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Organic Geochemistry of Palaeozoic Source Rocks, Central North Sea (CNS)

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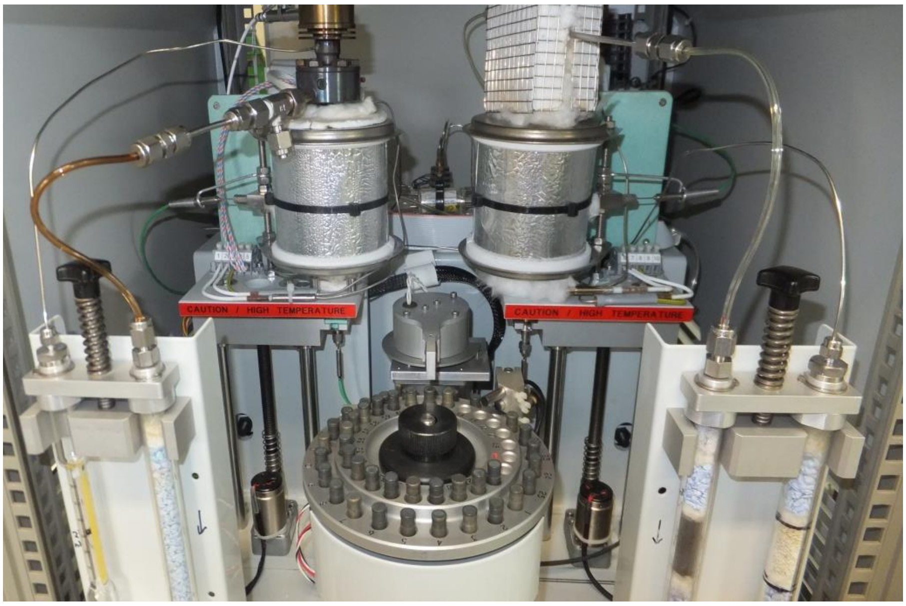

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Organic Geochemistry of Palaeozoic Source Rocks, Central North Sea (CNS)

C H Vane, C Uguna, A W Kim, K Johnson, A A Monaghan

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1 Executive Summary

This report details a regional analysis of the source rock quality and potential of Palaeozoic rocks of the UK Central North Sea for the 21CXRM Palaeozoic project. The objective was to undertake a regional screening of all intervals to identify source rocks using new and legacy datasets of all Carboniferous and Devonian samples. In addition, a literature review (Appendix 1) summarises source and kerogen typing information from legacy reports. The background and stratigraphic nomenclature are given in Monaghan et al. (2016), details on individual well interpretations and stratigraphy are given in Kearsey et al. (2015). Geological context on the results of this work are included in basin modelling (Vincent, 2015) and were synthesised into a petroleum systems analysis in Monaghan et al. (2015).

New and legacy Carboniferous and Devonian source rock geochemical data were examined per well using industry standard criteria to give an overview of the source rock quality, type (oil or gas prone) and maturity. The aims of this study were to classify the source rock quality of 33 wells, to examine if intervals were ‘gas-prone’ or ‘oil-prone’, and to ascertain the hydrocarbon generation stage of each well based on Rock-Eval pyrolysis, vitrinite reflectance (VR, where available) and total organic carbon (TOC) data. The term ‘gas prone’ was used to describe source rocks that have or could generate gas; ‘oil prone’ for source intervals that have or could generate oil. This study was a rapid screening exercise to identify intervals or areas of interest, and as such the data and inferences must be used concomitantly with other geological data to fully assess the source rock potential within the studied wells. It should be noted that the wells studied penetrate different parts of the geological succession and in many cases only small sections of the Devonian and Carboniferous interval.

An initial sift through the wells with available geochemical data indicated that 33 wells had enough data to be usefully evaluated. Subsequently it was found that 8 of the 33 wells had incomplete, unreliable or otherwise poor source rock quality data sets and therefore were not analysed further; the reasons are detailed in this report.

The remaining 25 wells selected for analysis were: 43/28-2, 26/07-1, 26/08-1, 36/13-1, 36/23-1, 38/16-1, 38/18-1, 39/07-1, 41/08-1, 42/10a-1, 42/10b-2ST, 42/09-1, 41/10-1, 42/10b-2, 41/15-1, 43/21-2, 41/01-1, 41/20-1, 41/14-1, 43/02-1, 43/17-2, 43/20b-2, 43/28-1, 43/28-2, 44/13-1, 44/16-1. Samples analysed from the majority of these wells were interpreted to be gas prone in the Carboniferous succession (Figure 1).

1. 41/10-1, 41/14-1 and 41/20-1 contained source rocks that were both gas window mature (e.g. VR >1.3) and can be regarded as excellent gas source. Strata in 43/17-2, 44/16-1 and 43/28-1 were also gas mature in all or parts of the section of interest, but with variable source rock quality. The six wells all had low S2 peaks: this may be due to either prior hydrocarbon generation and depletion or the initial presence of low amounts of non-inert kerogen.

2. 41/15-1, 42/10b-2 and 43/21-2 were also identified as possessing good gas-prone source rocks with elevated S2 values and also a high maturity attained by the source rocks. 41/01-1 was identified as a good for gas generation in the deeper section.

3. 26/07-1, 26/08-1, 36/13-1, 38/16-1, 39/07-1, 41/08-1, 42/10a-1, 42/10b-2ST, 42/09-1, 43/02-1, 43/20b-2, 43/28-2 and 44/13-1, contain good to excellent quality source rocks, but have not matured sufficiently to generate significant amount of gas, so these can be regarded as poor gas sources based on their current maturity. If present, in deeper basins some of these intervals will have generated significant quantities of gas.

4. 38/18-1, 43/21-2 and 43/28-1 were found to contain a mixture of gas and oil prone source rocks. Intervals within 36/23-1 were found to be gas prone with an oil prone interval.

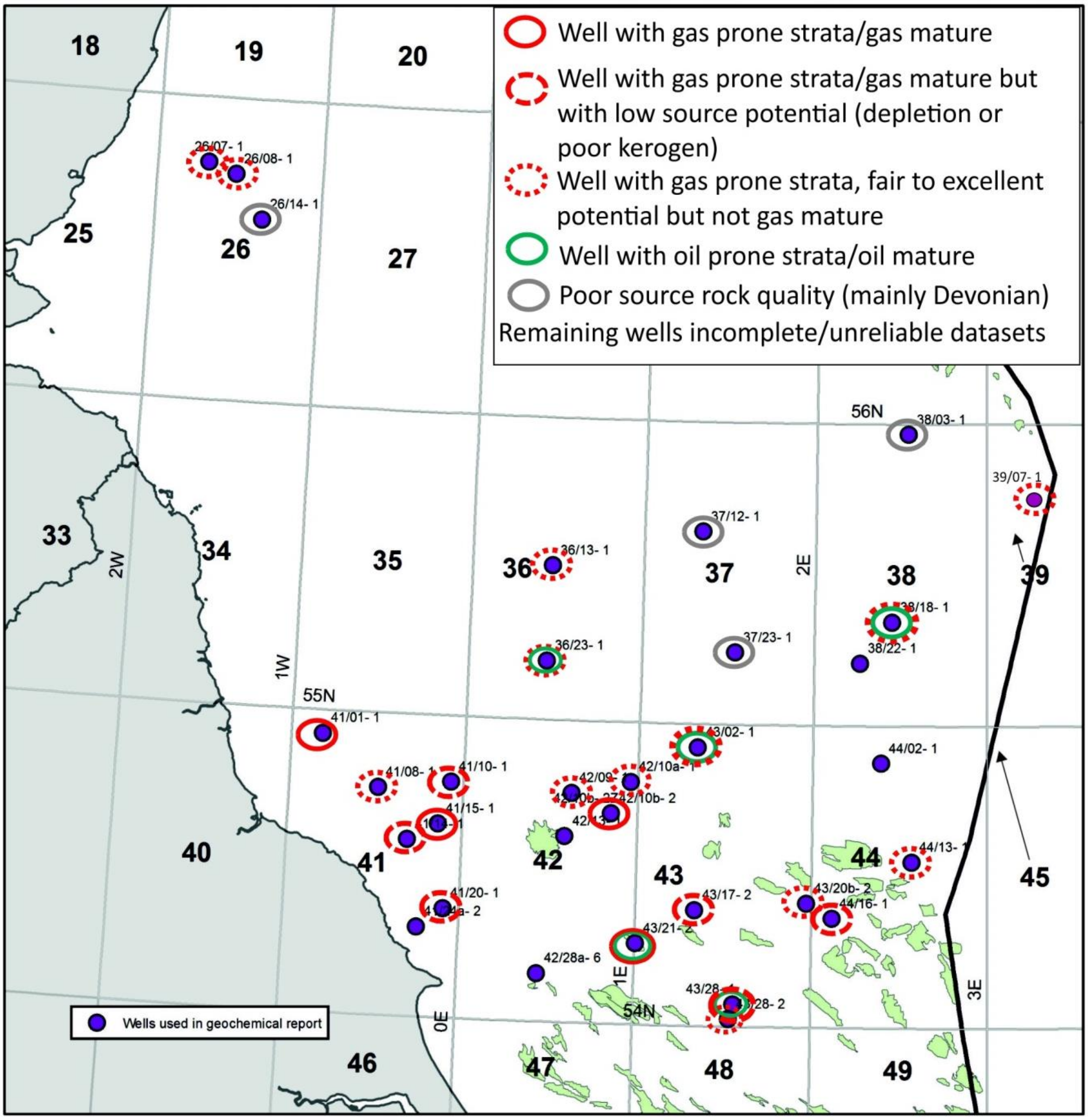

Figure 1 Summary map of geochemical screening analysis for the Carboniferous-Devonian interval in the wells shown.

The Scremerston, Yoredale and Millstone Grit formations (Figure 2) contain some good to excellent quality source rocks and coals, with characteristic variability in quality, within the studied wells (e.g. Figure 36/13- 1, 42/10b- 2). Gas prone intervals dominate, with oil prone intervals present in some wells (e.g. Figure 43/21- 2). These intervals reach gas maturity in Quadrant 41 and central-southern parts of Quadrant 42 and 43 and are at oil window maturity in Quadrants 26, 36, 38, 39.

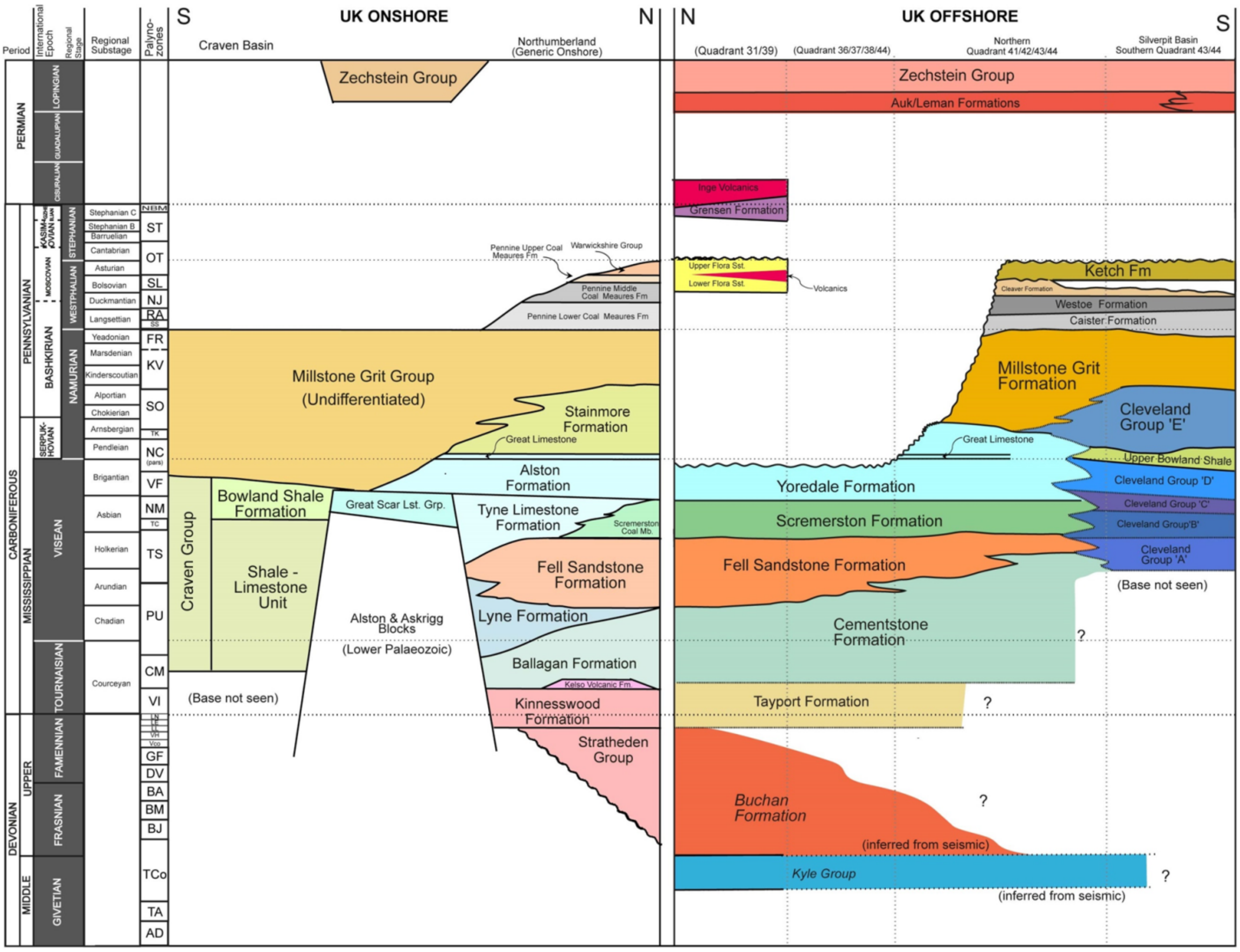

Figure 2 Schematic stratigraphy showing the relationships between the Carboniferous and Devonian strata of northern England and the Central North Sea.

The time-equivalent Cleveland Group/Upper Bowland Shale units (Figure 2) show some fair-excellent source rock quality but many analyses have low S2 values (Figures 43/17- 2, 41/14- 1). Maturity varies from the oil and gas window to overmature, and taken together with existing legacy kerogen typing, future work on depletion due to hydrocarbon generation versus a large proportion of woody and inert kerogens in some samples would be beneficial.

Westphalian Coal Measures strata (Caister, Westoe, Cleaver formations) also contain good quality, mature source rocks and coals (Figure 44/13- 1), as would be expected in the SNS Westphalian gas play. With some exceptions, some of which are thought to relate to contamination, analyses from the Fell Sandstone, Cementstone, Buchan formations and Kyle Limestone Group are generally of poor source rock quality. For the Fell Sandstone, Cementstone and Buchan formations this is consistent with their dominant non-mudstone lithology.

2 Introduction

The 21CXRM Palaeozoic Project aimed to stimulate exploration of the Devonian and Carboniferous plays of the Central North Sea - Mid North Sea High, Moray Firth - East Orkney Basin and in the Irish Sea area. The objectives of the project included regional analysis of the plays and building of consistent digital datasets, working collaboratively with the OGA, Oil and Gas UK and industry.

The project results are delivered as a series of reports and as digital datasets for each area. This report describes source rock organic geochemistry in the Central North Sea study area including a literature review (Appendix 1) of source and kerogen typing information. It should be read in conjunction with the background/overview (Monaghan et al., 2016), stratigraphy (Kearsey et al., 2015), basin modelling (Vincent, 2015) and synthesis (Monaghan et al., 2015). These reports provide the geological background and integration of results to place the organic geochemistry presented here into context.

The geochemical parameters commonly used to characterise potential source rocks in conventional hydrocarbon systems include: source rock richness, source rock or kerogen type and maturity. The main analytical techniques used for this study were Rock-Eval pyrolysis and optical (reflected light) microscopy.

Rock-Eval analysis provides:

- S1 (free hydrocarbons in mg/HC/g of rock TOC);
- S2 (generated hydrocarbons in mg/HC/g of rock TOC);
- HI (hydrogen index calculated from S2 * 100/TOC);
- OI (oxygen index calculated from S3 * 100/TOC);
- TOC;
- $T_{max.}$ (Temperature of maximum S2 peak); and
- PI (Production Index, derived from S1/S1+S2

Optical microscopy includes vitrinite reflectance (VR or Ro%) measurement of source rock maturity and is also used to identify kerogen type.

2.1 CRITERIA USED TO ASSESS GAS AND OIL PRONE SOURCE ROCKS

Screening criteria used are given in Table 1 below. Rock-Eval data extracted mainly from CDA well reports was often incomplete in that key parameters were missing. This limits the interpretation of the source potential within these samples and consequently increases uncertainty. Consequently, only 25 wells in which the majority of the depths have complete data sets (TOC, HI, S2 and T_{max}) were considered further in this report.
Given the oil window maturity levels across much of the study area, the Rock-Eval hydrogen index (HI) used to estimate hydrogen richness, to assist in chemical kerogen typing, and to differentiate gas and oil prone source rocks was a particularly useful parameter. The original HI (HI_o), can be calculated from HI using a simple formula (see 2.2 below).

Criteria used to assess gas and oil prone source rocks.

Parameter	Inference & Comment
HI_o < 300 mg/g TOC	• Gas prone source rocks and will generate mainly gas.
HI_o > 300 mg/g TOC	• Oil prone source rocks and will generate mainly oil.
S2 < 1 mg/g and/or TOC (< 1.0 %)	• Poor or no hydrocarbon generative potential before burial, or • Good quality source interval that has been matured and generated hydrocarbons. • Where vitrinite reflectance (VR) maturity data is available VR can be used to help ascertain whether these parameter ranges were the result of hydrocarbon generation or inert maceral assemblage types.
Production Index (PI)	• An increase and stabilisation of PI values can be used as a secondary line of evidence for hydrocarbon generation. (A positive departure from a generally increasing PI value may indicate in situ generation of contamination by migrant or pollutant hydrocarbons) • High PI values (over 0.5-1) indicate generation compared to potential i.e. mature or migrated hydrocarbons.
T_{max}	• Generally reliable indicator of maturity in and around the oil window. • Should be used together with other maturity parameters in order to avoid false positives. • Requires high S2 peaks to enable reliable temperature readings on the S2 curve.
High T_{max} (>480°C) obtained with low S2	• Due to interferences from inorganic matter and technical limitations of the Rock-Eval instrument.
High T_{max} and low S2	• Can be obtained from a good source rock that has lost its potential during source rock maturation, equally can be obtained from a poor source rock with high maturity. To mitigate this problem it is necessary to assess the maceral content to determine whether there are relict indications of original source richness.
S1 (free gas & oil content, some Rock Eval instruments separate gas (S0) and oil (S1)).	• poor 0-0.5 • fair 0.5-1 • good 1-2 • very good 2-4 • excellent >4
Vitrinite Reflectance (% Ro)	Criteria for thermal maturity of organic matter. • Immature = 0.2 – 0.5 • Early to mature oil = 0.5-0.7 • Mature oil = 0.7-1.0 • Late to mature oil = 1.0-1.3 • Main gas = 1.3-2.2 • Late gas = 2.2-3.0

Table 1 Summary of screening criteria used as 'rules of thumb'. Note that in detail, cut-off values will vary dependent on kerogen type.

2.2 MEASURED HI VS. ORIGINAL HI

As mentioned above, an important Rock-Eval parameter used to differentiate oil or gas prone source rocks is the hydrogen index, HI.

HI decreases during hydrocarbon generation and source rock maturation reactions, therefore as these rocks have been buried to different depths, some differential hydrocarbon generation and maturation reactions between these wells will have occurred. As such, for many wells the measured HI (present day HI) will be lower than the original HI (HI_o). Therefore, as HI_o provides a more accurate measure of original hydrocarbon source potential than using the measured HI alone, it is useful to classify wells into pre-burial gas or oil prone source rocks (prior to hydrocarbon generation). The HI_o for each well was calculated using the formula "measured HI x (1000/833)" of Jarvie et al. (2007) in order to determine whether the well originally contained oil or gas prone kerogen.

The HI_o >300 used as a cut off from gas to oil prone source rocks in this report refers to HI prior to petroleum generation, and not the present HI of the analysed samples. Some source rocks with HI_o between 200 and 300 are expected to generate some liquid petroleum and due to this continuum, there is the potential for limited oil generation from intervals classed here as 'gas prone'.

2.3 UNCERTAINTY OF T_{MAX} TO VR EQUIVALENT IN GAS-PRONE SOURCE ROCKS (TYPE III).

Where measured vitrinite reflectance data were available, this was preferentially used to indicate thermal maturity of the samples (i.e. where VR-measured was available this was used in favour of VR-calculated).

T_{max} data (where reliable) was used to calculate the pseudo vitrinite reflectance using the formula "(0.018 * T_{max}) – 7.16" of Jarvie et al. (2012), along with measured VR data (where available) to ascertain the maximum thermal maturity of the wells. This maturity data was used in combination with the measured and original HI, S2, and TOC values to classify the original source potential of the 25 wells in this study.

The Jarvie et al. (2012) formula was originally developed testing T_{max} and VR measurements from marine shales, which are rich in type II kerogen. It has been shown that for coal (type III source rocks) there is significant deviation from the Jarvie et al. trend particularly outside the oil window of thermal maturity. It is therefore estimated that the use of this formula in the present study introduces a high degree of uncertainty regarding the accuracy of the assessment of source rock thermal maturity. Based on these considerations the calibration of T_{max} with measured VR (where available) for a certain type of organic matter (e.g. gas-prone humic coal/associated carbonaceous shales) is recommended for further work. The use of Jarvie et al. formula is recommended to be limited for marine type II source rocks and inside or close to the oil window maturity range. In some of the well plots presented below, it can be seen that distinctly different trends of T_{max} occur with depth within the different formations (e.g. 41/01- 1). This is likely because the-organic matter type varies. The uncertainty in the maturity estimation introduced by the use of a single Jarvie formula for the conversion of T_{max} to VR equivalent regardless of the organic matter type (Type II vs II/III vs III) causes inaccuracy.

2.4 DATASETS

Data was extracted from a variety of data sources:

1. CDA well reports;

2. Sample analyses by third parties from material held at the BGS core store ;

3. Dutch Petroplay data from Schroot et al. (2006);

4. Reports donated to the Palaeozoic project; and

5. 150 new BGS samples analysed for this project. The samples were chosen to complement the legacy data that was available at an early stage in the project, to give a regional spatial and temporal distribution through mudstone-siltstone intervals and were limited to the core available at the BGS corestore.

As part of the project results, non-confidential data is supplied as a spreadsheet where the data sources are listed. A separate spreadsheet is also provided with the new BGS Rock-Eval 6 data analysed for this project.

The approach taken in this regional screening was to plot a standard set of graphs combining new and legacy data for each well (Figures 26/07-1 to 44/16-1 below). The number of data points on the graphs sometimes varies between parameters analysed in the legacy dataset collated. For example, there is often a good spread of TOC data but no OI analyses available (e.g. Figure 41/20-1).

Well penetrations, and thus core and cuttings samples analysed, encounter a variety of ages of strata through the Devonian and Carboniferous succession and facies variations within the strata of the same age. Samples on the plots have been grouped into approximately time-equivalent intervals with different stratigraphic nomenclature, to assist in regional synthesis. These are;

- Yoredale Formation = Cleveland Group units D & E= Upper Bowland Shale
- Scremerston Formation=Cleveland Group units B & C=Firth Coal Fm in Quad 26
- Fell Sandstone Formation=Cleveland Group A= (superseded) Tayport Fm in 26/07-1
- Buchan Formation= Tayport Formation in Quads>36 =Upper Devonian

On the Figures, for units with time-equivalent nomenclature, the stratigraphic name given first in the key is the unit proven in that well. Some Figures contain the classification ‘above Carb’ meaning these samples are above the top Carboniferous. Most are Permian but a generic classification has been given as the stratigraphy of this interval has not been re-interpreted during this study.

3 Wells Analysed

Individual wells assessed are discussed below.

<u>26/07-1 (depth 450-2135 m)</u>: Figures 26/07-1 (a & b)

The Auk (1148.8 m) and Tayport (2135 m) formations were not considered due to the very low S2 and/or TOC which results in an unreliable measured HI and HI_o calculation. The HI_o vs depth plot shows that the HI_o for Zechstein Group (293 mg/g) and Firth Coal Formation (73-141 mg/g) were all < 300 mg/g TOC, indicating that 26/07-1 will generate mainly gas during burial and thermal maturation. Source rock quality in the Firth Coal Formation varies from poor to excellent. However the VR (calculated from T_{max}) for Zechstein (0.51% Ro) and Firth Coal (0.60-0.78% Ro) and HI vs T_{max} plot shows that the formations are early to mature oil window maturity. This suggests that the Palaeozoic interval is not thermally mature enough to generate gas, and as such will have not expelled significant volumes of hydrocarbons. In summary, 26/07-1 is classed as a poor gas source based on the current maturity of the source rocks, however if buried to a higher maturity, the source rocks have the potential to be a good source of gas. As discussed in section 2, the Jarvie et al. (2012) formula may not have generated accurate conversion of T_{max} to VR equivalent in this coal-bearing succession and thus the true maturity of the succession may differ.

<u>26/08-1 (2624.33-3419.86 m)</u>: Figures 26/08-1 (a & b)

Combined with good-excellent associated TOC values for 26/08-1, HI_o for the Boulton (175 mg/g) and Firth Coal formations (100-220 mg/g) is < 300 mg/g TOC and indicates this well is contains predominantly gas prone source rocks. However the VR (calculated from T_{max}) for Boulton formation (0.63% Ro) indicates early oil window maturity, while the Firth Coal formation VR (0.67-1.08) indicates early oil to mature oil window. The calculated VR together with the HI vs T_{max} plot suggests that the formations are in the oil window and may not have generated significant amount of gas at this location. However the source rock quality of the Firth Coal Formation is good-excellent and as such indicates that more deeply buried equivalent strata in the vicinity of this well would be good-excellent gas sources.

<u>36/13-1 (1266.44-1372.21 m)</u>: Figures 36/13-1 (a & b)

36/13-1 contains the Yoredale Formation which the HI_o vs depth plot shows is predominantly gas prone (HI_o < 300 mg/g TOC), with the exception of 1372 m (HI_o > 300 mg/g TOC). The calculated and measured VR (0.47-0.76% Ro) indicates that the well is early to mature oil window and will not yield significant volumes of gas at this maturity. The source rock quality is judged to be good to excellent. In summary the formation in this well is not likely to have generated much gas, deeper burial is required.

<u>36/23-1 (987-1819 m)</u>: Figures 36/23-1 (a & b)

36/23-1 contains the Yoredale Formation which can be classified as gas prone, based upon the HI_o vs depth plot, with some oil prone intervals. The less reliable calculated T_{max} derived VR values (0.77-0.99% Ro) indicate oil window maturity, whereas the more reliable measured VR for some depths indicate lower pre-oil window maturity (0.37-0.49% Ro). Nevertheless both maturity parameters suggest that the Yoredale Formation in this well is not of sufficient maturity to have generated significant amount of gas. However some S1 values are >3 mg/g indicating some in situ generation of oil or oil ingress may have occurred. Source rock quality of the Yoredale Formation samples are good-excellent. A possible explanation for the discrepancy in maturity between VR calculated and measured VR might be the result of hydrogen-rich coaly sediments and suppression of hydrogen-rich vitrinite reflectance (G. Siavalas. *pers.comm*)

<u>38/16-1 (1949.20-2165.0 m)</u>: Figures 38/16-1 (a & b)

38/16-1 source rock data is entirely contained within the Scremerston Formation with poor to excellent source rock quality. Although limited Rock-Eval data was available, this well was included within the source rock assessment due to the frequent high TOC values ranging from 8-52% which correspond to coaly intervals according to the lithological rock descriptions. The HI_o vs depth plot indicates gas-prone rock (HI_o < 300 mg/g TOC) with some oil prone intervals. The measured Ro (0.39-0.66% Ro) indicates immature (pre-oil) to early mature (oil window), with a similar maturity evaluation obtained using VR calculated from T_{max} (0.49-0.67% Ro). This suggests that the gas shows reported for 38/16-1 may have come from greater depths (higher maturity).

<u>38/18-1 (2314.96-2464.31 m)</u>: Figures 38/18-1 (a & b)

38/18-1 contains mainly the Scremerston Formation (2360-2452 m). The HI_o vs depth plot indicates that the well contains a mixture of gas and oil prone source rocks (HI_o of 47-582 mg/g TOC). The calculated VR (0.44-0.87% Ro) shows that the well is immature (pre-oil) to mature (oil window), so is not mature enough to generate significant amount of gas. The Scremerston Formation is considered to have excellent source rock quality, with some high S1 values (>10 mg/g) indicating some in situ oil generation or ingress.

<u>39/07-1 (3352.80-3561.55 m)</u>: Figures 39/07-1 (a & b)

This well contains the Yoredale (3352.80-3477.77 m) and Scremerston (3540.26-3561.55 m) formations. The HI_o vs depth plot shows the units in this well are mainly gas prone (HI_o < 300 mg/g TOC). The VR calculated from T_{max} (0.44-0.81% Ro) indicates that the well is pre-oil to early oil window maturity and will not generate significant amount of gas. The source rock quality is judged to be poor to good. In summary the Yoredale Formation in this well will not have generated much gas; burial to greater depth (higher maturity) is required for gas generation.

<u>41/01-1 (910-2036 m)</u>: Figures 41/01-1 (a & b)

This well contains the Yoredale, Scremerston, and Cementstone formations. The HI_o vs depth shows that the well mainly contains gas prone source rocks (HI_o < 300 mg/g TOC) apart from an oil prone sample in the Yoredale Formation. The measured and calculated VR values together with the HI vs T_{max} plot suggest that at depth of 910-931 m, the source rock is at the oil window maturity (0.60-0.83% Ro), while at greater depth (1000-2036 m) the source rock is at the oil to gas window maturity (0.81-1.48% Ro). This suggests that at shallower depths the source rock is not mature enough to generate gas, but at greater depth it is mature enough to generate some gas. The source rock quality varies from poor to excellent for the Scremerston and Yoredale formations and is poor for the Fell Sandstone Formation. S1 and PI values are raised between 1200-1800 m possibly indicating some hydrocarbon generation or ingress at these levels. This well is a good example of how T_{max} behaves with different organic matter type, distinctly different trends of T_{max} which occur with depth internally within the different formations, because the-organic matter type varies from type II to II/III to III (M Sugden & G Siavalas *pers.comm*.). As such the T_{max} plot highlights the uncertainty caused by using VR calculated using the Jarvie et al. (2012) formula in mixed kerogen intervals.

<u>41/08-1 (1133.86-1244.19 m)</u>: Figures 41/08-1 (a & b)
This well contains undifferentiated Carboniferous strata. The HI_o vs depth indicates a gas prone interval, however the calculated VR (0.72-1.01% Ro) suggests that the source rock is at the mature oil stage, as such, significant amount of gas are unlikely to have been generated. The quality of the source rock varies from poor to fair. However, there remains the possibility that gas maybe generated at greater depths from any laterally equivalent unit.

<u>41/10-1 (792.48-4157.47 m)</u>: Figures 41/10-1 (a & b)
This well contains the Yoredale, Scremerston and Cementstone formations. The HI_o vs depth indicates that the source rocks in this well are gas prone (HI_o < 300mg/g TOC). The calculated VR from T_{max} (1.01-3.24% Ro) and HI vs T_{max} suggests that the source rocks are mainly in the gas window and significant volumes of gas can be expected to have been generated and hence the present day low S2 values obtained for some depth intervals. Low S2 is an indication of a hydrocarbon-poor source rock, either a source rock not having enough hydrocarbon generative potential prior to burial or a source rock that has already generated significant amounts of hydrocarbon during maturation. On balance, low and decreasing S2 values coincide with increasing T_{max} and PI values suggesting that the source rocks have become progressively depleted by hydrocarbon generation. Towards the base of the well samples are over mature and are therefore regarded as having no residual gas potential.

<u>41/14-1 (1984.25 -3462.53 m)</u>: Figures 41/14-1 (a & b)
This well contains the Cleveland Group units C, D, E and the Upper Bowland shale. It can be classified as gas prone due to the measured and calculated HI_o < 300 mg/g TOC. The S2 values (< 1 mg/g) and measured HI of depth vs S2 and depth vs HI) were very low for majority of the depths. The measured VR between 1984.25 and 3386.33 m were significantly high (1.48-2.61% Ro). This measured VR together with the HI vs T_{max} indicates that the well is in the gas window. The PI generally increases from 1984 to around 3100 m and is commonly around 0.7 in the Cleveland Group C unit (Scremerston Formation equivalent), taken together with the low S2 and high T_{max} the source rocks in this well are likely depleted due to hydrocarbon generation.
Previous work noted the organic matter has lost nearly all its potential for hydrocarbon generation and that much of the organic material is inertinite, however, there were gas shows recorded within and above the Carboniferous (CDA well reports Geochem, 1991 and Anadrill, 1990). Maturity modelling work (Vincent, this study) showed phases of Carboniferous and Mesozoic-Cenozoic oil and gas generation for this well, as such this section can be considered as once being an excellent gas source. Further work on the maceral types/visual kerogen inspection in this well and on a test of the T_{max} to VR calculation would be beneficial.

<u>41/15-1 (2293.62-3429 m)</u>: Figures 41/15-1 (a & b)
This well contains the Yoredale and Scremerston formations. Rock-Eval data were only available to a depth of 2689 m. The calculated HI_o indicates that the well contains a gas prone source rock. The calculated VR (0.90-1.88% Ro) indicates that the well is mainly in the gas window. The maturity together with the HI vs T_{max} indicates that significant gas generation may have occurred in these sections within the well, and as such the Yoredale and Scremerston Formations may be good gas sources. The source rock quality of the Yoredale Formation is classified as poor to excellent.

<u>41/20-1 (1194.82-3450.34 m)</u>: Figures 41/20-1 (a & b)

This well contains the Cleaver, Westoe Coal, Caister Coal, and Millstone Grit formations, and these can be classified as gas prone due to the measured and calculated original HI being < 300 mg/g TOC. TOC values greater than 2 % are encountered in Millstone Grit and Coal Measures, however only some horizons within the Coal Measures have good TOC and S2. For majority of the depth the S2 value is < 1 mg/g TOC, and in some cases the S2 value is zero. The measured VR (1.25-2.74% Ro) was significantly high, indicating that this well is in the gas window and any source potential realised.

The S1 values for some of the Coal Measures interval are over 5 mg/g and the production index is variable and up to 1, which together with the measured VR values suggest that maturation through the gas window and generation of hydrocarbons has occurred. The reason for low S2 values could be that the source rock is depleted by hydrocarbon generation during maturation. Minor traces of gas and occasional bitumen staining were observed in this well (CDA well report) and gas generation is supported by maturity modelling (Vincent, this study). Therefore these formations in this well can be classed as once being an excellent gas source.

<u>42/09-1 (2465.68-2843.78 m)</u>: Figures 42/09b-1 (a & b)

This well contains the Yoredale Formation. The HI_o indicates gas prone source rock, the measured VR (0.73-0.84), and calculated VR (0.72-1.07% Ro) together with the HI vs T_{max} show that the source rock is in the oil window. Significant amounts of gas may not have been generated due to insufficient maturity. The source rock quality of the Yoredale Formation samples varies from poor to excellent/coal, so there is the possibility of gas being generated from similar intervals at greater depth.

<u>42/10a-1 (1650-3711.70 m)</u>: Figures 42/10a-1 (a & b)

This well contains the Yoredale Formation, with data below 2522 m. Below this depth the HI_o vs depth indicate a gas prone source rock. The calculated VR (0.51-1.32% Ro) and HI vs T_{max} indicate that the source rock is oil window maturity, suggesting it is not mature enough to generate a significant amount of gas. The source rock quality varies from poor to good. Kerogen types range from Type I-III as indicated within the pseudo Van Krevelen plot. The S1 and PI values are relatively high in the top part of the Carboniferous section.

<u>42/10b-2 (2380.18-4038.60 m)</u>: Figures 42/10b-1 (a & b)

This well contains the Yoredale, Scremerston, Fell Sandstone, Cementstone formations and upper Devonian strata. The calculated HI_o shows that the source rocks are gas prone (HI < 300 mg/g TOC). The calculated VR at depth of 2380-3078 m were between 0.78-1.88% Ro (oil to gas window maturity), and below this depth to 3225 m the measured VR reached gas window maturity (1.41-1.72% Ro). The VR of 0.78-1.88% Ro (both calculated and measured together with the HI vs T_{max} plot indicates that there is the potential in this well to have generated gas. The quality of the source rock is notably higher in the Yoredale, Scremerston and some of the Fell Sandstone formation samples, with a distinct decrease to the Cementstone and Upper Devonian units.

<u>42/10b-2ST (2926-3200 m)</u>: Figures 42/10b-1 (a & b)

This sidetrack well contains the Fell Sandstone formation. The HI_o indicates that this well section is gas prone. The calculated VR (0.65-1.2% Ro) together with the HI vs T_{max} indicates that the source rocks are mature to the oil window levels, as such, significant amount of gas is not expected to be generated. Source rock quality is judged to range from poor to excellent.

43/02-1, Figures 43/02-1 (a & b)

Most of the Rock-Eval data were missing. The measured VR were in the range of 0.27-0.73% Ro with the exception of depth 2751.28 m that was 1.19% Ro. This value may be attributable to measurement of reworked vitrinite or non vitrinic maceral. The measured VR indicate that the well is at the beginning of the oil window, and not mature enough to generate gas. Data from the Yoredale and Scremerston formations suggests variable source rock quality ranging from poor to excellent. HI_o is indicative of gas and oil prone source rock and T_{max} values indicate the well is just within the oil window. Some oil may have been generated and if these formations are buried to greater depth elsewhere then, this section could be a potential source of gas.

43/17-2, Figures 43/17-2 (a & b)

This well penetrates the Cleveland D to Millstone Grit units. Most of the TOC and S2 values were low, also the majority of the original HI were too low to be considered as source rocks that can generate a good volume of hydrocarbons. One VR measurement (1.03% Ro) was available at 3149.80 m consistent with the majority of the T_{max} values which give a linear trend with depth through the oil to gas windows. Analytical errors were observed in a subset of the T_{max} values, this data was not used. S1 and PI values contain peaks within the Millstone Grit and Cleveland E unit indicative of in situ hydrocarbons or ingress, hence generation. Gas flowed from a DST test in the Millstone Grit and peaks in gas flows were observed adjacent to coals (CDA well report). Previous work suggested coaly shales and mudstones shallower than 3596.6 m to be very good to rich source rocks with some woody or inertinite kerogen types. Deeper shales were believed to offer poor potential and below 4800.6 m any potential was believed to be exhausted (CDA well report).
Maturity modelling (Vincent, this study) predicts gas generation from the Millstone Grit Formation strata in this well in Mesozoic and Cenozoic times.

43/20b-2, Figures 43/20b-2 (a & b)

This well penetrated the Caister Formation and Millstone Grit. The TOC, S2 and HI data were low. However, towards the base of the well the source rock quality appears more promising and there are some coal samples from the Caister Formation near the top of the section. T_{max} values were indicative of oil and gas window maturity; S1 and PI values also show a general increase in the bottom half of the well indicating possible hydrocarbon generation. The T_{max} was variable but centralised around T_{max} 450°C with a slight increase at the base of the well suggesting this basal section may have generated some gas, and could be a potential gas source at greater depth.

43/21-2 (3411-4964 m): Figures 43/21-2 (a & b)

This well contains the Millstone Grit, Cleveland Group D, E and the Upper Bowland Shale. The calculated HI_o (plot of HI_o vs depth) indicates a mixture of gas and oil prone source rock in this well. At the top of the well (3400-4200 m Millstone Grit), the shales are gas prone, and between 4200 and 4500 m (Cleveland Group/Bowland Shale) there is a mixture of oil and gas prone source rocks, with the oil prone source rocks dominating. At the bottom of the well (4530-4964 m) the rocks are mainly gas prone (Cleveland Group D). The calculated VR and HI vs T_{max} indicate that the top of the well (3411-4125 m, Millstone Grit Formation) is in the oil to gas window maturity range (0.70-1.91% Ro), while at the bottom (4125-4964 m) the source rocks are in the oil window (0.62-1.02% Ro). The apparent reversal in the maturity trend is attributable to the unreliability of the calculated VR data. Overall the section is likely to have generated more gas than oil, due to the maturity and the fact that the well contains more gas prone source rock. The quality of the source rock varies from poor to excellent, so significant hydrocarbon generation may be expected.

43/28-1, Figures 43/28-1 (a & b)

This well penetrated the Millstone Grit Formation. Most of the TOC (<0.5 or 1.0%) and S2 (<1 mg/g) values were very low, though there are coals and carbonaceous mudstones at depths 3550m, 3600m, and 3700 m with TOC's of 36.98%, 51.92%, and 40.36% and corresponding high S2 values of 16.4 mg/g (3550m), 128.05 mg/g (3600 m), and 112.88 mg/g (3700 m) compared to the far lower S2 range of 0.33-1.63 mg/g for the other depths. T_{max} values are indicative of mature oil to gas window maturity levels and thus generation of hydrocarbons from this source rock could be the cause of poor S2 and TOC values for non-coal samples. Alternatively the non–coal samples did not possess any potential to generate hydrocarbons. HI values are indicative of a gas and oil prone source rock. Sections in this well therefore might have generated some oil and gas due to the current maturity of the source rock, more gas generation is expected to have occurred if this source rock interval were buried at greater depths.

43/28-2 (3445-3855 m): Figures 43/28-2 (a & b)

This well contains the Caister Coal and underlying Carboniferous formations. The HI_o vs depth indicates that the source rock is gas prone. The S2 and TOC values are indicative of fair to excellent source rock quality. The calculated VR (0.74-1.06% Ro) indicates oil window maturity, and the HI vs T_{max} shows that the source rock is in the oil window. If buried more deeply the source rocks in this well have the potential to generate some gas.

44/13-1, Figures 44/13-1 (a & b)

This well penetrates the Westoe and Caister Coal formation. The majority of the TOC (<0.5 or 1%) and S2 (< 1 mg/g) values were low. There are some high TOC coal intervals. No measured VR were available to confirm if the low TOC and S2 were as a result of hydrocarbon generation and source rock maturation. The T_{max} values are indicative of oil window maturity, as such the source rocks are not mature enough to generate significant amount of gas. However, the S1 and PI values vary close to the formation boundary suggesting that some hydrocarbon generation or migration may have occurred.

44/16-1, Figures 44/16-1 (a & b)

This well dataset contains incomplete TOC values and values for HI of unclear origin. It has very low S2 (< 1 mg/g) at some depths. T_{max} is very high in most cases where S2 is very low. Measured VR were not available to confirm that the low S2 and TOC in some depths were as a result of hydrocarbon generation and source rock maturation. HI values are indicative of a gas-prone sequence, and the PI for Millstone Grit strata is variable, indicating that some hydrocarbon generation may have occurred or ingress of migrant hydrocarbons. Some T_{max} values indicate gas window maturity, with the possibility of some gas generated.

4 Wells Excluded

Eight of the 33 wells possessed incomplete, unreliable or had a poor source rock quality data sets, so these were not studied in detail:

26/14-1, Figures 26/14-1 (a) & 26/14-1 (b): Poor TOC values (<0.5 or 1.0%) in Devonian strata and the majority of the Rock-Eval data were missing.

37/12-1, Figures 37/12-1 (a) & 37/12-1 (b): The TOC values were very low, generally < 1.0%, and majority of the Rock-Eval data were not available. Rock-Eval data was only available for 6 depths.

