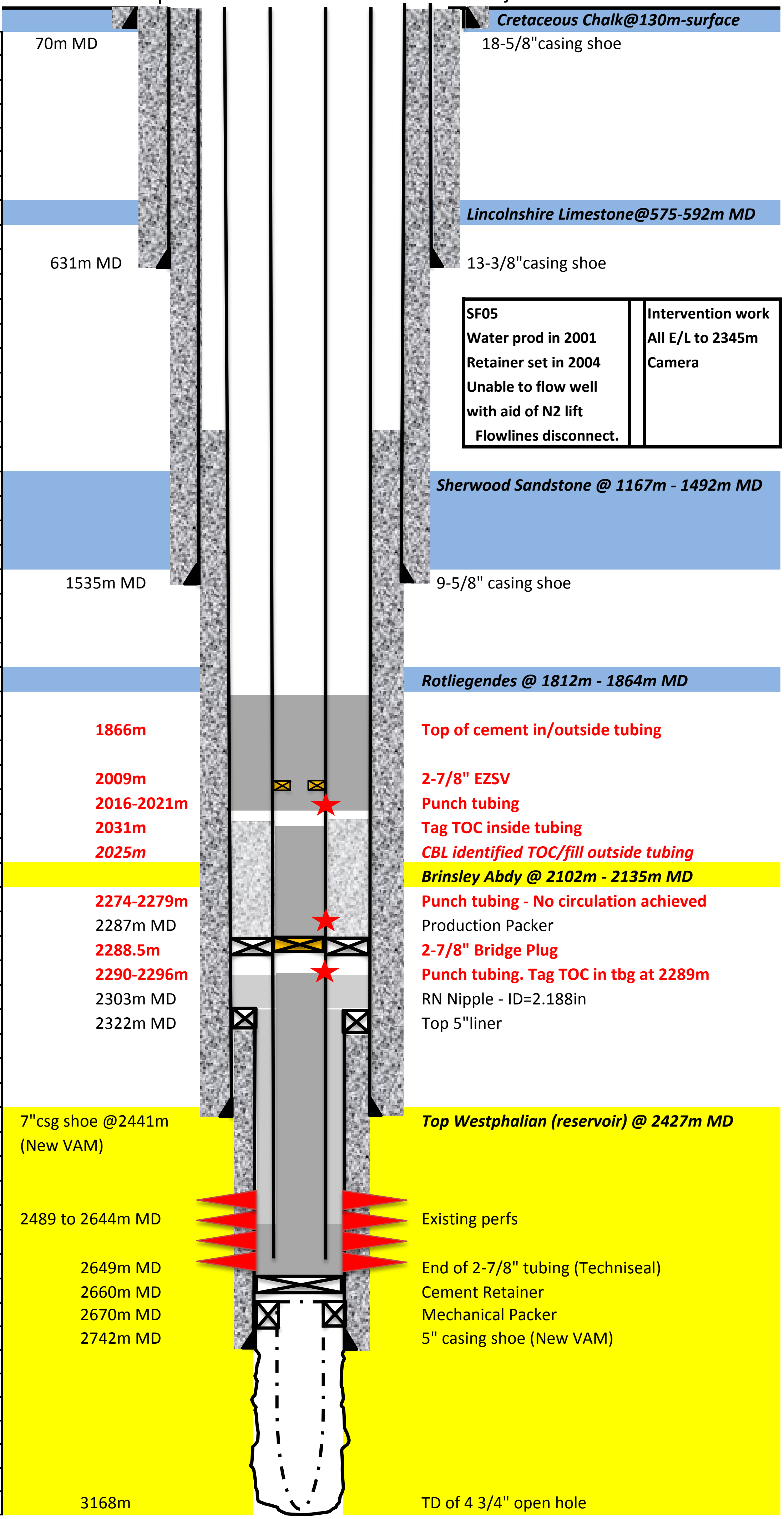
SF03z Suspension -As suspended

Measured Depth BRT (m)	Vertical Depth BRT (m)	Incli-nation (deg)
0	0	0
74	74	0
400	400	3
630	629	5
1000	998	5
1140	1137	5
1150	1147	6
1161	1158	6
1250	1245	17
1400	1382	31
1528	1488	35
1535	1494	35
1650	1588	35
1740	1662	34
1894	1792	34
1960	1847	34
1970	1855	34
1980	1863	34
1988	1870	34
1995	1876	34
2000	1880	34
2186	2036	35
2215	2059	36
2228	2070	36
2240	2080	35
2266	2101	37
2300	2127	39
2400	2191	53
2500	2247	69
2513	2251	71
2552	2262	77
2554	2263	77
2573	2267	78
2600	2271	82
2700	2270	92
2800	2269	92
2900	2271	86
2986	2274	90



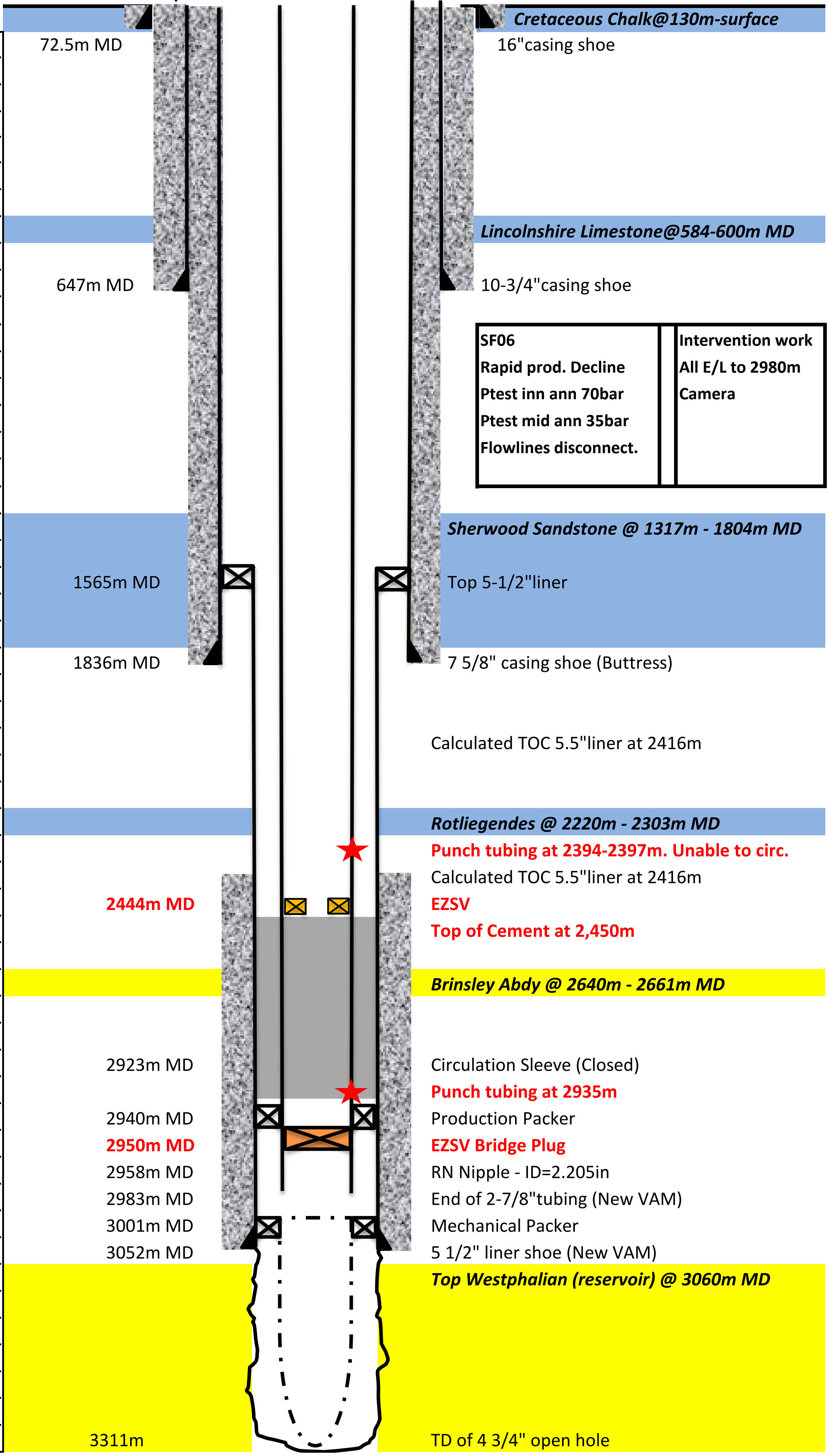
SF05 - As Suspended

Measured Depth BRT (m)	Vertical Depth BRT (m)	Incli-nation (deg)
0	0	0
150	150	0
300	300	6
500	498	9
631	627	9
1000	993	7
1167	1158	7
1535	1517	15
1812	1789	7
2102	2058	31
2287	2199	51
2345	2231	60
2427	2262	76
2500	2277	79
2600	2290	82
2700	2304	85
2800	2310	89
2900	2311	93
3000	2306	97
3168	2296	91



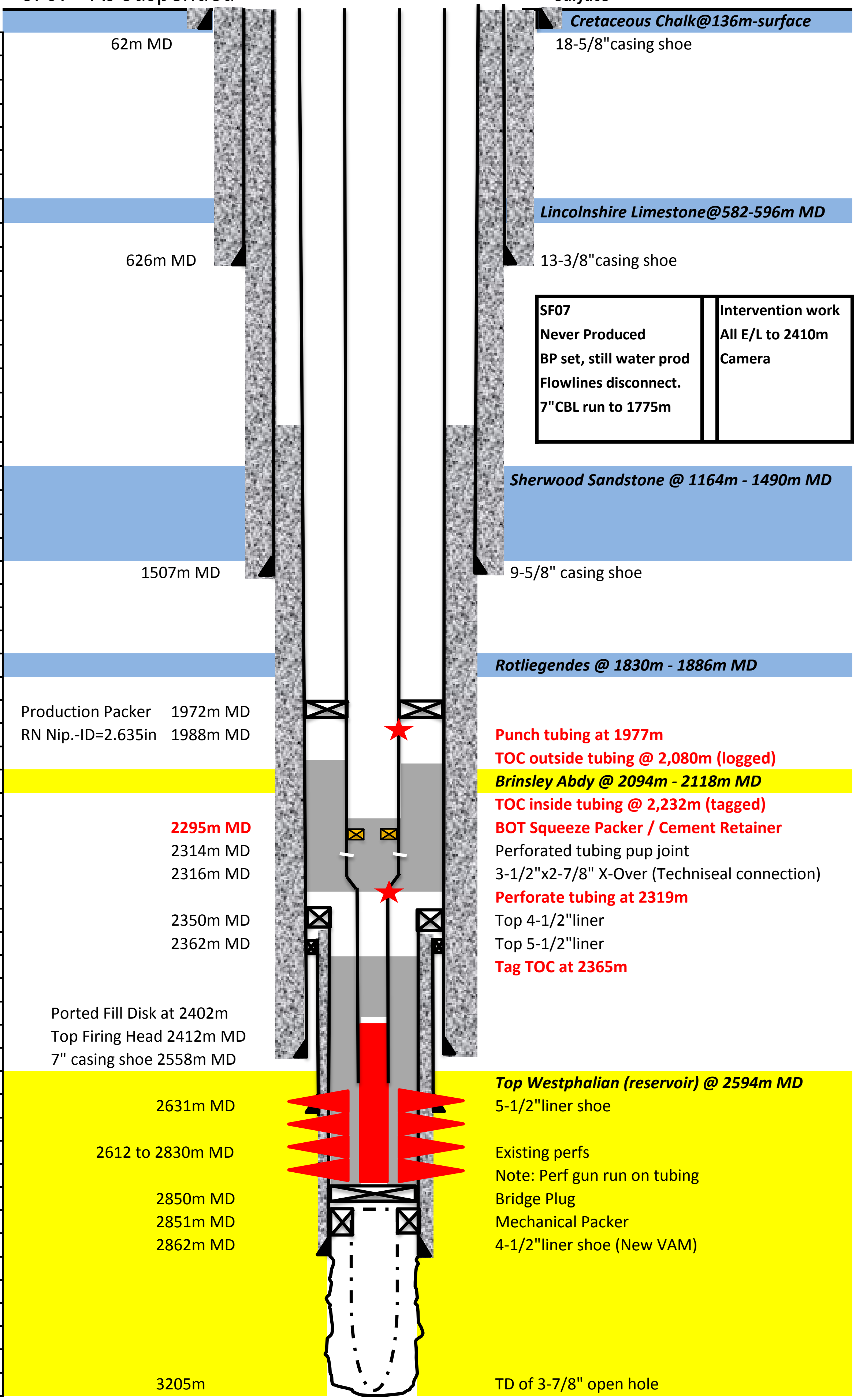
SF06 - As Suspended

Measured Depth BRT (m)	Vertical Depth BRT (m)	Inclination (deg)
0	0	0
200	200	1
400	398	10
584	578	16
800	778	32
1000	937	44
1317	1164	46
1836	1521	44
2000	1636	45
2220	1790	47
2500	1975	48
2640	2071	44
2750	2145	48
2780	2164	51
2850	2204	55
2940	2153	55
2958	2265	54
2983	2279	58
3001	2288	63
3052	2309	72
3060	2312	72
3100	2322	78
3150	2326	90
3200	2325	91
3300	2319	93
3311	2319	93



