



Practical Application of Sequence Stratigraphy and Risk Analysis for Stratigraphic Trap Exploration

Takeshi Nakanishi

B.Sc. Geology – Osaka City University (Japan)

M.Sc. Geology – Osaka City University (Japan)

National Centre for Petroleum Geology and Geophysics
The University of Adelaide

This thesis is submitted in fulfilment
of the requirements for the degree of Doctor of Philosophy
in the Faculty of Science, The University of Adelaide

September 2002



**THE UNIVERSITY
OF ADELAIDE**
AUSTRALIA

To Dr. George P. Allen.

Table of Contents

Abstract	viii
Declaration	x
Acknowledgments	xi
Chapter 1 – Introduction	1
1.1 Risk analysis in the petroleum exploration business	1
1.2 Stratigraphic traps: the targets to diversify exploration risk	5
1.3 Sequence stratigraphy and stratigraphic trap exploration	15
1.4 Designing an evaluation procedure for stratigraphic trap exploration	18
1.5 Publications	19
Chapter 2 – Methodology	20
2.1 Quantitative geologic risk evaluation and ENPV evaluation in JNOC's projects ...	20
2.1.1 Introduction	20
2.1.2 ENPV: Expected Net Present Value	20
2.1.3 Geologic risk evaluation	29
2.1.4 Consistency – the challenge for the future	36
2.2 Integration of sequence stratigraphy and 3D seismic data visualisation	37
2.2.1 Sequence stratigraphy	37
2.2.2 3D seismic data visualisation	47
2.2.3 Integration of sequence stratigraphic concept and 3D seismic data visualisation.....	52
Chapter 3 – Case Study Areas and Available Data	55
Chapter 4 – General Geologic Setting and Petroleum Systems of the Southern Cooper-Eromanga Basin	64
4.1 Stratigraphic and tectonic setting	64
4.2 Petroleum systems	68
4.2.1 Source rocks and migration.....	68
4.2.2 Reservoirs	69
4.2.3 Traps	71
4.2.4 Seals.....	71

Chapter 5 – Case Study 1 : Moorari 3D Seismic Survey Area	74
5.1 Introduction	74
5.2 Moorari / Woolkina fields	74
5.3 Prospect extraction in Permian succession	80
5.3.1 Sedimentary facies analysis	80
5.3.2 Sequence stratigraphy.....	86
5.3.3 3D seismic data visualisation and prospect extraction	90
5.4 Prospect extraction in Poolowanna Formation	104
5.4.1 Sedimentary facies analysis	104
5.4.2 Sequence stratigraphy	104
5.4.3 3D seismic data visualisation and prospect extraction	107
 Chapter 6 – Case Study 2 : Pondrinie 3D Seismic Survey Area	 114
6.1 Introduction	114
6.2 Pondrinie / Packsaddle fields	114
6.3 Prospect extraction in Toolachee Formation	120
6.3.1 Sedimentary facies analysis	120
6.3.2 Sequence stratigraphy	121
6.3.3 3D seismic data visualisation and prospect extraction	123
6.4 Prospect extraction in Poolowanna Formation	127
6.4.1 Sedimentary facies analysis	127
6.4.2 Sequence stratigraphy	127
6.4.3 3D seismic data visualisation and prospect extraction	131
 Chapter 7 – Case Study 3 : Merrimelia 3D Seismic Survey Area	 135
7.1 Introduction	135
7.2 Fields in the Merrimelia 3D seismic survey area	135
7.2.1 Merrimelia/ Meranji/ Pelican fields	135
7.2.2 The Birkhead and Hutton oil reservoirs in the Merrimelia Field	141
7.3 Distribution of the upper and middle Birkhead reservoirs	143
7.3.1 Sedimentary facies analysis	143
7.3.2 Sequence stratigraphy	144
7.3.3 3D seismic data visualisation	148
7.3.4 Reservoir and seal rock distribution	152
7.3.5 Capacity of the point bar sandstone reservoir.....	152

Chapter 8 – Implications for Sequence Stratigraphy	
in the Cooper-Eromanga Basin	155
8.1 Introduction	155
8.2 Sequence stratigraphic framework for the case study areas	155
8.3 Some implications for the sequence stratigraphy	
in the other areas of the Cooper-Eromanga Basin	158
Chapter 9 – Quantitative Risk Assessment for Prospect Inventory	163
9.1 Introduction	163
9.2 Play type of prospects	164
9.2.1 Moorari 3D seismic survey area	164
9.2.2 Pondrinie 3D seismic survey area	168
9.3 Chance of geologic success	170
9.3.1 Geologic chance factors for stratigraphic traps	170
9.3.2 Chance of geologic success of prospect inventory	173
9.4 Probabilistic reserves estimation	177
9.4.1 Parameter estimation	177
9.4.2 Reserves estimation results	180
9.5 Efficient exploration frontier	181
9.5.1 Efficiency of single exploration wells	181
9.5.2 Efficient exploration frontier of multiple exploration wells	182
9.6 Expected net present value analysis for portfolio candidates	185
Chapter 10 – Limitations	189
10.1 Geologic chance factors	189
10.2 Dependencies in multiple prospect	189
10.3 Estimation of maximum case of reserves distribution	190
10.4 Cash flow model	190
10.5 Reward estimation as mean value of many projects	192
10.6 Post audit	192
Chapter 11 – Conclusions	193
11.1 Summary	193
11.2 Concluding statement	199
References	200

Appendices

Appendix A

Monte Carlo Simulation Result of Probabilistic Reserves Estimation for Prospects

Appendix B

Publication: Nakanishi (2000) – Quantitative Geologic Risk Evaluation and Expected Net Present Value Evaluation in JNOC's Projects.

Appendix C

Publication: Nakanishi & Lang (2001a) – The Search for Stratigraphic Traps Goes On-
Visualisation of Fluvial-Lacustrine Successions in the Moorari 3D Survey,
Cooper-Eromanga Basin.

Appendix D

Publication: Nakanishi & Lang (2001b) – Visualisation of Fluvial Stratigraphic Trap
Opportunities in the Pondrinie 3D Survey, Cooper-Eromanga Basin.

Appendix E

Publication: Nakanishi & Lang (2002) – Towards an Efficient Exploration Frontier:
Constructing a Portfolio of Stratigraphic Traps in Fluvial-lacustrine Successions,
Cooper-Eromanga Basin.

Appendix F

Timetable.

Abstract

This research outlines an evaluation procedure for stratigraphic trap exploration by employing sequence stratigraphy, 3D seismic data visualisation and quantitative risk analysis with case studies in an actual exploration basin.

Open-file Moorari and Pondrinie 3D seismic survey datasets chosen to test the procedure come from the Cooper-Eromanga Basin, onshore Australia, encompassing the Permian fluvio-lacustrine, Patchawarra, Epsilon, and Toolachee formations and the Jurassic fluvial, Poolowanna Formation. Employing an integration of sequence stratigraphic concepts applied to non-marine basins and advanced 3D seismic data visualisation, eight stratigraphic trap prospects were extracted to be included in an exploration inventory..

In the Merrimelia 3D seismic survey dataset, the potential oil reservoir capacity of fluvial point bar sandstones in the Birkhead Formation was calculated (12.6 to 25.6 MMbbl in place), although the point bars were confirmed as water-wet and an effective stratigraphic trap was not included as prospect for the exploration inventory.

The geologic chance factors for an effective stratigraphic trap include the followings within each depositional systems tract: reservoir, top-, lateral- and bottom-seal. Additionally, the seal effectiveness of the adjacent depositional systems tracts and the appropriate spatial arrangement of these factors form part of the geologic chance factors. The confidence values for the existence of geologic chance factors were estimated according to sequence stratigraphic contexts, and multiplied to calculate the chance of geologic success of each prospect varying 4 to 34%. For probabilistic reserves estimation, geologically reasonable ranges were estimated for each reserves parameter employing Monte Carlo simulation to calculate the reserves distribution, ranging 3.9 to 21.2 bcf as mean values.

When a series of possible exploration portfolios, including single or multiple prospects from the prospect inventory are plotted in terms of the chance of geologic success vs. the mean value of the reserves estimate, an efficient exploration frontier emerges. The portfolio

candidates on the efficient exploration frontier were assessed with regard to expected net present value (ENPV) using a simple pre-tax cash flow model for the gas producing in the Cooper-Eromanga Basin. The results indicate that appropriate portfolios include multiple prospect exploration targeting the lowstand systems tract plays by single or multiple exploration wells.

Declaration

This work contains no material which has been accepted for the award of any other degree or diploma in any university or other tertiary institution and, to the best of my knowledge and belief, contains no material previously published or written by another person, except where due reference has been made in the text.

I give consent to this copy of my thesis, when deposited in the University Library, being available for loan and photocopying.

Takeshi Nakanishi

2 Sept 2002

Date

Acknowledgements

I would like to sincerely thank Japan National Oil Corporation (JNOC) for generous financial support. Particular thanks goes to Mr Noboru Tezuka for internal endorsement for establishing this research. Special thanks Mr Yasuhisa Kanehara for encouragement throughout the duration of the study.

I would like to thank Primary Industries and Resources SA (PIRSA) for courteously providing open file data in the Cooper-Eromanga Basin.

Special thanks to Dr Peter Rose for valuable suggestions regarding risk analysis from the early stage of this work. Thank you also for your providing information regarding current issues in industry.

I had many valuable discussions and suggestions to improve this research from arrange of industry experts. Special thanks to Dr Rhodri Johns (Santos), Mr Michael Frost (Beach Petroleum), Mr Steve Taylor (Santos), Ms Elinor Alexander (PIRSA), Dr Peter Boulton (PIRSA) and Mr Neil Gibbins (Beach Petroleum).

Thanks to supervisor, Assoc. Prof. Simon Lang (National Centre for Petroleum Geology and Geophysics, NCPGG) for providing valuable technical advice, overseeing and encouraging this research. Without your wide and deep ideas on sequence stratigraphy, I could not have accomplished this job.

Thanks to the staff and students of NCPGG. Special thanks to Director, Prof. John Kaldi for providing international-standard circumstance in NCPGG. Thanks to Mr Andy Mitchell for organising the database and providing information regarding seismic data interpretation.

Finally, I thank my family, Naomi, Akatsuki and Fuyuhi for your cheering me under the blue sky of Adelaide.

Chapter 1

Introduction

1.1 Risk analysis in the petroleum exploration business

Petroleum exploration is an investment and the aim is to achieve a profitable return. However, there are many aspects that introduce uncertainty and therefore increase the risk of losing capital (Figure 1.1.1). In order to control the profitable return, many oil companies are increasingly assessing their petroleum exploration projects with quantitative risk analysis (Rose, 1992a & b; Alexander & Lohr, 1998; McMaster, 1998; Kubota et al., 1999; Nakanishi, 2000; Rose, 2001).

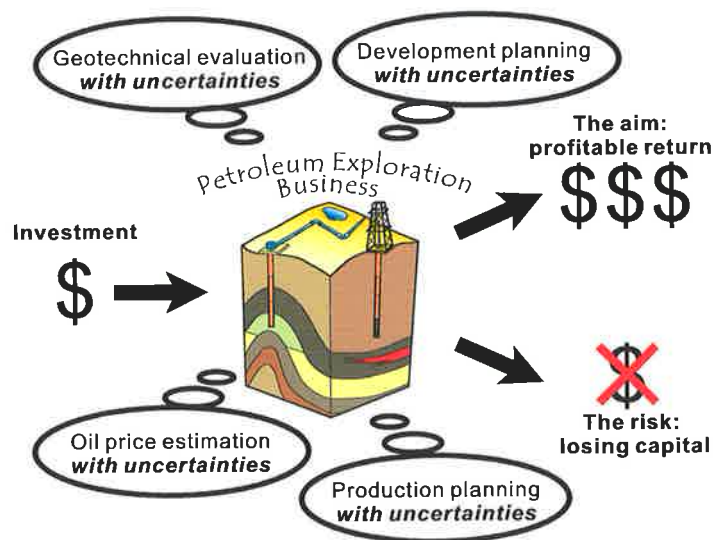


Figure 1.1.1. Concept of an investment in the petroleum exploration business. The aim of the investment is a profitable return. However, there are many aspects that introduce uncertainty and therefore increase the risk of losing capital. Quantitative risk analysis is an approach to assess the chance of success/failure, potential gain and potential loss, in order to control the profit from the exploration businesses.

Risk and Uncertainty are not synonymous (Rose, 1987). Risk connotes the threat of loss (Figure 1.1.2). Risk decisions weigh the level of investment against four considerations:

- Net financial assets.
- Chance of success/failure.
- Potential gain.
- Potential loss.

The last three considerations must rely on estimates, made under uncertainty, of the range of probabilities that some condition may exist or occur (Rose, 2001). Every exploration decision involves considerations of both risk and uncertainty. Risk comes into play in deciding how

much we are willing to pay for additional data or mineral interests, considering the high impact of front-end costs on project profitability. Uncertainty is intrinsically involved in all geotechnical predictions about the range of magnitude of the inferred mineral deposit, the chance of discovery, and the cost of finding and developing it. Therefore, once prospects have been identified, the problem in serial exploration decision making is to be consistent in the way we deal with risk and uncertainty, and to perceive uncertainty accurately and reduce it where possible (Rose, 2001).

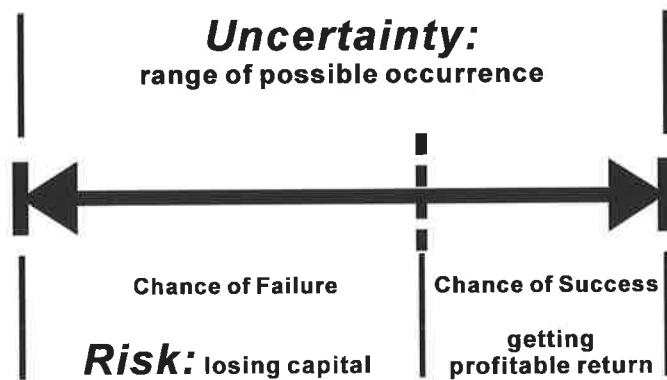


Figure 1.1.2. Relationship between uncertainty and risk. An uncertainty where we cannot determine which case will happen, may cause a failure of a business identified as a risk.

The different state of the uncertainties must be recognised according to the difference stage of the exploration business (Figure 1.1.3). In an exploration stage (i.e. drilling a wildcat to a prospect which has not been penetrated by a well), the major uncertainty is the existence of hydrocarbon accumulations and the potential reserve size. These uncertainties are involved in the geotechnical expectation of the existence of geologic factors which determine the hydrocarbon accumulation. Exploration experience shows that there is a considerably low chance of finding economically viable hydrocarbon accumulation, however the risk capital for prospect exploration is normally low (e.g. license acquisition fee, costs of seismic survey, exploration wells) when compared with the risk capital in the development stage. Risk analysis for the prospect exploration therefore should be prepared for managing the chance of success and the potential total gain from a series of exploration programs relative to the investment. This research will focus on the exploration stage for stratigraphic trap prospects.

In contrast with prospect exploration, the development stage (where wells have penetrated and confirmed hydrocarbon accumulation), the uncertainties lie rather in economic expectations (e.g. recoverable factor, development plan, production costs, oil price) than in geotechnical

expectations. This is because the chance of finding hydrocarbons is recognised as one hundred per cent and the range of the in-place reserve size is reduced in this stage. Importantly, the risk capital to construct production facilities can be large enough to make a significant risk for a major damage to the financial situation of the corporation if failure occurs; hence the risk analysis must be prepared to demonstrate not only the potential gain but also the sensitivities of the uncertainties to the maximum negative cash flow in the front-end of the business which must be within the risk tolerance of the corporation.

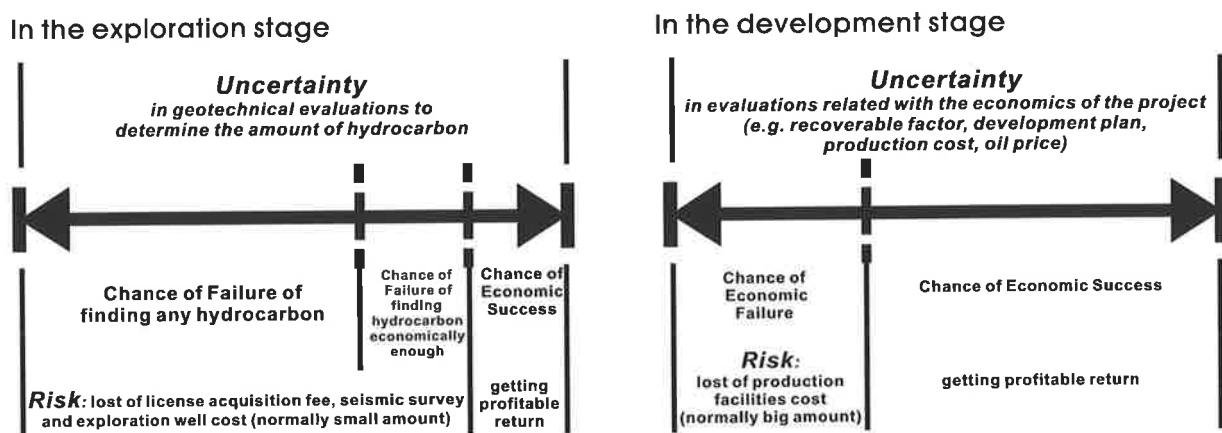


Figure 1.1.3. Comparison of the state of uncertainty between an exploration stage and a development stage. In the exploration stage (the objective of this research), major uncertainties exist in the geotechnical evaluation to determine the amount of hydrocarbon. Contrary to the exploration stage, uncertainties are involved in evaluations related to economics of the project in the development stage. Importantly, the amount of the risk capital which should be decided to invest in each stage is different; hence the focus of the risk analysis must be changed according to the stage of the project.

Although extensive scientific and geotechnical work is essential to successful petroleum exploration, risk analysis should be managed in terms of monetary value, because the ultimate aim of exploration is not merely to discover hydrocarbons, but to make a profitable return on the investment capital. Comparing exploration opportunities based on the monetary value allows the construction of an appropriate portfolio including global investment chances (i.e. be able to compare, in monetary value, 100 million bbl of oil in East Siberia and 100 bcf of gas in onshore Australia). Many oil companies now use expected monetary value (EMV), or expected net present value (ENPV) which has been derived from EMV and used in this thesis, to manage exploration investments (Rose, 1992a; Alexander & Lohr, 1998; McMaster, 1998; Johns et al., 1998; Kubota et al., 1999; Nakanishi, 2000; Rose, 2001). ENPV is the summation of the products of the chance of success and the monetary mean value of the success case, and the chance of failure and the monetary mean value (usually negative) in the failure case.

Investment in a project of which the ENPV is more than zero is usually recognised as a rational decision.

A good way to control the profitability from the exploration business is to invest into as many types of projects as possible, which have been consistently assessed by risk analysis and have positive ENPV. Total profit uncertainty is reduced as mean value as a result of multiple projects, even though each project has a fluctuation in its profitability. As in common stock business or financial ventures, a risk-reward optimisation can be applied to petroleum exploration to determine an appropriate exploration portfolio from project inventory (Bernstein, 1996; Rose, 2001). By employing the appropriate portfolio construction, a corporation can make a reasonable decision for exploration investment to reach their economic objectives.

1.2 Stratigraphic traps: the targets to diversify exploration risk

One of the ways to diversify risk capital is to invest globally in many projects which have positive ENPVs. It is often difficult, however, for corporations to deal effectively with many projects where opportunity is limited (e.g. a non-accessible area for the corporation to operate, lack of funds). An alternative approach is to diversify the risk by investing into as many exploration play types as possible within a limited area (Figure 1.2.1). Corporations have tended to dislike nominating stratigraphic trap plays into their inventory, particularly in the early stage of exploration, even if they should invest in as many play types as possible. Such behaviour is caused by recognising the higher risk of finding hydrocarbons in stratigraphic trap exploration than in conventional trap exploration.

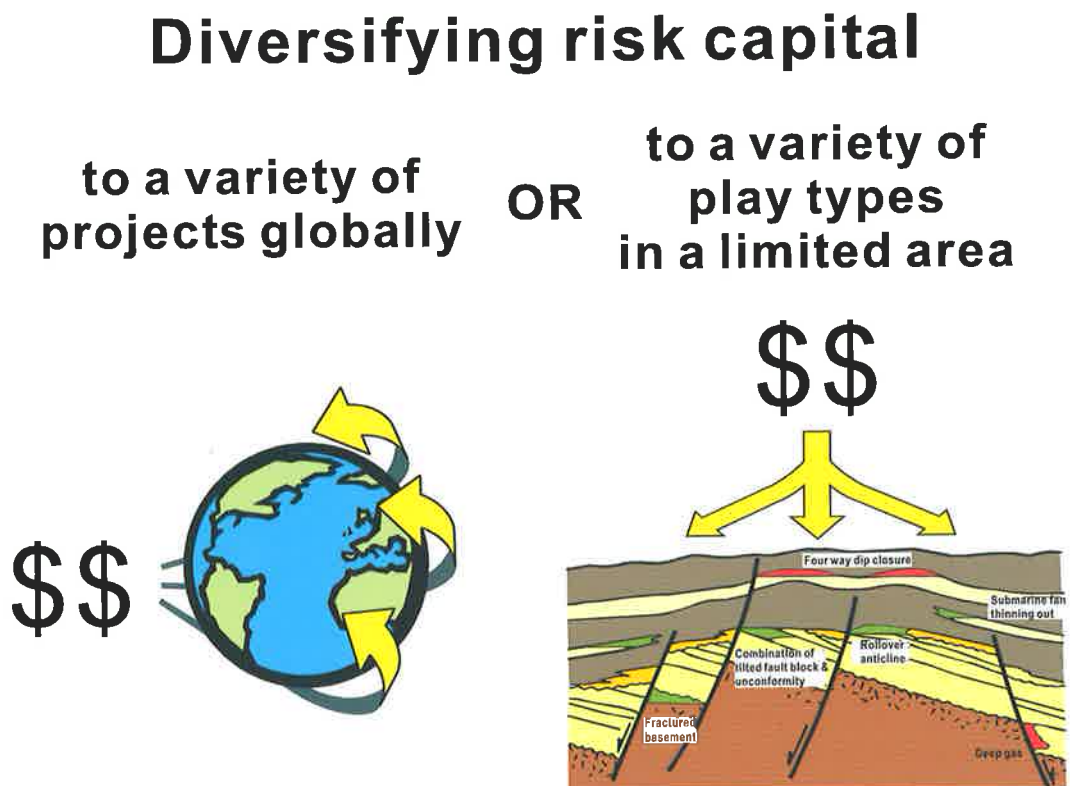


Figure 1.2.1. Concept of diversification of risk capital.

However, recent advances in geoscience, especially the development of sequence stratigraphy and 3D seismic data techniques, have greatly contributed to diminishing geologic uncertainty. Furthermore the economic impacts of the discoveries in stratigraphic traps have been significant. If we can identify the stratigraphic trap prospects effectively, we should expect outcomes which are the same as global investments into many areas.

To demonstrate the impact of the stratigraphic trap discoveries, a series of fields which have

stratigraphic trap components were selected from Brazil, USA, Canada and Australia and categorised into a sequence stratigraphic setting to show examples of stratigraphic trap variation.

Lowstand systems tract setting

A submarine channel and fan complex play is represented within the lowstand systems tract setting. As examples of the play type, the Marlim field and the Albacora field are located in the Campos Basin, offshore Brazil in water depths ranging from 250 to more than 2000m. The areas cover 350km² and 235km² and the reserves are assumed to have over 14.1 and 4.5 billion barrels of oil in place respectively (Candido & Cora, 1992). The Marlim and Albacora turbidite reservoirs, Eocene to Miocene Marlim Sandstone, are associated with a submarine channel / fan complex on the slope to the basin floor of the shelf system on the passive margin (Figure 1.2.2). The eastern portions of both fields are dominated by lobe-type sandstones with great lateral continuity. To the northwest, these sand bodies become elongated, presenting geometry and facies typical of channel deposits. These sandstones thin out laterally to the mudstones on the slope or the basin floor, and make mounds which themselves resulted from the differential compaction between sandy and muddy deposits. The distribution of the reservoir and seal rocks result in the mound and the stratigraphic trap combination. Peres (1993) describes that the Oligocene submarine-channel system, which makes extremely large stratigraphic trap fields, resulted from a relative fall of sea level, causing the subaqueous exposure of the shelf sediments resulting in sediment reworking in a shallow, high-energy marine environment and the transportation of the shelf sediments to the slope and the basin floor.

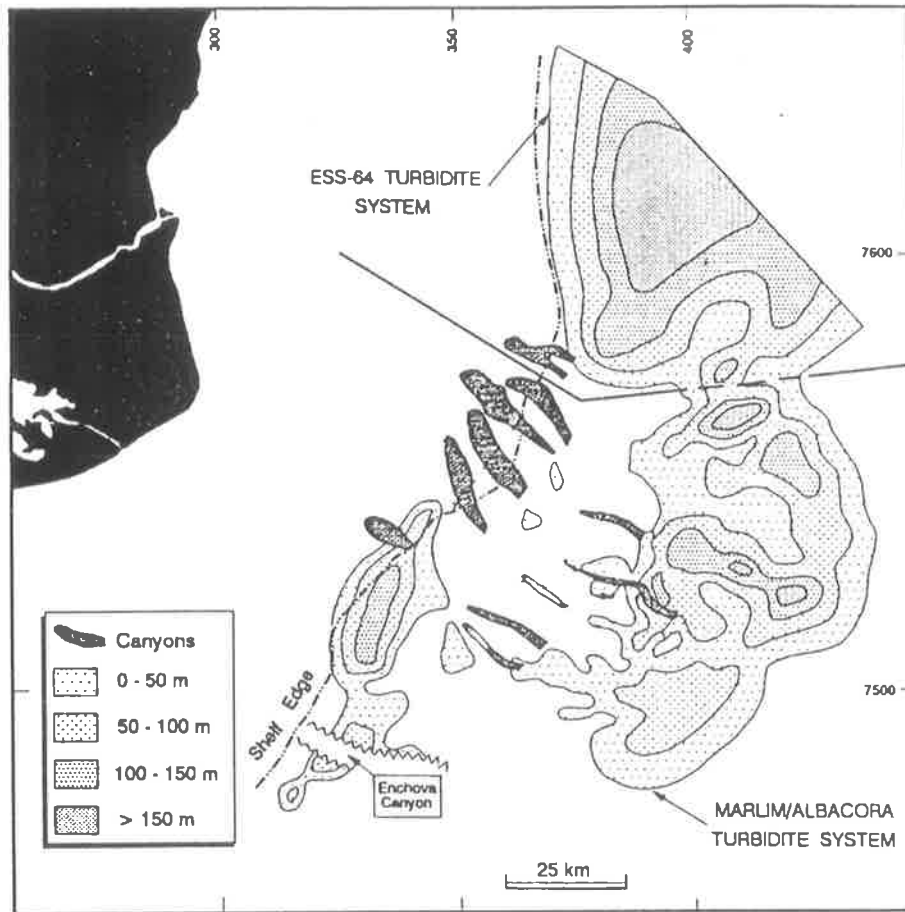


Figure 1.2.2. Net isopach map of the Campos Basin Oligocene sandstones interpreted from seismic data and well log data (modified after Peres, 1993). Dashed line represents the turbidite contemporaneous shelf edge, and the heavy solid line divides the sandstones into two systems: ESS-64 on the north and Marlim/Albacora on the south. The map also shows the relationship between the deep-water sandstones and the outer shelf and lower slope/basin-plain submarine canyons.

Combined lowstand systems tract and transgressive systems tract setting

An incised valley fill play is given as an example for the combined lowstand systems tract and transgressive systems tract setting. As an example of the play type, “the Clinton-Weatherford Upper Red Fork Trend” is located along the north flank of the central Anadarko Basin, in onshore Oklahoma, USA. The primary pay in the play is the Middle Pennsylvanian upper Red Fork sandstone that forms a continuous east-west-trending depositional system (Clement, 1991). The producing area includes portions of Southwest Geary, West Bridgeport, Libbie, South Hydro, South Weatherford, East Clinton, Clinton, Stafford, and Foss fields. The total combined areal extent of these fields is 194 km² and the estimated ultimate recovery in the upper Red Fork is 480 bcf of gas and 10.5 million bbl of condensate. The Upper Red Fork sandstone is deposited in the fluvial channel environment within the east-west elongated incised valley on the Middle Red Fork alluvial plain and shelf (Figure 1.2.3). The incised fluvial channel sandstones are trapped laterally against impermeable older, marginal marine

shales and siltstones or contemporaneous terrigenous shale fill (clay plugs) and vertically by younger alluvial shale and/or abnormally pressured marine shale valley fill. This incised valley fill sequence was caused by the falling relative sea level associated with the left-lateral compressional deformation at this time, followed by marine flooding during a relative rise in sea level.

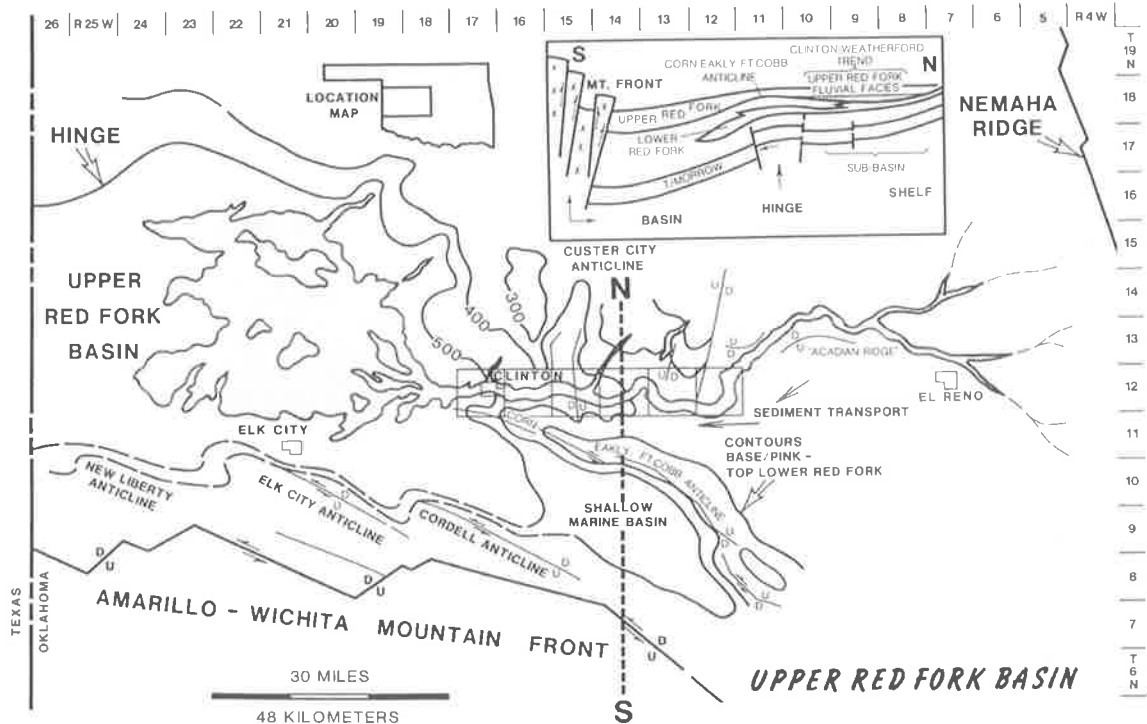


Figure 1.2.3. Upper Red Fork Basin after structural uplift along Corn-Eakly, Ft. Cobb anticline in late middle Red Fork time (Clement, 1991). Sediment transport and progradation were deflected westward along the north side of the anticline.

Isolated sandbodies developed within a forced regression are identified as another possibility for a stratigraphic trap in a lowstand-transgressive systems tract combination. Rapid fall of relative sea level causes a seaward shift of the shoreline leading to isolated sandbodies in the lowstand delta (Posamentier et al., 1992; Posamentier & Allen, 1999; Posamentier & Morris, 2000; Plint & Nummedal, 2000), of which the landward edge contacts the previous highstand offshore mud (Figure 1.2.4). The subsequent rise in relative sea level causes marine flooding associated with a transgressive surface of erosion (ravinment surface) and eventually sealed with marine muds covering the lowstand delta, thus constructing a stratigraphic trap. An example is the Joarcam Field in Alberta, Canada (Posamentier & Chamberlain, 1993). The reservoir consists of prograding shoreface deposits of the Lower Cretaceous Viking Formation, trending northwest-southeast with 4km wide and 40km long (Figure 1.2.4). Deposition of the areally restricted regressive shoreface sand occurred during a relative sea-level stillstand following an interval of relative sea level fall. The landward edge of the shoreface sands is

detached from the sandbody of the previous highstand systems tract. The shoreface progradation ended when a relative sea-level rise caused shoreline transgression, and was enveloped by offshore muds. Pressure data shows that the lowstand shoreface sandstone is separated from the other sand units, suggesting a stratigraphically isolated sandbody (Posamentier et al., 1992; Posamentier & Chamberlain, 1993).

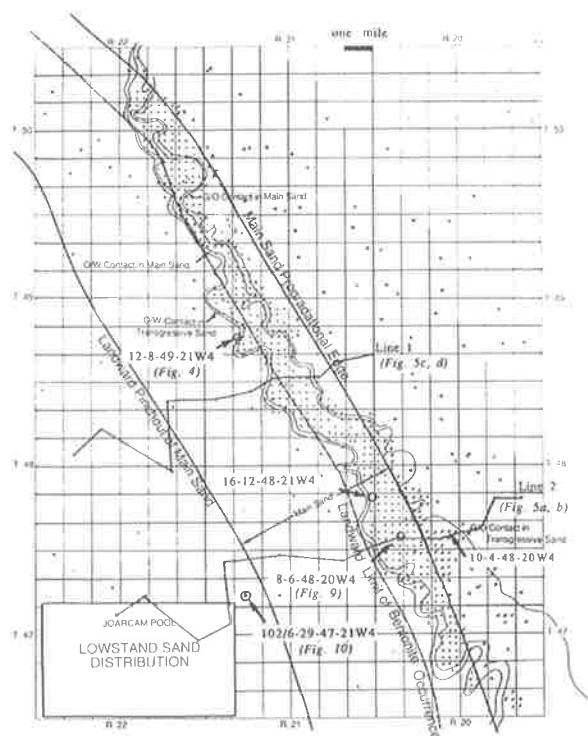


Figure 1.2.4. The lowstand systems tract reservoir in the Joarcam Field, Alberta, Canada, linearly trending northwest-southeast. The updip and downdip limits of the sandy facies was controlled by northeastward prograding wedge in the lowstand stage (Posamentier and Chamberlain, 1993).

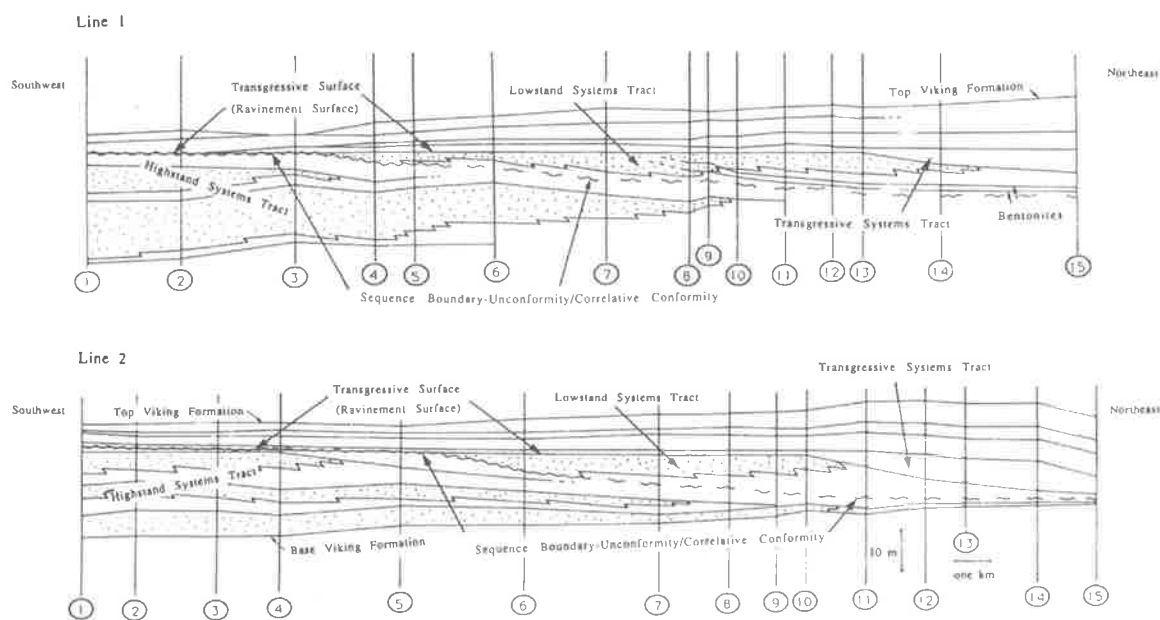


Figure 1.2.5. Dip-oriented cross-sections across Joarcam Field. Locations shown in Figure 1.2.4. In the proximal part of the LST, the sequence boundary at the base of the shoreface succession is characterised by sandy shoreface deposits sharply overlying offshore muds of previous highstand systems tract. The lowstand systems tract wedge is enveloped by offshore muds of the transgressive system tract following the relative sea-level-falling (modified from Posamentier and Chamberlain, 1993).

Transgressive systems tract setting

A transgressive barrier-island type is identified as the stratigraphic trap example in the transgressive systems tract. The Wembley field is located in Alberta, Canada, with in-place reserves of 56 million bbl in oil and 665 bcf in gas. The Triassic Halfway Formation of the field contains two stacked sandstone intervals (Willis & Moslow, 1994). The lower reservoir comprises a regressive shoreface and tidal-inlet channel sandstones which were deposited by a southwesterly prograding barrier-island system in the highstand systems tract (Figure 1.2.6a). The upper Halfway sandstone is the transgressive barrier-island formed by shoreface retreat during the marine flooding event, and the distribution is restricted to an area adjacent to the paleo-landward limit of the ravinment surface in the flooding (Figure 1.2.6b). The upper and lower Halfway sandstone reservoirs are separated both stratigraphically and hydrostatically by 1m of lagoonal dolomitic mudstone throughout the field area. The transgressive barrier island sandstones are 2-6m thick, up to 2km wide, and form paleo-shoreline trending tens of kilometres in length. The stratigraphic trap consists of the lateral seal caused by updip pinch-out of the sandstones in backbarrier mudstones and the top seal is provided by nonmarine mudstone and evaporites which buried the abandoned transgressive barrier in the following highstand stage.

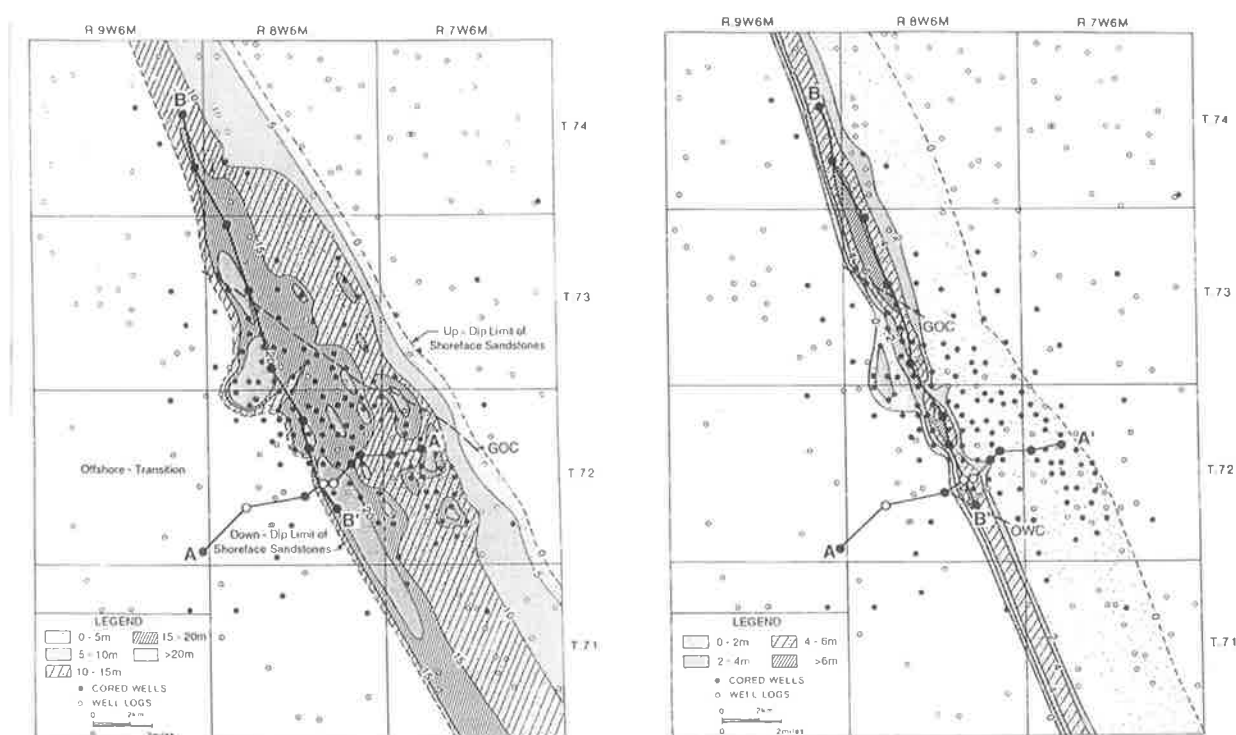


Figure 1.2.6. Isopach maps of the main reservoir of the Halfway Formation in Wembley Field (Willis & Moslow, 1994). a) Isopach map of regressive shoreface and tidal-inlet channel sandstones which were deposited by a southwesterly prograding barrier-island system in the highstand systems tract b) Isopach map of transgressive barrier-island sandstones. Gas-oil (GOC) and oil-water (OWC) contacts are shown.

Transgressive sheet sandstones can make stratigraphic traps. The Newburg and South Westhope fields, located along the eastern margin of the Williston Basin, North Dakota, USA, have a stratigraphic trap component in the transgressive sheet sands as a part of their oil producing reservoir (Le Fever & Le Fever, 1991). The reservoir is located in the lowest unit of the Triassic Spearfish Formation and the thickness varies from 3 to 12m. The sandstones are onlapping on the unconformity against the Mississippian Berentson Beds limestone and anhydrite, and ultimately pinches out up-dip towards the north-east and are overlain by impermeable marine shale. What is remarkable is that the oil pay zones vary according to the lithology of the underlying Berentson Beds, such as the impermeable rocks which can work as bottom seals of the stratigraphic trap system (Figure. 1.2.7).

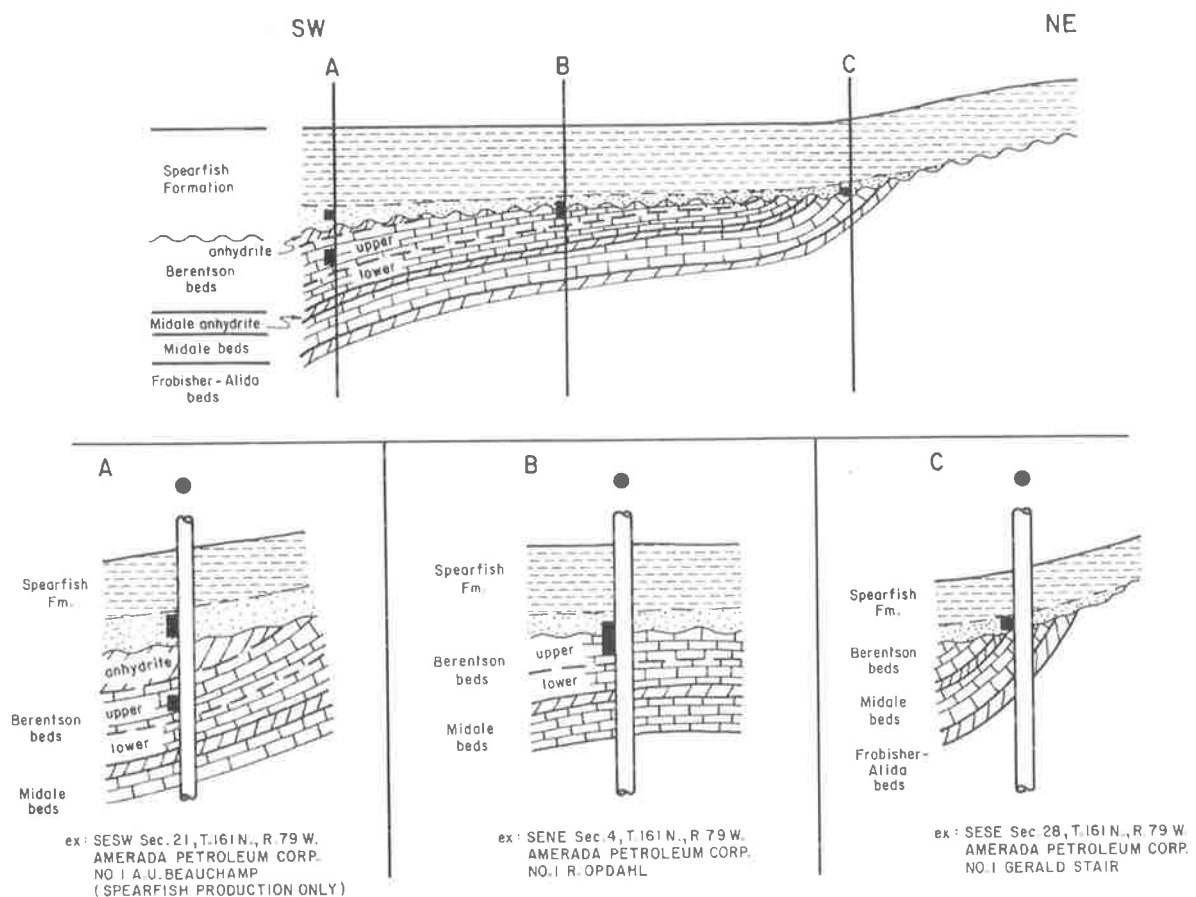


Figure 1.2.7. Schematic diagram showing different trapping situations present in Newburg and South Westhope fields. In addition to the Spearfish and Berentson production, the Midale beds produce locally throughout the fields (Le Fever & Le Fever, 1991). (A) Production may come from the Spearfish Formation, Berentson beds, or both. An impermeable layer of formation anhydrite, secondary anhydrite, or shale is below to the unconformity surface. In this case, the Spearfish pay section would be sourced from beds downdip. (B) The two producing zones are in contact, and the perforations cross the unconformity surface. (C) Perforations are only in the Spearfish Formation. The Spearfish is sourced downdip by fractures or by contact with the Berentson beds.

Another example is a delta progradation within an overall transgression. The Glenn Pool field is located in onshore Oklahoma, USA. The field is near the centre of the Northeast Oklahoma platform, which is situated between the Ozak uplift to the east, the Nemaha Ridge to the west, and the Arkoma Basin to the south (Figure 1.2.8). The field covers approximately 111km² and it is estimated that the field will ultimately produce over 400 million bbl (Kuykendall & Matson, 1992). The primary reservoir is the Middle Pennsylvanian age Bartlesville sandstone. The stratigraphic trap of the Bartlesville reservoir resulted from the updip (eastward) pinch-out, deltaic sandstones into laterally sealing siltstones and shales and overlying marine shales. This sandstone was deposited during overall transgression onto the existing shelf, interrupted by episodes of regression that were marked by southward progradation of deltas during stillstand sea level stages (Al-Shaieb et al., 1989). The general character of the Bartlesville sandstone may change greatly within a relatively short distance, and the sandstone has been interpreted as deltaic distributaries, some or all of which may be incised by a fall in relative sea level (Shelton, 1973).