37/23-1, Figures 37/23-1 (a) & 37/23-1 (b): Poor TOC values and most of the Rock-Eval data were missing. The measured VR of 0.22-0.36% Ro between 198.12 and 2316.48m and 0.76-0.95% Ro between 2371.34 and 2529.84 m indicate that the well is not thermally mature enough to generate gas.

38/03-1, Figures 38/03-1 (a) & 38/03-1 (b): Poor TOC (<0.5 or 1.0 % for majority of the depths) and low associated S2 values (< 1 mg/g) or missing Rock-Eval data. There was also an absence of measured VR data available to assess the thermal maturity of the well.

38/22-1, Figures 38/22-1 (a) & 38/22-1 (b): The majority of the TOC and Rock-Eval data were missing and the remaining few data points were considered unreliable. The measured VR (0.23-0.80) indicate that the source rock is not mature enough to generate either oil or gas.

41/24a-2, Figures 41/24a-2 (a) & 41/24a-2 (b): TOC values for the Bowland Shale are good (some >4% TOC), whereas the corresponding S2 values are low. The Rock-Eval data were poor with S2 in most cases <1 mg/g and therefore the HI_o were too low (<60 mg/g TOC) to be considered as potential good source rock. Measured VR was also not available for the samples where TOC and Rock-Eval data were available. S1 and PI values for some Bowland Shale samples are that are indicative of hydrocarbon ingress or in situ generation. As T_{max} values are mainly indicative of immature samples, the elevated S1 and PI values are indicative of hydrocarbon ingress or contamination.

42/13-1, Figures 42/13-1 (a) & 42/13-1 (b): About half of the TOC values were very low (< 0.5%), also majority of the Rock-Eval data (2509.42-3065.07 m) were missing and the original HI where present is too low to be considered good source rock for hydrocarbon generation. Measured VR were only available at depths 2439.92 m (0.91% Ro), 2455.16 m (0.99% Ro) and 2504 m (0.95% Ro). The measured VR indicates the section 2439.92 to 2504 m is in the oil window.

44/02-1, Figures 44/02-1 (a) & 44/02-1 (b): The well penetrated the Scremerston to Tayport formations but unfortunately TOC and T_{max} values indicated systematic analytical errors within the dataset. Despite the occasional coaly sample the majority of the TOC values are low (< 0.5 or 1%), also most of the S2 data were missing. Due to the analytical errors and missing data this well was not considered further.

5 Conclusions and Future Work

Source rock quality is variable within and between wells but there is evidence across the Central North Sea/Mid North Sea High area in the Carboniferous (Visean, Namurian and Westphalian) heterolithic strata for:

1. Good quality source rocks that are immature for gas generation but could generate hydrocarbons if similar strata were more deeply buried within the basins; and
2. Gas mature source rocks that have generated some hydrocarbons and may now be depleted or over mature.
3. Oil-prone source rock intervals and oil generation.
4. The location and extent of gas and oil generative source rocks are described further in Vincent (2015) and Monaghan et al. (2015)

The Scremerston, Yoredale and Millstone Grit formations contain some good-excellent quality source rocks and coals which are gas mature in Quadrants 41 and central-southern Quadrants 42-43. The time-equivalent Cleveland Group/Upper Bowland Shale are of variable source rock quality – gas mature to overmature intervals may have been depleted by hydrocarbon generation and/or a large proportion of inert kerogens may be present within the mudstone-dominated succession.

Oil prone intervals within the Carboniferous succession are of particular interest for further study due the extensive oil window maturity attained in Quadrants 26, 36, 38, 39.

Future work could examine the datasets in more detail and fully integrate new and legacy oil/gas typing. Specifically future work could usefully include:

1) Additional Rock-Eval6 analysis instrumentation, this generates a broader range of parameters thus enabling a better assessment of hydrocarbon potential;

2) Multiple individual VR particle measurement enabling for more accurate thermal maturity determination;

3) *n*-alkane distribution and or molecular biomarkers (e.g. hopanes and steranes) to characterise the solvent soluble (oil fraction) and facilitating oil source correlations; and

4) Analytical pyrolysis to accurately estimate kerogen type beyond that provided by Rock-Eval screening.

5) Optical kerogen analysis to better determine kerogen type and perhaps elucidate spent source rock’s original maceral composition, hence likely product: gas or oil.

6) New, in-depth analysis of Devonian shale samples to determine where Devonian aged sources could be present and where they generated hydrocarbons. Such analysis could include kerogen isotope and optical analysis.

7) Comparison of measured VR values with T_{max} data to give an formula for calculation of T_{max} -VR equivalence in UKCS, Type III source rocks , to improve upon the currently used formula of Jarvie et al. (2012).

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Figure 26/07-1 (a) TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 26/07-1.

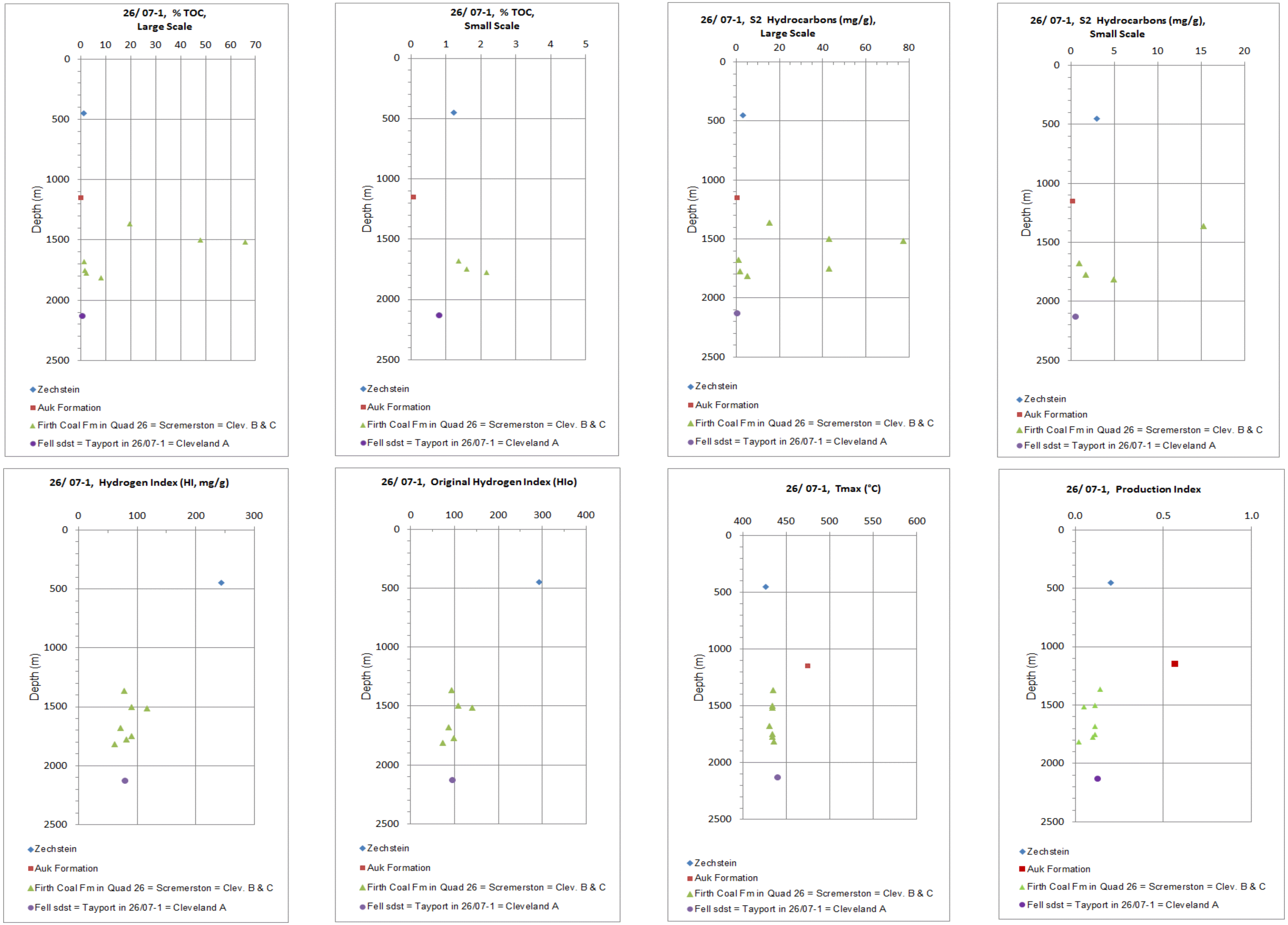
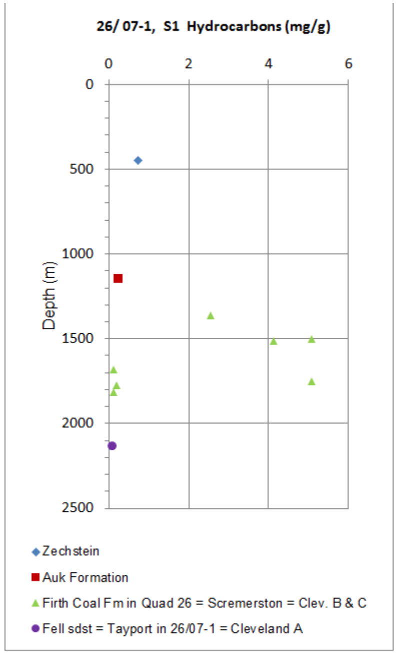
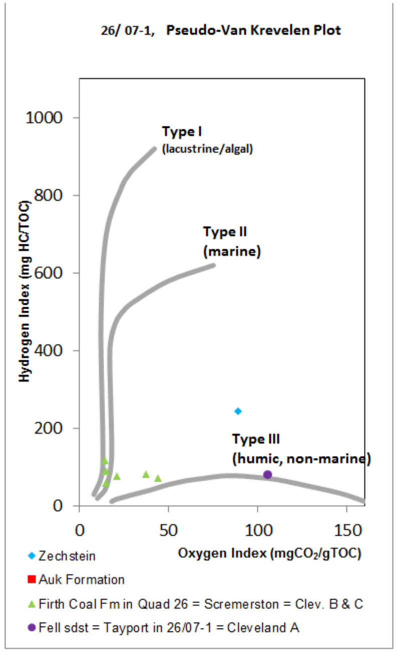
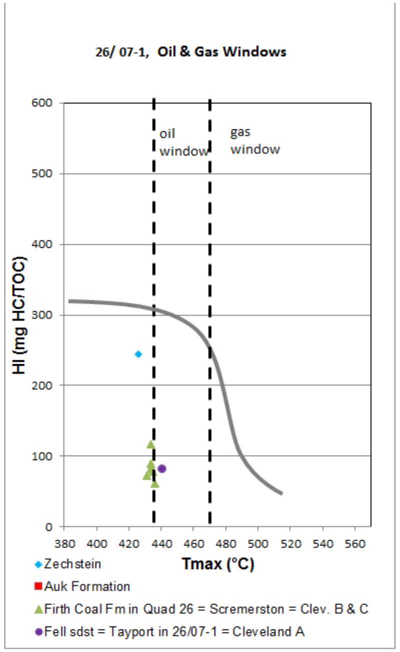
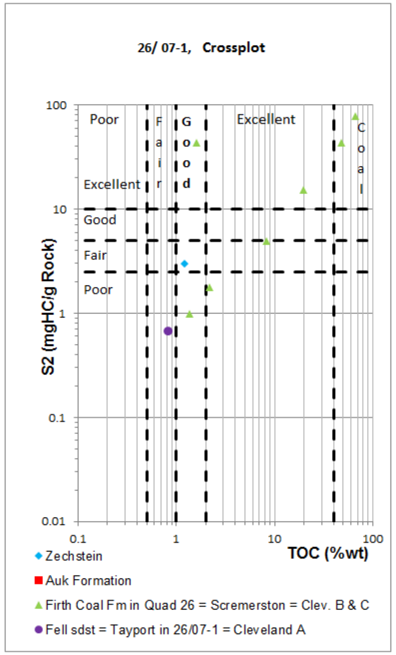


Figure 26/07-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 26/07-1.









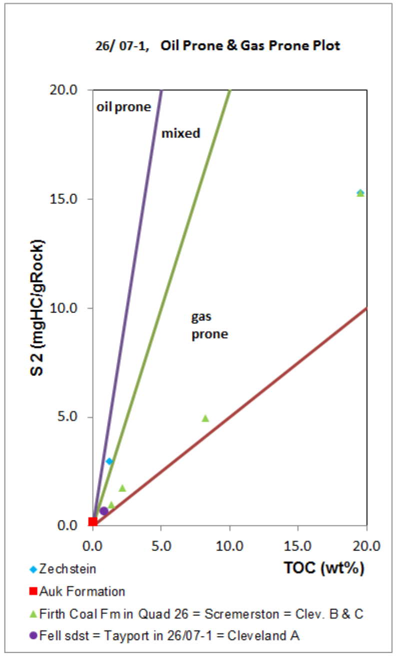


Figure 26/08-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 26/08-1.

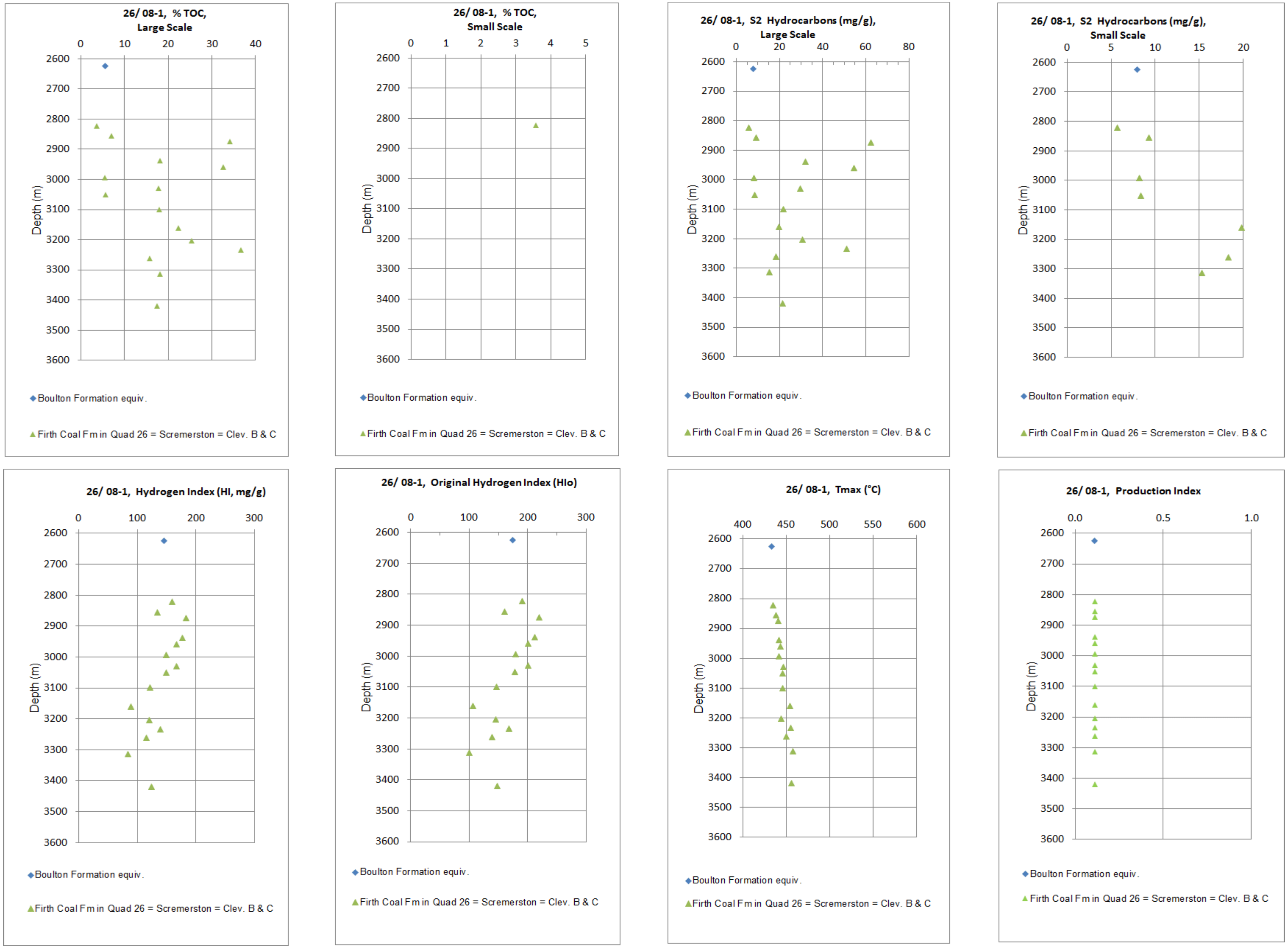


Figure 26/08-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 26/08-1.

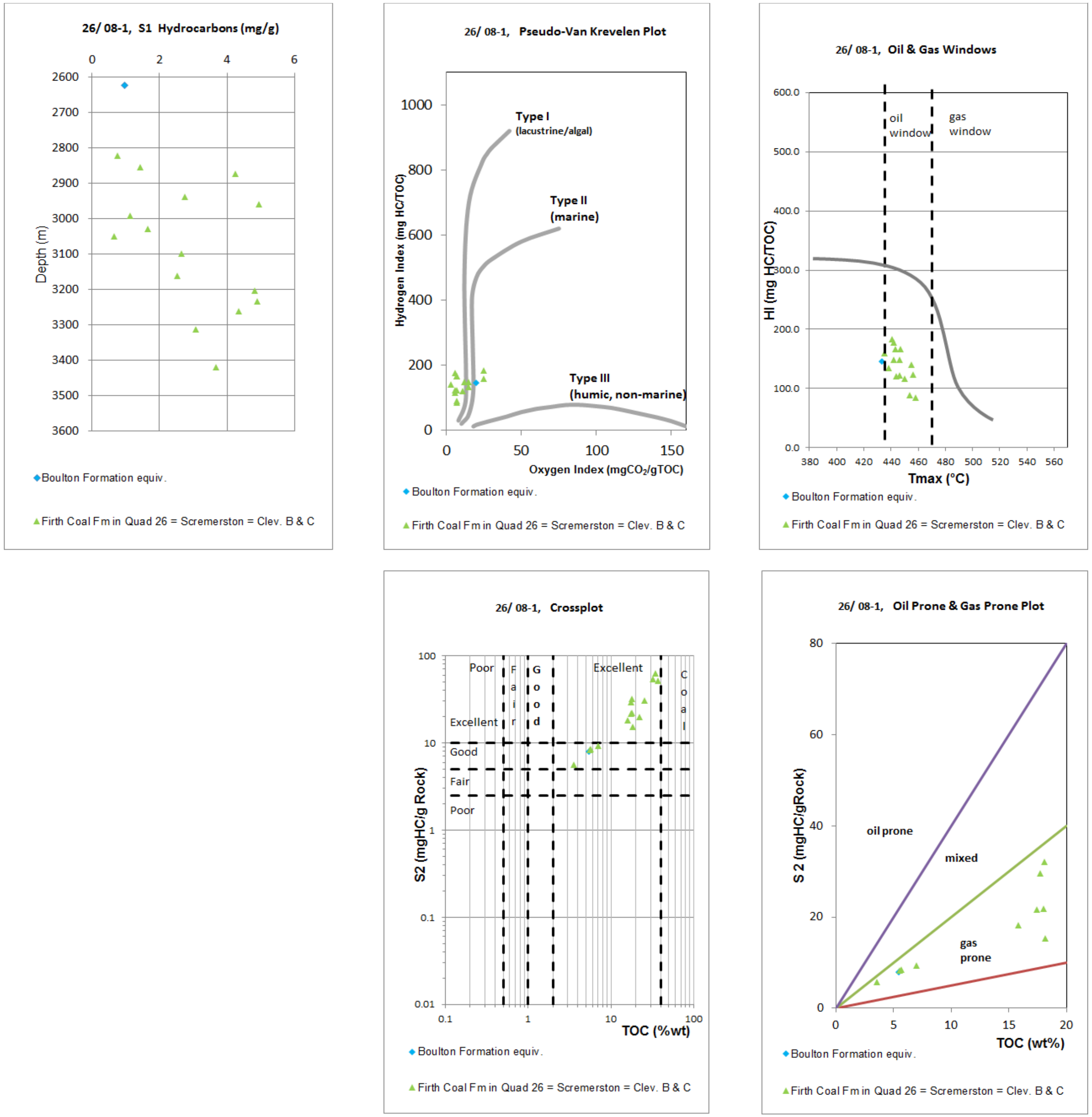


Figure 26/14-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 26/14-1.

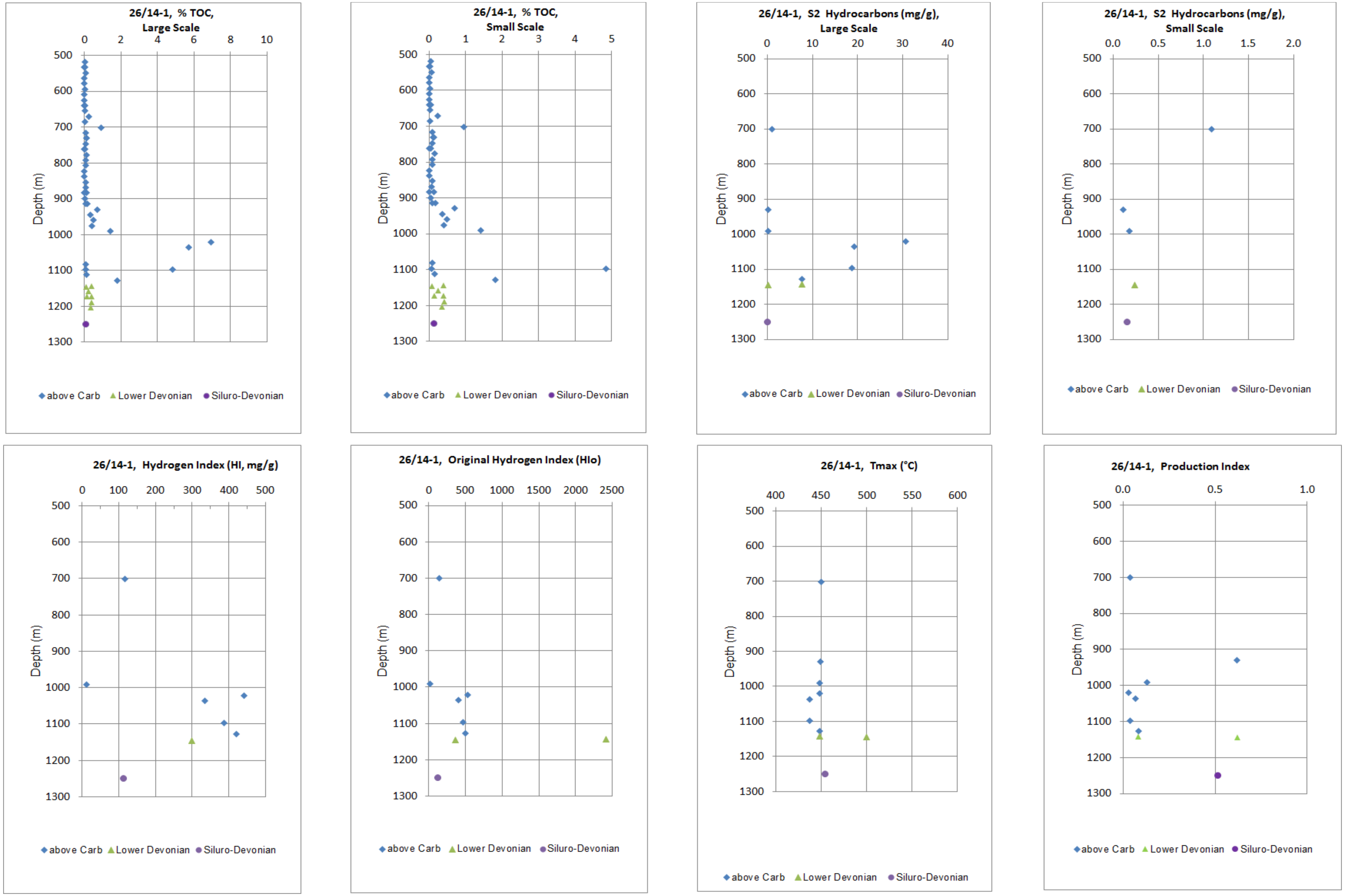


Figure 26/14-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 26/14-1.

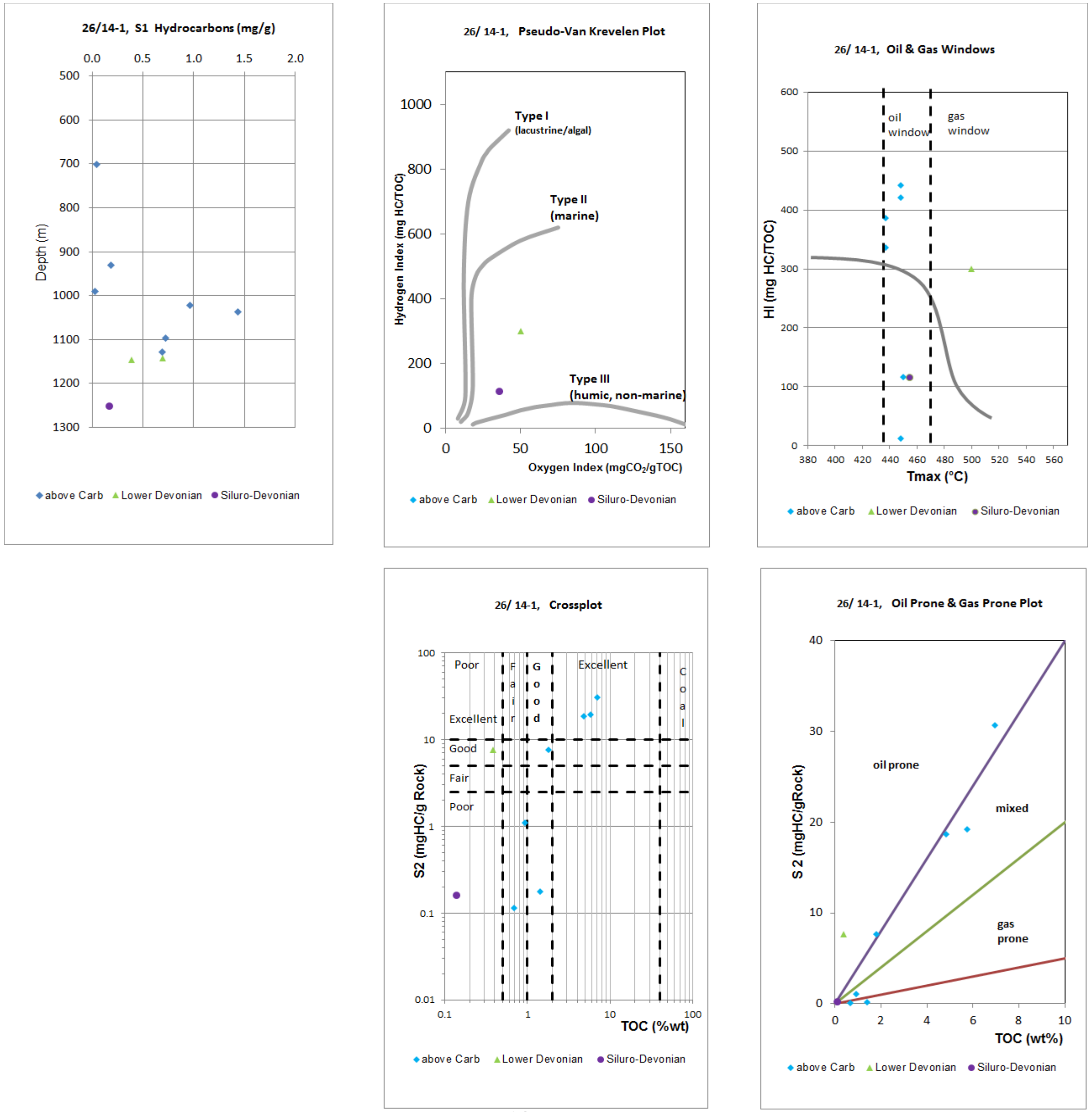


Figure 36/13-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 36/13-1.

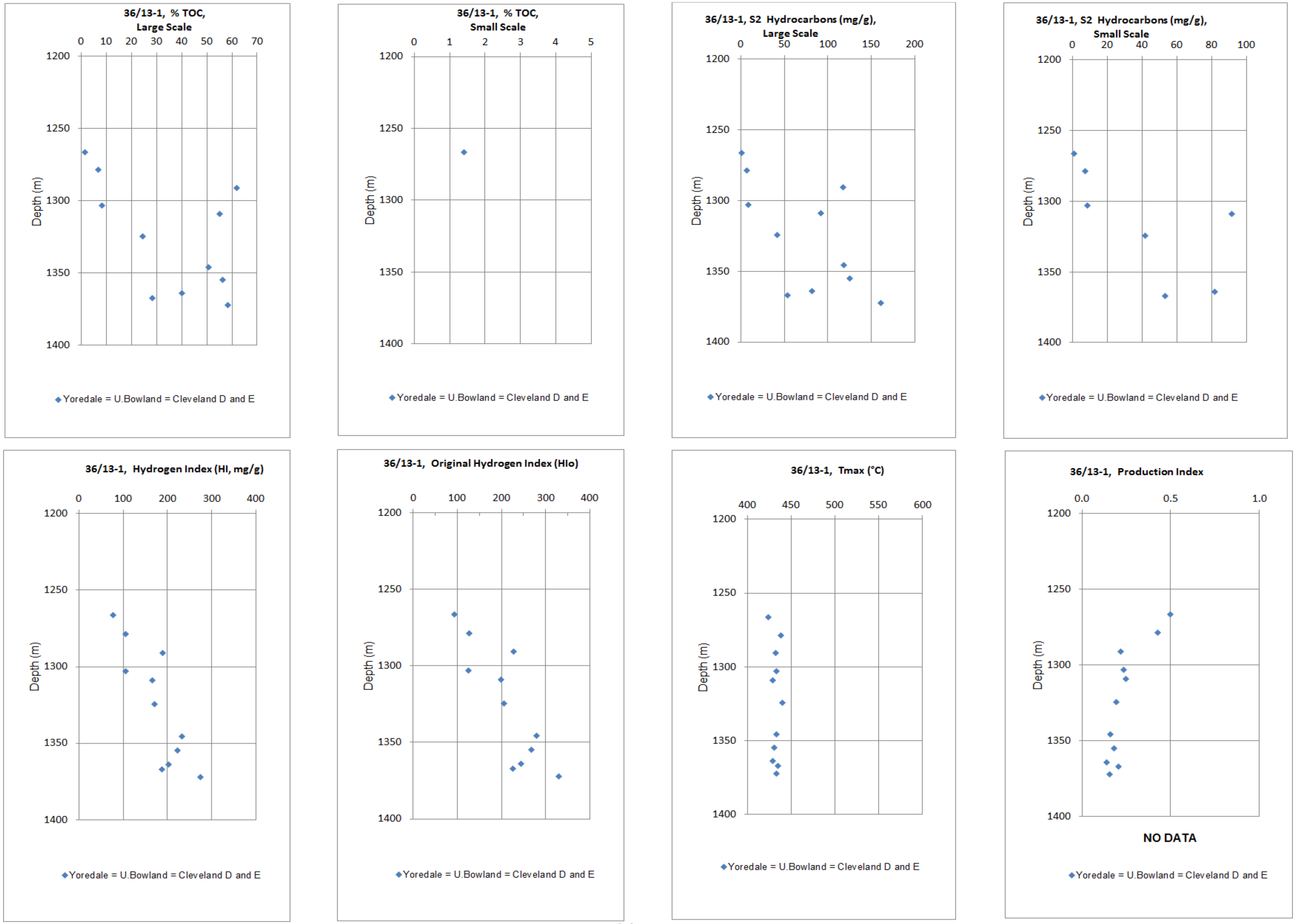


Figure 36/13-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 36/13-1.

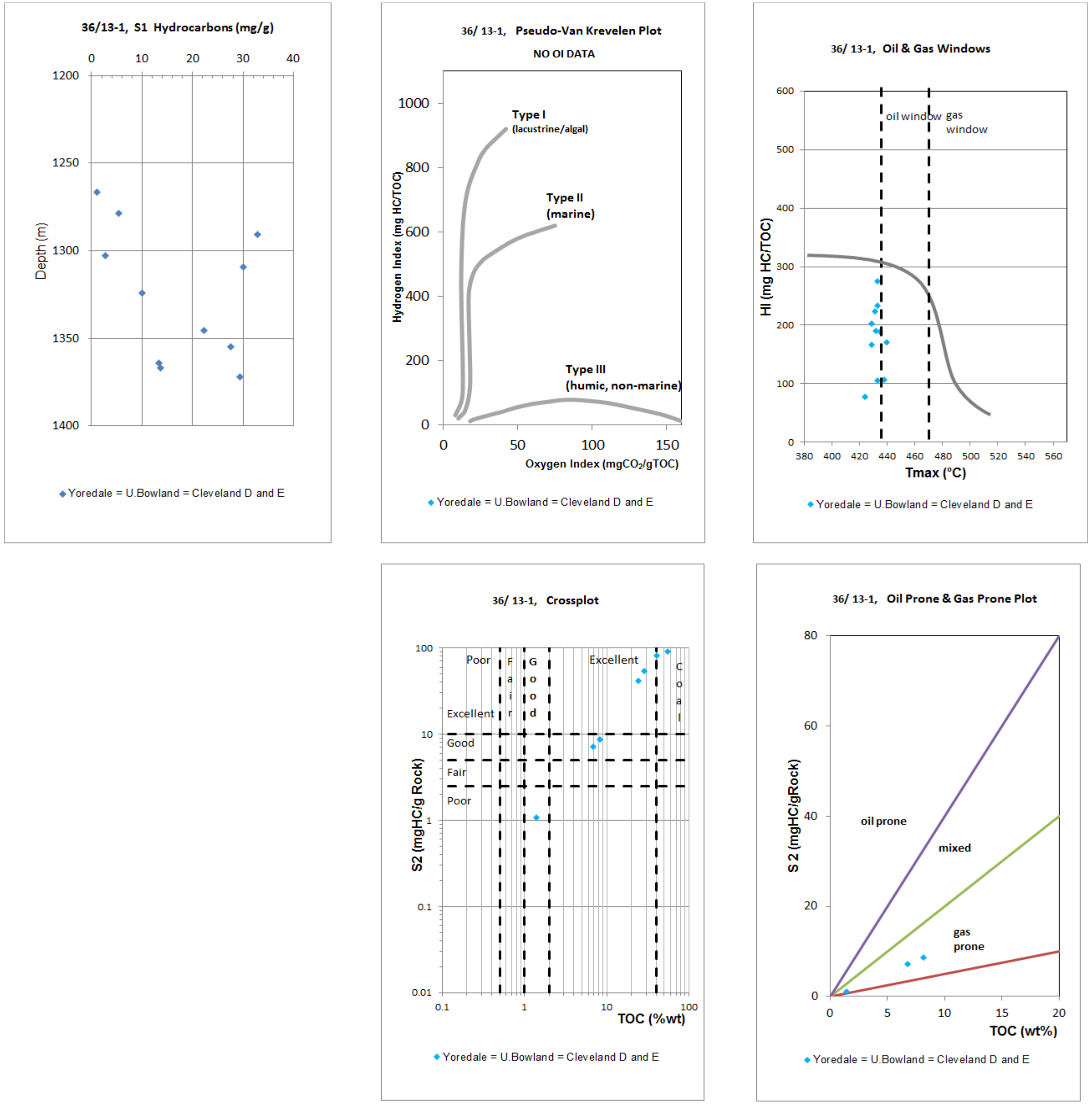


Figure 36/23-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 36/23-1.

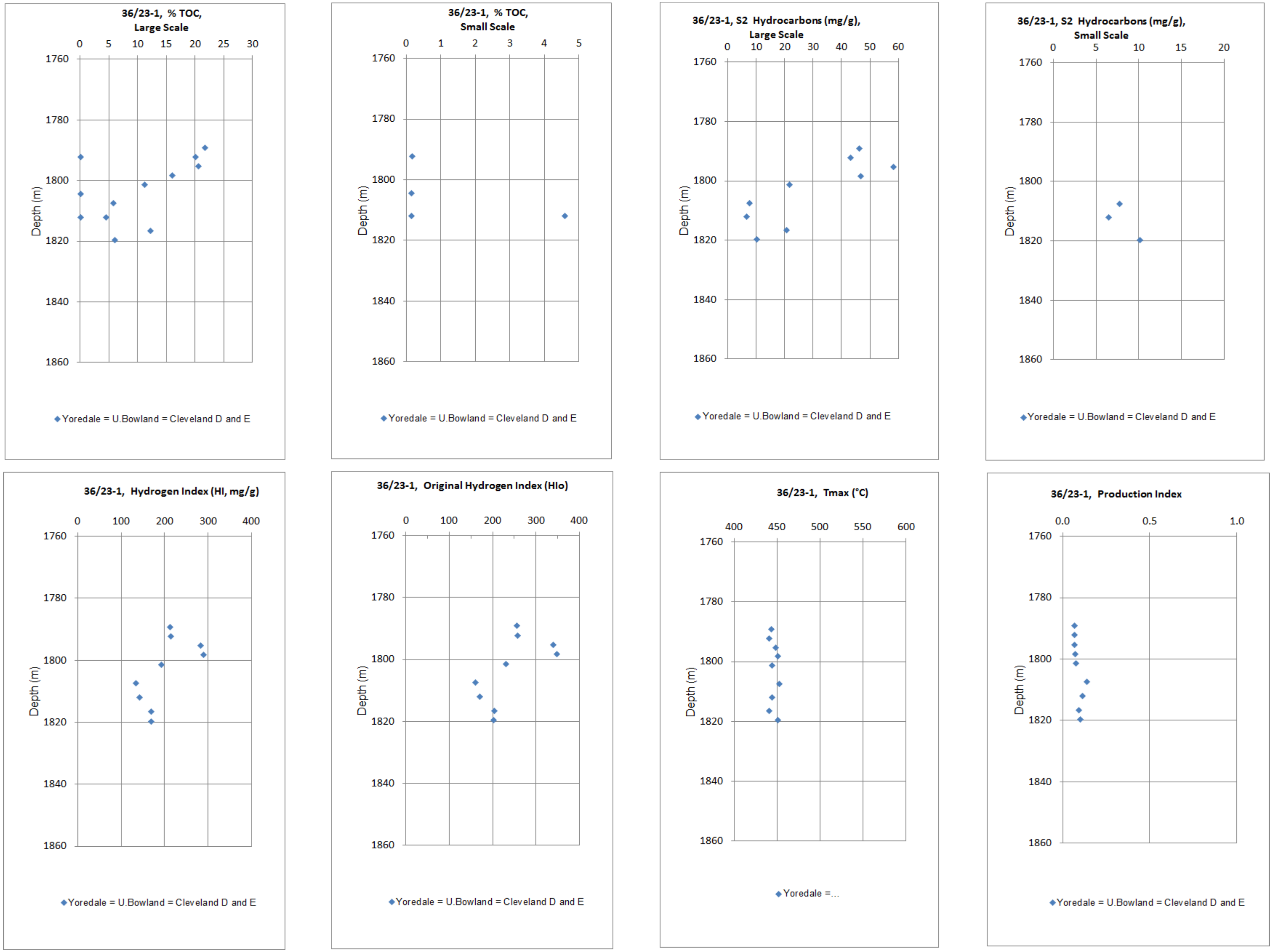


Figure 36/23-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 36/23-1.

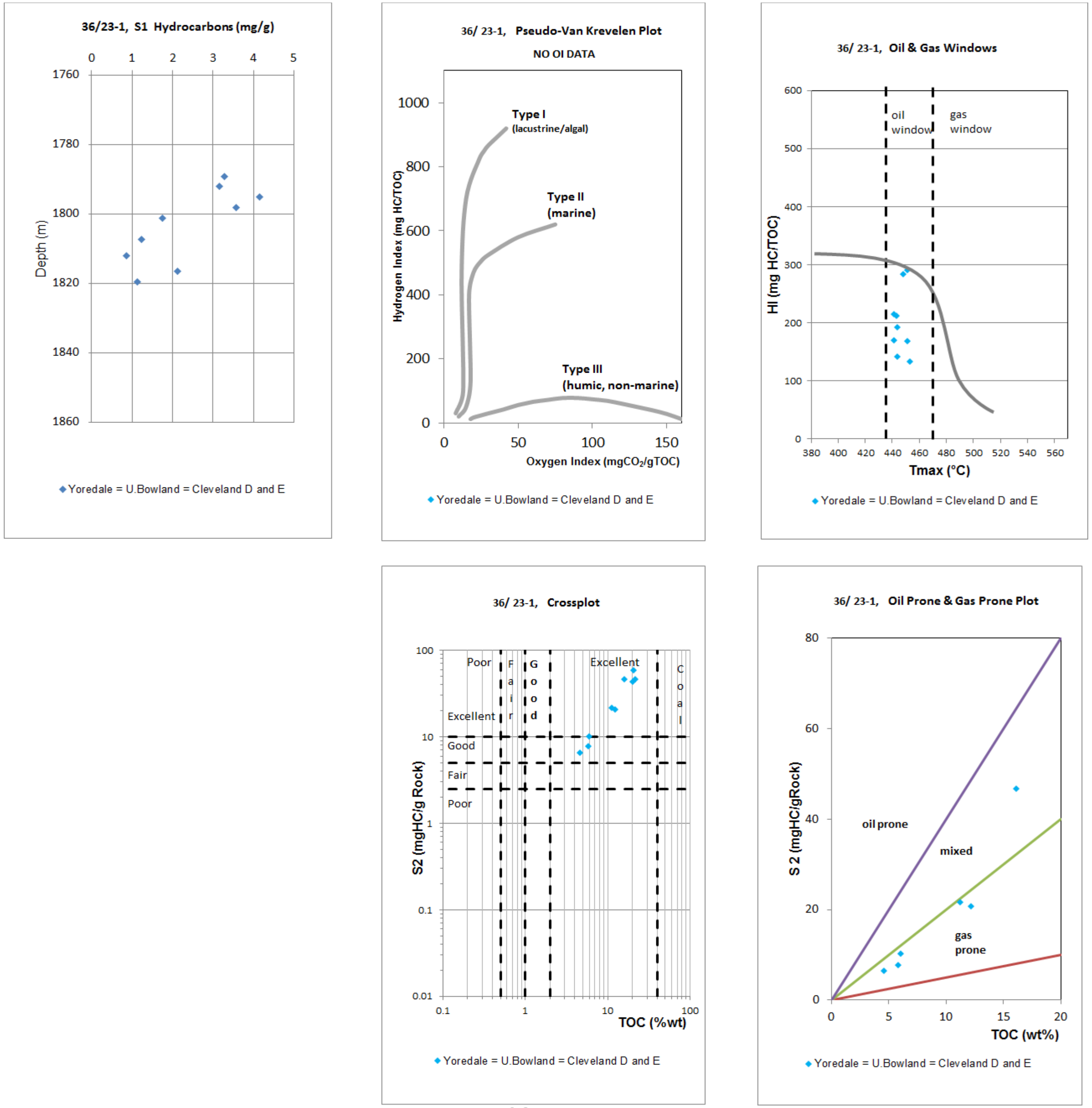


Figure 37/12-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 37/12-1.