SF07 - As Suspended

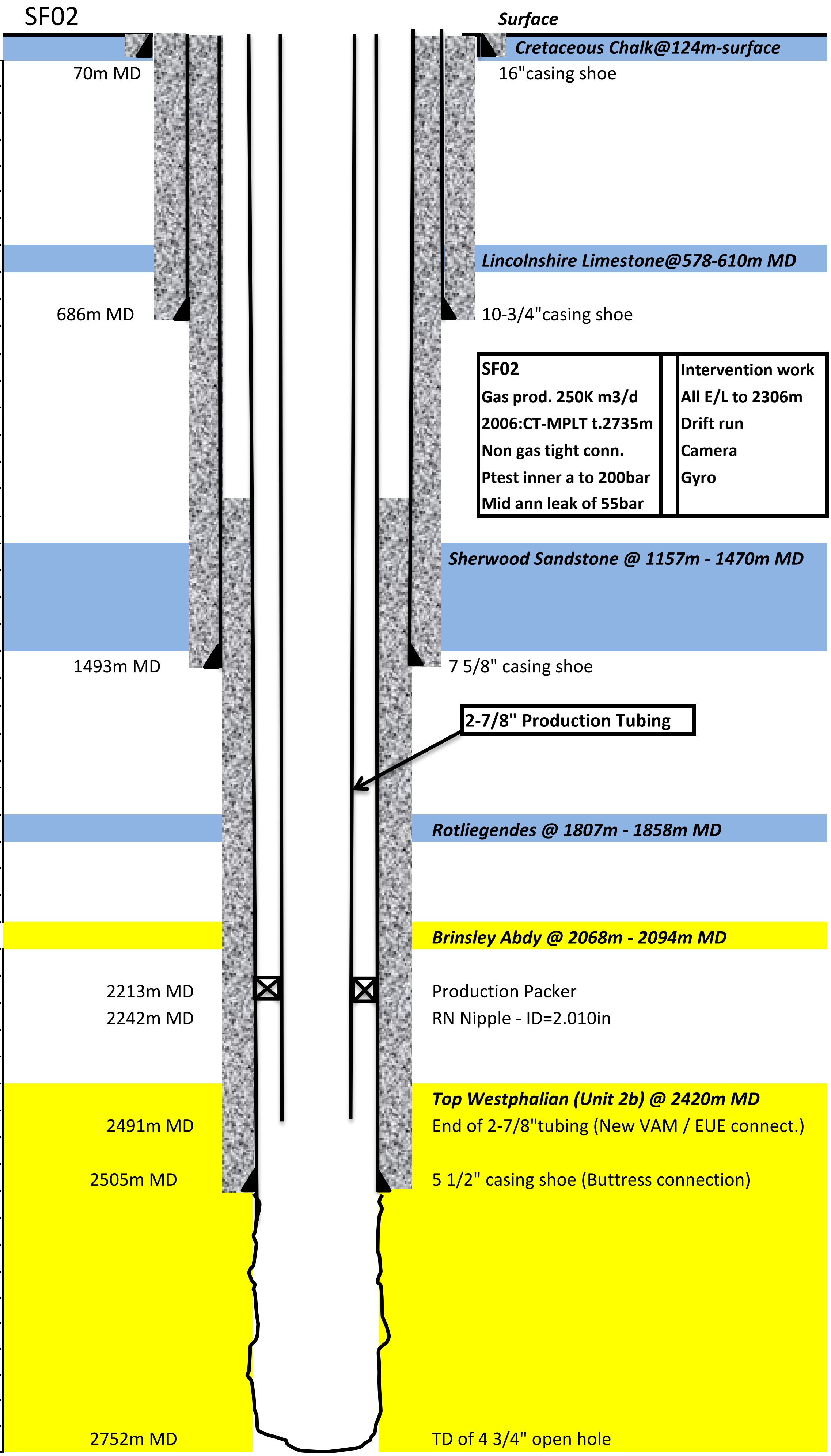
Measured Depth BRT (m)	Vertical Depth BRT (m)	Incli-nation (deg)
0	0	0
135	135	2
200	200	5
582	581	1
1000	999	2
1164	1163	2
1250	1248	2
1420	1416	15
1590	1574	27
1830	1789	27
1972	1914	33
1988	1926	35
2094	2010	45
2200	2084	48
2316	2155	54
2350	2175	55
2410	2207	60
2594	2278	79
2600	2279	81
2700	2295	79
2800	2312	80
2850	2322	74
2900	2332	83
2950	2331	93
3000	2330	90
3100	2325	94
3205	2326	87



Appendix 2B

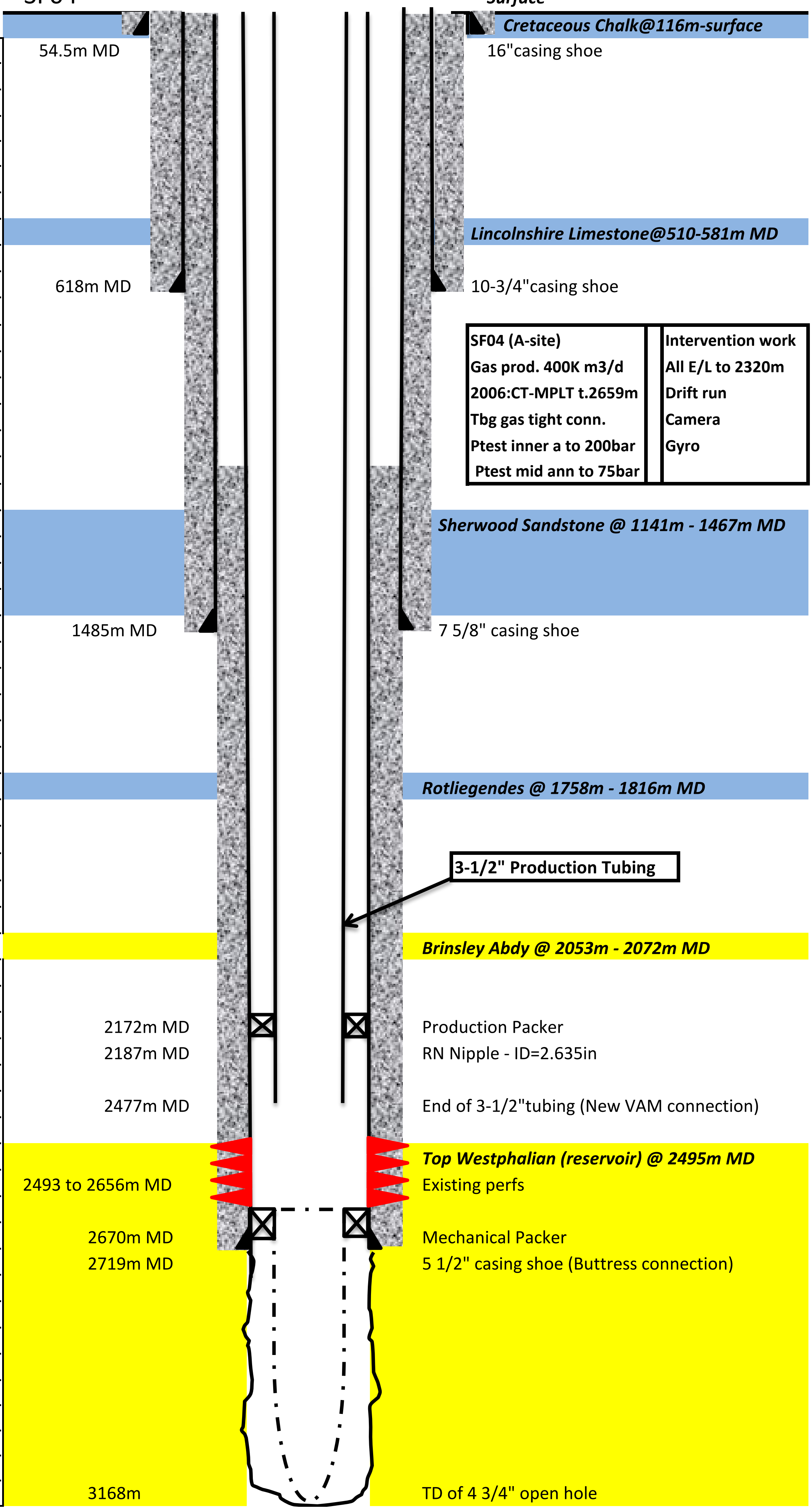
Status of existing wells (producing)

Measured Depth BRT (m)	Vertical Depth BRT (m)	Incli-nation (deg)
0	0	0
1000	1000	0
1530	1530	2
1600	1598	20
1800	1782	24
1900	1876	17
2050	2025	12
2165	2130	27
2213	2169	43
2306	2228	60
2400	2252	81
2420	2256	80
2491	2268	81
2505	2270	81
2600	2280	82
2700	2295	79
2752	2302	85

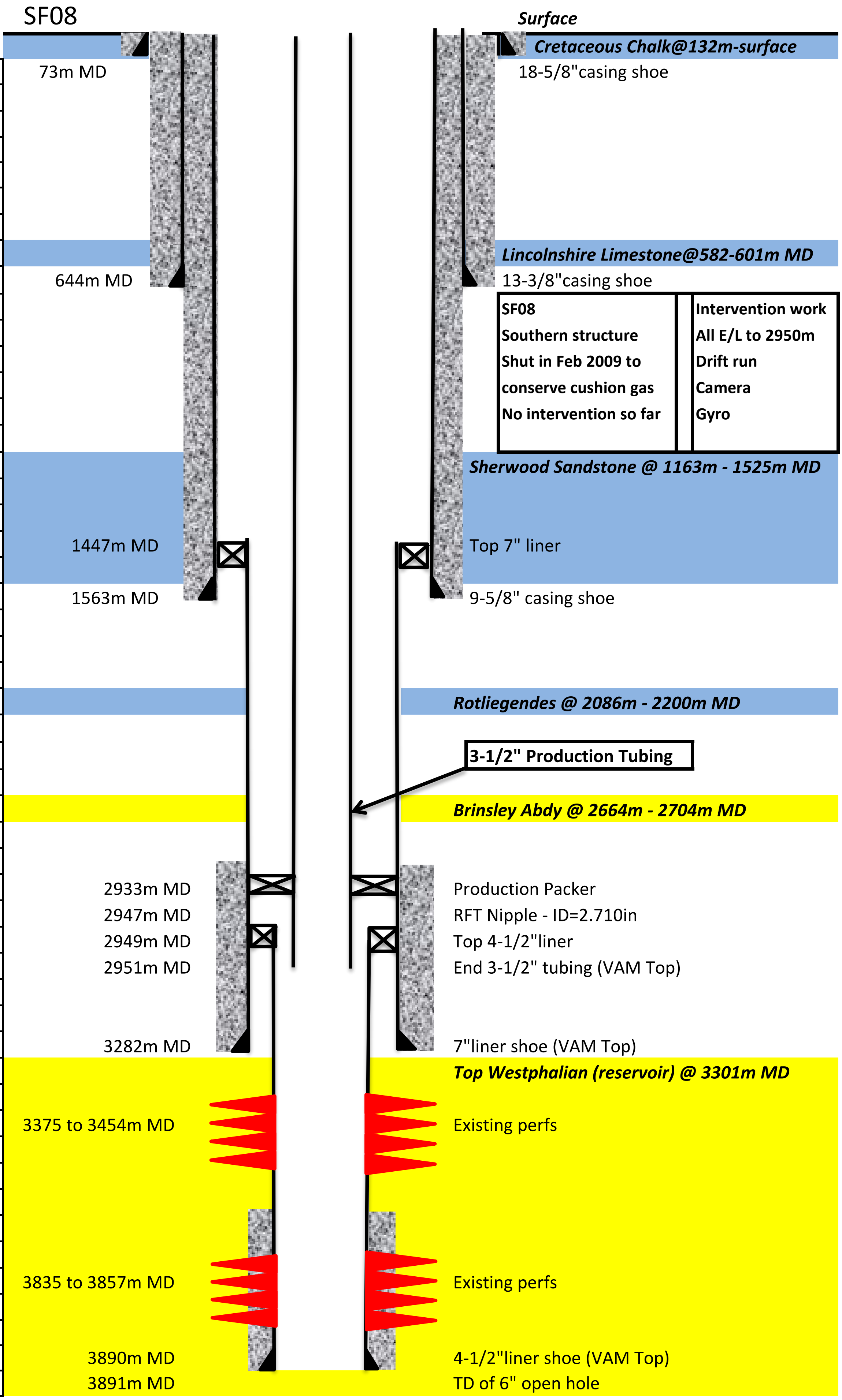


SF04

Measured Depth BRT (m)	Vertical Depth BRT (m)	Inclination (deg)
0	0	0
750	750	2
850	850	6
1141	1139	5
1485	1481	6
1758	1754	4
2000	1995	8
2053	2047	16
2172	2153	35
2320	2248	60
2477	2293	87
2495	2294	86
2600	2302	86
2719	2310	90
2800	2311	87
2900	2311	92
3000	2312	91
3100	2307	93
3168	2301	95



Measured Depth BRT (m)	Vertical Depth BRT (m)	Inclination (deg)
0	0	0
582	582	0
1000	1000	2
1163	1162	9
1400	1385	30
1800	1643	60
2086	1780	63
2664	2041	60
2933	2192	60
2951	2201	60
3218	2301	75
3301	2313	88
3400	2321	86
3500	2326	85
3600	2329	89
3700	2328	93
3800	2314	100
3891	2299	100



Appendix 3

Well Integrity Assurance Programme

Appendix 3 – Well Integrity Assurance Programme

The first phase of well integrity assurance was to resolve existing well integrity issues with L47/16-2U (SF01) and L47/16-6Z (SF03). To this end the wells were suspended with cement barriers placed as per the OGUK Guidelines for the Suspension and Abandonment of Wells. A decision will be made on the final use or abandonment of these wells when the decision to drill a further production well is made (or after gas storage wells are drilled if this course is taken).

Three further wells L47/16-9 (SF05), L47/16-10Y (SF06) and L47/16-11Y (SF07) were suspended with at least one cement barrier in place to isolate the producing reservoir. Again the barriers were placed as per OGUK Guidelines and the option now exists to side-track for production, to re-complete as gas storage monitoring wells, to recomplete as a water injection well or to fully abandon. Well integrity monitoring will continue on these wells (see below) because they cross porous strata and have not been fully abandoned.

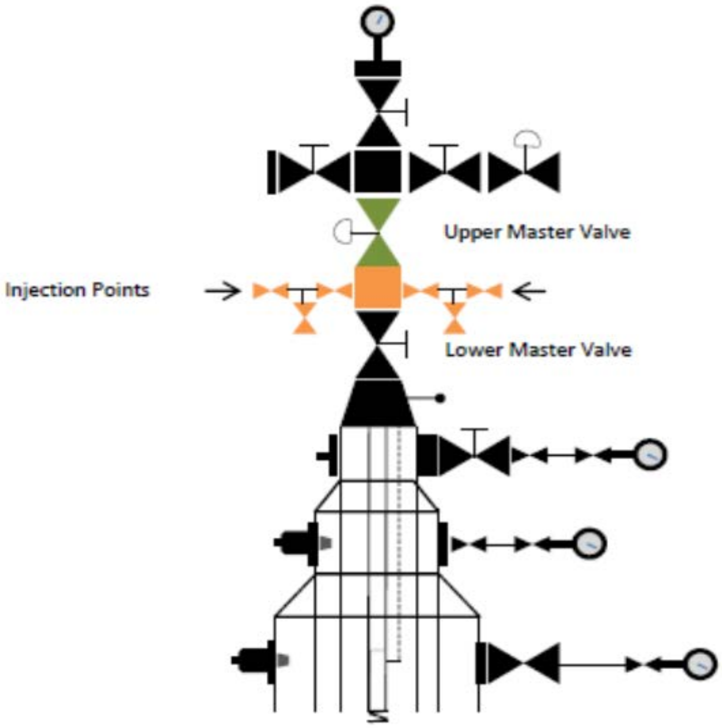
L47/16-5 (SF02), L47/16-7 (SF04) and L47/16-12X (SF08) remain as producing wells and will be subject to on-going well integrity monitoring. These wells have been subjected to camera surveys to establish basic condition, as well as gyro surveys to reliably establish their position. The same surveys were carried out on L47/16-9 (SF05), L47/16-10Y (SF06) and L47/16-11Y (SF07).