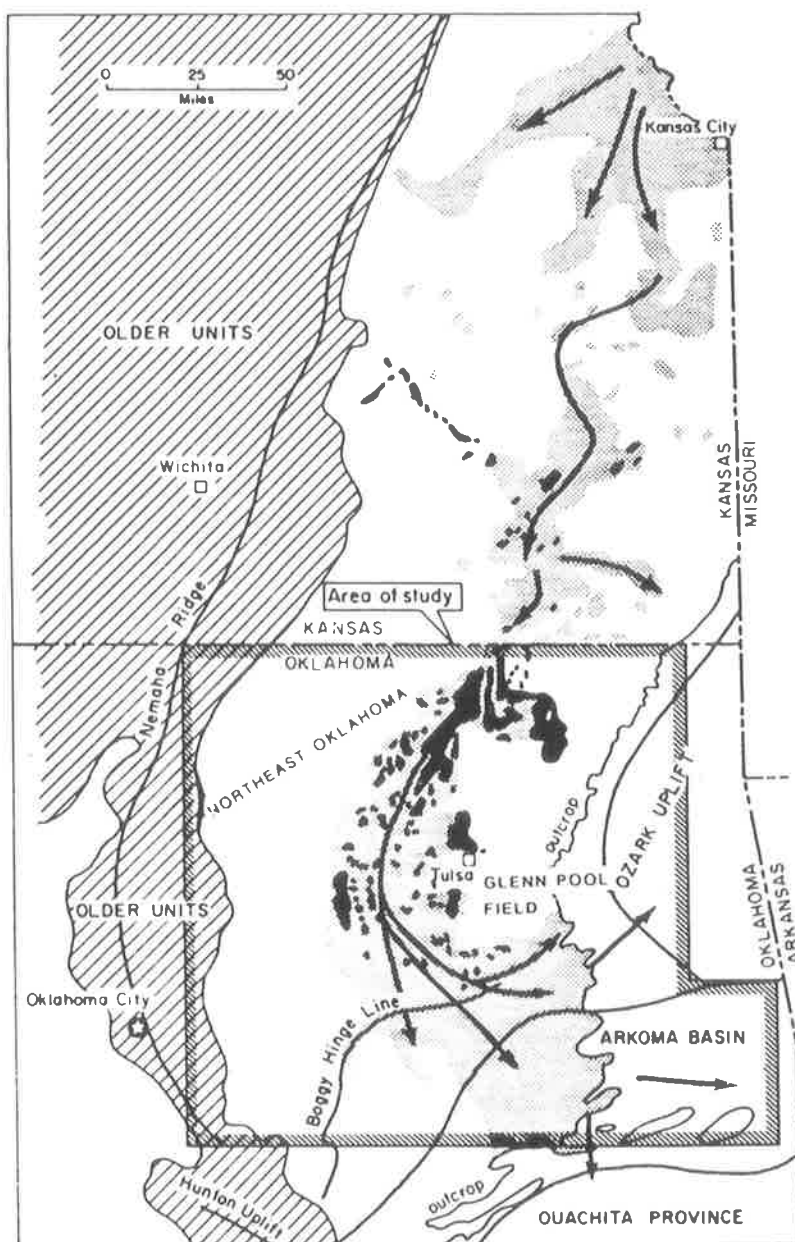


Figure 1.2.8. Generalised depositional framework of the Bartlesville-Bluejacket (Glenn) sandstone and location of producing fields (black). (Kuykendall & Matson, 1992)

A fluvial channel and floodplain complex can also form stratigraphic traps. This occurs more in intervals deposited during increased alluvial accommodation space (rising relative base level), which is characterised by low channel/floodplain ratios and isolated sandy channel fills (Figure 1.2.9, modified after Legarreta et al., 1993; Posamentier & Allen, 1999). The Dirkala and Dirkala South fields are located in the southern Cooper and Eromanga Basin, South Australia. The reservoir is the Jurassic Birkhead Formation which consists of fluvial channel and floodplain deposits. The reservoir distribution is restricted by the fluvial channel pattern (Figure 1.2.10). The lateral change from the channel fill facies to the floodplain mudstone exists updip toward the north-west along the structural nose and causes the pinchout stratigraphic trap (Mackie & Gumley, 1995). The reserves size has not been disclosed.

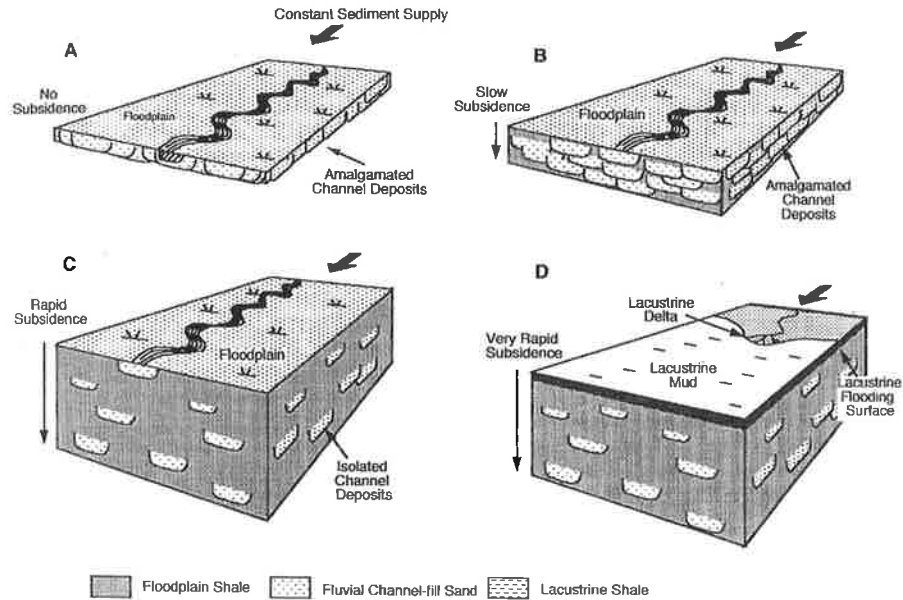


Figure 1.2.9. Illustration of the effects of increasing the rate of fluvial accommodation on alluvial stacking patterns (Allen et al., 1996). Sediment supply is assumed to be constant and fluvial accommodation is caused by tectonic subsidence. The higher the accommodation increase, the more isolated are the channels within floodplain shales. When the rate of accommodation is much higher than the rate of sediment supply, a lacustrine system is formed on the alluvial plain (D).

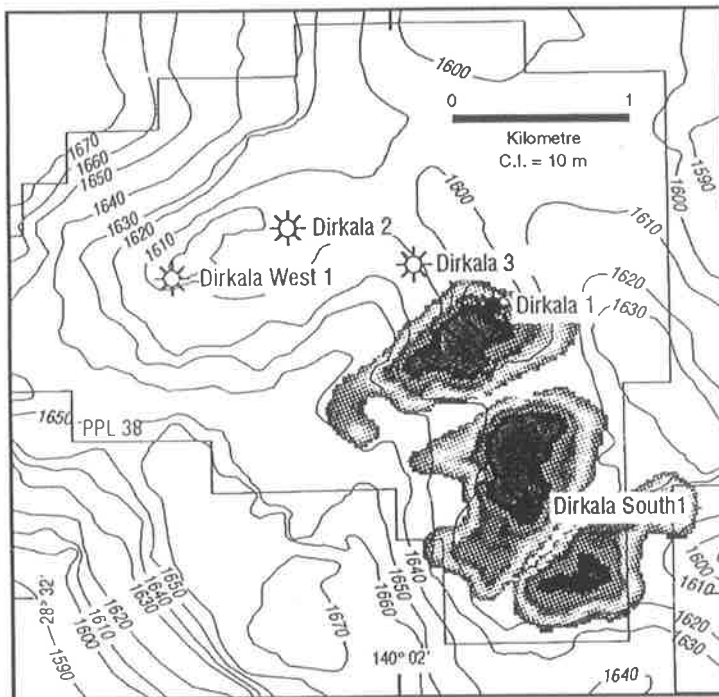


Figure 1.2.10. Depth structure map of Birkhead Formation with Birkhead sand thickness underlay derived from the time thickness in the seismic interval (black=thick, grey=thin) (Mackie & Gumley, 1995).

1.3 Sequence stratigraphy and stratigraphic trap exploration

The concept of a depositional systems tract provides a predictive framework for the spatial distribution of sedimentary facies. Sequence stratigraphy can therefore be used to evaluate the distribution of reservoirs and seals more systematically and with less uncertainty than lithostratigraphic approaches (Weimer & Posamentier, 1993; Posamentier & Allen, 1999). Especially for stratigraphic traps which have complex reservoir and seal components, spatial integration of sedimentary environments with sequence stratigraphic concept is a powerful tool to extract effective stratigraphic trap prospects.

Before sequence stratigraphy was established, MacKenzie (1972) comprehensively described the stratigraphic trap fields in USA. This paper contains important messages to characterise the stratigraphic traps and suggested the possibility of usage of the sequence stratigraphic concept to evaluate the stratigraphic traps.

Although the updip lateral change is commonly from reservoir sandstone to impermeable shale, the lithologic contrast need not be so great, and the key is not contrast in permeability but rather in capillary-pressure characteristics. It means that the capacity of the barrier is determined by the “critical throat,” the tightest part of the particular channel way that requires the least pressure for the passage of oil through it (Figure 1.3.1). However, no data is often available about the capillary-pressure characteristics of reservoir and seal rock of a prospect. Hence, it must still be necessary to assume the distribution of the capillary-pressure characteristics from the lithologic distribution derived from the well data or seismic data.

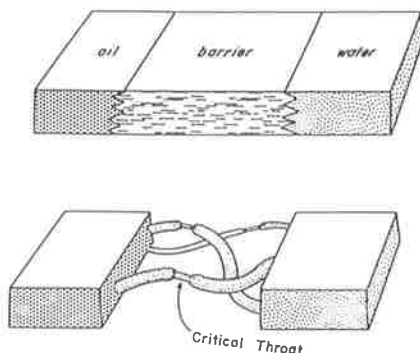


Figure 1.3.1. MacKenzie (1972) represented that the key for stratigraphic traps is not contrast in permeability but rather in capillary-pressure characteristics determined by the “critical throat”. However, it must still be necessary to assume the distribution of the capillary-pressure characteristics from the lithologic distribution. That is because well data are not often available, which directly indicate the capillary-pressure of objectives in a prospect.

Evaluating the lithologic distribution of the reservoir and seal rocks, the complex seal components of the stratigraphic trap should be defined as genetic stratigraphic events. MacKenzie (1972) described that, except for isolated lenticular sandstone enveloped in shale, most primary stratigraphic traps in sandstone have some structural elements; the configuration of the trap boundary is commonly governed by tilting or gentle arching as well as by stratigraphic variation. In such cases, three types of seal components: the top seal, the lateral seal and the bottom seal must be recognised, because all components must be present for the existence of the updip stratigraphic-trap barrier (Figure 1.3.2). The three seal components- the top, lateral and bottom seals- should be defined by the sealing potential of the rocks which were deposited after, contemporaneously, and before deposition of the reservoir facies. This definition for the seal rocks based on chronostratigraphic intervals leads us to a sedimentologically reasonable expectation of the chance of the existence of seals for the stratigraphic trap, and these intervals should be evaluated as genetic intervals in the sequence stratigraphy.

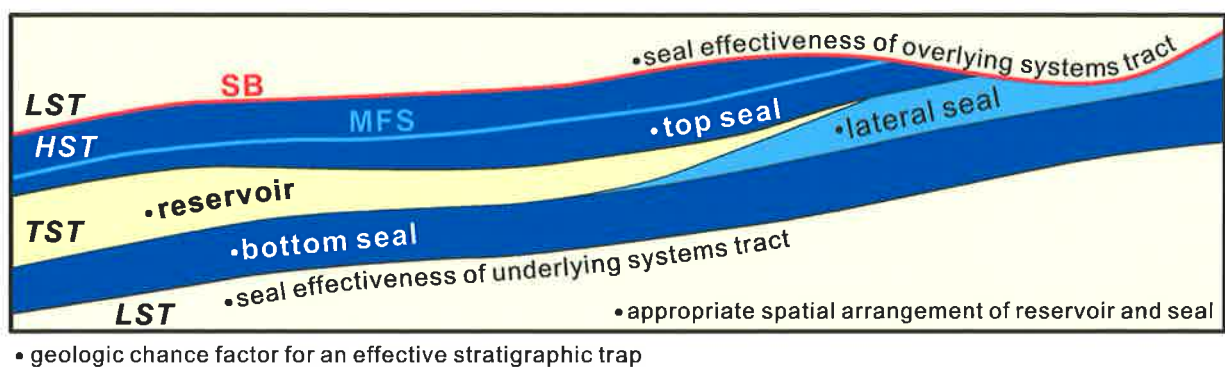


Figure 1.3.2. Schematic section showing the concept of three seal components for a stratigraphic trap: top seal, lateral seal and bottom seal. These three are defined by the sealing potential of the rocks which were deposited after, contemporaneously, and before deposition of the reservoir facies. Sequence stratigraphy is a tool to assess the chance of existence of each seal rock defined based on chronostratigraphic intervals.

The consideration in MacKenzie's paper about the potential of stratigraphic traps in transgressive settings versus the regressive settings, suggests the importance of the application of sequence stratigraphy to the evaluation of the stratigraphic traps. In parts of the Upper Cretaceous in the Rocky Mountain area, the deltaic distributary channels landward and updip from shoreline sandstone are deposited during overall regression. These deltaic deposits probably would be relatively poor barriers to the updip migration of hydrocarbons. In contrast, lagoonal mudstones landward and updip from shoreline sandstones are deposited during

overall transgression. This situation may provide relatively good barriers to the updip migration of hydrocarbons (Figure 1.3.3). This suggests that the chance of a stratigraphic trap would be strongly controlled by the relative sea level change. Such a spatial variation of the distribution of the potential reservoir and seal rocks, controlled by the relative sea level change, should be evaluated as genetic intervals of sequence stratigraphy (e.g. lowstand systems tract, transgressive systems tract, highstand systems tract).

Following MacKenzie, sequence stratigraphy was established and has been effectively applied to explain the complex components of the reservoir and seal of stratigraphic traps. The application of sequence stratigraphy may lead to a sedimentologically reasonable risk assessment for the stratigraphic trap exploration.

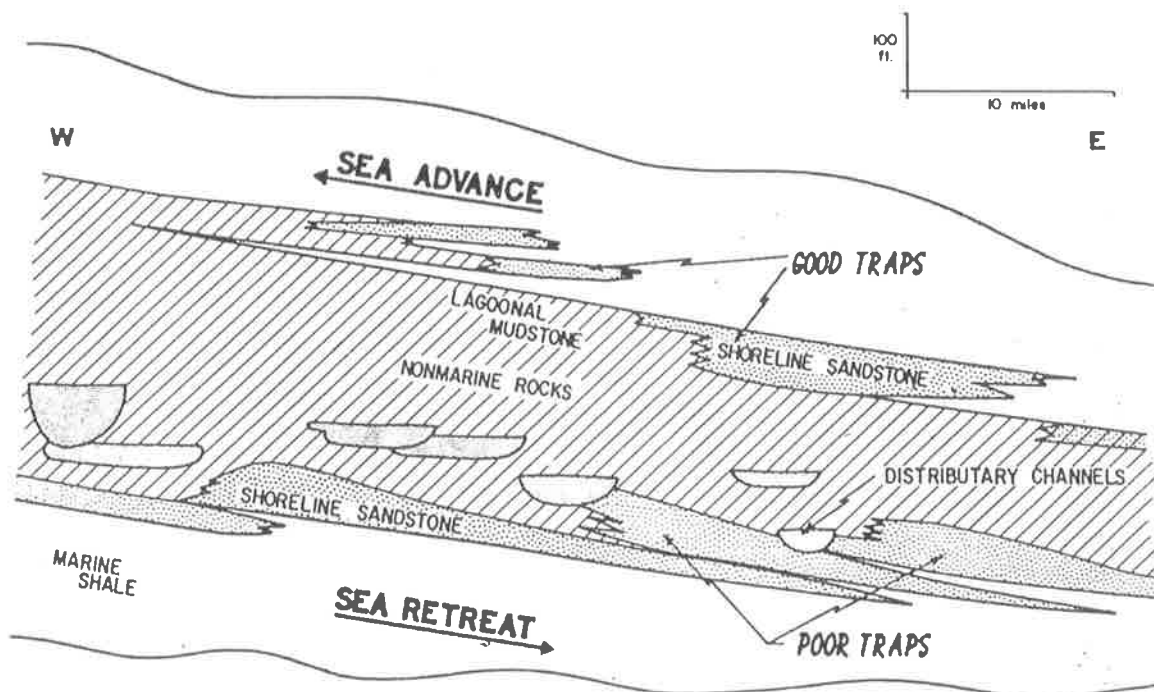


Figure 1.3.3. One schematic cycle in Rocky Mountain Upper Cretaceous showing deltaic distributary channels landward and updip from shoreline sandstones deposited during overall regression (below), and lagoonal mudstones landward and updip from shoreline sandstones deposited during overall transgression (above) (MacKenzie, 1972).

1.4 Designing an evaluation procedure for stratigraphic trap exploration

The purpose of this research is to design an evaluation procedure for stratigraphic trap exploration by employing sequence stratigraphy and quantitative risk analysis. A series of case studies, using open file well data and 3D seismic data, were selected in the Cooper Eromanga Basin, South Australia. The approach used is as follows:

- Select case study areas based on available data and diversity of potential stratigraphic traps.
- Conduct a facies analysis in well data.
- Develop a sequence stratigraphic framework suitable for an alluvial setting.
- Conduct 3D seismic data visualisation and identify potential stratigraphic trap prospects.
- Assess the chance of geologic success for selected prospects.
- Assess the probabilistic reserves distribution for selected prospects.
- Determine an efficient exploration frontier for the prospect inventory using risk-reward optimisation.
- Assess the chance of economic success, reward in the case of success, and determine the ENPV for the portfolio candidates.
- Construct an appropriate portfolio for stratigraphic trap exploration in the prospect inventory.

1.5 Publications

Several chapters included in this thesis have been progressively published in a series of papers as follows:

NAKANISHI, T., 2000 – Quantitative Geologic Risk Evaluation and Expected Net Present Value Evaluation in JNOC's Projects. *Journal of the Japanese Association for Petroleum Technology*, 65 (3), 217-228, for section 2.1 of Chapter 2 (Appendix B).

NAKANISHI, T. AND LANG, S.C., 2001a – The Search for Stratigraphic Traps Goes On-Visualisation of Fluvial-Lacustrine Successions in the Moorari 3D Survey, Cooper-Eromanga Basin. *APPEA Journal*, 41(1), 115 – 137, for Chapter 5 (Appendix C).

NAKANISHI, T. AND LANG, S.C., 2001b – Visualisation of Fluvial Stratigraphic Trap Opportunities in the Pondrinie 3D Survey, Cooper-Eromanga Basin. *Proceedings of the Eastern Australasian Basin Symposium 2001, PESA*, 301-310, for Chapter 6 (Appendix D).

NAKANISHI, T. AND LANG, S.C., 2002 – Towards an Efficient Exploration Frontier: Constructing a Portfolio of Stratigraphic Traps in Fluvial-lacustrine Successions, Cooper-Eromanga Basin. *APPEA Journal*, 42(1), 131-150, for Chapter 9 (Appendix E).

Chapter 2

Methodology

In this chapter, key tools for the evaluation procedure for stratigraphic trap exploration employed in this research will be introduced.

2.1 Quantitative geologic risk evaluation and ENPV evaluation in JNOC's projects

2.1.1 Introduction

Many international petroleum companies improved their exploration performance by using quantitative risk analysis during 1990s (Rose, 2001). The improvement in performance by companies adopting the quantitative risk analysis has been traced and reported by several authors including Rose (1997 & 1998), Alexander & Lohr (1998), Johns et al. (1998), McMaster (1998), Kubota et al. (1999), and Rose (2001). Japan National Oil Corporation (JNOC) implemented a quantitative risk analysis procedure to evaluate all their exploration projects in 1998, and as an example of the evaluation procedure, quantitative geologic risk analysis and ENPV (expected net present value) evaluation adopted by JNOC will be outlined (Nakanishi, 2000, Appendix B). The risk evaluation used for the case studies in this research generally follows this procedure.

2.1.2 ENPV: Expected Net Present Value

In any risk business, not only oil and gas exploration, expected value is used as an indicator for the decision to invest in projects. The expected value is the summation of the products of the chance of success and the monetary value of a successful case, and the chance of failure and the monetary value in the case of failure (Figure 2.1.1). An investment into a project of which the expected value is no more than zero is usually recognised as an economically unreasonable investment.

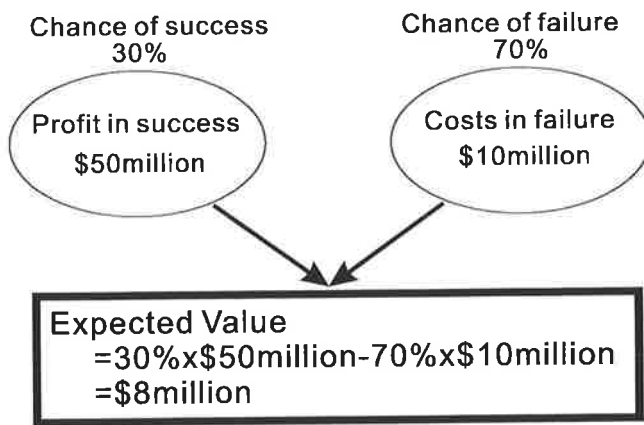


Figure 2.1.1. Concept of expected value.

Three cases are expected in a prospect evaluation: economic success (profit achieved), geologic success and economic failure (lost money), and geologic failure (lost money). ENPV is one of the expected values, the summation of the products of chance and the monetary value of each situation (Figure 2.1.2). One of the hurdles for approval of a project is that the ENPV should be more than zero.

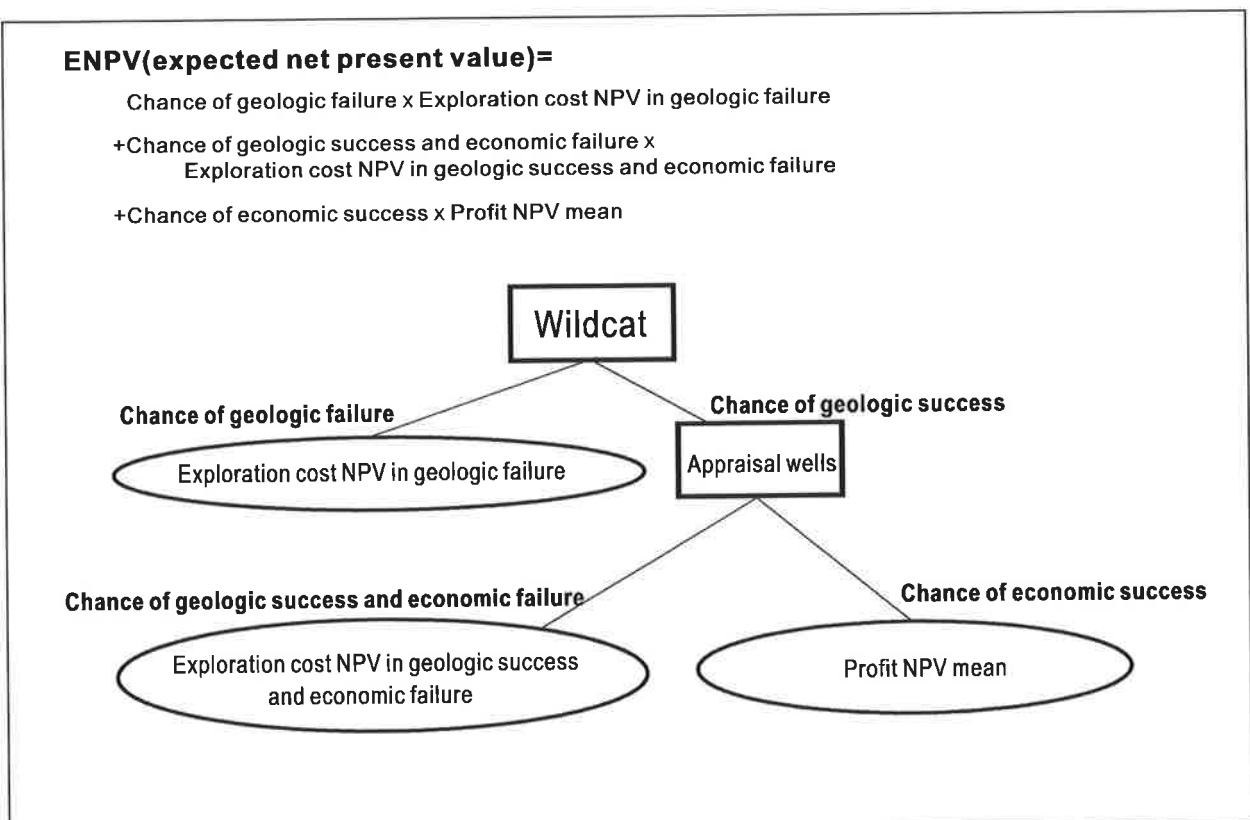
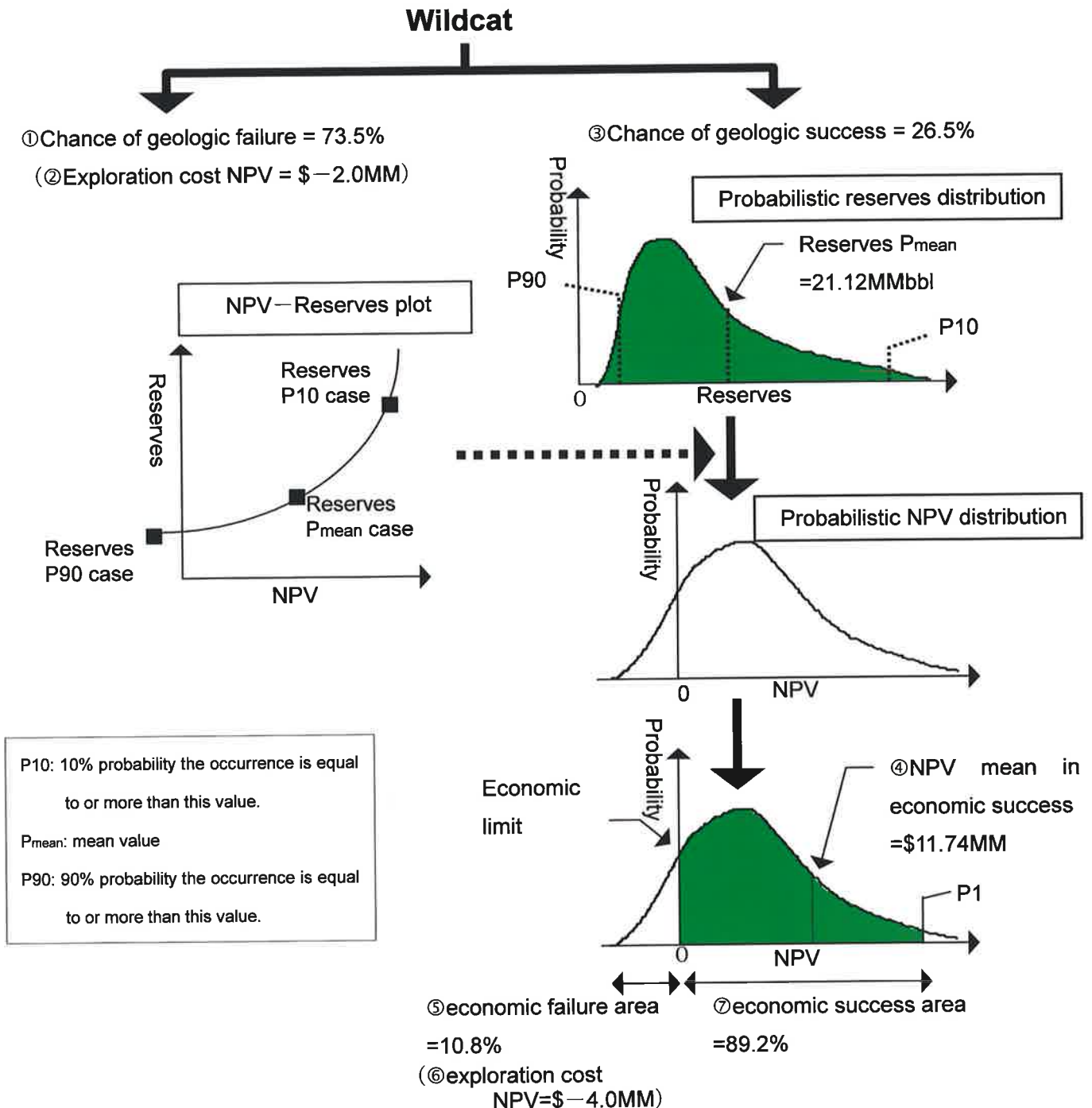


Figure 2.1.2. Concept of expected net present value (ENPV)



① Chance of geologic failure (P_{fg}) = 73.5%

③ Chance of geologic success / economic failure (P_{sgfe})

$$= ③ \text{ Chance of geologic success } (P_{sg}) \times ⑤ \text{ Probability in economic failure area} \\ = 26.5\% \times 10.8\% = 2.8\%$$

⑨ Chance of economic success (P_{se})

$$= ③ P_{sg} \times ⑦ \text{ Probability in economic success area} \\ = 26.5\% \times 89.2\% = 23.7\%$$

$$\begin{aligned} \text{ENPV} = & ① P_{fg} \times ② \text{ Exploration cost NPV in geologic failure} \\ & + ③ P_{sgfe} \times ⑥ \text{ Exploration cost NPV in geologic success/economic failure} \\ & + ⑨ P_{se} \times ④ \text{ Profit NPV mean in economic success} \\ = & 73.5\% \times (-2.0) + 2.8\% \times (-4.0) + 23.7\% \times 11.74 = \mathbf{\$1.19MM} \end{aligned}$$

Figure 2.1.3. ENPV calculation flow chart

Information required to calculate ENPV

The flow chart of ENPV calculation is shown in Figure 2.1.3.

Chance of geologic success

Chance of geologic success is defined as the chance that a well encounters mobile accumulated hydrocarbons. A mobility of hydrocarbons is usually recognised from a well test, so the chance of geologic success is practically defined as the chance that a well encounters enough accumulated hydrocarbons to sustain flow.

For a subsurface accumulation of hydrocarbons, five geologic factors need to exist:

- Thermally mature source rocks.
- Hydrocarbon migration.
- Reservoir rocks.
- Structural or stratigraphic closure.
- Hydrocarbon containment.

The chance of geologic success is calculated from the multiplication of confidence values of all five factors, which have a range from 0 to 1 (Figure 2.1.4). Consequently, the chance of geologic success is from 0 to 1 in range, and if any one of the confidence values of the geologic factors is zero, the chance of success is zero. The multiplication (not summation) shows all five of the factors must be met for hydrocarbon accumulation. The chance of geologic success estimation detail is shown in Section 2.1.3. below.

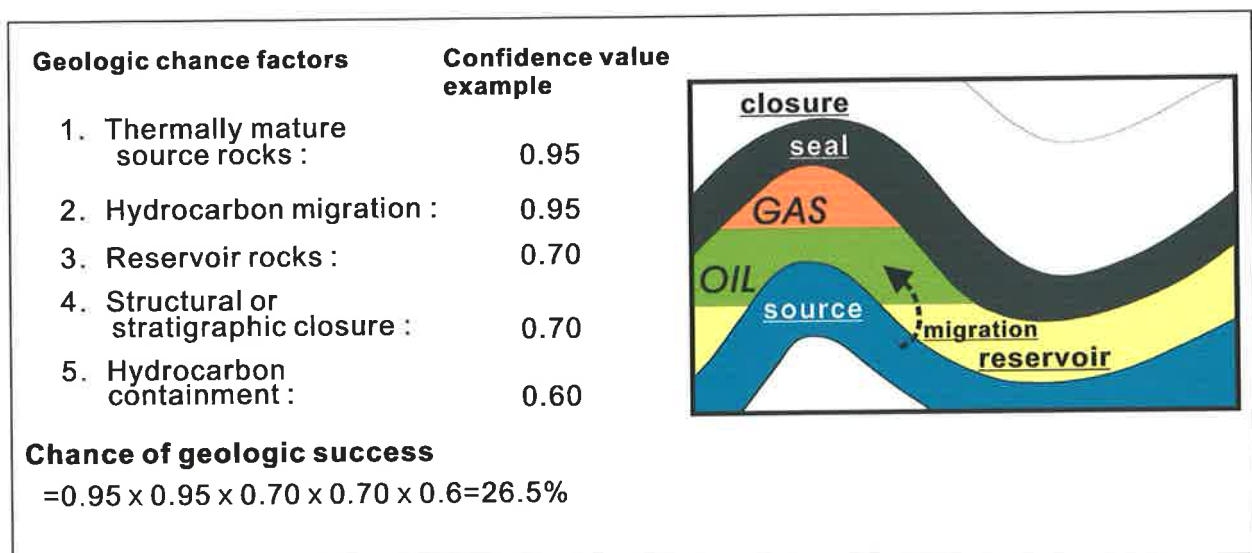


Figure 2.1.4. Illustration of the concept of the chance of geologic success.

Probabilistic reserves distribution

The probabilistic reserves distribution of a prospect is an estimate of the range of recoverable reserve size of hydrocarbon in the geologic success case where mobile accumulated hydrocarbons are discovered. The probabilistic reserves distribution (Figure 2.1.5) is the product of parameters each of which has a reasonable range with respect to a geologic and engineering setting:

- Productive area.
- Average net pay thickness.
- Average porosity.
- Average hydrocarbon saturation ratio.
- Recoverable ratio.
- Formation volume factor.

Monte Carlo simulation is employed for multiplying these parameters to make the probabilistic reserves distribution. The probabilistic reserves distribution estimation detail will be taken up in Section 2.1.3 below.

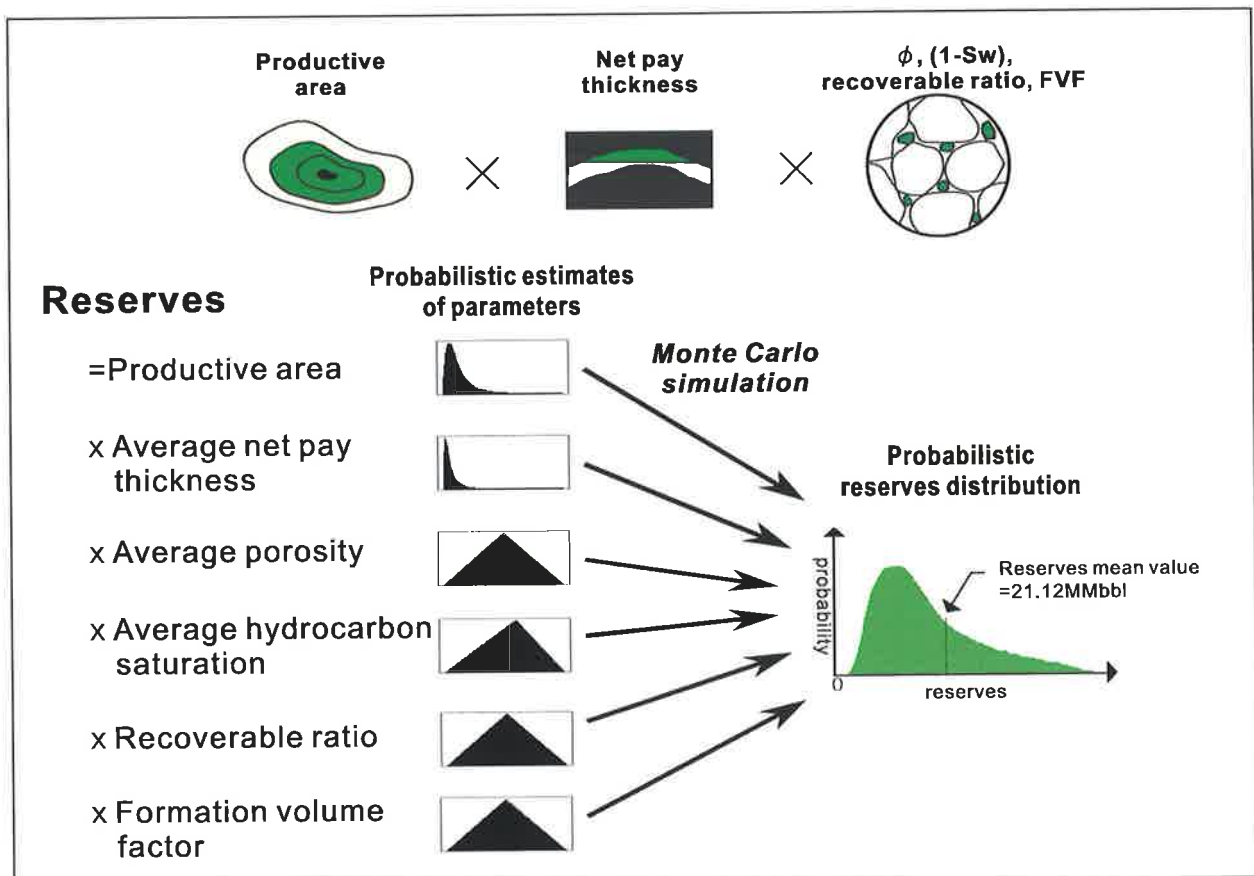


Figure 2.1.5. The concept of probabilistic reserves distribution.

Development and production scenario, cash flow model and minimum economic reserves

The minimum economic reserves are defined as the reserves from which the profit NPV (net present value) will be estimated as zero. To assess the minimum economic reserves, a plot of reserves vs. profit NPV should be made (Figure 2.1.6). The development and production scenarios will be made according to three reserves cases, P90 case (90% probability the occurrence is more than this level, i.e. small reserves), Pmean case, and P10 case (10% probability the occurrence is more than this level, i.e. large reserves) in the prospect reserves distribution. The cash flow models for each scenario will generate three points on the plot of reserves vs. profit NPV. The curve of best fit through to the three points will show the minimum economic reserves as the point along the curve where NPV equals to zero.

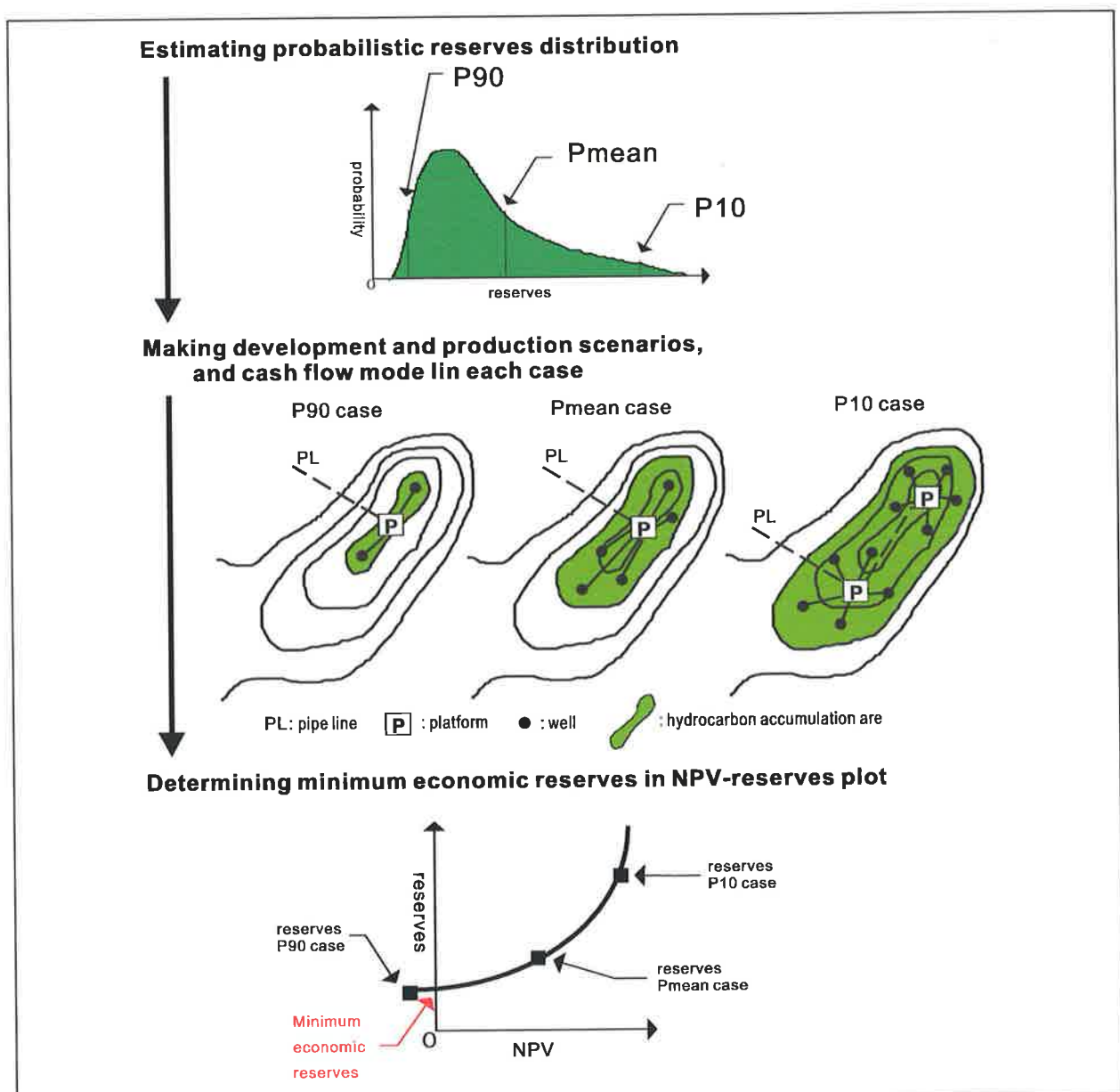


Figure 2.1.6. Determining the economic limit of reserves.

Chance of economic success, profit NPV mean in the economic success case

Economic success is defined as when the profit NPV is more than zero. The chance of economic success requires the probability of the profit NPV to be more than zero. The profit NPV mean is recognised as the mean value of the profit NPV in the economic success case.

To assess the chance of economic success and the profit NPV mean, the probabilistic reserves distribution needs to be converted to the profit NPV distribution (Figure 2.1.7). The profit NPV distribution is given by substitution of reserves distribution for the function of the fitting curve on the reserves vs. profit NPV plot. The area greater than zero NPV on the profit NPV distribution curve means economic success, hence the chance of economic success is the product of the chance of geologic success and the probability of greater than zero NPV on the profit NPV distribution. Note that if the relationship between the reserves and NPV is linear, it is straightforward to calculate the chance of economic success and the profit NPV mean in the economic success case. These are respectively the product of the chance of geologic success and the probability of more than minimum economic reserves, and the NPV in the mean reserves case.

The profit NPV mean is the mean value of the profit NPV distribution that is truncated less than zero and more than P1 value. The approach normally followed is to truncate the profit NPV distribution to more than P1 value to calculate the profit NPV mean, because P0 value (logical maximum) of a lognormal distribution shows infinity (Figure 2.1.7).

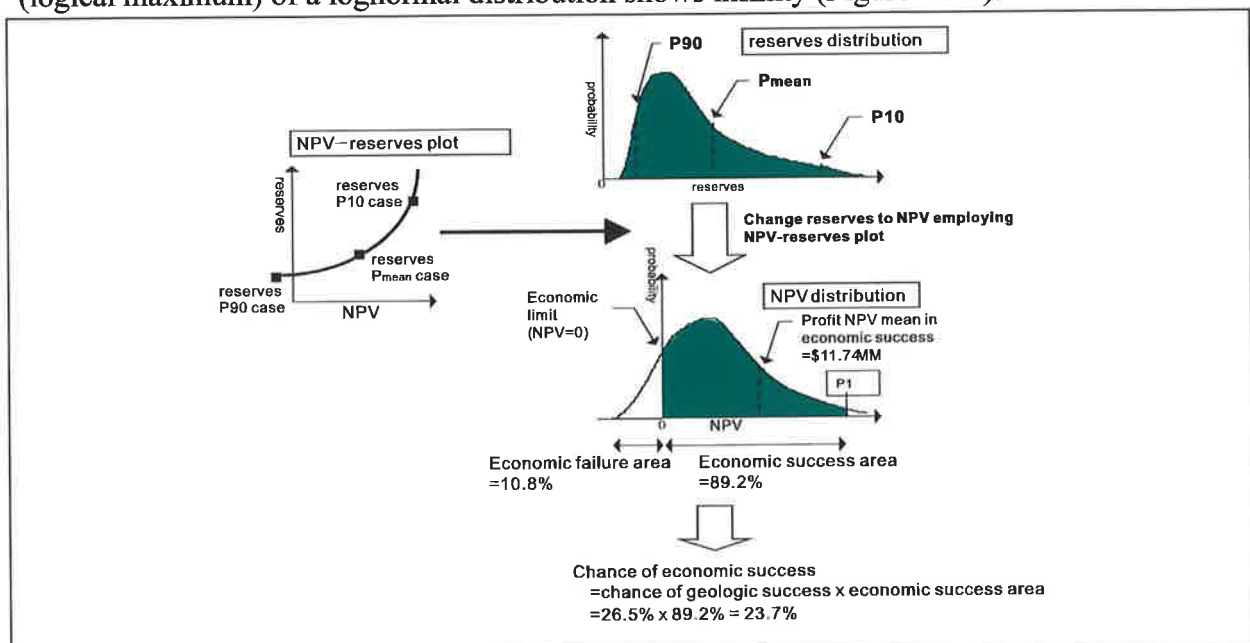


Figure 2.1.7. Determining the chance of economic success and NPV mean.

Chance of geologic failure, chance of geologic success and economic failure, and exploratory expenditure

The failure situation of a project is categorised by two cases (Figure 2.1.8), the case of geologic failure (a well does not encounter mobile accumulated hydrocarbons) and the case of geologic success and economic failure (a well encounters mobile accumulated hydrocarbons, but the amount is insufficient to make a positive profit).

The chance of geologic failure is 100% minus the chance of geologic success. The costs of geologic failure comprises all the exploratory expenditure (i.e. licence acquisition cost, seismic data acquisition cost, dry hole cost, study cost, administration cost).

The chance of geologic success and economic failure is the product of the chance of geologic success and the probability equal to or less than zero NPV on the profit NPV distribution. The exploratory expenditure comprises all costs of assessing whether the reserves are adequate to lead to economic success (i.e. appraisal well cost, feasibility study cost should be added to the expenditure in case of geologic failure).