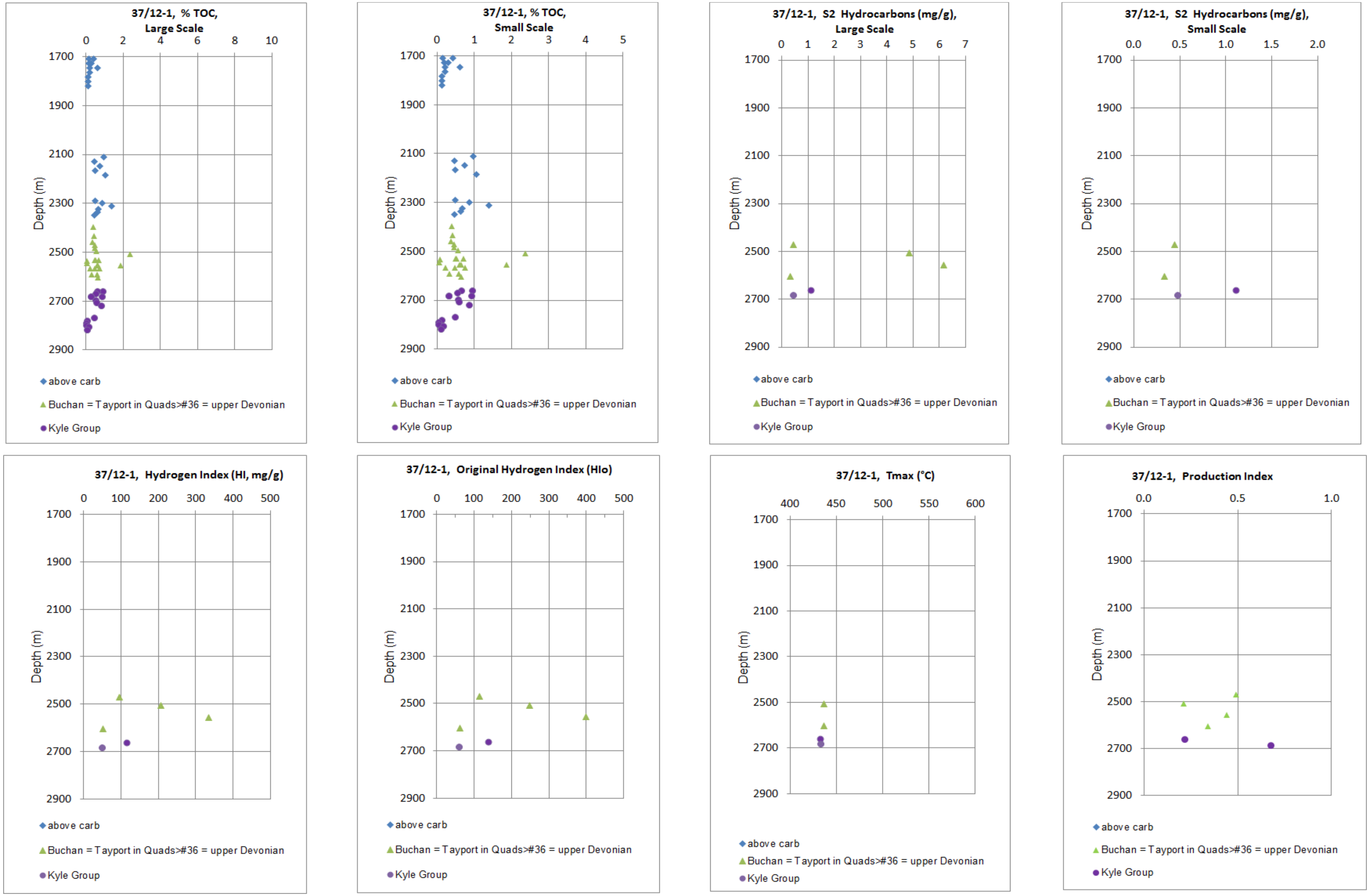


Figure 37/12-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 37/12-1.

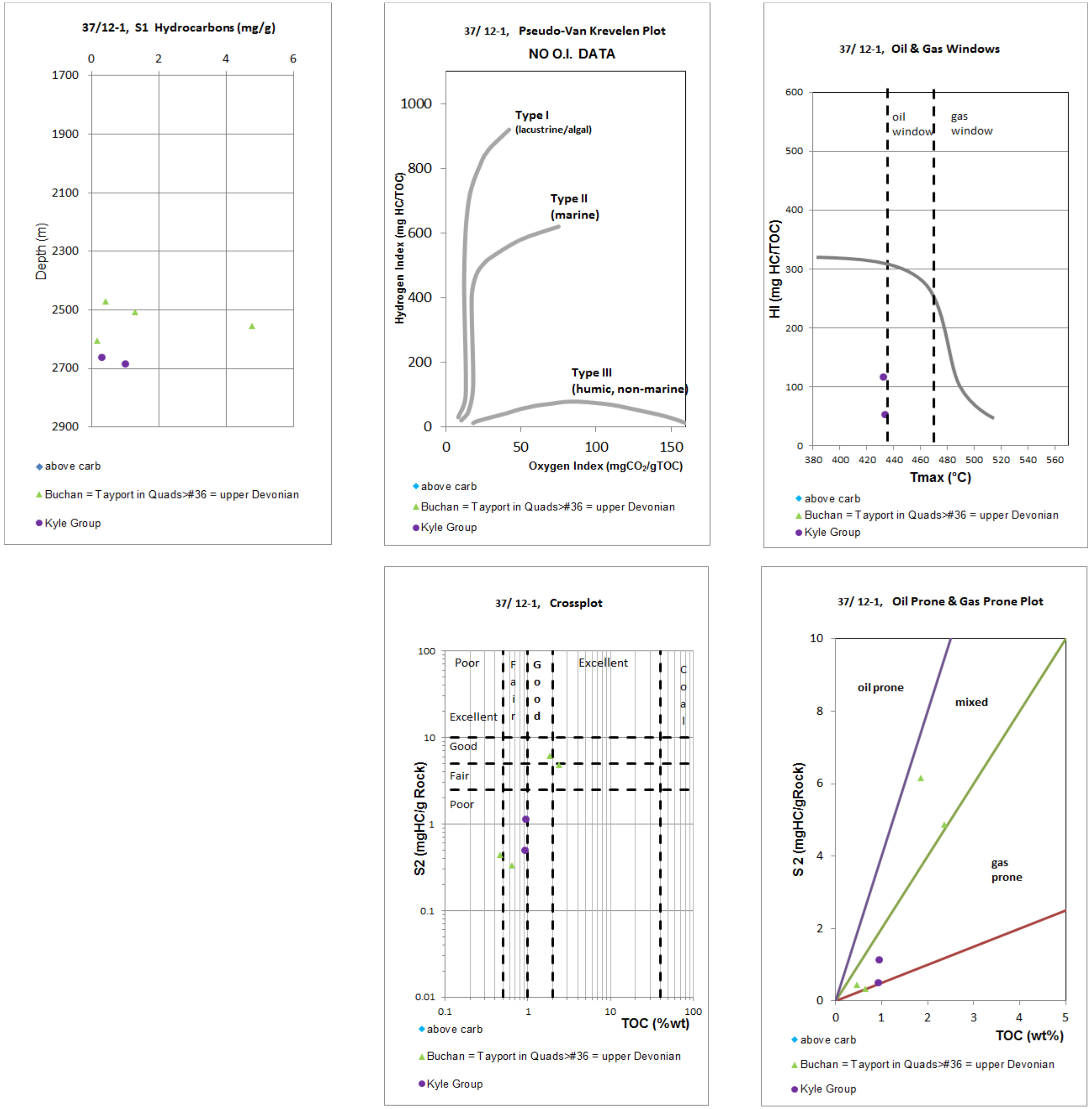


Figure 37/23-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 37/23-1.

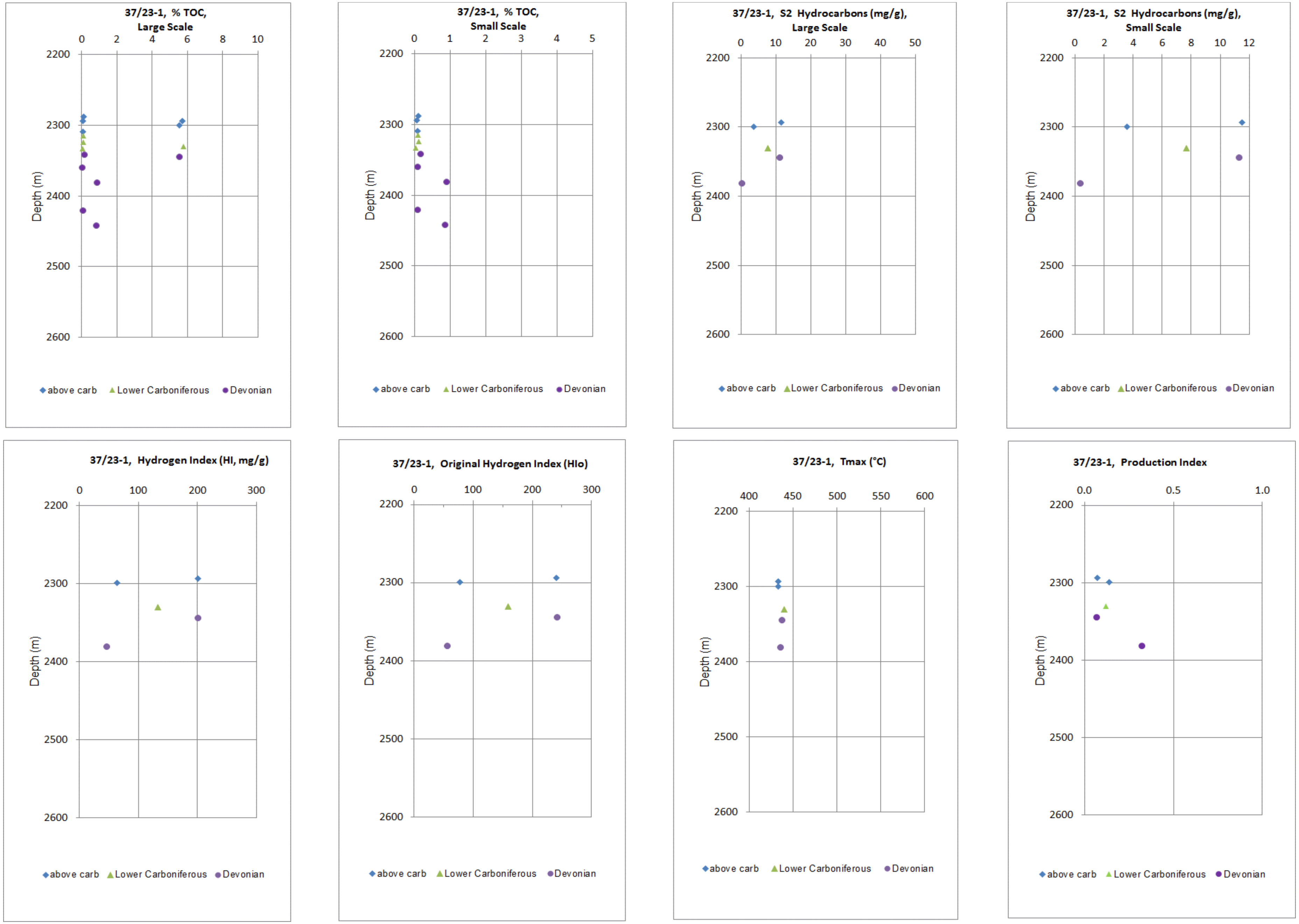
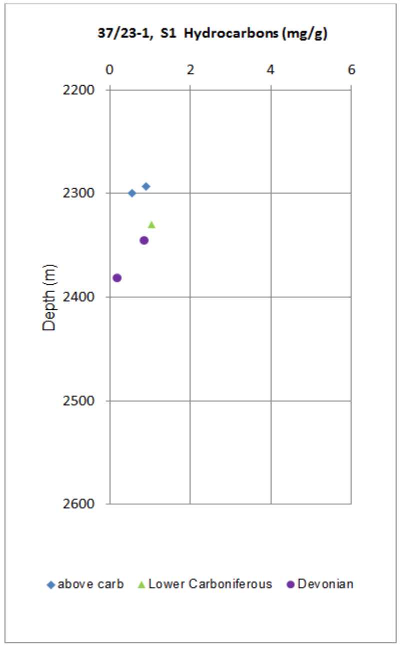
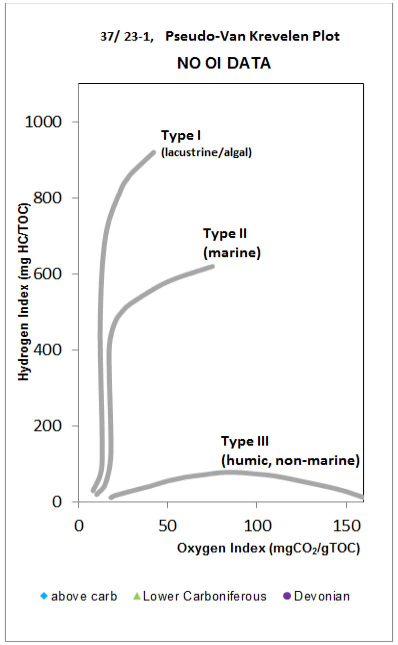
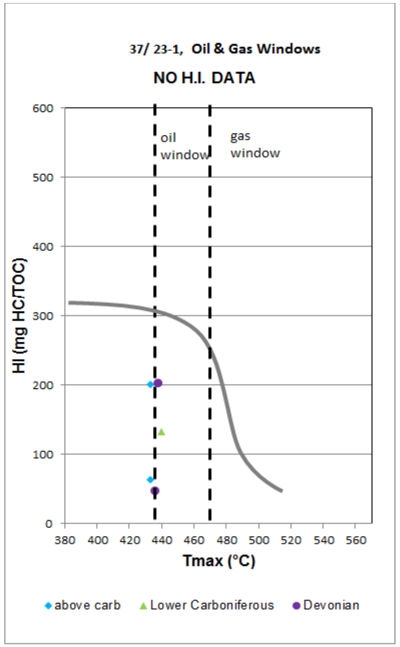
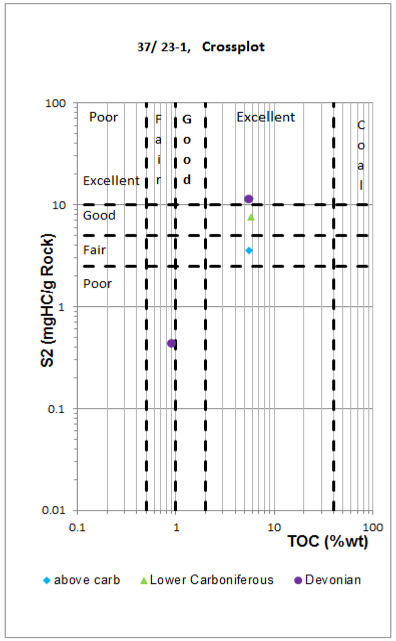


Figure 37/23-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 37/23-1.









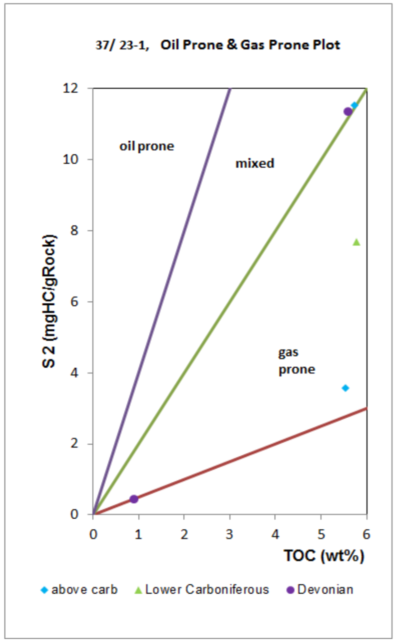


Figure 38/03-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 38/03-1.

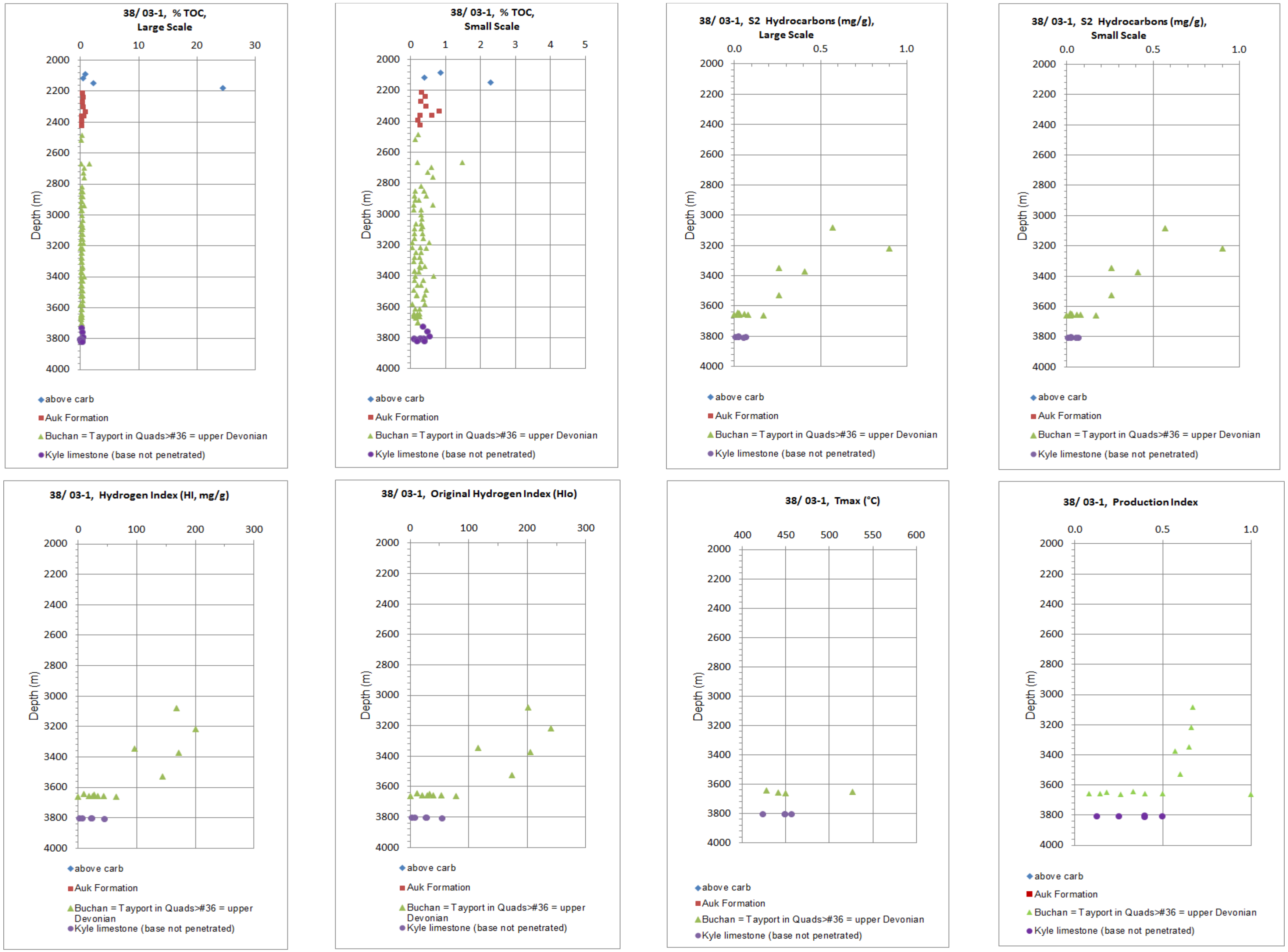


Figure 38/03-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 38/03-1.

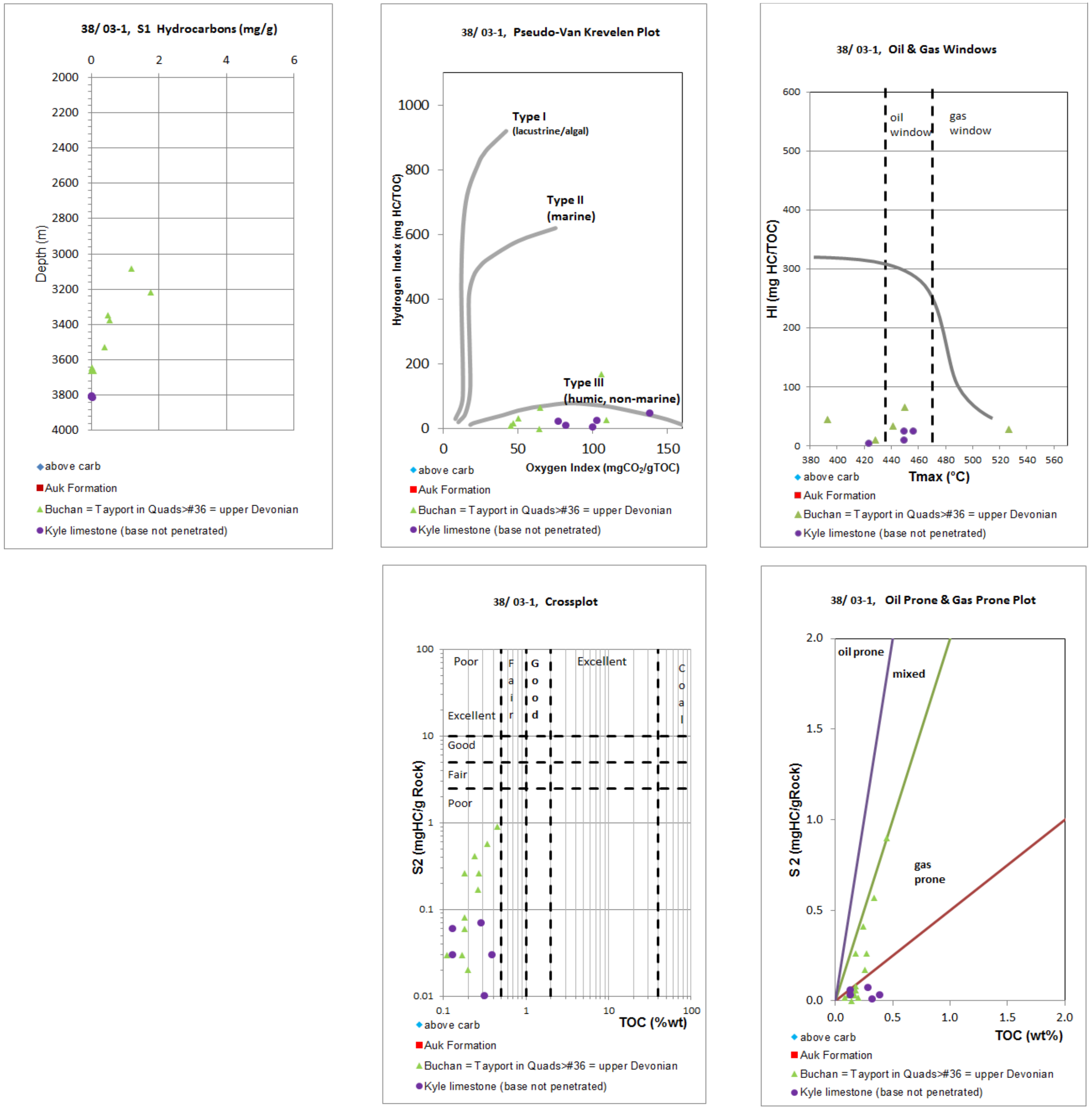


Figure 38/16-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 38/16-1.

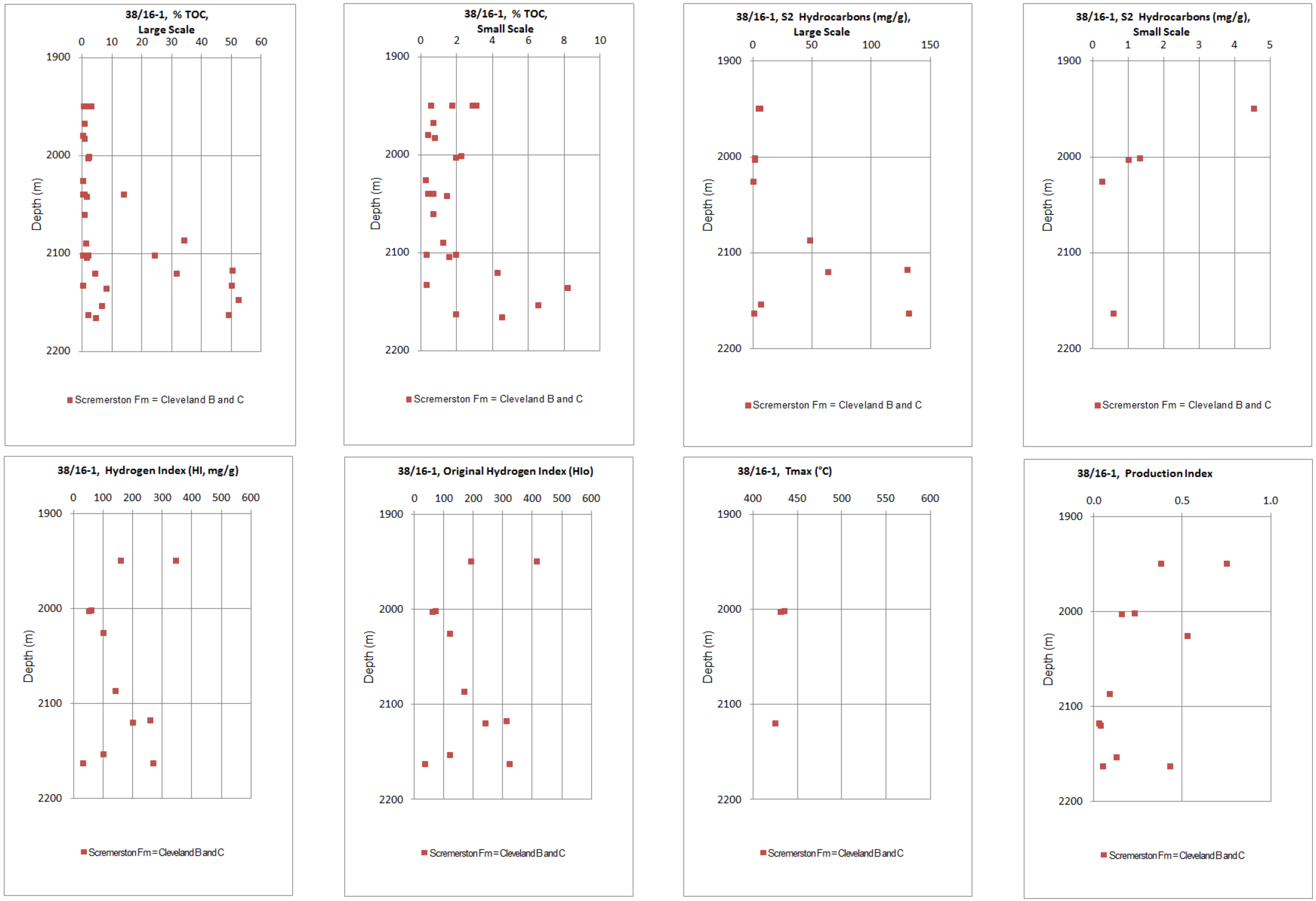


Figure 38/16-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 38/16-1.

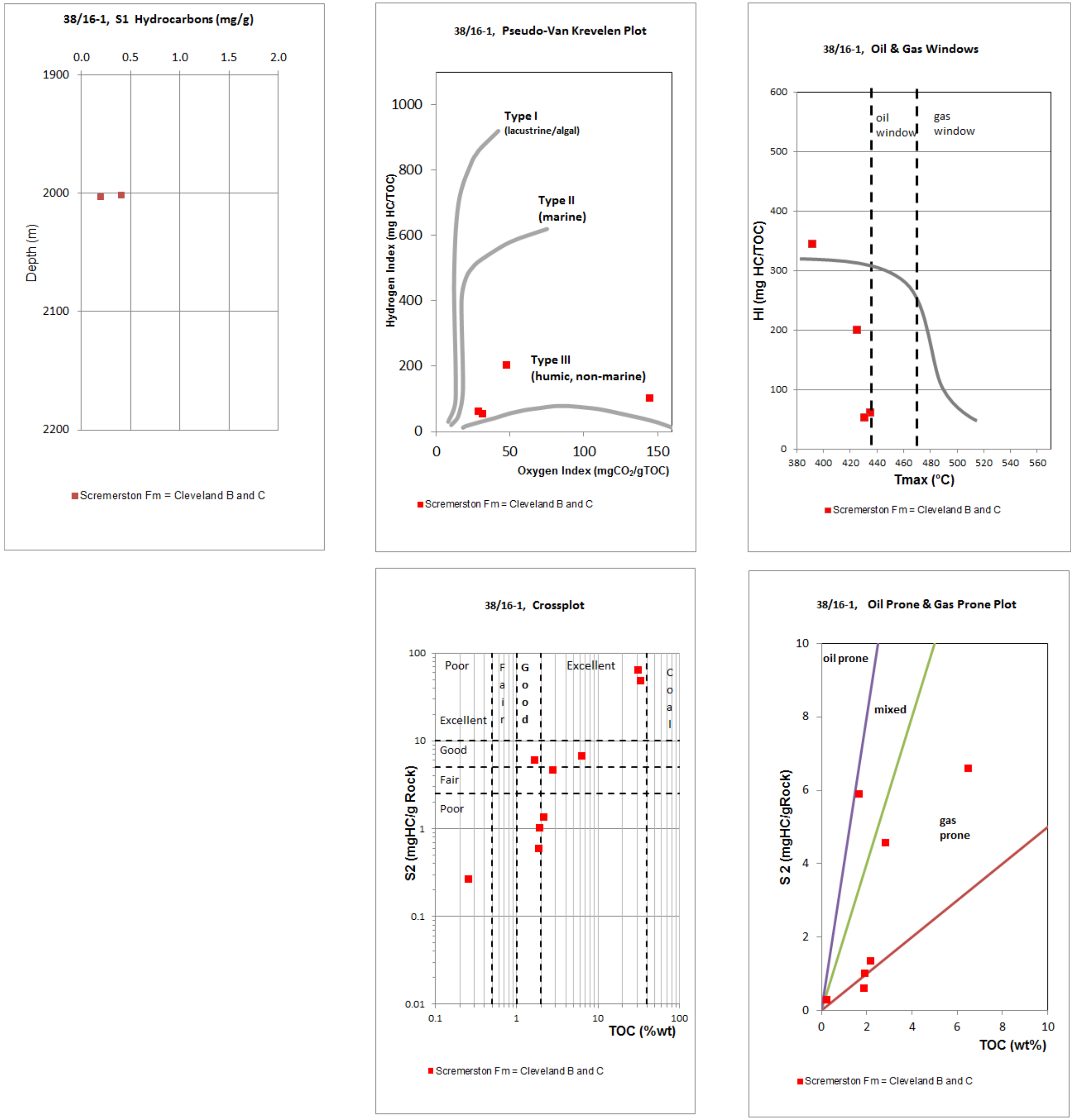


Figure 38/18-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 38/18-1.

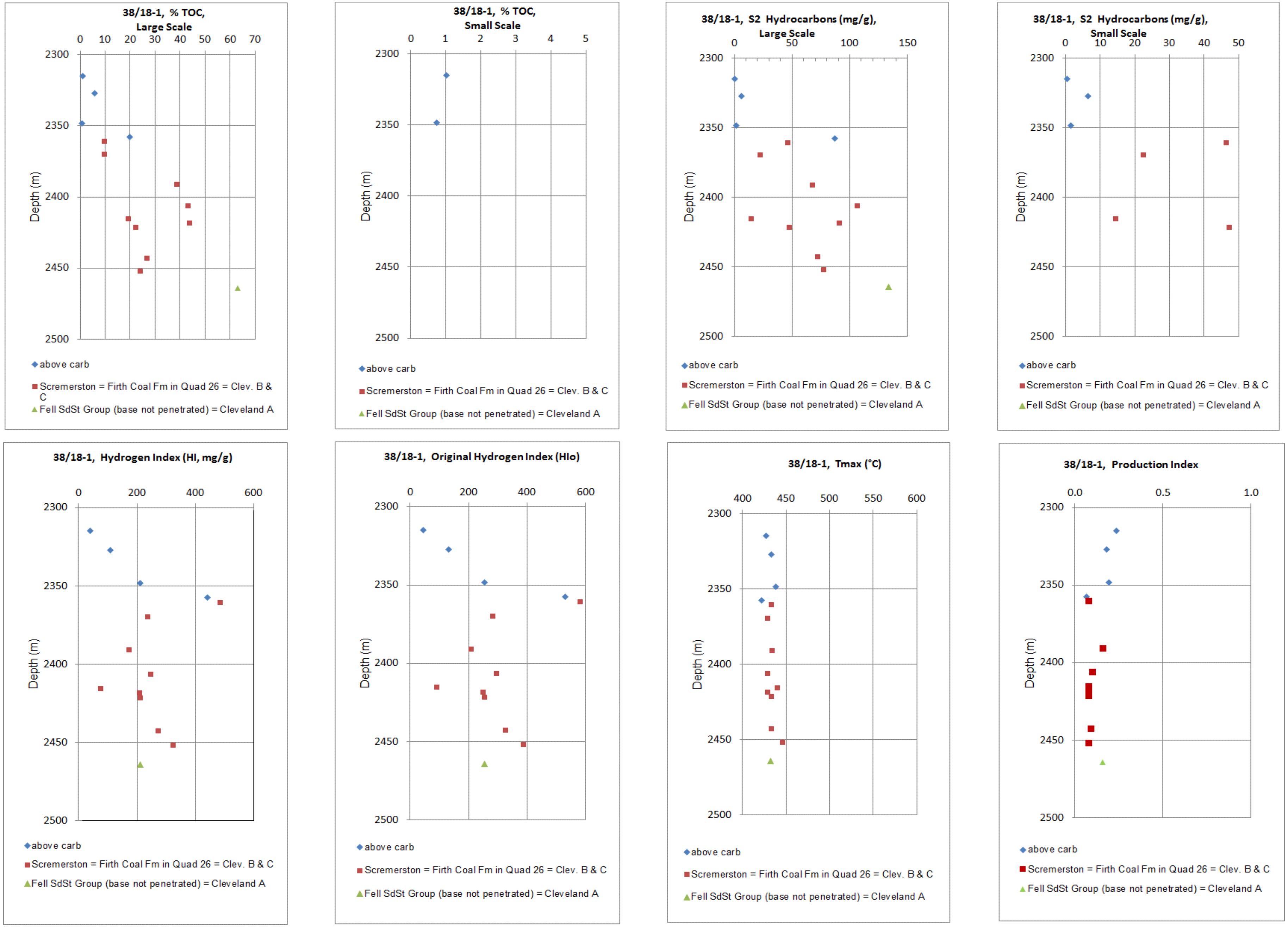
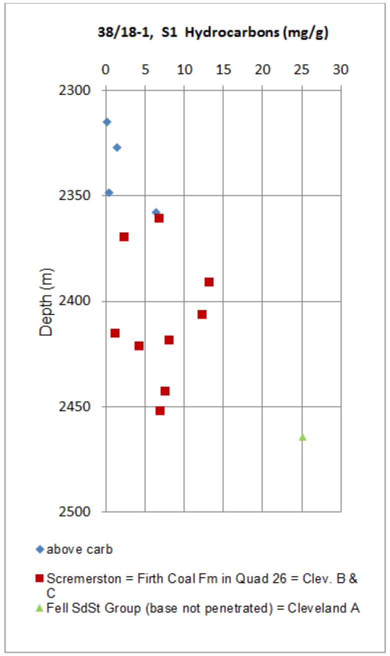
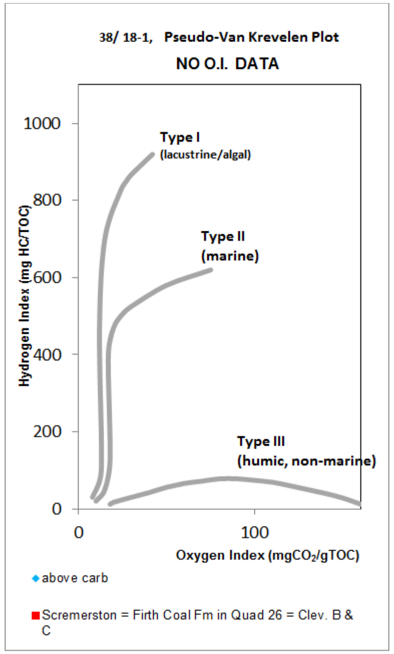
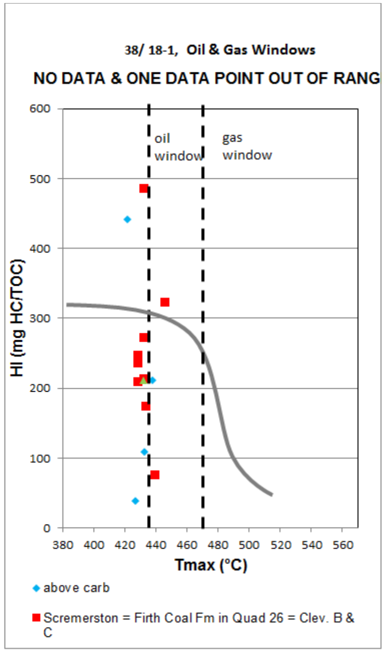
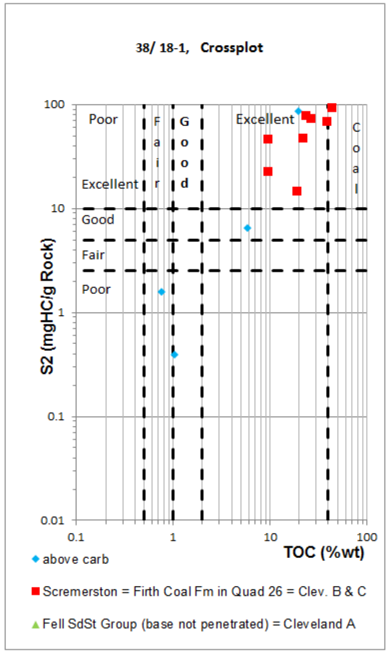


Figure 38/18-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 38/18-1.









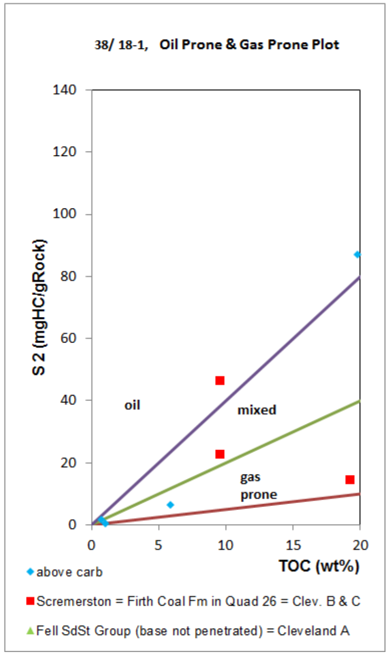


Figure 38/22-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 38/22-1.

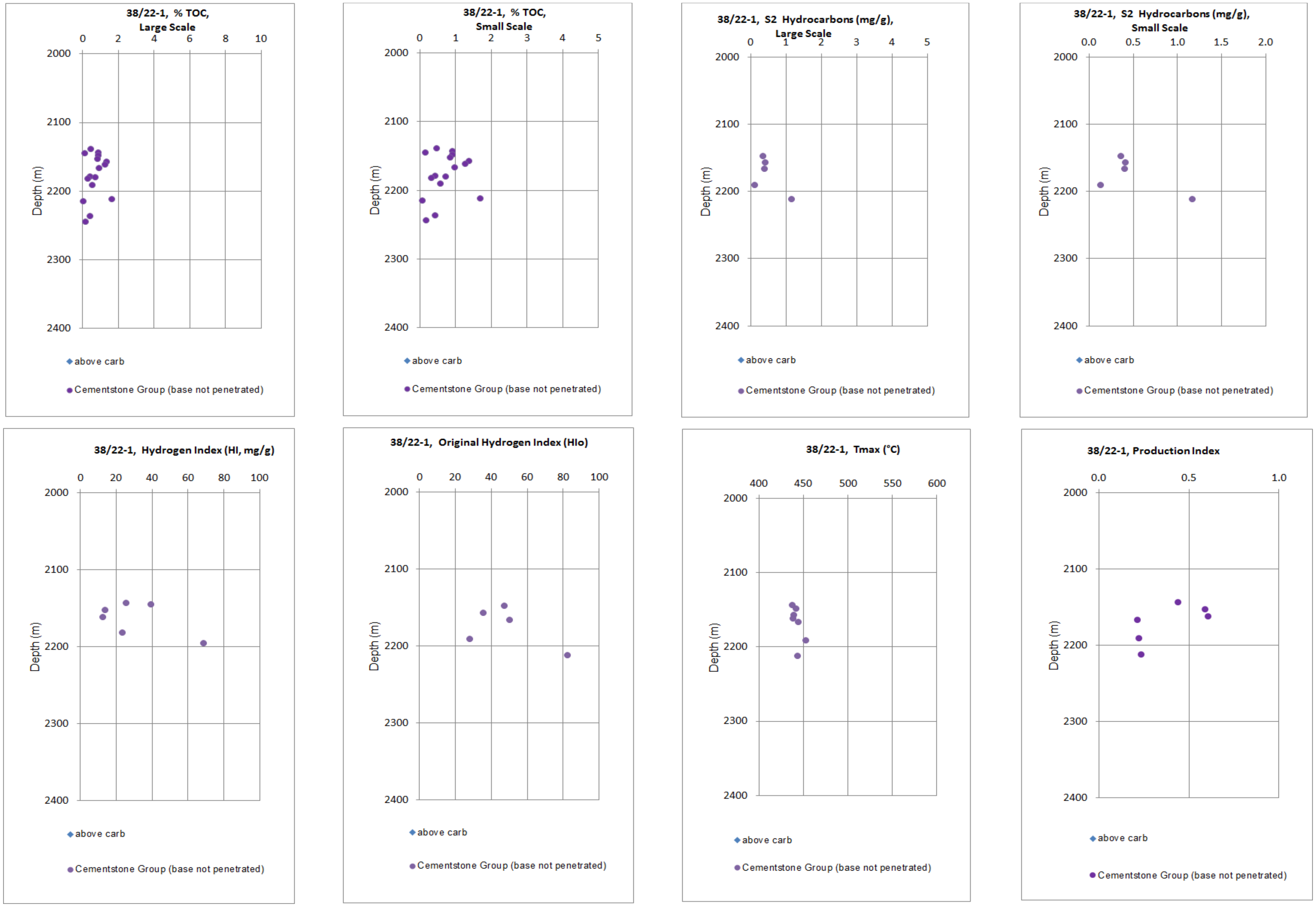


Figure 38/22-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 38/22-1.