The annulus side-arms and Christmas Tree configurations were checked for the producing and suspended wells using the Health and Safety Executive's Guidance on Well Construction Standards (SPC/Technical/General/42) and any compliance issues were identified. Issues identified included incorrect valve configurations on some annuli and incorrectly sited injection points on two Christmas trees. An initial work programme is in progress to correct these issues before 1st October 2012.

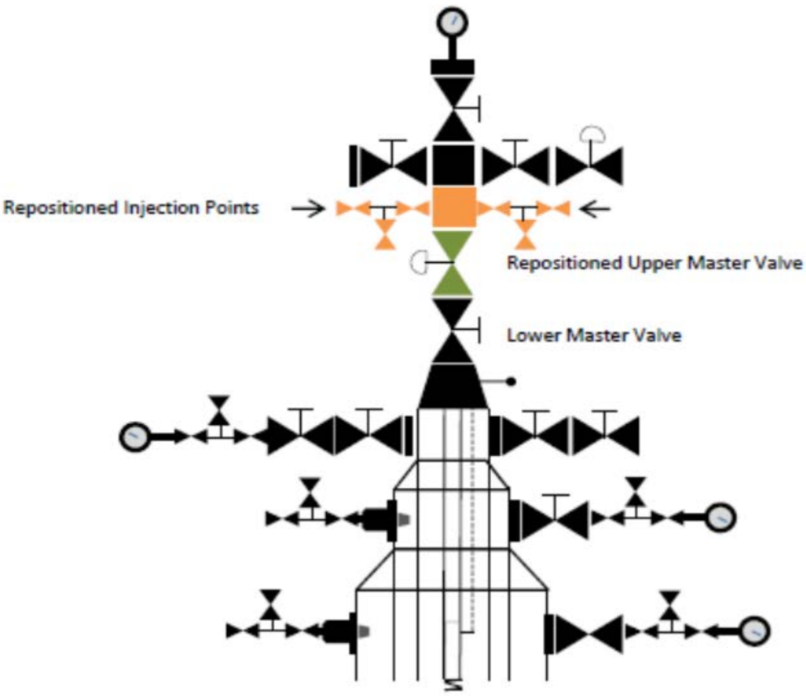
Concurrent with this work programme, an integrity monitoring scheme will be formalised and incorporated into the WINGAS policies, procedures and standards so that annulus pressures will be monitored, wellhead and Christmas tree components maintained and tested and that well integrity monitoring is prioritised. The policies, procedures and standards will clearly define actions required if any test is outside limits or if problems are identified with well components. This, when added to existing WINGAS maintenance schemes, policies procedures and standards, and the well examination scheme, will ensure the integrity of the Saltfleetby wells throughout their life.

The diagrams below show the planned final configuration of the Saltfleetby wells to ensure that they meet the requirements of the HSE Well Construction Standards Guidelines.

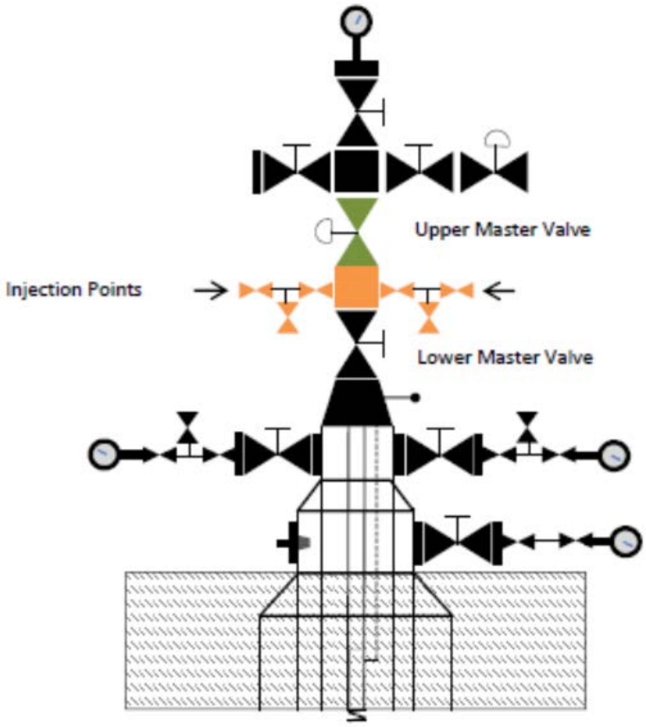
Saltfleetby 02 Well – Before Modification and Maintenance



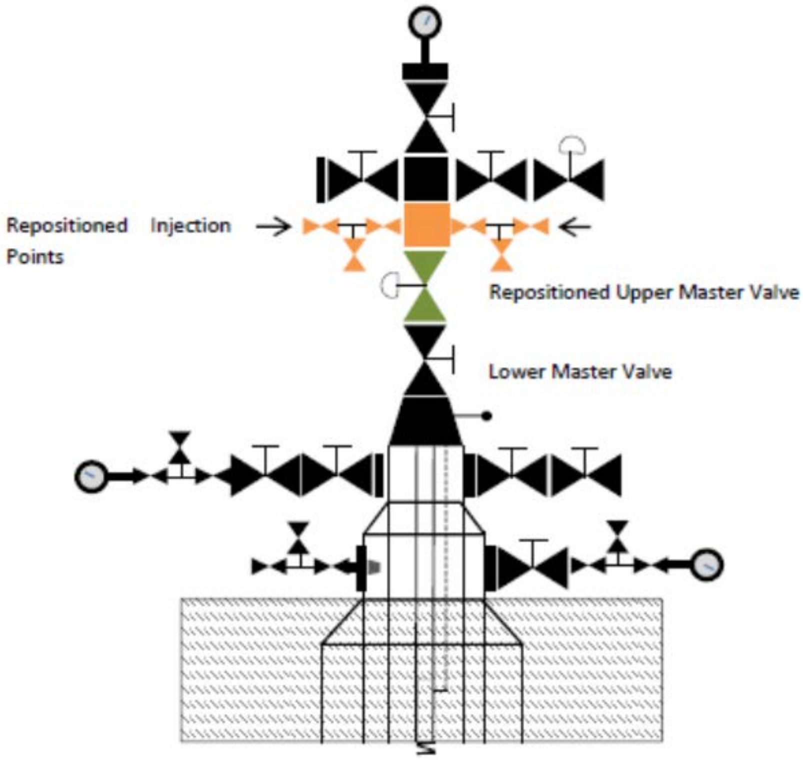
Saltfleetby 02 Well – After Modification and Maintenance



Saltfleetby 04 Well – Before Modification and Maintenance



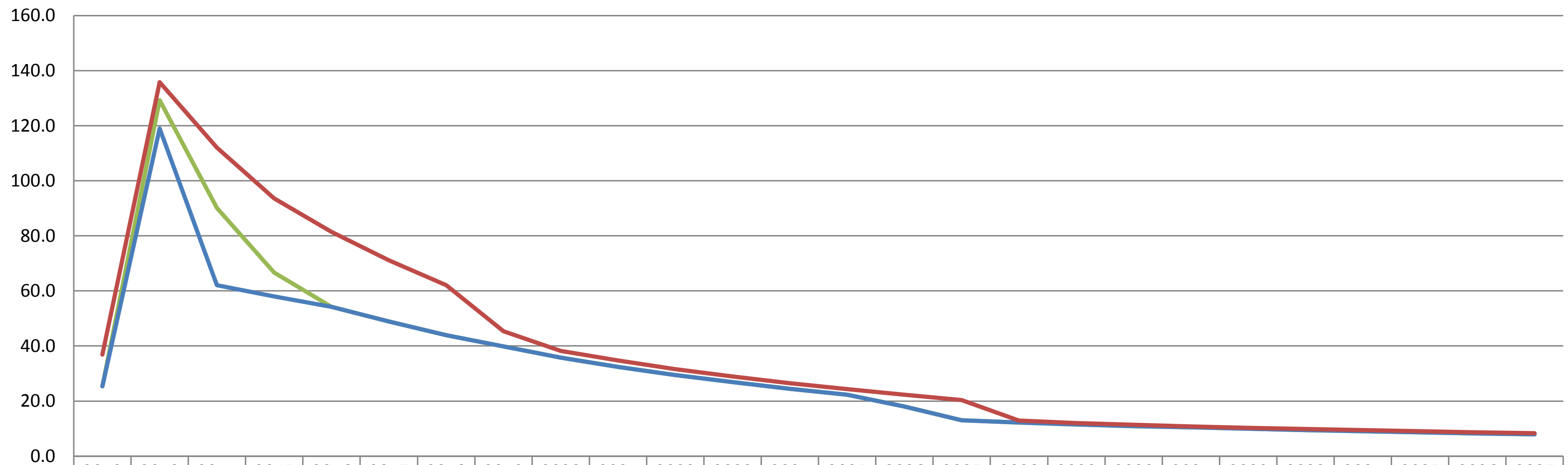
Saltfleetby 04 Well – After Modification and Maintenance



Appendix 4

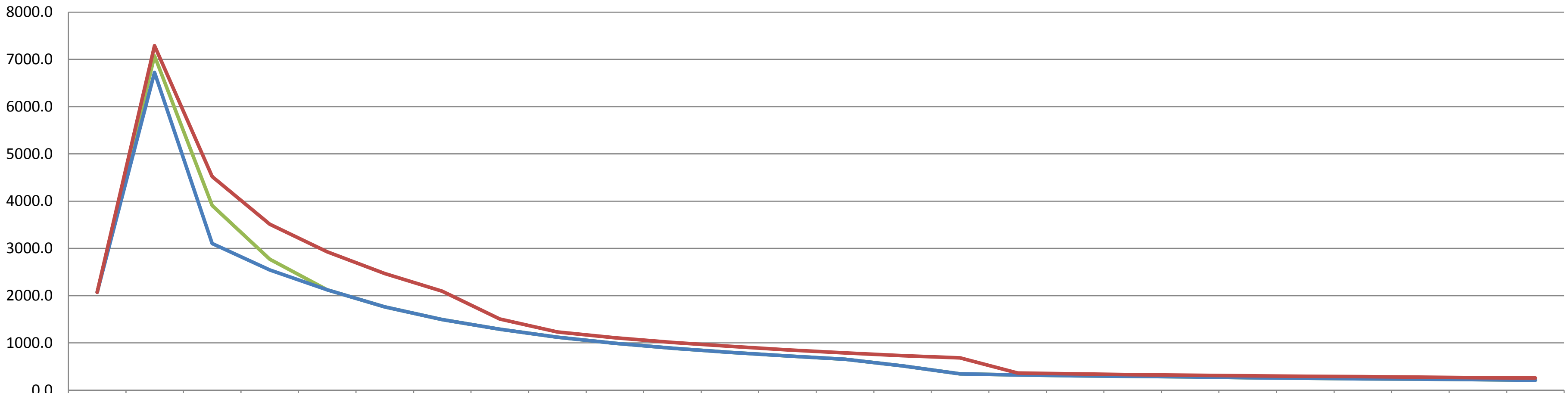
Expected production profiles

Annual Gas Production (Mio m3)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base case	25.3	129.3	90.2	66.7	54.2	48.9	44.0	39.8	35.8	32.4	29.5	26.9	24.4	22.3	18.0	13.0	12.2	11.5	10.9	10.4	9.9	9.5	9.0	8.6	8.2	7.9
Base Case minus	25.3	118.9	62.1	58.0	54.2	48.9	44.0	39.8	35.8	32.4	29.5	26.9	24.4	22.3	18.0	13.0	12.2	11.5	10.9	10.4	9.9	9.5	9.0	8.6	8.2	7.9
Base Case plus	36.9	135.8	112.0	93.6	81.5	71.2	62.1	45.3	38.2	34.7	31.6	28.9	26.5	24.3	22.3	20.4	12.9	12.0	11.4	10.8	10.3	9.8	9.4	9.0	8.7	8.3

Annual Condensate Production (m3)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case	2069.4	7072.7	3910.3	2769.9	2123.5	1762.2	1492.1	1289.6	1122.9	993.4	889.1	801.5	722.1	655.3	514.9	344.6	324.5	306.2	291.0	278.7	266.3	253.9	242.4	232.2	221.9	213.0
Base Case minus	2069.4	6724.8	3105.8	2543.1	2123.5	1762.2	1492.1	1289.6	1122.9	993.4	889.1	801.5	722.1	655.3	514.9	344.6	324.5	306.2	291.0	278.7	266.3	253.9	242.4	232.2	221.9	213.0
Base Case plus	2069.4	7286.5	4519.8	3511.5	2927.7	2468.0	2094.1	1504.1	1229.0	1109.7	1008.7	928.2	854.0	789.9	731.8	683.2	363.8	345.1	329.6	317.4	305.2	294.9	284.2	275.0	265.1	256.6

Well Name	Top (metres) TVD/TVT	Bottom (metres) TVD/TVT	Gross (metres) TVD/TVT	Net TVD/TVT	N/G TVD/TVT	Av Phi	Av Sw	Av Vcl	Phi*H TVD/TVT	Phi*So*H TVD/TVT
Saltfleetby 1u	2505	2925	300.8	289.8	0.963	0.116	0.169	0.145	2.495	2.074
	2291.96	2289.6	22.06	21.51	0.975					
Saltfleetby 2	2503.6	2713.4	203.3	140.4	0.691	0.092	0.22	0.145	1.675	1.306
	2282.52	2297.36	26.96	18.26	0.677					
Saltfleetby 3Z	2513	2948.2	324.7	276.65	0.852	0.107	0.139	0.19	2.332	2.007
	2270.24	2273.45	27.3	21.8	0.798					
Saltfleetby 4	2493	3159.3	446.6	317.55	0.711	0.11	0.242	0.171	1.454	1.102
	2303.06	2302.67	21.67	13.2	0.609					
Saltfleetby 5	2489	3125.6	299.2	233.65	0.781	0.107	0.203	0.13	2.671	2.129
	2301.3	2296.57	31.3	24.91	0.796					
Saltfleetby 6Y	3103.3	3291	83	71.05	0.856	0.089	0.175	0.099	0.357	0.294
	2320.66	2319.98	5.12	3.99	0.779					

Table 2. Summary of Log Derived Petrophysical Parameters. Cut-offs: Phi = 0.08 , Vcl = 0.4