Chance of geologic failure and exploration cost NPV

Chance of geologic failure
(100% - Chance of geologic success = 73.5%)

Exploration cost
(licence acquisition cost, seismic survey, wildcat, administration cost, et.al. e.g. \$-2MM)

Chance of geologic success and economic failure, and exploration cost NPV

Chance of geologic success and economic failure
(chance of geologic success x
probability of geologic success and economic failure area
= 26.5% x 10.8% = 2.8%)

Exploration cost to recognize economic failure
(exploration cost in geologic failure +
appraisal wells, feasible study, e.g. \$-4MM)

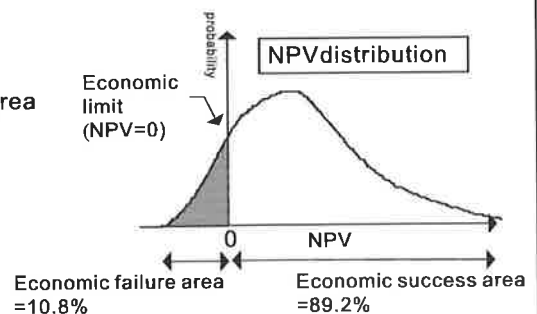


Figure 2.1.8. Determination of the chance of failure and loss in failure cases.

ENPV calculation

ENPV can now be calculated using the following equation.

ENPV=

(Chance of geologic failure) x (exploratory expenditure NPV in geologic failure case) +
 (Chance of geologic success and economic failure) x (exploratory expenditure NPV in geologic success and economic failure case) +
 (Chance of economic success) x (profit NPV mean in economic success case).

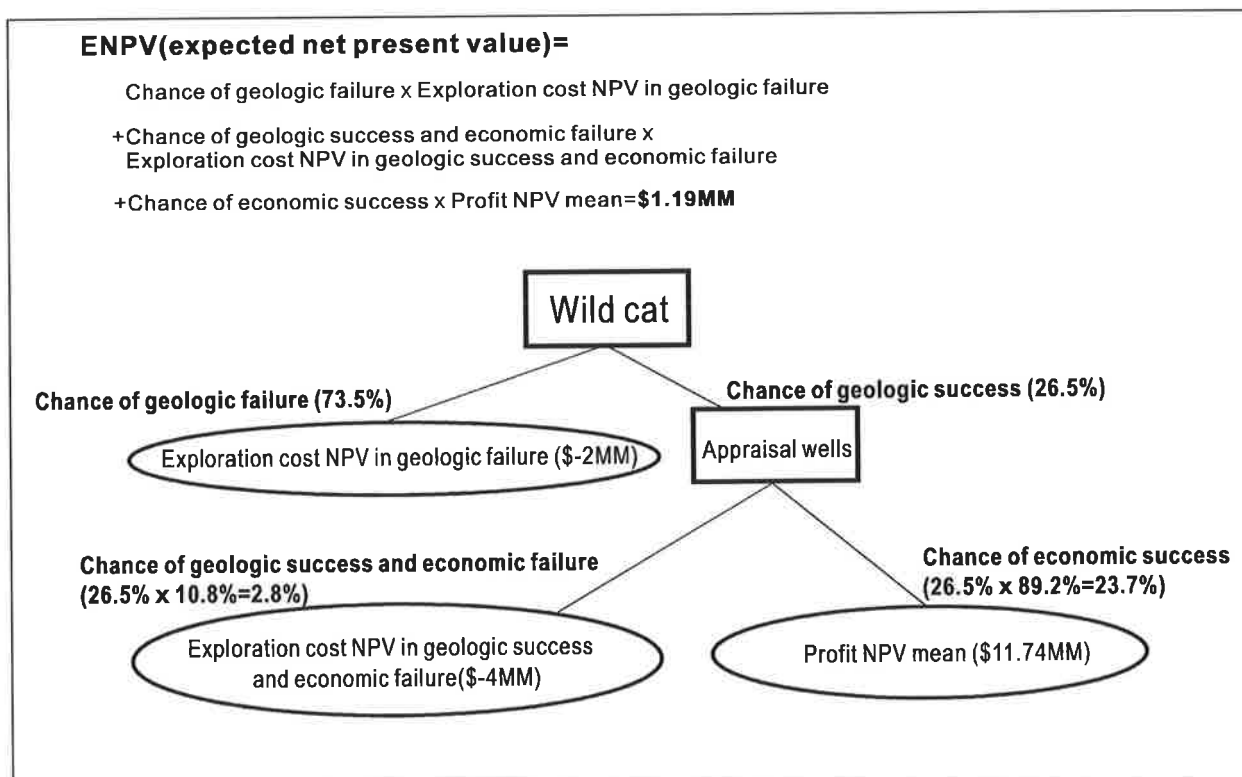


Figure 2.1.9. Example of ENPV calculation.

The utility of ENPV

ENPV is an economic indicator that incorporates geologic risk. ENPV can be used as an economic hurdle including geologic risk to approve investment in a project. ENPV can provide an assessment of appropriate entrance fee for a project because the expenditure for licence acquisition (i.e. number of obligation wells, sign bonus etc.) is sensitive to ENPV. ENPV allows quantitative comparison with the other projects. By recognising ENPV or the parameters for ENPV calculation (i.e. chance of economic success, profit NPV mean, exploratory expenditure) for all projects in the organisation with a consistent evaluation procedure, projects can be compared with each other quantitatively (high risk/ high return or

low risk/ low return). ENPV allows construction of an appropriate investment portfolio. The parameters for ENPV calculation can be the indicator to assess prospects to include in the organisation's investment portfolio.

2.1.3 Geologic risk evaluation

Chance of geologic success

The chance of geologic success is the chance that a well encounters mobile accumulated hydrocarbons, as defined above. Hence the chance of geologic success means the probability of finding hydrocarbons in sufficient quantities to sustain flow.

The geologic chance factors, which need to exist to result in an accumulation of mobile hydrocarbons in a prospect can be categorised into five factors (Figure 2.1.4). These factors are recognised as geologically independent. Each factor is given a confidence value, the range of which is from 0 to 1, according to a degree of confidence about the geologic factor's existence (Figure 2.1.10). As a scale for assessing the confidence value, if enough data are available to be confident that the factor's existence is certain, a value of 1 for the factor can be assigned. If enough data are available to be confident that the factor's non-existence is certain, a value of 0 for the factor can be assigned. If no information is available, or the factor's existence or non-existence is an even chance, a value of 0.5 for the factor can be assigned (Rose, 1992a & 2001). The way to assess confidence values for geologic factors will be discussed more in Chapter 9.

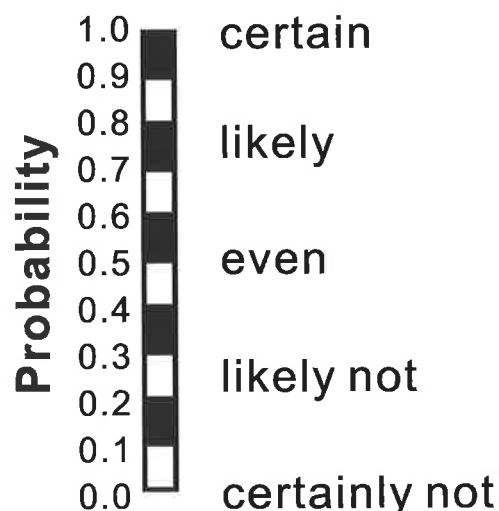


Figure 2.1.10. The probability scale for assessment of the confidence value of the geologic chance factor (modified after Rose 2001). The way to assess confidence values for geologic factors are discussed more in Chapter 9.

The chance of geologic success is calculated from the multiplication of the confidence values of all five factors. Consequently, the chance of geologic success has a range from 0 to 1. This means that if any one of the confidence values of the geologic factors is zero, the chance of success is zero. The multiplication (not summation) shows all five of the geologic factors must be met for hydrocarbon accumulation.

Each of the five geologic factors has several sub-components that must be considered in arriving at a confidence value estimate for the parent chance factor (see below). Because several sub-components can be dependent, the confidence value for the geologic chance factor must be assessed with concern about such dependencies between sub-components. For example, in the case of estimating the hydrocarbon migration chance factor, disadvantage in "efficiency" such as vertically long distance migration from the kitchen to prospect could be compensated by advantage in "migration path" via many normal faults.

The estimates of the confidence value for the geologic chance factors must be done from the viewpoint of hydrocarbons sufficient to sustain flow from a prospect, not with concerns about whether the amount of hydrocarbons is economically enough or not. Note that geologic success means finding mobile accumulated hydrocarbons.

The geologic chance factors and sub-components are as follows:

- **Thermally mature source rocks**

Quantity: The quantity of source rock needs to be of adequate volume.

Thermal maturity: The source rock needs to be thermally mature to generate hydrocarbons.

- **Hydrocarbon migration**

Migration path: Pathways along which hydrocarbons can migrate need to exist between kitchen area and the closure location.

Efficiency: The locations of kitchen and closure are adequate for efficient hydrocarbon migration and accumulation.

Timing: The timing of source rock maturation and closure construction is adequate for hydrocarbon migration and accumulation.

- **Reservoir rocks**

Storage capacity: The storage capacity of the reservoir rock is adequate in volume.

Porosity and Permeability: The porosity and permeability is enough for hydrocarbons to sustain flow.

- **Structural or stratigraphic closure**

Existence of trapping geometry: The closure exists and is of adequate area and vertical relief to contain a volume of reservoired hydrocarbons sufficient to support flow.

- **Hydrocarbon containment**

Effectiveness: An effective seal rock in both quality and thickness need to be present.

Preservation from subsequent spillage: Accumulated hydrocarbons need to have been preserved without suffering from subsequent spillage.

Probabilistic reserves distribution

Reserves estimation of a prospect must be assessed as a range, because prospect reserves are the products of many natural factors with much uncertainty and any scientific approach so far cannot find one true answer (Figure 2.1.11). In a prospect reserves distribution assessment, the range and form of the probabilistic distribution must be included.

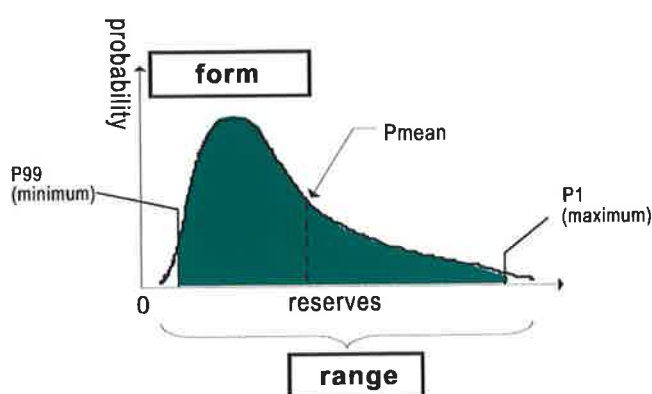


Figure 2.1.11. Probabilistic reserves distribution.

Range of probabilistic reserves distribution

Reserves can range from the amount which can barely sustain flow (just enough for geologic success) to the maximum amount which reservoir can contain within closure (Figure 2.1.12). The range can also vary according to the exploration stage of the prospect. One prospect in a

virgin exploratory area can be assessed as the range described above; however, the reserves range of another prospect in a matured exploratory area can be more narrowly estimated than that of the virgin area because of the surrounding evidence (Figure 2.1.13). Practically, such reserve size parameters are given a range, and multiplied in Monte Carlo simulation to determine reserves distribution.

From a practical standpoint, the minimum reserves case (which means geologic success) is set as P99 value of the reserves distribution, and the maximum reserves case is set as P1 value of the reserves distribution, because the P100 is the logical minimum, and P0 value is the logical maximum within a lognormal distribution for the reserves distribution of zero or infinity respectively. The mean value of the reserves distribution is therefore the mean between P99 to P1.

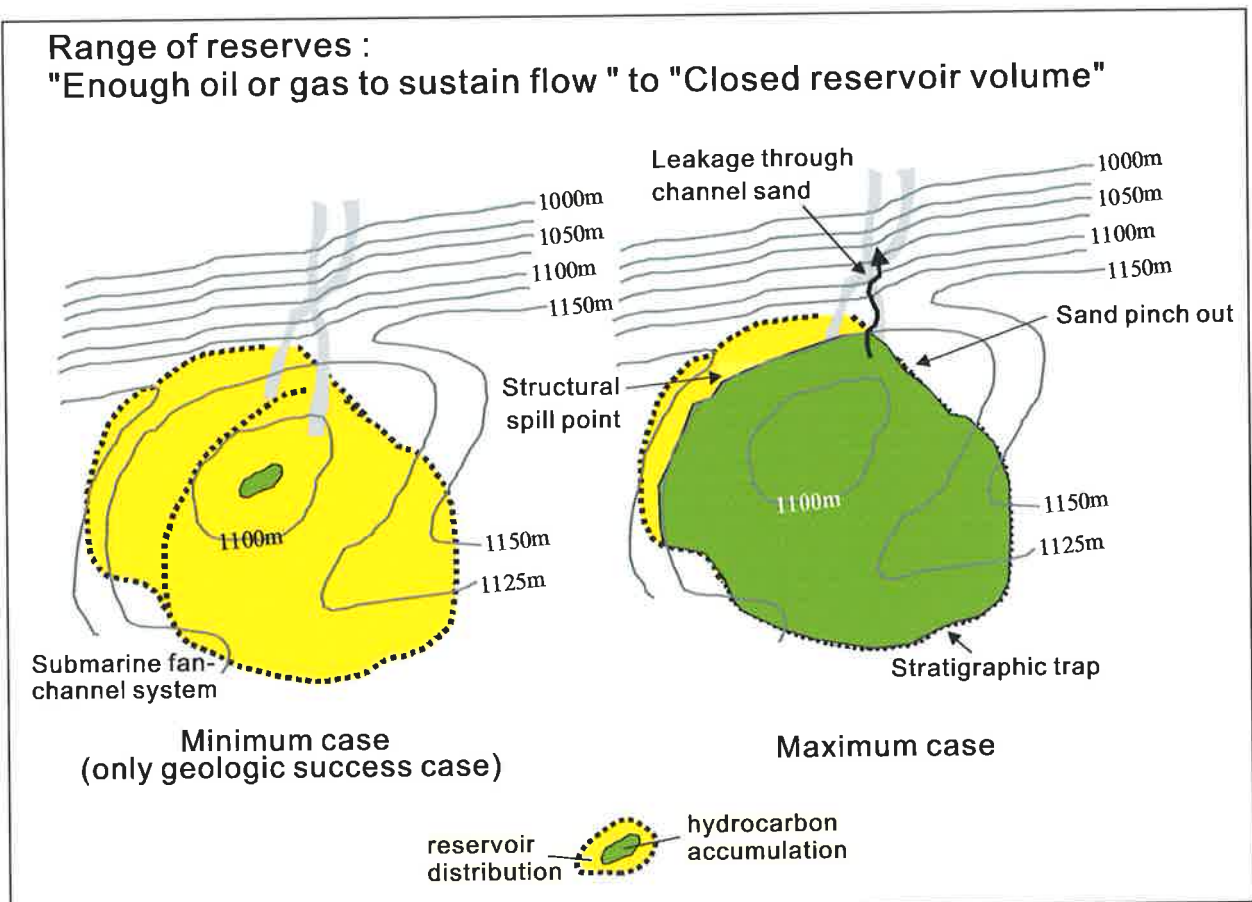


Figure 2.1.12. Range of reserves. Example of anticlinal and stratigraphic trap combination consisting of submarine fan-channel system. In this case, the range of reserves can be from accumulation at only the top of the anticlinal portion to accumulation in the whole of the closed reservoir.

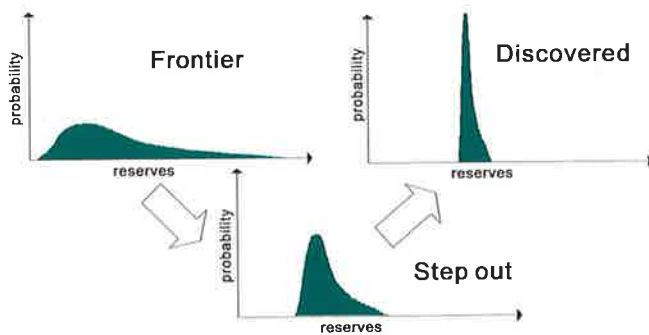


Figure 2.1.13. A variation of a range of reserves according to exploration stage.

Form of probabilistic reserves distribution

Natural multiplication of independent, random variables yields lognormal distributions. Most important geotechnical parameters involved with oil and gas occurrence are lognormal (Megill, 1984; Capen, 1992). The empirical data shows that actual field size distribution in a basin or in a play usually shows lognormal distribution (Figure 2.1.14-1). Such constancy on the field size distribution must indicate that prospects, of which the reserves chances have lognormal distribution, are explored and result in the lognormal field size achievement (Figure 2.1.14-4). Parameters to calculate reserves, productive area and average net pay thickness must be independent, random geologic variables, hence these parameters must be assessed using lognormal distribution (Figure 2.1.14-2, 14-3).

The distribution of reserves or parameters not having a lognormal distribution may exist in a particular sort of basin or play type, however it is necessary to have confidence based on statistical verification with enough data in order to adapt non-lognormal distribution.

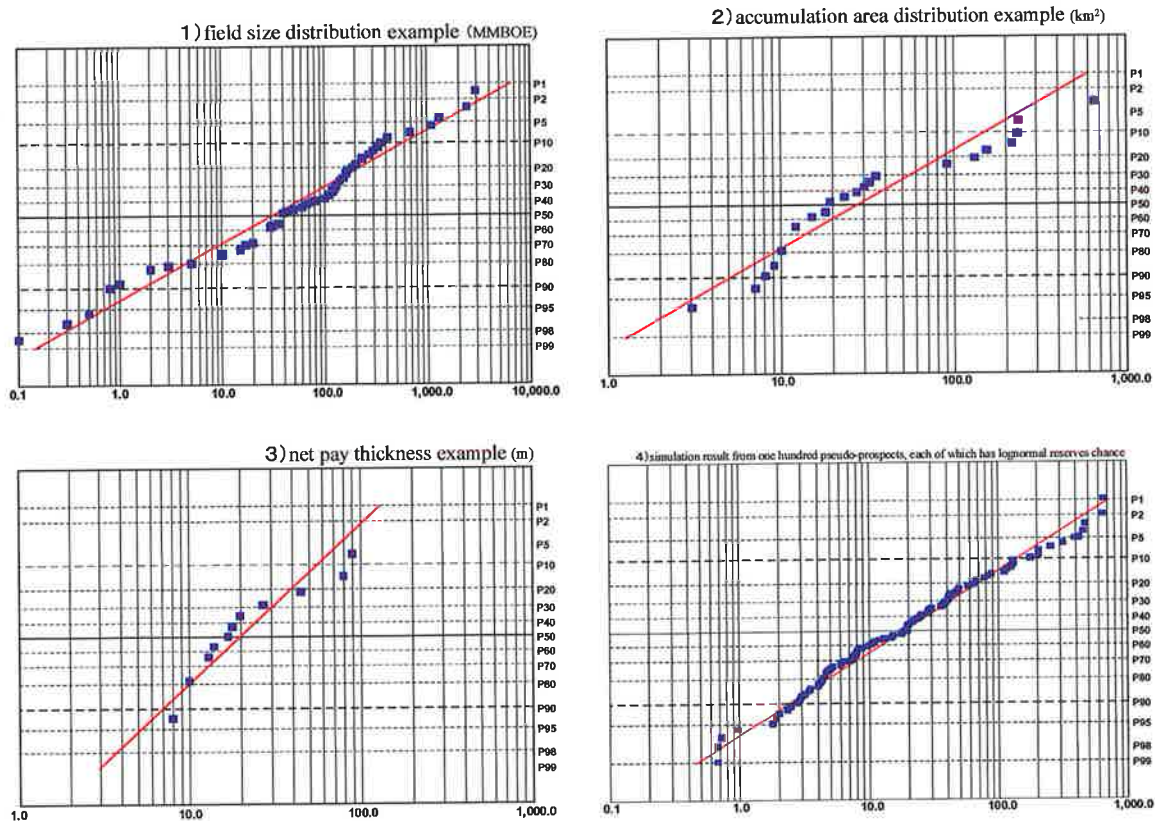


Figure 2.1.14. 1)-3) Examples of field size, hydrocarbon accumulation and net pay thickness distribution achievement in a basin on the cumulative log probability graph. The lineal order of plots indicates the distribution is lognormal. 4) Simulation results from one hundred pseudo-prospects, each of which has lognormal reserves chance. Lognormal distribution constancy on the field size achievement must indicate that each prospect, of which the reserves chance has a lognormal distribution, are explored and result in the field size achievement.

Reality check for reserves estimation

A reality check for reserves estimation must be done systematically in each evaluation. If it does not seem to be real, the estimation is re-assessed. For example, JNOC is using reality checks as follows (Nakanishi, 2000):

- **Reality of P99 (minimum case) of reserves distribution**

The minimum case (P99) of reserves distribution need to be checked to ensure it is not too large. For example, if a prospect in an exploratory virgin area is estimated as 10MMbbl for the minimum case, then the estimate is probably too optimistic and requires a re-estimation of the parameters.

- **Reality of the range of reserves distribution**

The reserves distribution needs to be checked to ensure it has an appropriate range relative to the exploration maturity of the prospect area. Practically, a P10/P90 ratio check

derived from some major oil companies' empirical values is used to determine the range (Table 2.1.1, Rose, 1997).

• Comparison with an achieved field size distribution

Comparison with an achieved field size distribution for a basin, or the same play type of the objective prospect, must be done to confirm the estimation is not too optimistic or pessimistic.

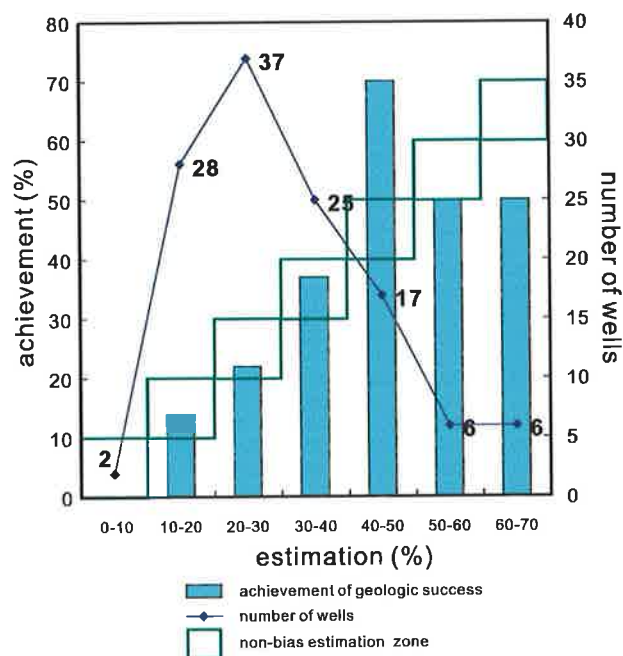
Table 2.1.1. P10/P90 ratio reality check for distribution range.

Well category	Step-out/ extension	Wildcat in known productive trend	Rank wildcat in proven trend	Rank wildcat in new play or new basin
P10/P90 ratio	5 – 25	10 – 120	55 – 170	120 – 650

Post-audit

A comparison between estimates and results helps the organisation to improve the risk analysis skill. From the comparison, optimistic and pessimistic assessments can be recognised, and future works should be concentrated on solving the problem. Figure 2.1.15 illustrates the post audit methods used by JNOC (Nakanish, 2000).

1) Comparison of geologic chance of success



2) Comparison of reserves

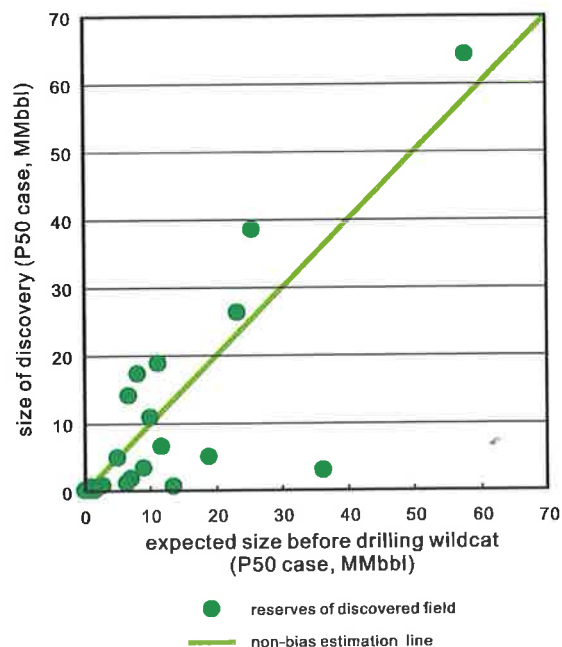


Figure 2.1.15. Examples of post audit for prospect evaluations (note that the data is not real) . 1) Comparison of chance of geologic success. The achievements plotted in the non-bias zone indicate that appropriate estimations for chance of geologic success of prospects have been performed. This example suggests the estimations of 40-50% geologic success were too pessimistic. 2) Reserves comparison in P50 case of probabilistic reserves estimates. If the plots are equally divided by the non-bias line, the estimations were appropriate.

2.1.4 Consistency – the challenge for the future

The risk analysis procedure shown above is typically for one prospect. However, real exploration projects usually have a more complicated scheme, for example, multiple prospects, multiple licence areas and so on. Consequently, some dependencies between objectives take place (i.e. geologic factor dependency among prospects or multiple development scenarios dependent on a success pattern in multiple prospects). Most important issue is consistent risk analysis for all such projects. For example, JNOC is employing decision tree analysis to evaluate complex projects (Nakanish, 2000), but the workload for maintaining a consistent approach is huge. The key issue for risk analysis is to diminish the workload in evaluating complex projects without losing consistency.

2.2 Integration of sequence stratigraphy and 3D seismic data visualisation

2.2.1 Sequence stratigraphy

The development of sequence stratigraphy has been of great importance to the petroleum exploration industry. Prediction of the spatial and temporal distribution of reservoir, seal, and source facies has been improved by use of the sequence stratigraphic approach. Enhanced understanding of reservoir compartmentalization and continuity has been an outgrowth of development of those concepts, and in some instances new and different exploration plays have been developed in consequence of sequence stratigraphic analyses (Weimer & Posamentier, 1993; Posamentier & Allen, 1999).

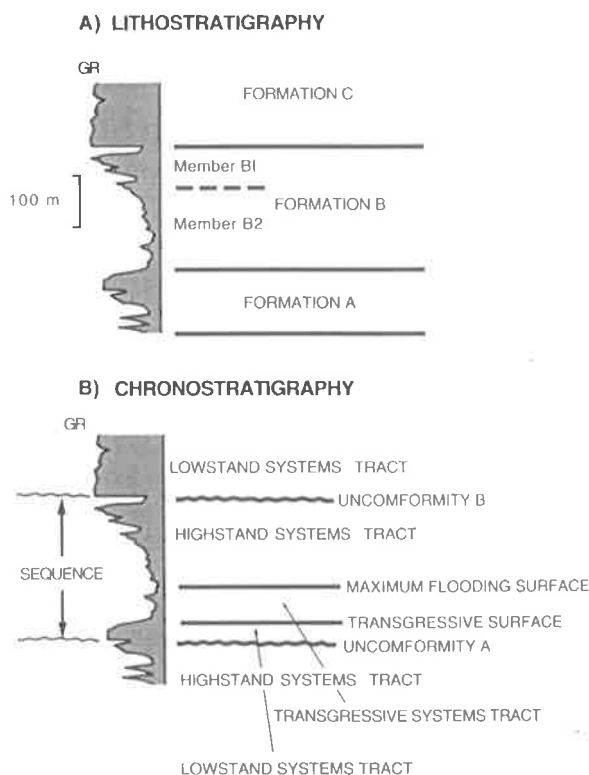


Figure 2.2.1. Schematic illustration of the different approaches of “classical” stratigraphy, i.e., A) lithostratigraphy, and B) sequence stratigraphy or chronostratigraphy (modified after Posamentier and Allen, 1999). Lithostratigraphy defines rock units on the basis of physical characteristics of rocks, whereas sequence stratigraphy defines rock units based on chronostratigraphy and focuses on the significance of surfaces separating major sedimentary successions.

Sequence stratigraphy is the study of rock relationships within a chronostratigraphic framework of cyclical, genetically related strata bounded by surfaces of erosion or nondeposition, or their correlative conformities (Figure 2.2.1, Posamentier et al., 1988; Van Wagoner et al., 1988, Posamentier & Allen, 1999). The methodology pioneered by Vail et al. (1977) offers the potential for documenting the depositional and erosional history of a basin relative to the tectonic setting, eustasy and rate of sedimentation. The sequence is the

fundamental stratal unit for sequence-stratigraphic analysis. Mitchum (1977) defined a depositional sequence as: “a stratigraphic unit composed of relatively conformable succession of genetically related strata and bounded at its top and base by unconformities or their correlative conformities”. In this thesis this definition for the depositional sequence is used although other time-stratigraphic-based approaches have been offered (Galloway, 1989). Sequences can be subdivided into systems tracts (Posamentier et al., 1988; Posamentier & Vail, 1988; Van Wagoner et al., 1990). A systems tract consists of a sedimentary succession with a specific type of stacking pattern. Systems tracts generally are deposited during a specific phase of relative sea level (or relative base level in alluvial environment), though the precise timing of deposition of systems tracts is a function of the local balance between sediment flux and rate of change of accommodation (Posamentier & Allen, 1999). Constructing sequence stratigraphic architecture including systems tracts in a basin or a specific prospect area, therefore, leads us to a genetically reasonable expectation of the existence of reservoir and seal rocks assuming spatial and temporal distribution of sedimentary succession.

The key to the analysis, as applied in case studies used in this research, lies in the use of sequence stratigraphic concepts in non-marine environments. The concept of sequence stratigraphy which has been developed in marginal marine and shelf setting, has also been increasingly adopted in the non-marine environment (Legarreta et al., 1993; Wright & Marriott, 1993; Shanley & McCabe, 1994; Allen et al., 1996; Howell & Flint, 1996; Legarreta & Uliana, 1998; Posamentier & Allen, 1999; Lang et al., 2000; Lang et al., 2001; Lang et al., 2002). The concept is outlined below following Posamentier & Allen (1999).

A basic and important stratigraphic first principle is that “water flows downhill seeking the lowest topographic location”. All rivers flow down topographic gradients, and alluvial systems always form above sea level (unless the alluvial system drains into a body of water below sea level). Sea level, therefore, represents the lowest level or base level to which a river adjusts its flow.

Fluvial accommodation is a critical factor that controls sedimentation and resulting facies and stratal architecture in a fluvial environment. In a fluvial setting, accommodation comprises the

space between the surface of the existing fluvial or coastal plain and the position in space of the fluvial equilibrium profile (Figure 2.2.2). The fluvial equilibrium profile represents the profile that a river strives to attain in order to maintain equilibrium between the alluvial gradient at every point and the water and sediment load it is transporting. Equilibrium is achieved, when the velocity of the river at any point along its profile is sufficient to transport the available sediment load through the system without net sediment lost or gained through deposition or erosion. If disequilibrium conditions occur, the river will attempt to re-establish the equilibrium slope by erosion (Figure 2.2.2C) or aggrading the alluvial plain (Figure 2.2.2D).

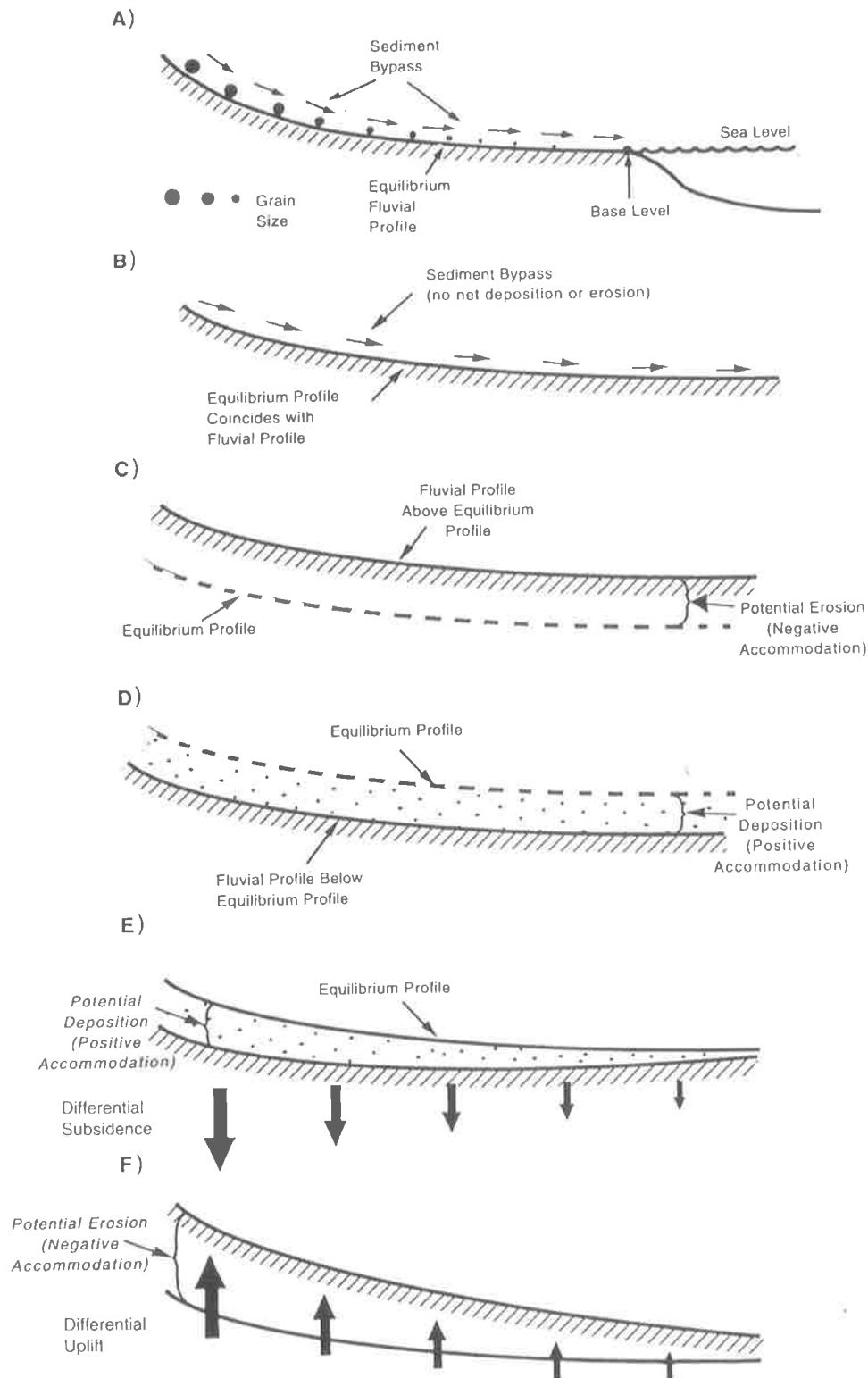


Figure 2.2.2. Schematic depiction of positive and negative fluvial accommodation (Posamentier & Allen, 1999). A) and B) illustrate an equilibrium fluvial profile anchored at sea level (i.e., base level). Everywhere along this profile, the sediment grain size is in equilibrium with river flow, so that as much sediment leaves the fluvial system at the mouth and is discharged onto the shelf, as enters the system from the hinterlands. C) If the equilibrium profile falls below the alluvial profile, the river is out of equilibrium and incises into the substrate in order to re-establish an equilibrium profile. In this instance, the space between the profile of the river and the equilibrium profile forms negative subaerial accommodation. D) If the equilibrium profile rises above the alluvial profile, the river aggrades its floodplain in order to re-establish equilibrium. This aggradation gives rise to sedimentation on the alluvial plain as the river fills the subaerial accommodation. E) In foreland basins, flexural loading because of crustal overthrusting can cause "backward" rotation of alluvial profiles, thereby creating accommodation that increases in the landward direction. F) Tectonic uplift can cause negative accommodation to exist, thereby leading to alluvial erosion.

Two important notions concerning the equilibrium profile are its shape (i.e., gradient and form) and its position in space regarding controlling fluvial accommodation. The shape of the fluvial equilibrium profile is controlled by hydrologic and sedimentary factors such as water discharge, sediment volume, and sediment calibre as well as substrate erodibility. The coarser the sediment load, the steeper the equilibrium profile, as the river requires a higher flow velocity to transport the sediment. One of the most common factors causing a change in the position of the alluvial profile is tectonic tilting (figures 2.2.2E, 2.2.2F and 2.2.3). Localised tectonic subsidence or uplift along a fluvial profile also can induce local fluvial incision and deposition (Figure 2.2.4).

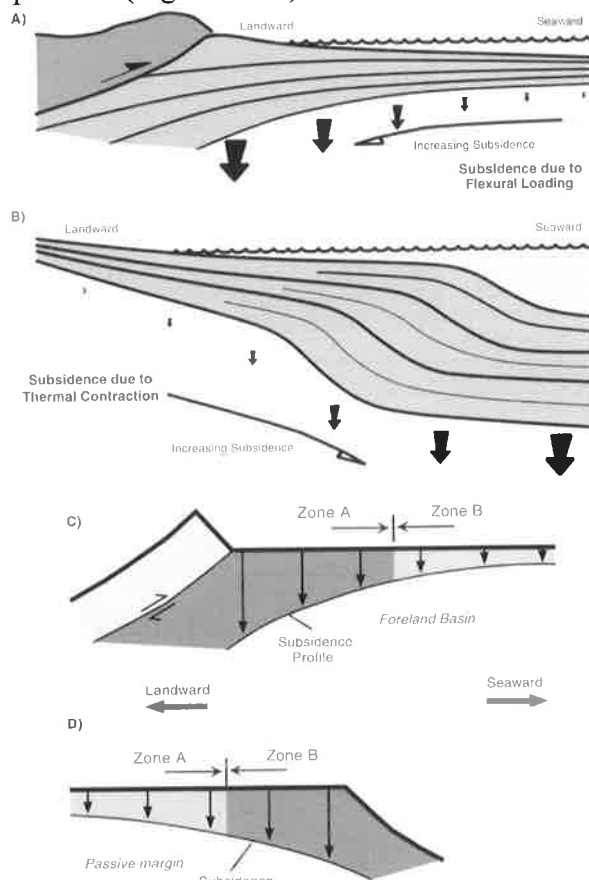


Figure 2.2.3. Effects of regional subsidence patterns on accommodation patterns (Posamentier & Allen, 1999). In foreland basins (A), accommodation increases landward (i.e., toward the orogenic belt), whereas in passive margins (B), subsidence and accommodation increase seaward. These variable accommodation patterns favour fluvial (A) and shelf aggradation (B) respectively. C and D) On the basis of subsidence and eustasy, profiles can be subdivided into two zones. Zone A is defined as the part of the profile where the rate of subsidence is always greater than the rate of eustatic fall. In this zone no interval of relative sea-level fall occurs; consequently, if the shoreline is restricted to this zone, lowstand deposits do not form there. Zone B is defined as the part of the profile where the rate of eustatic fall for a short period is greater than the rate of subsidence. In this zone, relative sea-level fall does occur, and if the shoreline lies in this zone, lowstand deposits are formed (modified after Posamentier & Allen, 1999).

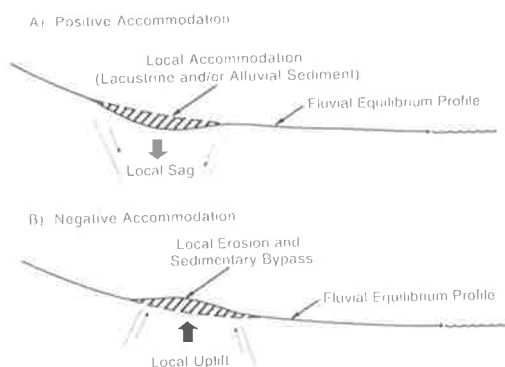


Figure 2.2.4. Schematic depiction of the effects of localised subsidence or uplift on accommodation in the Nonmarine environment (Posamentier & Allen, 1999). A) Where subsidence or sag occurs, positive accommodation is created. If sedimentation rate keeps up with the rate of subsidence, then the space is filled with predominantly alluvial deposits. If, however, the rate of subsidence exceeds the rate at which sediment is supplied, then the continental equivalent of transgression occurs: a lake forms as the fluvial profile is flooded, and lacustrine sedimentation ensues. B) Where uplift occurs, a negative accommodation situation exists and fluvial incision through the uplifted area follows, as the fluvial system seeks to re-establish its equilibrium profile (modified after Posamentier & Allen, 1999).

The position in space of the equilibrium profile is determined primarily by the level of the body of water into which the river debouches (i.e. base level). Ultimate base level is synonymous with relative sea level. It is common under certain circumstances that temporary base levels may exist for periods of time, and these can be lake level, or even another river. In practical terms, base level is represented by the level that a river attains at its mouth, and constitutes the surface to which the equilibrium profile is anchored (Figure 2.2.2A). The concept of anchoring of the profile at the level of the river mouth is critical to understanding potential accommodation change. If this point moves in space either landward or seaward, or up or down, the alluvial equilibrium profile responds in kind, and can result in a corresponding increase or decrease of accommodation with concomitant fluvial aggradation or incision and consequently fluvial stratal patterns.

Some examples of the correspondence of the fluvial accommodation to the spatial position of the equilibrium profile are demonstrated below. If a shoreline progrades under conditions of relative base level stillstand or slow rise, a coastal plain is formed with an alluvial plain following behind (Figure 2.2.5). As the shoreline migrates seaward, it becomes increasingly difficult for the river to maintain flow across the coastal plain, because the low gradient of the coastal plain is unable to maintain flow velocity, and the river profile becomes understeepened. This reduction of fluvial flow velocity results in a re-establishment of a steeper gradient and raising the equilibrium profile at each point upstream from the seaward-migrating river mouth. Consequently, regression of the shoreline is associated with upstream fluvial aggradation under condition of relative base level stillstand and slow rise. Where a rapid rise in base level results in transgression and landward migration of the shoreline, an alluvial plain at equilibrium does not necessarily need to be modified (Figure 2.2.6). Effectively, unless there is a change in the nature of the fluvial sediment supply or stream discharge concomitant with transgression, relative base level rise and transgression do not in themselves result in fluvial aggradation or incision. The fluvial system is, however, aggraded to the base level as a result of new accommodation in a body of water. If sediment supply is adequate, then a delta can prograde in the body of water to establish a new equilibrium profile and a new positive alluvial accommodation is produced. When a relative base level fall exposes the sea (or lake) floor whose slope is greater than that of the fluvial equilibrium profile (Figure 2.2.7A), the mouth of a river is shifted to the base of the

oversteepened section. The fluvial equilibrium profile that begins at this new river mouth location extends upstream from this position. As a consequence, fluvial incision occurs as the fluvial system strives to re-establish equilibrium. If the slope of the exposed sea floor is equal to or less than that of the equilibrium profile (Figure 2.2.7B and 2.2.7C), the river respectively remains in equilibrium or even aggrades, although the former situation can be observed in some instances whereas the latter seems quite rare.

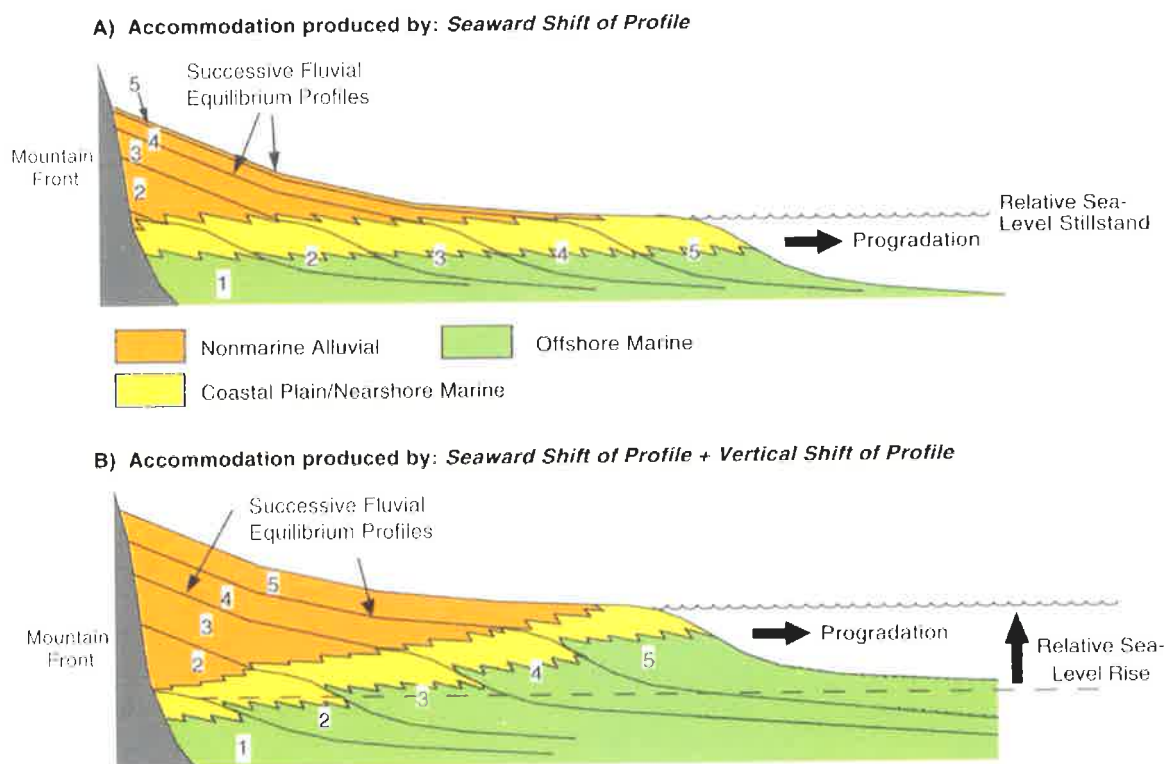


Figure 2.2.5. Schematic cross sections through the alluvial and coastal plain behind a prograding shoreline under A) relative sea-level stillstand conditions and B) relative sea-level rise (Posamentier & Allen, 1999). As the shoreline progrades, the fluvial equilibrium profile migrates seaward in order to keep up with the shoreline. With farther seaward extension of the fluvial profile, the sediments of the distal alluvial plain become finer grained and the profile gradient decreases. As illustrated, for the same equilibrium profile, significantly more accommodation is generated per unit time when relative sea level is rising (B) than during stillstand (A). Also, note that in both instances, the rate of creation of accommodation decreases in the lower reaches of the stream, as the equilibrium profile shifts seaward and is characterised by a progressively lower gradient (modified after Posamentier & Allen, 1999).