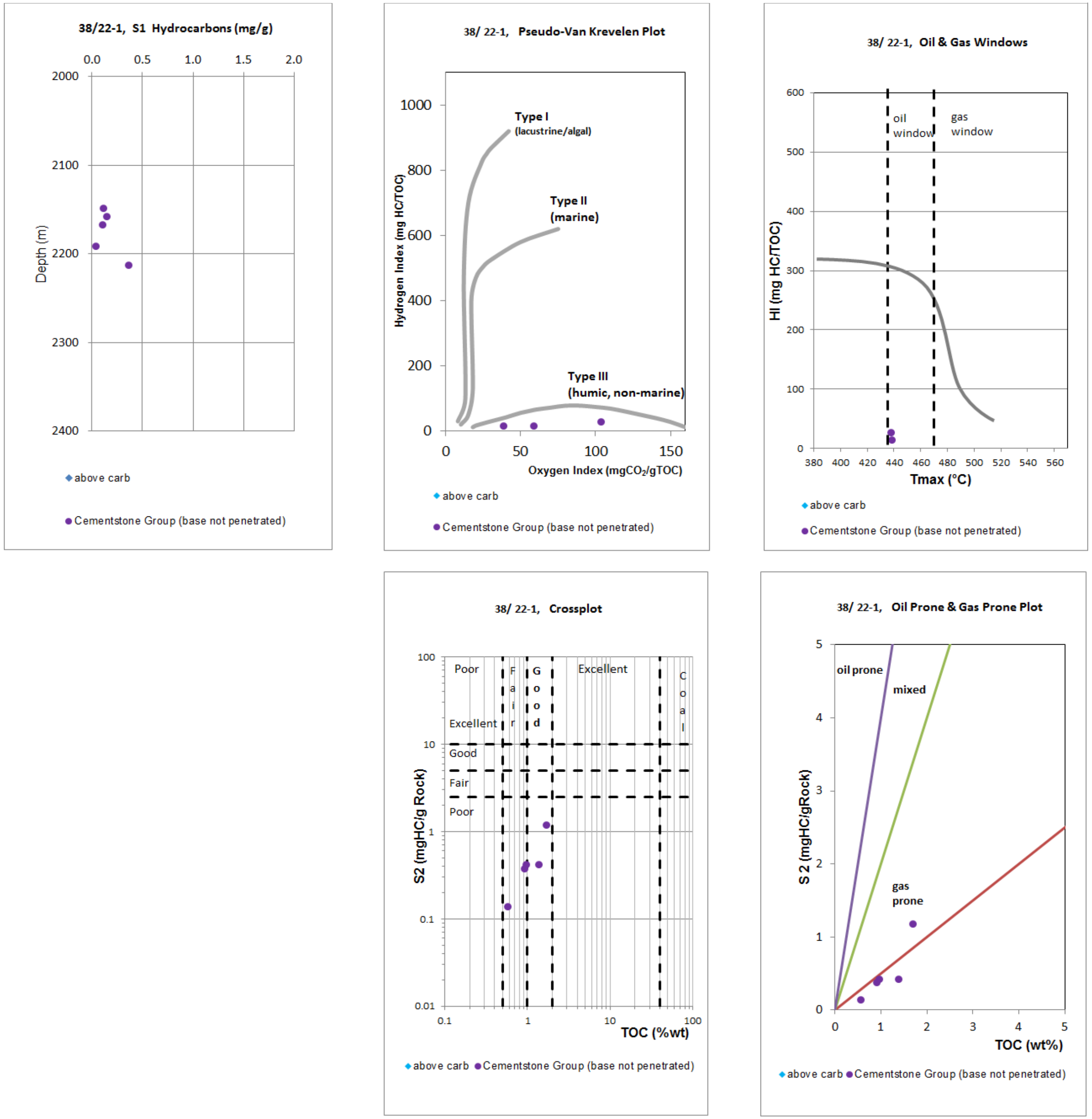


Figure 39/07-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 39/07-1.

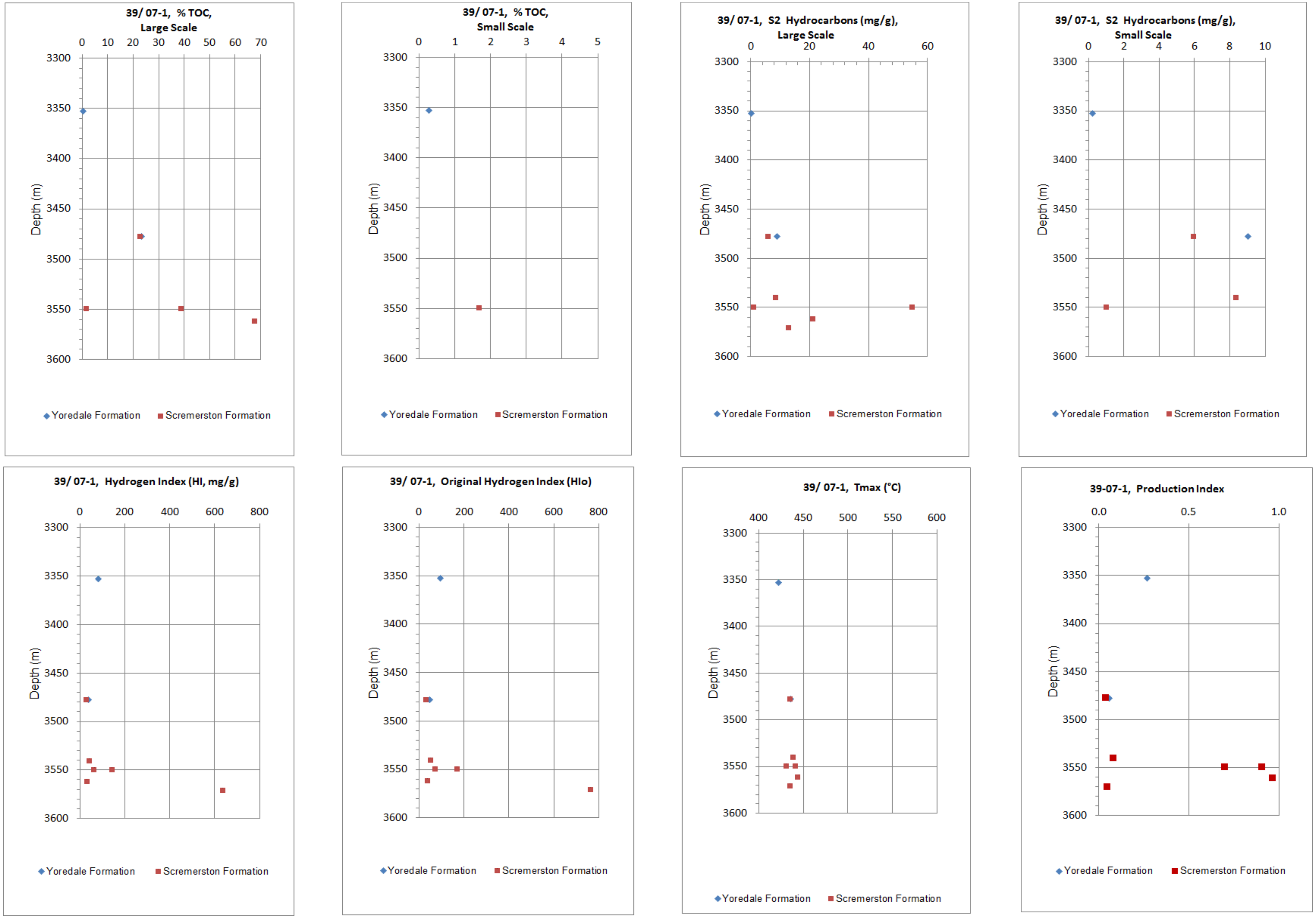


Figure 39/07-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 39/07-1.

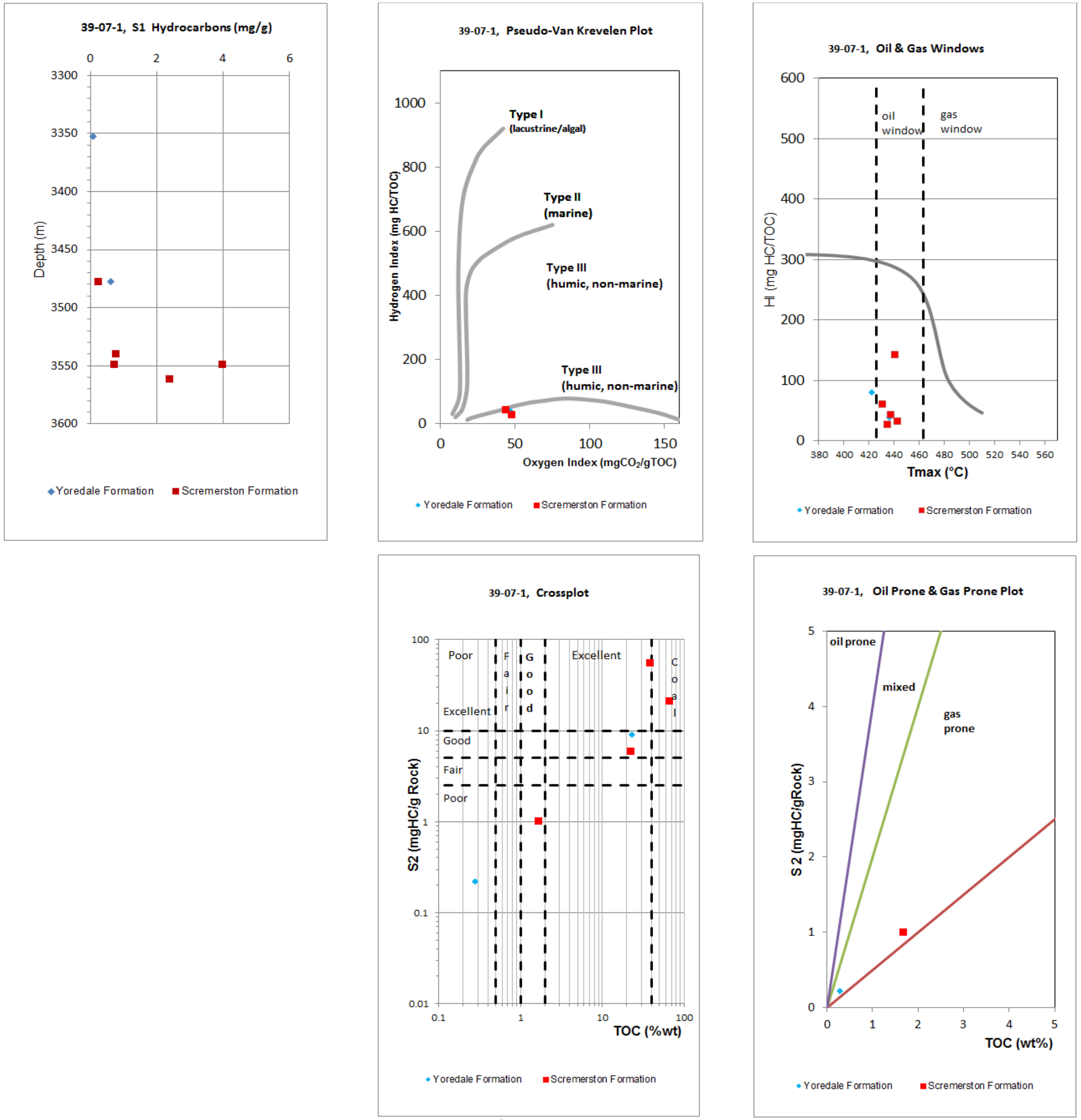


Figure 41/01-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 41/01-1.

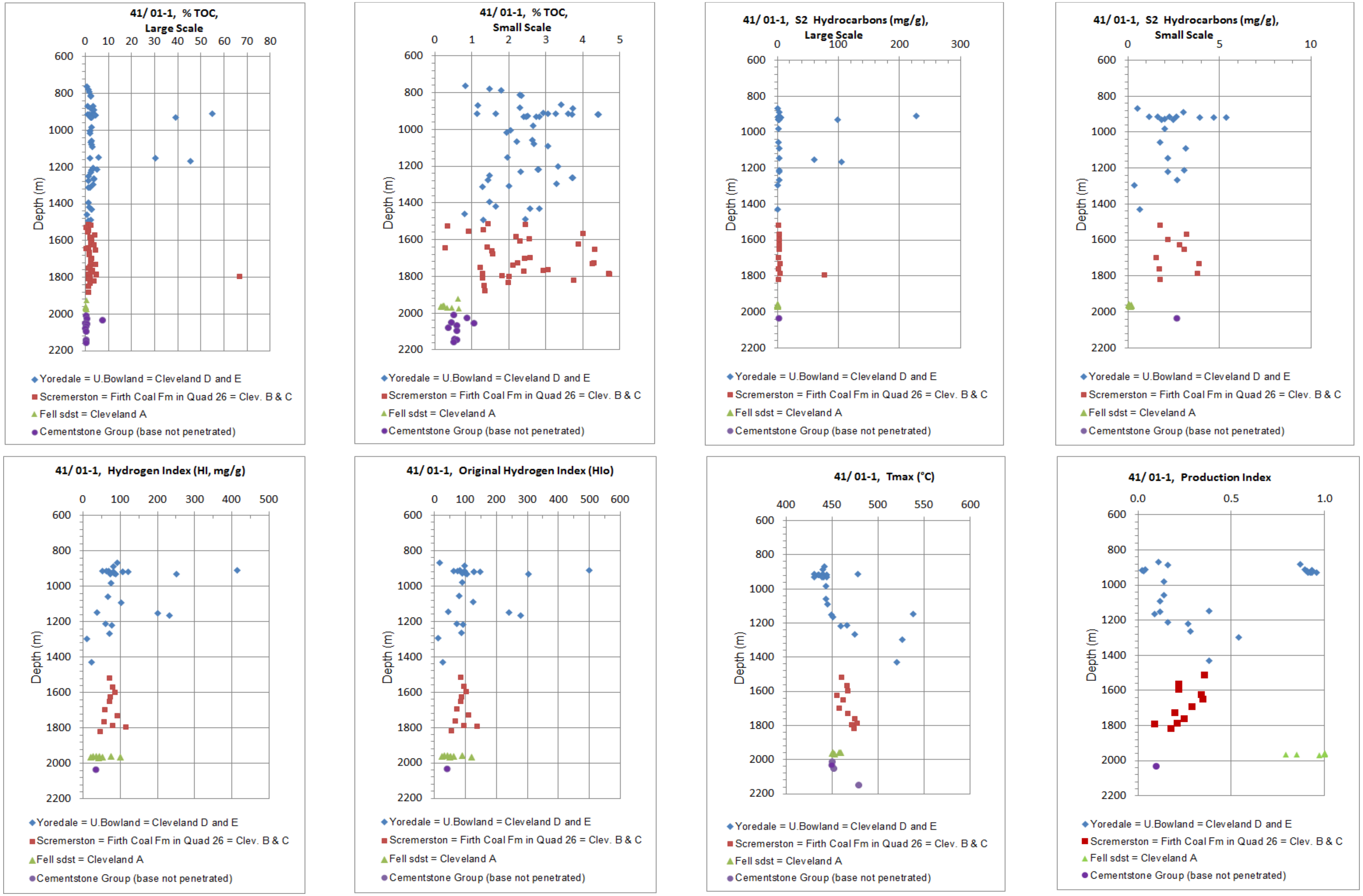


Figure 41/01-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 41/01-1.

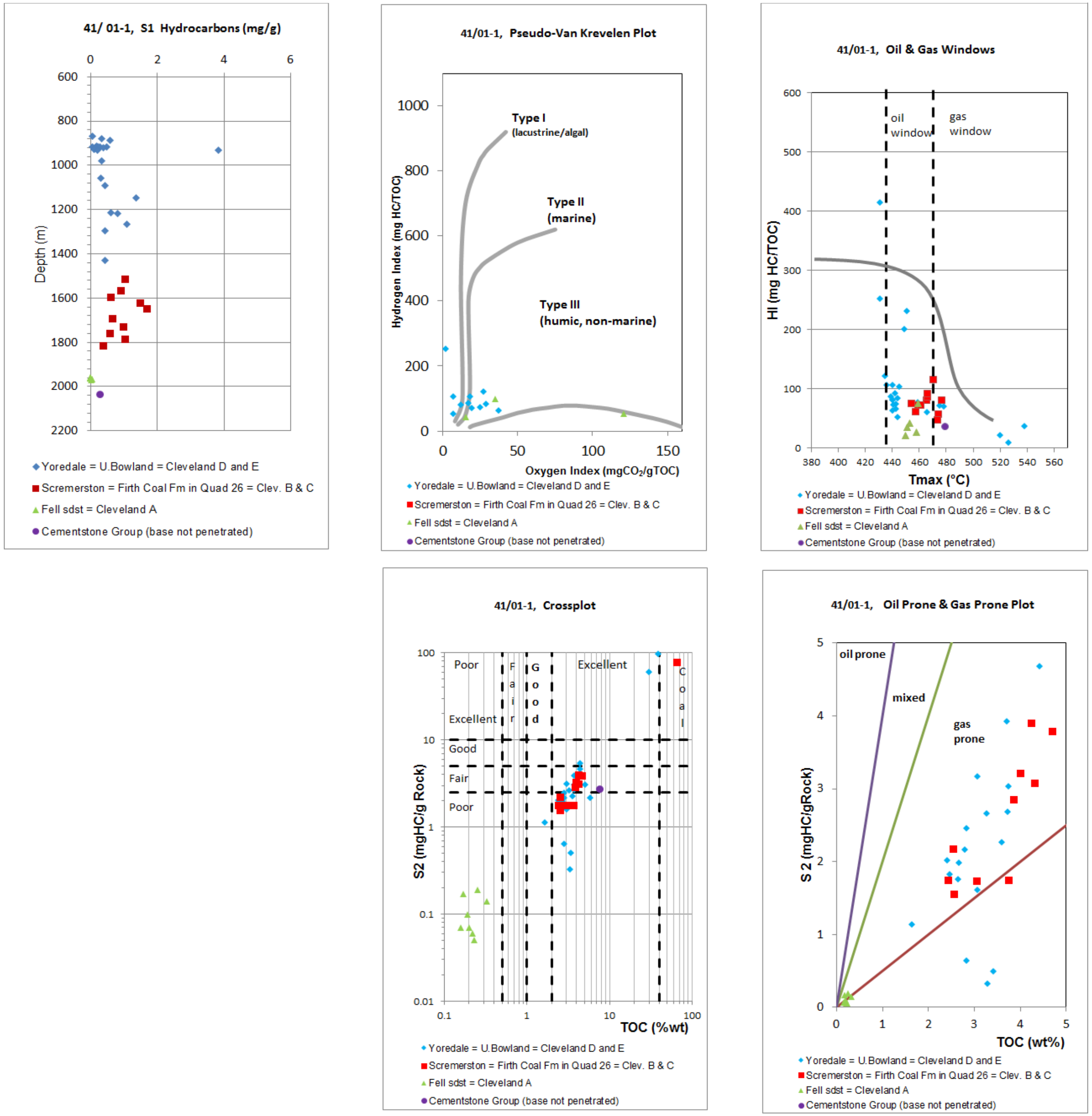


Figure 41/08-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 41/08-1.

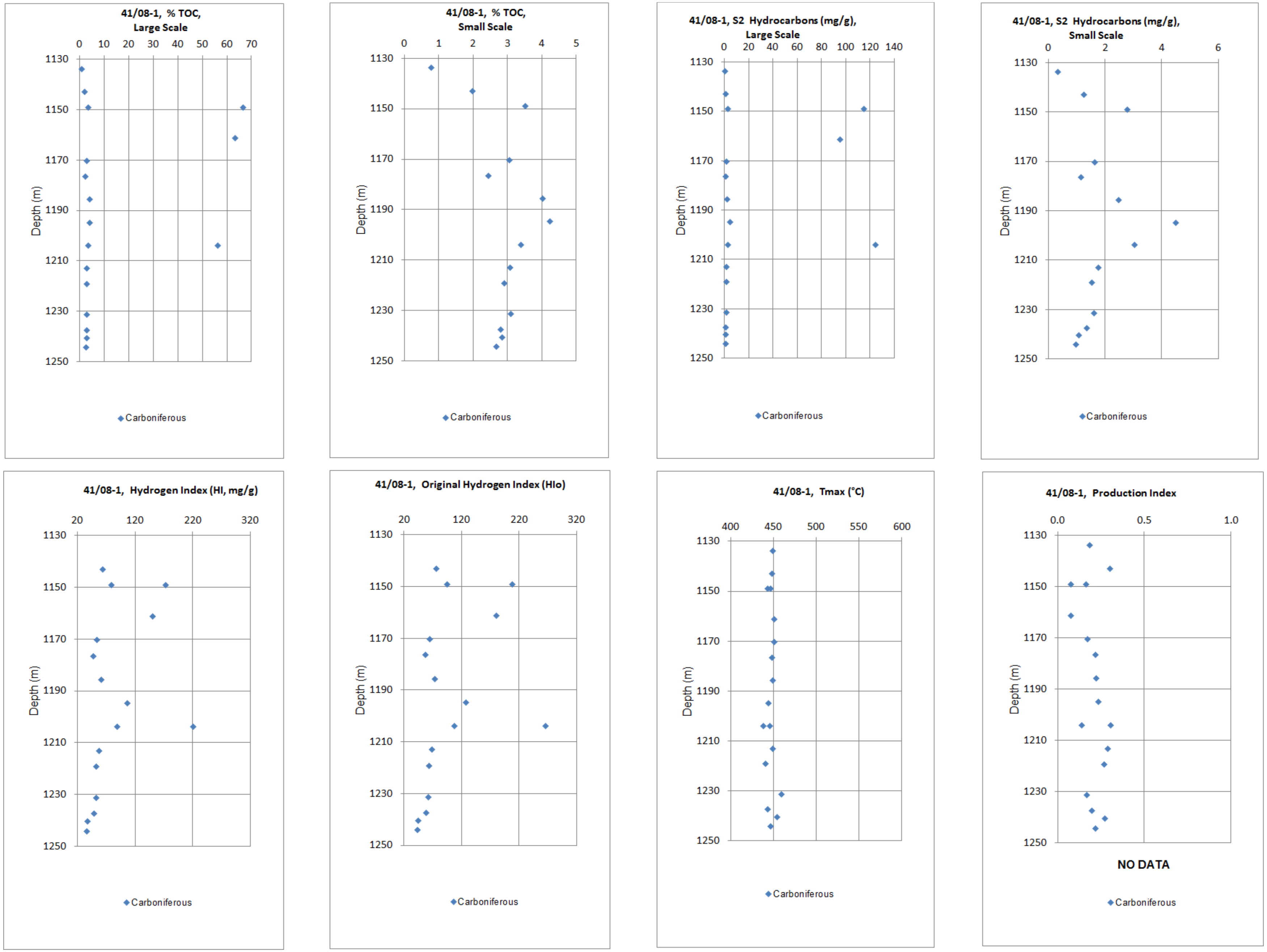
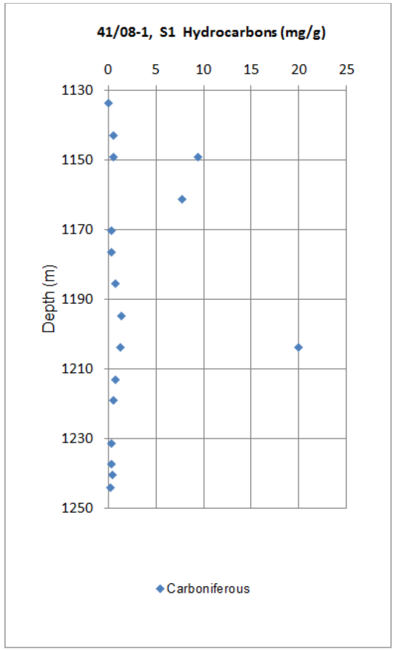
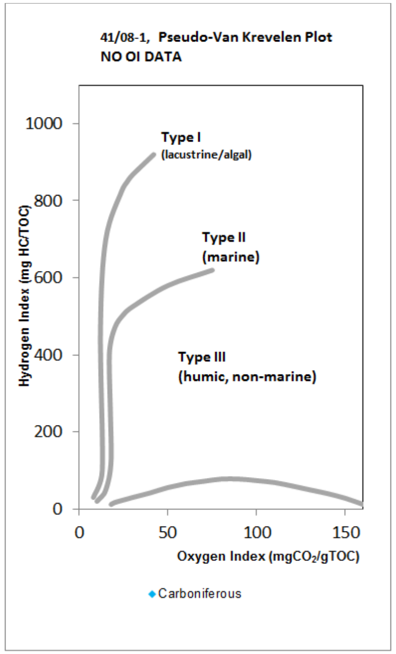
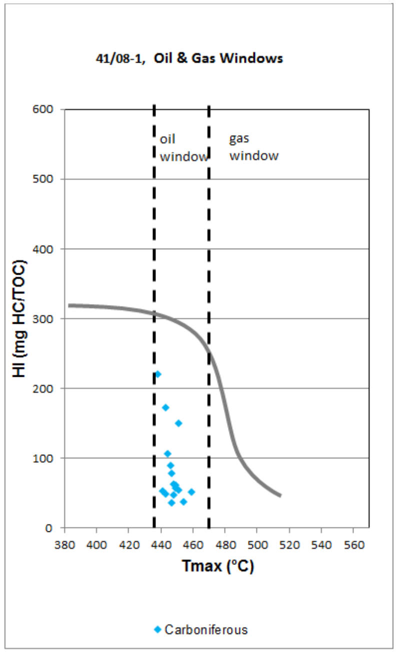
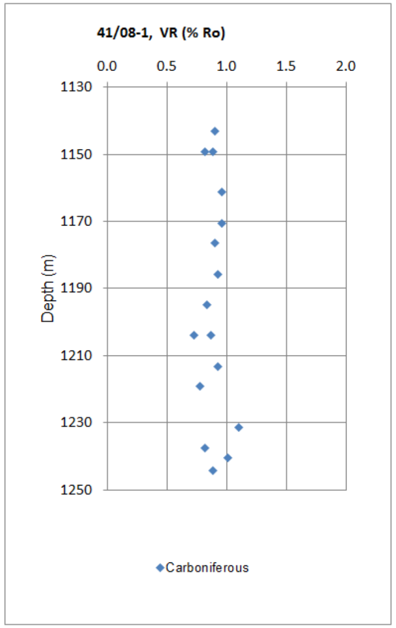


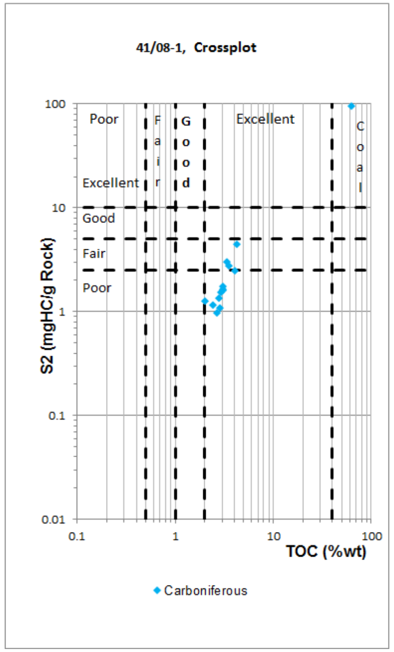
Figure 41/08-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, VR, S2 vs TOC plot, and oil prone and gas prone plot for well 41/08-1.











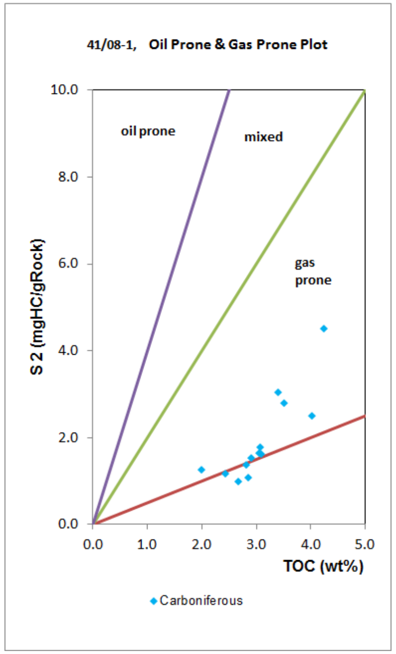


Figure 41/10-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 41/10-1.

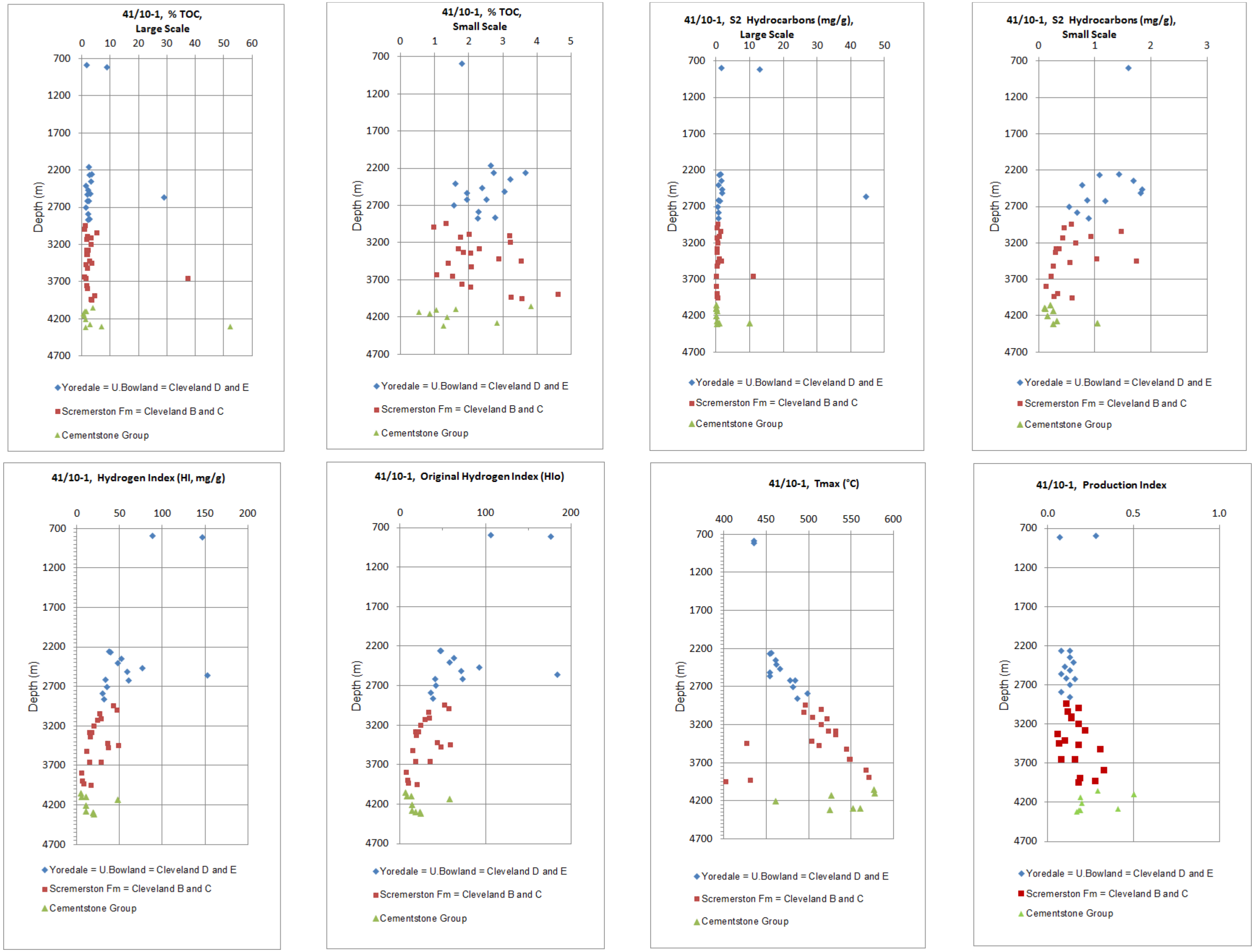


Figure 41/10-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 41/10-1.

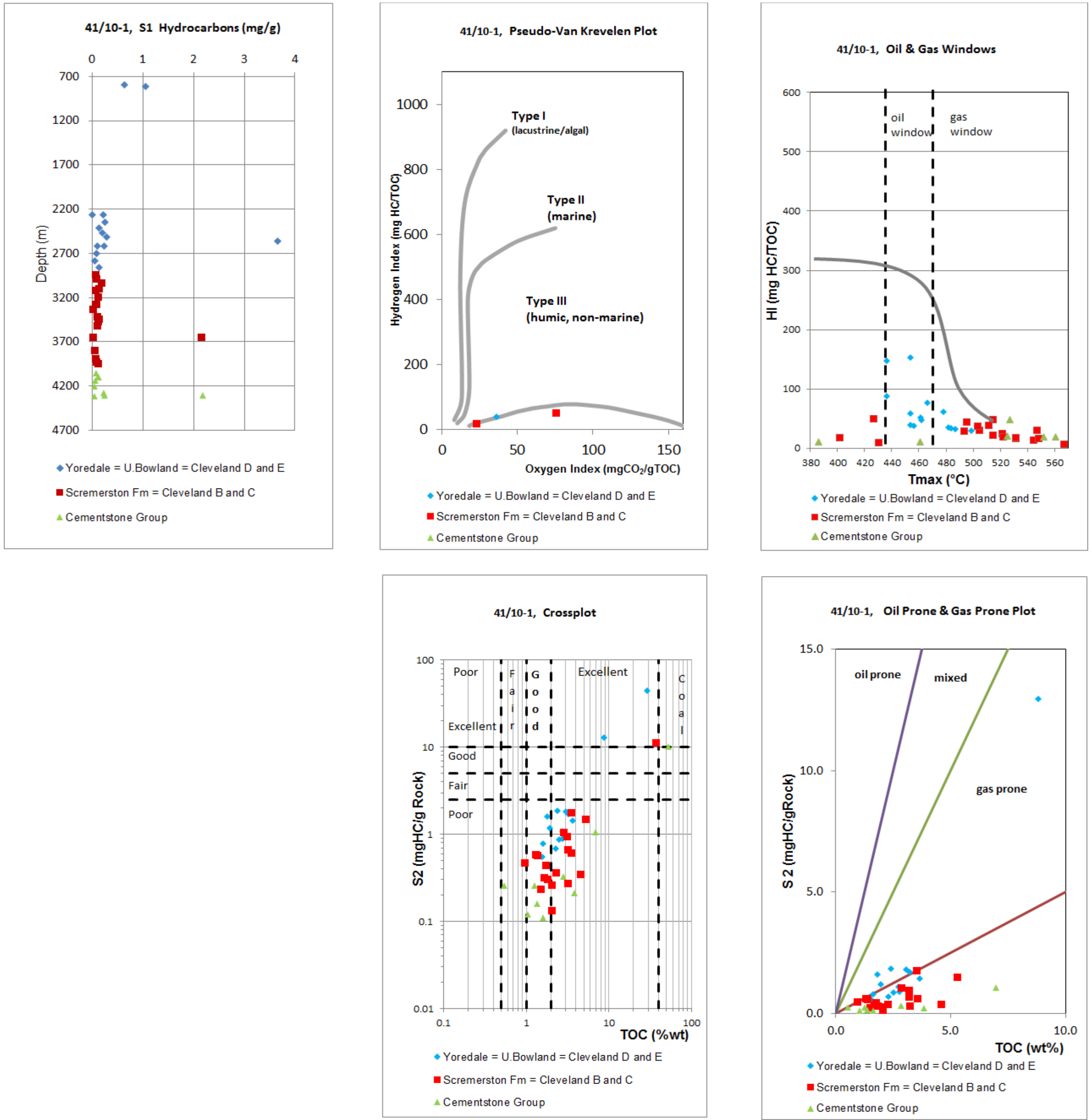


Figure 41/14-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 41/14-1.

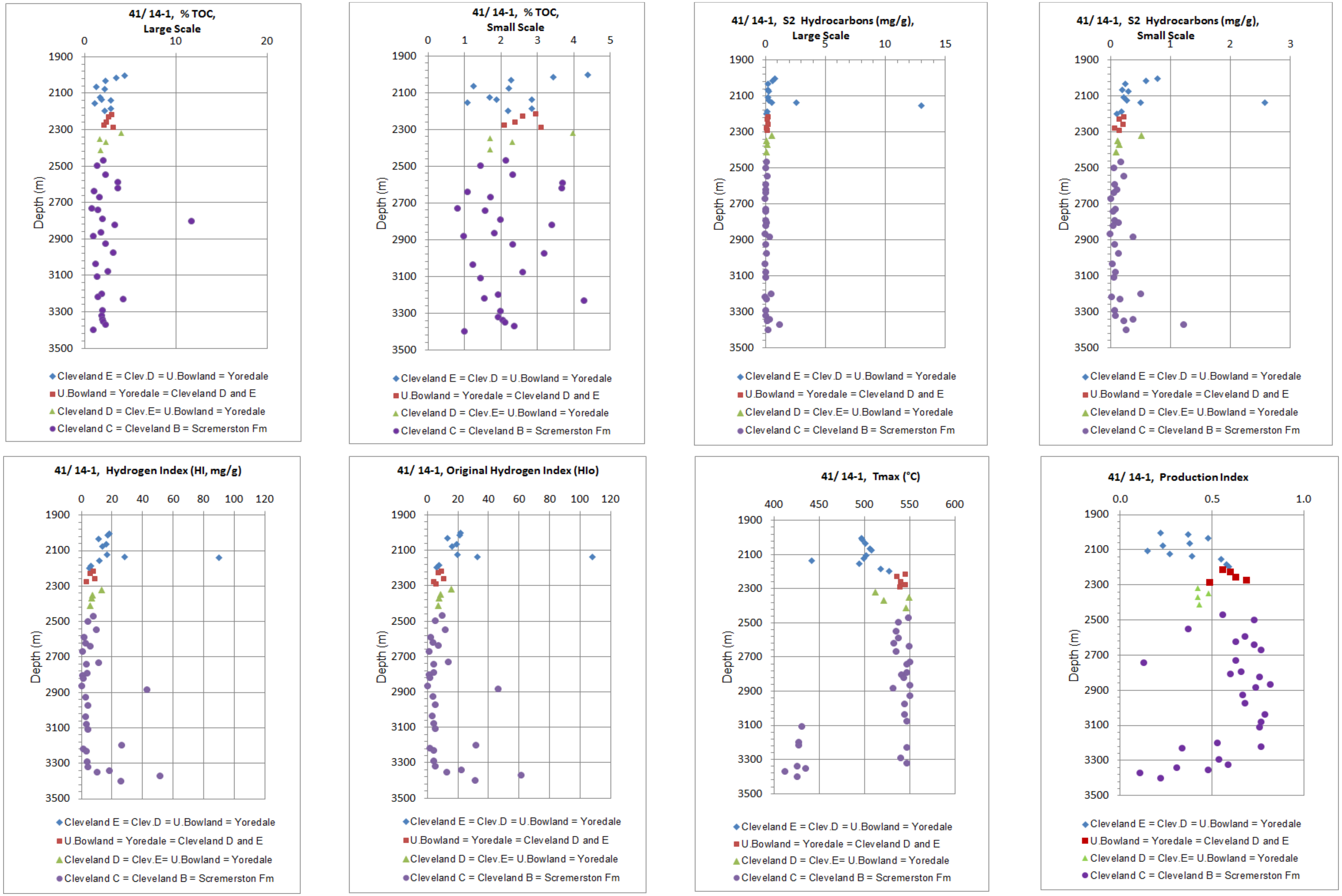


Figure 41/14-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 41/14-1.

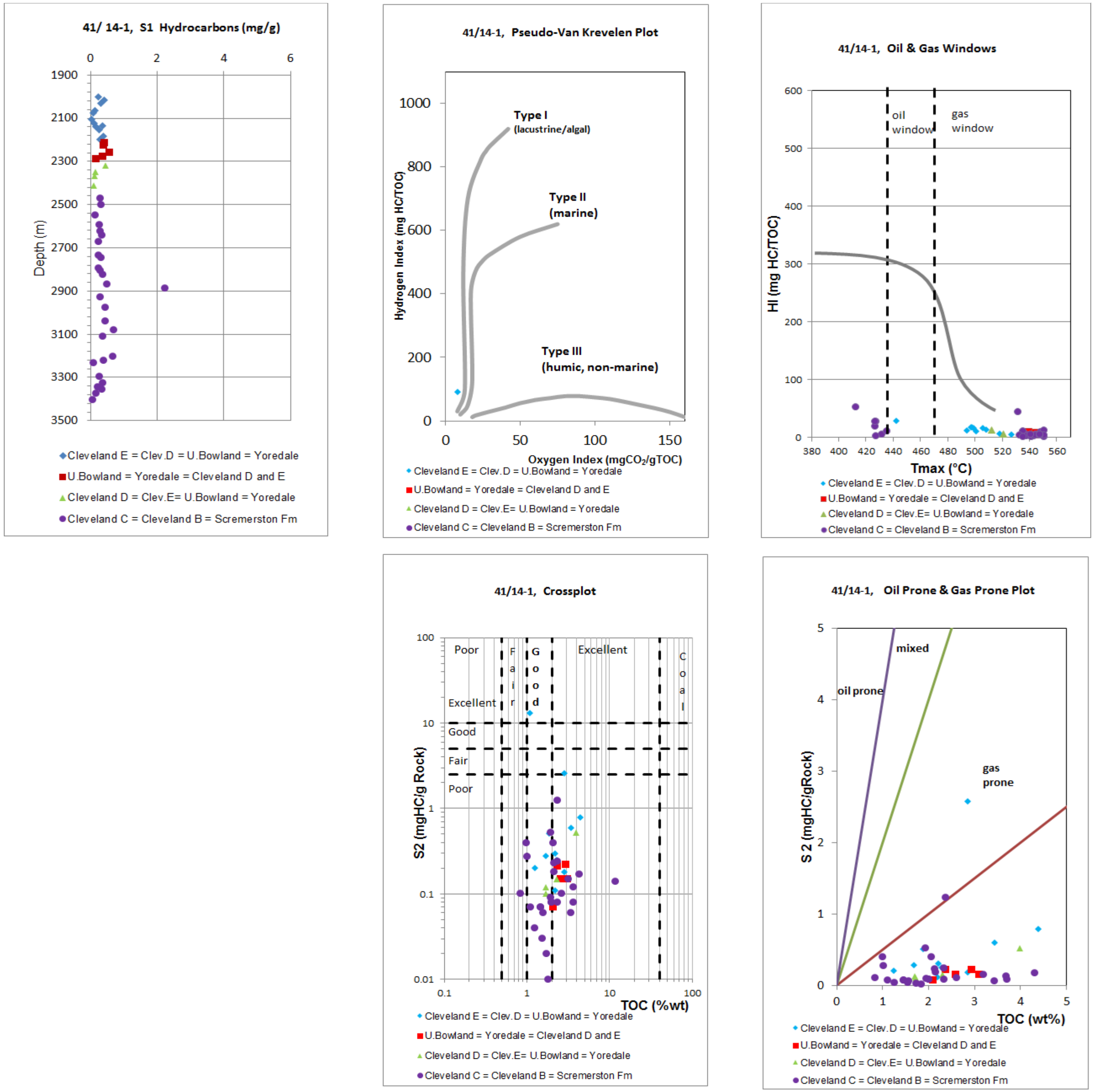


Figure 41/15-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 41/15-1.