Saltfleetby PVT Data Overview

			SF01u				SF01u - Unit2		SF03	SF03z	SF03z	SF05 - Nam.
Sampling	Sample number		1.1+1.2	2.1+2.2	3.1+3.2	4.1+4.2	3.1+3.2	4.1+4.2				
	Flow period		clean up	Flow #1	Flow #2	Flow #3						
	Date		14/11/1998	15/11/1998	16/11/1998	18/11/1998	10/12/1998	11/12/1998	19/05/1999	04/07/1999	22/03/2000	09/09/2000
	Method		Separator	Separator	Separator	Separator	Separator	Separator	Bottom Hole	Separator	Separator	Separator
	Separator Pressure	psia	116.7	48.7	89.7	124.7	20	29		129	1175	310
	Separator Temperature	°F	48	62	62	58	68	80		64.4	95	32-34
	Gas Rate	mmscf/d	15.04	5	10.08	14.17	2.13	3.13				
	Oil Rate	sep bbl/d	453.12	235	187.5	493	5.76	35.52				
	Field CGR	sep bbl/mmscf	30.128	47.000	18.601	34.792	2.704	11.348		37.8		37.0
	Separator gas SG (Air = 1)		0.74	0.75	0.74	0.74	0.762	0.763				
	Separator Condensate SG at 60°F		0.821	0.75	0.766	0.765				0.753		
Experiments	Experiments Performed		None	None	None	CCE	None	None	None	CCE	None	CCE / CVD
	Dew Point determined in CCE	psig				3220				5135		3040
	Max Liquid drop out CCE	% Vol @ DP				>1.27%				3.94%		1.90%
Determined	C1			75.57	77.92	77.47	78.03	78.27	75.17	77.4	78.073	77.082
Wellstream	N2			3.44	3.53	3.5	3.38	3.39	4.75	4.23	4.384	4.881
Composition	CO2			2.15	2.12	2.16	2.19	2.13	1.46	1.77	1.741	1.606
	C7+	molar %		3.97	1.64	2.38	1.08	1.58	5.56	2.08	1.605	1.9
	MW of C7+	g/mol			119	117	99	115		153		116
	RHO of C7+	g/cm^3			0.7755	0.7697	0.7642	0.7721		0.794		0.76

Table 3. PVT Data Overview

(bscf)	Main Structure	Southern Structure	Total
Westphalian Unit 2	24 (18-27)	2.5 (2-8)	26 (20-35)
Westphalian Unit 1 (Main Reservoir Unit)	**95** (85-100)	21 (15-25)	116 (100-125)
Namurian	20 (15-20)	0	20 (15-20)
Total	139 (118-147)	23 (17-32)	162 (140-180)

Table 4. GIIP derived from Geologic Model
Most likely and range of uncertainty given in brackets

Well Name	Short Name	On Production	Current Status	Cumulative Raw Gas Production 01-11-2005 (mmscm)	Cumulative Raw Gas Production 01-11-2005 (mmscf)
SF01u	A1	Dec 1999	Producer	492.7	17,399
SF02	B2	Dec 1999	Producer	273.9	9,674
SF03z	B3	Dec 1999	Shut-in	342.7	12,104
SF04	A4	Dec 1999	Producer	377.8	13,342
SF05 (Nam.)	B5	Nov 2000	Abandoned	44.7	1,577
SF05 (Wesph.)	B5	Aug 2002	Shut-in	63.5	2,244
SF06y	B6	Jan 2002	Producer	11.8	417
SF07y	B7	Jan 2004	Shut-in	0.08	3
Total				1612.7	56,954

Table 5. Summary of Well Production Data

Well Status at 1st November 2005

Abandoned Wells:

Saltfleetby -1 Abandoned as Dry Hole in 1986.
Saltfleetby -1z Abandoned after testing gas and condensate, sidetracked as 1y.
Saltfleetby -1y Abandoned after hole lost in drilling out of casing, sidetracked as 1x.
Saltfleetby -1x Abandoned horizontal reservoir section after inability to run liner, sidetracked as 1v.
Saltfleetby -1v Abandoned after mechanical junk,
sidetracked as 1u. **Saltfleetby -3** Abandoned after appraisal punch
through. **Saltfleetby -6** Abandoned after appraisal punch through.
Saltfleetby -6z Abandoned attempt at horizontal reservoir
section. **Saltfleetby -7** Abandoned attempt at horizontal reservoir
section.
Saltfleetby -7z Abandoned high angle appraisal penetration of reservoir section.

Producinc Wells:		Producing Interval Metres BRT (Perforated Casing)	Producing Interval Metres BRT	Total Completed Interval Metres (Open Hole)
Saltfleetby-1u	On Production – December '99 – Basal Westphalian	2505-2540	2559.6-2925.0	231
Saltfleetby-2	On Production – December '99 – Basal Westphalian	None	2420.8-2558.0 2562.4-2672.1 2672.1-2713.5	288
Saltfleetby-4	On Production – December '99 – Basal Westphalian	2656-2493	2719.0-3016.0 3051.0-3168.0	612
Saltfleetby-6y	On Production – January 2002 – Basal Westphalian	None	3102.7-3135.9 3185.9-3238.8 3277.3-3311.0	120
Shut-in Wells:				
Saltfleetby -3z	December '99 – Basal Westphalian Water Hold Up	2513-2552	2573.0-2985.0	452
Saltfleetby-5	November '00 – March '02 Namurian, Abandoned	None	2756.8-2848.3 3002.2-3131.6	221
	August '02 -- Basal Westphalian Water Hold Up	2489-2644	None	155
Saltfleetby -7y	Failed to Produce – Namurian - Abandoned	None	2911.5-3170.1	259
	Low Flow -- Basal Westphalian	2612-2830	None	218

Table 6. Well Status and Producing Intervals

Saltfleetby - Basal Westphalian / Namurian Top Reservoir Interval 2b

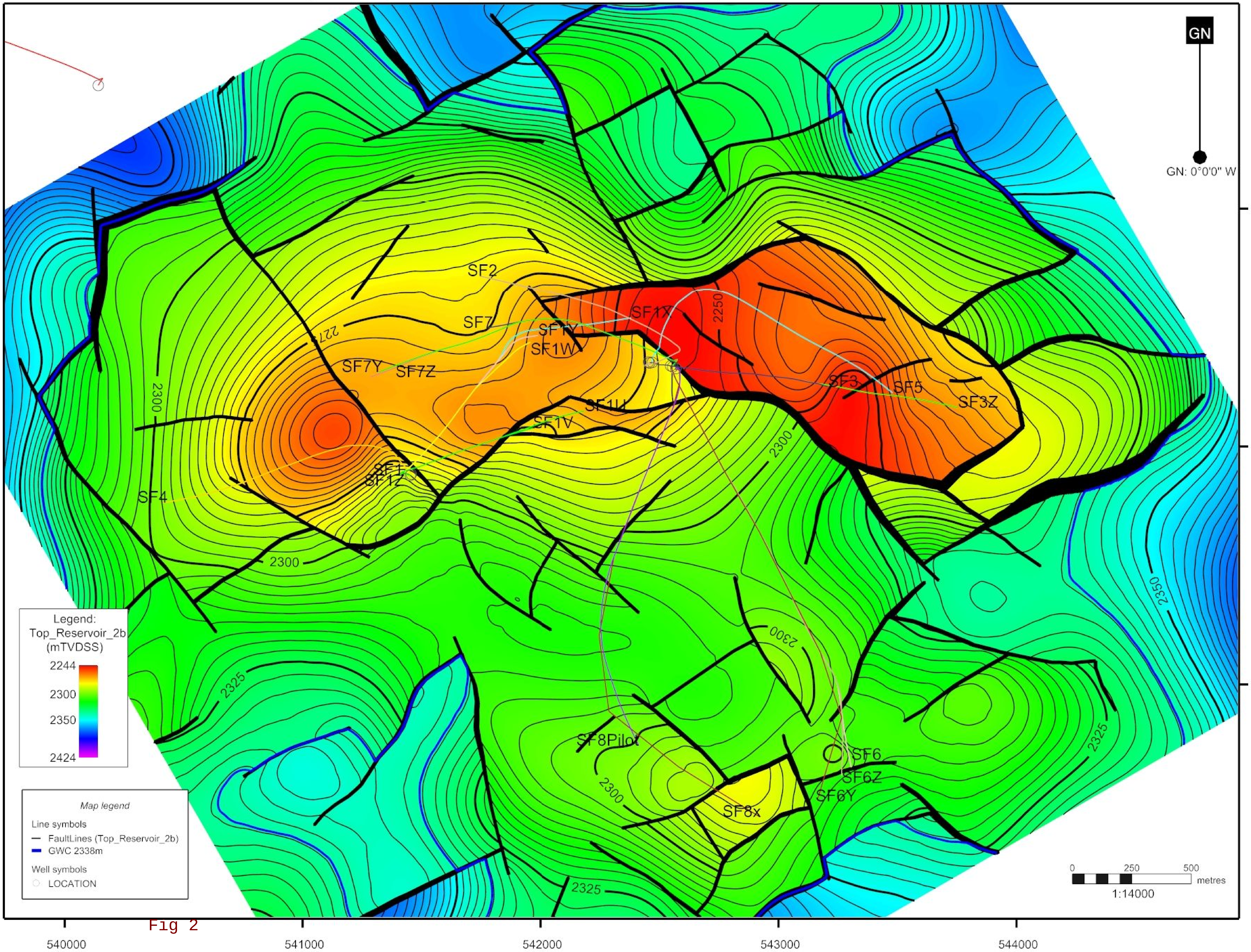


Fig 2

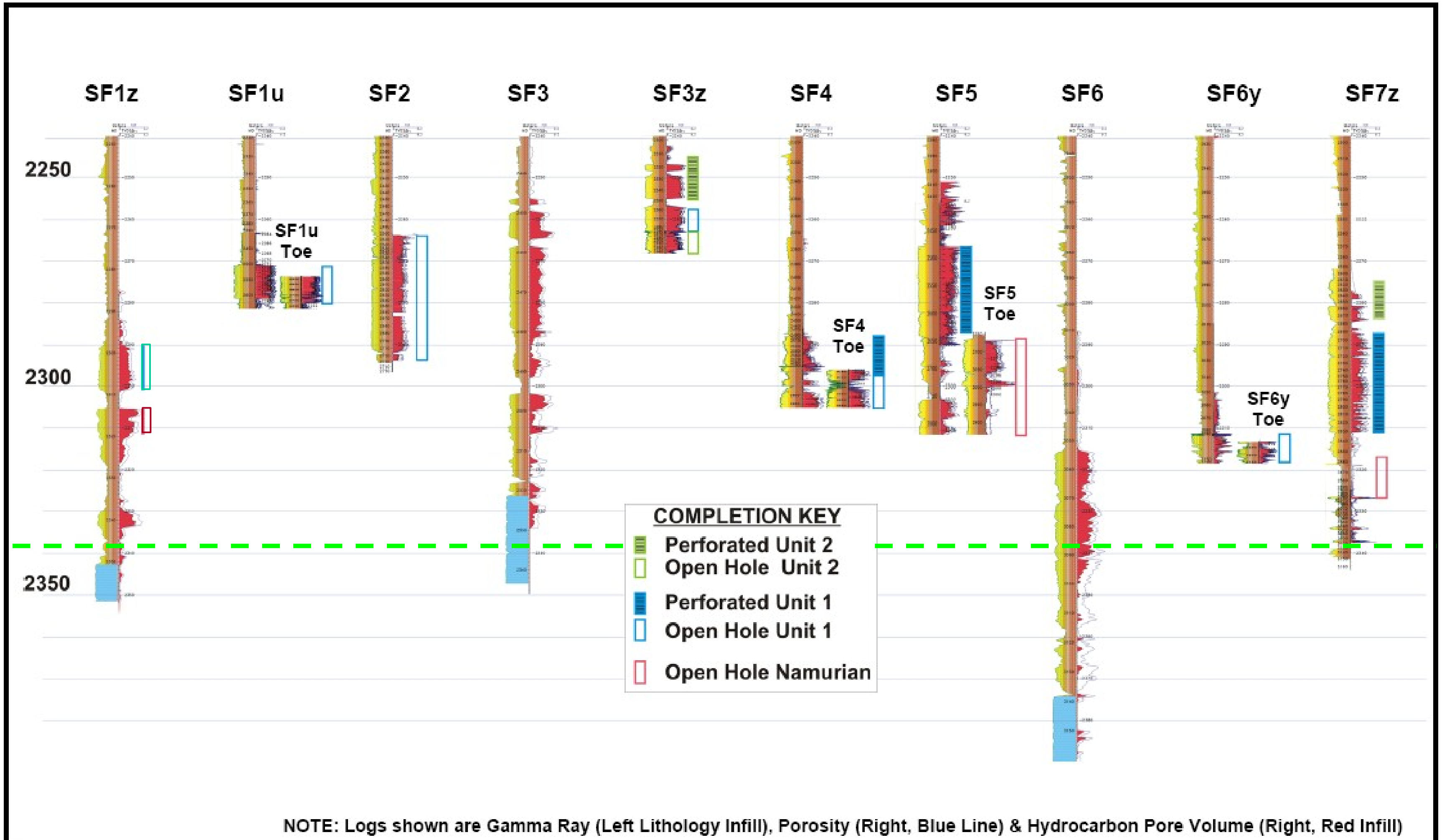


Fig 3 **Saltfleetby Field - Elevations of Completions & Hydrocarbon Association**