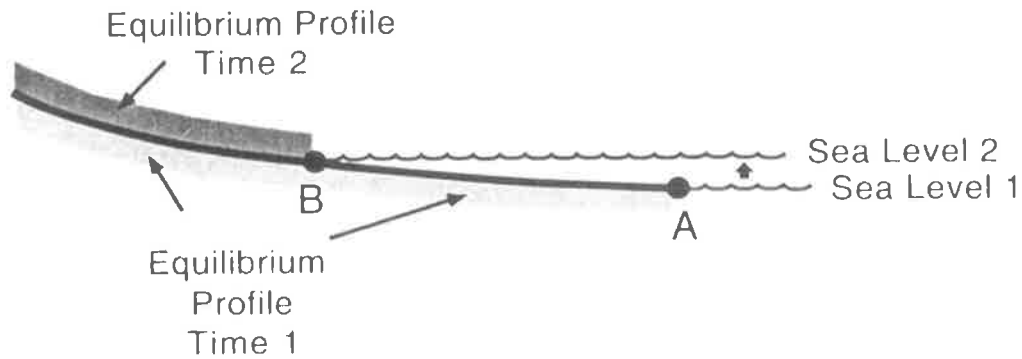
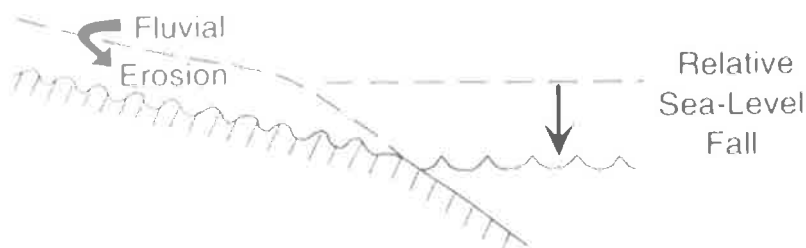


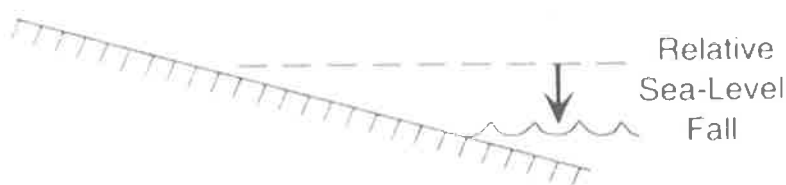
Figure 2.2.6. Fluvial equilibrium profile shown before and after a period of rapid relative sea-level rise (Posamentier & Allen, 1999). When sea level rises rapidly from level 1 to level 2, the sea transgresses the coastline without concomitant coastal aggradation. During this period of rapid transgression, there is insignificant seaward or upward shift of the equilibrium profile and therefore no new accommodation is created. Steady-state conditions are maintained as the alluvial profile is progressively flooded. The fluvial system is aggraded to the sea at point A (at time 1), and then to point B at time 2.

A) Fluvial Incision



B)

Steady State



C)

Fluvial Aggradation

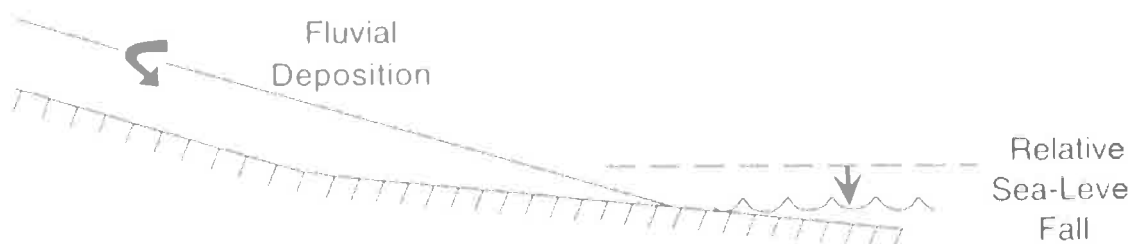


Figure 2.2.7. Three scenarios of fluvial response to relative sea-level fall (Posamentier & Allen, 1999). A) Fluvial incision occurs due to exposure of a shelf surface steeper than the graded (i.e., equilibrium) alluvial profile. B) Steady-state conditions with no net fluvial erosion or deposition occurring, because of exposure of a shelf surface with the same gradient as the graded alluvial profile. C) Fluvial aggradation occurring, because of exposure of a shelf surface with a gradient lower than that of the graded alluvial-plain profile. Note that C is likely to be the least common scenario.

Variation of fluvial sediment supply, expressed as sediment flux and grain size, is another major parameter that determines the patterns of basin fill in siliciclastic basins. The primary controls on sediment supply include climate, the relief of the fluvial drainage basin, lithology of the substrate, and vegetative cover (Blum, 1993). Changes of sediment supply can be caused by tectonism, climatic changes, or more local effects such as stream piracy, as well as mechanisms intrinsic to the fluvial systems (Wescott, 1993). Variations in sedimentary supply can control stratal patterns in two ways (Schlager, 1993): 1) for a given rate of change of accommodation (e.g., as a result of relative base level variations or tectonism), the stratigraphic architecture is largely a function of the calibre and volume of local sediment influx (i.e., very different stratal patterns form at the same time in different parts of the basin in response to different local rates of sediment influx), 2) the volumes and rates of sediment supply can directly modify accommodation through the effect of isostatic and flexural effects of sediment loading (e.g., changes in subsidence rates and patterns brought about by sediment loading, modification of the fluvial equilibrium profile associated with changes in the grain size and sediment flux).

A variety of sediment stacking patterns in fluvial environments form corresponding to cyclic variations in fluvial accommodation (figures 2.2.8 and 2.2.9). The sequence boundary results from a base level fall or a tectonic tilt of the fluvial profile. Depending on the depth of incision, either isolated incised valleys or a sheet of amalgamated fluvial channels are formed above the sequence boundary. As fluvial accommodation again increases after the formation of the sequence boundary, the channel sands become increasingly isolated within fine-grained overbank and floodplain sediments. When the rate of increase of accommodation exceeds the rate of sediment supply, the alluvial plain is transgressed by a lacustrine environment and a lacustrine environment and a lacustrine maximum flooding surface forms. As the rate of new accommodation added diminishes above the maximum flooding surface, an upward-coarsening succession is formed, comprising increasingly amalgamated lacustrine deltaic or fluvial-channel sands. As described, lowstand, transgressive, and highstand systems tracts can be identified. The fluvial section above the sequence boundary constitutes the lowstand; it is overlain by lacustrine deposits, which can be amalgamated into a transgressive systems tract. Regressive highstand lacustrine delta and fluvial sediments then cap these deposits.

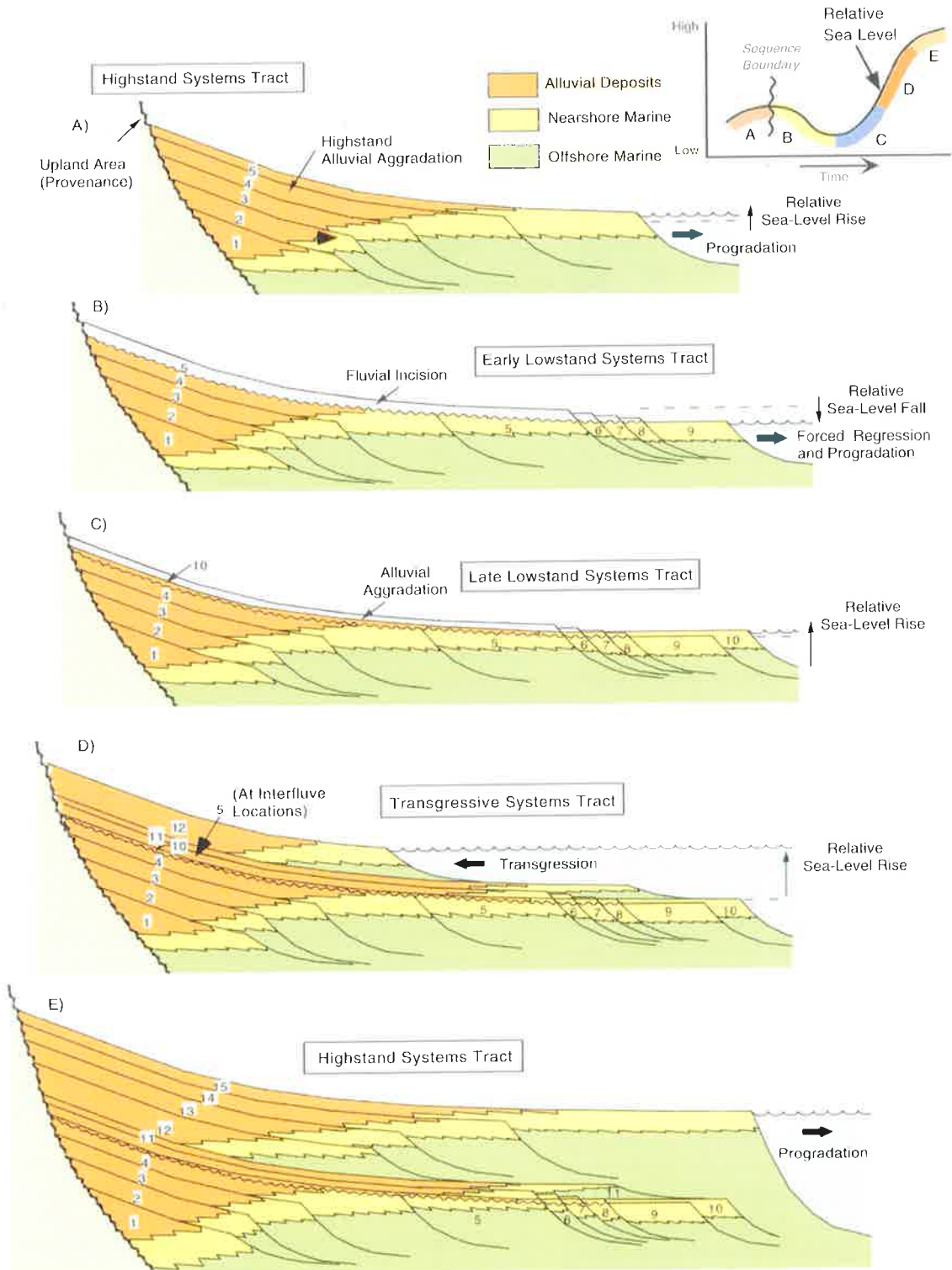


Figure 2.2.8. Dip cross section illustrating shifts of the fluvial equilibrium profile and changes of accommodation in response to a cycle of relative sea-level change (i.e., base level change) (Posamentier & Allen, 1999). Each systems tract is shown to comprise several small-scale regressive cycles (i.e., parasequences), so that at each phase of normal shoreline regression within a parasequence, fluvial accommodation is created. For the purpose of this illustration, it is assumed that rivers respond rapidly to this accommodation and fill the space available. Note that fluvial accommodation is positive (i.e., space is being made available and deposition occurs) during each time period shown, with the exception of the early lowstand systems tract (B), when accommodation is negative (i.e., erosion occurs).

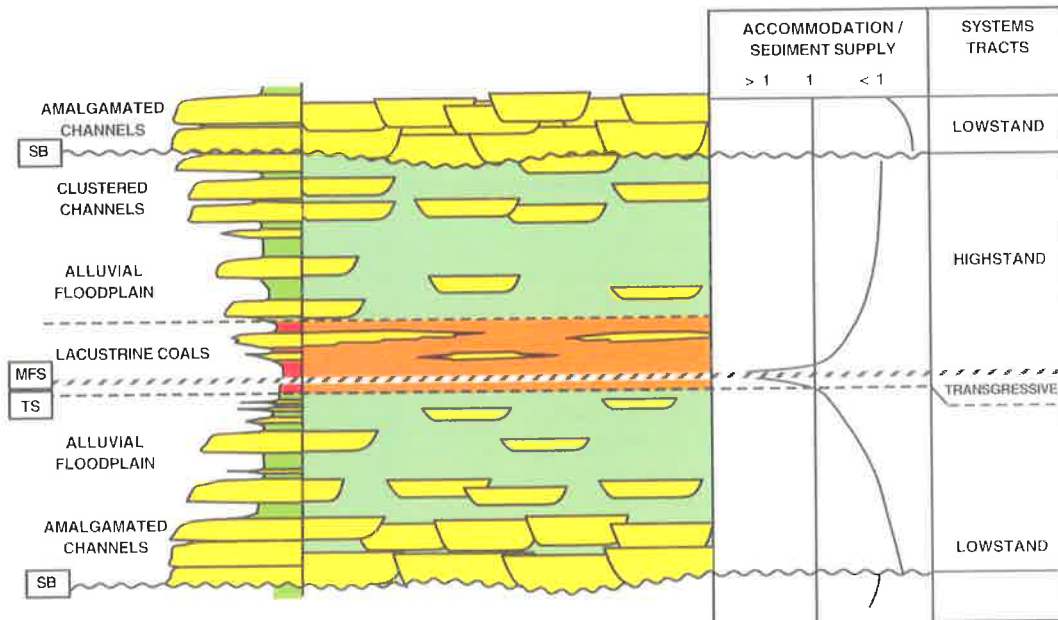


Figure 2.2.9. Hypothetical illustration of a vertical section within a nonmarine sequence (modified after Legaretta et al., 1993; Posamentier & Allen, 1999). The sequence is formed by cyclic variations in fluvial accommodation; the sequence-boundary unconformity results from a base-level fall or a tectonic tilt of the fluvial profile. Depending on the depth of incision, either isolated incised valleys or a sheet of amalgamated fluvial channels are formed above the sequence boundary. As fluvial accommodation again increase after the formation of the sequence boundary, the channel sands become increasingly isolated within fine-grained overbank and floodplain sediments. When the rate of increase of accommodation exceeds the rate of sediment supply, the alluvial plain is transgressed by a lacustrine environment and a lacustrine maximum flooding surface forms. As the rate of new accommodation added diminishes above the maximum flooding surface, an upward-coarsening succession is formed, comprising increasingly amalgamated lacustrine deltaic or fluvial-channel sands. As shown, lowstand, transgressive, and highstand systems tracts can be identified. The fluvial section above the sequence boundary constitutes the lowstand; it is overlain by lacustrine deposits, which can be amalgamated into a transgressive systems tract. Regressive highstand lacustrine delta and fluvial sediments then cap these deposits.

2.2.2 3D seismic data visualisation

3D seismic data visualisation techniques are outlined by Kidd (1999). 3D seismic data visualization has two basic types: map-based (or surface visualisation) and volume-based (or volume visualisation). Surface visualisation results from mapping individual horizons, and then reinterpreting them collectively in 3D space as a 3D model. This requires two interpretation steps and the data represent only a portion of the 3D volume. Surface visualisation is the logical outcome of conventional interpretation.

Volume visualisation is based on a different attribute of the data; transparency. In voxel-based volume visualisation (Figure 2.2.10), each data sample is converted into a voxel (a three dimensional pixel with dimensions approximating the bin spacing and sample interval). Each voxel has a value that corresponds to the parent 3D volume, an RGB (red, green, blue) colour value and an opacity variable that allows the degree of transparency to be regulated. Therefore,

each seismic trace is converted to a column of voxels. The data are scaled to eight-bit and displayed as a histogram representing the distribution of the voxel values (Figure 2.2.11). Data parameters such as phase, frequency, and seismic signatures should be reviewed prior to detailed visualisation. This is critical for guiding the application of transparency and in designing visualisation strategies for specific interpretation problems.

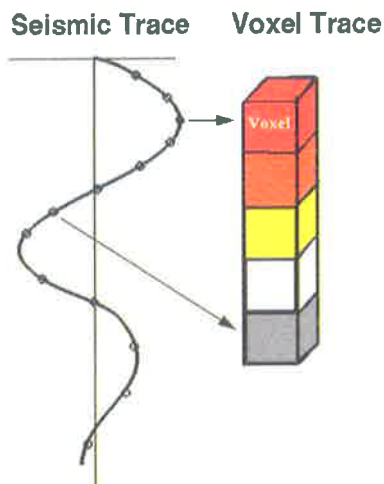
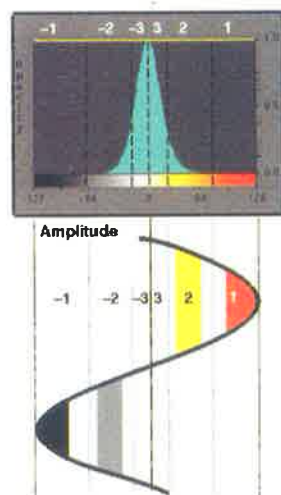


Figure 2.2.10. Seismic sample to voxel relationship. Each data sample is converted into a voxel (a three-dimensional pixel) which has a colour that corresponds to the parent 3D volume (Kidd, 1999).



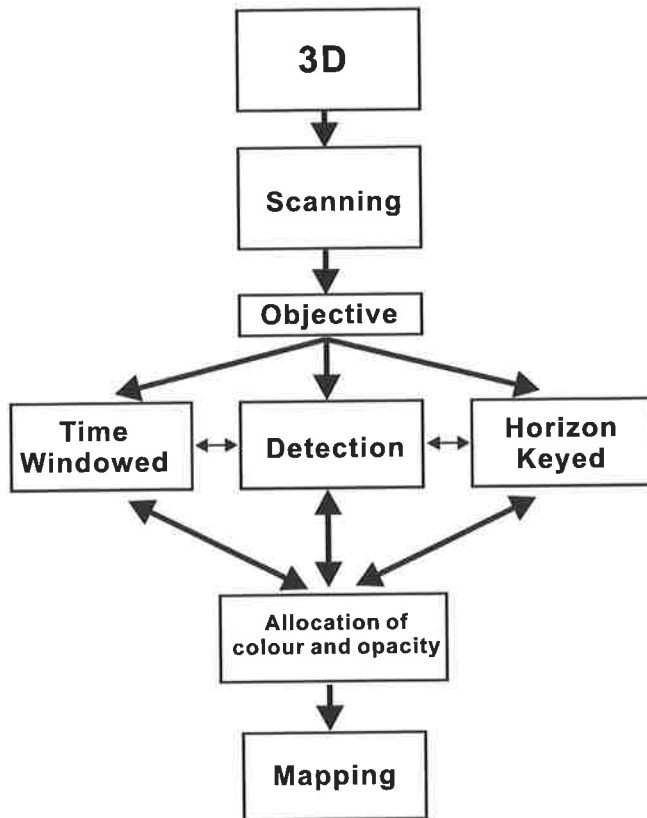


Figure 2.2.12. Seismic volume visualisation workflow (Kidd, 1999).

A generalised volume visualisation workflow is illustrated in Figure 2.2.12. Starting at the top, survey parameters and data scaling are inspected and corrected if necessary. Poor data scaling (i.e. where the data's full dynamic range is severely under-utilised) or excessive clipping greatly reduce the effectiveness of volume visualisation. Next, data are prepared for opaque 2D slice overviews by setting defaults, parameters, and colours so that the data represent a setting similar to those in conventional interpretation. Then, scanning is performed along all three primary axes for both 3D regional and prospect-specific overviews. After an objective is identified, a focusing strategy; time windowed (Figure 2.2.13), detection (Figure 2.2.14), or horizon keyed (Figure 2.2.15), isolates the objective as preparation for application of opacity. In shallow-dipping strata, time windowed visualisation is very effective for evaluating geology (Figure 2.2.13). Detection is based on the physical connectivity of voxels within a user-defined amplitude range (Figure 2.2.14). The result can be immediately evaluated for internal amplitude variations or to generate surfaces. Horizon keyed focusing strategies are the most accurate method for evaluating an interval because they only include data within the zone of interest (Figure 2.2.15). Employing horizon keyed focusing, deep-dipping strata can be detected accurately. A single horizon can be used to create a bulk-shifted interval.

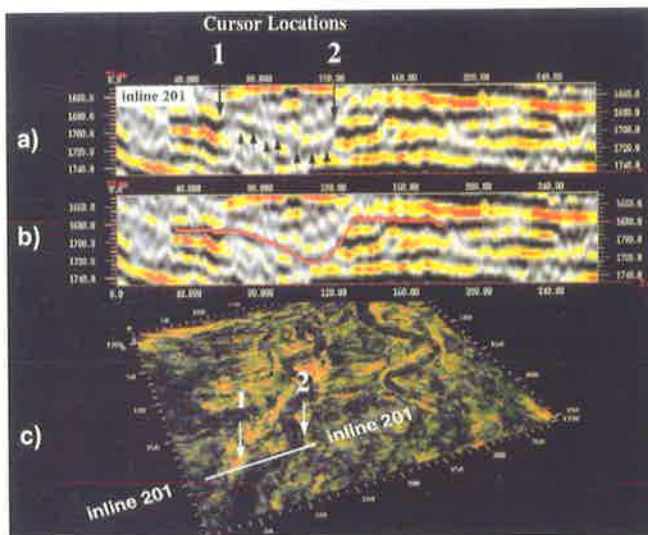


Figure 2.2.13. Volume visualization of a fluvial channel belt using a time-windowed strategy (Kidd, 1999). Within the volume focussed by time window, the positive amplitudes were represented as red and yellow. The negative amplitudes were given transparency to make invisible from the view.

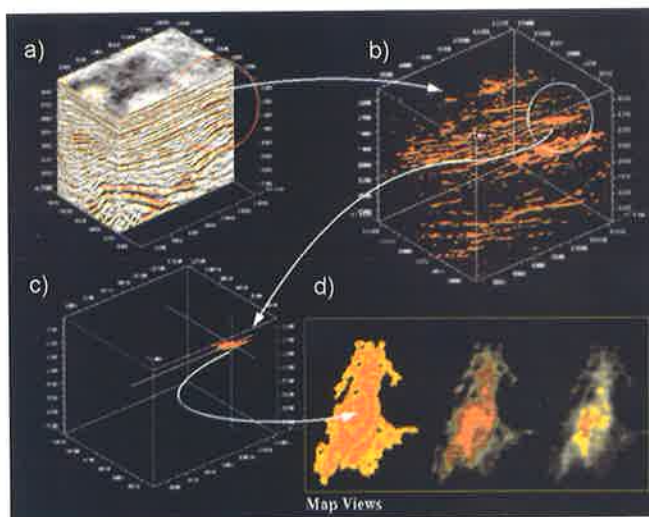


Figure 2.2.14. An example of detection focussing strategy (Kidd, 1999). Voxels connected within a user-defined amplitude range were detected from the seismic volume (a to c), and transparency was allocated according to amplitude value (d).

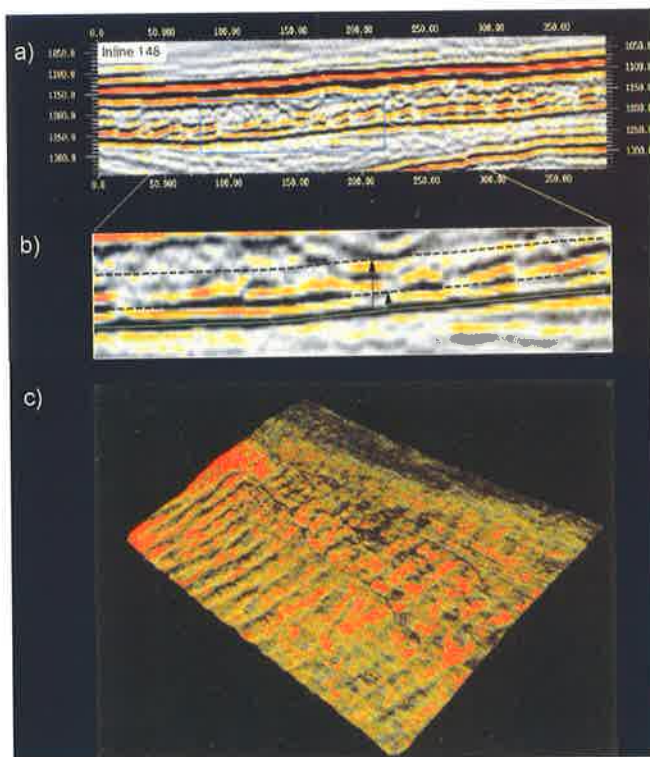


Figure 2.2.15. An example of horizon-keyed focussing strategy (modified after Kidd, 1999). Wavy and discontinuous amplitude (a) was focused by the window of 20msec to 48msec above the continuous key horizon. Dune-like features were revealed by allocating transparency to negative amplitudes in the volume (c) and interpreted as deep-water contourites.

After focusing, opacity is applied to voxel values. The opacity can be set according to the amplitude which each voxel possesses. The opacity curve is managed in the opacity editor to give an appropriate transparency to enhance a specific geologic feature (Figure 2.2.16). For instance, high opacity is allocated in the high positive amplitude, and high transparency is set less than the zero amplitude to enhance the high ends of the amplitude variation. Allocating transparency to voxels allows a viewer from outside of the volume to survey the three dimensional distribution of a series of voxels. The colour allocation according to the amplitude also can be shifted in the opacity window to enhance to demonstrate a variation of a particular amplitude zone (Figure 2.2.17). These processes of allocating the opacity and the colour are iterated until the geologic features are optimally enhanced in the focusing interval.

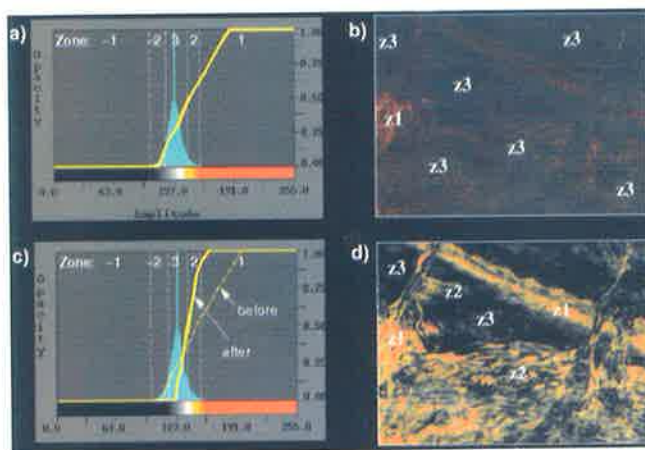


Figure 2.2.16. Managing opacity. (a) Initial opacity curve with (b) key amplitudes classified by zone. (c) Adjusted opacity curve increases the visibility of Z1 and Z2 amplitudes and decreases the visibility of Z3 amplitudes. (d) Resultant visualization (Kidd, 1999)

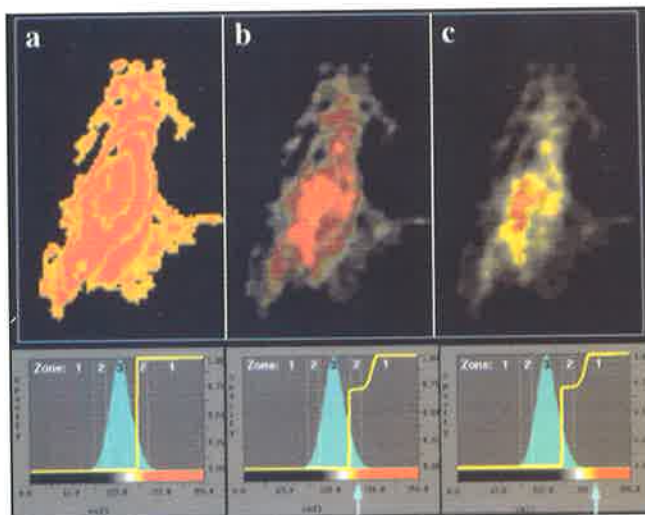
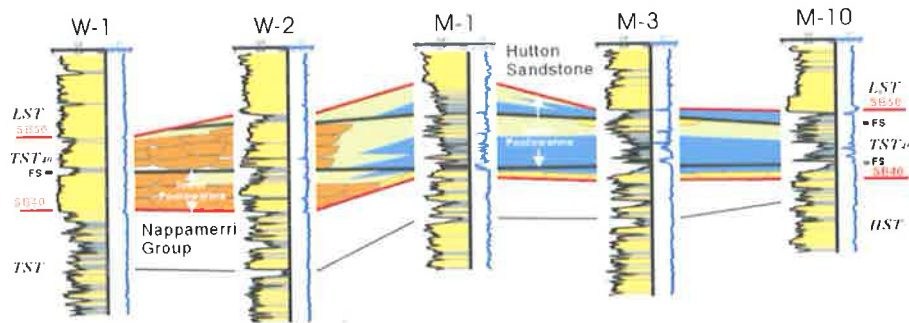


Figure 2.2.17. Application of colour and transparency shift to enhance to demonstrate a variation of a particular amplitude zone (Kidd, 1999).

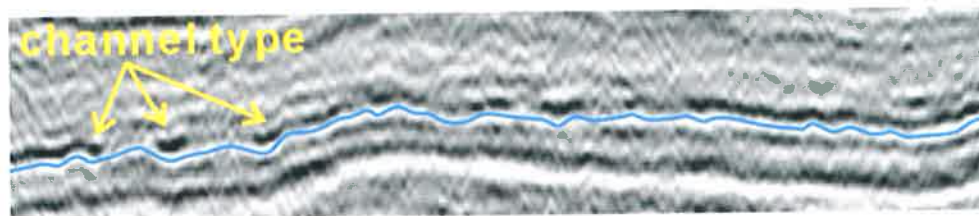
2.2.3 Integration of sequence stratigraphic concept and 3D seismic data visualisation

Three dimensional demonstration of the seismic amplitude variation focusing on the sequence stratigraphic genetic intervals is a powerful tool to extract stratigraphic trap opportunities (Figure 2.2.18). Tying genetic surfaces to seismic events, the sedimentary environment interpreted in the well log data is inter- or extrapolated into 3D seismic space. The geologic feature displayed as seismic amplitude variation can diminish uncertainty in the interpretation in the non-well area and even in the wells. The distribution of the sedimentary environment, which is chronostratigraphically bundled by genetic surfaces, represents spatial arrangements of potential reservoir and seal rocks for stratigraphic trap.

Sequence stratigraphy



Genetic surface represented in seismic event



3D seismic data visualisation with integration of sequence stratigraphic concepts

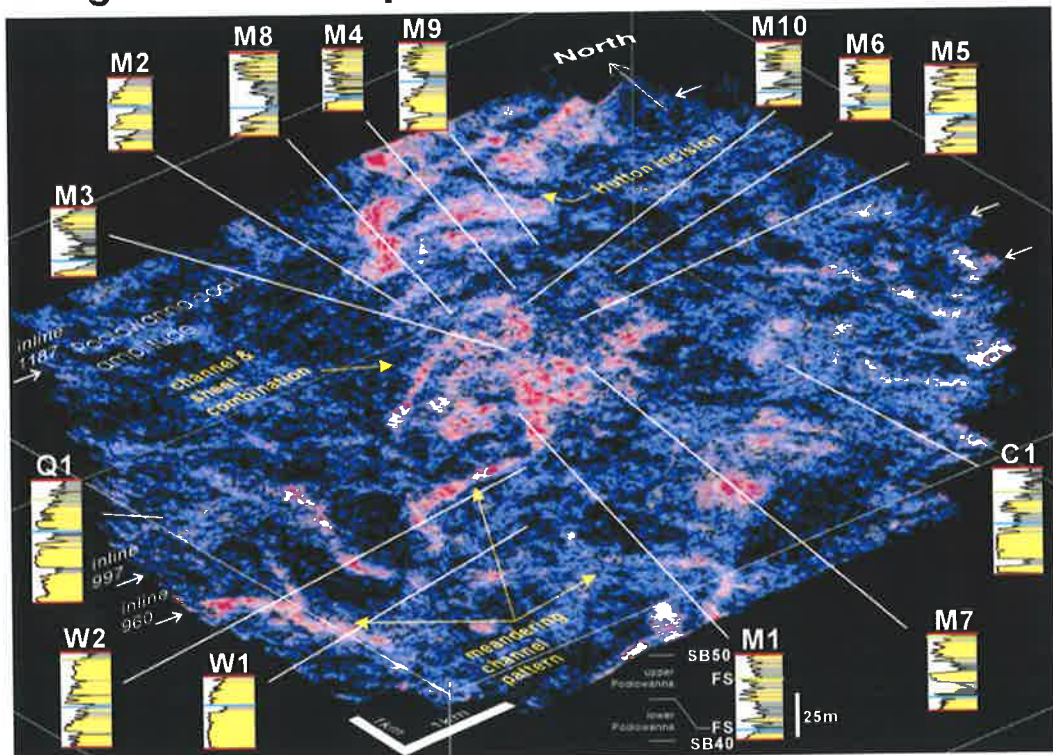


Figure 2.2.18. Integration of sequence stratigraphic concept and 3D seismic data visualisation.

In summary, to perform stratigraphic trap extractions in this research, the process is followed as below:

- Sedimentary facies analysis in well data.
- Identification of genetic surfaces in well data.
- Identification of systems tracts in well data.
- Tying genetic surfaces into seismic event.
- Focusing objective interval in 3D seismic data.
- Allocating colour and opacity in 3D seismic data to visualise geologic features.
- Representation of spatial distribution of sedimentary environment.
- Representation of spatial distribution of potential reservoir and seal rocks.
- Extraction of stratigraphic trap opportunities.

Chapter 3

Case Study Areas and Available Data

A risk evaluation procedure should be applicable to exploration opportunities in any area, whether it is mature or virgin regarding exploration. The amount of data and geotechnical ideas obtained for an objective is then evaluated with a degree of confidence. The aim of this research, however, is to design an evaluation procedure for stratigraphic trap exploration, which includes sequence stratigraphy, 3D seismic data visualisation, quantitative risk analysis and portfolio construction. This study also demonstrates the impact of the evaluation procedure on managing an exploration business.

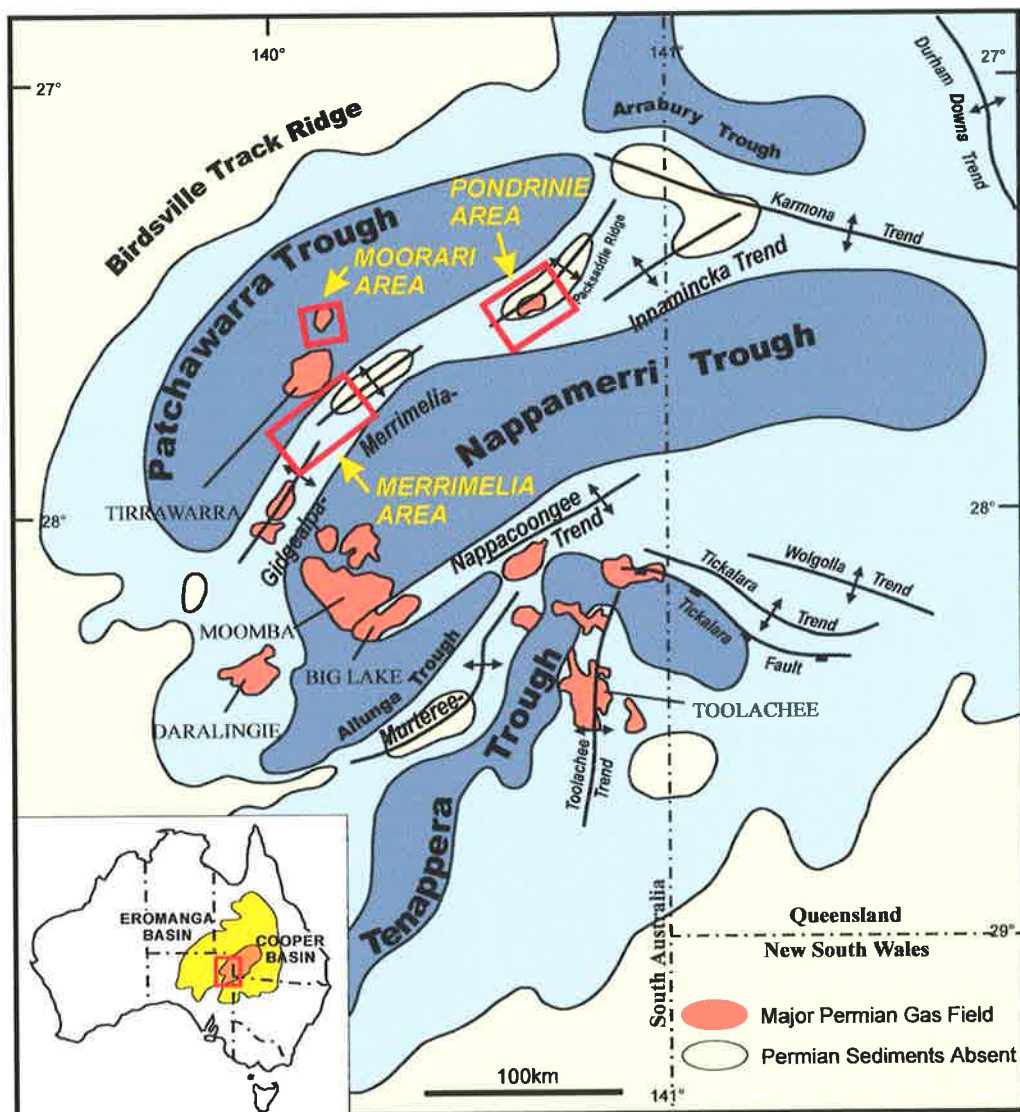


Figure 3.1. Major structural elements of the southern Cooper Basin (modified after Thornton, 1979; Apak et al., 1997) and the locations of study areas.

Relatively mature exploration with conditions as below are suitable:

- An area where hydrocarbons have been already discovered, in order to concentrate discussions in the reservoir and seal, particularly for stratigraphic traps and avoid issues regarding hydrocarbon generation and migration risks.
- An area which is developed, in order to get a relatively realistic cash flow model.
- An area where some wells have penetrated, in order to do sedimentary facies analysis and sequence stratigraphy construction.
- An area where 3D seismic survey has been acquired, in order to apply the visualisation technique.
- An area where the well and seismic data are not confidential so that they can be published.

Based on the above criteria, three sets of 3D seismic survey data, the Moorari, the Pondrinie and the Merrimelia 3D seismic surveys and well data were selected from the southern Cooper-Eromanga Basin in South Australia (Figure 3.1). The open file data (courtesy of PIRSA) includes the final migrated stack 3D seismic survey data, wireline logs and well completion reports in the seismic survey areas, and reservoir property data from the PEPS database of PIRSA. The specifications of these 3D seismic data are summarised in figures 3.2, 3.3, 3.4 and 3.5 and tables 3.1, 3.2 and 3.3. The seismic data are displayed in this thesis according to Brown's (1999) 'European polarity convention', i.e. the main lobe of a zero phase reflection from an isolated positive reflection coefficient is represented by a trough.

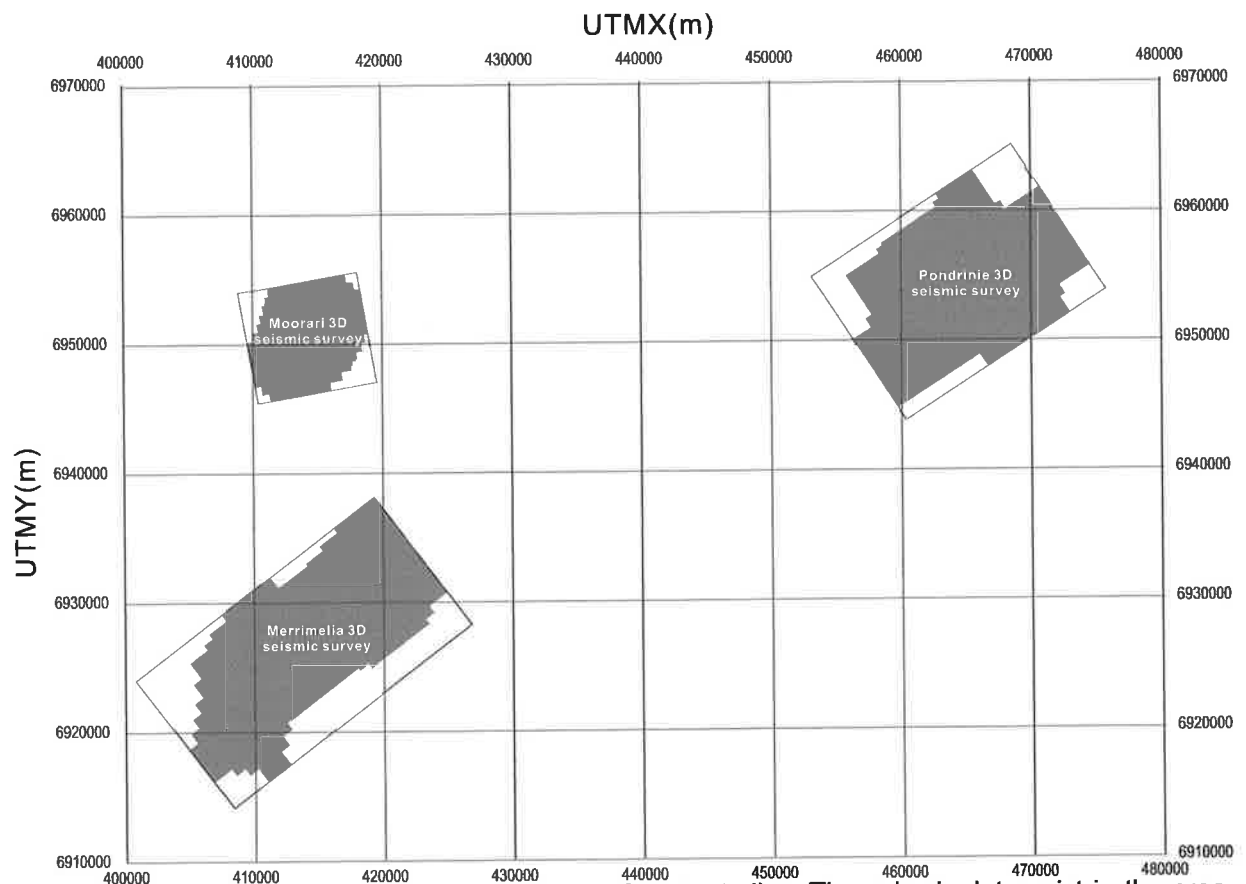


Figure 3.2. Locations of 3D seismic survey data of case studies. The seismic data exist in the area coloured in grey.

Survey	Moorari 3D		
Covered fields	Moorari Field, Woolkina Field		
Covered wells	Moorari-1,2,3,4,5,6,7,8,9,10, Woolkina-1,2, Quartpot-1, Cardam-1		
Date	1994		
Processing	Final 3D migrated stack with spectral whitening		
Company	Santos Ltd		
Source	PIRSA		
Medium	5Gb Exabyte		
Format	SEG-Y, one in-line file, single EOF between files		
Record length	4244 bytes (including trace header)		
Time of first sample	0 msec		
Datum	Mean Sea Level		
Sample format	IBM floating point		
Time range	0 – 4000 msec		
Inline range	0800 - 1230		
Crossline range	1000 - 1463		
Time sample interval	4 msec		
Inline interval	20 m		
Crossline interval	20 m		
Note All inlines padded with dead traces to give 464 traces per file.			
Header information			
Attribute	Header	Byte range	Format
Inline no.	Binary	005 - 008	32 bit integer
Inline no.	Trace	193 - 196	32 bit integer
Inline no.	Trace	205 - 208	32 bit integer
Crossline no.	Trace	197 - 200	32 bit integer
CMP no.	Trace	021 - 024	32 bit integer
Composite no.	Trace	201 - 204	32 bit integer
Bin centre X	Trace	217 - 220	32 bit integer
Bin centre Y	Trace	221 - 224	32 bit integer
Note CMP no. =Modulo ((Inline–750), 600)+ (Crossline–949) Composite no. =(Inline*10000)+Crossline X and Y coordinates are in meters, UTM projection, Central Meridian 141 degree East, AGD84 datum (ANS spheroid)			
Corner coordinates			
Inline / Crossline	X / Y (AGD84)	X / Y (GDA94)	
800 / 1000	410,348.35 / 6,945,266.10	410,470.93 / 6,945,444.07	
800 / 1463	419,471.02 / 6,946,854.95	419,593.58 / 6,947,032.92	
1230 / 1000	408,872.73 / 6,953,738.55	408,995.32 / 6,953,916.51	
1230 / 1463	417,995.41 / 6,955,327.41	418,117.98 / 6,955,505.36	
Note All coordinates in meters, UTM projection, Central Meridian 141 degrees east. Inlines are rotated by 9.87986 degrees anticlockwise from AGD84 grid east. GDA94 coordinates were computed from the AGD84 values.			
Amplitude information			
Peak amplitude	3.5892*10^9		
RMS amplitude	1.5913*10^8		
Av. Abs. amplitude	1.1067*10^8		
Suggested clip value	2.0*10^9 as 16bit loading / 8.8*10^8 as 8bit loading		

Table 3.1. Specifications for Moorari 3D seismic data.

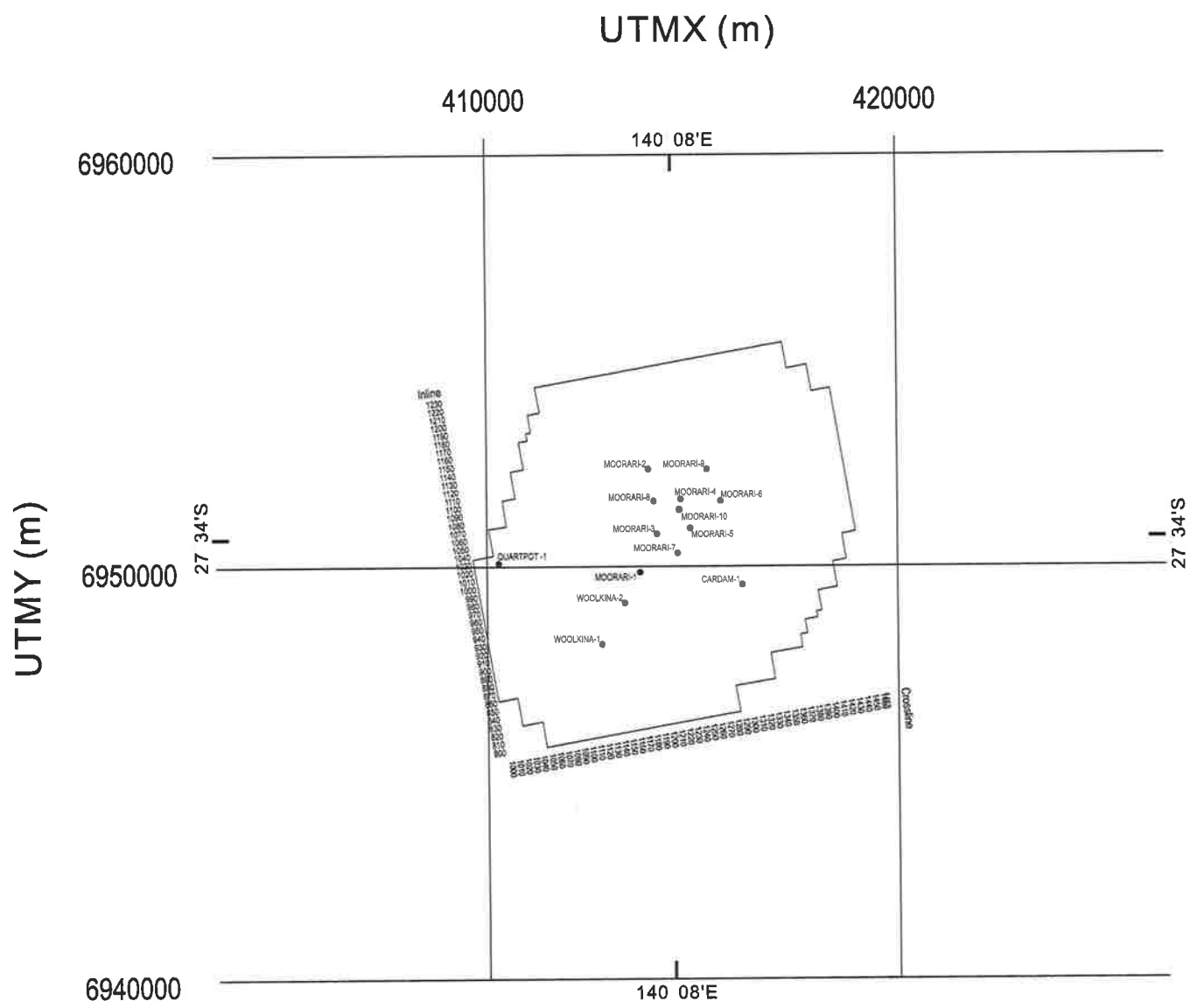


Figure 3.3. Location map of Moorari 3D seismic data and wells.