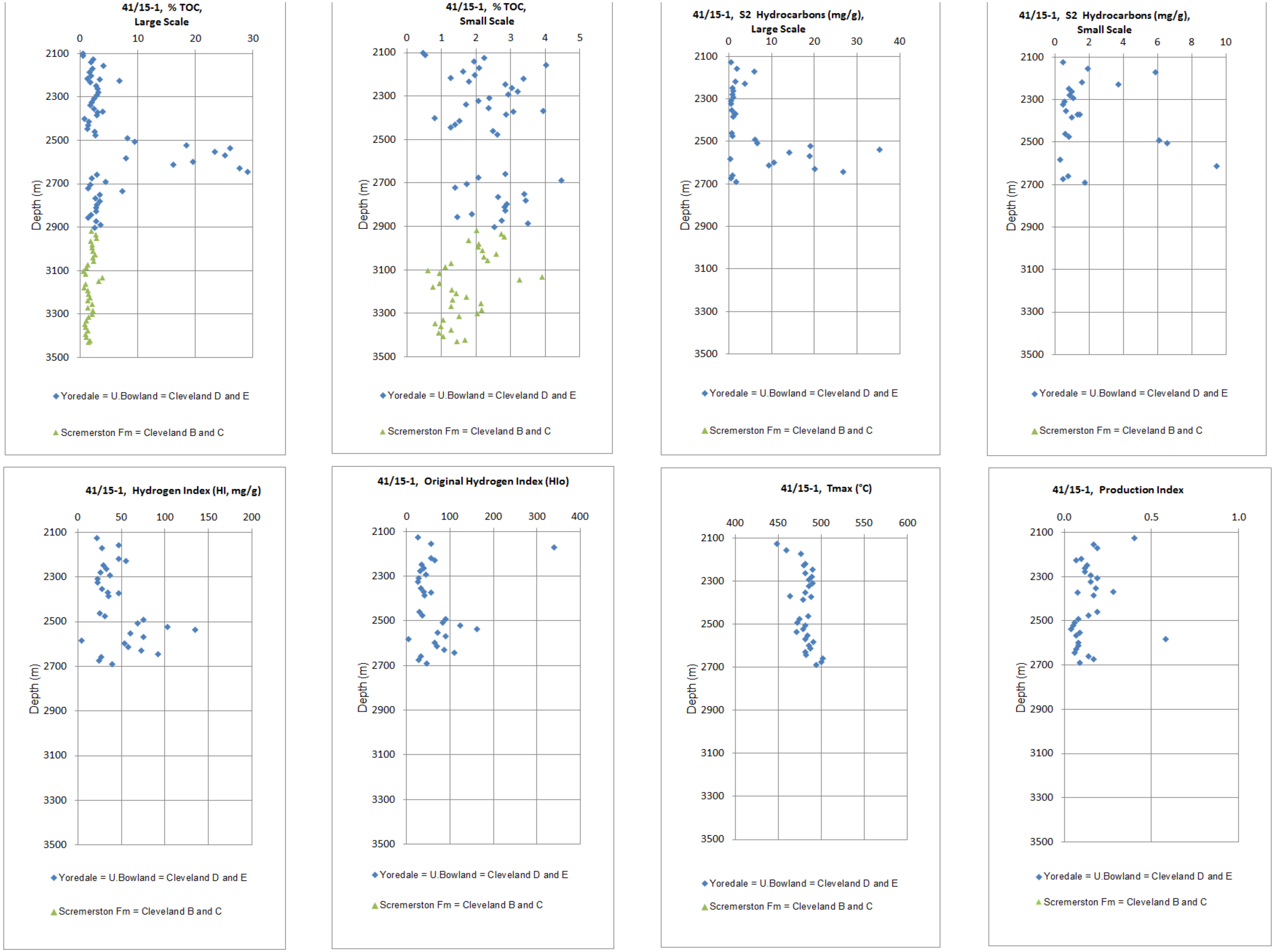


Figure 41/15-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 41/15-1.

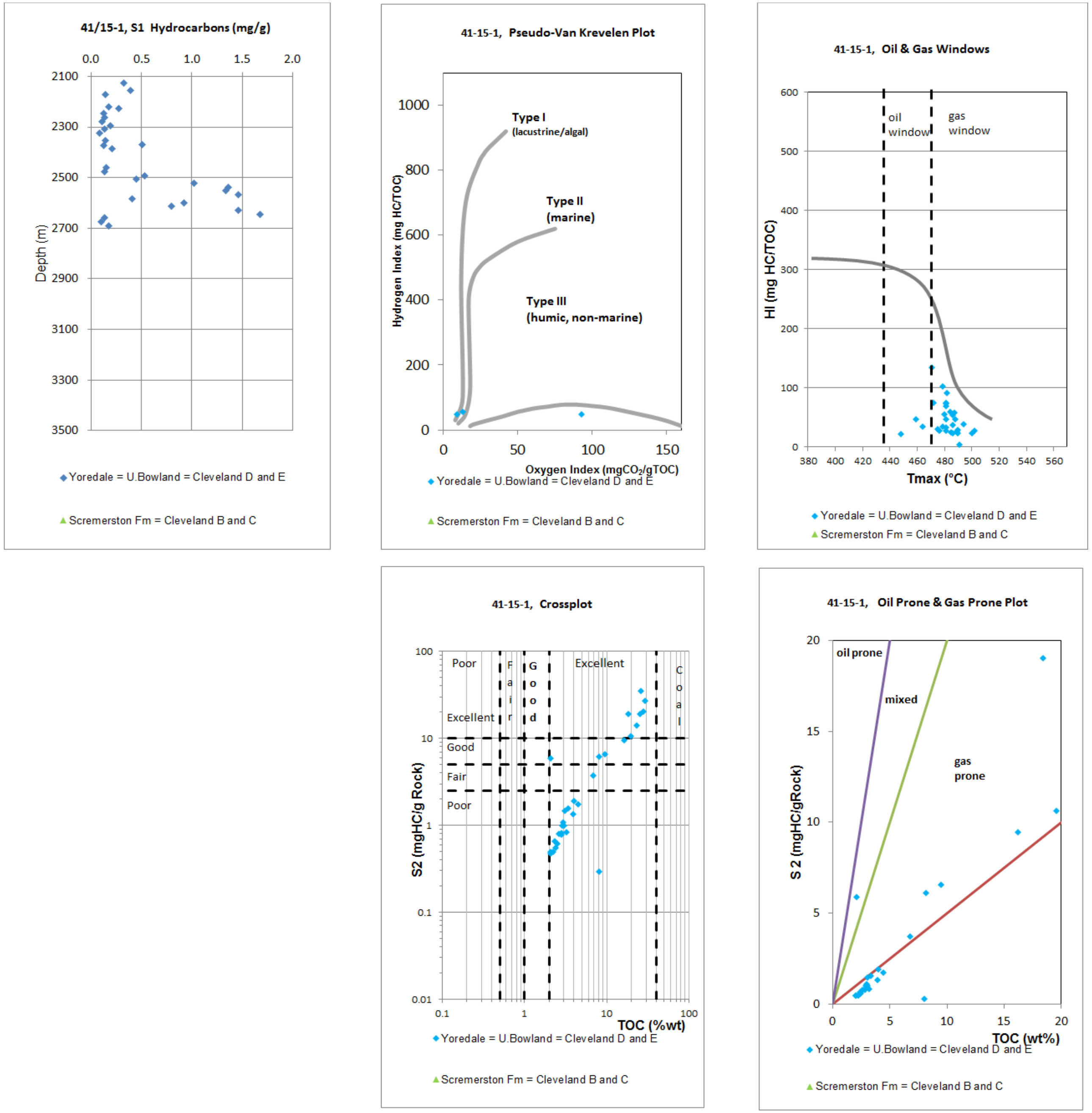


Figure 41/20-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 41/20-1.

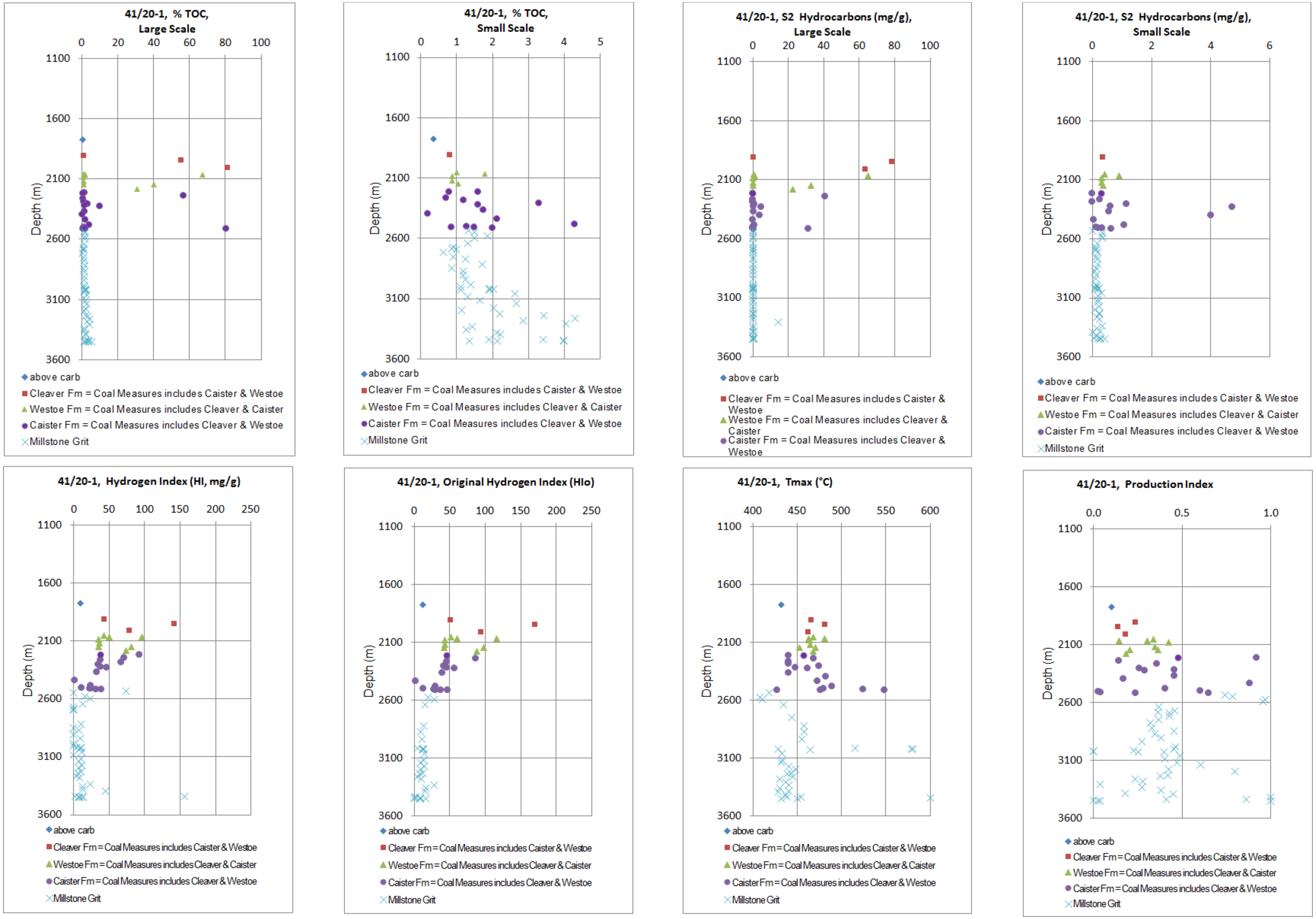


Figure 41/20-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 41/20-1.

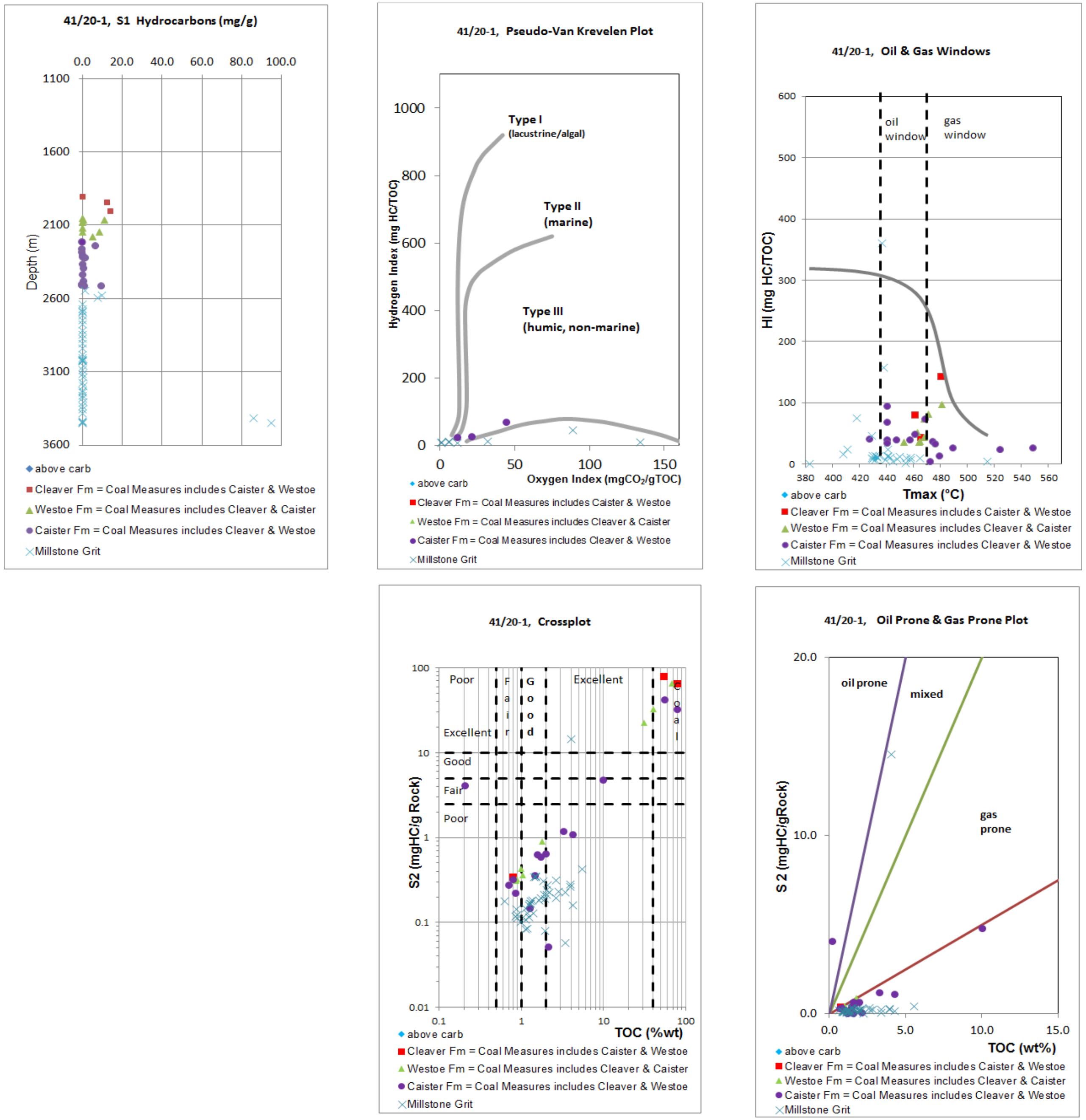


Figure 41/24a-2 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 41/24a-2.

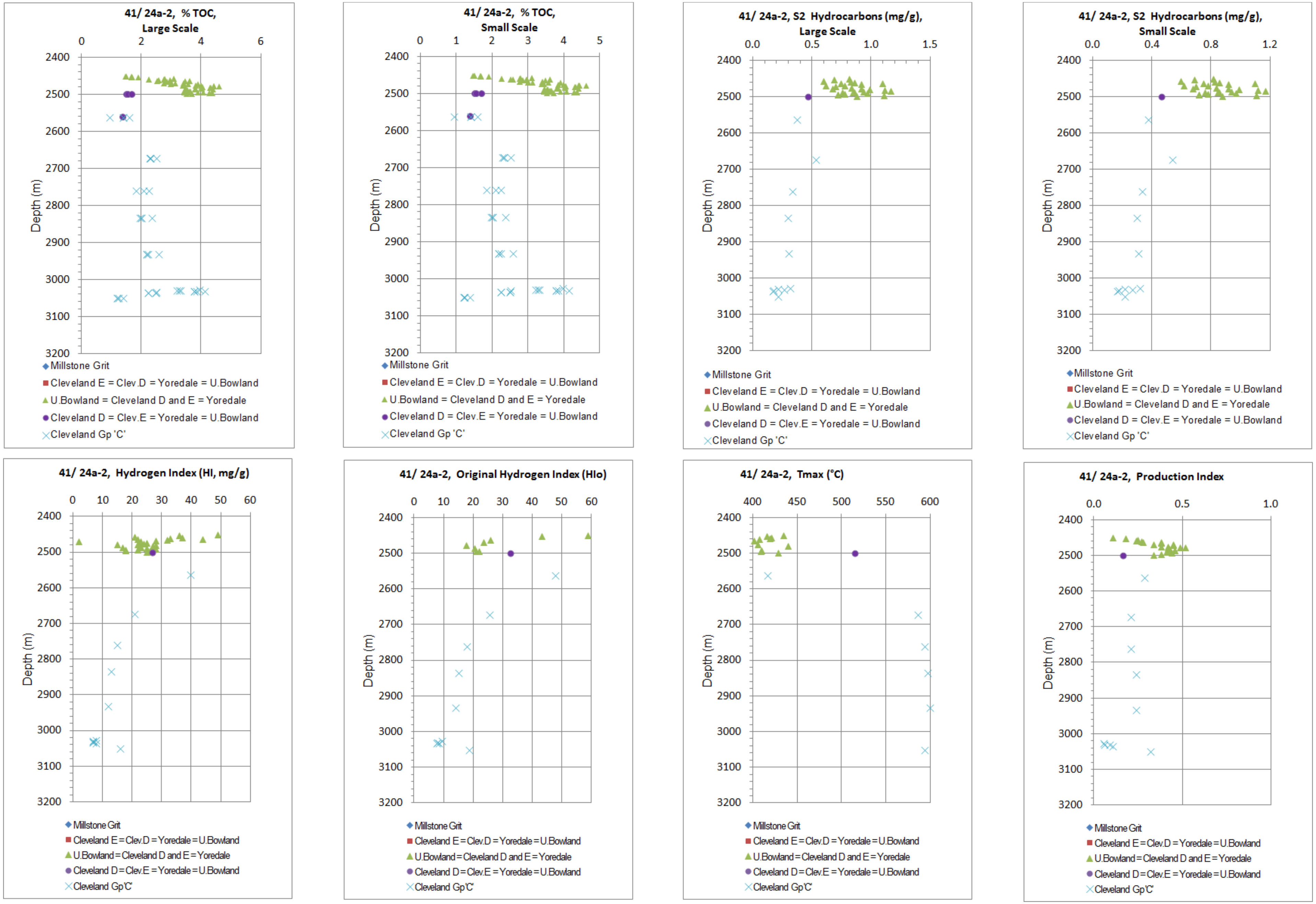


Figure 41/24a-2 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 41/24a-2.

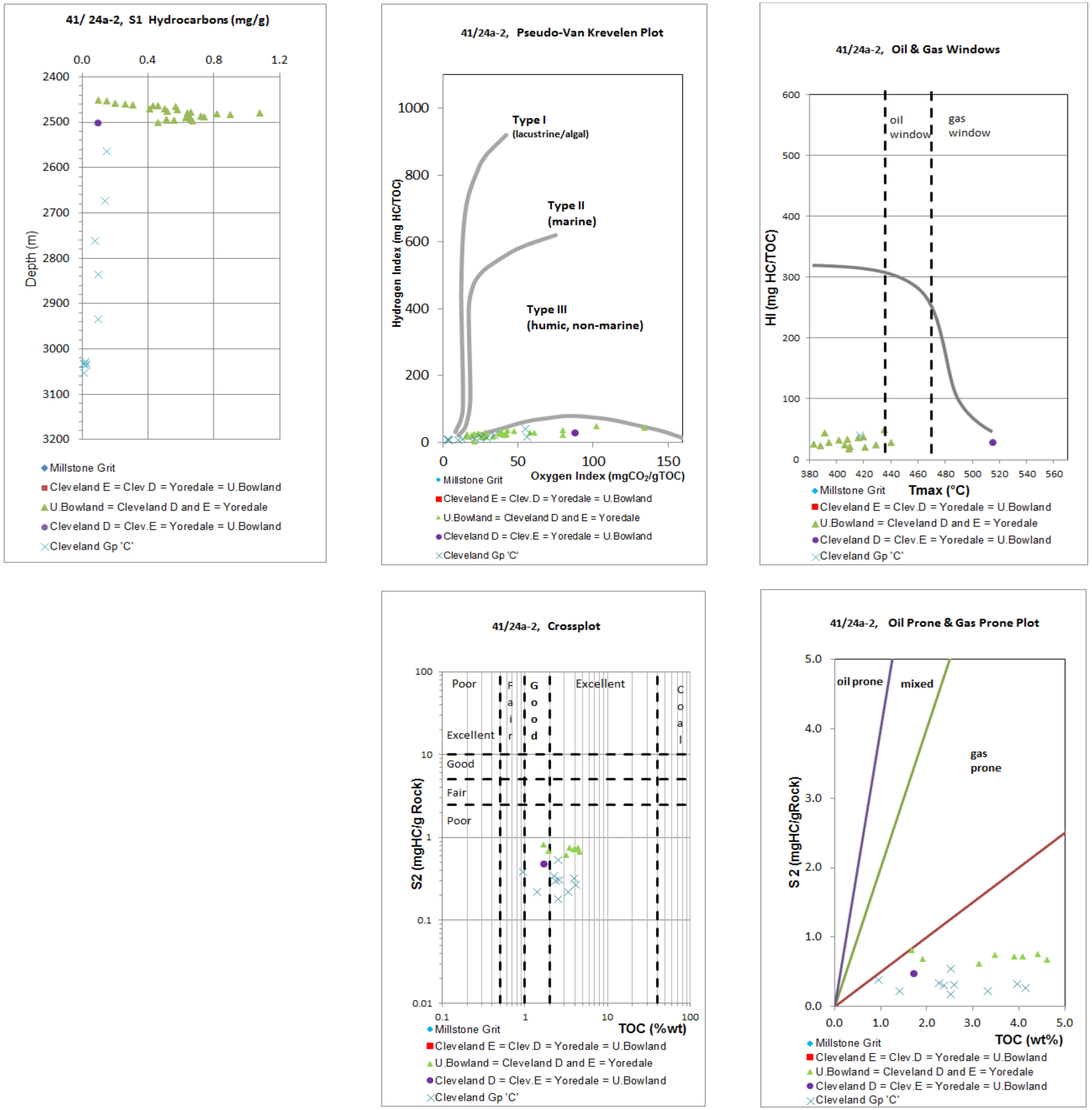
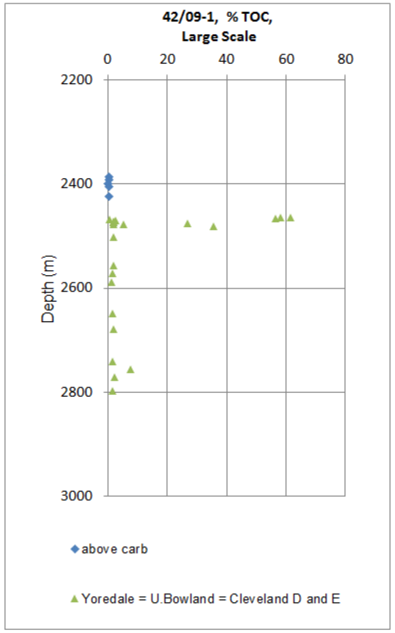
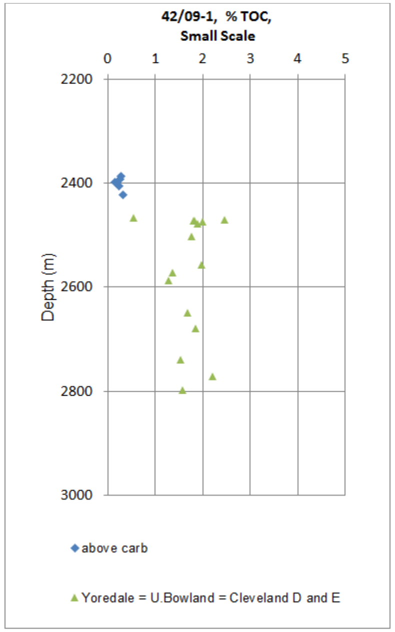
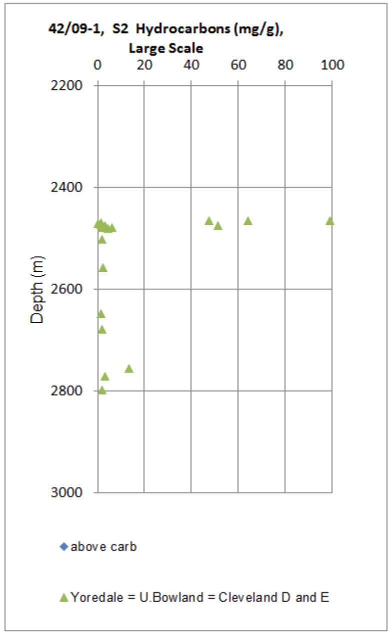
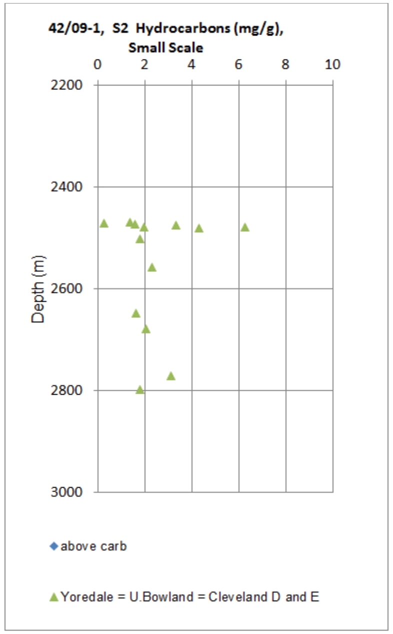


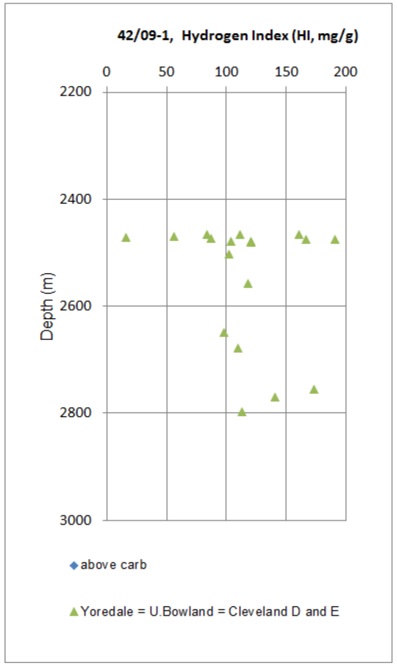
Figure 42/09-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 42/09-1.

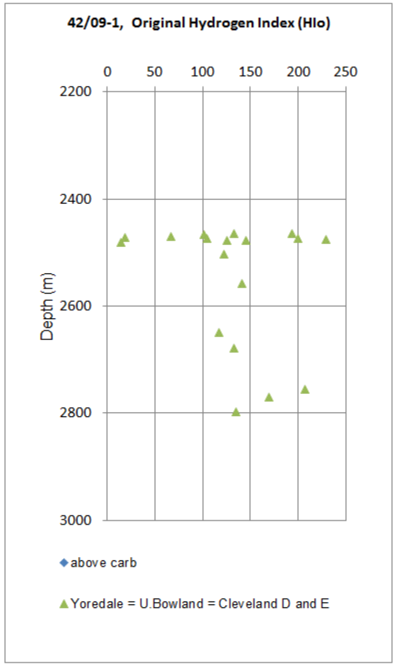


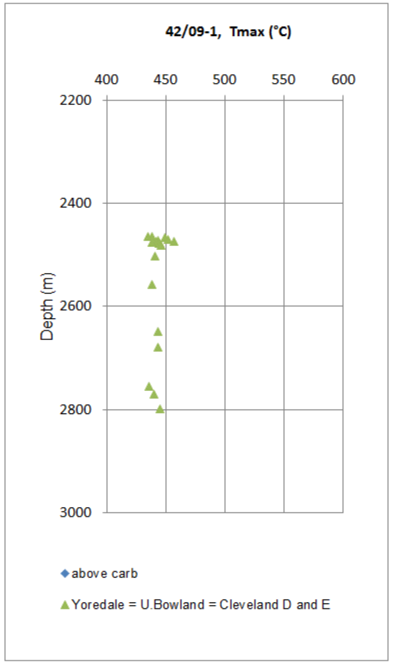












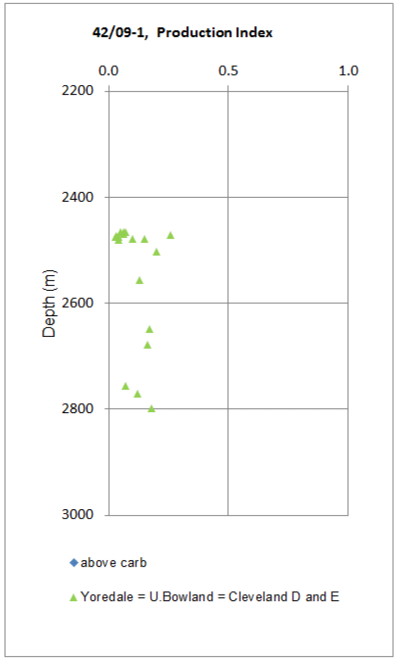


Figure 42/09-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 42/09-1.

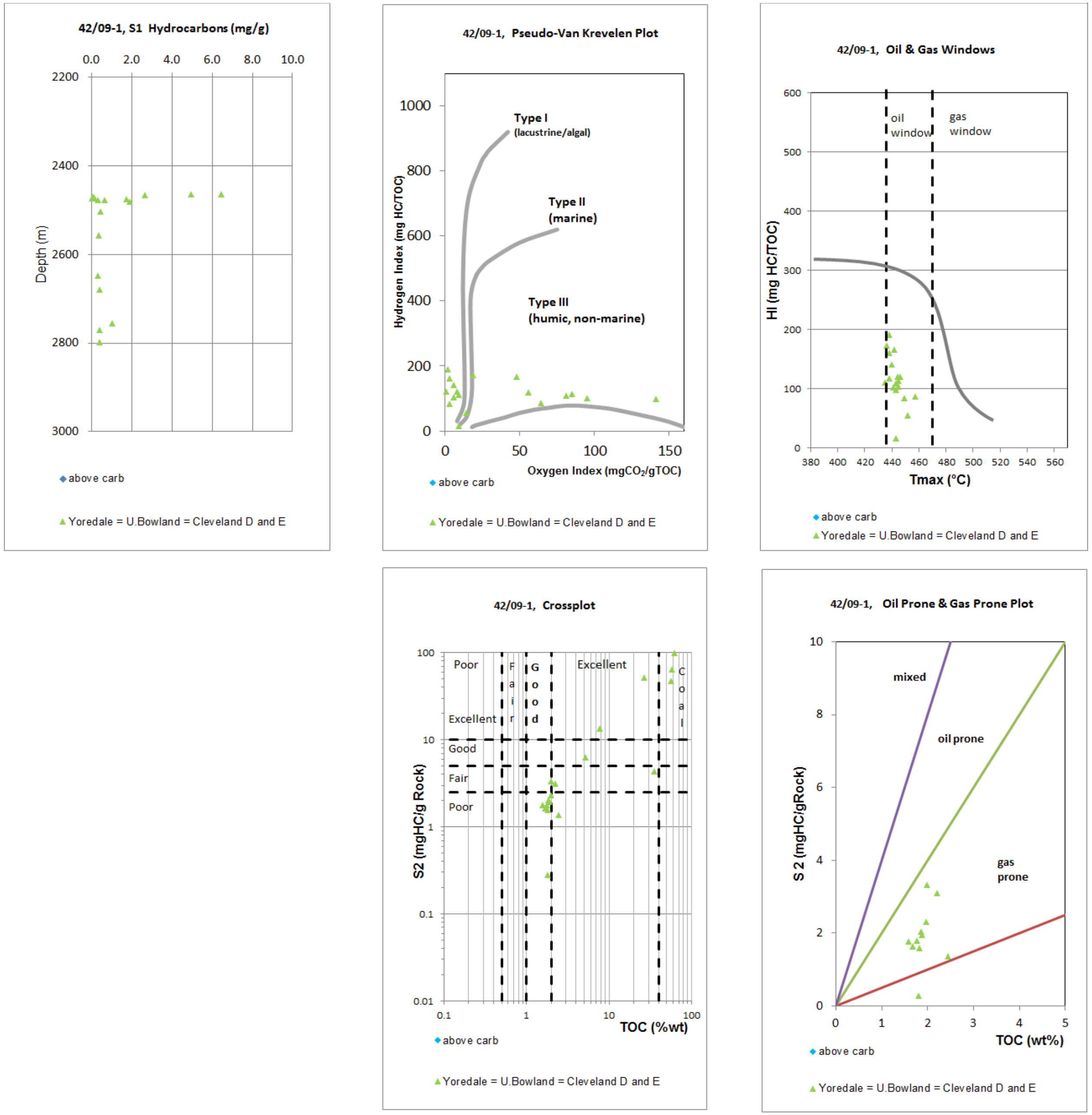


Figure 42/10a-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 42/10a-1.

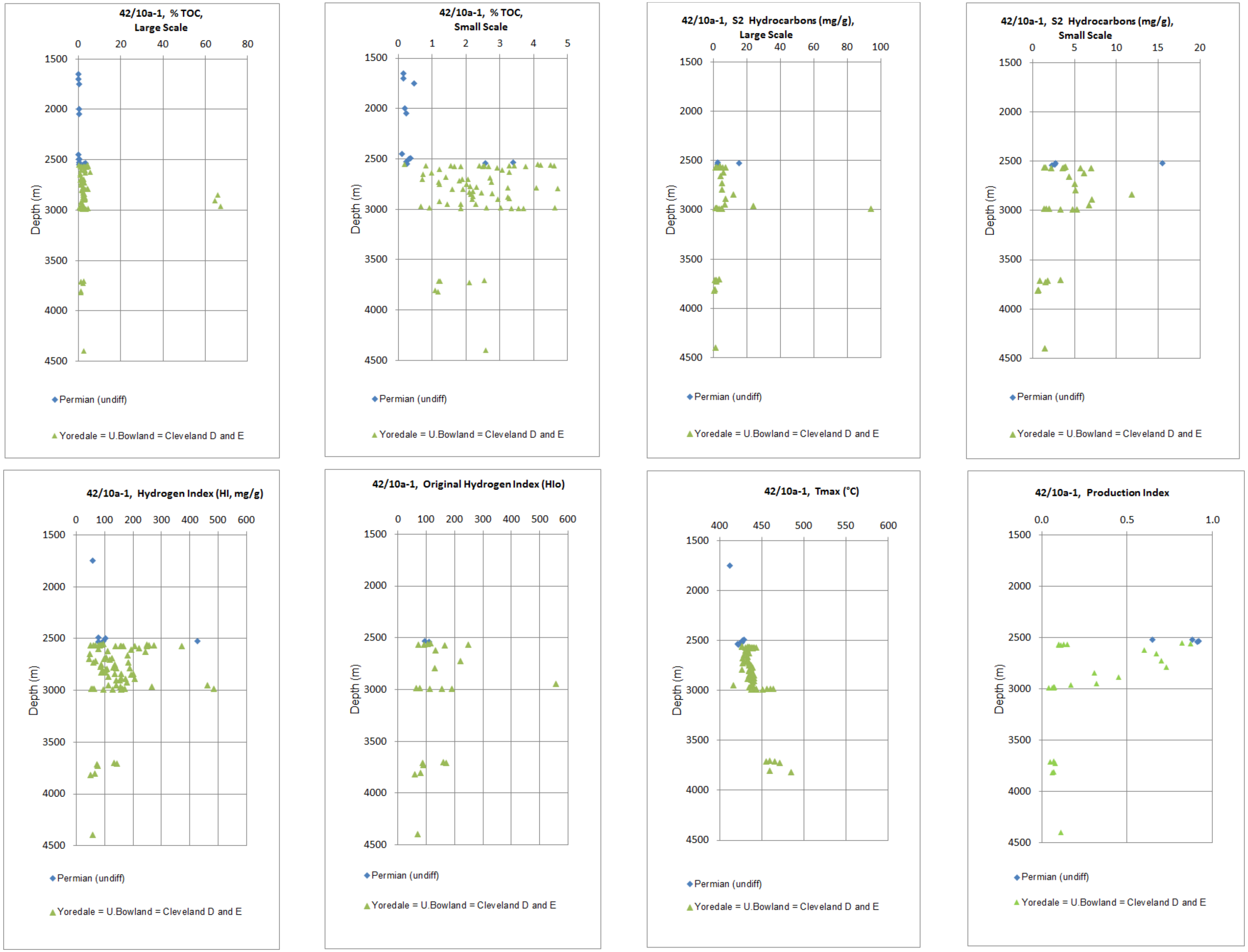


Figure 42/10a-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 42/10a-1.

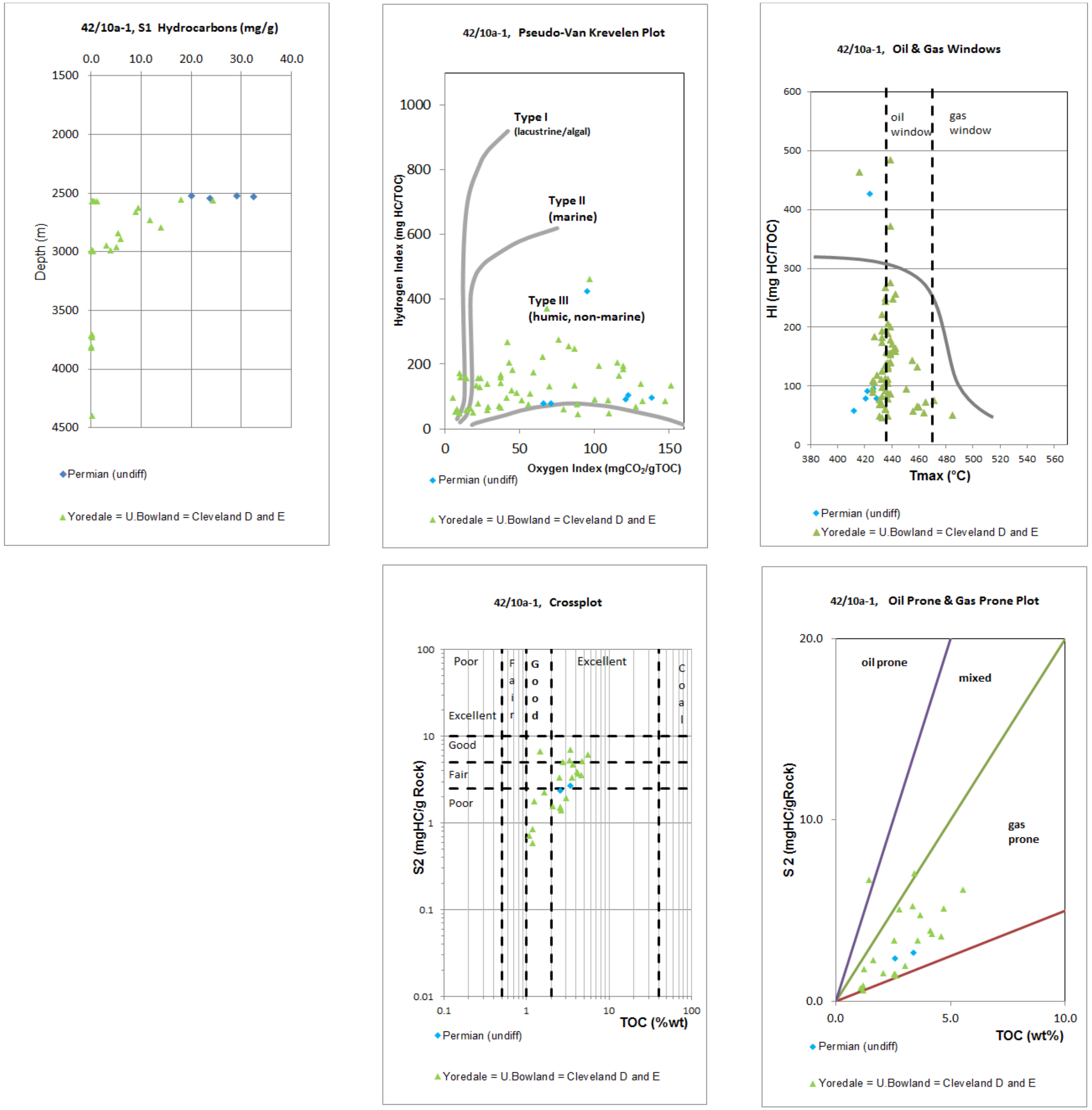


Figure 42/10b-2 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 42/10b-2.

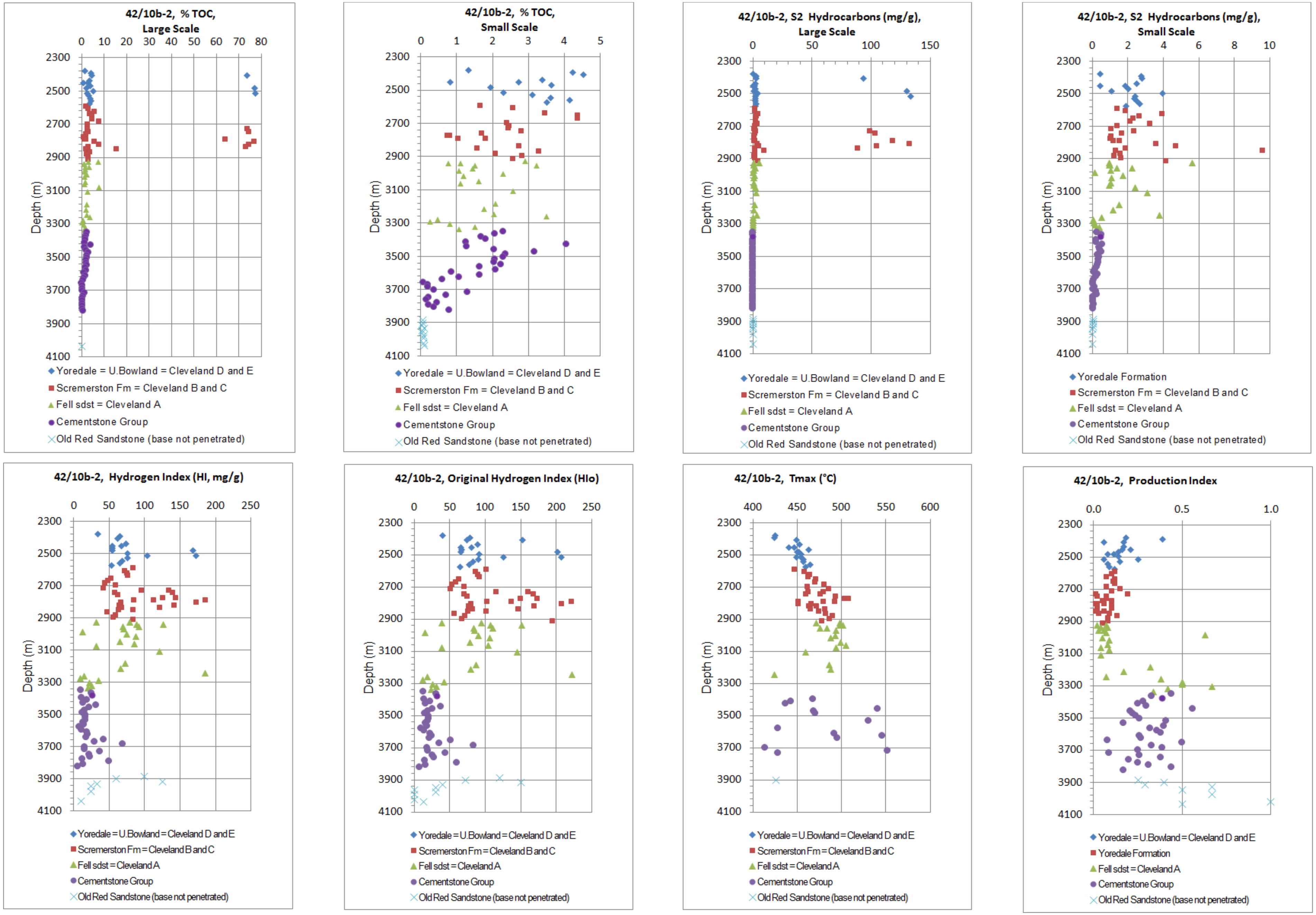


Figure 42/10b-2 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 42/10b-2.