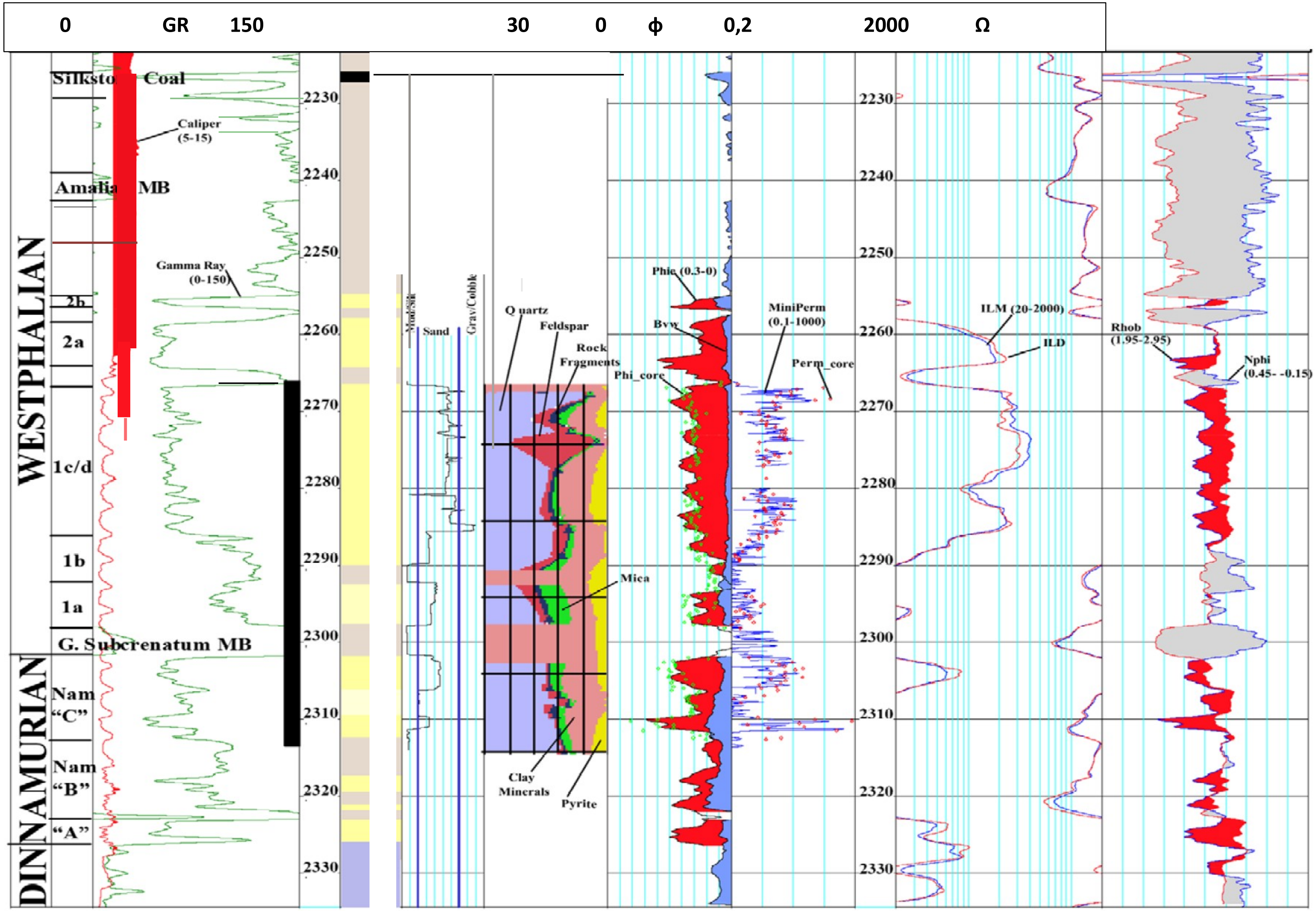


Fig 4. Saltfleetby 3. Field type section

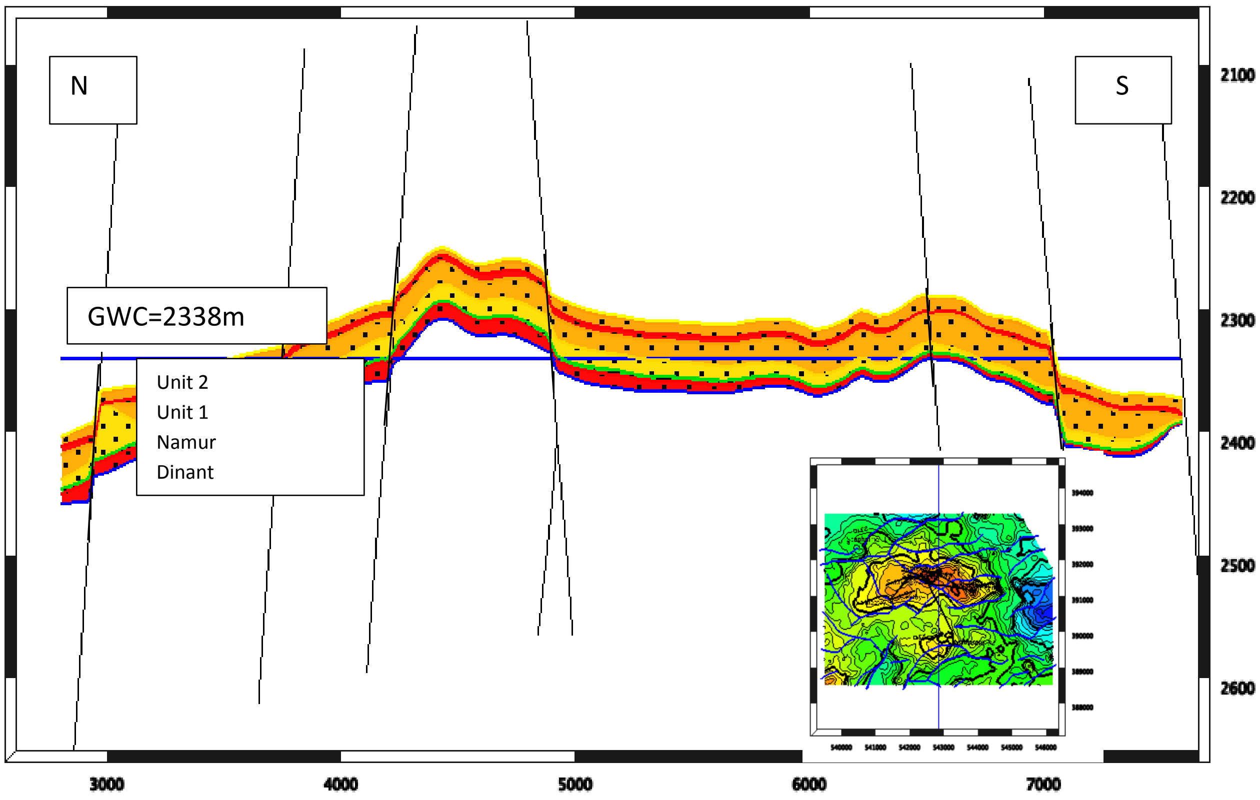


Fig 5.1 – Cross sections

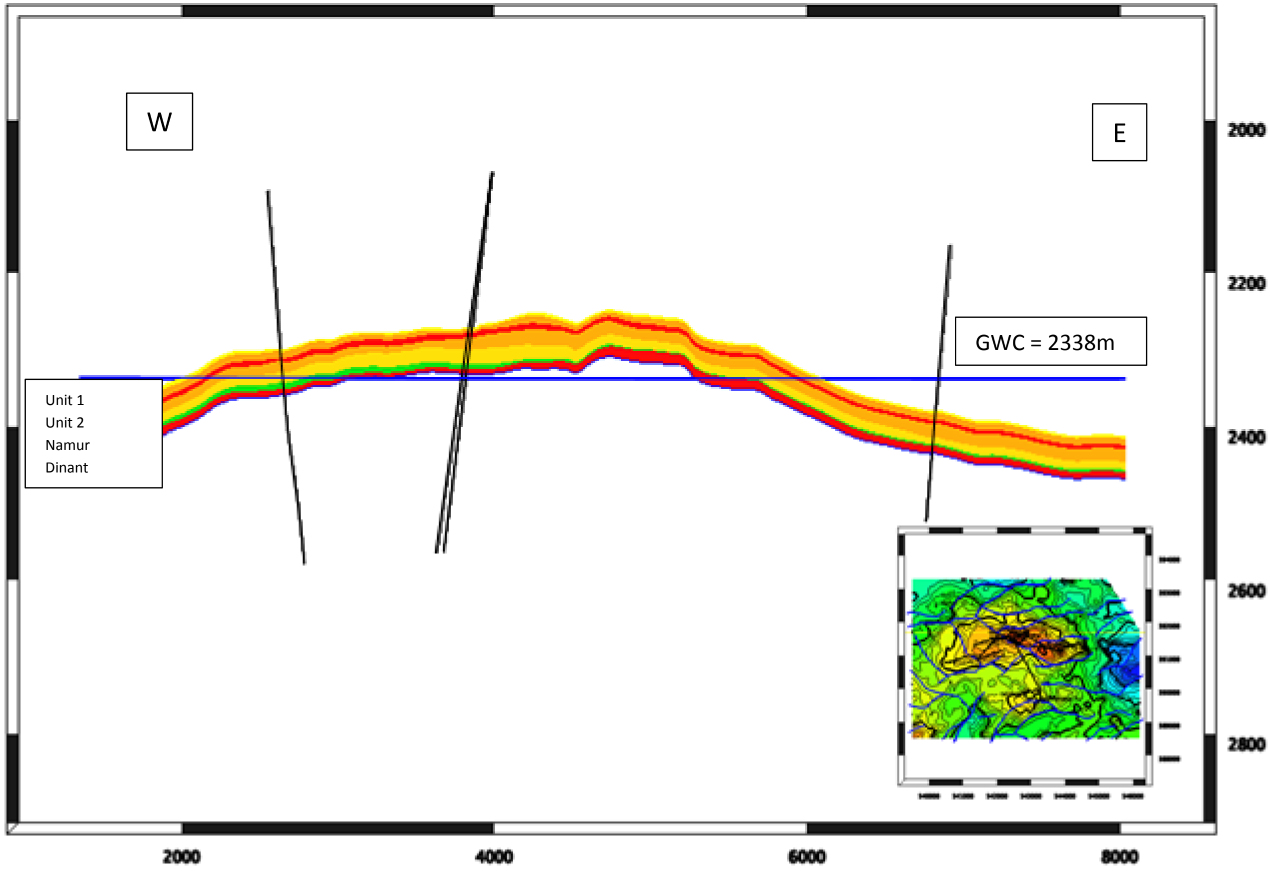


Fig 5.2 – Cross sections

Seismic Horizons

Middle Jurassic Carbonates

Triassic Mercia Mudstone

Triassic Sherwood Sandstone

Permian Brotherton Limestone

Permian Rotligende Sandstone

Top Carboniferous

Brinsley Abdy Reservoir

Top Unit 2 Gas Reservoir
Top Unit 1 Gas Reservoir
Dinantian Limestone

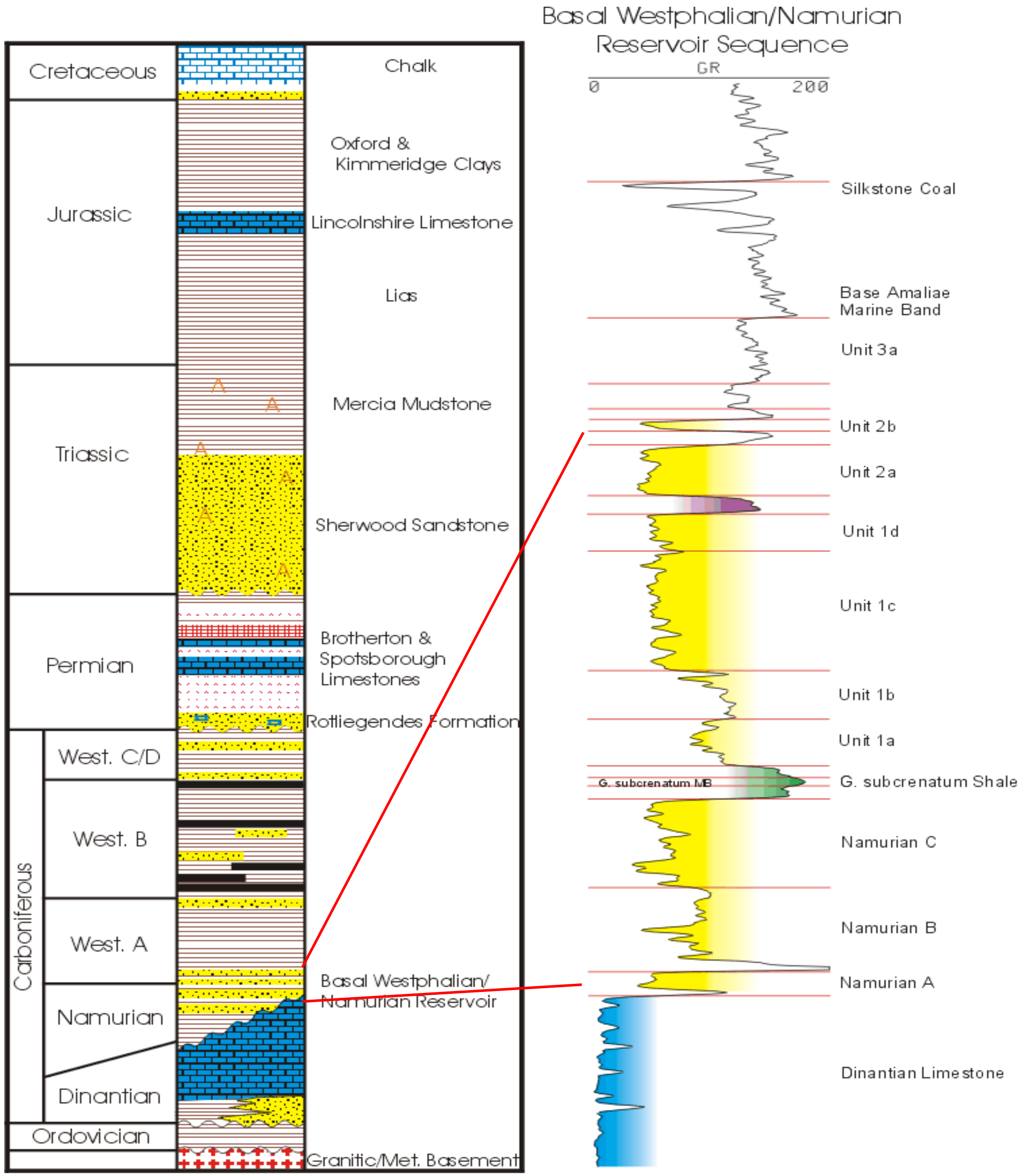
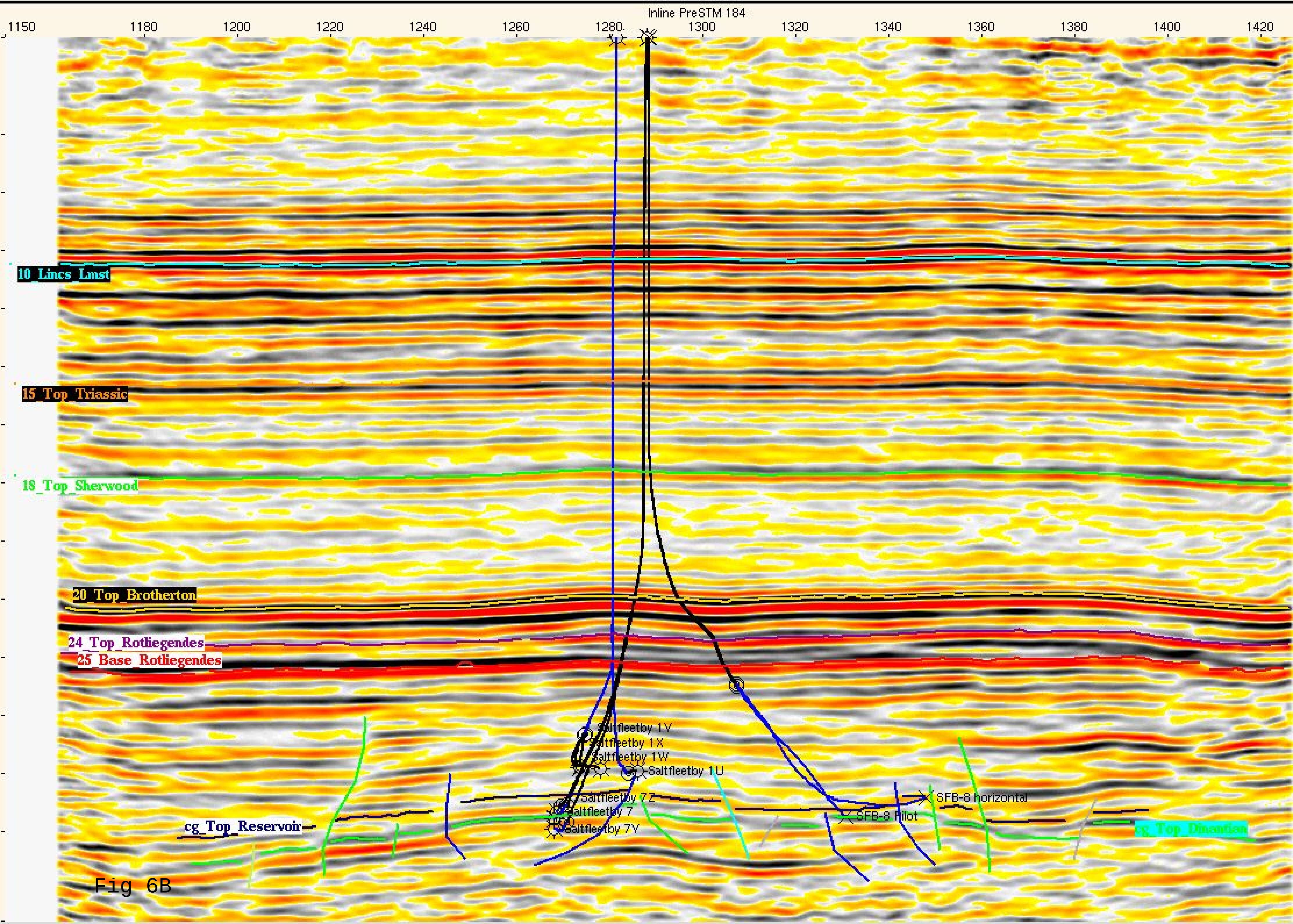