Survey	Pondrinie 3D		
Covered fields	Packsaddle Field, Pondrinie Field		
Covered wells	Packsaddle-1,2,3,4,5, Pondrinie-1,2,3,4,5,6,7,8,9,10,11,12,13,14,15, Nardu-1, Napowie-1,2, Yalchirrie-1		
Date	1997		
Processing	Final filtered 3D migrated stack		
Company	Santos Ltd		
Source	PIRSA		
Medium	5Gb Exabyte		
Format	SEG-Y, one in-line file, single EOF between files		
Record length	4244 bytes (including trace header)		
Time of first sample	0 msec		
Datum	Mean Sea Level		
Sample format	IBM floating point		
Time range	0 – 4000 msec		
Inline range	0368 – 1422		
Crossline range	1768 – 2528		
Time sample interval	4 msec		
Inline interval	17.5 m		
Crossline interval	17.5 m		
Note	Inlines contain only live traces, so number of traces per file varies.		
Header information			
Attribute	Header	Byte range	Format
Inline no.	Binary	005 - 008	32 bit integer
Inline no.	Trace	009 - 012	32 bit integer
Crossline no.	Trace	021 - 024	32 bit integer
Bin centre X	Trace	201 - 204	32 bit integer
Bin centre Y	Trace	205 - 208	32 bit integer
Note	X and Y coordinates are in meters, UTM projection, Central Meridian 141 degree east, AGD84 datum (ANS spheroid)		
Corner coordinates			
Inline / Crossline	X / Y (AGD84)	X / Y (GDA94)	
368 / 1768	452,969.9 / 6,954,640.2	453,092.4 / 6,954,818.1	
368 / 2528	460,260.1 / 6,943,515.9	460,382.6 / 6,943,693.9	
1422 / 1768	468,397.3 / 6,964,750.5	468,519.8 / 6,964,928.4	
1422 / 2528	475,687.5 / 6,953,626.2	475,810.0 / 6,953,804.1	
Note	All coordinates in meters, UTM projection, Central Meridian 141 degrees east. Inlines are rotated by 56.76 degrees clockwise from AGD84 grid east. GDA94 coordinates were computed from the AGD84 values.		
Amplitude information			
Peak amplitude	2.9314*10^4		
RMS amplitude	2.2442*10^3		
Av. Abs. amplitude	1.5437*10^3		
Suggested clip value	3.0*10^4 as 16bit loading / 1.3*10^4 as 8bit loading		

Table 3.2. Specifications for Pondrinie 3D seismic data.

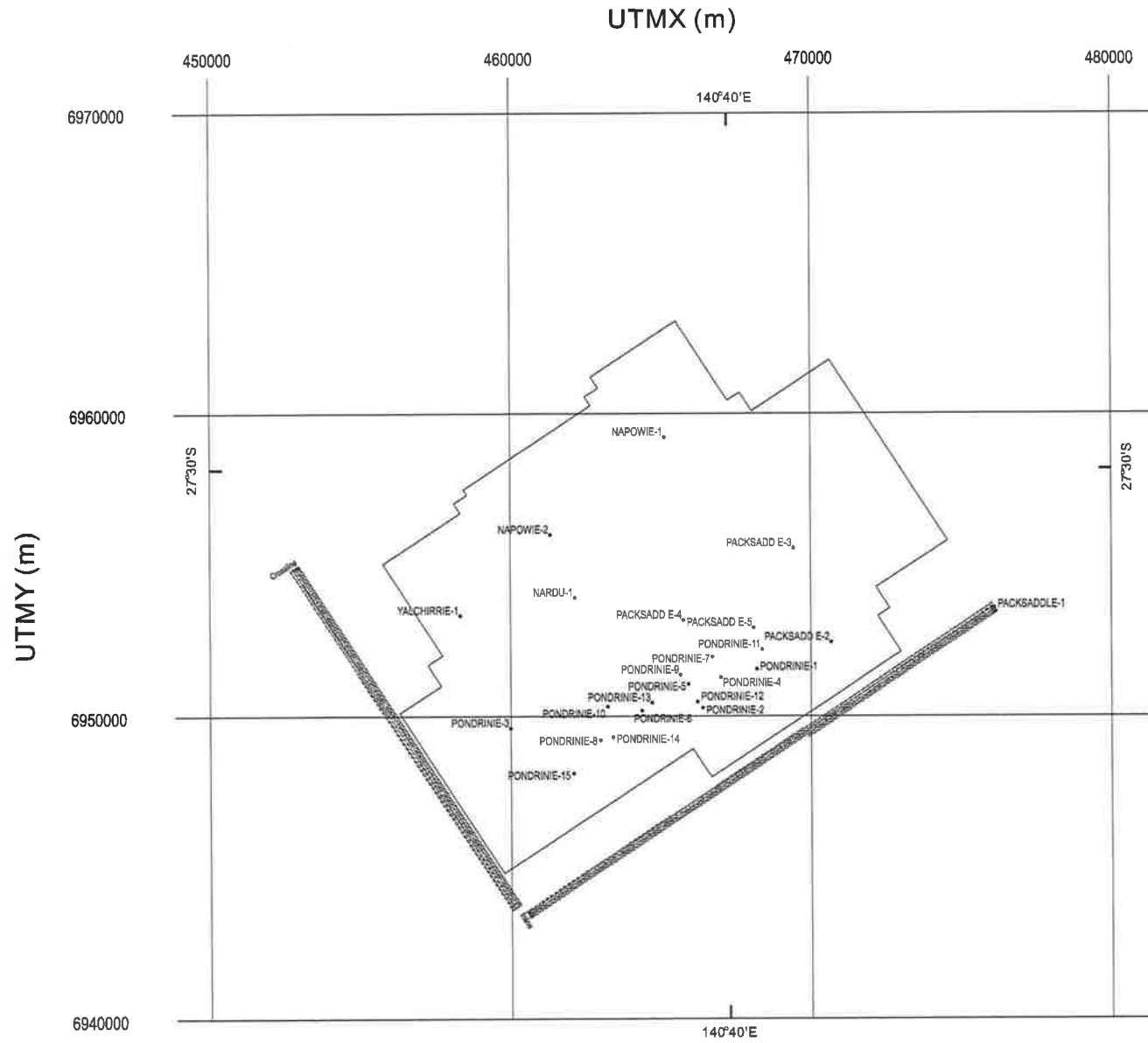


Figure 3.4. Location map of Pondrinie 3D seismic data and wells.

Survey	Merrimelia 3D		
Covered fields	Merrimelia Field, Meranji Field, Swan Lake Field, Pelican Field, Bindah Field, Massy Field, Ficus Field, Narie Field		
Covered wells	Merrimelia-1,3,4,5,6,7,8,9,10,11,12,13,14,15,17,18,20,22,24,25,26, 27,28,29,30,31,32,33,35,36,37, Meranji-1,2,4,7,9,13,15, Meranji South-1, Pelican-1,2,3,4,5, Pelican South-1, Narie-1,2, Massy-1, Ficus-1, Correa-1, Bindah-1, Cooba-1 (wells which wireline logs are available and drilled to Birkhead level are listed)		
Date	1993		
Processing	Final filtered 3D migrated stack		
Company	Santos Ltd		
Source	PIRSA		
Medium	5Gb Exabyte		
Format	SEG-Y, one in-line file, single EOF between files		
Record length	4244 bytes (including trace header)		
Time of first sample	0 msec		
Datum	Mean Sea Level		
Sample format	IBM floating point		
Time range	0 – 4000 msec		
Inline range	0002 – 1328		
Crossline range	001 – 708		
Time sample interval	4 msec		
Inline interval	17.5 m		
Crossline interval	17.5 m		
Note	Inlines contain only live traces, so number of traces per file varies.		
Header information			
Attribute	Header	Byte range	Format
Inline no.	Trace	187 - 188	16 bit integer
Crossline no.	Trace	189 - 190	16 bit integer
CMP no.	Trace	021 - 024	32 bit integer
Note	CMP no. =(Inline*1000)+Crossline		
Corner coordinates			
Inline / Crossline	X / Y (AGD84)	X / Y (GDA94)	
0002 / 001	408,289.25 / 6,913,934.00	408,411.81 / 6,914,112.03	
0002 / 708	400,774.50 / 6,923,762.89	400,897.08 / 6,923,940.91	
1328 / 001	426,723.63 / 6,928,027.98	426,846.17 / 6,928,205.97	
1328 / 708	419,208.89 / 6,937,857.05	419,331.45 / 6,938,035.03	
Note	All coordinates in meters, UTM projection, Central Meridian 141 degrees east. Inlines are rotated by 37.4 degrees anticlockwise from AGD84 grid north. GDA94 coordinates were computed from the AGD84 values.		
Amplitude information			
Peak amplitude	2.3186*10^4		
RMS amplitude	1.4790*10^3		
Av. Abs. amplitude	9.3229*10^2		
Suggested clip value	2.4*10^4 as 16bit loading / 1.1*10^4 as 8bit loading		

Table 3.2. Specifications for Merrimelia 3D seismic data.

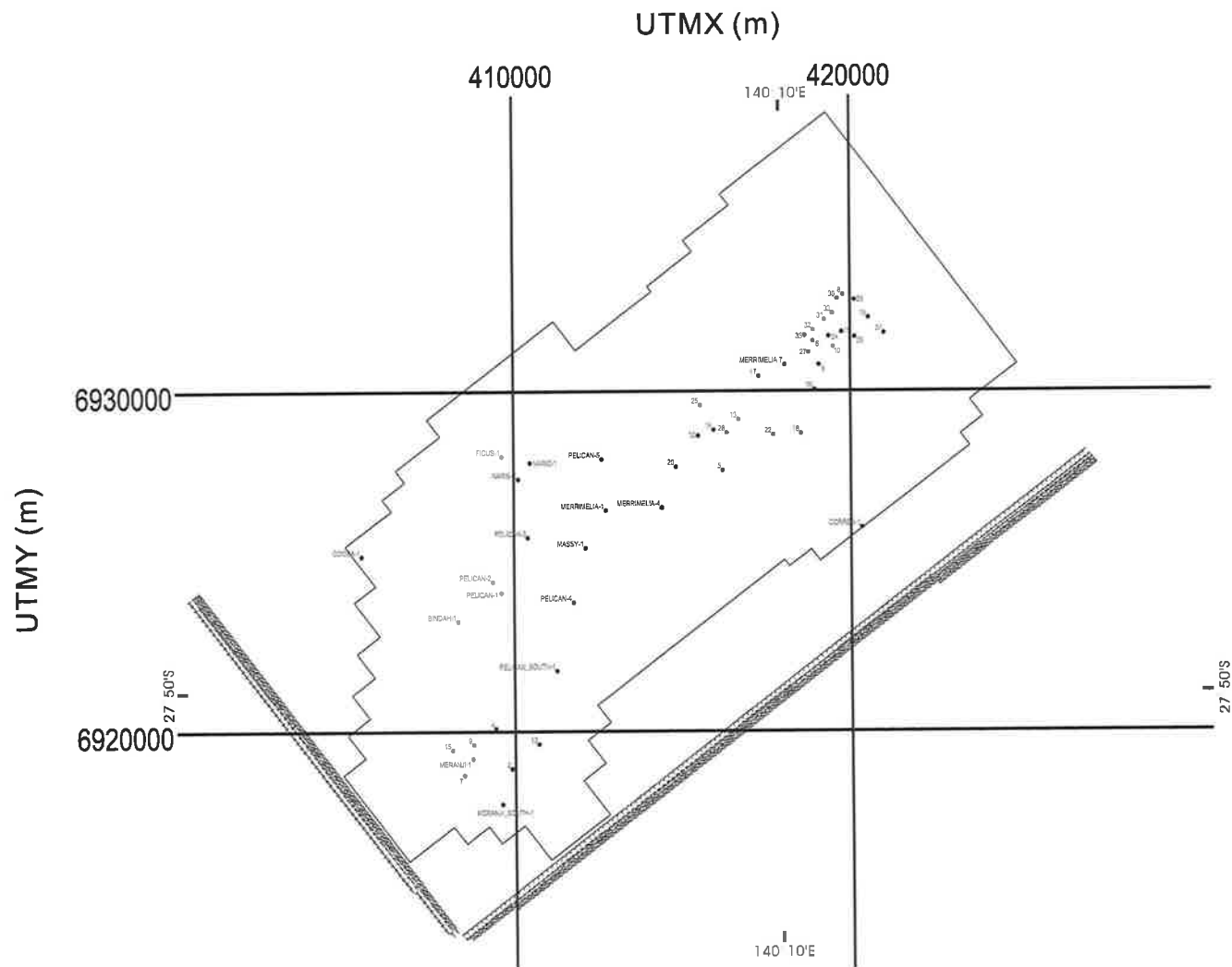


Figure 3.5. Location map of Merrimelia 3D seismic data and wells. Wells of which wireline logs are available and drilling depth reached to the Birkhead level, are shown.

Chapter 4

General Geologic Setting and Petroleum Systems of the Southern Cooper-Eromanga Basin

4.1 Stratigraphic and Tectonic Setting

The Cooper Basin is a northeast-trending Permian-Triassic basin covering approximately 130,000km² in northeastern South Australia and southwestern Queensland (Figure 4.1.1). The basin unconformably overlies the Cambrian-Devonian Warburton Basin, and Carboniferous igneous rocks. These Permian-Triassic strata are unconformably overlain by Jurassic-Cretaceous successions of the Eromanga Basin (Apak et al., 1997). Major northeast-trending folds and associated faults mainly occur in the southern Cooper Basin of South Australia. These features include two NNE-oriented intra-basinal highs, the Gidgealpa-Merrimelia-Innaminka (GMI) and the Nappacoongee-Murteree (NM) trends, plus three major depocenters, the Patchawarra, Nappamerri, and Tenappera troughs, which are now gently folded synclines (Thornton, 1979; Hill & Gravestock, 1995; Apak et al., 1997). All these structures were controlled by reactivation of basement structures during the Permian to Middle Triassic (Apak et al., 1997). The Moorari field area- case study 1- is on a structural high bounded on a fault traversing the Patchawarra Trough (Figure 4.1.1, also see figures

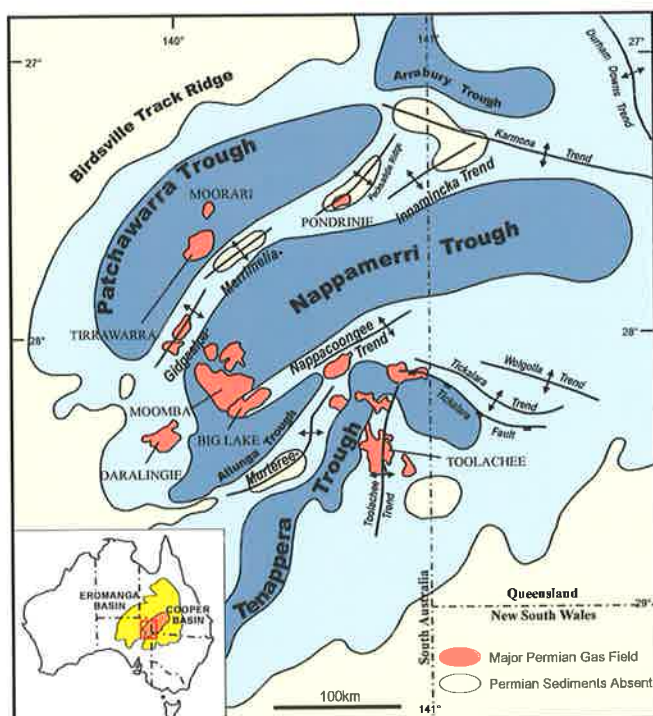


Figure 4.1.1. Major structural elements of the southern Cooper Basin (modified after Thornton, 1979; Apak et al., 1997)

AGE		STRATIGRAPHY		PALYNOLOGICAL ZONE	BASIN	Sequence boundaries in this study
CRETACEOUS	LATE	MARREE SUBGROUP	Winton Fm	PK7	EROMANGA BASIN	
	EARLY		Mackunda Fm	PK6		
			Oodnadatta Fm	PK6.2		
			Adams Mudstone	PK5.1		
			Toolebuc Fm	PK4		
			Coorikiana Sandstone	PK3.2		
			Wallumbilla Fm	PK3.1		
			Bulldog Shale	PK2.2		
			Wyandra Sandstone Member	PK2.1		
	JURASSIC		LATE	ALGEBUCKINA SANDSTONE		Murta Fm
MIDDLE		Namur Sandstone	PK1.1			
		McIntyre Member	PJ6.2			
		Westbourne Fm	PJ6.1			
		Adori Sandstone	PJ5.1			
EARLY		Birkhead Fm	PJ5			
		Hutton Sandstone	PJ4.2			
			PJ4.1			
			PJ3.3			
		Poolowanna Fm	PJ3.2			
		PJ3.1				
TRIASSIC	LATE	NAPPAMERRI GROUP		PJ2.2	EROMANGA BASIN	SB40
	MIDDLE			PJ2.1		
				PJ1		
			Cuddapan Fm	PT5		
				PT4		
	EARLY		Tinchoo Fm	PT3		
			Wyandra Sandstone Member	PT2		
			Paning Member	PT1		
			Arrabury Fm	PP6		
			Callamurra Member			
PERMIAN		LATE	GIDGEALPA GROUP	Toolachee Fm	PP5	COOPER BASIN
	EARLY			PP4.3		
		Daralinga Fm		PP4.2		
		Roseneath Shale		PP4.1		
		Epitilon Fm		PP3.3		
		Murtee Shale		PP3.2		
				PP3.1		
				PP2.2.3		
				PP2.2.2		
				PP2.2.1		
Patchawarra Fm	PP2.1					
CARBON-IFEROUS	LATE		Tirrawarra Fm	PP1.2.2		SB10
			Merrimella Fm	PP1.2.1		
				PP1.1		

Figure 4.1.2. Generalised stratigraphic column of the Cooper-Eromanga Basin in northeast South Australia (modified after Moussavi-Harami, 1996; Alexander, 1998).

5.2.3, 5.2.4 and 5.2.5). The Pondrinie field and Merrimelia Field areas- case study 2 and 3- are located on the GMI structural high trend (Figure 4.1.1, also see figures 6.2.3, 6.2.4 and 6.2.5 for the Pondrinie field area, and figures 7.2.3, 7.2.4 and 7.2.5 for the Merrimelia field area).

Initial sedimentation within the Cooper Basin consisted of glacial deposits of the Merrimelia Formation, interfingering by glaciofluvial braded outwash sandstones of the Tirrawarra Sandstone (Hill & Gravestock, 1995, Moussavi-Harami, 1996, Alexander 1998, Figure 4.1.2).

Seggie (1997) highlighted a continuous lacustrine shale interval and placing an unconformity (sequence boundary) between the distributary channels and the overlying fluvial channel deposits in the Tirrawarra Sandstone. The overlying Patchawarra Formation is dominated by meandering stream, peat swamp/mire, deltaic and lacustrine deposits, consisting of sandstone and shales, together with coals. In particular, a coaly interval in the mid-Patchawarra (VC coal) lies on top of the palynostratigraphic unit PP2.2.1, and forms the boundary between the upper and middle units of the Patchawarra Formation throughout most of the southern Cooper Basin. Apak et al. (1993) demonstrated the absence of the palynostratigraphic unit PP2.2.2 above the VC coal in the structurally high areas and suggested the presence of uplift and erosion at the end of PP2.2.2 time. The upper Patchawarra Formation is conformably overlain by the Murteree Shale and Epsilon Formation, which record a lacustrine transgression and regression within the Cooper Basin. In the southern Cooper Basin, the continued interplay of the lacustrine environments is reflected by the overlying Roseneath Shale and Daralingie Formation, but in the case study areas these units and the upper part of the Epsilon Formation were eroded during the Daralingie uplift in the Late Permian (Apak et al., 1993). The overlying Toolachee Formation was deposited above the regional unconformity in fluvial, peat swamps and lacustrine environments, and comprises sandstone, shale and coal. The final phase of sedimentation within the Cooper Basin, the Late Permian-Middle Triassic, Nappamerri Group, conformably overlies the Toolachee Formation and consists dominantly of interbedded shales and sandstones deposited in fluvial and lacustrine environments (Hill & Gravestock, 1995).

The base of the Jurassic-Cretaceous Eromanga Basin succession is marked by an irregular regional unconformity characterised by incised valleys (Wiltshire, 1982; Alexander & Sansome, 1996), which is overlain by the Poolowanna Formation. The Poolowanna Formation comprises fluvial sandstones interbedded with shales and discontinuous, thin coals. The distribution of this unit is strongly controlled by the irregularity of the basal Jurassic unconformity surface. The Poolowanna Formation is overlain by the Hutton Sandstone which comprises a thick succession of quartzose sandstones. In the Surat Basin, eastern of the Eromanga Basin, the base of the Hutton Sandstone has been interpreted as a regionally conformable, though locally disconformable, erosional contact. The relatively abrupt transition from lacustrine to high energy fluvial environments implies a basinal tilt to the east.

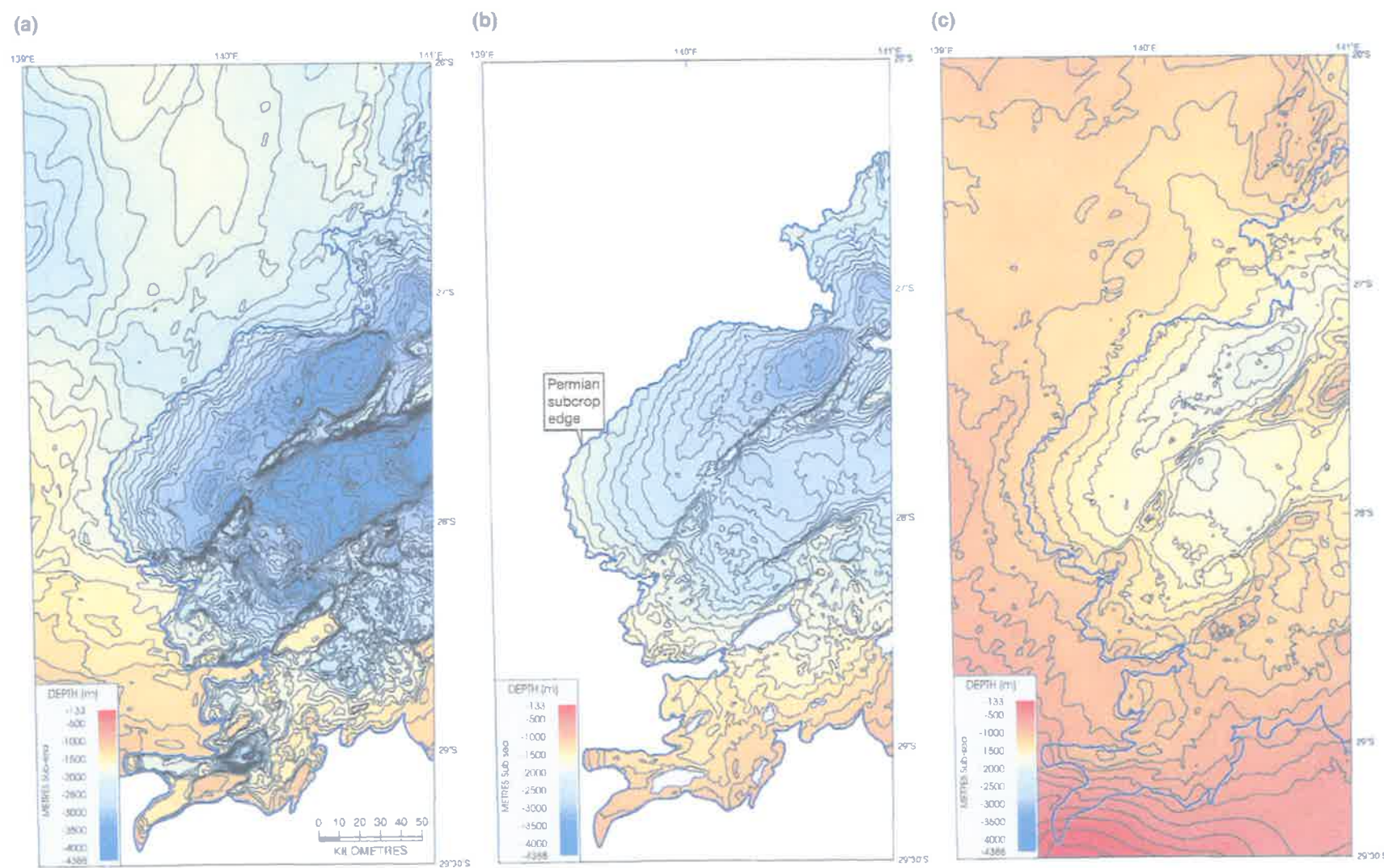


Figure 4.1.3. (a) Top of Warburton Basin depth structure contour map. (b) Near top of Permian depth structure contour map. (c) Near top of Cadna-owie Formation depth structure contour map. Edge of Cooper Basin (Permian subcrop edge) is shown on each map. (Gravestock & Jensen-Schmidt, 1998)

Wiltshire (1982 & 1989), however, proposed alternative interpretation of a transition from the Evergreen lacustrine environment (the Poolowanna Formation equivalent) to the Hutton fluvial environment with no significant tectonic input. In this research, the possibility that the Hutton Sandstone base is an erosional surface in the Eromanga Basin area will be discussed from the integration of sequence stratigraphy and 3D seismic data visualisation. Earlier models have assumed the Hutton fluvial transport to the east and northeast from westerly sediment sources (e.g. Moore et al., 1986; Watts, 1987), reaching the sea via the Surat Basin in Queensland. Wiltshire (1989) suggested that braided streams transported the sand into the basin, where aeolian and lacustrine processes distributed sand across the basin. The Hutton Sandstone is overlain by the Birkhead Formation which comprises silts, muds and coals deposited in a lacustrine ('Lake Birkhead') and coal swamp environment, cut by meandering fluvial channels (Paton, 1986). The transition from clean Hutton Sandstone to Birkhead Formation is marked by an influx of volcanoclastic sandstones in Queensland (Watts, 1987) and in South Australia, which was distant from any volcanoclastic source (Gravestock, 1982). This reflects a change in provenance to an active mobile belt off the east coast of Australia during deposition of the Birkhead Formation (Watts, 1987; Whitford et al., 1994; Boulton et al., 1998). Boulton et al. (1998) demonstrated the lateral change of thickness and the amount of influx of volcanoclastic sandstones in the Birkhead Formation, and suggested that the Birkhead Formation was deposited on an unconformity which lies on the top of the Hutton Sandstone. The Birkhead Formation is overlain by a Late Jurassic-Early Cretaceous non-marine and marine succession (Alexander & Sansome, 1996).

4.2 Petroleum systems

4.2.1 Source rocks and migration

In the Cooper Basin, the Toolachee Formation is the richest source unit (Boreham & Hill, 1998). The Patchawarra Formation is considered the other major source unit (Jenkins, 1989), especially the lower beds of shale and coal (Hunt et al., 1989). The lacustrine Murteree and Roseneath Shales appear to have little source potential. Together, the petrographic and geochemical evidence supports coal and associated inertinite dispersed organic matter (DOM) as the effective source rocks of generating gas and minor oil, albeit in low yields (Hunt et al., 1989). At maturity levels of 0.7-0.95% measured vitrinite reflectance (R_o), initial generation

from the richer facies led to partial filling of reservoirs with wet gas and oil. Burial history study (Deighton & Hill, 1998) demonstrates that most hydrocarbons from the Permian source rocks were generated in the mid-Cretaceous. The generated oil and gas migrated and was contained by the Permian-Triassic reservoirs (figures 4.2.2, 4.2.3 and 4.2.4, Bowering & Harrison, 1986; Boreham & Hill, 1998). Faulting along anticlinal trends or basin margin pinchouts can provide migration paths for Cooper Basin-derived hydrocarbon into the reservoirs in the Eromanga Basin (Heath et al., 1989; Passmore, 1989).

The source rocks in the Eromanga Basin are the coals and carbonaceous shales of the Birkhead Formation, the organic-rich shales and siltstones of the Murta Formation, and the highly carbonaceous shales of the Poolowanna Formation (Michaelsen & McKirdy, 1996). These units display a wide range of source richness and quality, but all contain varying quantities of type II/III (oil/gas-prone) and Type II (oil-prone) organic matter. Burial history study (Moussavi-Harami, 1996) suggests that the Jurassic source rocks are likely to have reached the initial stage of hydrocarbon generation in the late Early to Late Cretaceous and became fully mature in the Late Cretaceous to early Tertiary. The generated oil migrated and was contained by the Jurassic-Cretaceous reservoirs (figures 4.2.2, 4.2.3 and 4.2.4, Boulton et al., 1986; Boreham & Hill, 1998).

4.2.2 Reservoirs

Nearly all units of the Permian and the Triassic successions in the Cooper Basin contain gas reservoirs except the lacustrine shale intervals of the Murteree Shale and the Roseneath Shale. Major oil accumulations were discovered in the Merrimelia Formation, Tirrawarra Sandstone and Nappamerri Formation (Figure 4.2.1; Yew & Mills, 1989).

In the Eromanga Basin in South Australia, nearly all units from the Poolowanna Formation to Murta Formation contain oil reservoirs, with the exception of the Adori Sandstone (Alexander, 1996). The Hutton Sandstone has proved to be the most productive onshore unit within the Jurassic-Cretaceous. In Queensland, the Cadna-owie Formation (Wyandra Sandstone Member) has produced oil, although no economic discoveries have been made in South Australia.

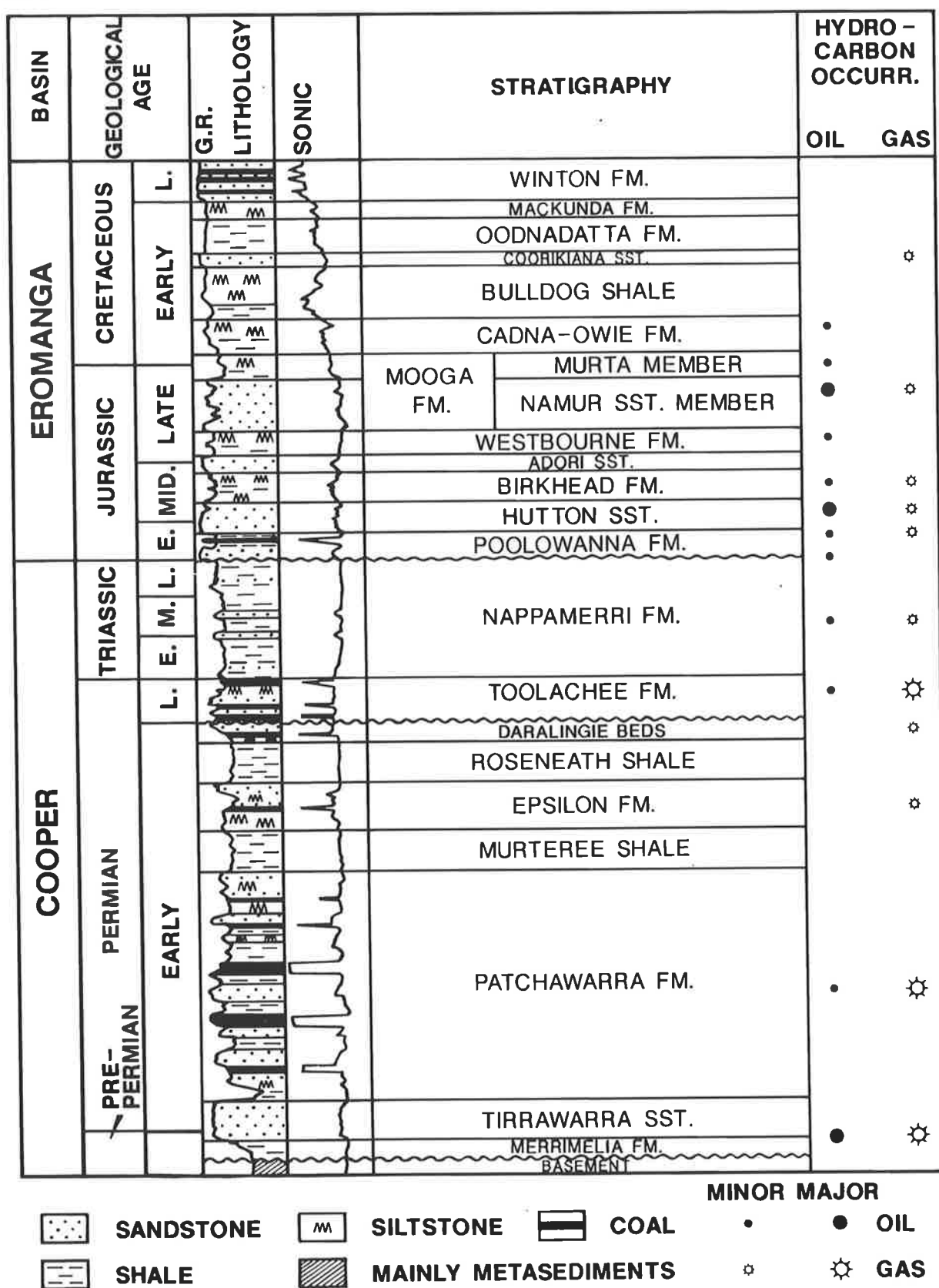


Figure 4.2.1. General stratigraphic column and hydrocarbon occurrences in the southern Cooper Basin (modified after Yew & Mills, 1989).

4.2.3 Traps

Exploration in the Cooper-Eromanga Basin has led to the discovery of oil and gas in both structural and structural/stratigraphic traps, however the hydrocarbon potential of the basin has largely been addressed by drilling the crest of the major anticlines. The chance of stratigraphic trap in this basin has been described by several authors (Stanmore & Johnstone, 1988; Stanmore, 1989; Taylor et al., 1991). Stanmore (1989) reviewed hydrocarbon discoveries in the Cooper Basin and identified three non-crestal traps, a) reservoir sandstones are truncated below an erosional unconformity and sealed by shale, coal, and/or impermeable sandstone, b) reservoir sandstones are replaced laterally by shale and/or impermeable sandstone, usually due to structurally controlled updip facies change, which provide the seal to the trap, c) faults provide an updip or lateral barrier to hydrocarbon movement.

Most of the oil trapped in the Eromanga Basin has migrated to the attics of low amplitude, dip-closed anticlines or domes. However, stratigraphic trap components related to reservoir/seal interfaces are also recognised in some fields (Gravestock, 1996). Mackie and Gumley (1995) described a stratigraphic trap comprising fluvial channel sandstones up-dip thinning out into shales of the Birkhead Formation in the Dirkala Field (Figure 1.2.10).

4.2.4 Seals

The principal regional seal in the Cooper Basin comprises the Arrabury Formation (the lowest unit of the Nappamerri Group) (Figure 4.2.2). The Arrabury seal separates Jurassic freshwater aquifers from more saline Permian brines but mixing occurs towards the seal edge in the basin margin (Dunlop et al., 1992). Where the regional seal is thin or absent, multiple oil and gas pools are stacked in Permian-Mesozoic structures (Gravestock et al., 1998). Beneath the Daralingie unconformity are two important Early Permian regional seals, the Roseneath and Mutereee Shales. The Roseneath Shale is the top seal of the Epsilon Formation and the Murteree Shale seals the Patchawarra Formation (Gravestock et al., 1998). At a prospect scale, most of the effective Permian seals are intraformational. The impermeable seal is typically a succession ranging from 3 to 20m thick of carbonaceous siltstone and shale beds with thin coal seams or alternatively, it may consist of thick, 10-20m coal seams with thin interbedded shale. These fine-grained carbonaceous lithologies effectively cap the reservoirs (Gravestock et al., 1998).

In the basal unit of the Eromanga Basin, shales within the Poolowanna Formation are intraformational seals, but the occurrence of stacked oil pools in fields indicates they are not wholly effective. Seal effectiveness is reduced by their limited areal extent, thickness and siltstone mineralogy (Alexander, 1996). Extensive lacustrine shale intervals, the Birkead Formation and Murta Formation, exist. However, the seal efficiency of these intervals is low (Boult et al., 1998) and controlling the thickness of Hutton and Namur oil columns less than 20m (Heath et al., 1989). As a result, no reservoir is filled to spill point.

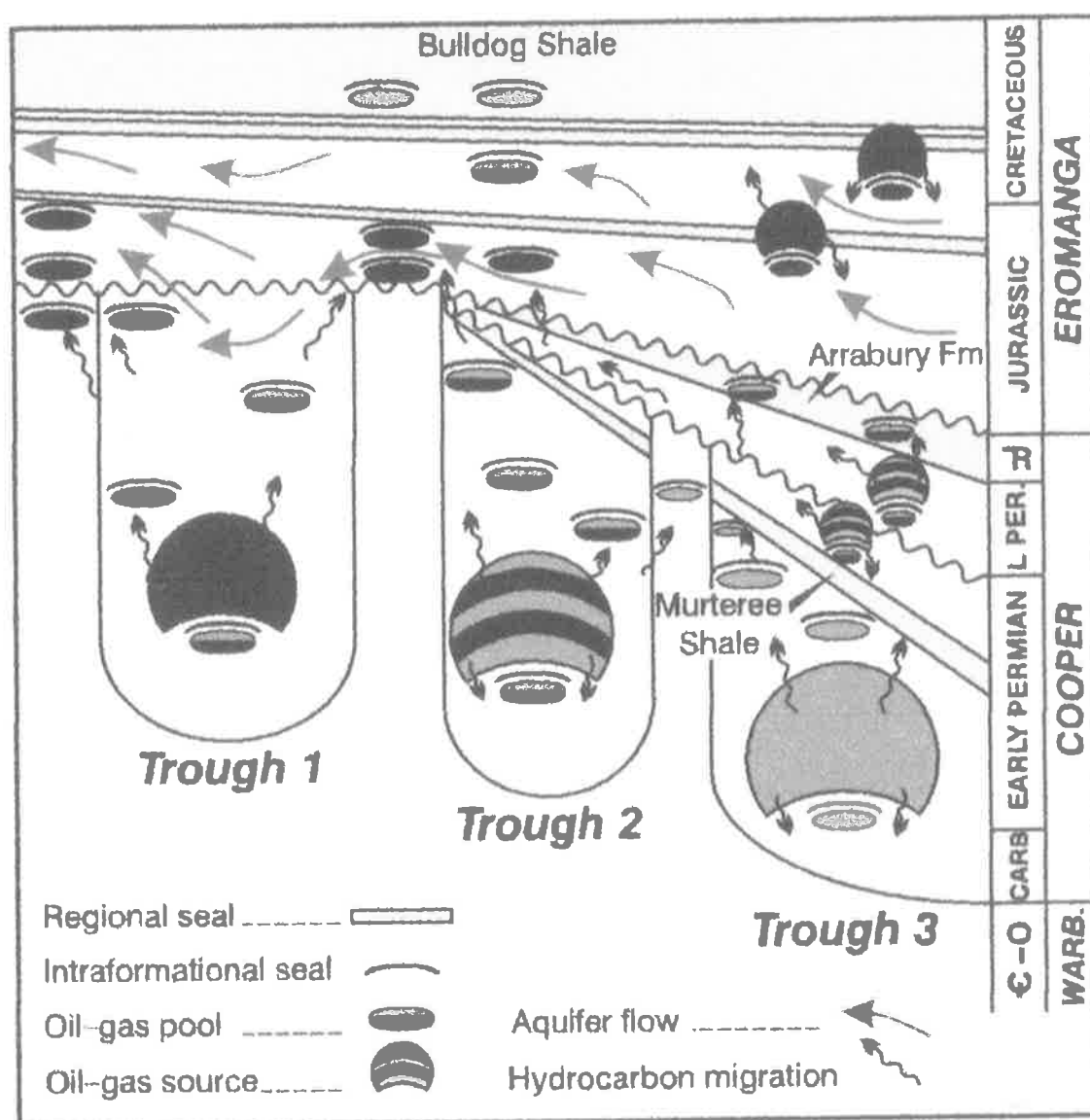


Figure 4.2.2. Schematic diagram of source, seal and secondary hydrocarbon migration in the Cooper-Eromanga Basin (Gravestock et al., 1998). Troughs are separated by ridges of elevated Warburton Basin rock. Trough 1 represents e.g. the southern Patchawarra and Tenapperra Troughs close to the basin margin; Trough 2 the Patchawarra, Wooloo and Allunga Trough; Trough 3 the Nappamerri and Patchawarra Troughs.

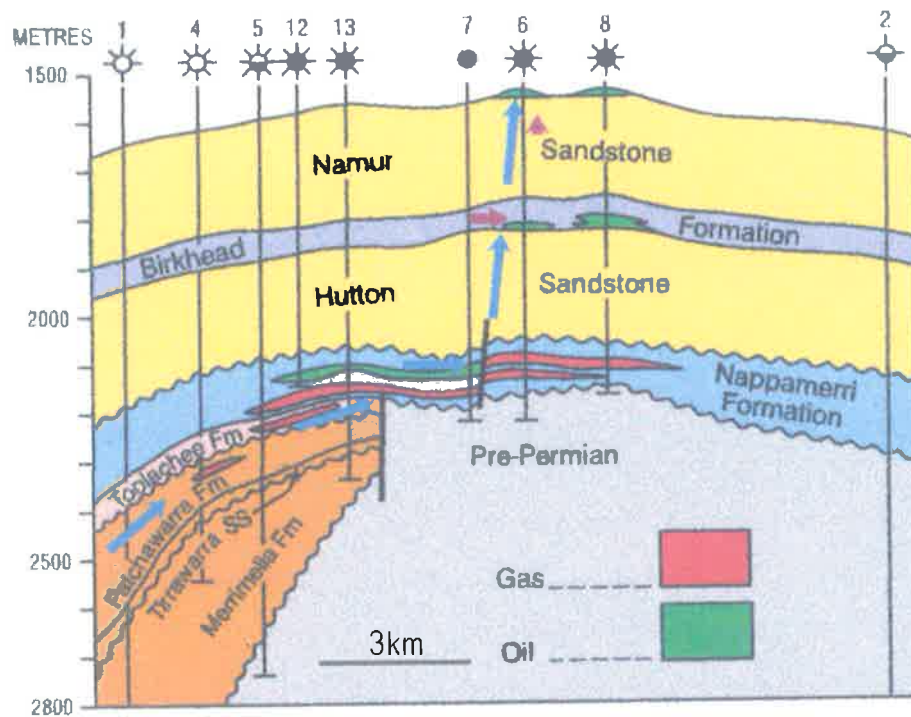


Figure 4.2.3. Cross section of Merrimelia Field showing oil and gas accumulations and migration pathways from Cooper (blue arrows) and Eromanga (purple arrows) sources (after Bowering & Harrison, 1986; Boreham & Hill, 1998).

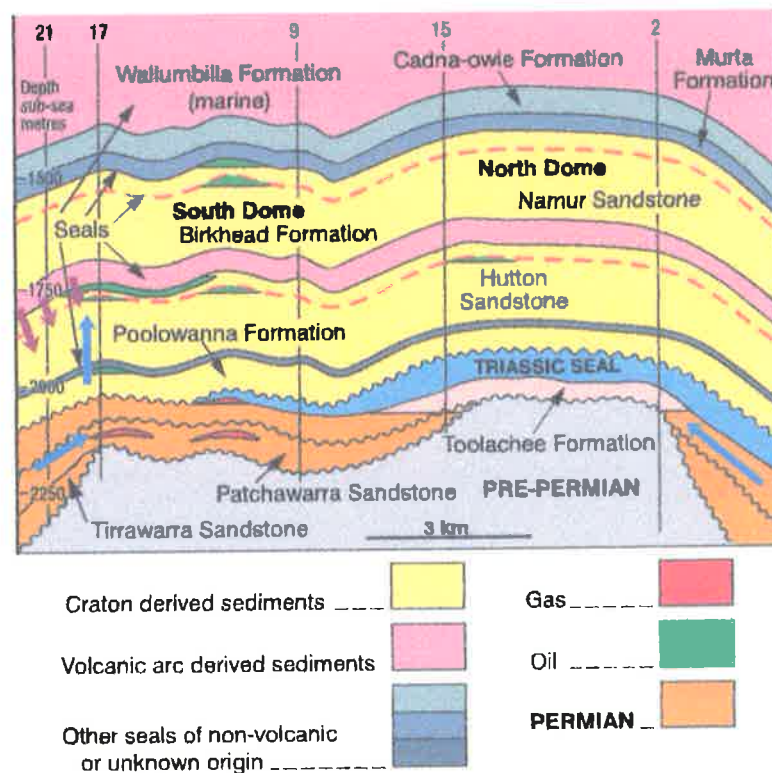


Figure 4.2.4. Cross section of Gidgealpa Field showing oil and gas accumulations and migration pathways from Cooper (blue arrows) and Eromanga (purple arrows) sources (after Boulton et al., 1986; Boreham & Hill, 1998).

Chapter 5

Case Study 1: Moorari 3D Seismic Survey Area

5.1 Introduction

The Moorari 3D seismic survey area was selected as the first case study, and six stratigraphic trap prospects were recognised in the Permian succession and the basal Jurassic Poolowanna Formation.

5.2 Moorari / Woolkina fields

The Moorari 3D seismic survey area is located in northeastern South Australia in the Patchawarra Trough of the southern Cooper Basin (Figure 5.2.1). The seismic survey covers the locations of the Moorari Field and the Woolkina Field. The Moorari field is an anticline with a four-way dip closure, bounded to the west at Early Permian level by a NNE striking, westward dipping fault (figures 5.2.3, 5.2.4 and 5.2.5). The accumulation of oil was discovered in the Tirrawarra Sandstone in 1971 with the drilling of Moorari-1 on the anticline. Accumulations of gas and condensate were also discovered in the Patchawarra and Toolachee formations and Nappamerri Group. The field was appraised in the downthrown fault block to

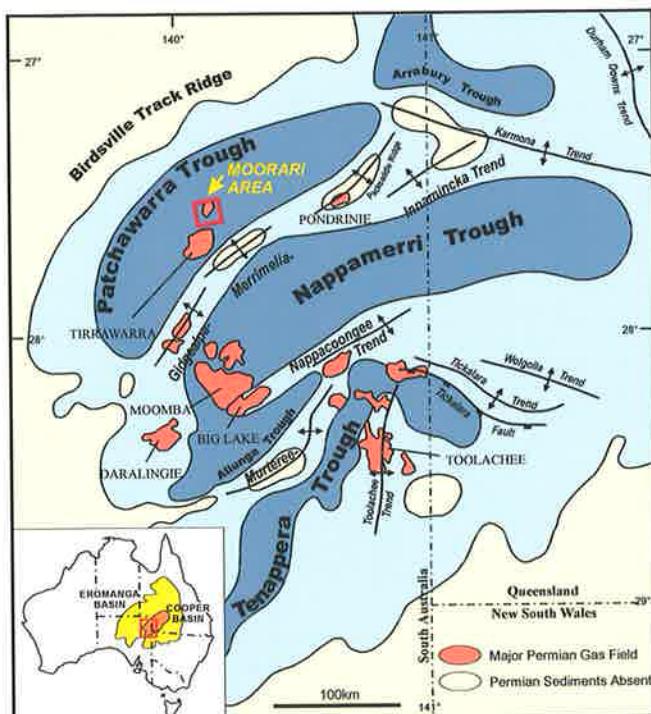


Figure 5.2.1. Major structural elements of the southern Cooper Basin (modified after Thornton, 1979; Apak et al., 1997) and the location of the case study area.

the west (Moorari-2), but the well proved to be unsuccessful and was plugged and abandoned. Further eight appraisal and development wells (Moorari-3,4,5,6,7,8,9 and 10) were drilled on the upthrown block from 1980 to 1994 which developed oil and gas accumulations in the Tirrawarra Sandstone, Patchawarra and Toolachee formations and the Nappamerri Group.