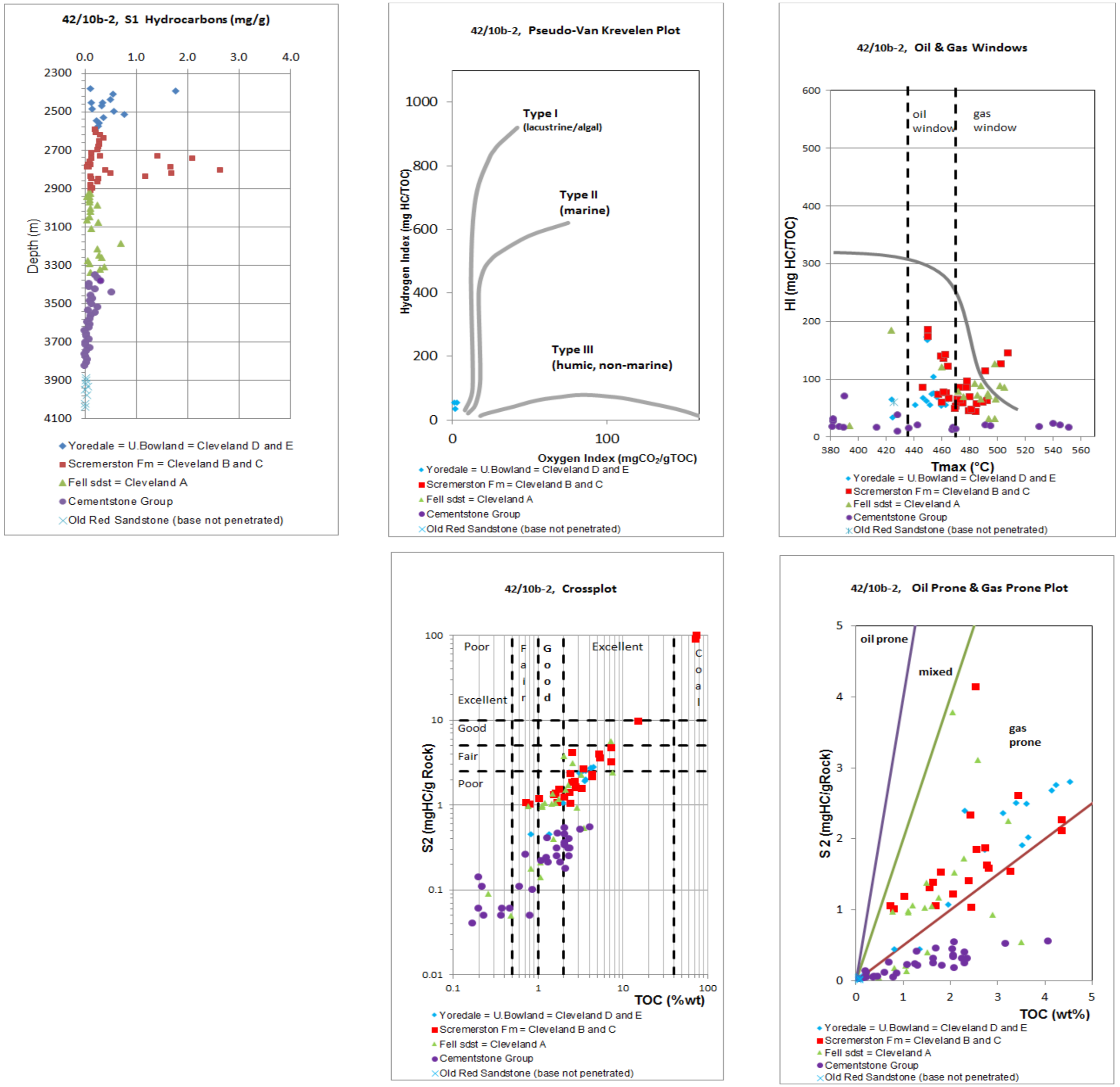


Figure 42/10b-2ST (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 42/10b-2ST.

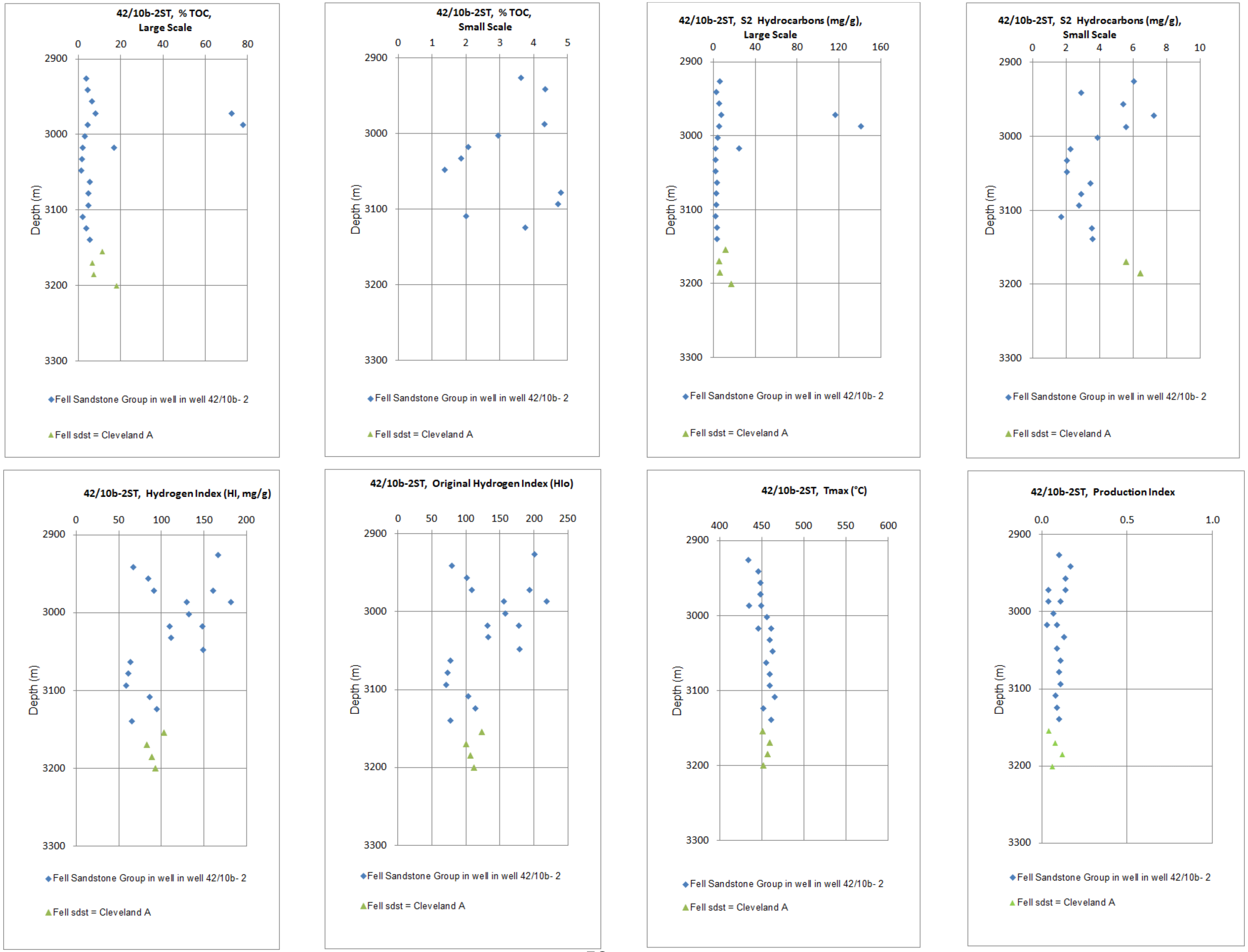


Figure 42/10b-2ST (b). S1,Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 42/10b-2ST.

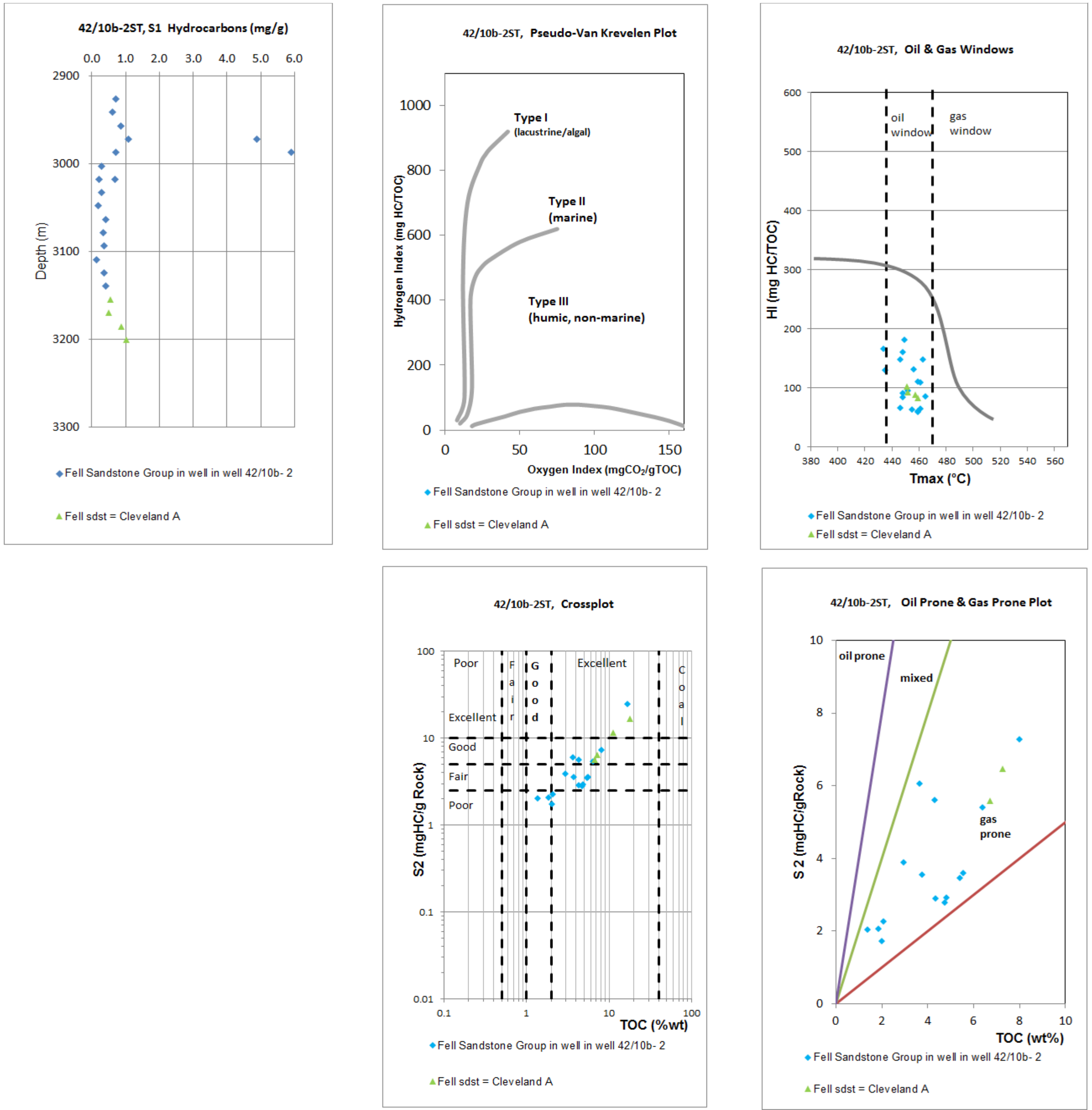


Figure 42/13-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 42/13-1.

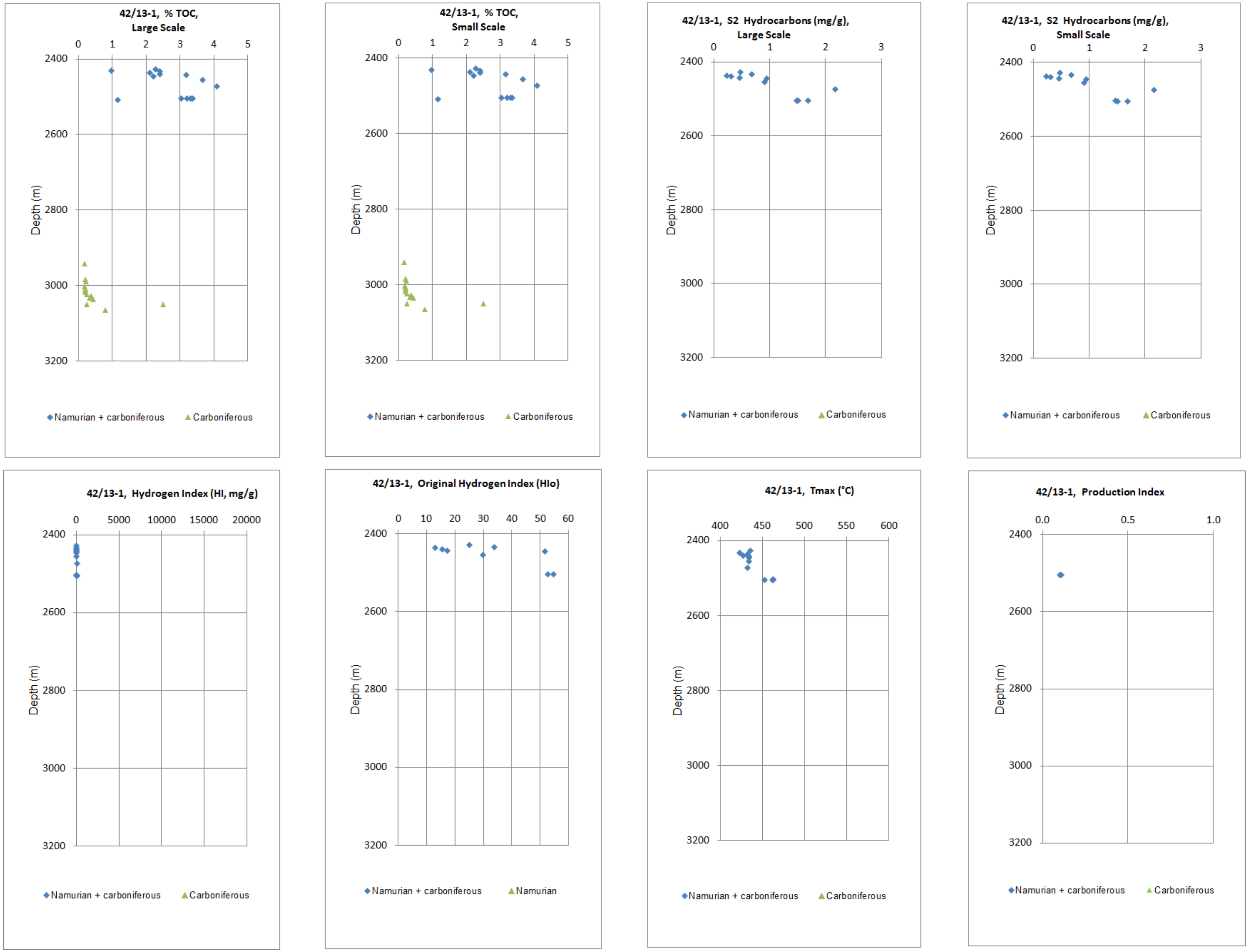


Figure 42/13-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 42/13-1.

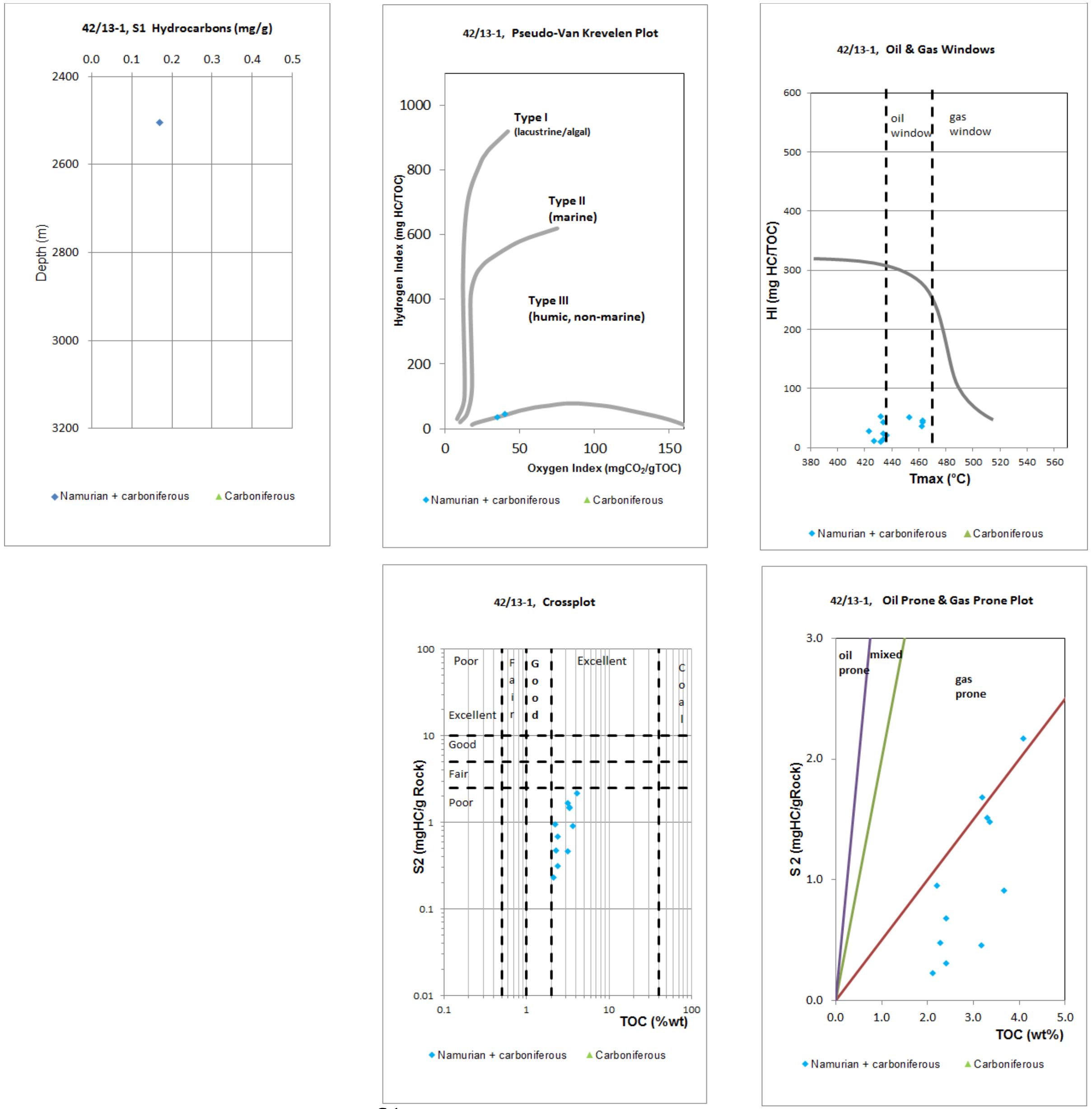


Figure 43/02-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 43/02-1.

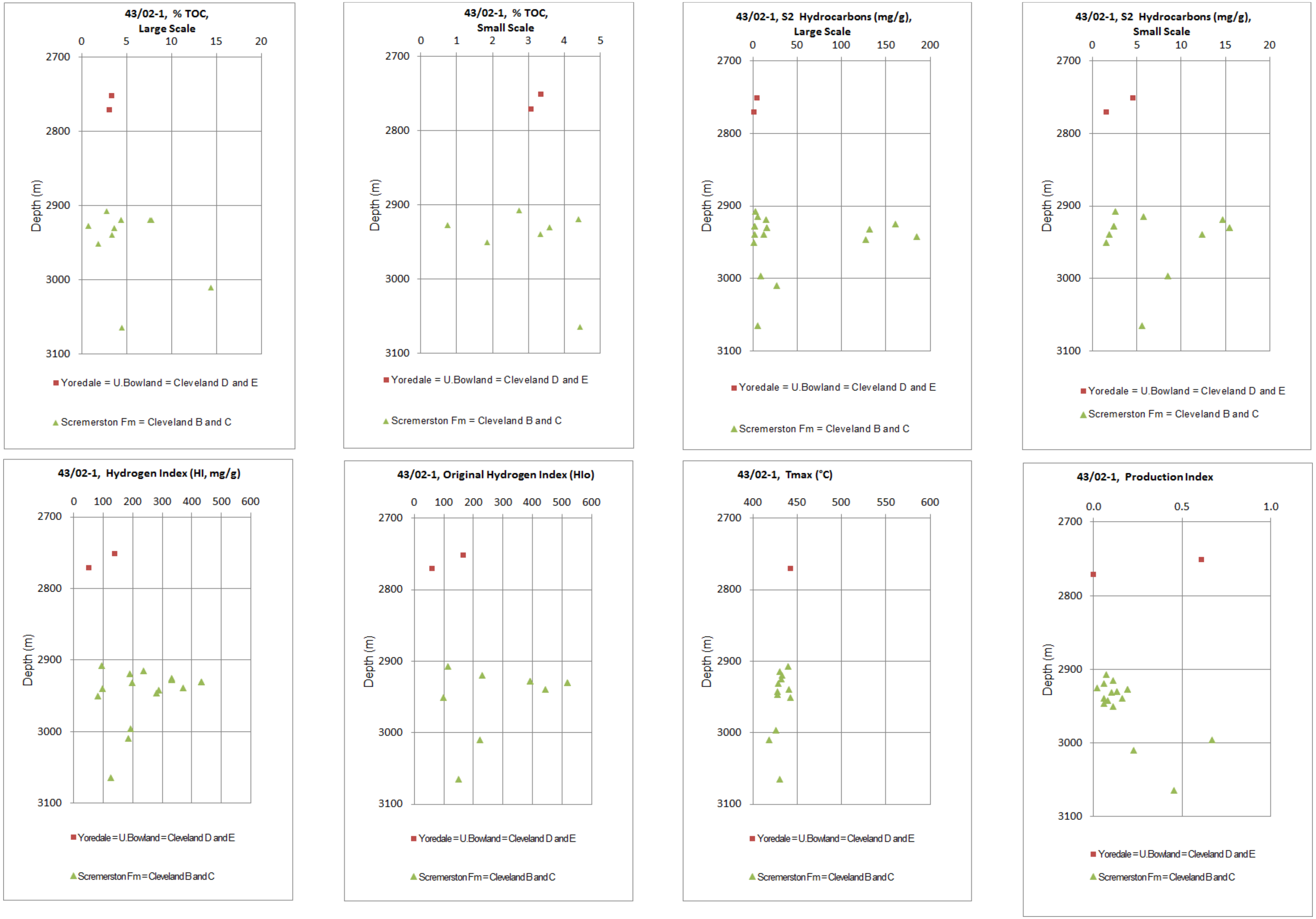


Figure 43/02-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 43/02-1.

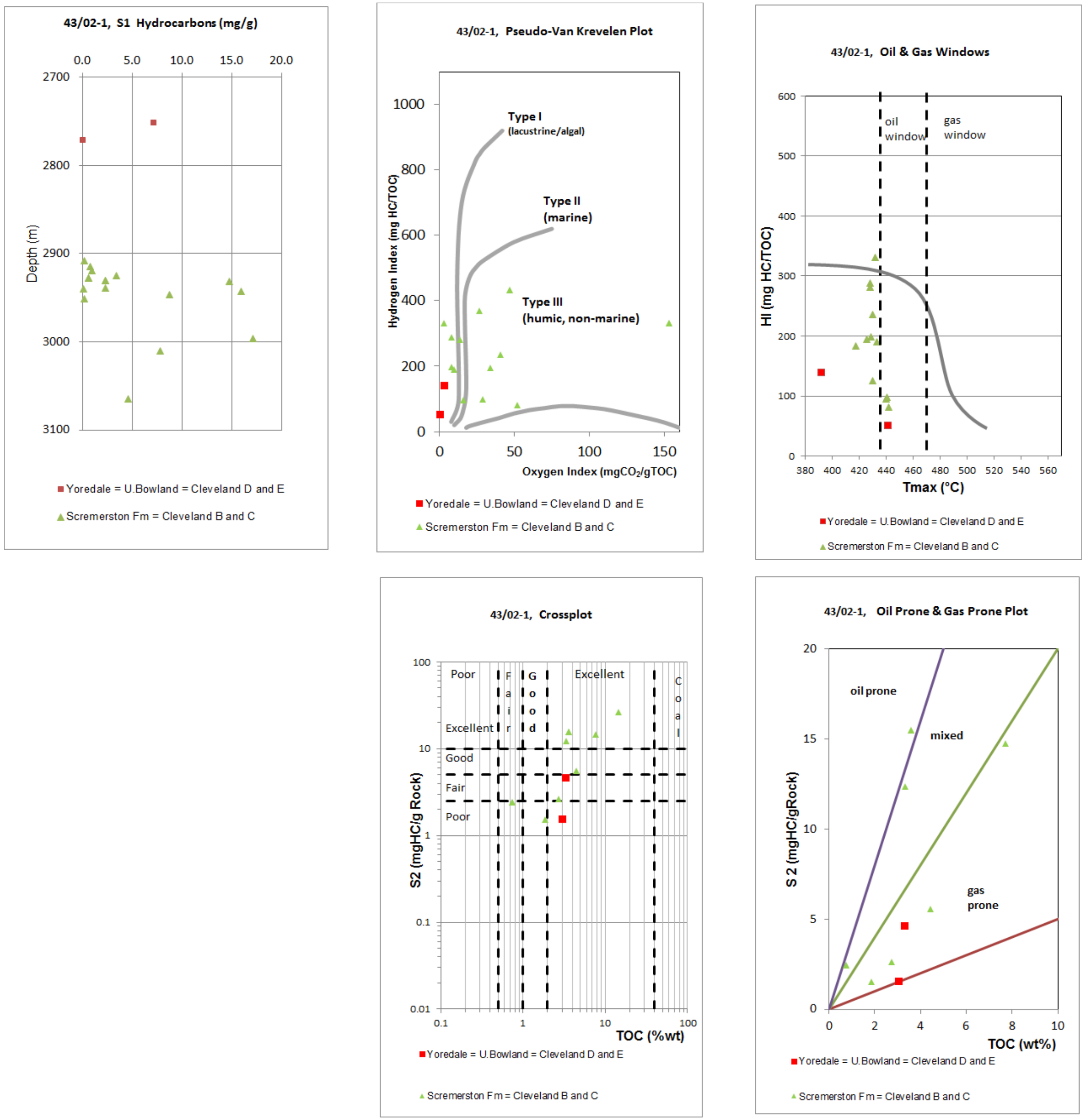


Figure 43/17-2 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 43/17-2.

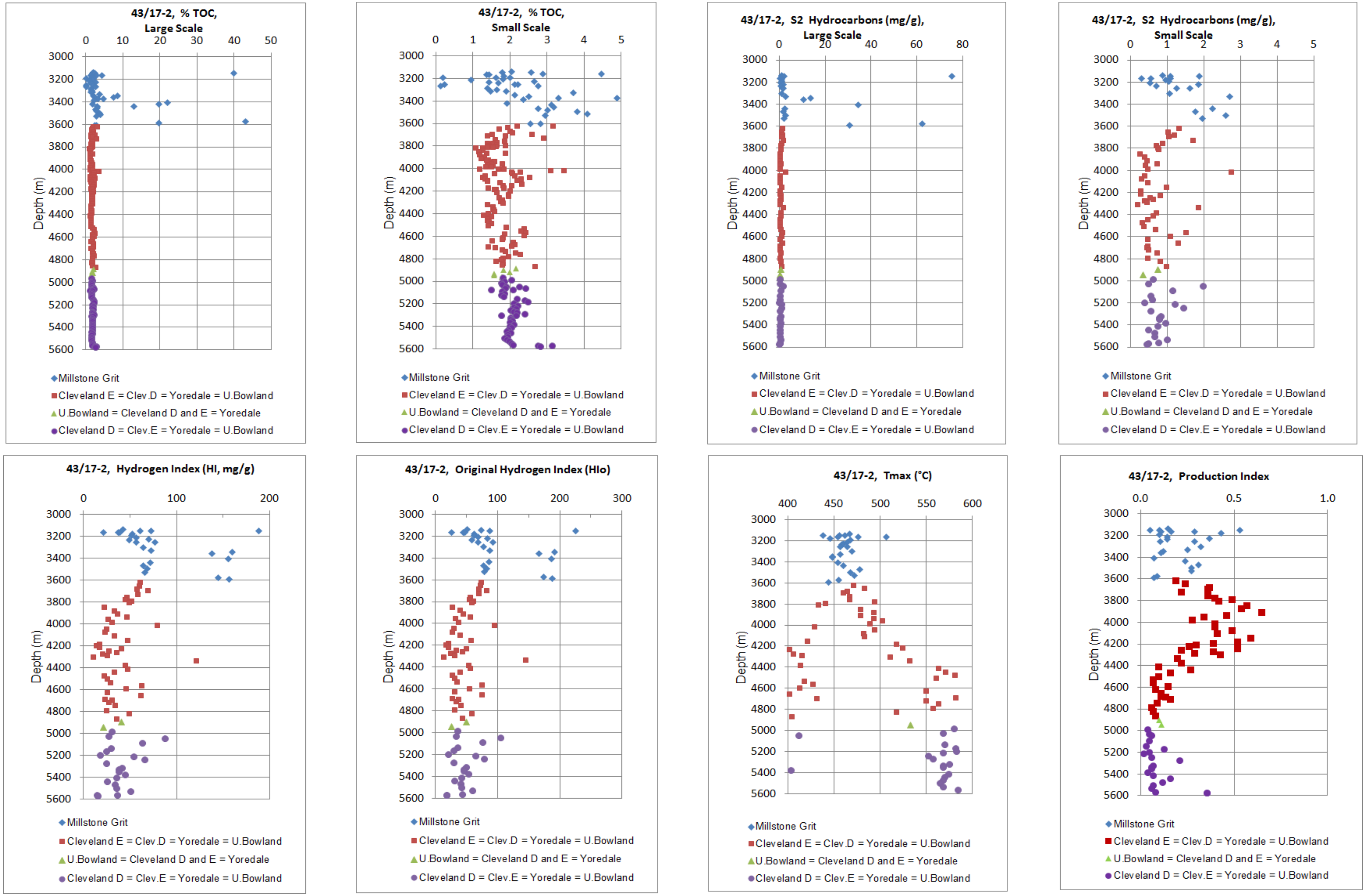


Figure 43/17-2 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 43/17-2.

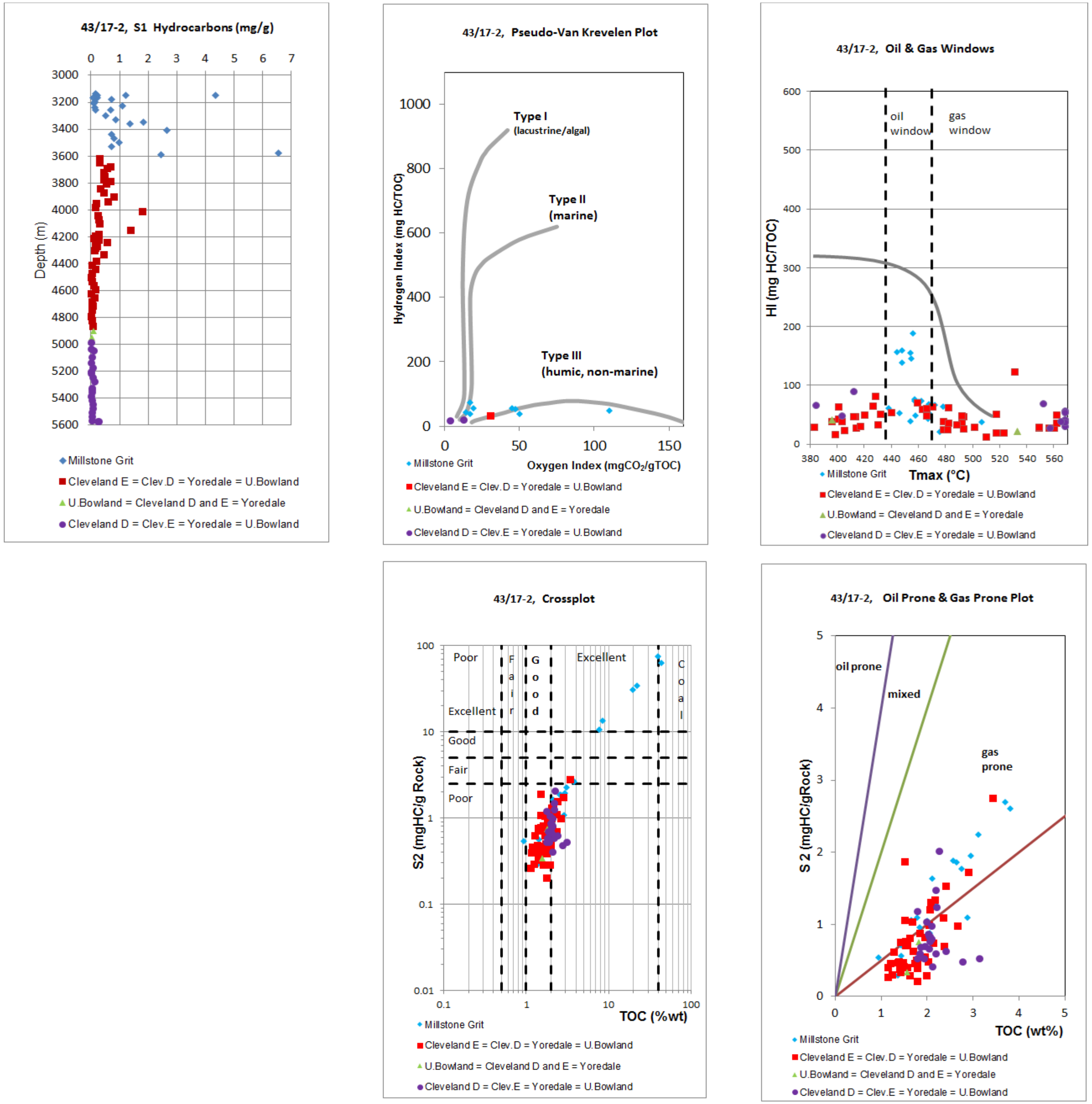


Figure 43/20b-2 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 43/20b-2.

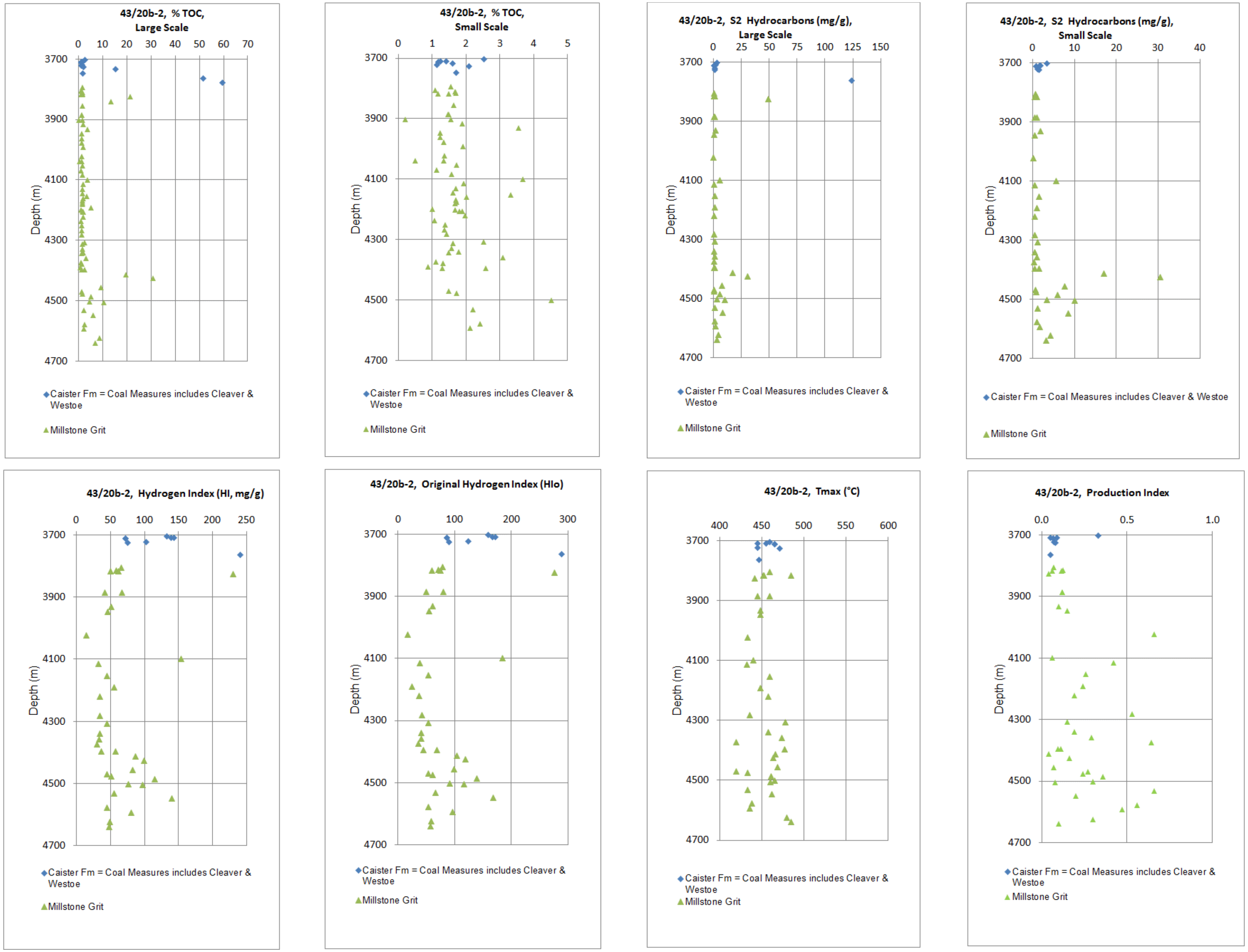
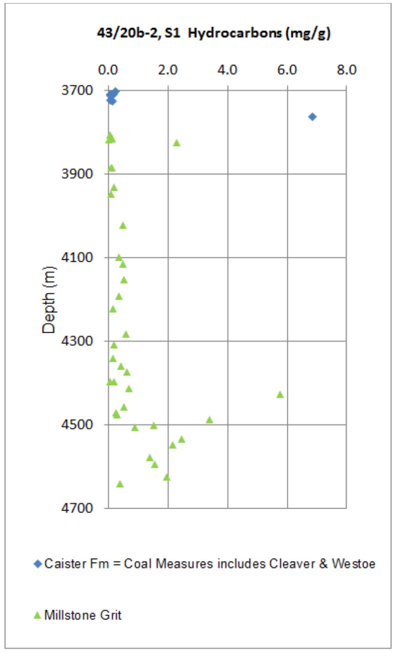
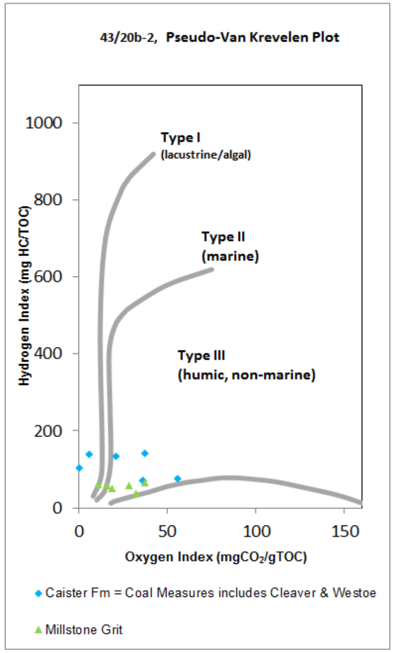
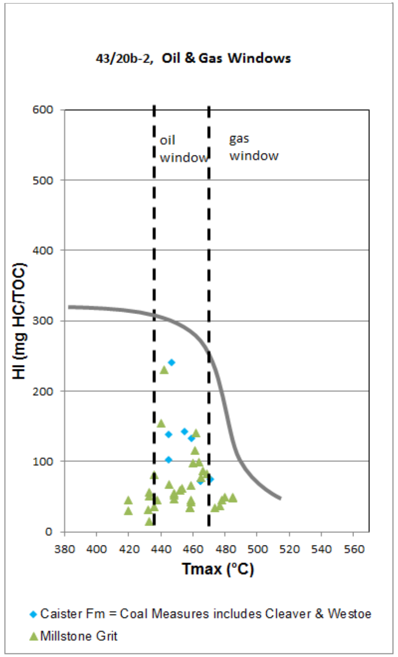
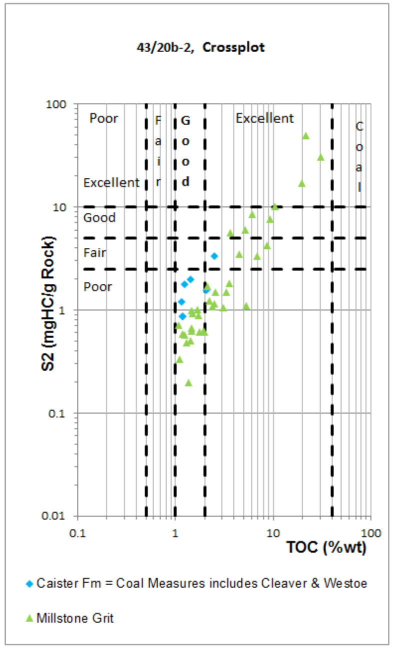


Figure 43/20b-2 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 43/20b-2.









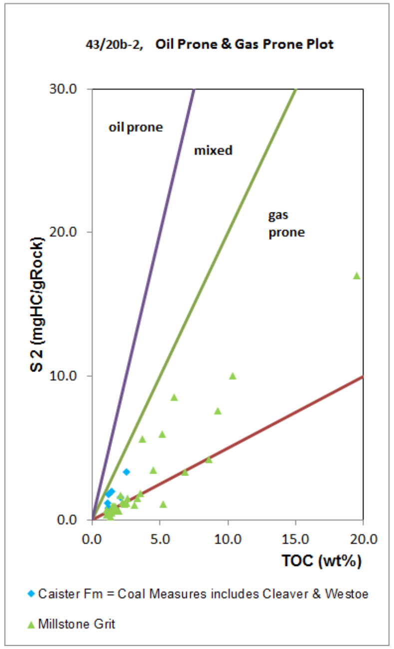


Figure 43/21-2 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 43/21-2.