Fig. 6 ! – Reservoir section and position of seismic horizons



Inline PreSTM 184
1150
1180
1200
1220
1240
1260
1280
1300
1320
1340
1360
1380
1400
1420
10_Lincs_Lmst
15_Top_Triassic
18_Top_Sherwood
20_Top_Brotherton
24_Top_Rotliegendes
25_Base_Rotliegendes
Saltfleetby 1Y
Saltfleetby 1X
Saltfleetby 1W
Saltfleetby 1U
Saltfleetby 7Z
Saltfleetby 7
Saltfleetby 7Y
SFB-8 horizontal
SFB-8 Pilot
cg_Top_Reservoir

Fig 6B

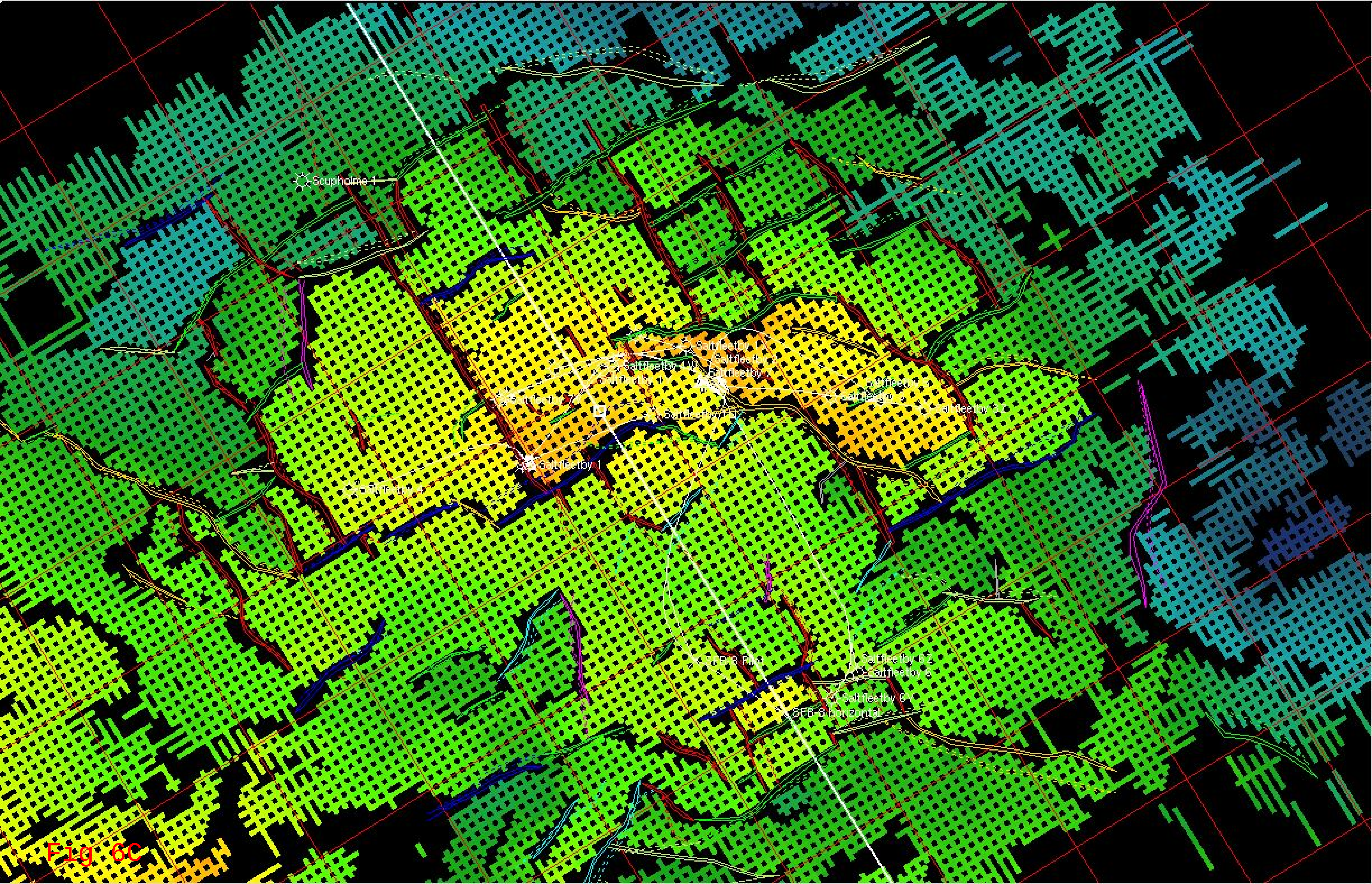
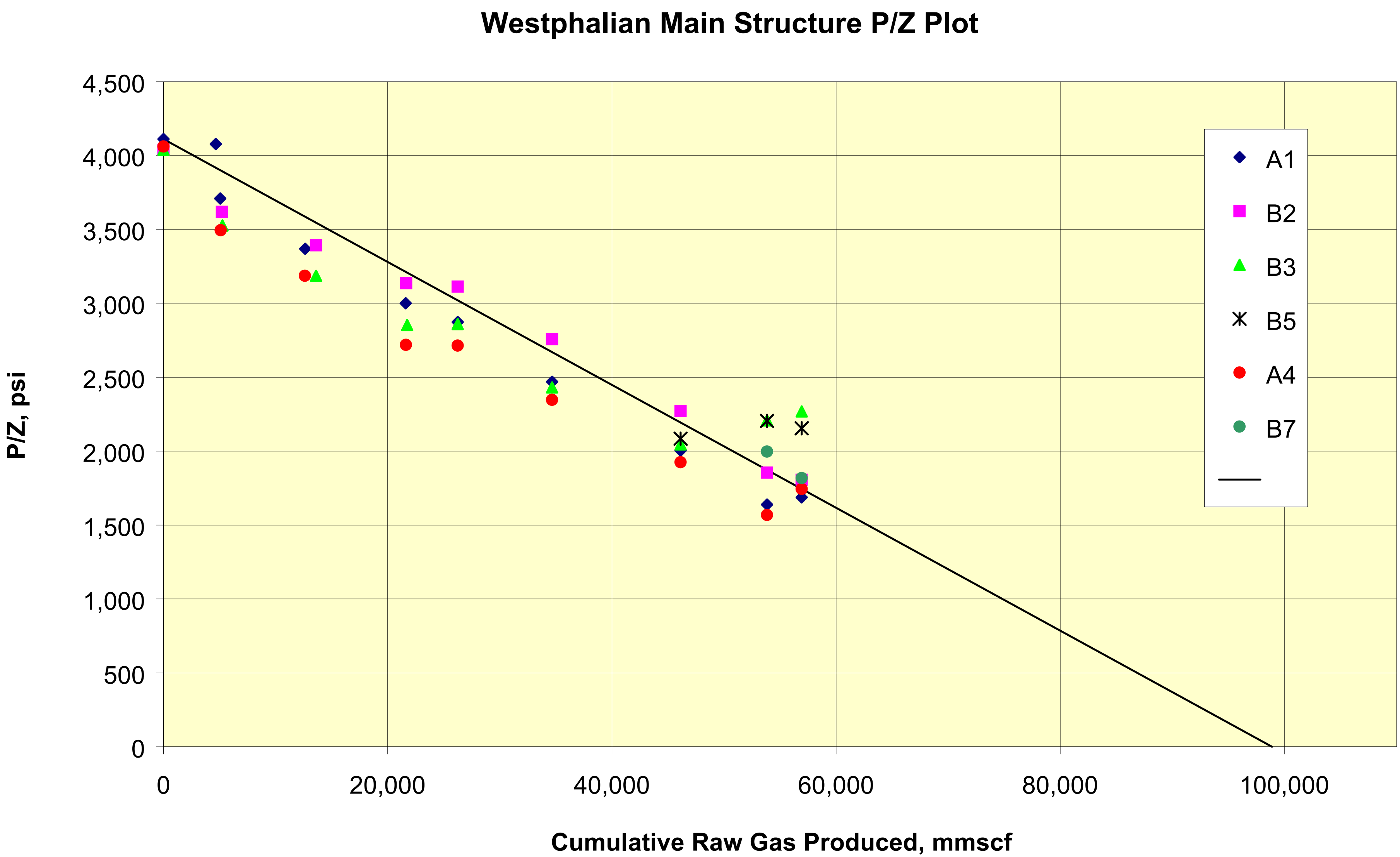

Scupholme 1
Saltfleetby 1
Saltfleetby 6Z
Saltfleetby 6
Saltfleetby 6Y
SFB 8 Horizontal

Fig 6C

Fig. 7 PZ Plot



Westphalian Main Structure P/Z Plot
P/Z, psi
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0
20,000
40,000
60,000
80,000
100,000
Cumulative Raw Gas Produced, mmscf
A1
B2
B3
B5
A4
B7