The Woolkina Field is on a small structural culmination to the south of Moorari Field (Figure 5.2.3). Woolkina-1 was drilled in 1982 and intersected the oil accumulation in the Tirrawarra Sandstone. The saddle between Woolkina and Moorari was successfully appraised in 1988 by the drilling of Woolkina-2, which intersected oil in the Tirrawarra Sandstone and gas in the Patchawarra Formation.

Quartpot-1 was drilled in 1988 on a structural high, west of the Moorari Field, but was plugged and abandoned after no commercial accumulation was discovered. Cardam-1 was drilled in 1998, on the eastern flank of the Moorari structural high, in order to test a stratigraphic trap in the Patchawarra Formation. The well discovered several gas accumulations in the Patchawarra Formation, and was cased and suspended.

AGE		STRATIGRAPHY		PALYNOLOGICAL ZONE	BASIN	Sequence boundaries in this study	Objective interval in case study 1		
CRETACEOUS	LATE	MARREE SUBGROUP	Winton Fm	PK7	EROMANGA BASIN				
			Mackunda Fm	PK6					
	EARLY		Oodnadatta Fm	PK5.2					
			Allen Modstone	PK5.1					
			Toolebuc Fm	PK4					
			Coorikana Sandstone	PK3.2					
			Bulldog Shale	PK3.1					
			Wyandra Sandstone Member	PK2.2					
			Gadna-owie Fm	PK2.1					
			Murta Fm	PK1.2					
JURASSIC	LATE	MARREE SUBGROUP	Namur Sandstone	PK1.1	EROMANGA BASIN				
			McKinlay Member	PJ6.2					
	MIDDLE		Westbourne Fm	PJ6.1					
			Adori Sandstone	PJ5		SB60			
			Birkhead Fm	PJ4.2					
			Hutton Sandstone	PJ4.1					
	EARLY		Algebuckina Sandstone	PJ3.3		SB50			
			Poolowanna Fm	PJ3.2					
				PJ3.1		SB40			
				PJ2.2					
TRIASSIC	LATE	NAPPAMERRI GROUP	Cuddapan Fm	PJ2.1	EROMANGA BASIN				
				PJ1					
	MIDDLE			PT5					
				PT4					
	EARLY		Tinchoo Fm	PT3					
			Winton Sandstone Member	PT2					
			Paning Member	PT1					
			Arrabury Fm	PP6					
	PERMIAN		LATE	GIDGEALPA GROUP	Callamurra Member	PP5	COOPER BASIN	SB30	
					Toolachee Fm	PP4.3			
EARLY		Darlingia Fm	PP4.2						
		Roseneath Shale	PP4.1						
		Epsilon Fm	PP3.3						
		Murteree Shale	PP3.2						
			PP3.1		SB20				
			PP2.2.3						
			PP2.2.2						
			PP2.2.1						
Patchawarra Fm	PP2.1								
Tirrawarra Fm	PP1.2.2	SB10							
CARBON-IFEROUS	LATE		Merrimella Fm	PP1.2.1					
				PP1.1					

Figure 5.2.2. Generalised stratigraphic column of the Cooper-Eromanga Basin in northeast South Australia (modified after Moussavi-Harami, 1996; Alexander, 1998) and objective intervals in this case study.

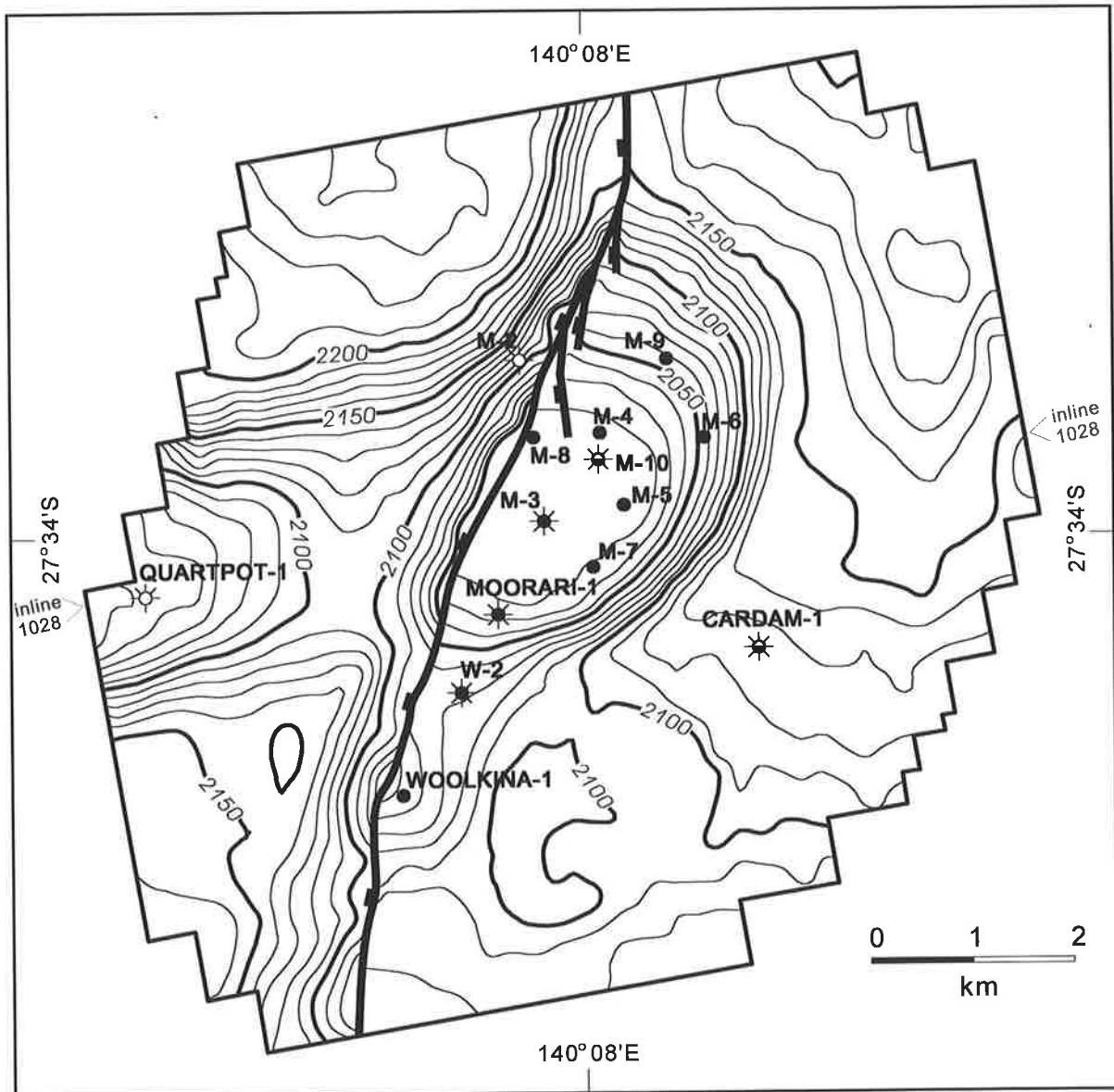


Figure 5.2.3. Two-way-time structure map of the SB20 (VC coal) horizon in Moorari 3D seismic survey area.

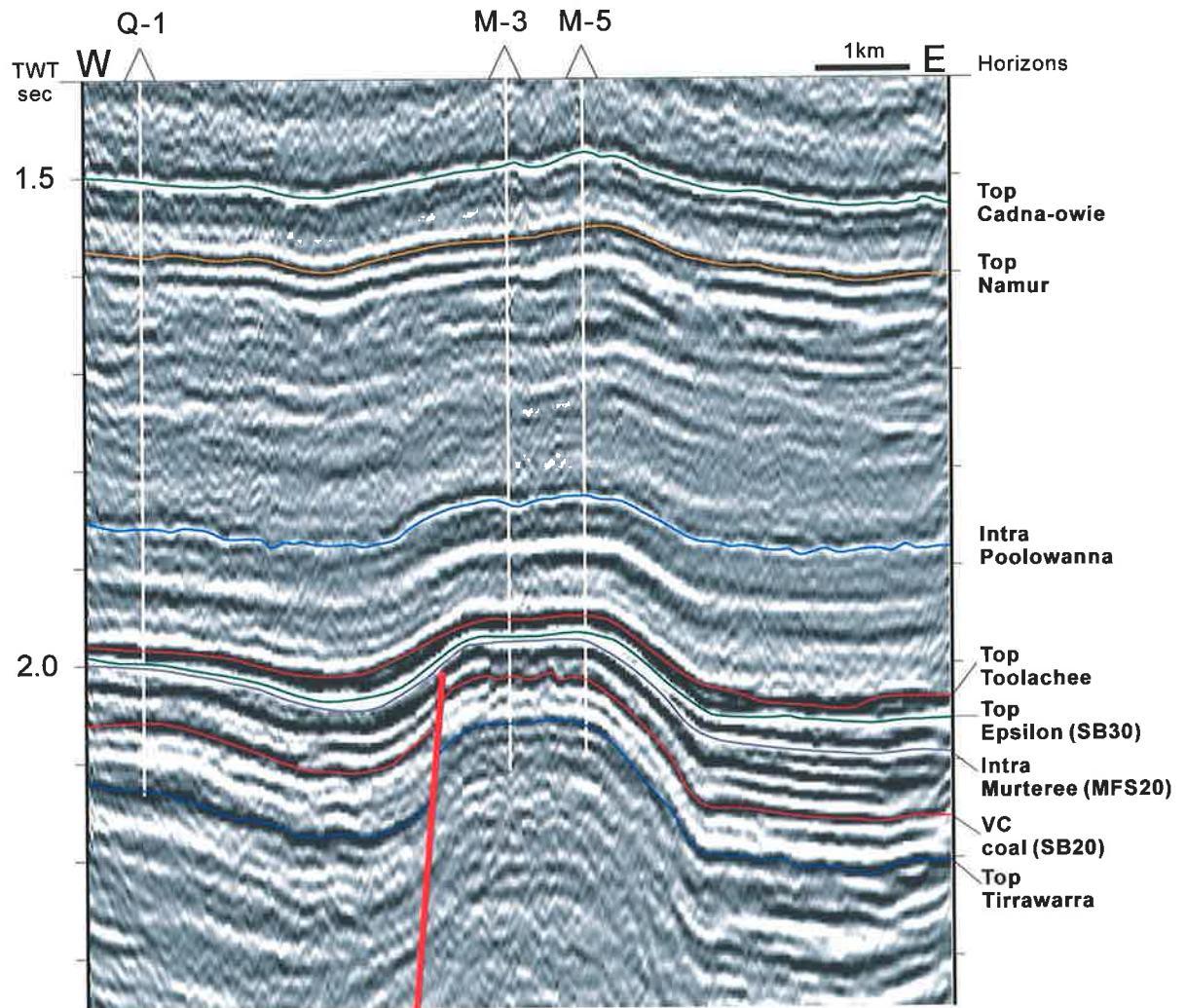


Figure 5.2.4 Seismic section across Moorari Field (inline 1028, see the location in Fig. 5.2.3).

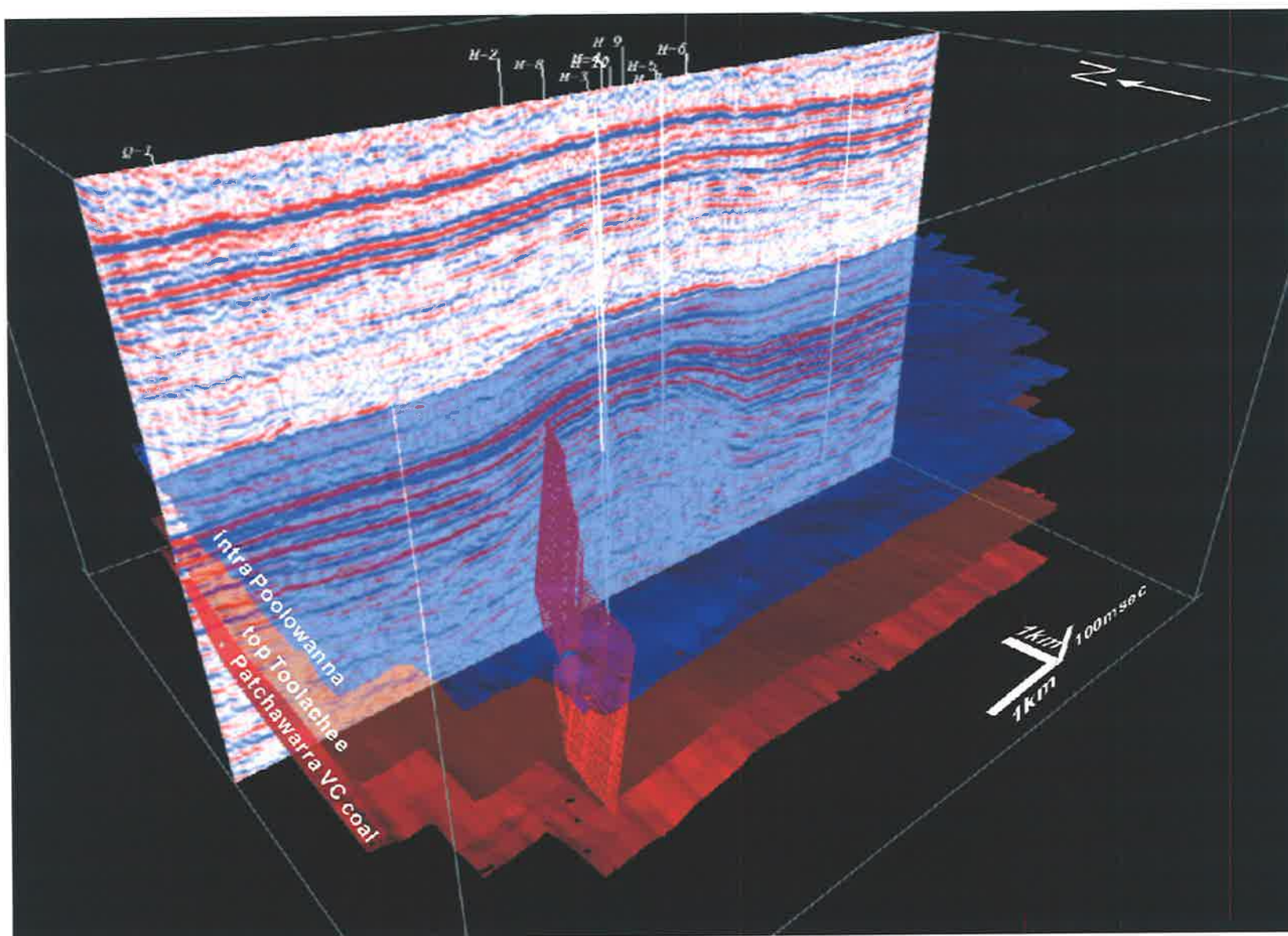


Figure 5.2.5. Outline of the structural highs in the Moorari Field area.

5.3 Prospect extraction in Permian succession

5.3.1 Sedimentary facies analysis

Six sedimentary facies are interpreted in the Patchawarra Formation, the Murteree Shale, the Epsilon Formation and the Toolachee Formation, based on wireline logs, cuttings and core descriptions (figures 5.3.1, 5.3.1a, 5.3.1b and 5.3.2).

Fluvial channel facies (FC)

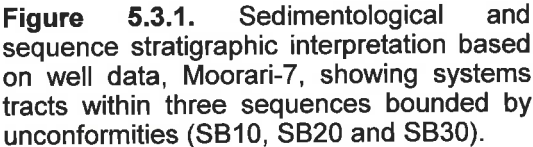
The fluvial channel facies consists of sandstone with thin shale. The basal contact is sharp below a fining upward succession comprising 3 to 5m thick cross-bedded or rippled sandstone (figures 5.3.1 and 5.3.1a), gradually changing upward into shale or coal of the floodplain facies (FP). The fluvial channel facies can be relatively continuous stacked, amalgamated sandstones more than 10m thick, but the sandstone may change laterally into shale or coal representing floodplain and peat swamp/mire (Figure 5.3.2).

The sharp basal contact represents the erosion surface of the channel, and the fining upward succession represents the infilling process as the channel was filled by sandy bars and then abandoned (Miall, 1992).

Crevasse splay channel facies (CSC)

The crevasse splay facies consists of interbedded sandstone and shale. The sandstone typically has sharp basal contacts, with a fining upward succession of 1 to 3m thickness, characterised by parallel lamination, ripple and climbing ripple cross-lamination, gradually changing vertically into fine-grained floodplain facies. This facies is laterally discontinuous and changes into the fluvial channel facies or floodplain facies in a given genetic interval (figures 5.3.1 and 5.3.2).

The relatively thin fining upward succession represents rapid deceleration of flow within a shallow channel. The interbedded sandstone and shale suggests that floods from the main channel occurred intermittently. This facies are predominantly located between the fluvial channel facies and floodplain facies, forming part of the channel margin complex on the floodplain.



Floodplain-crevasse splay complex (FP-CS)

The floodplain-crevasse splay complex comprises interbeds of fine-grained sandstones and shales including ripple and parallel laminations (figures 5.3.1 and 5.3.1b). It sometimes includes thin coal beds. Each sandstone bed is less than 2m thick and is typically blocky or often shows a coarsening upward succession. The facies often changes laterally into the fluvial channel facies or crevasse splay channel facies (Figure 5.3.2).

The sandstone beds in this facies are crevasse splay lobes on the floodplain. The coarsening upward nature of the sandstones suggests the progradation of the lobes into floodplain lakes as crevasse delta mouth bars.

Floodplain and peat mire facies (FP)

The floodplain and peat mire facies consist of shales with intercalations of coals and thin sandstones or thick coal (figures 5.3.1 and 5.3.1b). This facies changes laterally and vertically into the floodplain-crevasse splay complex facies adjacent to the main channel belt (Figure 5.3.2).

Areas of the floodplain away from the clastic input accumulated peat in raised mires or forest swamps.

Lacustrine delta facies (LD)

The lacustrine delta facies comprises a coarsening upward succession from 10 to 25m thick, changing vertically from thick lacustrine offshore shale at the base to sandstone at the top, sometimes with coal intercalations. Laterally, this facies is continuous throughout the study area in the Epsilon Formation (figures 5.3.1 and 5.3.2).

The coarsening upward succession is interpreted as the progradation of a lacustrine delta. The lower shale part of this facies is deposited on the prodelta environment and the upper sandy part is deposited in the delta front or partly in the distributary channel. Coal represents both abandoned channel fills and emergent lower delta plain.

Lacustrine offshore facies (LO)

This facies consists of thick shale, sometimes with thin intercalations of coal and underlies the lacustrine delta facies (figures 5.3.1 and 5.3.2).

It is interpreted as the distal facies of the lacustrine delta system, with the thin coals representing detrital organic materials washed into the lake, or possibly floating swamps (McCabe, 1984).

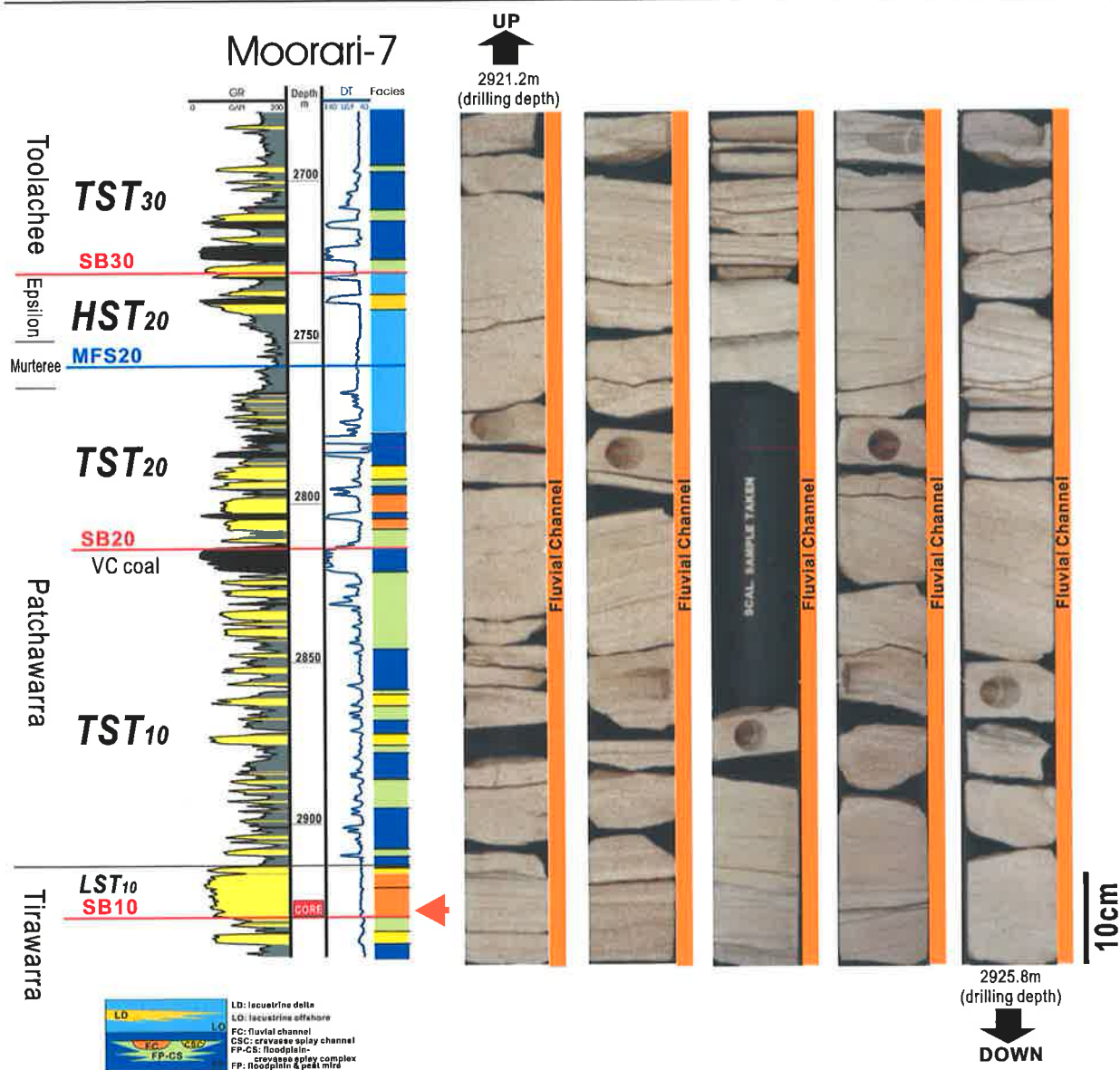


Figure 5.3.1a. Integration of sedimentary facies interpretation from core with well log motifs. The fluvial channel facies consists of sandstone with thin shale. The basal contact is sharp below a fining upward succession comprising 3 to 5m thick cross-bedded or rippled sandstone, gradually changing upward into shale or coal of the floodplain facies (FP). The fluvial channel facies can be relatively continuous stacked, amalgamated sandstones more than 10m thick, but the sandstone may change laterally into shale or coal representing floodplain and peat swamp/mire.

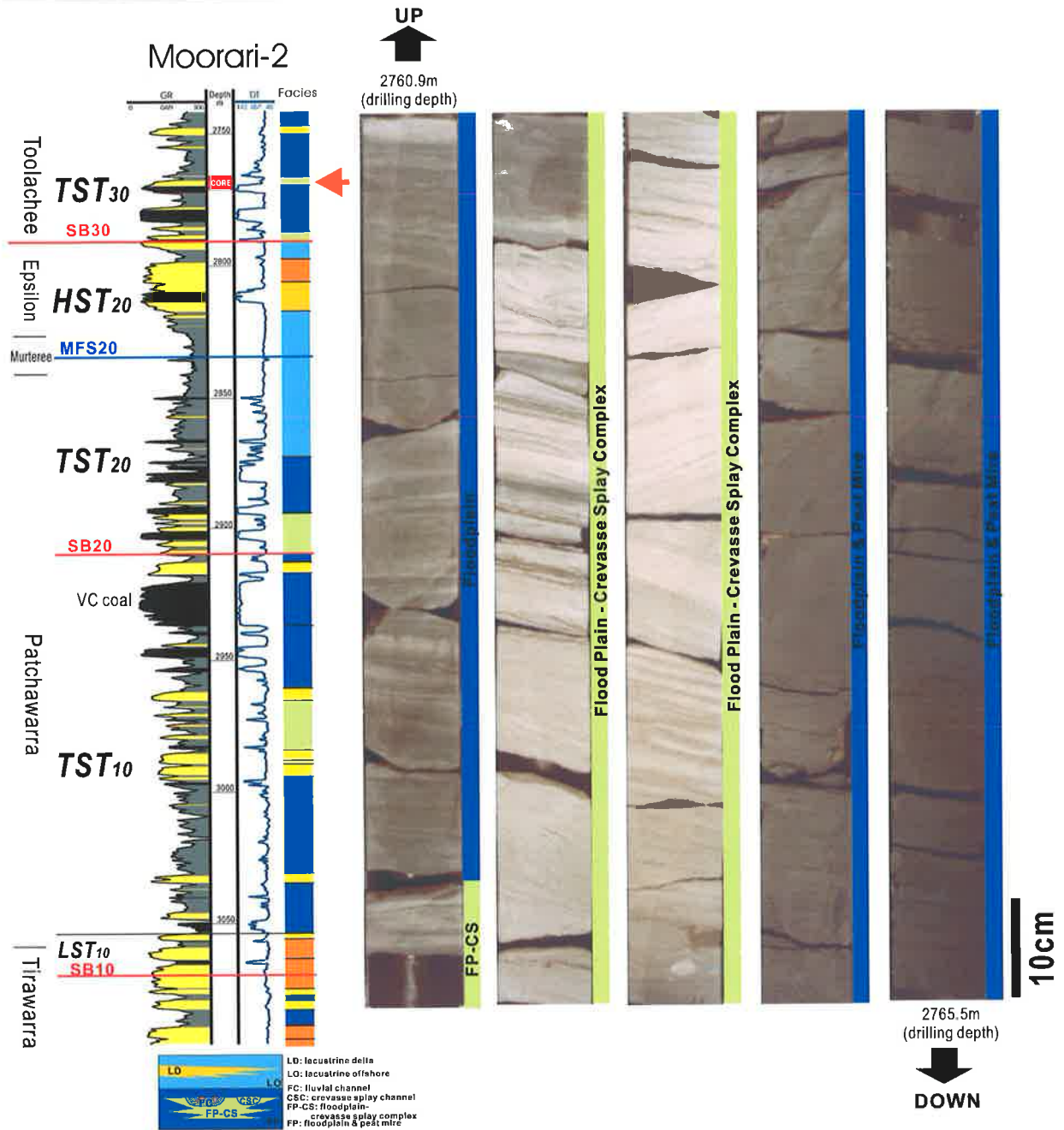


Figure 5.3.1b. Integration of sedimentary facies interpretation from core with well log motifs. The floodplain and peat mire facies consist of shales with intercalations of coals and thin sandstones or thick coal. The floodplain-crevasse splay complex comprises interbeds of fine-grained sandstones and shale, including ripple or parallel lamination.

5.3.2 Sequence stratigraphy

Three second order sequences (sequence 10, 20 and 30) were identified in the Patchawarra Formation, the Murteree Shale, the lower Epsilon Formation and the Toolachee Formation in the Moorari Field area (figures 5.3.1, 5.3.2 and 5.3.3). Within these sequences, higher order cycles are evident but are not discussed here because the Moorari field data is restricted in area, and a more regional discussion is represented to develop this aspect further in Chapter 8.

Sequence 10

Sequence 10 comprises the top of the Tirrawarra Sandstone and the lower Patchawarra Formation, consisting of fluvial deposits (figures 5.3.1 and 5.3.2). Seggie (1997) described the sequence stratigraphy of the Tirrawarra Sandstone in the Moorari area, highlighting a continuous lacustrine shale interval which represents a maximum flooding surface, and placing a sequence boundary (SB10) between the highstand distributary channels and the overlying fluvial channel deposits that are mapped as part of the lithostratigraphic Tirrawarra Sandstone. SB10 is interpreted in the 3D seismic data as a peak corresponding approximately to the top of the Tirrawarra Sandstone (Figure 5.3.3).

The top of the sequence 10 (SB20) is marked by the absence of palynostratigraphic unit PP2.2.2. Palynostratigraphic surveys in the Moorari area (Apak, 1994; Moorari-9 well completion report) show that PP2.2.2 is absent above the VC coal in the structurally high area. On the flank of the structure, however, shale correlative to unit PP2.2.2 is found overlying the VC coal (see Moorari-2 and Cardam-1 in Figure 5.3.2). Apak et al. (1993) described the absence of PP2.2.2 unit in the GMI trend area and suggested that this absence was caused by erosion at the uplift event at the end of PP2.2.2 time. The thick peat that developed the VC coal was perhaps resistant enough to withstand erosion so that most of the coal remains over the structurally high area. The resistance of peat to erosion is a common phenomenon in coal measures (McCabe, 1984). SB20 is interpreted in the 3D seismic data as a peak horizon corresponding to the top of the VC coal (Figure 5.3.3). The thin interval between the SB20

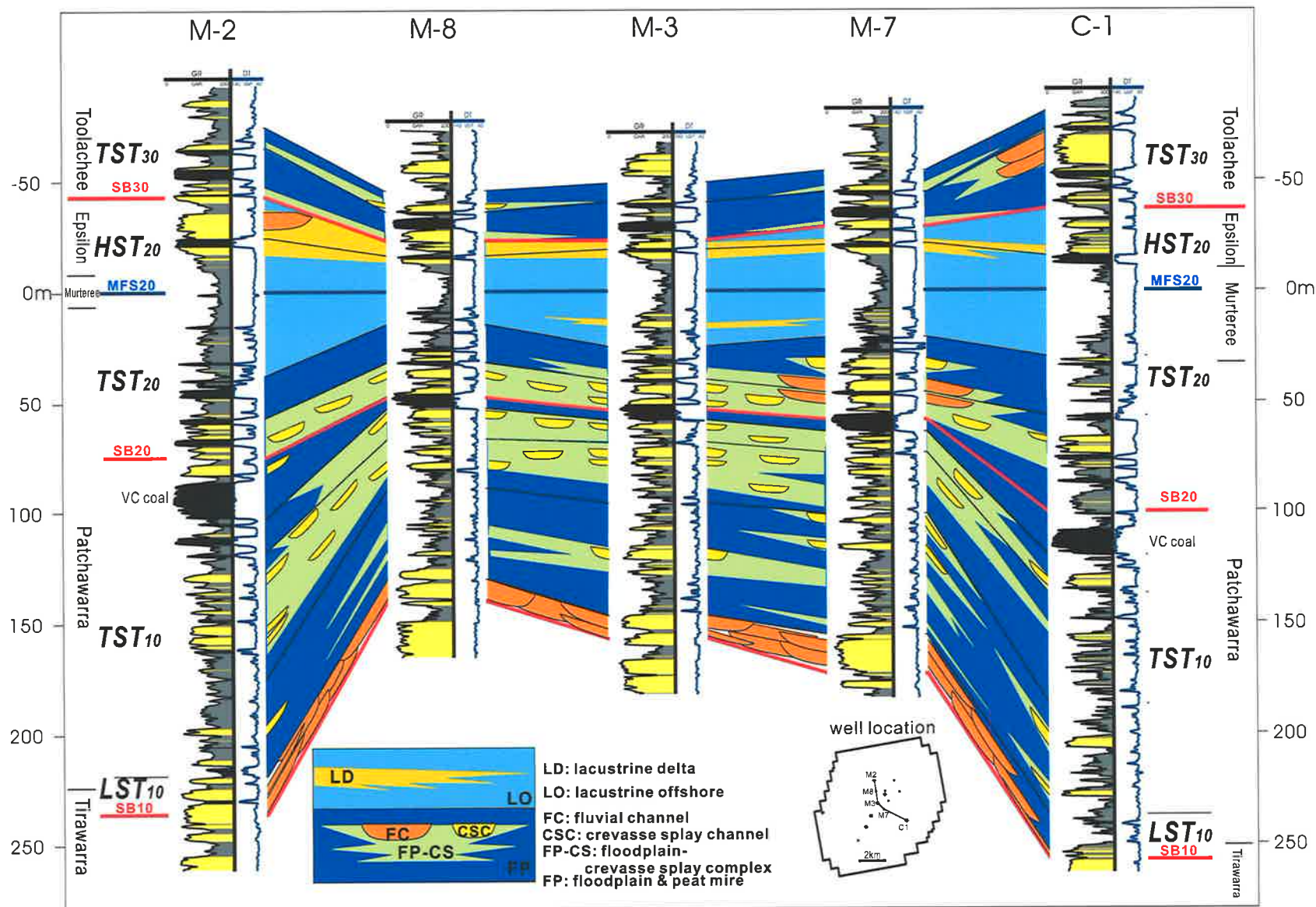


Figure 5.3.2. Sequence stratigraphic correlation across the Moorari high, from Moorari-2 to Cardam-1, showing the facies distribution.

and the top of the VC coal on the flank of the structural high is below the resolution of the seismic data.

Sequence 10 is divided into a lowstand systems tract (LST10) and a transgressive systems tract (TST10). LST10 comprises stacked and amalgamated fluvial channel fill sandstones of the upper Tirrawarra Sandstone. The sandstone is laterally continuous and is interpreted as the fluvial deposits of a period of low accommodation space. TST10 consists of floodplain and crevasse splay deposits of the lower Patchawarra Formation. The shaly succession and the lateral discontinuity of the facies in this section suggest that these sediments were deposited during a period of increasing accommodation space caused by rising relative base level (Posamentier & Allen, 1999). The coarsening and thickening upward succession through TST10 probably suggests a decreasing rate of base level rise. However, a significantly continuous shaly interval cannot be readily identified in this section, hence the maximum flooding surface is interpreted to be above the VC coal and eroded by SB20 (i.e. the highstand systems tract is missing). The main fluvial channel, which could generate crevasse splays on the floodplain in TST10, cannot be seen on the structurally high area penetrated by the wells. A possible location for the main fluvial channel lies on the flank of the structure and will be discussed later in this report.

Sequence 20

Sequence 20 includes the upper Patchawarra Formation, the Murteree Shale and Epsilon Formation (figures 5.3.1 and 5.3.2). The base of the sequence is characterised by SB20, as described above. The top of the sequence is defined by a sequence boundary (SB30), which is the unconformity at the base of the Toolachee Formation, caused by the Daralingie uplift.

Sequence 20 is divided into a transgressive systems tract (TST20) and a highstand systems tract (HST20), separated by a maximum flooding surface (MFS20). MFS20 is characterised by the finest-grained lacustrine offshore shale interval which is laterally continuous in sequence 20 (Figure 5.3.2). MFS20 represents the most rapid relative base level rise in the area.

TST20 comprises fluvial deposits in the lower portion and lacustrine deposits in the upper

portion. The fluvial deposits include fluvial channel, crevasse splay and floodplain facies. Though the fluvial facies is not so continuous laterally, relatively coarse facies (CSC and FP-CS facies) are dominant in the lowest part of TST20. Such a facies distribution suggests that accommodation space was increasing slowly after the development of SB20 in this area (Posamentier & Allen, 1999). The fluvial deposits are overlain by lacustrine deposits, consisting of lacustrine delta sandstones and shales. The lacustrine succession shows one cycle of the delta progradation locally, with an overall fining upward succession topped by MFS20.

HST20, which overlies MFS20, consists of sandstones, shales and coals associated with the lacustrine delta progradation typical of the Epsilon Formation. The coarsening upward succession of this delta is apparent throughout this area (Figure 5.3.2). The Epsilon coal, which sits at the top of the upward coarsening succession, is interpreted as peat deposition on the emergent inter-distributary zone of the lacustrine delta plain. The lateral continuity of the coarsening upward succession associated with the coal, suggests that delta progradation occurred during relatively stable base level. In the structurally high area, the upper section of the delta was eroded by SB30, hence the relatively thick section is preserved only on the flank area of the structural high.

SB30 is picked on the seismic data midway between the overlying zero crossing and a prominent trough corresponding approximately to the top of the Epsilon Formation (Figure 5.3.3). MFS20 is interpreted as an entirely continuous amplitude trough. Between these two horizons, the Epsilon coal appears as an amplitude peak (see the peak reflection between SB30 and MFS20 on the eastern flank of the Moorari high in Figure 5.3.3). Though the peak reflection disappears in the structurally higher area (because the thickness of the coal becomes too thin for seismic resolution), the deltaic sediments associated with the coal still exist over the high area.

Sequence 30

The lower part of sequence 30 comprises fluvial sandstones, shales and coals of the Toolachee Formation, which overlies SB30 (figures 5.3.1 and 5.3.2). The total section consists of shaly deposits with some laterally continuous coal and floodplain facies. The fluvial channel facies

is relatively thick but laterally discontinuous. The lateral discontinuity of the fluvial channel deposits on the sequence boundary suggests that this section is the transgressive systems tract overlying the sequence boundary, produced by increasing accommodation space associated with rising relative base level (Posamentier & Allen, 1999), and inundating the structural high. The lowstand systems tract of the basal Toolachee Formation is not represented in the study area.

5.3.3 3D seismic data visualisation and prospect extraction

The interpretation of the sedimentology and the sequence stratigraphy of the Permian succession were applied to the 3D seismic data, and the various types of potential stratigraphic traps were high-lighted by employing the sequence stratigraphic concepts and the 3D seismic visualisation.

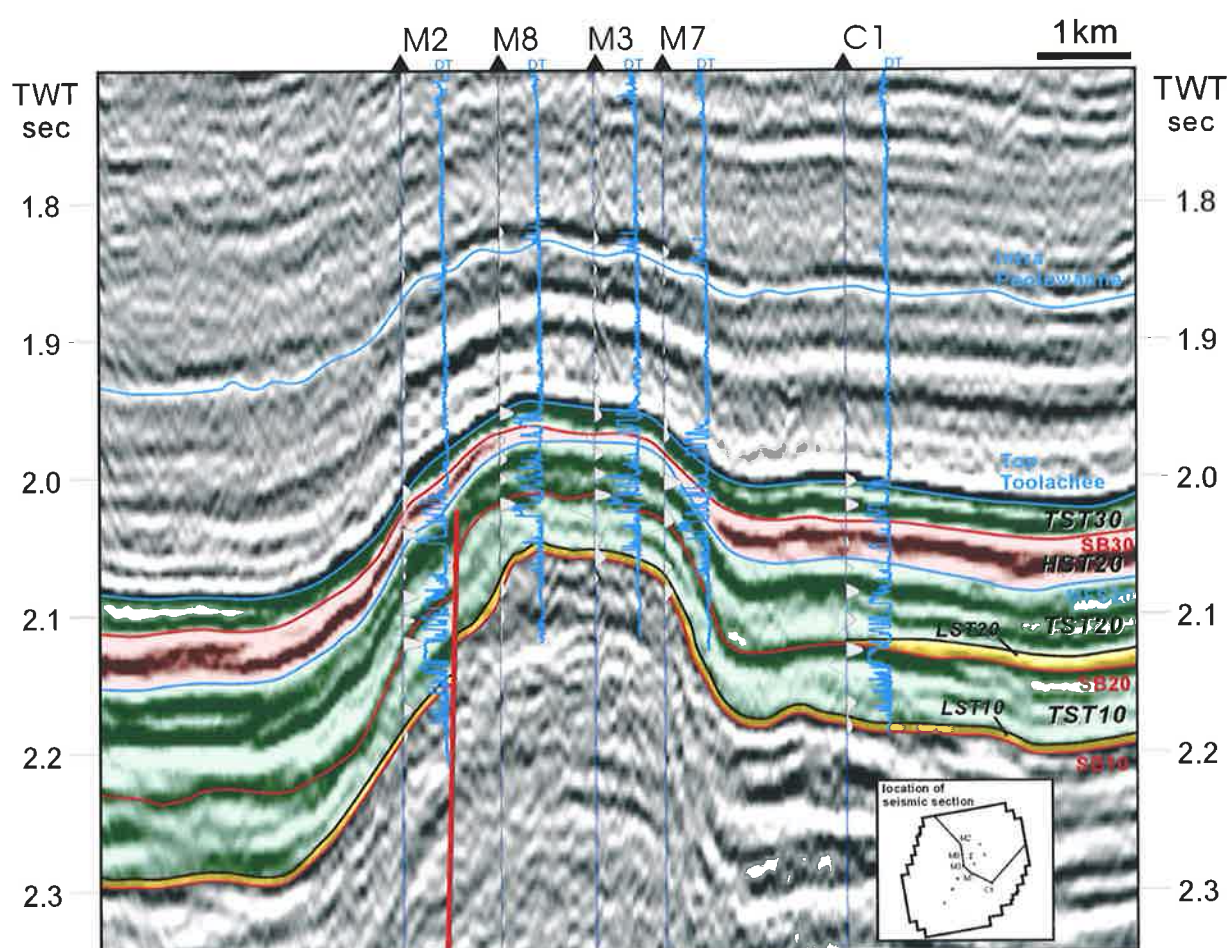


Figure 5.3.3. Sequence stratigraphic interpretation on an arbitrary seismic section across the Moorari high through the wells shown in Fig 6. For each well, a sonic log and a synthetic seismogram are displayed. The wavelet is zero phase with a 5-10-65-70 Hz trapezoidal bandpass.

Prospect T10: Isolated fluvial channels in the transgressive systems tract of the lower Patchawarra Formation

Visualisation

The amplitude trough (green horizon, Figure 5.3.4), in TST10 on the eastern flank of the Moorari high, is possibly a reflection of the base of a coal bed, and the lateral change of the amplitude shows the variation of the coal thickness on the eastern flank of the Moorari high. Figures 5.3.5a and 5.3.5b show the amplitude distribution of the trough in TST10. The low amplitude area, which represents thin coal distribution, is sinuously elongated north to south. The high amplitude areas show thick coal, and are sitting on both sides of the elongated low-amplitude area. The amplitude pattern suggests the existence of a fluvial channel within the floodplain or peat mire in the transgressive systems tract (Figure 5.3.6). The channel could have aggraded in response to the increasing base level, resulting in an isolated sand body. This channel probably fed sediments across the peat mire and floodplain of TST10 in the Moorari high area.

Possible stratigraphic trap

The sinuously elongate, low amplitude distribution suggests an isolated fluvial channel sandstone body among the peat mire or floodplain deposits (prospect T10). The amplitude trough containing the fluvial channel is dipping northwards. The southern extension (structurally up-dip) of the channel is outside the 3D seismic data, hence there is uncertainty in the geometry of the channel, causing a risk of hydrocarbon leakage along the sand body extending southwards. However, a gas accumulation in a crevasse splay sandstone in the equivalent interval has been confirmed at Cardam-1 and it suggests the possibility that a gas accumulation may exist in the channel sandstone in the flank area of the Moorari high.

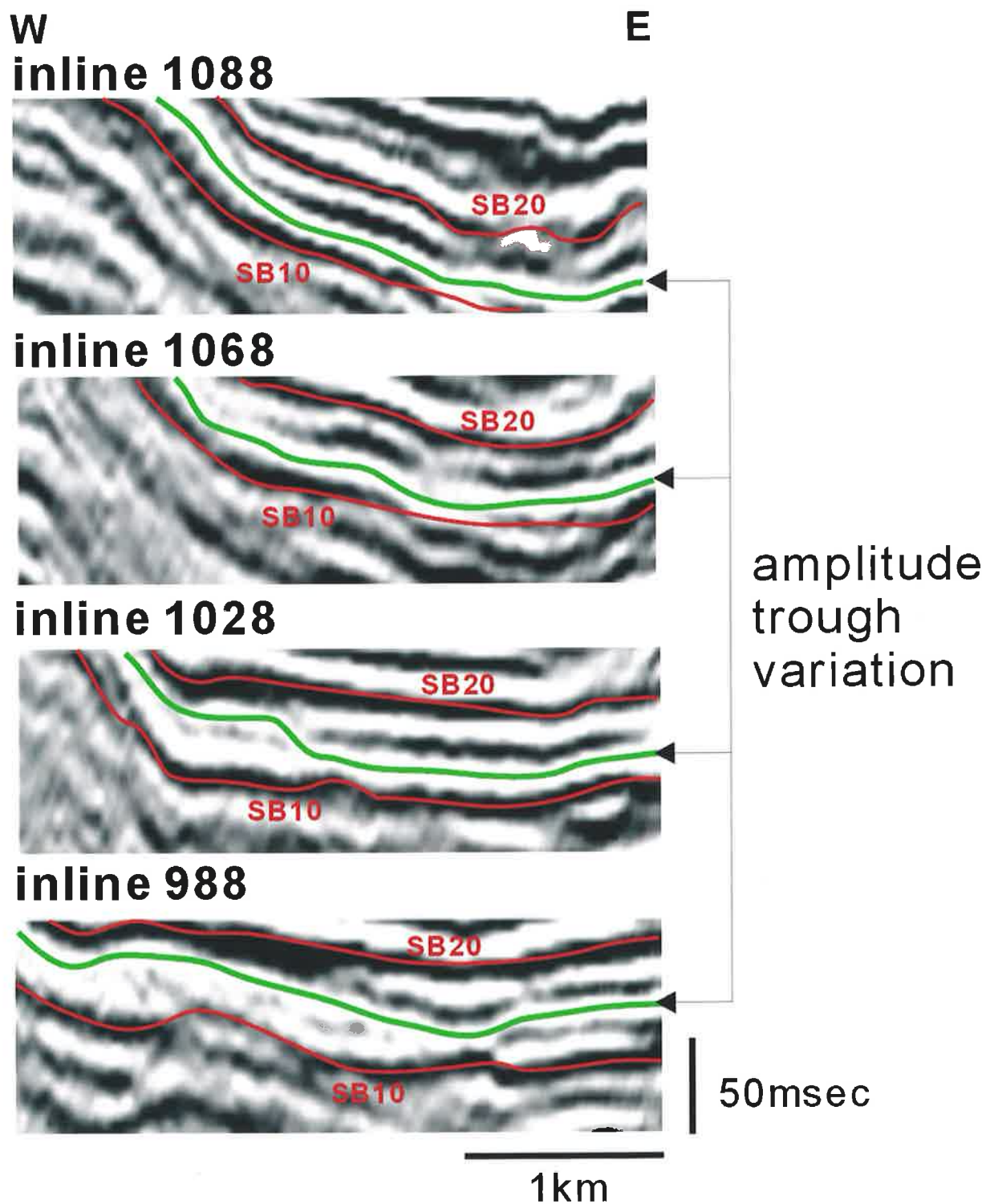


Figure 5.3.4 Amplitude trough representing the base of coal interval in TST10 on the eastern flank of the Moorari high (see the locations in Fig.5.3.5b). The amplitude variation corresponds to coal thickness.