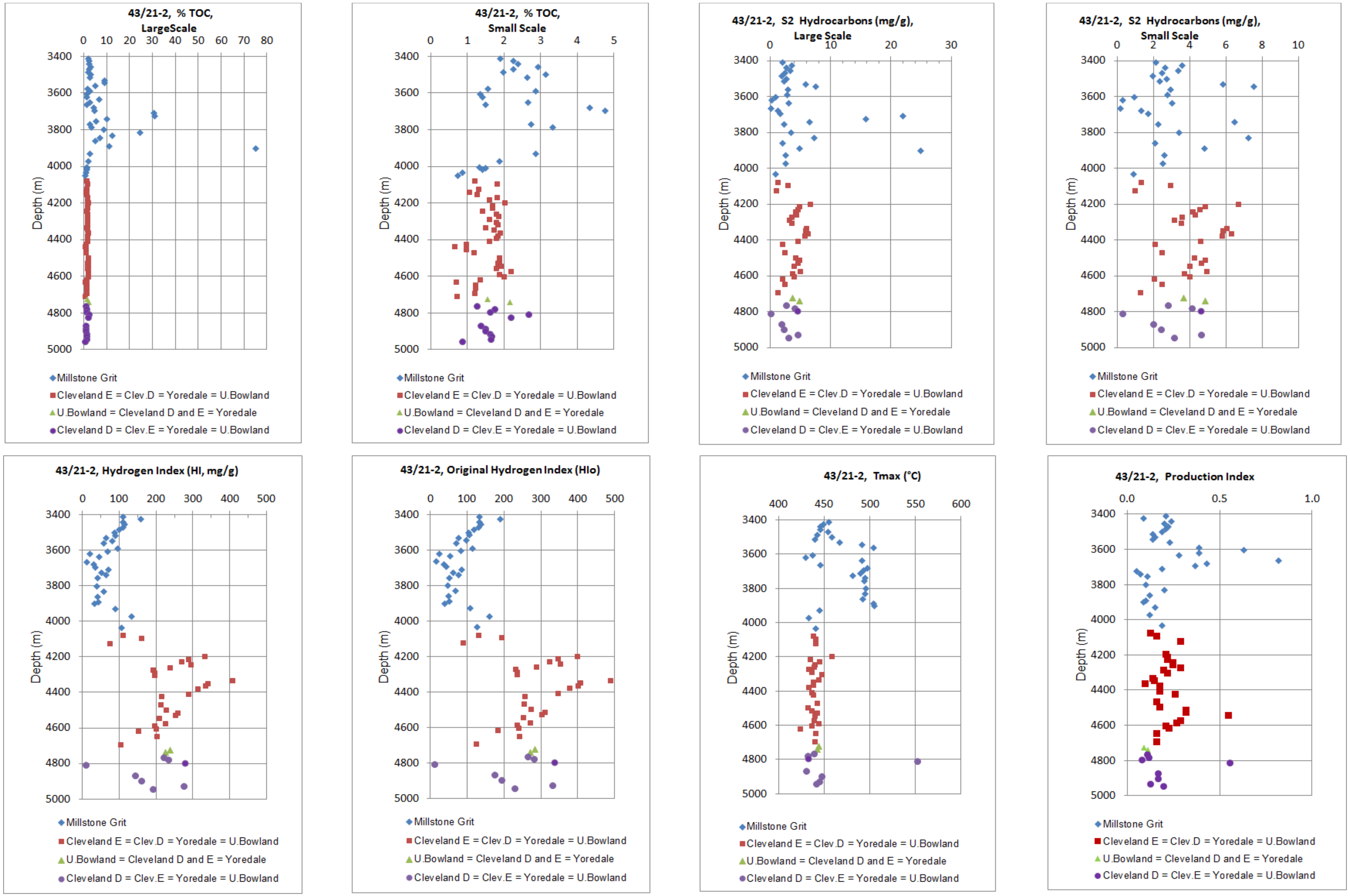


Figure 43/21-2 (b). Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 43/21-2.

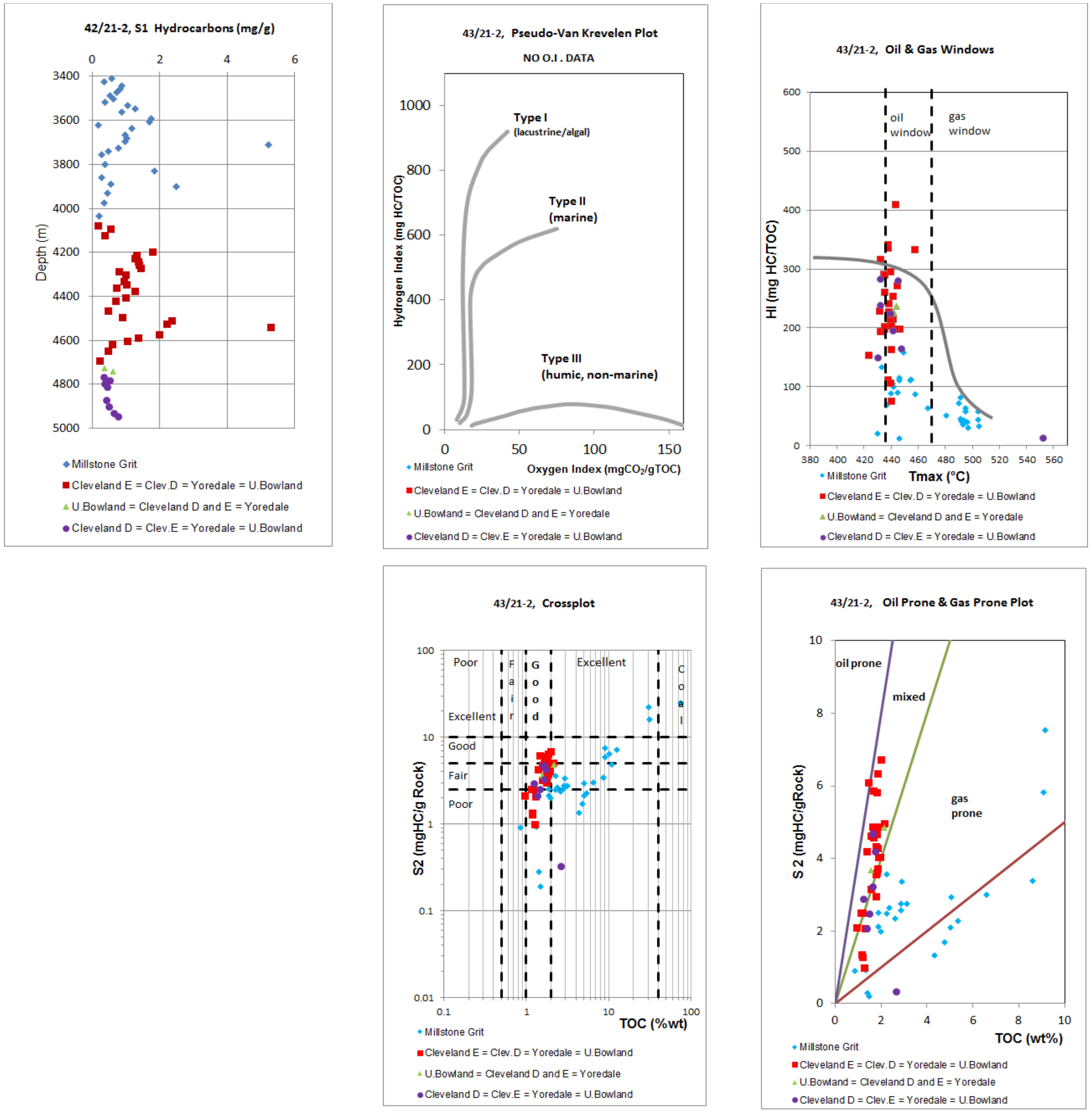


Figure 43/28-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 43/28-1.

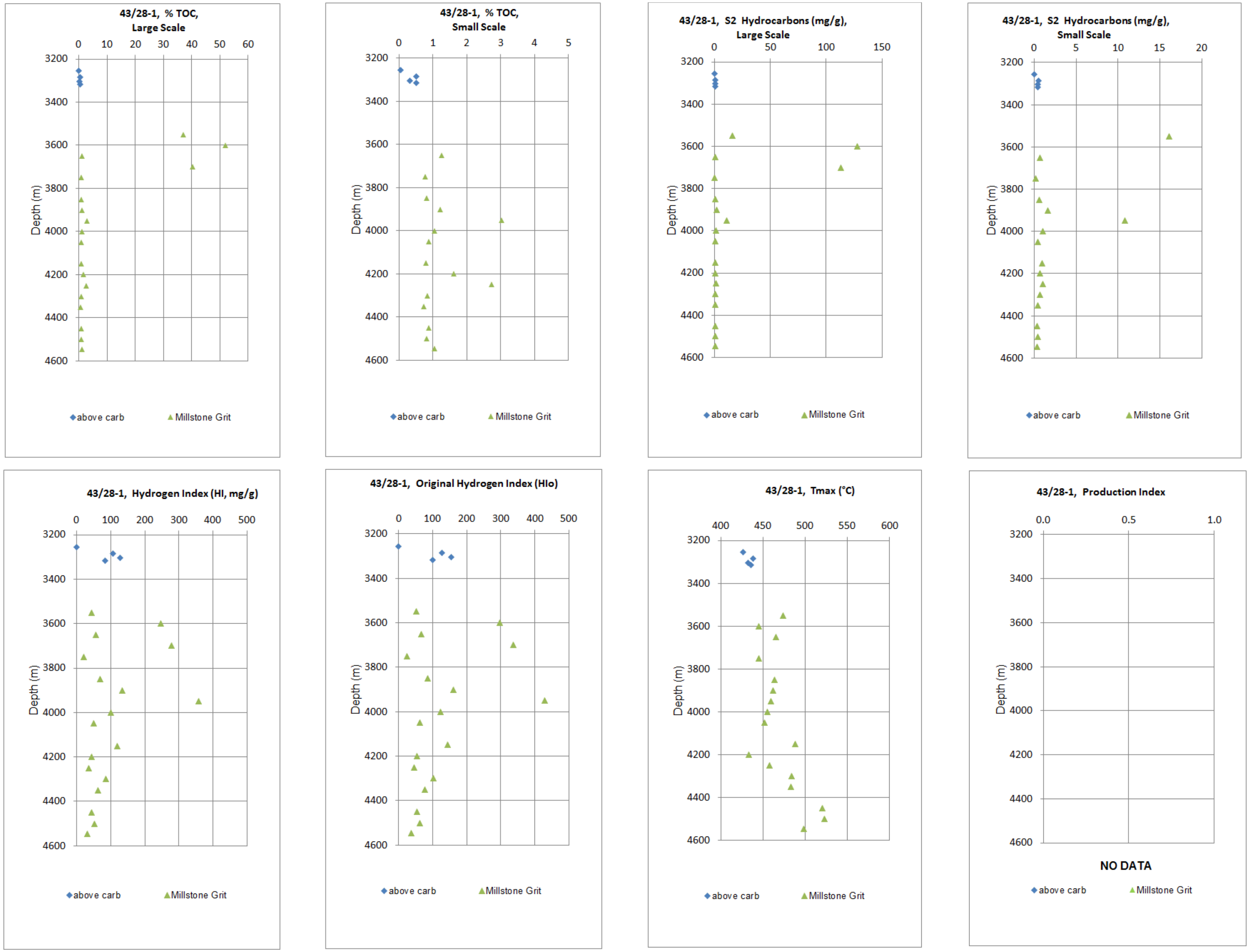


Figure 43/28-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 43/28-2.

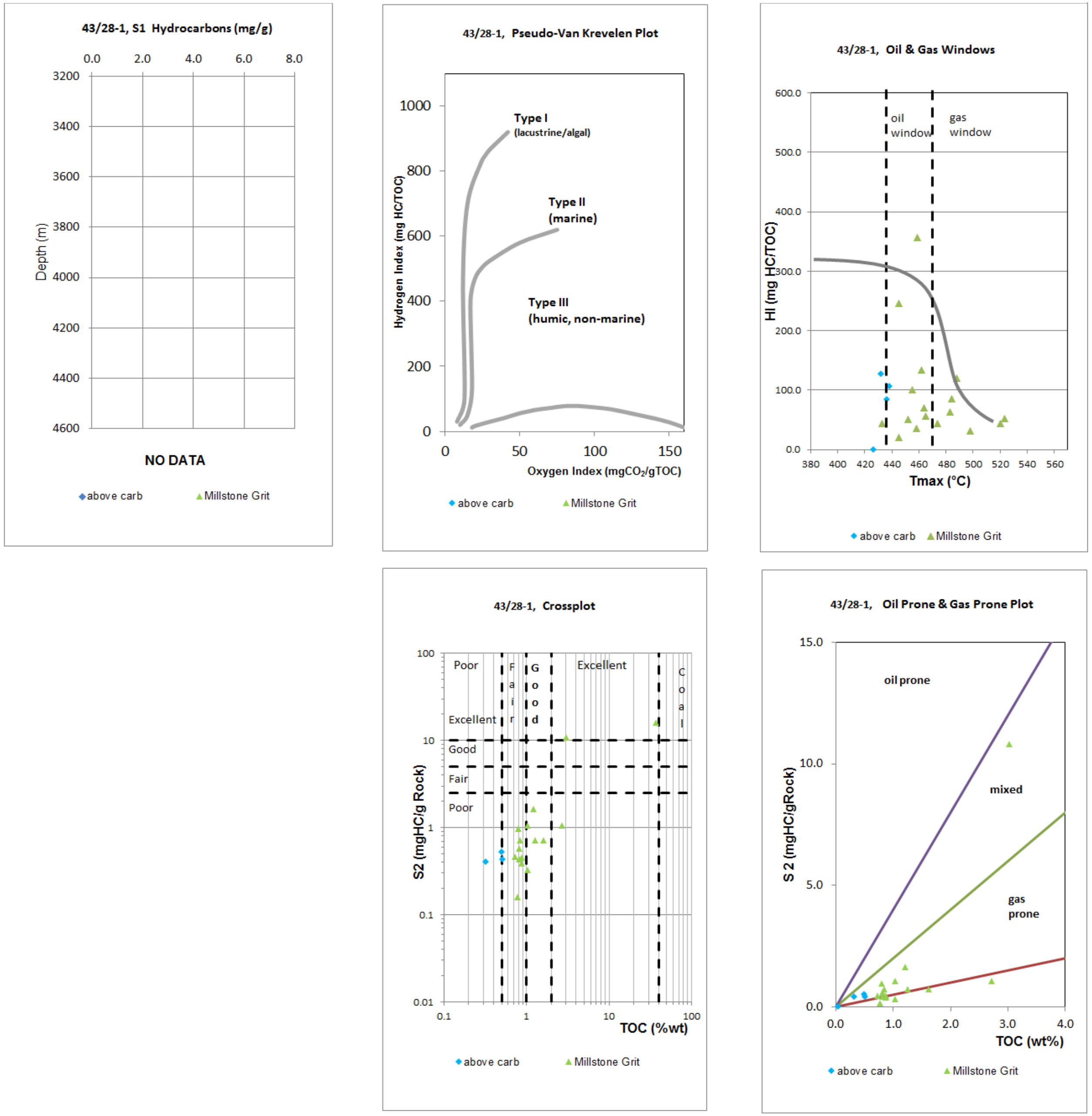


Figure 43/28-2 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 43/28-2.

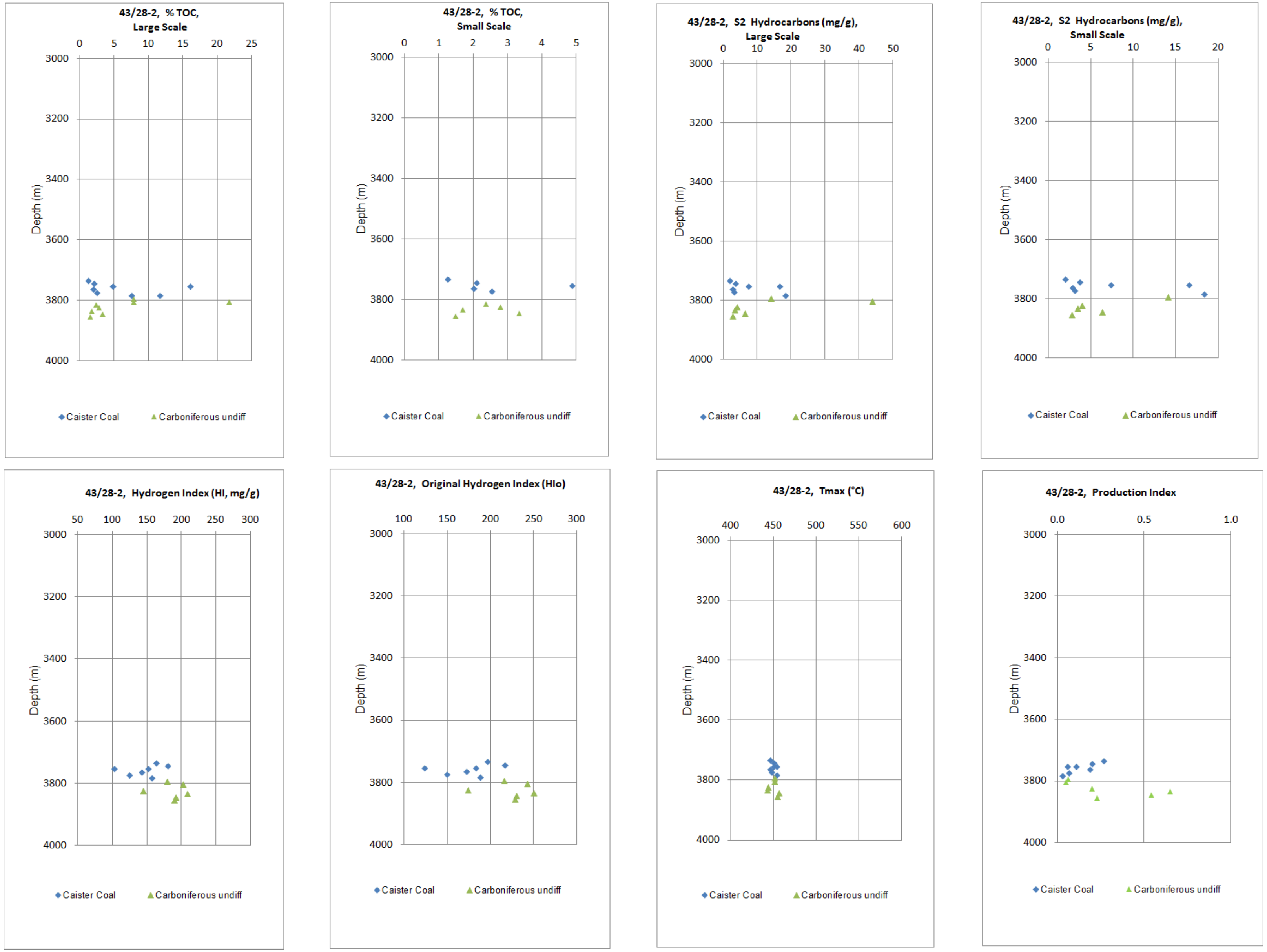


Figure 43/28-2 (b). Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 43/28-2.

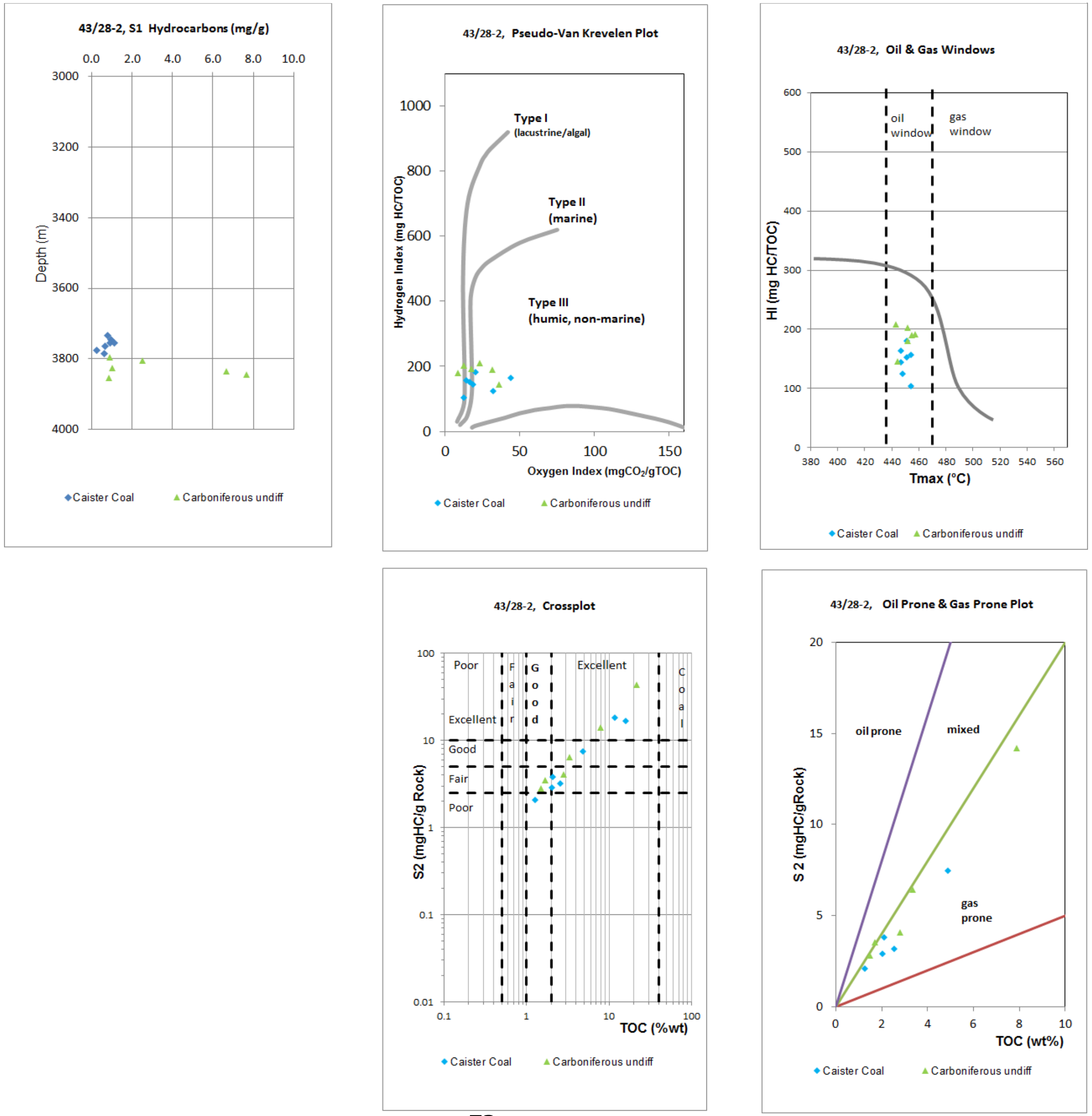


Figure 44/02-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 44/02-1.

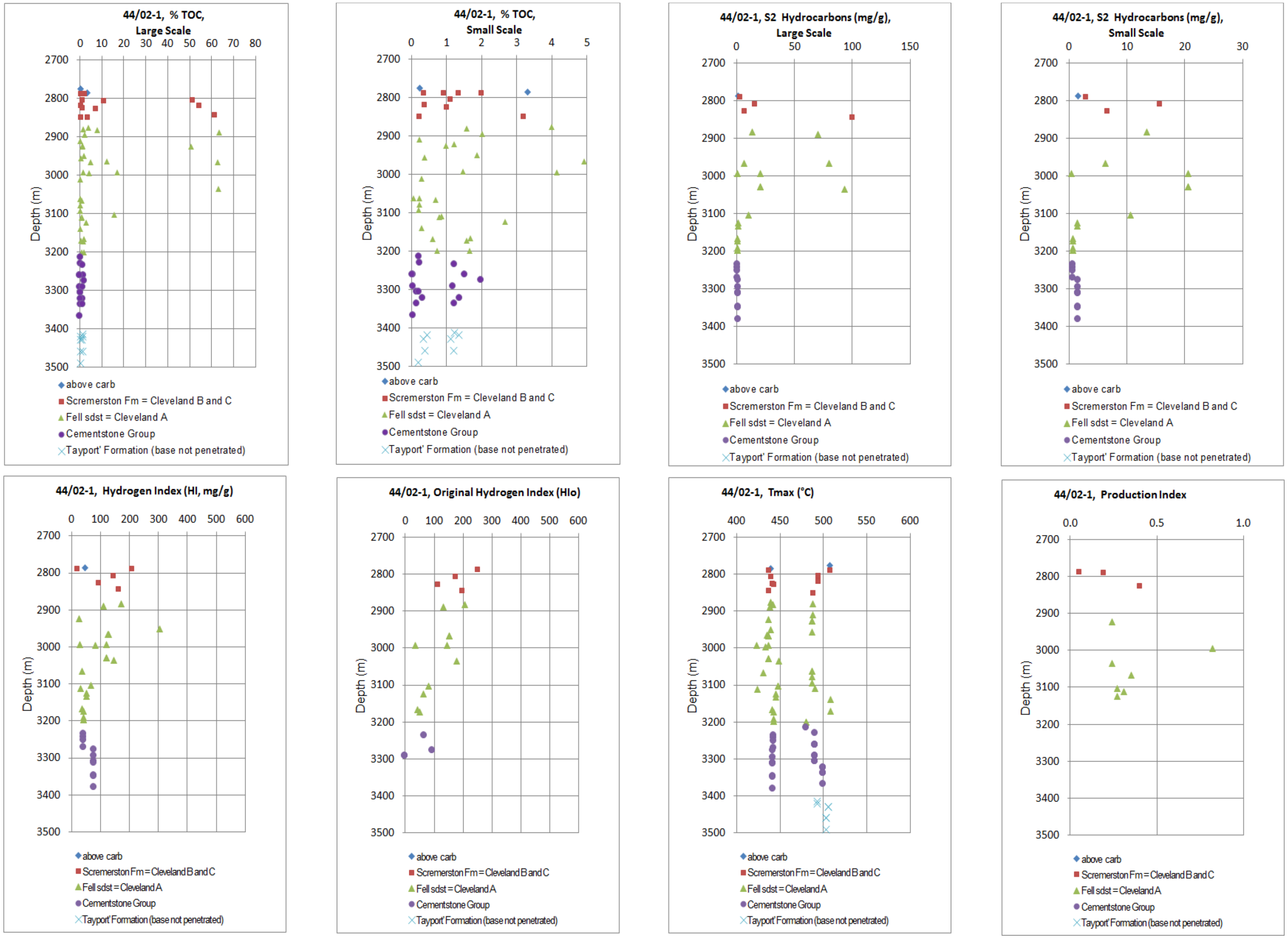


Figure 44/02-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 44/02-1.

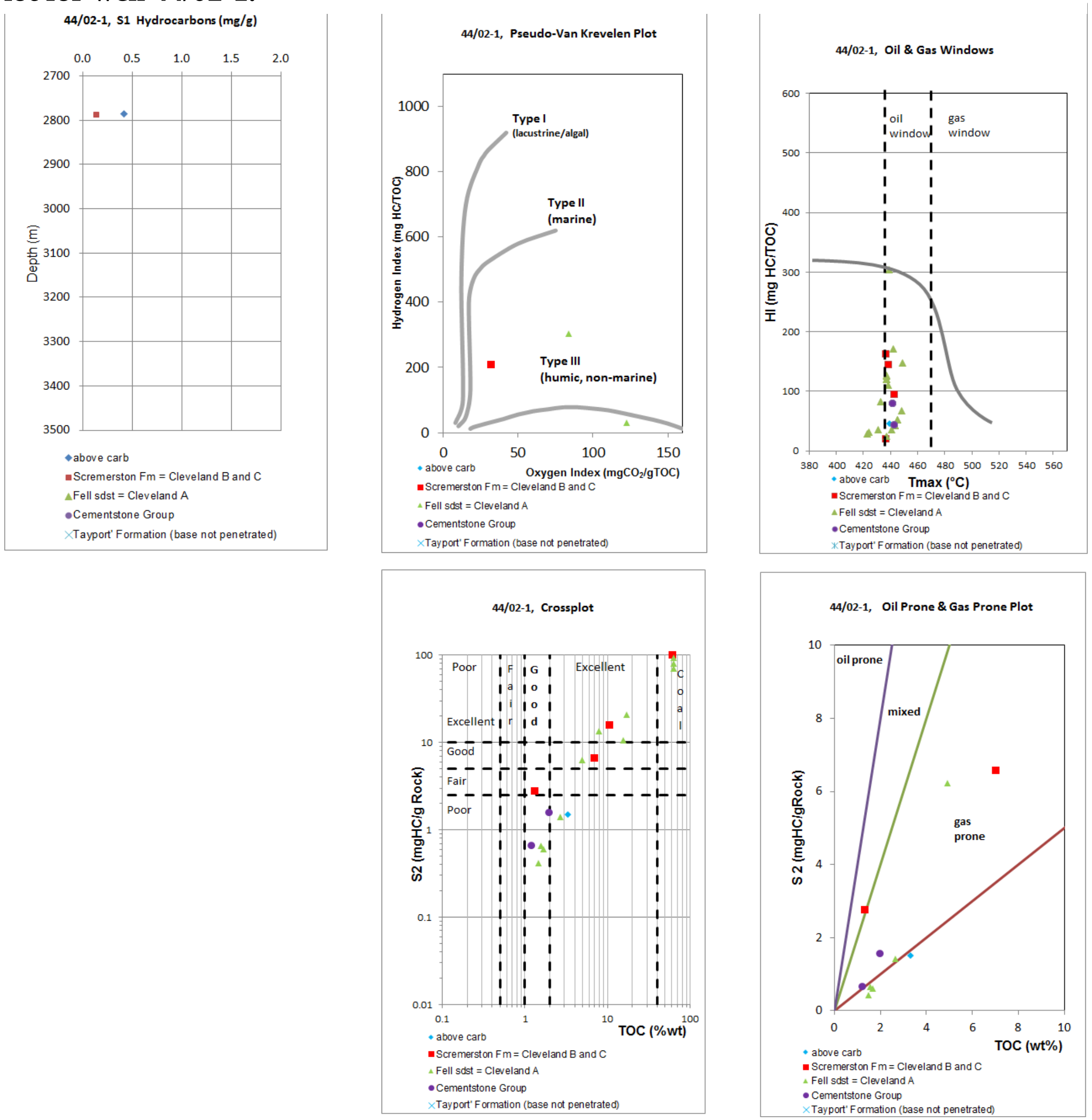


Figure 44/13-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 44/13-1

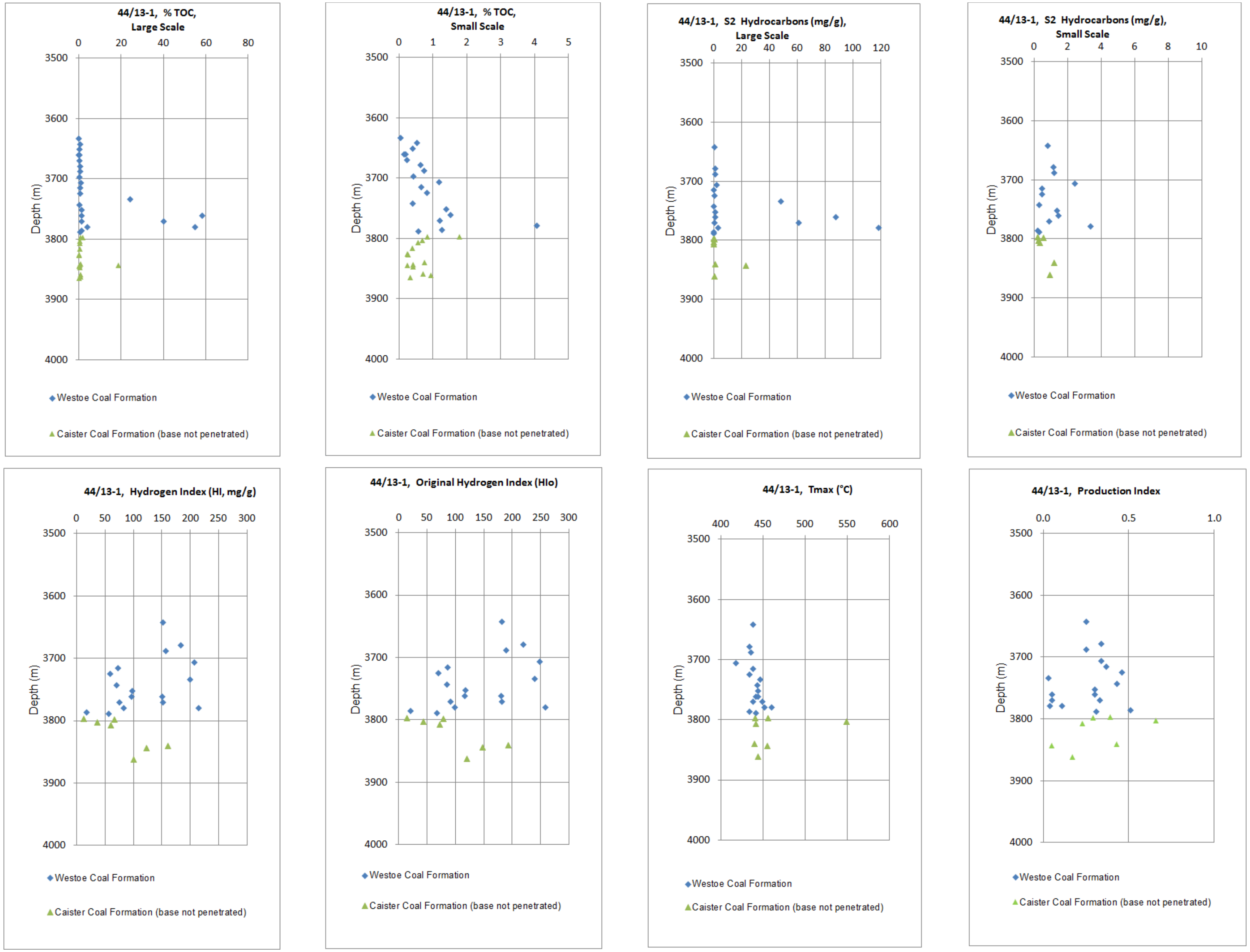


Figure 44/13-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 44/13-1.

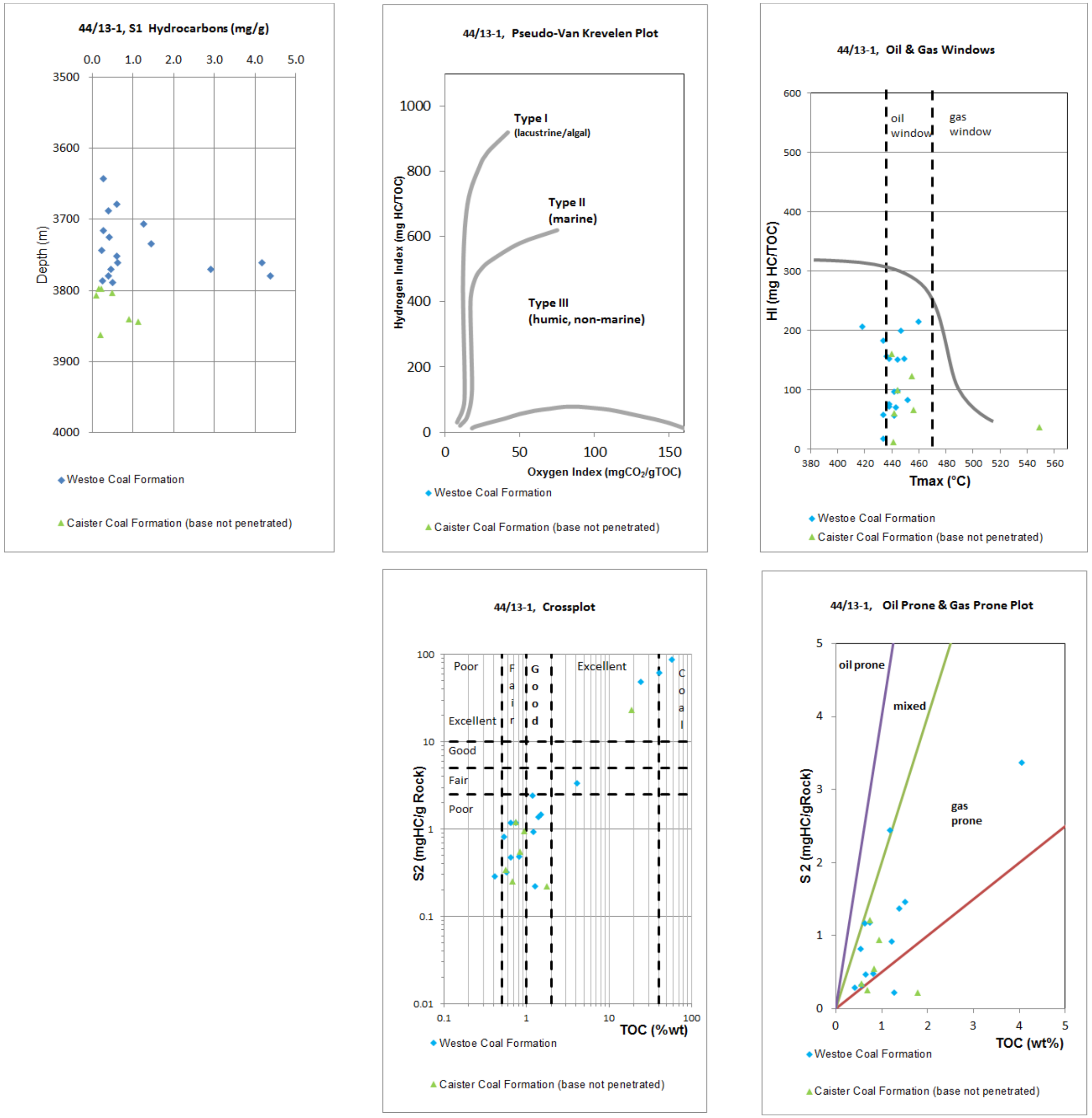


Figure 44/16-1 (a). TOC vs depth and Rock-Eval parameters (S2, HI and Tmax) vs depth plot for well 44/16-1

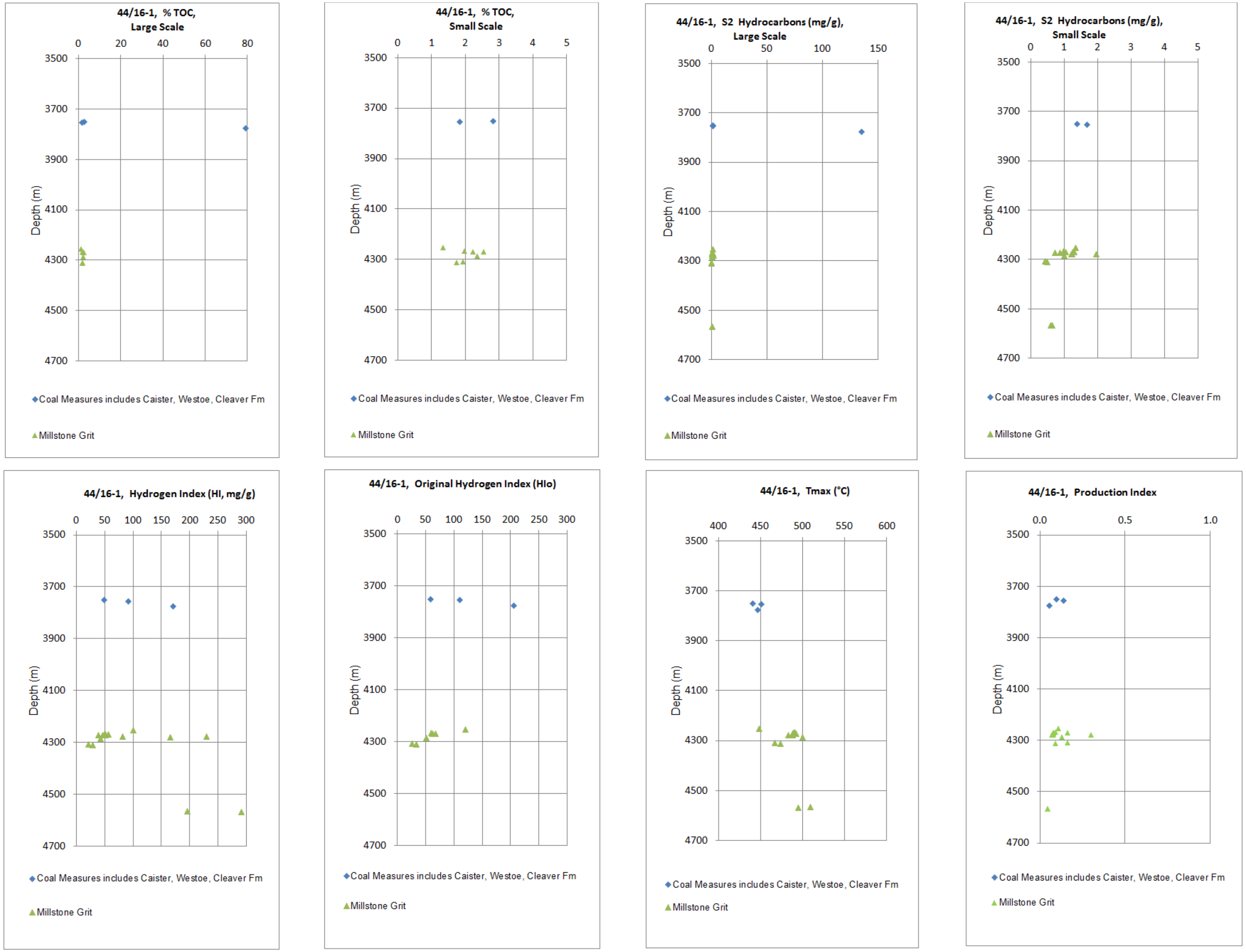
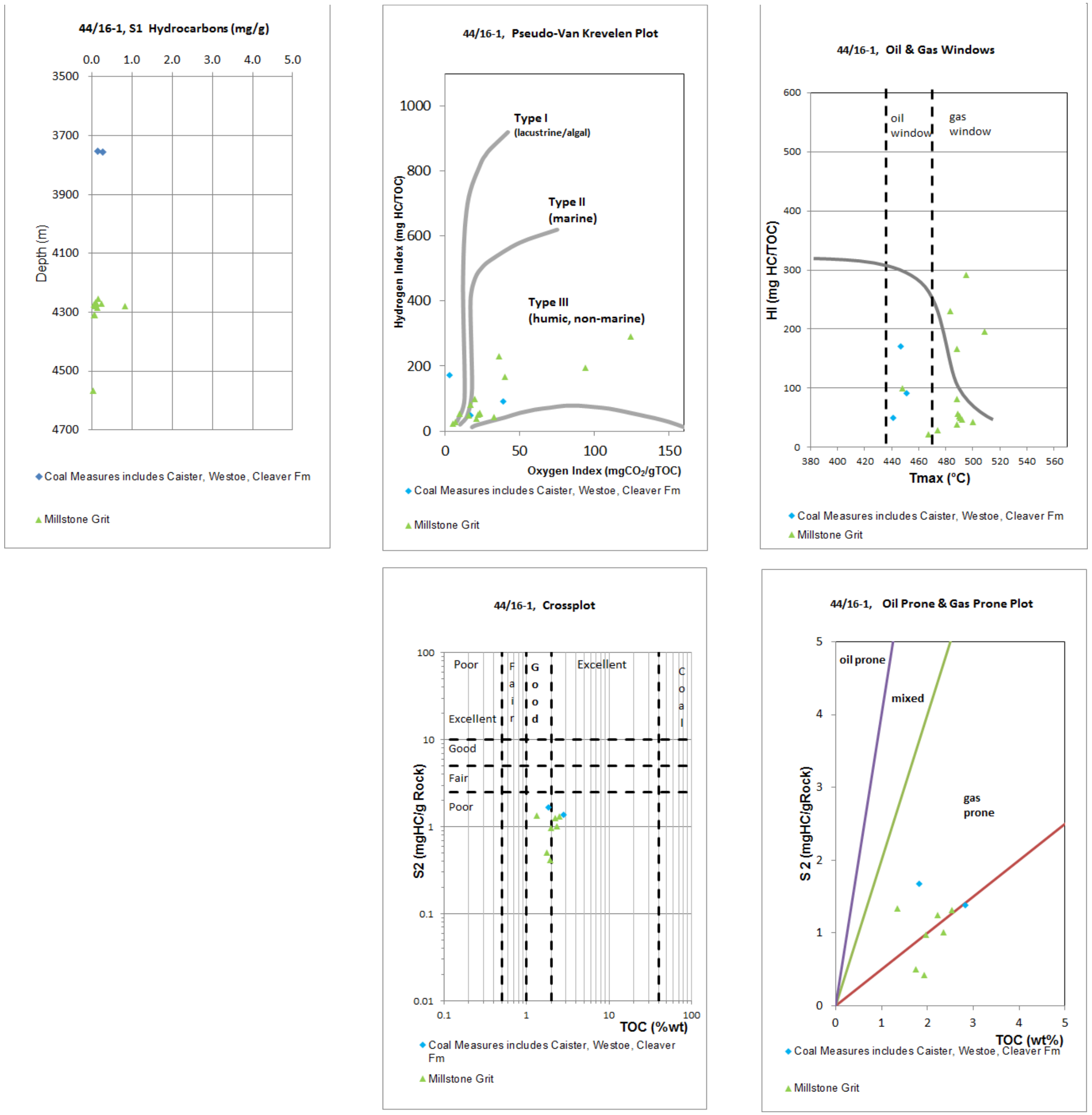


Figure 44/16-1 (b). S1, Van Krevelen plot, HI vs Tmax plot, S2 vs TOC plot, and oil prone and gas prone plot for well 44/16-1



Appendix 1 Literature review of source typing and kerogen types

Kirstin Johnson

The following literature review comprises data extracted from legacy geochemical reports of North Sea wells, with the aim of summarising any source and kerogen typing information, to complement the Rock-Eval datasets discussed above. The legacy reports are from the 1960's onwards and as such some of the kerogen/maceral terminology used is now obsolete. Where appropriate, current equivalent terminology has been used in lieu of these terms using the ICCP 1994 classification (see Table 2 below). This was not always possible as the data supplied is sometimes limited to simple descriptions, e.g. "amorphous kerogen". The stratigraphic and age terminology used below comes from the legacy reports rather than re-interpretations made for this study. Further integration of source and kerogen typing datasets with the Rock-Eval data, burial history and depositional environment studies would be beneficial in future, detailed studies.