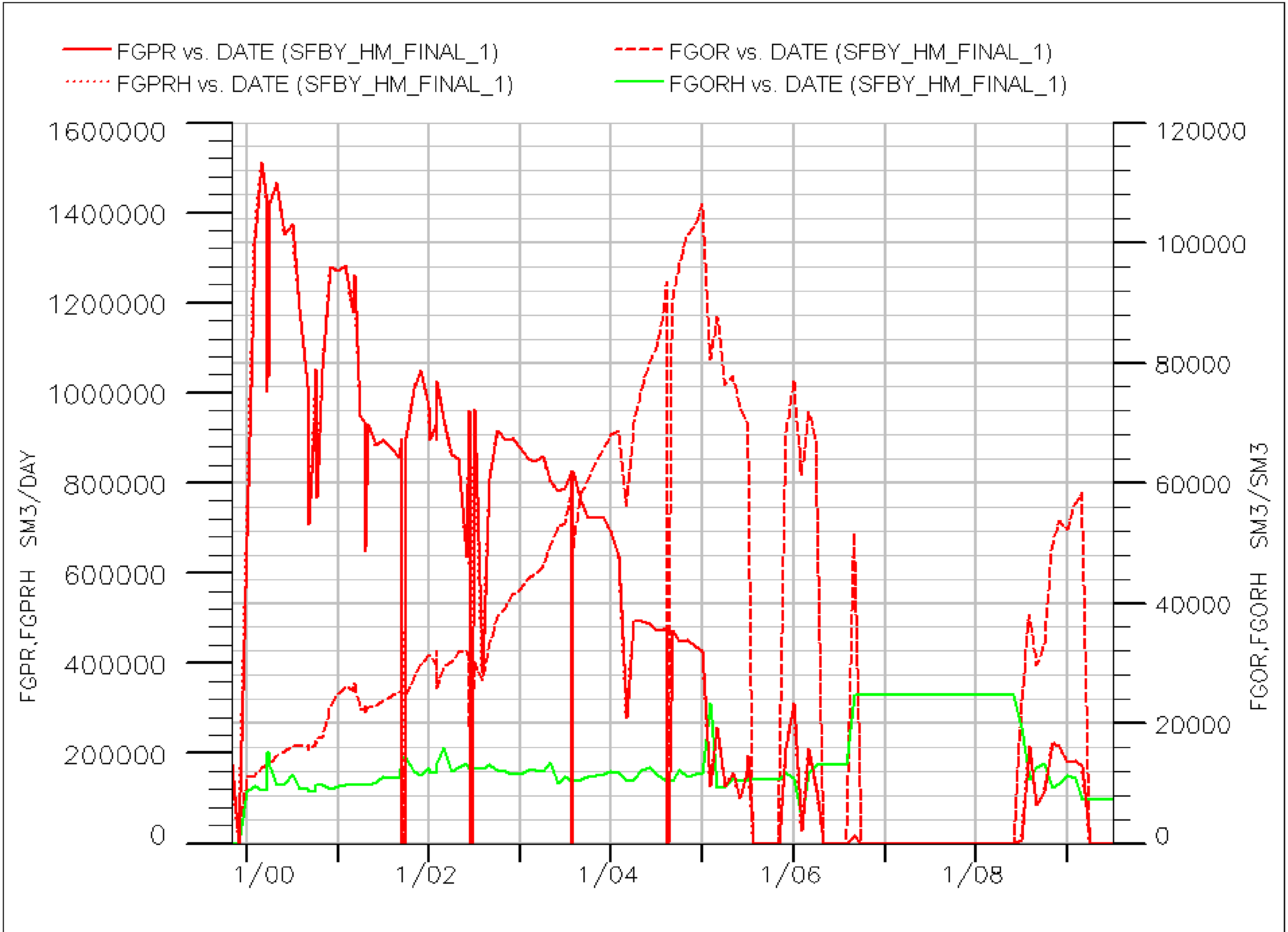


Fig. 8 – Well Production History

Fig. 9a – Well SF-1u History Match

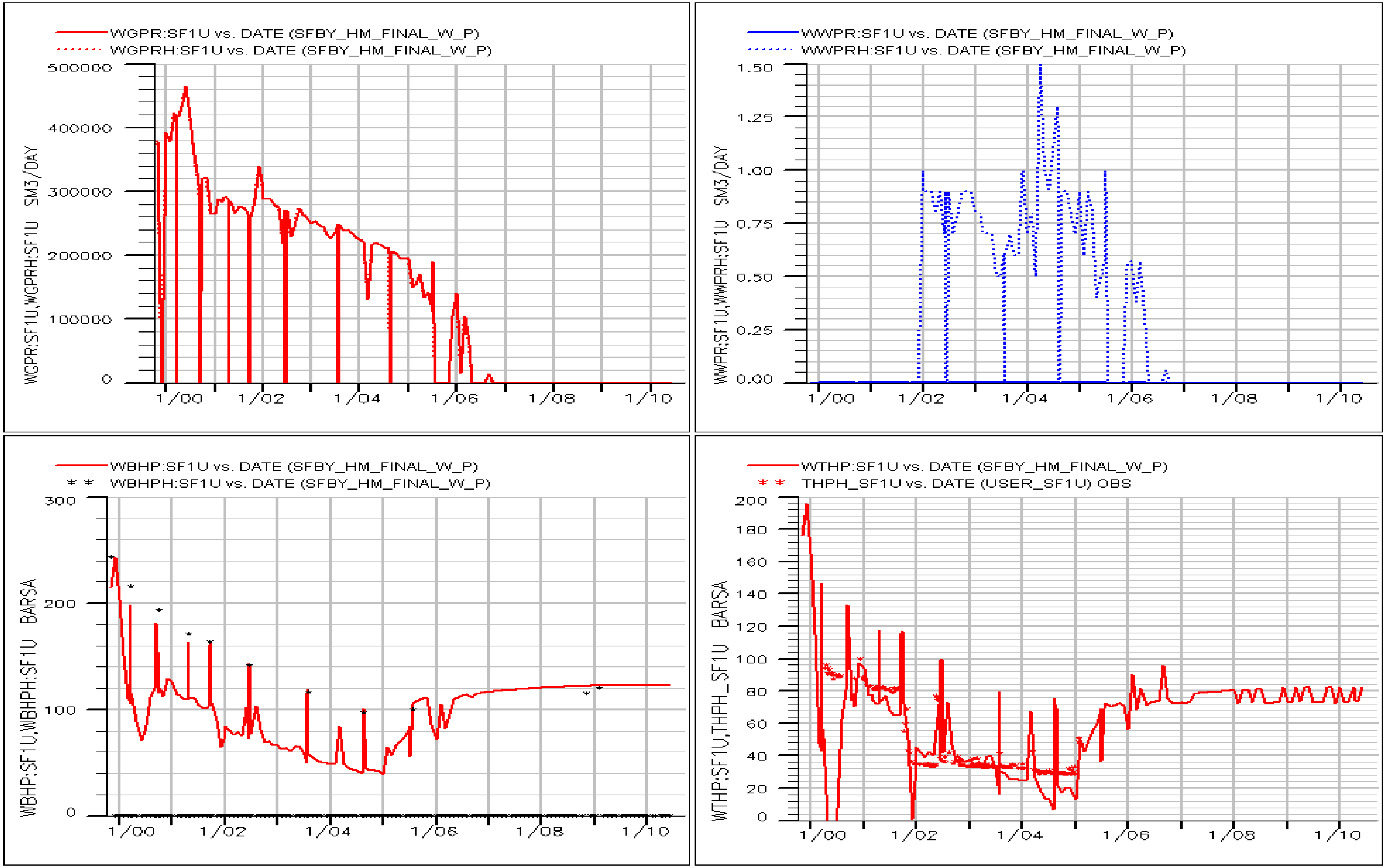


Fig. 9b – Well SF-2 History Match

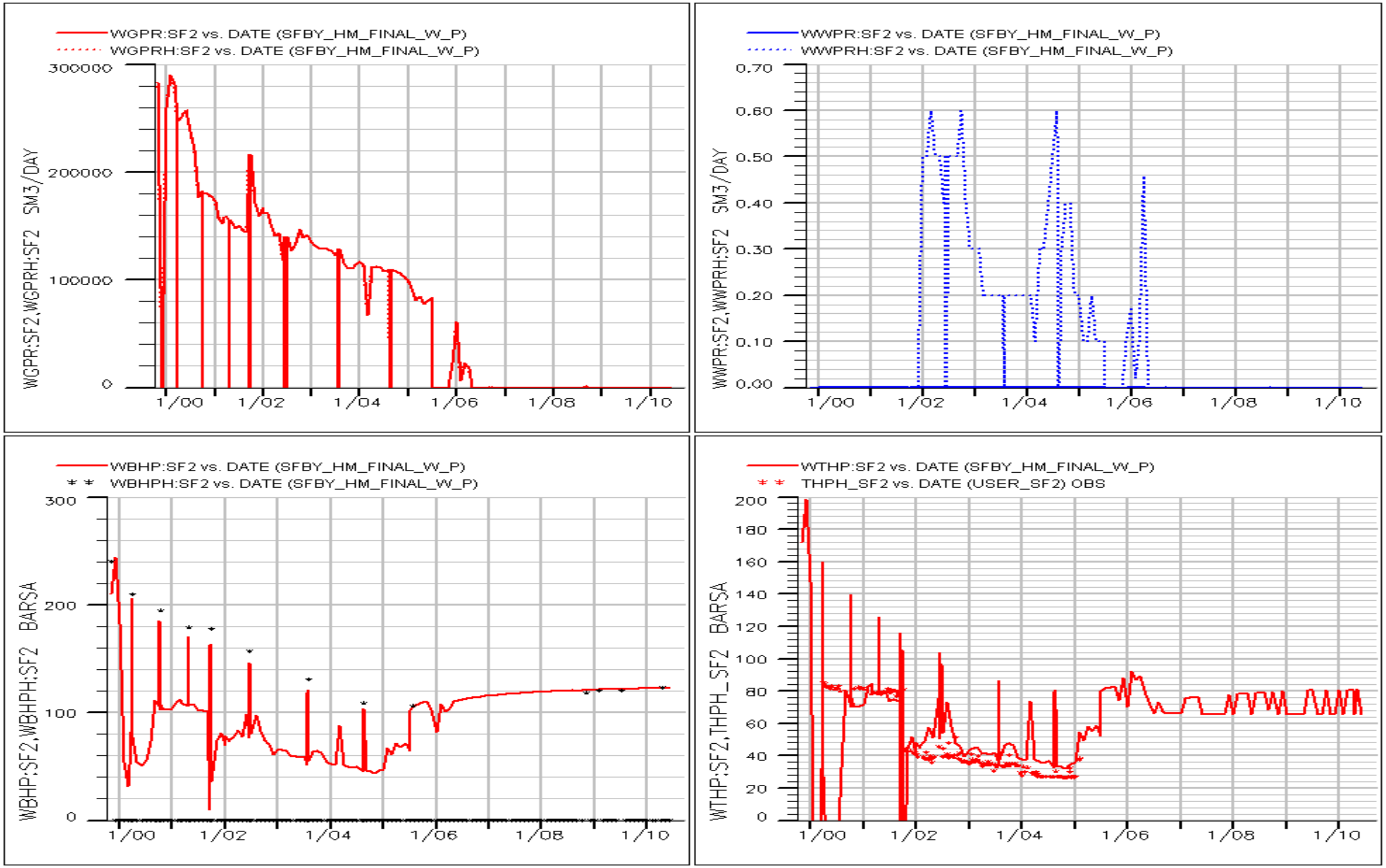
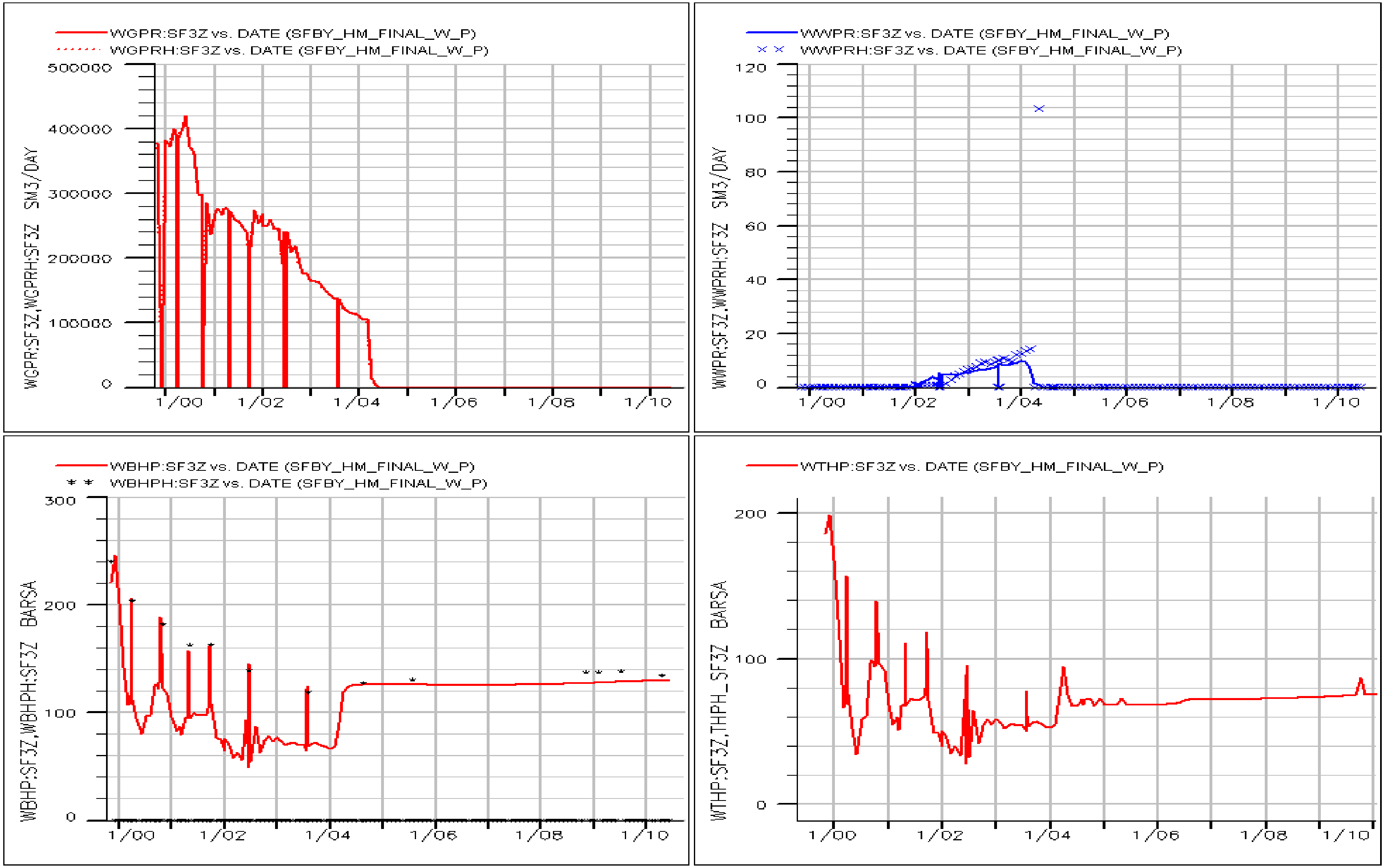