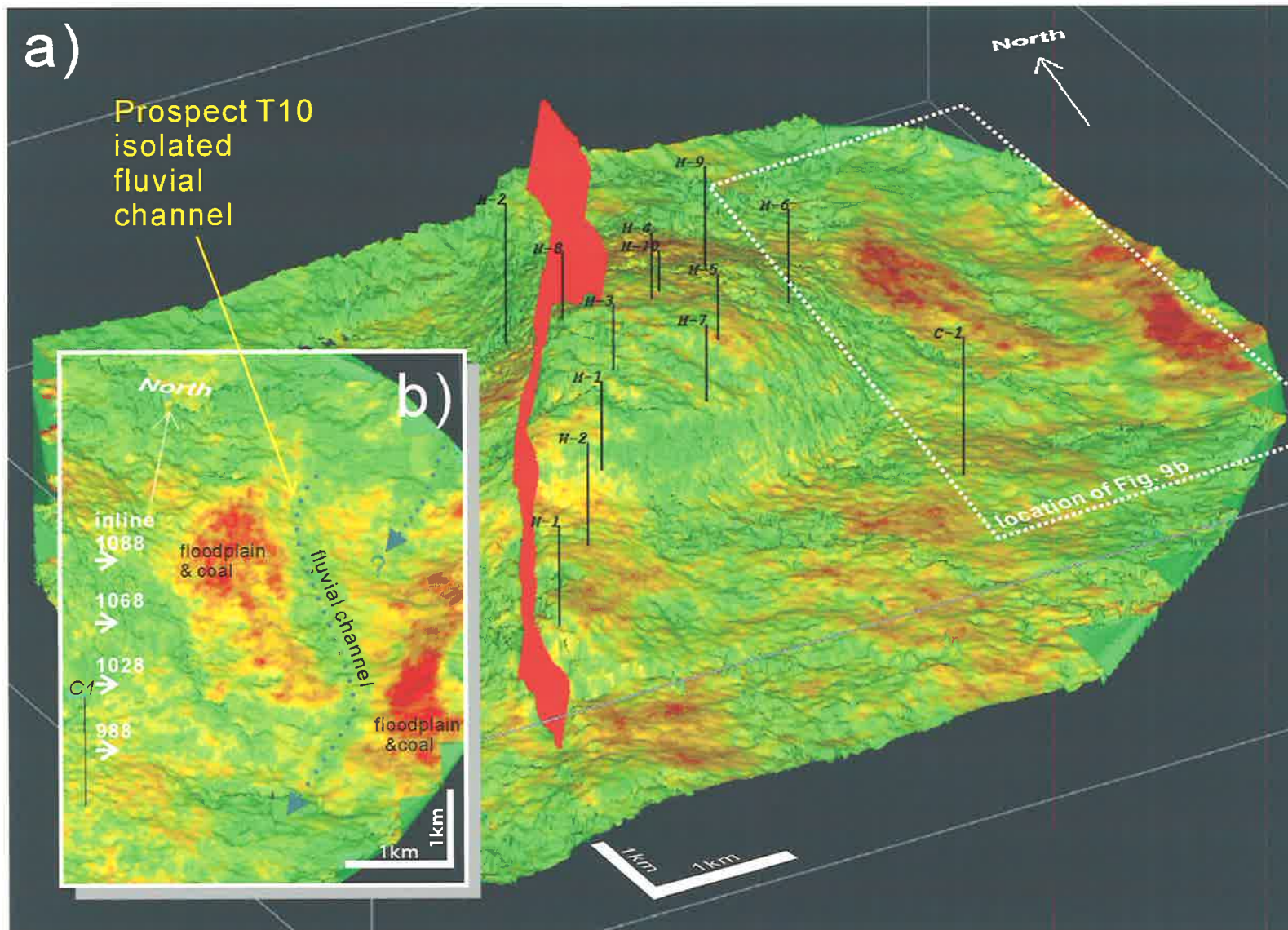


Figure 5.3.5. a) Trough amplitude variation in the Patchawarra TST10 (red; high amplitude, green; low amplitude). b) Elongate and sinuous pattern of low amplitude on the eastern flank of the Moorari high, interpreted as a fluvial channel surrounded by floodplain and coal (prospect T10).

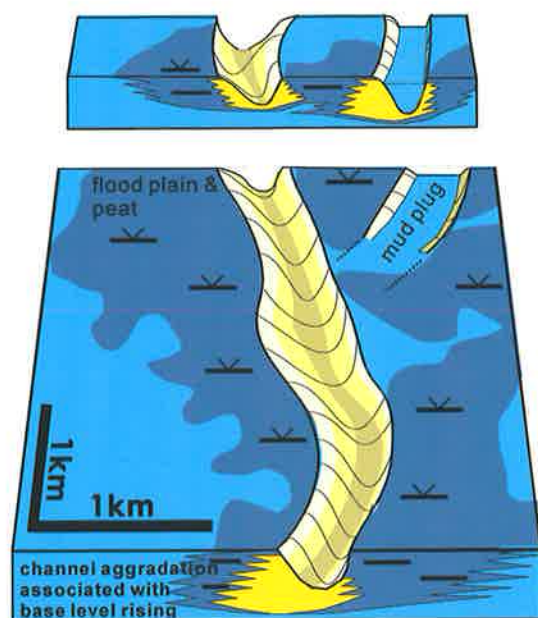


Figure 5.3.6. Schematic diagram of the fluvial channel and floodplain environments including peat in TST10 on the eastern flank of the Moorari high (compare to Fig. 5.3.5b).

Prospects L20E and L20SW: Fluvial sand bodies in low accommodation intervals in the lowstand systems tract of the upper Patchawarra Formation

Visualisation

The onlap of the amplitude trough above SB20 can be observed against the Moorari high (figures 5.3.3 and 5.3.7). The amplitude trough is located on SB20 and beneath the TST20 section confirmed in the wells over the structurally high area, hence the amplitude trough may show the existence of a lowstand systems tract (LST20) on the flanks of the Moorari high. Figure 5.3.8 shows amplitude trough distributions of LST20 above SB20. The LST20 amplitude trough is restricted to the low areas above SB20 on the eastern and southwestern flanks of the Moorari high. LST20 represents a low accommodation interval relative to sediment supply and hence stacked fluvial sand bodies can be expected (Allen et al., 1996; Posamentier & Allen, 1999).

Possible stratigraphic trap

The bottom, top and lateral seals of LST20 are the floodplain shaly sediments of the

transgressive systems tracts above and below (TST10 and TST20). LST20 on the eastern flank of the Moorari high is dipping northwards (prospect L20E, Figure 5.3.9). The southern extension (structurally up-dip) of LST20 is outside the 3D seismic data area, hence there is an uncertainty in the trapping geometry. However, the gas accumulation in the crevasse splay sandstone of TST20 close to SB20 (Cardam-1 well completion report) suggests a gas accumulation in the interval identified as LST20. On the southwestern flank of the Moorari high, another part of LST20 may exist (prospect L20SW). This part of LST20 appears to be isolated and dipping up towards the structural high, hence there may be a stratigraphic trap opportunity southwest of Woolkina-1, west of the fault.

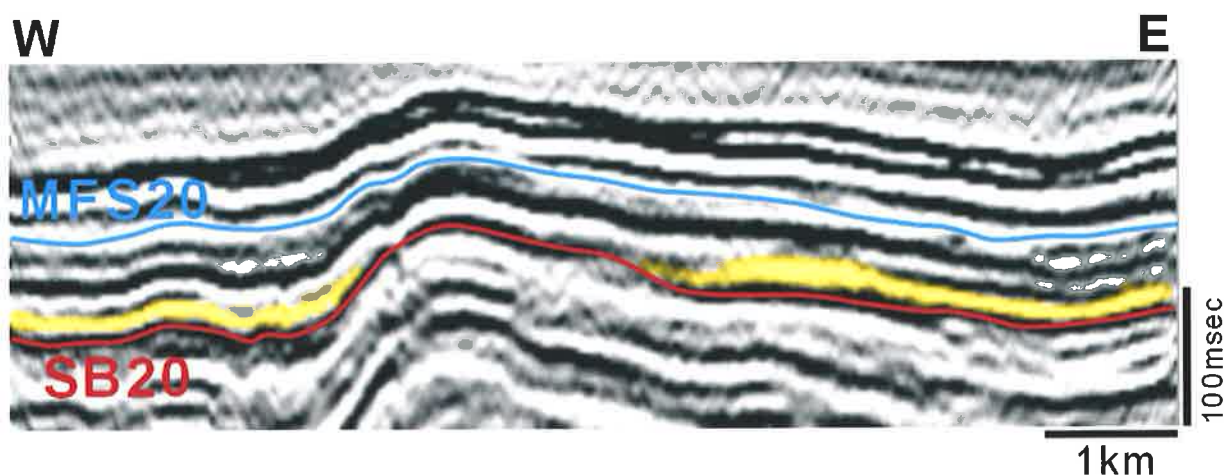
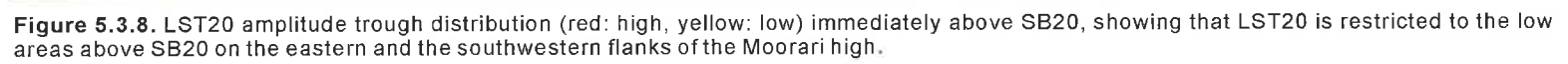


Figure 5.3.7. LST20 (yellow) onlapping on SB20 in seismic section (inline 961, see the location in Fig.5.3.8).



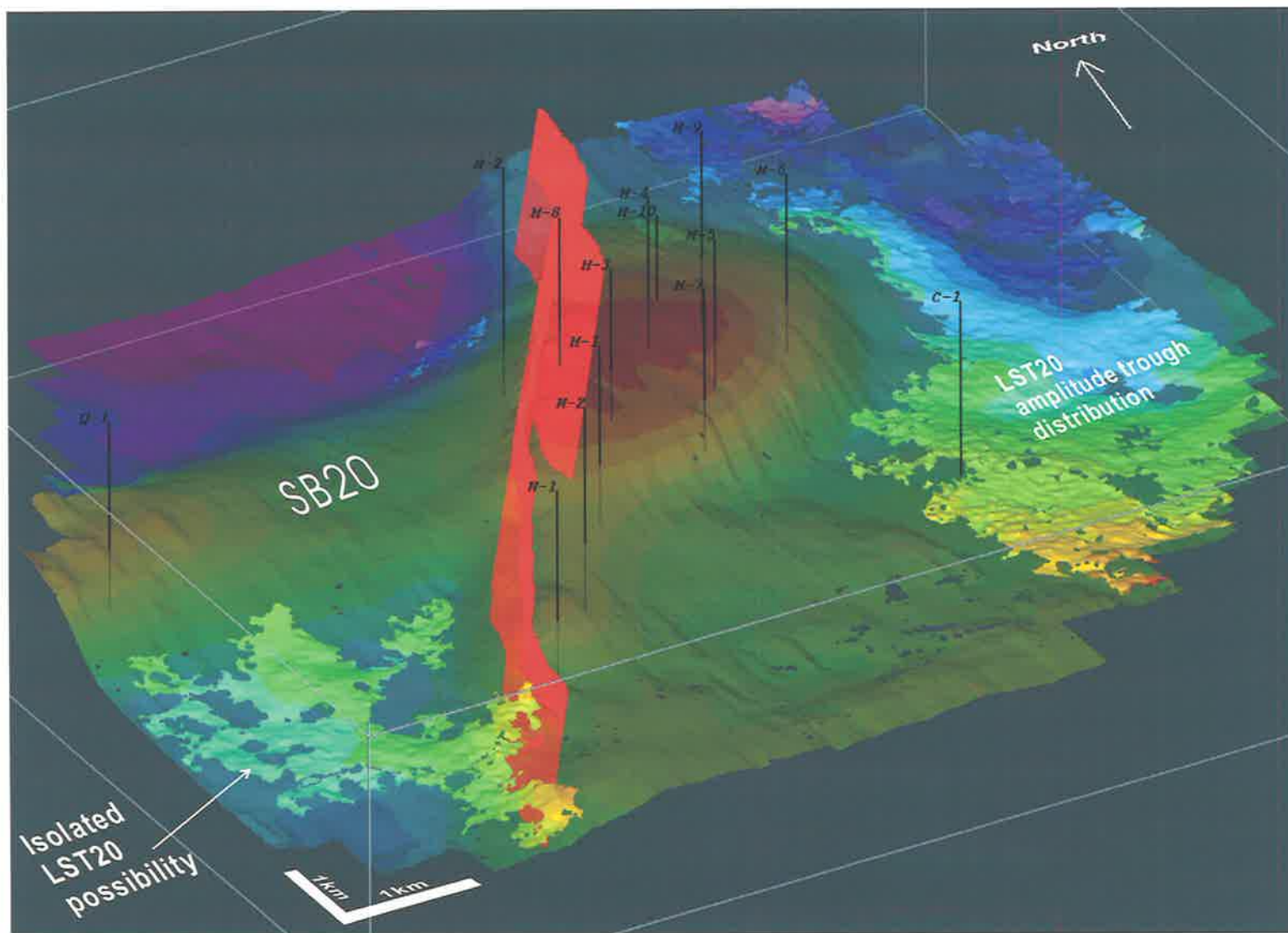


Figure 5.3.9. LST20 two-way-time structure map (yellow: shallow, purple: deep). On the southwestern flank of the Moorari high, LST20 appears to be isolated and dipping up towards the high possibly causing an efficient stratigraphic trap. On the eastern flank of the Moorari high, the southern extension of LST20 (structurally up-dip) is outside this seismic survey area and there is an uncertainty in the geometry.

Prospect H20: Highstand lacustrine delta of the Epsilon Formation below the regional sequence boundary

Visualisation

The amplitude peak between the MFS20 horizon and the regional unconformity (SB30) thins out against the Moorari high (Figure 5.3.10). The amplitude peak corresponds to the Epsilon coal associated with the lacustrine delta progradation in HST20 (Figure 5.3.11). Figure 5.3.12 shows the Epsilon coal amplitude peak distribution above MFS20, and the gamma ray log motifs characteristic of the Epsilon delta. A thin coal remains over the structural high area, but the amplitude peak has disappeared due to the thinning of the coal below seismic resolution. On the other hand, another amplitude peak appears to thin out in a stratigraphically shallower interval than the Epsilon coal amplitude peak on the northwestern flank of the Moorari high. This upper Epsilon amplitude peak represents the upper coal bed associated with the lacustrine delta. The upper Epsilon lacustrine delta and coal appears to be eroded by SB30 on the northwestern flank of the Moorari high, because the coal corresponding to the shallower amplitude peak does not appear in the wells (figures 5.3.11 and 5.3.12).

Possible stratigraphic trap

The upper Epsilon delta sandstone eroded by SB30 on the northwest flank of the Moorari high is a possible stratigraphic trap (prospect H20). The two-way-time structure map of the amplitude peak (Figure 5.3.12) shows the upper Epsilon delta is thinning out and dipping up towards the Moorari high. The top and the bottom of the delta sandstone are sealed by lacustrine offshore shales. However, the delta sandstone may be in contact with the fluvial sandstone of the Toolachee Formation above the SB30 (which will be described later) and this represents a hydrocarbon leakage risk through the juxtaposition of the sandstones (Figure 5.3.11).

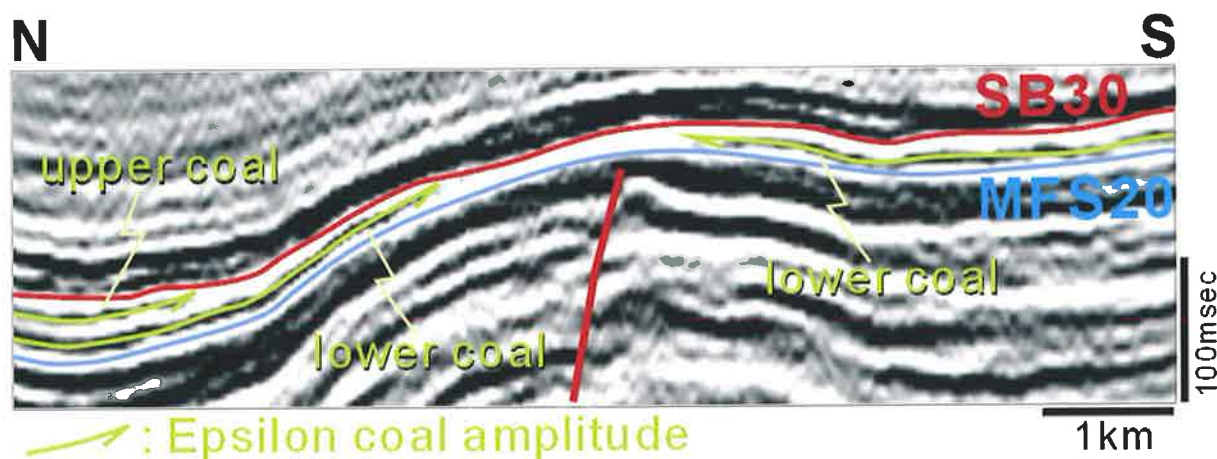


Figure 5.3.10. Epsilon coal amplitude peak in seismic section showing lateral thinning-out against the Moorari high (cross line 1172, see the location in Fig. 5.3.12). The thin lower Epsilon coal extends over the high in well data, though the amplitude peak disappears (see Fig. 5.3.12 and text).

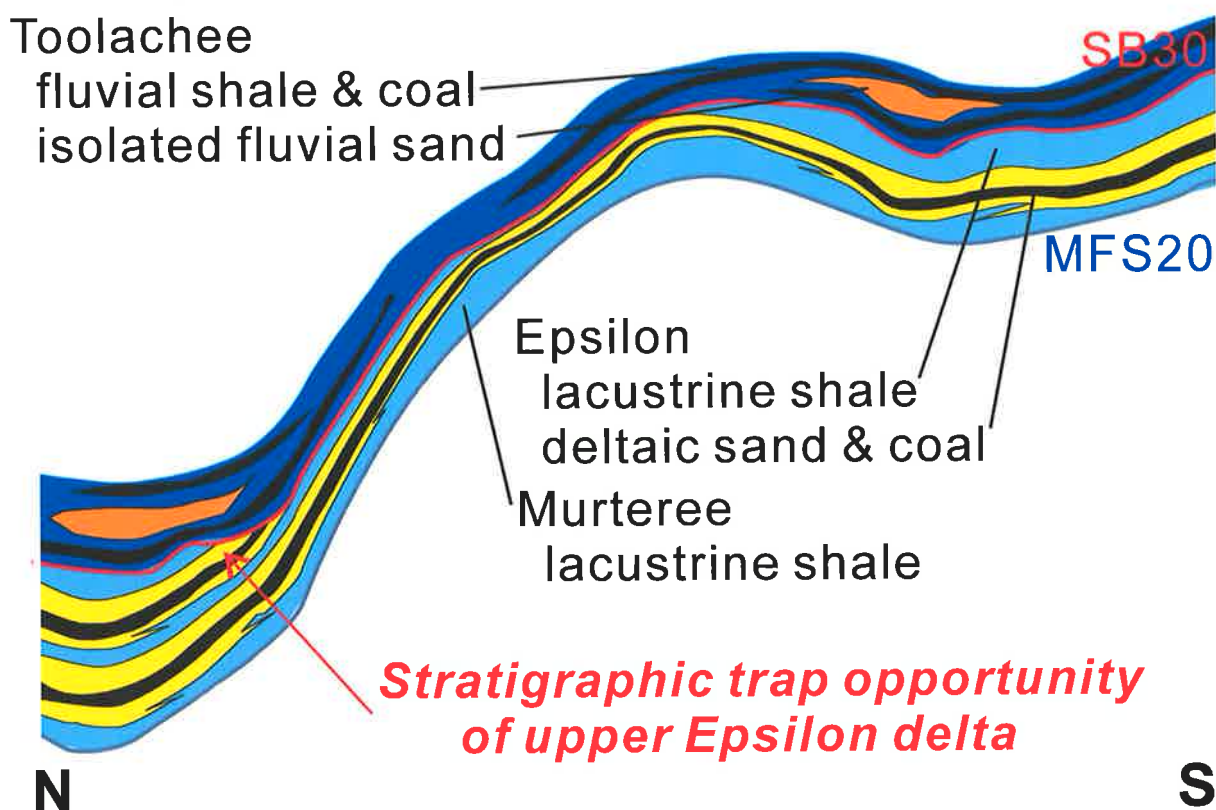


Figure 5.3.11. Schematic section of HST20 on cross line 1172 (see Fig. 5.3.10), showing a possible Epsilon stratigraphic trap on the northwest low side of the Moorari high.

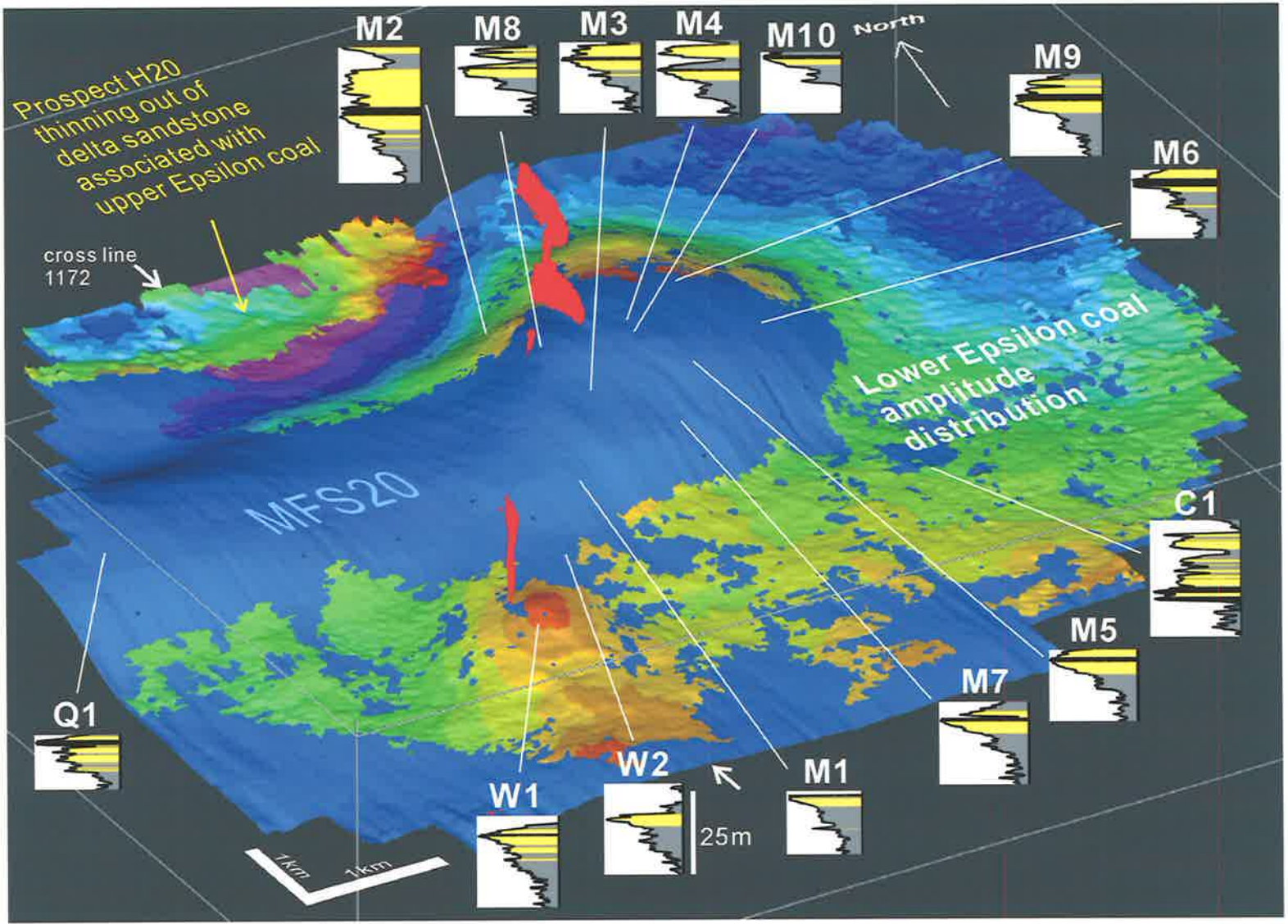


Figure 5.3.12. Two-way-time structure map of Epsilon coal amplitude distribution (red: shallow, purple: deep) on MFS20 and well log facies of Epsilon delta. Thin coal extends over the high, but is below seismic resolution and therefore does not show on the amplitude peak distribution. On the northwest flank of the high, the upper Epsilon coal, which no well penetrated, appears to be thinning-out against the high.

Prospect T30: Isolated fluvial channels in the transgressive systems tract of the Toolachee Formation

Visualisation

Lenticular negative amplitudes (amplitude troughs) are identified above SB30 on the seismic section (Figure 5.3.13). The negative amplitudes correspond to the stacked fluvial channel sandstones among the floodplain shale and coal in TST30 of the Toolachee Formation, which appear in Cardam-1. Figure 5.3.14 shows the distribution of the negative amplitudes employing the detection-focussing-strategy (see Chapter 2 for visualisation technique), and the two-way-time structure of SB30. The distribution tends to sit on the southeastern and northwestern sides of the Moorari high. Though such fluvial sandstones are recognised in Woolkina-1, 2 and Moorari-1, the intervals between the coal beds which include the sandstone are too thin to appear as negative amplitudes because they are below seismic resolution. The amplitude distribution and facies map from well data suggest that there is an elongate fluvial channel belt lying in an approximately east-west direction on the southern flank of the Moorari high, and there is a possibility of another channel belt to the northwest of the high.

Possible stratigraphic trap

In TST30 of the Toolachee Formation, Cardam-1 confirmed a fluvial channel sandstone, but it was water saturated. Woolkina-1 discovered a gas accumulation in a sandstone, whereas Woolkina-2 confirmed water-saturated sandstone down-dip. The lenticular negative amplitude on the northwestern side of the Moorari high may be a fluvial channel sandstone belt, and presents the possibility of a stratigraphic trap (prospect T30). The fluvial sandstone could be enveloped and sealed by floodplain shale and coal. However, it is difficult to confirm the isolation of the sand body because the amplitude trough extends outside the seismic survey area (Figure 5.3.15).

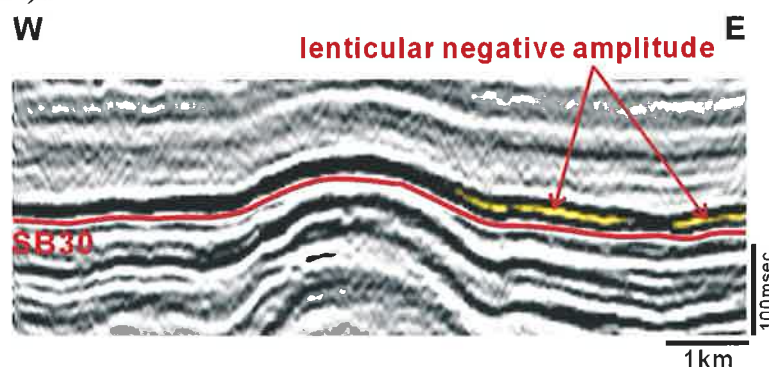


Figure 5.3.13. Seismic section showing lenticular negative amplitudes (amplitude troughs) corresponding to fluvial channel sandstones in TST30 of the Toolachee Formation (inline 988, see the location in Fig. 5.3.14).

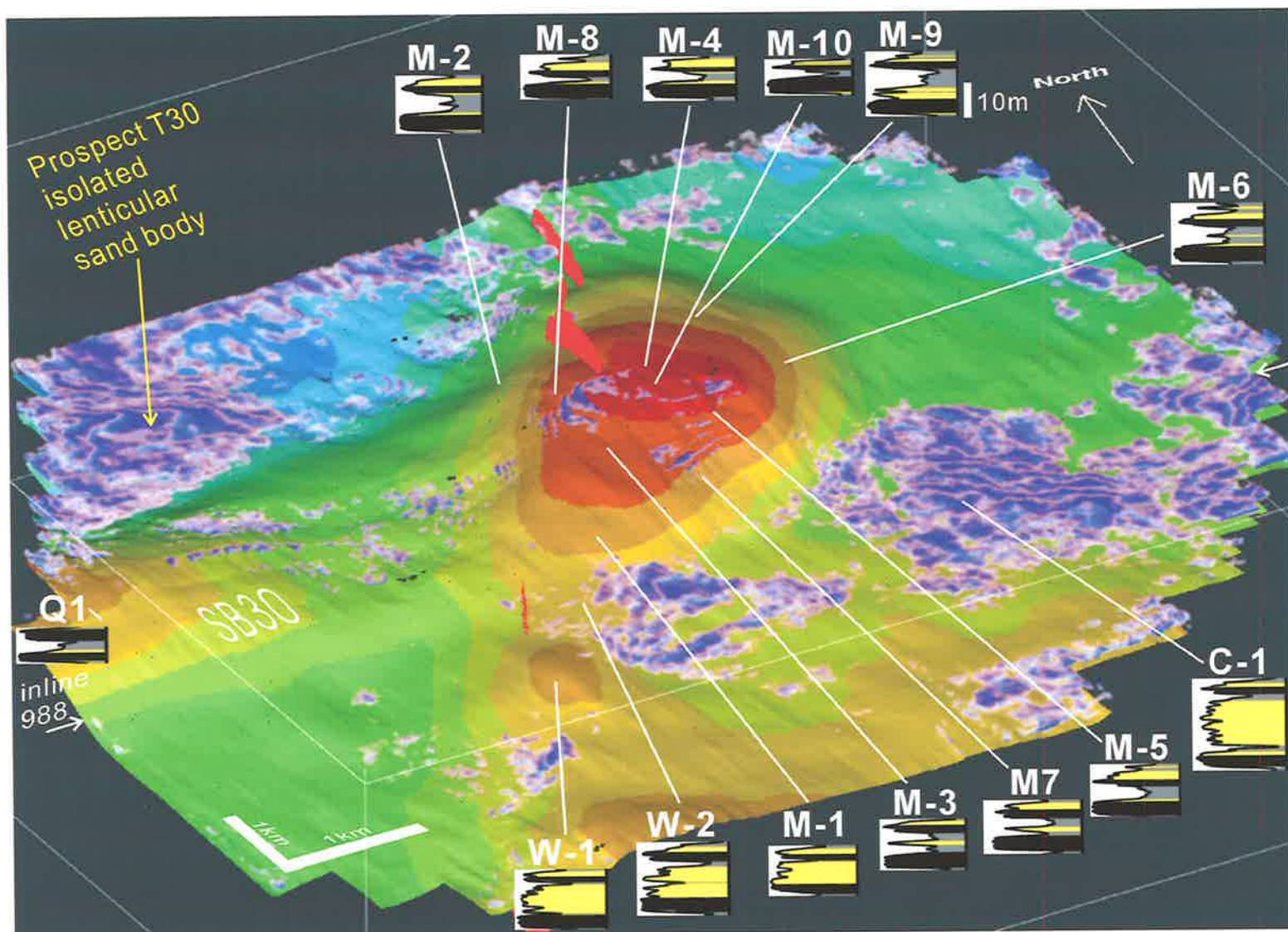


Figure 5.3.14. Lenticular negative amplitude distribution (purple) in TST 30 on SB30 in the Toolachee Formation, showing a possible fluvial channel sandstone distribution represented in Cardam-1. The sandstones in Woolkina-1, 2 and Moorari-1 are too thin to appear as a negative amplitude because they are below seismic resolution.

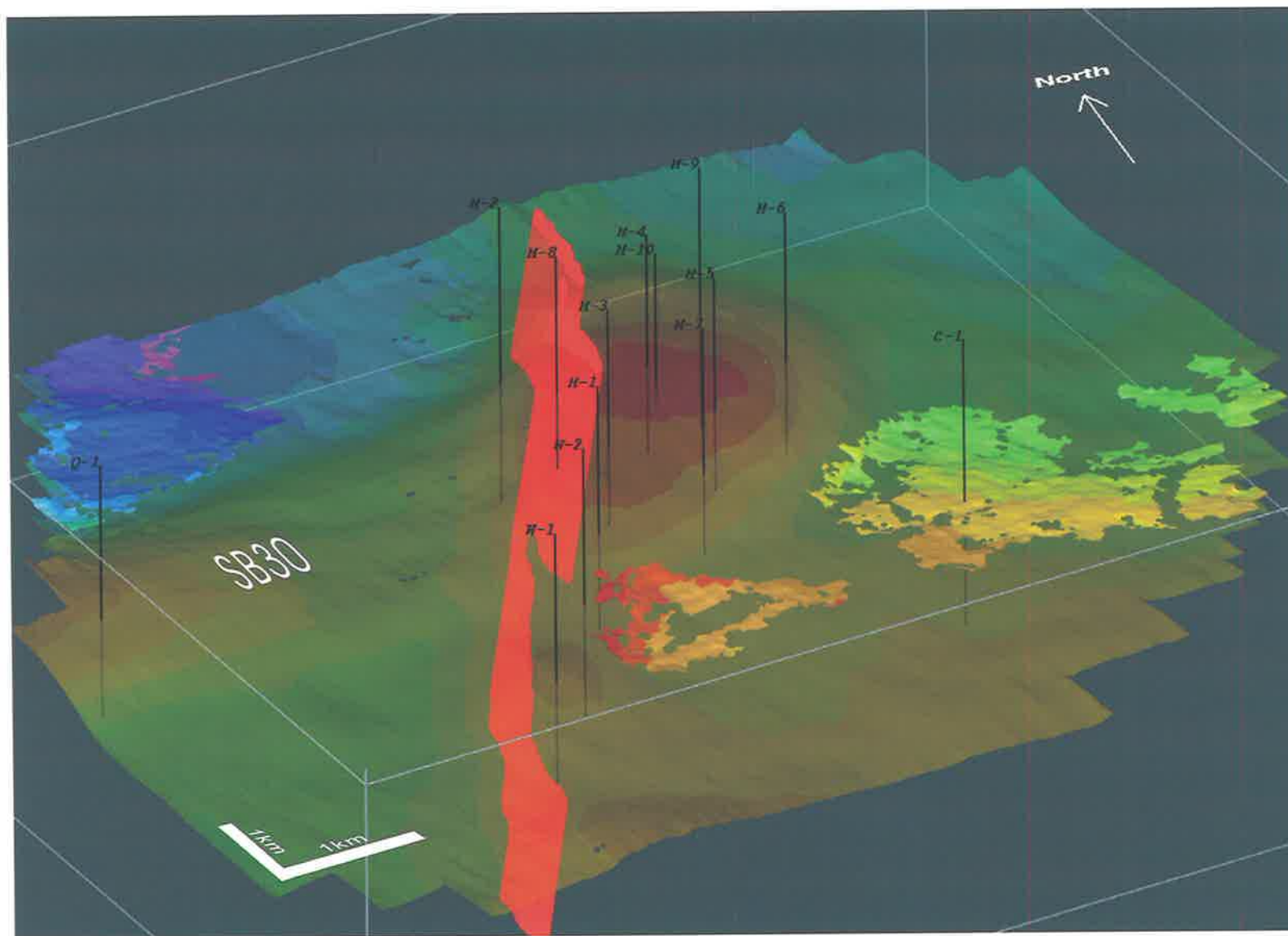


Figure 5.3.15. Two-way-time structure map of lenticular amplitude trough in TST 30 on SB30 of the Toolachee Formation (red: shallow, purple: deep).

5.4 Prospect extraction in Poolowanna Formation

5.4.1 Sedimentary facies analysis

A similar definition of facies as in the Permian interval is used for the Poolowanna Formation. Four sedimentary facies are recognised, all representing fluvial environments including fluvial channel, crevasse splay channel, floodplain-crevasse splay complex and floodplain (figures 5.4.1 and 5.4.2, see the facies definitions in section 5.3.1).

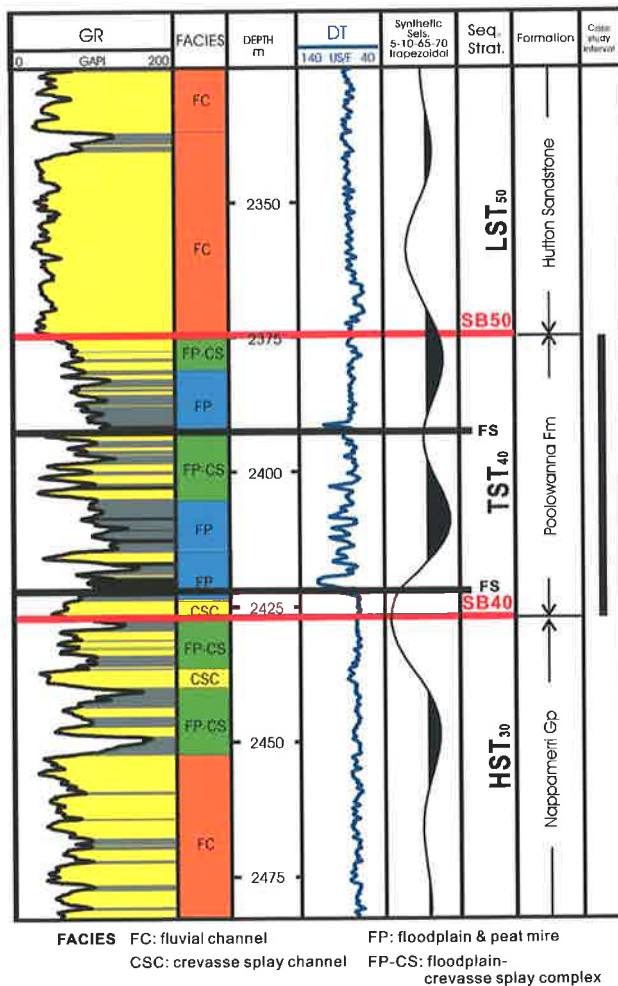


Figure 5.4.1. Sedimentological and sequence stratigraphic interpretation of the Poolowanna Formation based on well data, Moorari-1.

5.4.2 Sequence stratigraphy

The Poolowanna Formation lies at the base of the Jurassic-Cretaceous Eromanga Basin. It unconformably overlies the Permian-Triassic Nappamerri Group. The sequence boundary (SB40, figures 5.4.1 and 5.4.2) is an erosional surface characterised by an irregular, incised valley system (Wiltshire, 1982; Alexander and Sansome, 1996). The Poolowanna Formation is overlain by the Jurassic Hutton Sandstone, a thick succession of stacked fluvial channel sandstone. Visualisation of the 3D seismic data suggests that incision occurs at the base of the Hutton Sandstone (SB50, this will be discussed later).

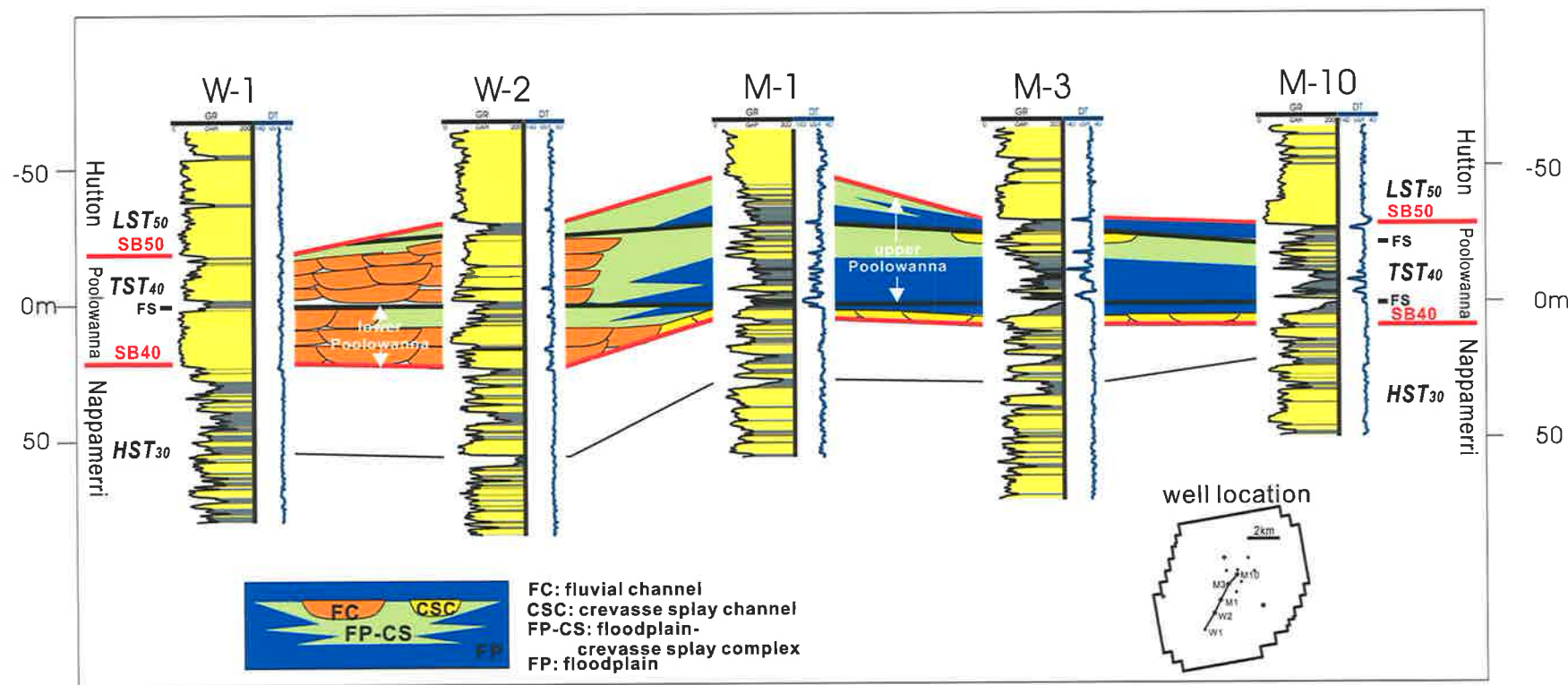


Figure 5.4.2. Sequence stratigraphic correlation of the Poolowanna Formation.

The Poolowanna Formation comprises fluvial channel and floodplain deposits (Figure 5.4.1). The fluvial channel facies laterally changes into crevasse splay and floodplain deposits (Figure 5.4.2). The laterally discontinuous fluvial sediments above the sequence boundary were deposited during increasing accommodation caused by the rising of relative base level, and are assigned to a transgressive systems tract (TST40).

Within the Poolowanna Formation, laterally continuous shale-prone intervals are identified that lie on top of a fining upward abandoned channel succession or its correlative floodplain deposits (Figure 5.4.2). The extensive abandonment of the fluvial channels suggests a widespread, elevated relative base level leading to the development of the shaly interval that can be identified as a flooding surface.

The lower part of TST40 is characterised by fluvial channel and crevasse splay channel facies (Figure 5.4.2). The channel deposits appear to have filled the incised topographic relief above the Nappamerri Group.

The upper section of TST40 consists of fluvial channel, crevasse splay and floodplain deposits (Figure 5.4.2). In particular the sequential combination of the floodplain facies and the floodplain-crevasse splay complex facies often shows an upward coarsening succession, which includes thin coal and sandstone intercalations within the shale. This is interpreted as a progradational succession of a crevasse splay delta system infilling a relatively shallow floodplain lake. From well log motifs, the proximal fluvial facies (FC) lies in the southwest whereas the distal facies (CSC, FP-CS and FP) lies in the northeast (figures 5.4.2 & 5.4.4). The distribution of the facies suggests that the crevasse splay delta system prograded from the southwest near to the main fluvial channel belt; however, most of the wells are drilled in the floodplain area to the northeast.

There is a limitation to the seismic interpretation of the sequence boundary (SB40) because the high amplitude reflection is controlled by the contrast in acoustic impedance between coals and non-coal successions. The coal in TST40 of the Poolowanna Formation is not always sitting on SB40, hence mapping the coal is not necessarily showing the topographic features of the sequence boundary. In the seismic data, nevertheless, the typical amplitude

peak and trough combination can be tied to the Poolowanna coal, and the amplitude trough is then picked as the intra-Poolowanna horizon (Figure 5.3.3). The peak and trough show lateral discontinuity of the amplitude that corresponds to the coal distribution pattern in the Poolowanna Formation (Figure 5.4.3).

5.4.3 3D seismic data visualisation and prospect extraction

Prospect T40: Crevasse splay channels and crevasse splay delta complex of the transgressive systems tract of the Poolowanna Formation

Visualisation

Employing the horizon-keyed strategy (see Chapter 2 for the visualisation technique), the distribution of positive amplitudes (amplitude peak) immediately above the intra-Poolowanna horizon was displayed in Figure 5.4.4. The window for the display was set from the intra-Poolowanna horizon to 16msec above the horizon to encompass the zone of the interest.

Three types of positive amplitude seismic facies, which show variations of coal distribution, are identified above the intra-Poolowanna horizon (Figure 5.4.3). The first seismic facies type shows a positive amplitude restricted to a channelised morphology of the intra-Poolowanna horizon (Figure 5.4.3a). The distribution of this positive amplitude displays a meandering channel pattern in the southwest of the study area (Figure 5.4.4). The two-way-time structure map of the intra-Poolowanna horizon (Figure 5.4.5) shows that the channelised morphology extends along the high positive amplitude pattern (compare Figure 5.4.4). The stacked fluvial channel sandstones exist in the upper part of the Poolowanna Formation in the wells (W-1 and Q-1, see Figure 5.4.4) beside the meandering pattern, hence such a meandering pattern of the positive amplitude suggests fluvial channels abandoned and plugged by mud and peat in the channel belt.

The second seismic facies type is made up of a combination of a channel-like and sheet-like positive amplitude distribution. It is characterised as the extension of the high amplitude sheet on both sides of the channel (Figure 5.4.3b). This seismic facies type is located in the middle of the seismic survey area (Figure 5.4.4). The channel-like facies extends from the southwestern channel belt to the middle of the survey area, and changes into the sheet-like

facies which distributes like a lobe in front of the channel. The well data, in the upper Poolowanna Formation, shows channel fill deposits adjacent to the sinuous channel-like amplitude (W-2) and crevasse splay delta progradations occur in a lobe shaped amplitude area (M-1, 3, 4, 7, 8, 9, 10).

The third seismic facies type is the sheet-like positive amplitude distribution incised by the base of the Hutton interval (Figure 5.4.3c). The incision appears in the northeast of the survey area, where the high amplitude disappears leaving a valley-like gap extending northwest to southeast (figures 5.4.4 and 5.4.5). It suggests that the base of the Hutton Sandstone is an erosive boundary caused by relative base level fall. The visible incision in the seismic data only appears in this portion of the study area; however, the base of the Hutton Sandstone is sharp over the Poolowanna Formation, suggesting it may be a regional erosion surface (Figure 5.4.2).