Original Terminology in Legacy Reports	**Likely Equivalent of Updated Terminology**	
Exinite	Liptinite (general group)	
	Sporinite, Cutinite (Type II)	
	Resinite, Alginite (Type I)	
	Amorphinite (Type II)	Liptinite derived from bacterial degredation of algal bodies, faecal pellets, sporinite or cutinite
"Amorphous" Vitrinite	Gelovitrinite	Unstructured vitrinite derived from decomposed plant tissues
"Herbaceous" Vitrinite	Detrovitrinite	Unstructured vitrinite comprising fragmented plant remains
"Woody" Vitrinite	Telovitrinite	Preserved structured vitrinite derived from woody plant tissues

Table 2. Original nomenclature from well reports used in the literature review and the current equivalents after ICCP, 1994 definitions including 'The New Vitrinite Classification (ICCP System 1994), Fuel, 77, pp 349-358, 1998'

Southern Margin of the Mid North Sea High

41/01- 1

Within the Middle Limestone and Scremerston Coal Groups, source rocks were identified as early mature to mature for condensate oil generation and highly mature for dry gas generation, respectively. Recoverable reserves in the Upper Namurian reservoir (Scremerston Formation and Fell Sandstone) is estimated at 132Bcf gas and the Visean as 75Bcf. Typing for source rocks varies from type II and II/III to type III. Shales in the Middle Limestone group had average TOC and HI values of 4.07% and 82mg HC/g TOC, respectively, while coals within this interval had average TOC and HI values of 43.5% and 283 mg HC/g TOC, respectively. Shales in the Scremerston Coal Group had average TOC and HI values of 3.58% and 71 mg HC/g TOC, respectively. Coals in this interval had average TOC and HI values of 66.8% and 114 mg HC/g TOC, respectively (Shell UK Exploration and Production, 1992; Shell Expro, 1992; Silverstone Energy Ltd, 2009).

41/08-1

Kerogens from Carboniferous organic matter samples were predominantly inertinite (10 to >30%) with some vitrinite (5-30%), 1-10% “amorphous kerogen” and trace amounts of liptinite (cutinite) (PetraChem Ltd, unknown author a).

41/10- 1

Gas shows are within the Permian and Carboniferous (Yoredale, Whitby and Scremerston formations) of 41/10-1 (Wintershall 2010a; Wintershall, 2010b; Silverstone Energy Ltd, 2009). Carboniferous shows are seen to be predominantly C1 and C2 within the Yoredale Sequence, with wet gas and early dry gas generated. Very dry gas is expected to be produced from the Visean age Cementstone, Scremerston and Fell Sandstone formations (Kaye, 1995).

Within the Scremerston Formation kerogen types are 10-20% liptinite (Type II), 40-90% vitrinite (Type III) and trace -50% inertinite (Type IV). Within the Yoredale Formation kerogen types are 10-25% liptinite (Type II), 60-80% vitrinite (Type III) and trace to 25% inertinite (Type IV) (Kaye, 1995).

41/14- 1

Within undifferentiated Upper Carboniferous strata gas shows were mainly C1, with some C2 and trace C3-5. Gas shows in the Visean age strata consisted primarily of C1 with trace C2 and C3, indicating dry gas generation. Source rocks identified within the Carboniferous strata are very poor due to high thermal over-maturity, with all original hydrocarbon potential generated and expelled (Greene, 1991).

Within the Namurian age samples kerogen types average at >35% inertinite, 10 to >35% vitrinite and often <10% liptinite. Within the Visean age samples kerogen average at >35% inertinite, 10 to >35% vitrinite and >10% liptinite (Bailey, 1991).

41/15- 1

Around half the Carboniferous interval encountered by 41/15-1 was found to be thermally mature for hydrocarbons (wet gases and methane). Gas-prone types are evident in the uppermost Visean interval and the Namurian. Mixed kerogen and gas prone source types were seen in a large portion of the lower Visean section. Between 8000 and 9000 ft of the middle Visean interval, oil-prone kerogen types were identified (PetraChem Ltd, 1991).

Kerogen from the uppermost Namurian consists of 1-5% liptinite, 10-30% inertinite and 30% vitrinite. Kerogen from the remaining Namurian interval consists of 1-5% liptinite (cutinite), 5-30% vitrinite and >30% inertinite and very mature structured vitrinite. Within most of the Visean interval kerogen types comprise 0-5% liptinite (cutinite), 5 to >30% vitrinite and 10 to >30% inertinite and very mature structured vitrinite. Between 8000 and 9000 ft within the middle Visean interval, kerogen types comprise 5-30% vitrinite, 5-30% inertinite and very mature structured vitrinite and 10 to >30% liptinite (PetraChem Ltd, 1991).

41/20- 1

Strong methane-dominated gas shows were seen throughout the Carboniferous. However samples from the Namurian interval show a wetter liquid signal with a distinct mode around C15-C18 saturates in the gas chromatographs which quickly decreases to heavier alkanes, this could be due to contamination from diesel based drilling mud. The CPI ratios are close to, and less than, 1 and pristane/phytane ratios are low (0.9-1.4). The aromatic hydrocarbons are almost entirely composed of monoaromatics and the quantity of resins plus asphaltenes is variable (30-70% of extracts), saturates are also variable but almost always higher than the amount of aromatics. These data indicate the high maturity of extracts and confirm provenance from the surrounding Carboniferous (Namurian from well 41/20-1), alternatively, contamination may have skewed the results. The pristane/phytane ratios from the overall Carboniferous strata indicate an overall anoxic and saline environment (Pittion 1981).

Kerogens from the Namurian interval samples comprise 1-10% liptinite, 1-10% vitrinite, 1-30% “amorphous” and 5 to >30% inertinite, indicating a gas to mixed hydrocarbon prone source rock with intervals of minimal to no potential for hydrocarbon generation. A sample from the Dinantian interval comprised 10-30% liptinite, 10-30% inertinite, 5-10% vitrinite and 5-10% “amorphous” kerogens. From this, the potential for hydrocarbon generation is believed to be minimal for the source rock sampled (Pittion, 1981).

42/09- 1

Samples from the Namurian interval were found to comprise 0-15% inertinite and 85-100% vitrinite. Gas shows were seen in the top 500ft of the Namurian interval (Robertson Research International Limited, 1998a).

42/10a- 1

Within the Carboniferous interval, methane dominates head space gas analysis, with usually less than 20% wet gas. Organic matter is primarily composed of vitrinite kerogen with around 8-15% liptinite and some inertinite. The organic matter is also found to be fairly mature and likely to be within the oil window, based on vitrinite reflectance values of 0.78-0.92 % and TAI of 2+ to 3 (Pittion, 1983).

42/10b- 2

The Carboniferous Scremerston Coal Group is found to be mature for wet gas generation (the Brigantian strata being mature for oil generation) and doesn’t become fully mature for dry gas until the Devonian Upper Old Red Sandstone. Samples of organic matter from the Carboniferous intervals had a scattered range of iC4/nC4 ratios, possibly attributed to migrated gases of different compositions. Organic matter from Brigantian and Asbian age formations and the upper Fell Sandstone Formation is found to be predominantly vitrinite (Kaye, 1996).

The Agincourt gas discovery, (now the Crosgan gas discovery) was encountered in 42/10b-2 within the Yoredale, Whitby and Scremerston Formations with an estimated 95-265 bcf GIIP. A DST run on the Whitby Sands (24/10b-2Z) had flowrates of 7.8mmscfgpd. The gases produced from this DST were 87% methane, 6% N_2 and 7% CO_2, and were likely sourced from Namurian to Dinantian coals (Premier, 2008).

42/13- 1

Potential reservoirs within the Carboniferous interval of this well were water-wet. Around the lowest interval of the Carboniferous intersected by this well, kerogen types from samples comprise 5-30% liptinite, 5-30% structured woody vitrinite, 10 to >30% inertinite and 5-30% "amorphous" kerogens. These percentages give indication that the source rocks in this interval have gas to mixed gas and oil potential. Within this same interval, Pr/Ph ratios vary from 1.5 to 1.9, indicating some terrestrial input and the source rock's mixed oil and gas potential (PetraChem Ltd, unknown b).

42/13- 2

42/13- 2 encountered a 350ft gas column within the Visean Carboniferous interval (the Breagh gas field), with flowrates of 3mmscfpd (Symonds, 2015). The field began producing in 2013 with a flowrate of 2.75million m^3/d and is believed to host a total of 19.8 billion m^3 gas (DEA Group, 2015).

Kerogens from the Carboniferous interval (Fell Sandstone Group) comprise 40-50% inertinite and 50-60% vitrinite, with minor sapropelic material. This indicates the source rock is gas prone, however nearly half of the organic matter in the source rocks of 42/13-2 has no hydrocarbon generation potential at all (is dead carbon) (Robertson Research International Limited, 1998b, Hicken and Hughes, 1998).

42/13-3

A 500ft gas column was encountered within Carboniferous strata, identified as the Breagh field. A DST from the interval had a flowrate of 17.6mmscfpd (Symonds, 2015).

42/13a- 6

42/13a- 6 targeted the Breagh field ("Breagh East Well"). Weak gas shows are evident in the top of the Lower Limestone (Visean) interval and strong gas shows were seen throughout the Middle Limestone (Visean) interval (RWE Dea UK SNS Ltd, 2011).

42/15a- 2

The Carboniferous sequence is found to be thermally mature for oil and early mature for gas generation, but source rocks generally have poor gas generation potential, with the exception of a thin coal horizon near the top of the Visean interval (Riddick, 1991).

Within the Carboniferous samples, methane and ethane are found to be more prevalent than within Jurassic samples. Carboniferous samples were 10-30% wet gas, indicating the mature to late mature nature of the organic matter. Kerogen types from samples were predominantly inertinite with portions of gas-prone vitrinite. "Amorphous" kerogens decrease from up to 30% to <1% with increasing depth. The iC4/nC4 ratio indicates somewhat immature hydrocarbons at the top of the Carboniferous interval, maturing with depth until the well encounters the lower portion of the Visean interval and hydrocarbons are interpreted to be late to post-mature (Riddick, 1991).

Gas shows are seen in the Lower Yoredale Limestone (Wintershall, 2008).

42/15a- 3

This appraisal well proved the presence of gas in the western part of the Crosgan field, within the Yoredale Formation, Whitby Sandstone and overlying Carboniferous sections (Sterling Resources, 2015).

42/22- 1

Airspace gas analysis suggests the Carboniferous interval encountered in this well is post-mature for oil with up to 98.1% methane readings (very dry gas). At the top of the interval, a sample has around 90% C1, 8% of C2 and 1.6% C3, indicating a slightly wetter gas than found in deeper samples (Barnard and Richards, 1988).

Vitrinite makes up 20-60% of the kerogens sampled, with the remainder of organic material being primarily inertinite. Fair potential for gas generation is indicated from other Rock-Eval data. Results from gas chromatography is suggestive of condensate potential, however, these results may be a result of contamination (Barnard and Richards, 1988).

42/23-1

The organic matter from the Carboniferous interval of this well is found to be primarily inertinite (Barnard and Richards, 1988).

42/26-1

The organic matter from the Carboniferous interval of this well is found to be primarily inertinite (Barnard and Richards, 1988).

42/28a- 4

Dominant kerogen types within the Carboniferous samples of this well were found to be woody and inertinitic. Gas chromatography results showed C2-C5 was around 39% and C6-C14 around 50%, with a fairly low C1 (methane) peak, indicating the source rocks are not gas prone (D'Elia, 1991).

42/28a- 6

The undifferentiated Carboniferous interval encountered in this well is likely mature for significant gas generation and late mature for oil generation (from spore colouration, R_o). Mainly vitrinite kerogens (80-90%) with some inertinite (10-20%) and minor liptinite make up the organic matter of the samples, indicating good gas source potential but no significant oil source potential (Bastow, 1993).

43/15b- 3A

The Westphalian A interval in this well has excellent potential for gas and oil and has started to generate non-commercial, but still significant, amounts of hydrocarbons. Kerogens were found to be woody and widely sapropelic (sapropelic coals are typically Type I or II source rocks). Pyrolysis-gas chromatography found there to be around 40% C6-C14 and 12-14% C15+ hydrocarbons in samples from the Westphalian A interval. Gaseous hydrocarbons are also indicated with 15-18.5% C1 and around 30% C2-C5, indicating potential for liquid hydrocarbons and wet gas generation (Sauer, 1993).

The Namurian interval has been found to have good potential for gas and condensate. Kerogen types are predominantly land plant derived, with structured woody and "amorphous" vitrinite making up a large proportion of organic matter. Pyrolysis-gas chromatography found there to be around 43.5% C6-C14 and 11-21% C15+ hydrocarbons in samples from the Namurian interval indicating the presence of light oil or condensate alongside 5-11% C1 and 30-35% C2-C5 indicating the presence of gas hydrocarbons (Sauer, 1993).

43/16- 2

DST1A within the Namurian interval had an average flowrate of 0.0754 mmscfpd. Gases sampled comprised over 91% methane and 3% ethane. Kerogens from organic matter sampled appears to be predominantly (up to 80%) vitrinite with no algae observed, indicating the source rocks are gas prone. The rest of the kerogens appear to be made up of inertinite. Gas chromatography of the kerogens further supports this interpretation (Jones, 1994).

One of the samples from the Chokerian to Alportian (Namurian) interval contains palynomorphs indicative of a Carboniferous age (trilete spores, denospores and saccate sporomorphs) for the organic matter (Jones, 1994). This is the typical maceral composition of the Carboniferous coal in northern Europe.

43/17-2

The Namurian interval is believed to hold significant volumes of dry gas within sandstone reservoirs. Three DSTs were run within the Namurian strata, producing variable amounts of gas between 4,416 and 486,000 scfpd. The DST 2 gas log kicks next to coals and the DST 3 gas readings may indicate localised movement of hydrocarbons due to the similar percentage of C2-C4 in the C1-C4 fraction (readings of 26.3% from logs and 10.4% from DST 3). The DST 1 gases were extremely dry (<0.5% $C2_{+}$ HC) likely derived from a highly mature source. The source rock for DST 3 is believed to be thin coals and claystones in the underlying sandy sequence. For DST 2 the source rock again is believed to be thin coals and claystones within the immediate interval (Grinham, 1989).

Numerous gas peaks were also seen throughout the Carboniferous, and gas chromatograms indicate gas and minor condensate have been produced from some of the Namurian (Parkin, 1989).

43/19- 1

The Cavendish gas field was discovered by this well within the Namurian and Westphalian Carboniferous intervals. DSTs were run in Westphalian A strata (DST 1) and Upper Namurian strata (Yeadonian) (DST 2, 2A). DST 2 had a flowrate of 18.4 mmscfpd, with a total of 26.4 mmscf gas and 202 BBLS condensate produced through a separator. DST 2A had a flowrate of 22.7 mmscfpd. DST 1 had a flowrate of 14.6 mmscfpd, with a total of 16.8 mmscf gas and 256 STB condensate produced (Baylis, 1989, Jones, 1994).

Condensate from DST 1 showed very high maturity. The Pr/Ph ratio indicates a terrestrial higher land-plant origin for the source rock with a smaller input of marine algal-sourced material. The condensate from DST 2 appears less mature than that from DST 1 and has a Pr/Ph ratio indicative of a higher input of marine algal-sourced material, and consequently less from higher land-plant material. Gases sampled from the DSTs are likely from thermal cracking of oil to gas and are probably related to the condensate samples (Baylis, 1989, Jones, 1994).

43/19a- 4Z

Gas shows are seen from the top of the Westphalian to the Kinderscoutian (Namurian) within this well (Amoco (UK) Exploration Co, 1996).

43/20b- 2

The Kepler gas discovery was made by this well. Mature Westphalian and Namurian intervals were sampled and analysed, the latter of which was found to be the better source rock in a small 300ft section, with potential for gas and condensate generation. The Westphalian coals and mudstones were found to still have excellent potential for gas and condensate generation. In general migrated hydrocarbons are not suggested by the data and the samples were found to comprise dry to marginally wet gases (Walko, 1989).

43/20b- 2R01

Kerogen types from Namurian aged samples were found to be predominantly (>35%) “amorphous” vitrinite; woody vitrinite and inertinite is commonly 10-35% of sampled organic matter. Herbaceous and inertinite material makes up for <10% of the organic matter. The “amorphous” kerogen is interpreted to be of poor quality and therefore claystones within the interval are believed to have potential for generation of gas and possibly condensates, rather than oil (Walko, 1989).

43/21- 2

A DST was run in the Leman Sandstone to Carboniferous (Namurian to Westphalian A) interval and produced 7.17 (from just the Carboniferous) to 19.5mmscfpd (from both the Leman Sandstone and the Carboniferous) on three different runs. Kerogen types within the Carboniferous strata comprises primarily of inertinite and “woody” vitrinite. The Kinderscoutian and Alportian “amorphous” kerogens become more prevalent in comparison to woody vitrinite, but the organic matter is still more gas-prone (Sauer, 1992).

43/24-1 (43/24-P4Z, 43/24-P2)

Well 43/24-1 made the Trent gas discovery within the Namurian interval. Gas shows were seen throughout the Namurian interval encountered by wells 43/24-P4Z and P2. Two DSTs run in well 43/24-P2 within the Namurian Trent Sandstone Unit. DST 1 had a maximum flowrate of 0.5 mmscfpd and DST 2 35.4 mmscfpd (Lynden, 1995, Lynden 1997).

43/28- 1

Airspace gases analysed within the Carboniferous interval were primarily dry gases with negligible C3-C5 ratios and the presence of these gases increased with proximity to coaliferous strata. Samples from this interval were found to be predominantly vitrinite and inertinite, which, coupled with low HI values indicates a gas prone source rock. Gas chromatography on coaly samples further indicate this gas prone source rock has a composition of mainly aromatic components typically produced by type III kerogen (Riddick, 1992).

43/28- 2

No shows were detected within Carboniferous (Westphalian A and late Namurian), however source rock sampling proved potential for gas and very light liquids and were interpreted to be at peak maturity (indicated by low isobutane/butane ratio, Ro and T_{max} values) Samples show kerogen types to primarily be vitrinite (>35%) with significant amounts of liptinite (10-35%). Inertinite values are typically <10% (Riddick, 1993).

Within the lower Westphalian A to late Namurian gas wetness values vary from 7.7-60.4% C^{-}_{2+} hydrocarbons which are believed to be accounted for by indigenous in situ species and not migrated hydrocarbons (Riddick, 1993).

44/02- 1

Within Visean strata encountered in this well, kerogen types from samples were primarily gas prone vitrinite (>35%), 10-35% inertinite, trace to 35% liptinite and trace to 10% structured woody vitrinite. One sample from this interval was found to be >35% inertinite, with trace to 10% vitrinite and liptinite. Kerogen types from the Tournaisian interval comprised >35%inertinite, liptinite and structured woody vitrinite and <10% “amorphous” vitrinite. Samples from the Strunian (Carboniferous/Devonian) interval comprised >35% structured “woody” vitrinite, 10-35% inertinite and Type II liptinite and >10% “amorphous” vitrinite (Sauer, 1980).

Another sample from the Strunian (Devonian) interval was found to have trace (1-5%) liptinite and vitrinite, with lean (5-10%) inertinite through visual kerogen analysis with mineral matter-free samples. The remaining percentage and type of material is not known. Overall, there is very little potential within the sampled source rock (PetraChem Ltd, unknown b).

Gas shows were seen within the Cementstone Formation (P1527, PA Resources, 2010).

44/08- 1

The Carboniferous Limestone Group equivalent samples have trace to 10% liptinite, trace to 30% vitrinite and 70-100% inertinite and reworked kerogen types, indicating this interval is primarily inert with very little mixed oil- and gas-prone source rocks. There is a section comprising 5–25% of this interval with fair potential to generate gas and condensate (Burgess and D'Elia, 1994).

A Carboniferous Scremerston Coal Group sample has 50% vitrinite, 30% liptinite and 20% inertinite and reworked kerogen types, meaning this interval tends towards being mixed oil- and gas-prone. Samples analysed were also shown to very likely be mature for oil generation (Burgess and D'Elia, 1994).

44/13- 1

The Carboniferous strata intersected by this well is of Westphalian age and has kicks of dry gas within the Westphalian B. Kerogen types are primarily inertinite and structured woody vitrinite (>35%) (Walko, 1995).

44/17a- 4

Westphalian B is the lowest strata within this well. Samples from the top of this section indicate mature, mainly anoxic and marine sourced oils with a pristane/phytane (Pr/Ph) ratio of 0.94 and a CPI of 1.04. The Pr/Ph ratio also indicates some terrestrial input. These hydrocarbons exhibit properties typical of Kimmeridge/Draupner oils. It is important to note that there was some contamination of the sample from drilling muds therefore these data may not be reliable (Ferguson, 1998).

44/21- 1

The Carboniferous interval consists of Westphalian A to Namurian and appears early mature for gas and mature for wet gas. Organic matter identified comprises predominantly vitrinite (Pittion, 1981). The Boulton gas field is encountered in this well, and to end 2014 has produced a total of 7185 mcm gas (DECC, 2014b).

WEST CENTRAL SHELF-NORTH DOGGER BASINS (QUADRANT 29-38) BASINS

29/10-3st1

Isotopic signatures from the Auk Formation in this well are comparable to Carboniferous coal-prone source rocks (Farris et al., 2012).

29/20-1

Fluid samples from the Zechstein and Fulmar were analysed and found to have maturities matching the Lower Carboniferous Oil Shales and Scremerston Coal Groups, indicating Carboniferous aged source rocks. It has been suggested that the source rock age is older, i.e. Devonian (Copestake et al., 2009).

The samples from the Fulmar and Zechstein intervals contained β-carotene and gammacerane, which are indicative of a lacustrine environment. This is consistent with the presence of terrestrial kerogen in the gas-chromatography traces (variable nC25+ alkanes). N-alkanes are abundant in the oil samples, indicating that the hydrocarbons have not been heavily biodegraded. Further evidence supporting a Lower Carboniferous age for the source rocks is seen in the presence of torbanites and the sterane C28/C29 ratios from the oil stains and fluid inclusions (0.55 – 0.60) (Carr, 2009). Further to this, Bisnorhopane is common in Kimmeridge Clay sources and is absent here. Due to the clastic characteristics and interpreted lacustrine depositional environment, the Zechstein Kupferschiefer cannot be the source for the sampled hydrocarbons (Carr, 2009, Copestake et al., 2009).

30/24-2

Devonian sandstones within this well are found to be oil bearing (Argyll field, now Ardmore field). The field originally produced 72.6 mmbbl of light crude as Argyll, now as Ardmore/Alma the field (comprising three productive reservoirs – Zechstein carbonates, Rotliegend sandstone and Devonian sandstone) is believed to host around 20.7 mmbbl oil. The source for the field is believed to be the upper Jurassic Kimmeridge Clay Formation (Farris et al., 2012) and gas-prone upper Devonian coal seams (as encountered in well 38/03-1) (CGG Veritas, 2010) .

30/24-25

Devonian oil bearing sands penetrated by this well have an estimated 150mmbbl STOIIP. Well 30/24-2 also penetrates this field; see well description for more information on production of the Ardmore field (Farris et al., 2012).

31/26a- 12

The Flora field, an oil discovery sourced from Upper Jurassic mudstones (likely Kimmeridgian), is encountered within this well. The reservoir is believed to be within Carboniferous Westphalian B to Stephanian aged sandstones (Bruce and Stemmerik, 2003). Over 15 mmbbl of liquid hydrocarbons were produced during the lifetime of the field (DECC, 2014a).

Oil samples were missing karoten (resin diterpane) missing in gas chromatogram, indicating absence of higher land plant organic matter. The Pr/Ph ratios remain between 1.21 and 1.26, indicating a marine to terrestrial source for organic matter and the CPT value remains around unity, or just above, indicating the source is either mature or organic matter is marine in origin (Hall, 1997).

36/23-1

Terrestrial input within undifferentiated Carboniferous source rocks is indicated by a Pr/Ph of 2.14 (PetraChem Ltd, unknown a).

37/12- 1

Within the Visean to Tournaisian interval, source rocks are believed to have good potential for gas and condensate, with organic matter being predominantly (10 to >30%) composed of inertinite and woody vitrinite kerogens. The Carboniferous is believed to be immature for gas. CPI and pristane/phytane ratios indicate terrestrial input for organic matter; however, these values may be unreliable due to contaminants (GeoChem Laboratories Ltd, unknown).

38/03- 1

The Devonian subcrops against the Rotliegendes Group in this well. The upper portion of the Devonian is mature for oil generation, with at least the last 1000ft (to T.D) of the interval falling within the transitional zone for oil and gas generation. “Amorphous” kerogens make up much of the kerogen content (trace to 20%, up to 50% at the top of the Devonian interval), indicating a marine depositional environment and suggesting an oil-prone source rock. From around the Middle Devonian, woody vitrinite and inertinite kerogens become more prevalent, trace to over 50% and trace to 20%, respectively. This suggests a mixed oil- and gas-prone source rock from the Middle Devonian to T.D. (Bailey, 1975).

The maturity of the hydrocarbons differs from the maturity of the sediments hosting the fluids within the Permian and upper Devonian strata, indicating these hydrocarbons are non-indigenous. These hydrocarbons also have relatively high APIs, C2-C4 depletion and high paraffin-naphthene to aromatic ratios, indicating contamination rather than migration (Bailey, 1975).

Core from Devonian strata had CPI values of between 1.02 and 1.05 indicating a mature source, however these readings came from trace amounts of n-paraffins, typical of petroleum-like mixtures, but also of contamination (Cousins, 1976).

38/16- 1

Gas shows are seen throughout the Visean Carboniferous strata encountered by the well (Amoco (U.K.) Petroleum Ltd, 1967).

Coals within Visean strata were found to be mature for oil expulsion, but immature for gas generation. The organic matter is gas-prone with high potential yields, however it requires further maturation. Two DSTs were run within the Carboniferous strata, returning formation water and drilling mud (Robertson Research, unknown).

38/18- 1

The Carboniferous interval encountered in this well was found to be middle to just late mature for oil generation and immature for gas. The interval is found to initially host good quality source rock for oil generation, becoming more gas-prone with depth as the organic matter changes. These gas-prone shale source rocks have very good gas source potential, but require further maturation (No Author Specified, unknown a).

38/22- 1

The Carboniferous interval within this well was found to be just too late for oil generation, and early mature for gas generation. Organic matter samples from the Tournaisian comprised 40-90% inertinite and 10-70% vitrinite, indicating the source rocks have no (90% inertinite) to some (70% vitrinite) gas generation potential (No Author Specified, unknown b).

39/02- 1

Carboniferous aged reservoirs had 100% water saturation with no shows. One sample of organic matter from the undifferentiated Carboniferous interval was found to predominantly (>30%) consist of woody vitrinite kerogen, with 10-30% inertinite (Total Marine Ltd, 1971).

39/07-1

Poor oil shows were seen in the Carboniferous interval with a thick coal sequence in the Scremerston Formation (source rock is known to be the oil source in other wells) (Hay et al., 2005).

FORTH APPROACHES

26/04-1

Inclusion gases from Old Red Sandstones (Devonian) are comparable to migrated Carboniferous gas sampled from well 26/08-1. The likely source for these gases is Carboniferous strata from a downthrown block to the northeast with Type III organic matter (Farris et al., 2012).

26/07-1st1

Inclusion gases from the Rotliegend Group have been found comparable to migrated gases from the Carboniferous, indicating a working petroleum system. Oil shows believed to be locally sourced were seen in Visean strata (Farris et al., 2012).

26/08- 1

Shows in the Visean B consisted of dull orange fluorescence and very slow pale milky white cut with no residual oil was seen in sandstones adjoining gas prone shales and coals. Gas shows related to coal intervals within the Visean B interval consist of predominantly methane. The oil shows are believed to have been sourced from Asbian to Brigantian aged strata (Mobil North Sea Ltd, 1992, 1993).

Isotopic signatures from Visean sandstones plot similarly as SNS Carboniferous gases. Plots from the overlying Rotliegend and Westphalian-Stephanian sands are comparable, indicating gas migration from underlying oil shales and coals containing Type III kerogens (Farris et al., 2012).

26/14- 1

Visual kerogen examinations within the Devonian strata commonly found “amorphous” kerogen (10-30%), indicative of an oil-prone source, however these were dark in colour, suggesting the source rock is overmature. What kerogen there is present in the Silurian interval appears to comprise 10-30% vitrinite-like particles (Fenton, 1984).

Studies on fluid inclusions from the Devonian interval indicate the hydrocarbons are migrated Carboniferous wet gas. (Farris et al., 2012)

SUMMARY TABLES AND PLOTS FROM LITERATURE REVIEW

Source	Wells (with shows / discoveries / fluid inclusion) with sampled interval	
Devonian	29/20-1	Possible source for Zechstein and Fulmar Reservoirs
	30/24-2	Devonian Sandstone Reservoir (gas prone coal seams) hypothesized (not measured)
Carboniferous (Marine)	26/07-1st	Visean oil shows
	26/08-1	Visean oil shows
	26/14-1	Devonian fluid inclusion (wet gas)
	41/20-1	Namurian Reservoir and source
Carboniferous (Non-marine)	26/04-1	Old Red Sandstone Reservoir (Devonian)
	26/05-1	Rotliegend Group Reservoir
	26/07-1st	Rotliegend Group Reservoir (gases)
	26/08-1	Visean gas shows; Rotliegend and Westphalian-Stephanian Reservoirs
	29/10-3st1	Auk Formation
	29/20-1	Zechstein and Fulmar Reservoirs, Sourced from Scremerston Coal Groups and Lower Carboniferous Oil Shales (Lacustrine)
		Yoredale gas (dry and wet)
	41/10-1	Agincourt Discovery sourced from Namurian to Dinantian coals
	42/10b-2	Breagh
	42/13-2	Crosgan – Namurian and Dinantian Coals
	42/15a-3	Namurian Interval gas with potential for light oil and condensate
	43/15b-3A	Namurian gas from coal and claystones
	43/17-2	Cavendish Gas Field – gas likely from thermal cracking of condensates
	43/19-1	Kepler Gas Discovery - Westphalian and Namurian locally derived gas
	43/20b-2	Trent Gas Discovery within Namurian interval
	43/24-1 (43/24-P4Z, 43/24-P2)	Gases associated with coaliferous strata in Westphalian A to Namurian
	43/28-1	Boulton Gas Field – Westphalian A to Namurian
	44/21-1	
Jurassic Kimm. Clay	30/24-2	Devonian Sandstone Reservoir (oil prone)
	30/24-25	Devonian Sandstone Reservoir (oil prone)
	30/25a-4	Devonian Old Red Sandstone Reservoir
	31/26a-12	Carboniferous Reservoir
	44/17a-4	Westphalian B Reservoir with Kimm./Draupner oils

Table 3 of source typing in wells from literature review

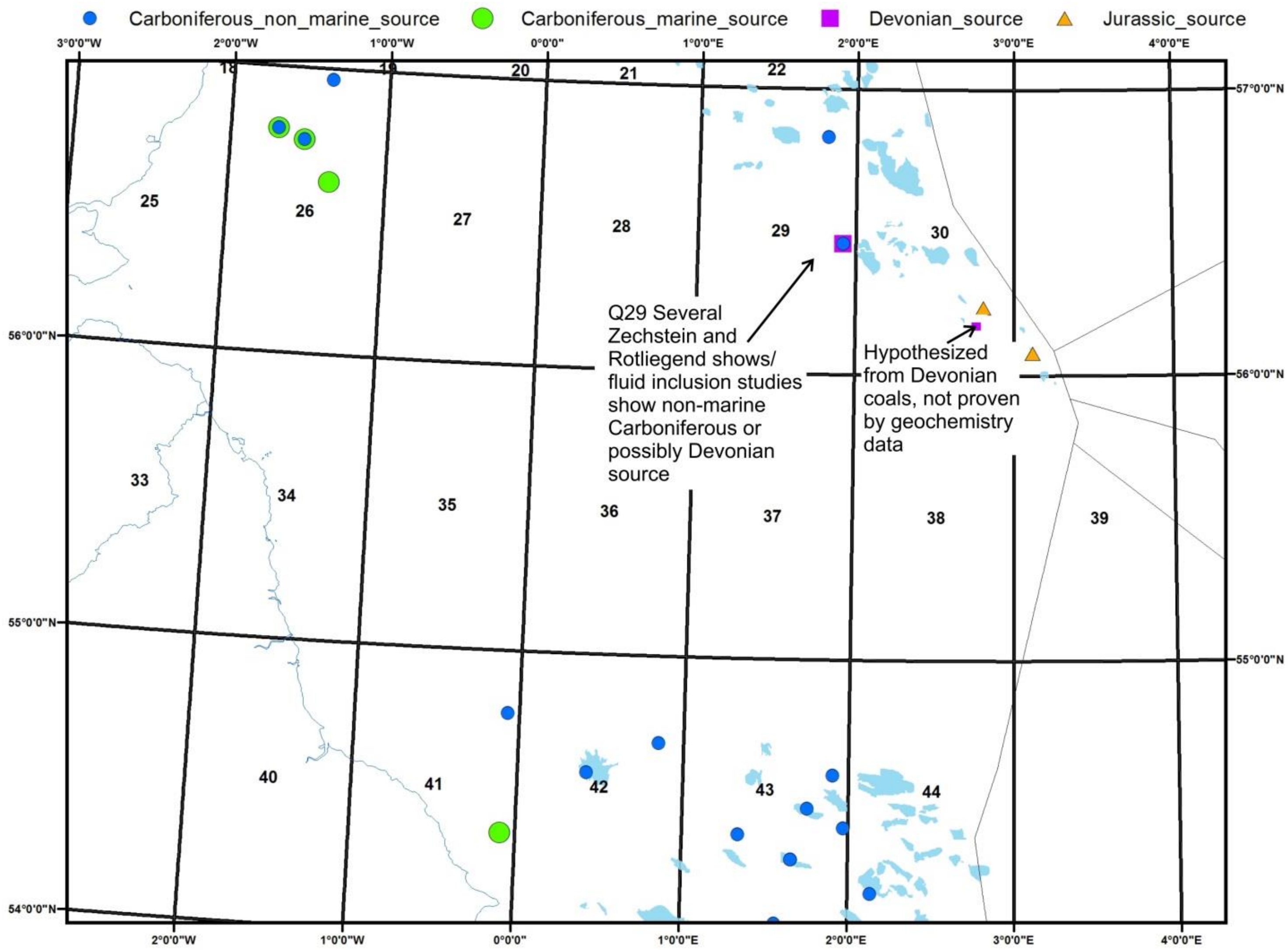


Figure of migrated hydrocarbons, shows and fluid inclusions geochemically analysed for source rock type, from a literature review of well and other donated reports.

Visually Examined Kerogen Types		**Wells (with shows / discoveries / fluid inclusion) where Kerogen type is ≥30%**	
		Well	*Sample Interval*
I	Oil Prone (Liptinite: alginite and resinite)	26/14-1	Devonian
		38/03-1	Devonian
		41/20-1	Namurian?
II	Gas and Oil Prone (Liptinite: sporinite, cutinite, amorphinite)	41/01-1	Carboniferous
		41/15-1	Visean
		41/20-1	Dinantian
		42/13-1	Carboniferous
		43/28-1	Namurian
		44/02-1	Tournaisian, Strunian (DevonoCarb)
		44/08-1	Scremerston Coal Group
		43/20b-2R1	Namurian (very poor quality)
III	Gas Prone (Vitrinite Humic)	41/01-1	Carboniferous
		41/08-1	Carboniferous
		41/10-1	Scremerston Fm, Yoredale Fm
		41/14-1	Namurian, Visean
		41/15-1	Namurian, Visean
		42/09-1	Namurian
		42/13-1	Carboniferous
		42/13-2	Fell Sandstone Group
		42/15a-2	Carboniferous
		42/22-1	Carboniferous
		42/28a-6	Carboniferous
		43/15b-3A	Namurian
		43/16-2	Namurian
		43/21-2	Carboniferous
		43/28-1	Namurian
		43/28-2	Carboniferous
		44/02-1	Tournaisian, Strunian (DevonoCarb)
		44/08-1	Carboniferous Limestone Group equivalent, Scremerston Coal Group

		44/21-1	Carboniferous
		38/22-1	Tournaisian
		39/02-1	Carboniferous
		26/08-1	Carboniferous
		37/12-1	Visean to Tournaisian
		38/03-1	Middle Devonian
IV	Inertinite	41/08-1	Carboniferous
		41/10-1	Scremerston Fm
		41/14-1	Namurian, Visean
		41/05-1	Namurian, Visean
		41/20-1	Namurian, Dinantian
		42/13-1	Carboniferous
		42/13-2	Fell Sandstone Group
		42/15a-2	Carboniferous
		42/22-1	Carboniferous
		43/20b-2R1	Namurian
		43/21-2	Carboniferous
		43/28-1	Namurian
		43/28-2	Carboniferous
		44/02-1	Tournaisian, Strunian (DevonoCarb)
		44/08-1	Carboniferous Limestone Group equivalent
		38/22-1	Tournaisian
		39/02-1	Carboniferous
		37/12-1	Visean to Tournaisian
		42/23-1	Carboniferous
		42/26-1	Carboniferous
		42/28a-4	Carboniferous

Table 4 of kerogen types >30% in wells shown, from literature review

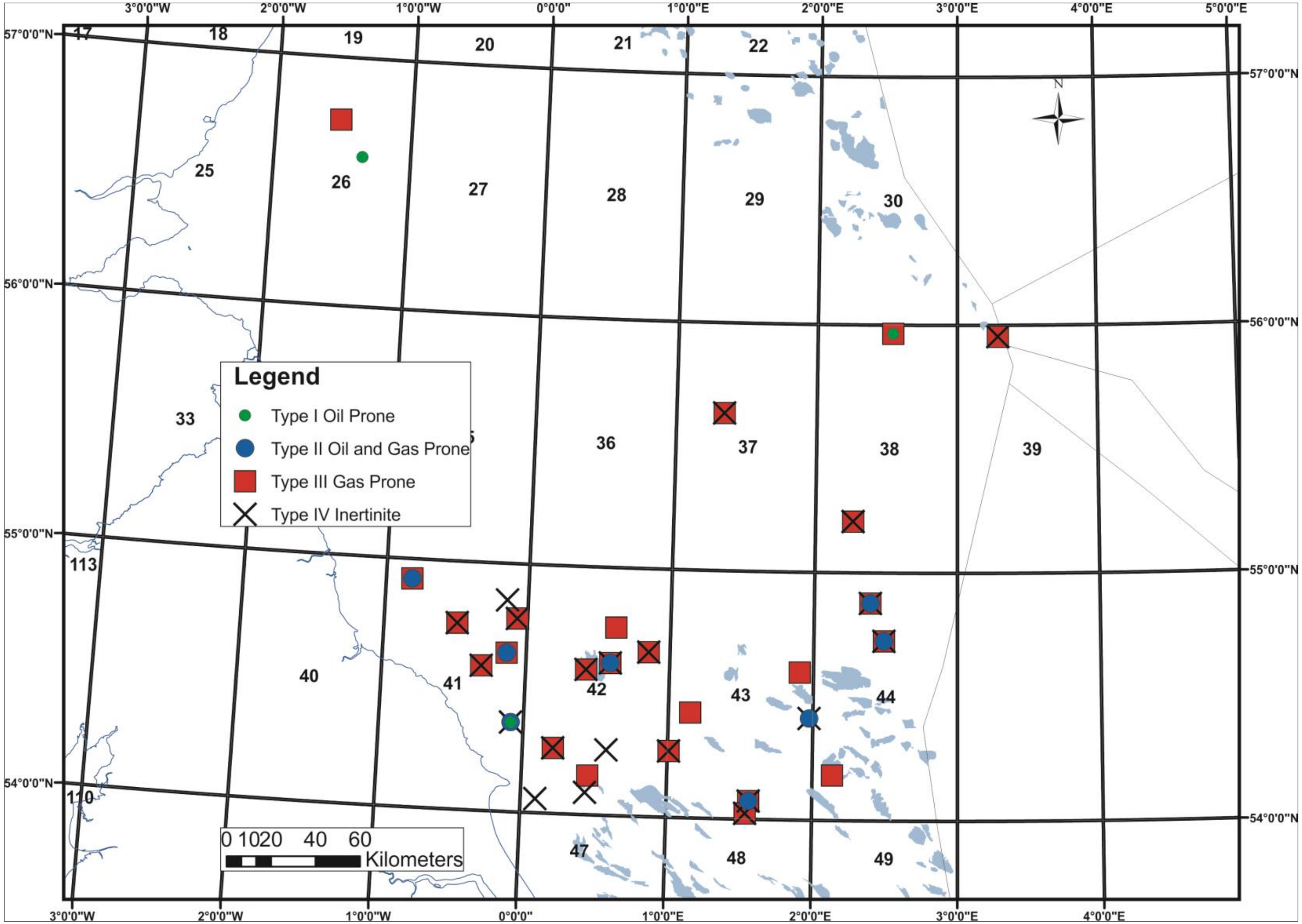


Figure of wells with of kerogen >30% of type in wells shown, from literature review

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