Fig 9c - Well SF-3z History Match



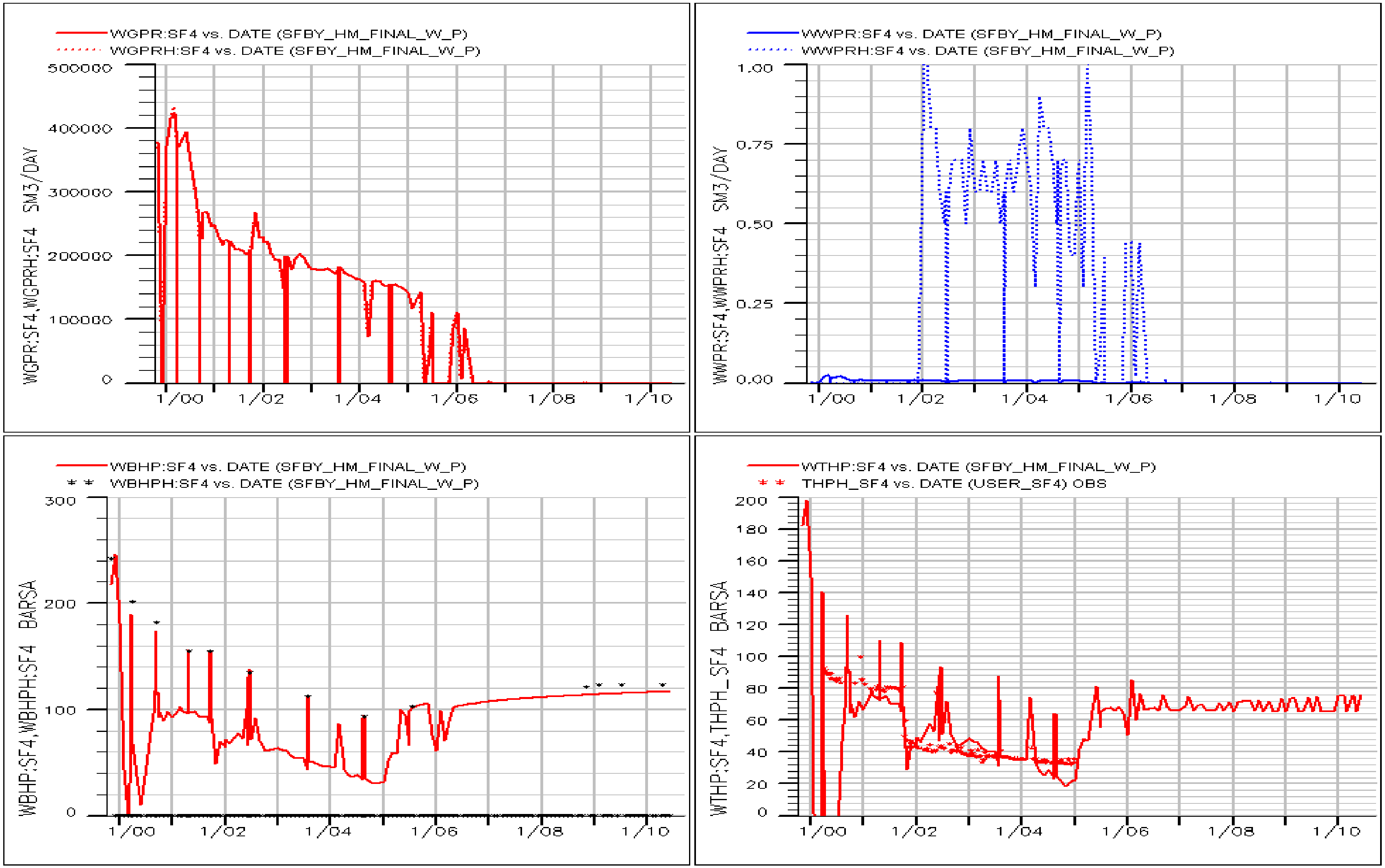


Fig. 9d - Well SF-4 History Match

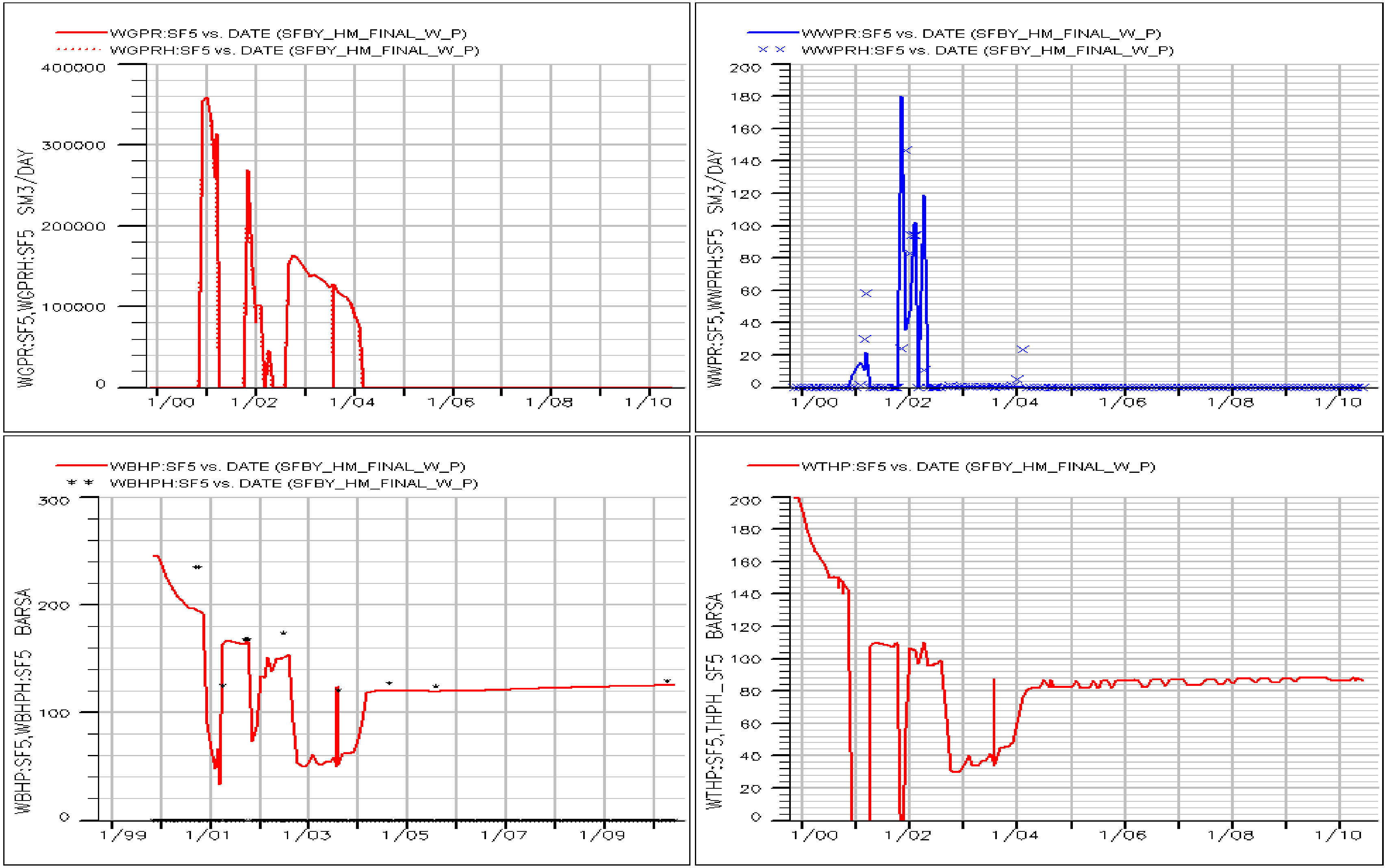


Fig. 9e - Well SF-5 History Match

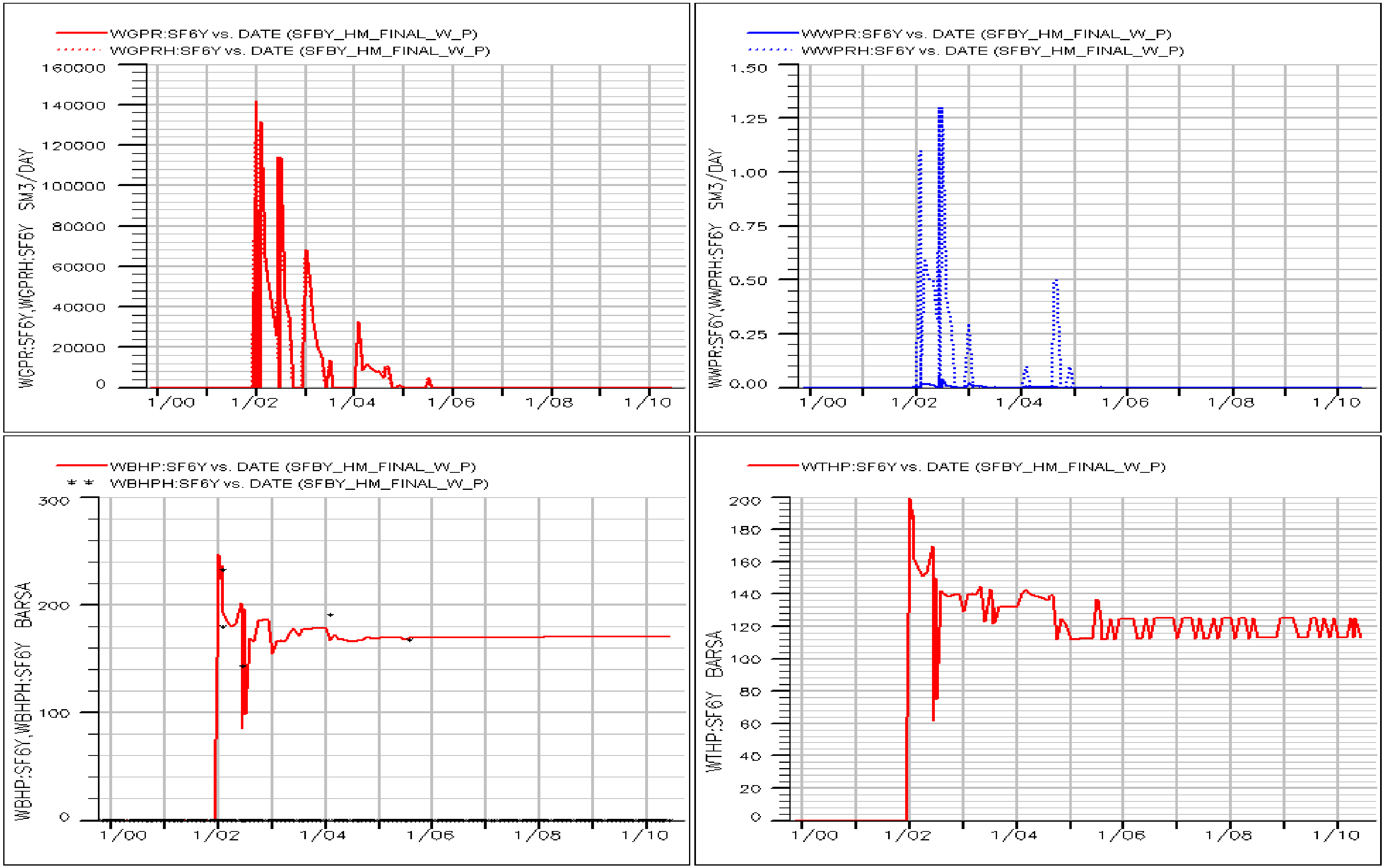


Fig. 9f - Well SF-6y History Match

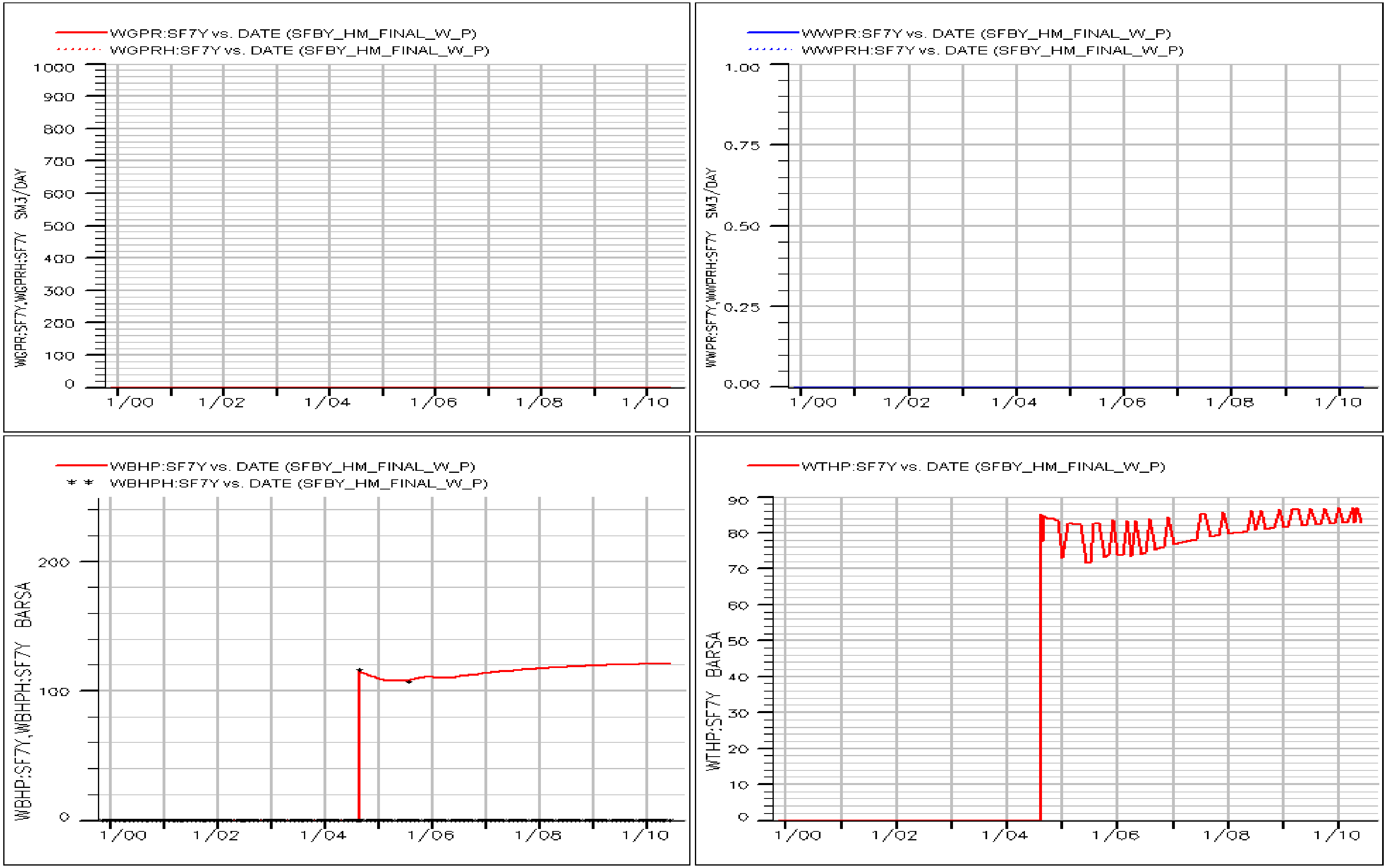


Fig. 9g - Well SF-7y History Match

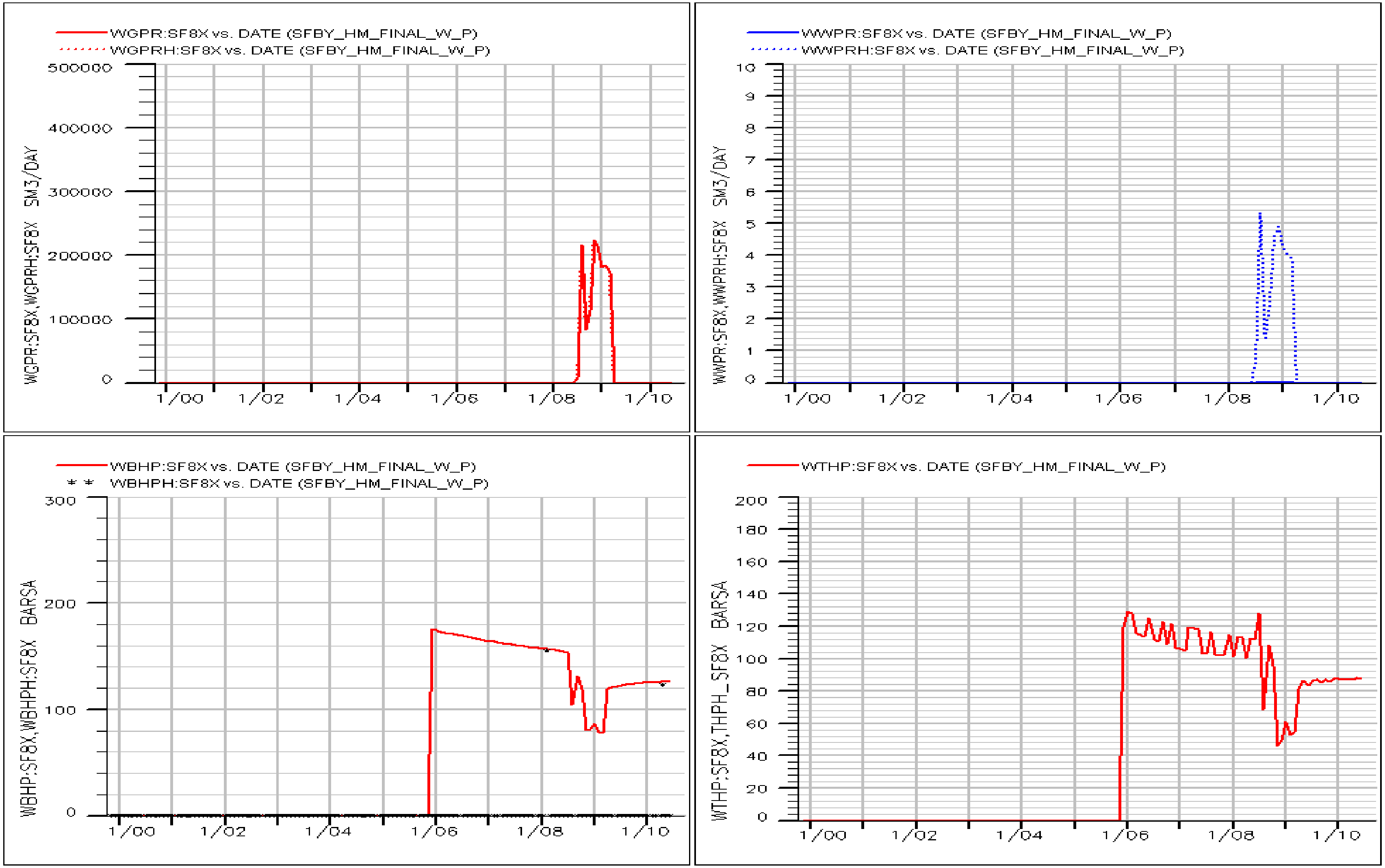


Fig. 9h - Well SF-8x History Match

Fig. 9i – Separator CGR History Match per Well