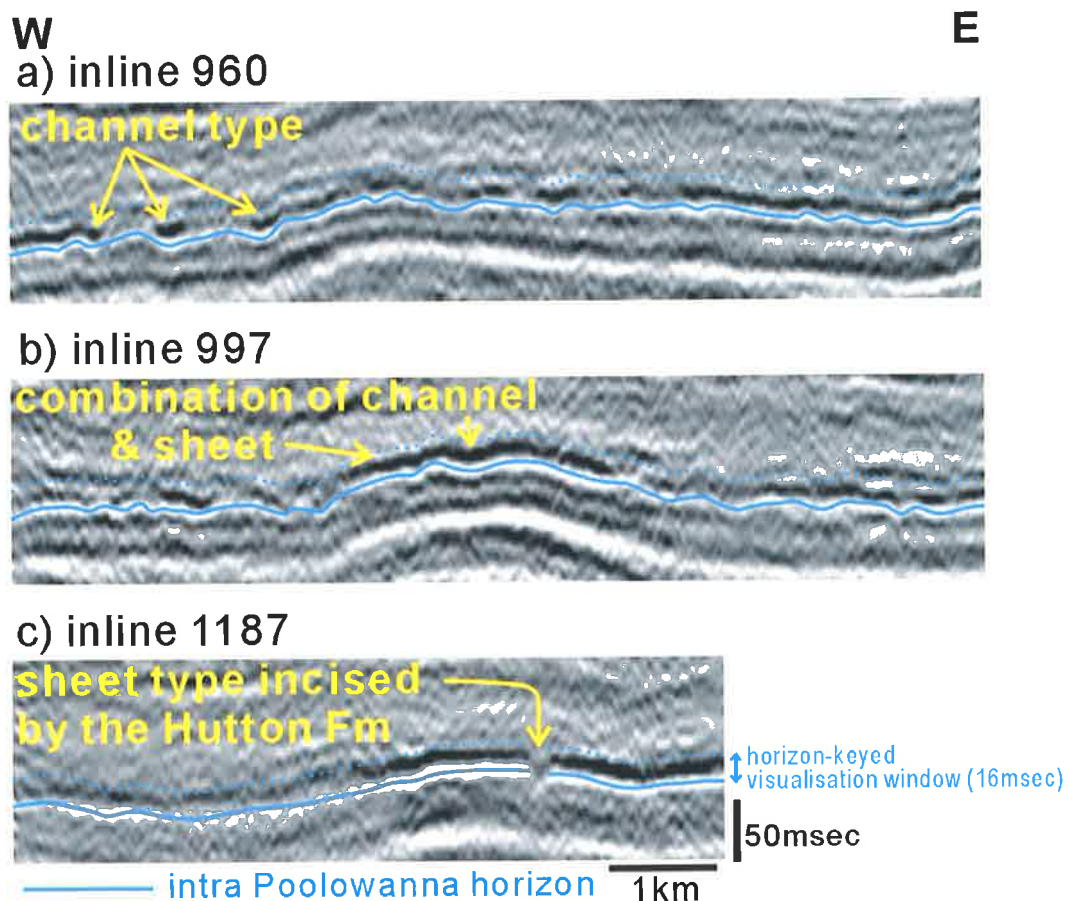


Figure 5.4.3. Three types of amplitude seismic facies above the intra-Poolowanna horizon: a) high positive amplitude which is restricted to the channelised morphology of the intra-Poolowanna horizon, b) combination of channel-like and sheet-like distribution of positive amplitude, c) sheet-like amplitude distribution incised by the base of the Hutton Sandstone (see the location of the sections in Fig. 5.4.4). The distribution of the positive amplitudes within the visualisation window is displayed in Figure 5.4.4.

As described above, the amplitude distribution can be related to the lateral changes in fluvial environments in the upper Poolowanna Formation. The amplitude variation does not show the morphology of the sequence boundary (SB40) but rather the fluvial system within the transgressive systems tract (TST40). The reason that the sequence boundary between the Poolowanna Formation and the Nappamerri Group (SB40) cannot easily be discriminated on seismic is because there is no significant difference in the acoustic impedance.

The facies distribution map of the upper Poolowanna Formation is shown in Figure 5.4.6. Based on seismic facies mapping at Moorari 3D seismic survey, Salter (1998) suggested that the Poolowanna Formation consisted of a river-dominated delta in a shallow and extensive lake. In this thesis, however, a crevasse splay complex (channels and mouth bars) was interpreted on a floodplain, adjacent to the main fluvial channel belt.

Possible stratigraphic trap

All wells in the study area penetrate the Poolowanna Formation, but no hydrocarbons of economic interest have been discovered. A possible reason for failure in the Poolowanna Formation could be hydrocarbon leakage through the contact between the Poolowanna sandstone and the Hutton Sandstone caused by the Hutton incision.

The sheet-like positive amplitude in the northeastern area has not been penetrated by a well, and the positive amplitude distribution is a response to the crevasse splay delta of the second seismic facies type (prospect T40). It is possible that the crevasse splay channel (the upper Poolowanna in Moorari-2, 5, and 6) which extends from the crevasse splay delta complex in the centre of the survey area could feed the sediments there. However, the Hutton incision on the crevasse splay delta could cause hydrocarbon leakage.

For future exploration and development of the Poolowanna Formation, the fluvial channel and floodplain complex shows significant lateral variations of reservoir and seal properties which correspond to the change in environmental facies. If the thinning-out of the channel belt against the floodplain can be located, this may present a good opportunity for a stratigraphic trap. The crevasse splay complex is another potential reservoir, but the crevasse splay delta mouth bar sandstones tend to be thin. However, if the crevasse channel network, which is

interconnected with the crevasse splay complex, can be located where it was not completely plugged by mud, the crevasse channel could be a higher permeability conduit to gather hydrocarbons from the crevasse splay complex.

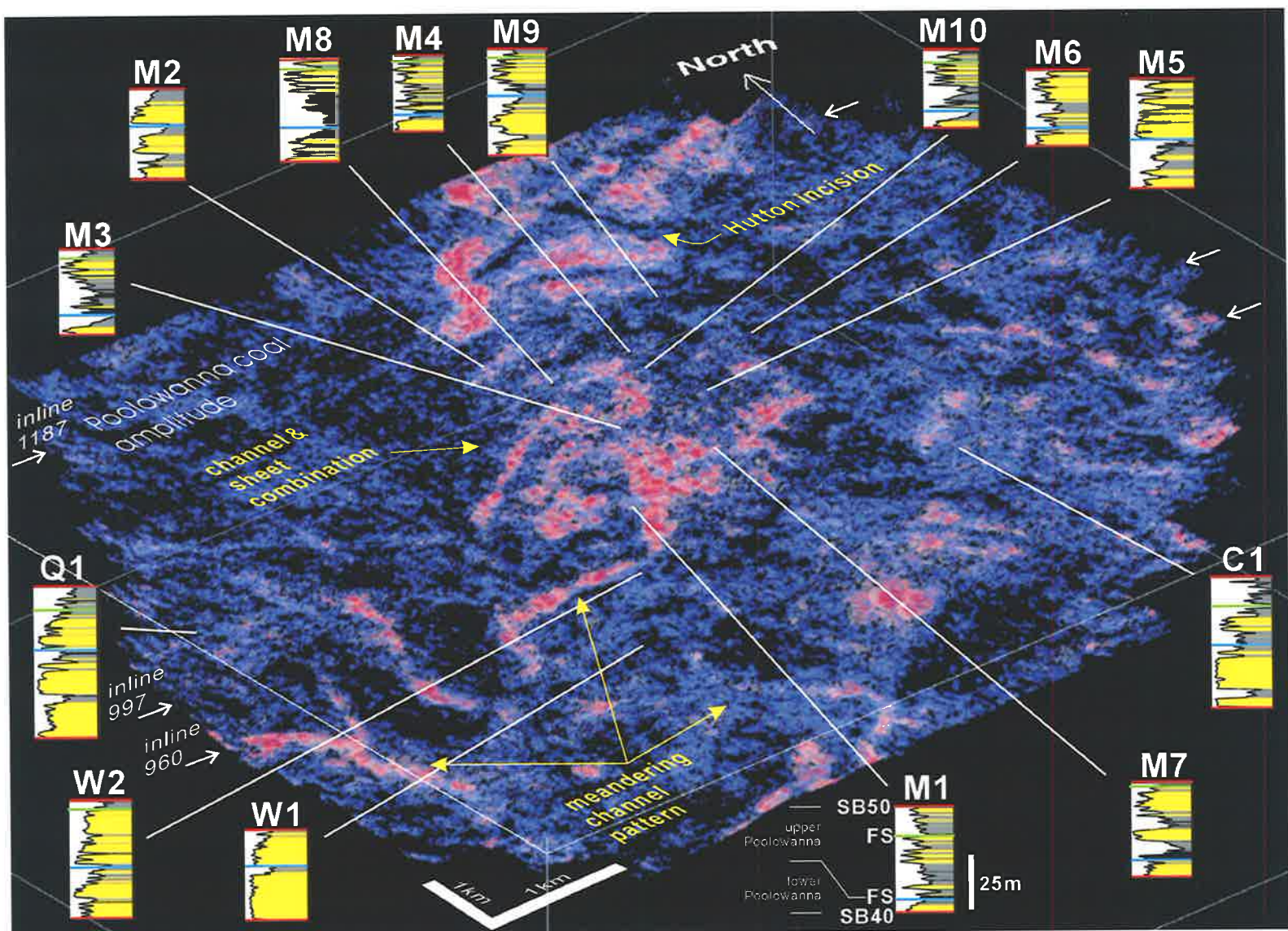


Figure 5.4.4. Distribution of the positive amplitude above the intra-Poolowanna horizon and facies variation of the Poolowanna Formation in well logs. The high amplitude (red) shows coal distribution.

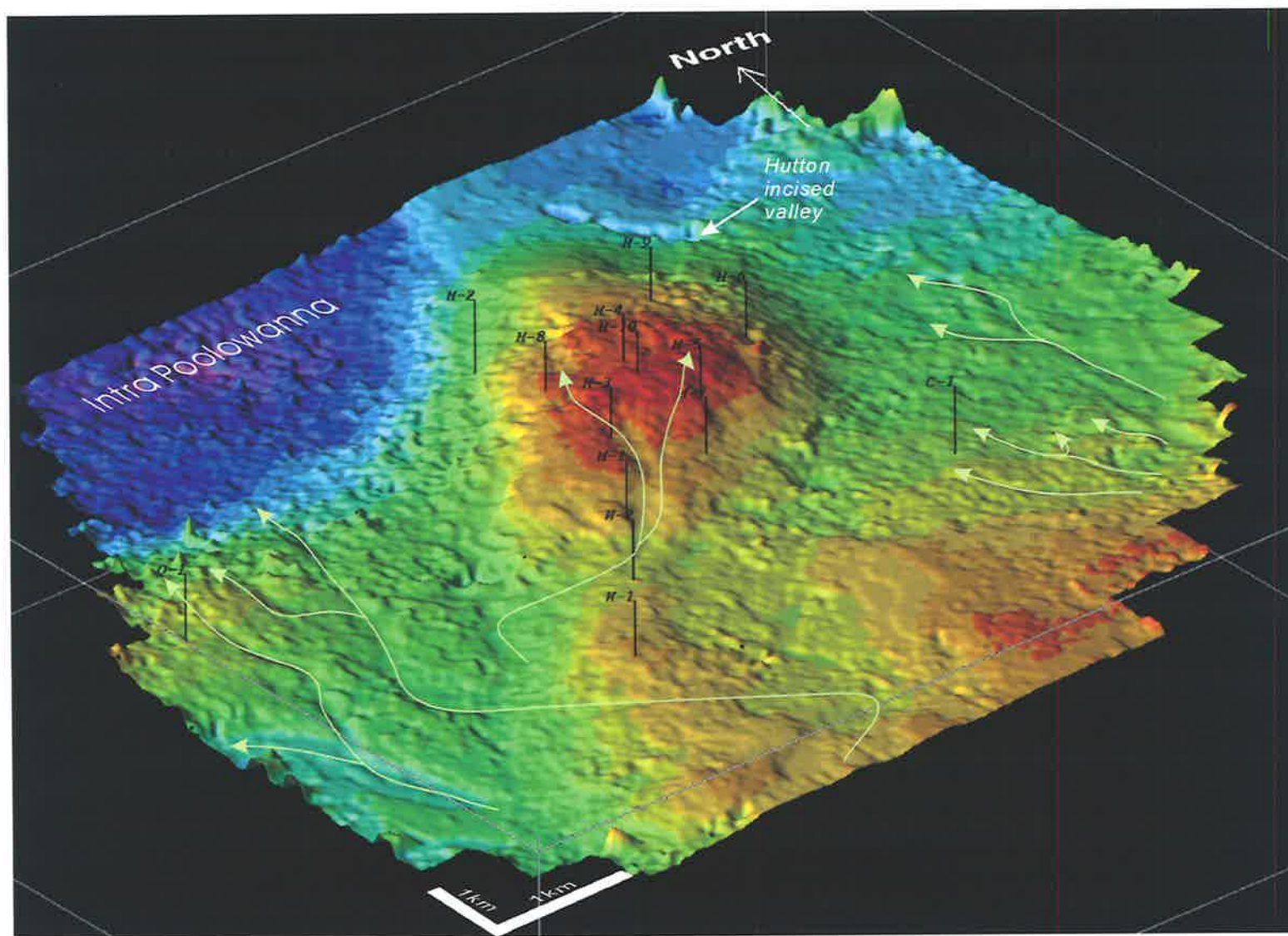


Figure 5.4.5. Two-way-time structure map of the intra-Poolowanna horizon (red: shallow, purple: deep). Channel features trending NS or NE-SW can be seen on the Moorari high and the low area. The channels extend along the high amplitude peak pattern of the Poolowanna coal (compare to Fig.5.4.4).

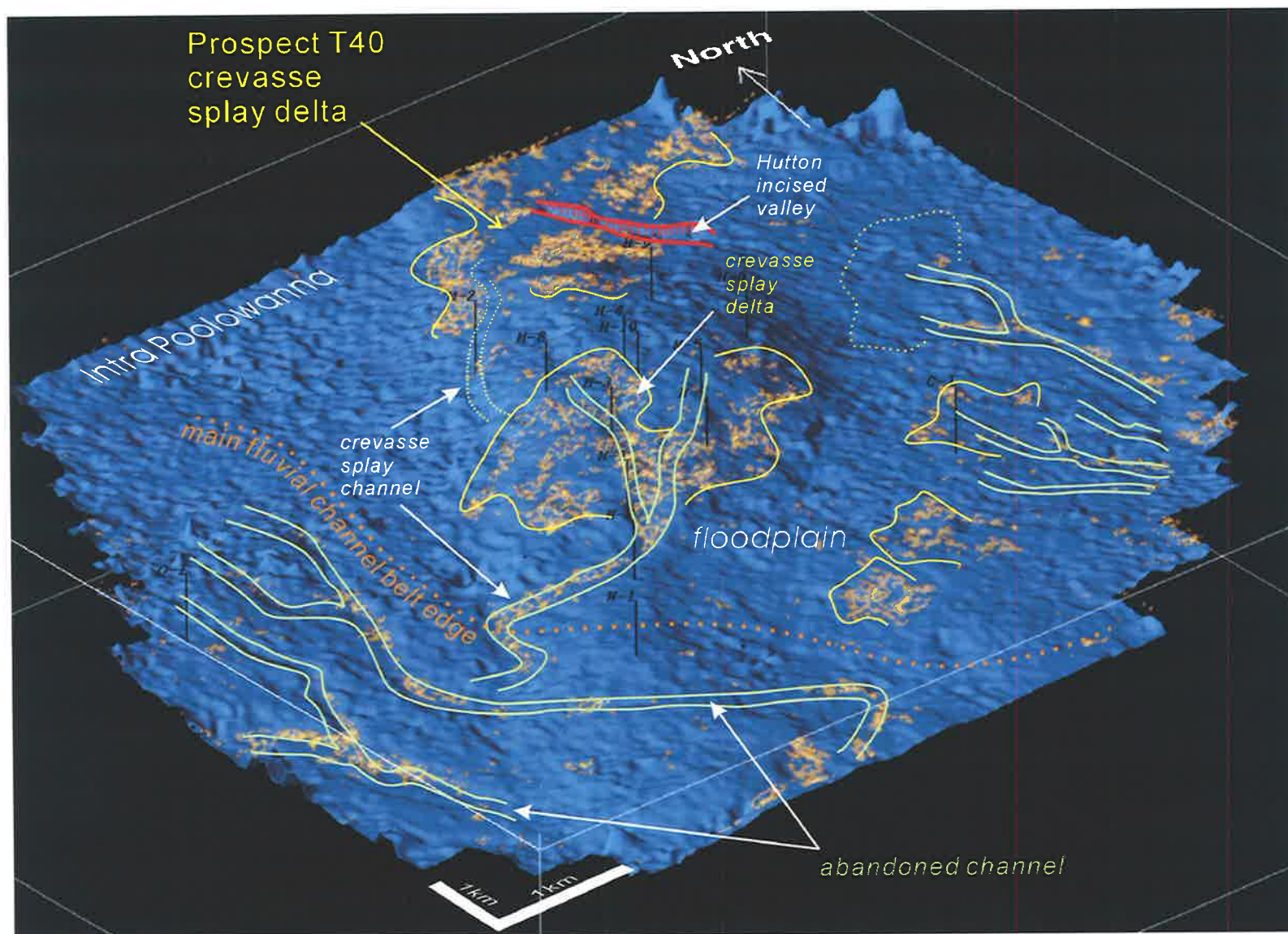


Figure 5.4.6. Interpretation of sedimentary environments of the upper Poolowanna Formation. A crevasse splay complex exists on a floodplain adjacent to the main fluvial channel belt. The distribution pattern of coals (yellow coloured high positive amplitude) changes according to the sedimentary environment.

Chapter 6

Case Study 2: Pondrinie 3D Seismic Survey Area

6.1 Introduction

The second case study covers Pondrinie 3D seismic survey area, and includes two stratigraphic trap prospects recognised from the upper Permian Toolachee Formation and the basal Jurassic Poolowanna Formation.

6.2 Pondrinie / Packsaddle fields

The Pondrinie 3D seismic survey area is located in northeastern South Australia on the Packsaddle ridge, part of the Gidgealpa-Merrimelia-Innaminka structural high trend of the southern Cooper Basin (Figure 6.2.1). The seismic survey covers the locations of the Pondrinie Field and the Packsaddle Field. The Pondrinie and Packsaddle structural high is an anticline with a four-way dip closure, bounded to the northwest by an ENE striking, southward dipping reverse fault produced by inversion tectonics (figures 6.2.3, 6.2.4 and 6.2.5; Apak et al. 1997).

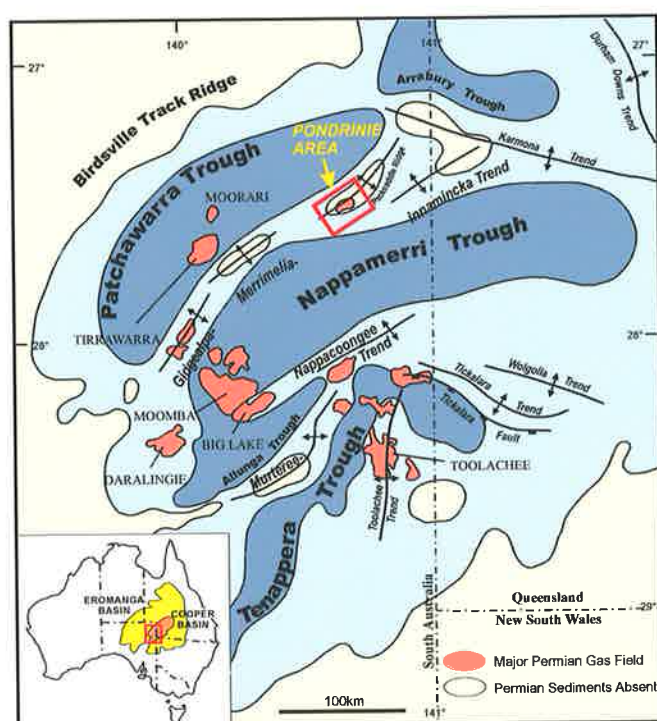


Figure 6.2.1. Major structural elements of the southern Cooper Basin (modified after Thornton, 1979; Apak et al., 1997) and the location of the case study area.

Gas was discovered in the Patchawarra Formation in 1970 with the drilling of Packsaddle-1 on the eastern side of the Pondrinie and Packsaddle high. Packsaddle-2 and 3 were drilled to explore the Patchawarra gas accumulation in the eastern flank of the upthrown block of the fault, but no economically producible hydrocarbons were proved. From 1984 to 1996, thirteen exploration and appraisal wells (Packsaddle-4, 5, Pondrinie-1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11) were drilled on the top and southeastern flank of the upthrown block, and gas was discovered within the Nappamerri Group, Toolachee Formation, Tirrawarra Sandstone and the Merrimelia Formation. In 1991, Nardu-1 was drilled on the northwestern flank of the block to evaluate an erosional pinchout play of the Permian succession, but the succession was absent. In the downthrown block of the fault, two exploration wells (Yalchirrie-1 and Napowie-1) were drilled from 1991 to 1993, with Napowie-1 discovering a gas accumulation in the Epsilon Formation. After Pondrinie-11 was drilled, 3D seismic data was obtained in 1997. The 3D seismic enhanced the successes of several appraisal and development wells. Napowie-2 was drilled in the downthrown block as an appraisal well for the Epsilon gas accumulation discovered in Napowie-1, and confirmed that the Epsilon Formation was absent but discovered a gas accumulation within Toolachee Formation.

AGE		STRATIGRAPHY		PALYNOLOGICAL ZONE	BASIN	Sequence boundaries in this study	Objective interval in case study 2			
CRETACEOUS	LATE	MARREE SUBGROUP	Winton Fm	PK7	EROMANGA BASIN					
	EARLY		Mackunda Fm	PK6						
			Oodnadatta Fm	PK5.2						
			Alley Mudstone	PK5.1						
			Toolebuc Fm	PK4						
			Coorikiana Sandstone	PK3.2						
			Wallumbilla Fm	PK3.1						
			Bulldog Shale	PK2.2						
			Wyandra Sandstone Member	PK2.1						
	Cadna-owie Fm		PK1.2							
JURASSIC	LATE	MARREE SUBGROUP	Murta Fm	PK1.1	EROMANGA BASIN	SB60				
	MIDDLE		Namur Sandstone	PJ6.2						
			McKinlay Member	PJ6.1						
			Westbourne Fm	PJ5						
	Adori Sandstone		PJ4.2							
	Birkhead Fm		PJ4.1							
	Hutton Sandstone		PJ3.3							
	Poolowanna Fm		PJ3.2							
			PJ3.1							
	EARLY			PJ2.2			SB40			
TRIASSIC	LATE	NAPPAMERRI GROUP		PJ2.1	EROMANGA BASIN					
	MIDDLE		Cuddapan Fm	PJ1						
				PT5						
	EARLY			PT4						
			Tinchoo Fm	PT3						
			Wanna Sandstone Member	PT2						
			Paning Member	PT1						
			Arrabury Fm	PP6						
	PERMIAN		LATE	GIDGEALPA GROUP		Callamurra Member	PP5	COOPER BASIN	SB30	
			EARLY			Toolachee Fm	PP4.3			
		PP4.2								
Daralinga Fm		PP4.1								
Roseneath Shale		PP3.3								
Epsilon Fm		PP3.2								
Murree Shale		PP3.1								
		PP2.2.3								
		PP2.2.2								
		PP2.2.1								
CARBONIFEROUS	LATE		Patchawarra Fm	PP2.1	COOPER BASIN	SB20				
			Tirrawarra Fm	PP1.2.2						
			Merrimella Fm	PP1.2.1		SB10				
				PP1.1						

Figure 6.2.2. Generalised stratigraphic column of the Cooper-Eromanga Basin in northeast South Australia (modified after Moussavi-Harami, 1996; Alexander, 1998) and objective intervals in the Pondrinie case study.

Economic gas accumulations occur within the Merrimelia Formation, Tirrawarra Sandstone and Toolachee Formation in the structurally high area of the upthrown block. The reservoirs show lateral facies changes including wedging-out of sandstone into shale or thinning toward the structural high. These facies changes have produced a combination stratigraphic-structural trap to be developed over the high. The laterally continuous shale-prone interval of the Nappamerri Group is the regional seal for these reservoirs. In the downthrown block, the shale-prone interval of the Patchawarra Formation is a seal for gas accumulation in the Epsilon Formation and Patchawarra Formation.

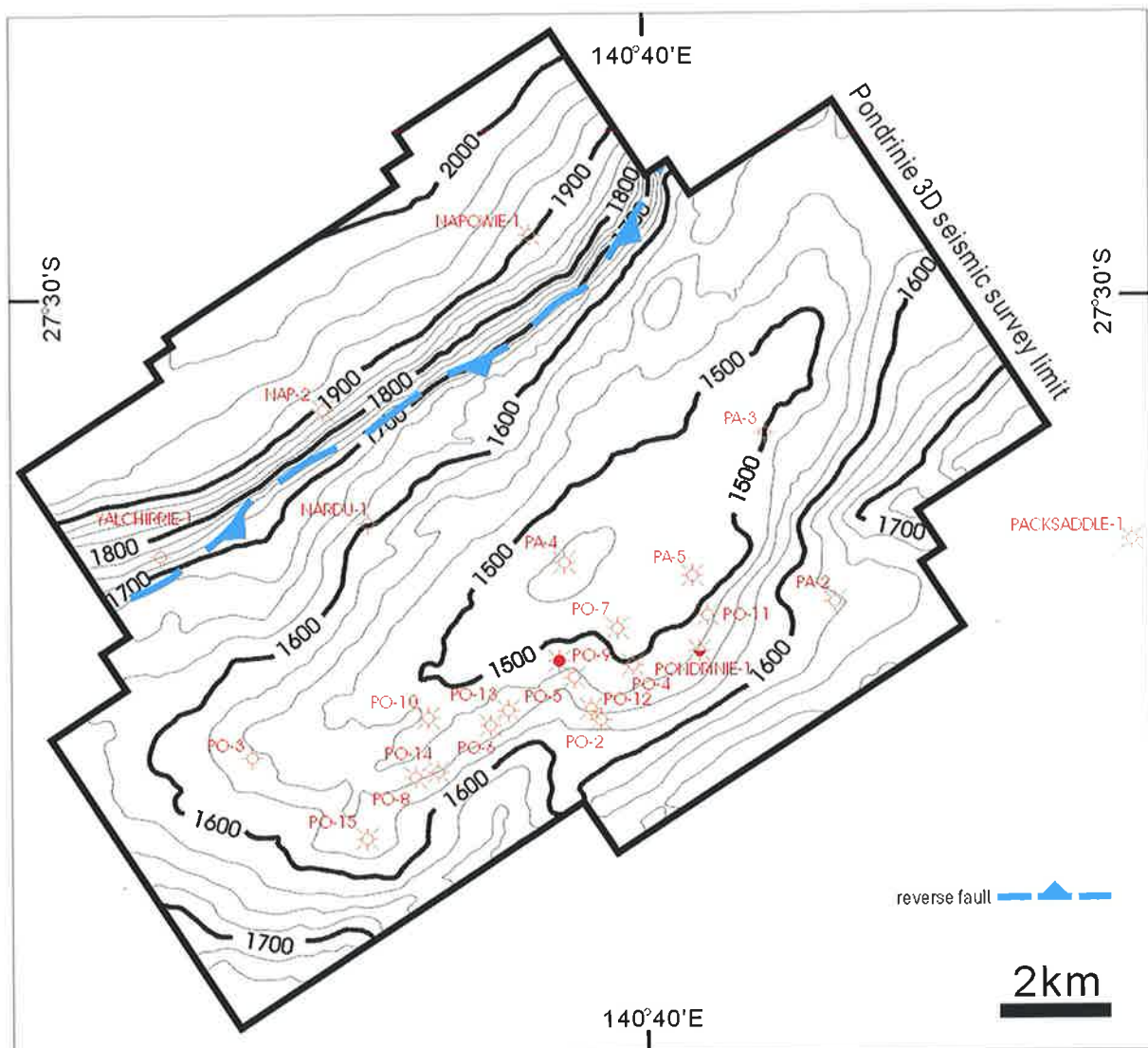


Figure 6.2.3. Two-way-time structure map of the base of the Nappamerri Group in the Pondrinie and Packsaddle fields area. The fault bounding the northwest of the structural high terminates just below the base of the Nappamerri Group (also see Fig 6.2.4).

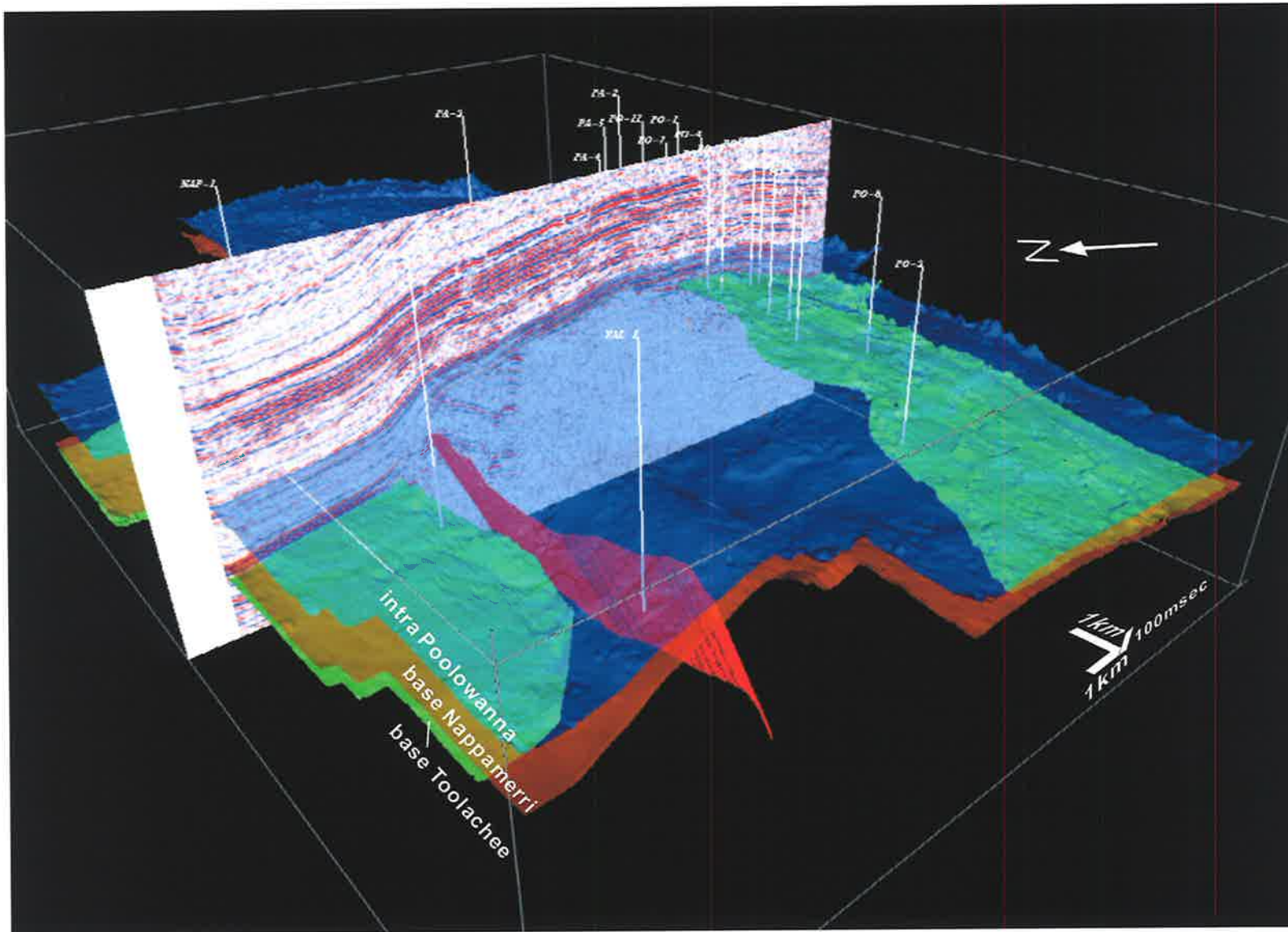


Figure 6.2.4. Outline of the structural highs in the Pondrinie Field area, showing well distribution, key seismic surfaces and faults.

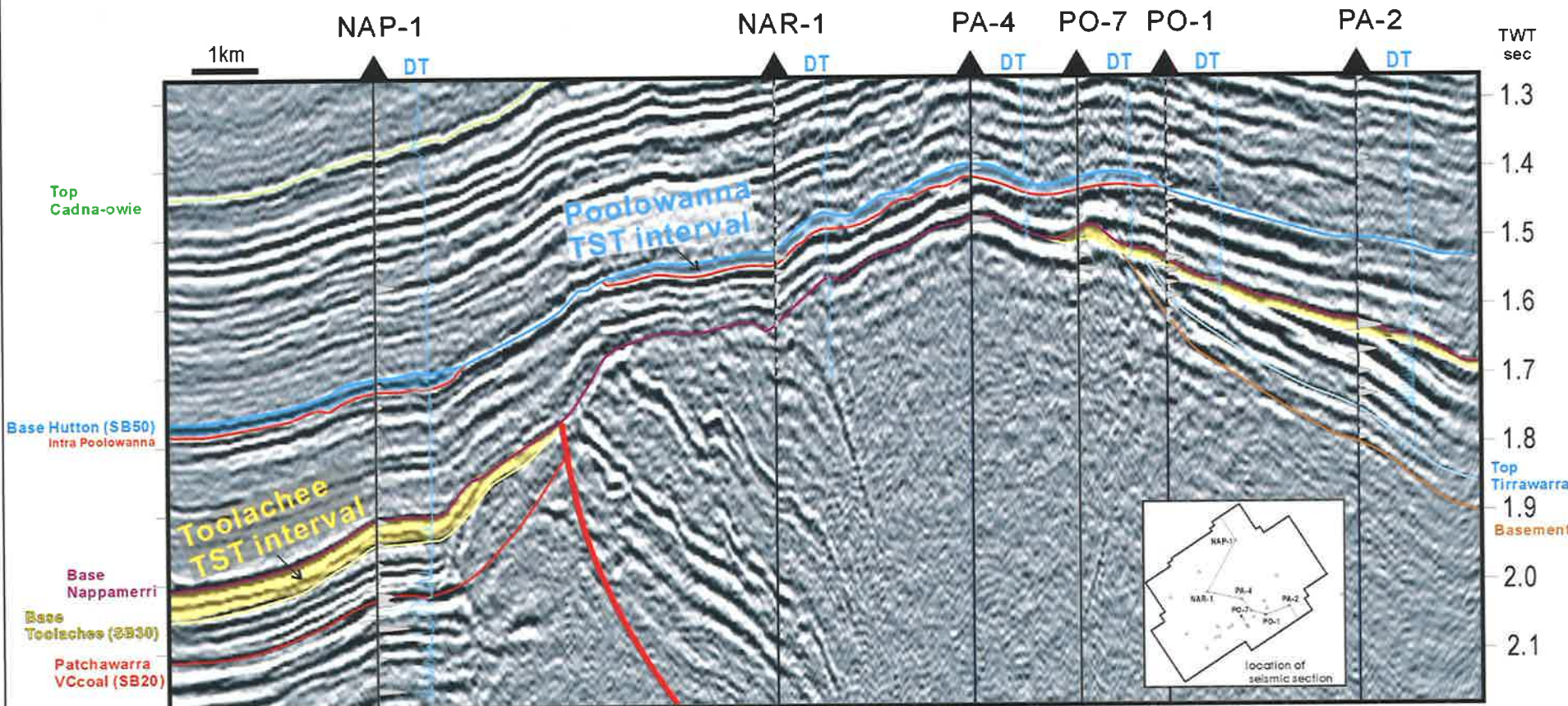


Figure 6.2.5 Interpreted key surfaces on an arbitrary seismic section with sonic logs and synthetic seismogram of key wells. The wavelet is zero phase with a 5-10-65-70 Hz trapezoidal bandpass.

6.3 Prospect extraction in Toolachee Formation

6.3.1 Sedimentary facies analysis

The same definition of facies as in the Permian interval in the Moorari Field area is used for the Patchawarra Formation, the Murteree Shale, the Epsilon Formation and the Toolachee Formation in the Pondrinie area. Six sedimentary facies such as fluvial channel, crevasse splay channel, floodplain-crevasse splay complex, floodplain and peat mire, lacustrine delta and lacustrine offshore, are interpreted based on wireline logs, cuttings and core descriptions (figures 6.3.1 and 6.3.2, see the facies definitions in section 5.3.1).

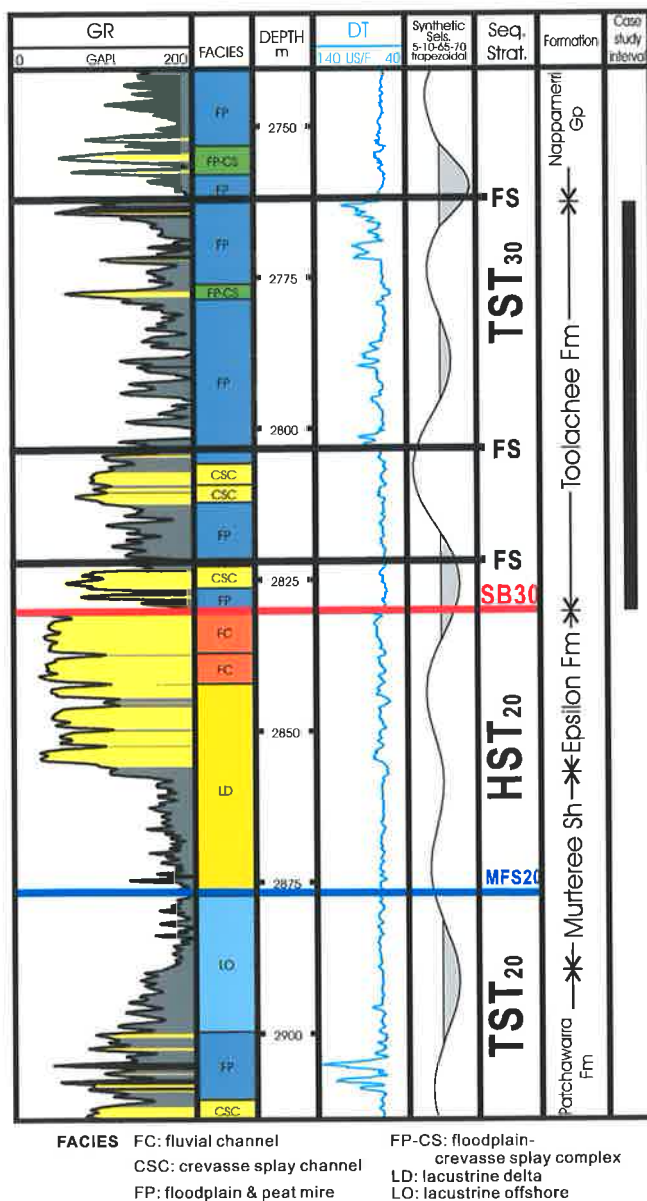


Figure 6.3.1. Sedimentological and sequence stratigraphic interpretation based on well data, Napowie-1, showing systems tracts.

6.3.2 Sequence stratigraphy

A sequence stratigraphic framework comprising second-order sequences for the Patchawarra, Epsilon and Toolachee Formation was described in the Moorari Field area in the Patchawarra Trough. This framework can also be applied to these formations in the Pondrinie area (figures 6.3.1 & 6.3.2).

The upper Patchawarra Formation consists of laterally discontinuous fluvial deposits of transgressive systems tract (TST20). Only Napowie-1 in the downthrown block of the fault intersected the Epsilon Formation and the upper part of the Murteree Shale comprises progradational lacustrine delta deposits of the highstand systems tract (HST20). The finest portion of the Murteree Formation is identified as a maximum flooding surface (MFS20).

The base of the Toolachee Formation is a regional unconformity resulting from the Daralingie uplift and is interpreted as a sequence boundary (SB30). The SB30 could have been placed within the uppermost part of the blocky sandstones currently shown as Epsilon Formation. However, in this case the boundary placed above the main sandstone was the preferred interpretation because it was on the paleohigh caused from the Daralingie uplift, and then misses the basal Toolachee amalgamated sandstone. Because of the absence of palynological data, this can not be resolved at this moment. Below this sequence boundary, the entire Roseneath Shale, Daralingie Formation, and part of the Epsilon Formation and Patchawarra Formation are eroded. The Toolachee Formation comprises fluvial sandstones, shales and coals. The fluvial channel facies is relatively thick, but is known to be laterally discontinuous from well logs. The lateral discontinuity of the fluvial channel deposits lying above the sequence boundary suggests that the Toolachee Formation at the Pondrinie Field represents the transgressive systems tract (TST30) produced by increasing alluvial accommodation associated with rising relative base level (Posamentier & Allen 1999). This interval shows thinning toward the Pondrinie structural high in both the upthrown and downthrown blocks of the fault bounding the structural high to the northwest. This thinning suggests that the Toolachee fluvial system was deposited onlapping on a palaeo-high formed by compressional activity during a period of relative base level rise in the late Permian. The Toolachee Formation is conformably overlain by the Nappamerri Group, comprising fluvial channel and associated floodplain and lacustrine deposits.

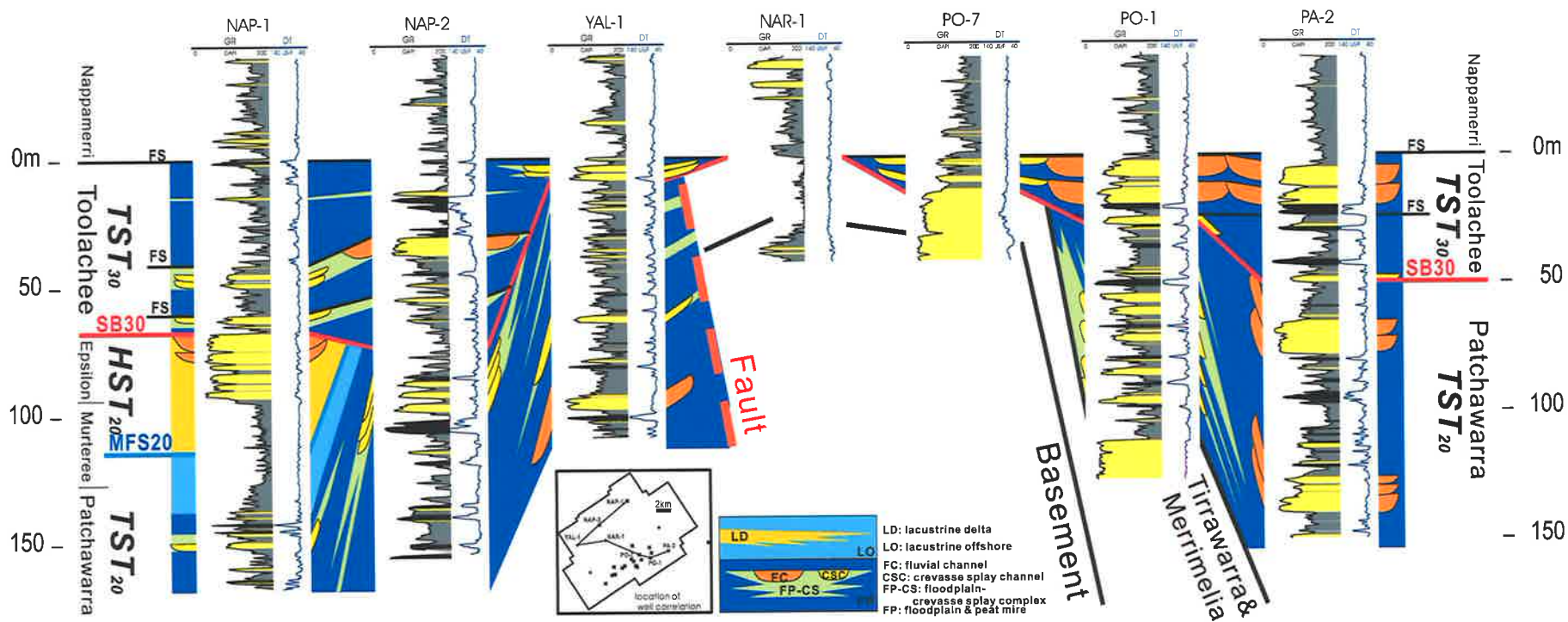


Figure 6.3.2. Sedimentary facies distribution and sequence stratigraphic correlation of the Patchawarra, Murteree, Epsilon and Toolachee Formation across the Pondrinie structural high.

In the 3D seismic data in the downthrown block, SB30 at the base of the Toolachee Formation is represented by various amplitude patterns corresponding to combinations of the coaly and non-coaly intervals among the Toolachee Formation, Epsilon Formation and Patchawarra Formation. The sequence boundary on the seismic data is practically picked midway between a peak corresponding to the lowest coaly interval of the Toolachee Formation and the underlying zero crossing (figures 6.3.1, 6.2.5 and 6.3.3). The sequence boundary is characterised by terminations of the underlying amplitude peaks and troughs of the Epsilon Formation and the Patchawarra Formation. The top of the Toolachee Formation is interpreted as a very continuous amplitude peak corresponding to the top of the Toolachee coaly succession. The horizons of the base and top of the Epsilon Formation merge together, resulting from thinning of the formation over the structural high (Figure 6.2.5). The existence of a seismic shadow zone along the fault striking ENE makes it difficult to interpret these horizons and internal seismic amplitude facies in this zone.

6.3.3 3D seismic data visualisation and prospect extraction

Prospect Ttc: Isolated fluvial channels in the transgressive systems tract of the Toolachee Formation

Visualisation

The amplitude variation (Figure 6.3.3) in the Toolachee interval in the downthrown block of the fault is thought to reflect the distribution of coaly intervals, and the lateral change of the amplitude shows the variation of the coal thickness. To visualise the amplitude distribution, the horizon-keyed window was set 12msec above the SB30 to 8msec below the top of the Toolachee Formation. Figure 6.3.4 shows the amplitude distribution within the visualisation window of the Toolachee Formation interval. The area of negative amplitude (yellow) represents non-coal distribution, and is sinuous, elongate, and trends northeast to southwest along the fault. The positive amplitude areas (blue) indicate coal distribution and are sitting on the western side of the elongated negative-amplitude area. On the eastern side of the negative amplitude area near Napowie-1, a smaller scale sinuous pattern is represented by variable amplitude. Napowie-1 intersected floodplain and crevasse splay deposits in the transgressive systems tract. The amplitude patterns imaged in Figure 6.3.4 suggest the existence of a fluvial channel belt surrounded by splay complexes and floodplain accumulated in the transgressive

systems tract. The channel belt probably aggraded in response to increasing base level, resulting in an isolated sand body. This channel belt seems to be oriented parallel to the fault and extends where fluvial channel facies sandstone has been intersected by Napowie-2. However there is an uncertainty in the channel geometry caused by the seismic shadow zone.

Possible stratigraphic trap

The sinuous elongate, negative amplitude distribution suggests an isolated fluvial channel sandstone body among floodplain and peat mire deposits (Prospect Ttc, Figure 6.3.4). The negative amplitude containing the fluvial channel is changing southeastwards into the amplitude pattern, suggesting floodplain deposits on the structural high side. This configuration of fluvial sandstone reservoir and lateral floodplain-shale may result in a stratigraphic trap. Although there is uncertainty in the seismic shadow zone regarding the channel geometry and the relationship between the channel and the fault, a gas accumulation in the fluvial channel sandstone in Napowie-2 suggests that gas has accumulated in the isolated fluvial channel sandstone (Prospect Ttc) in the downthrown fault block.

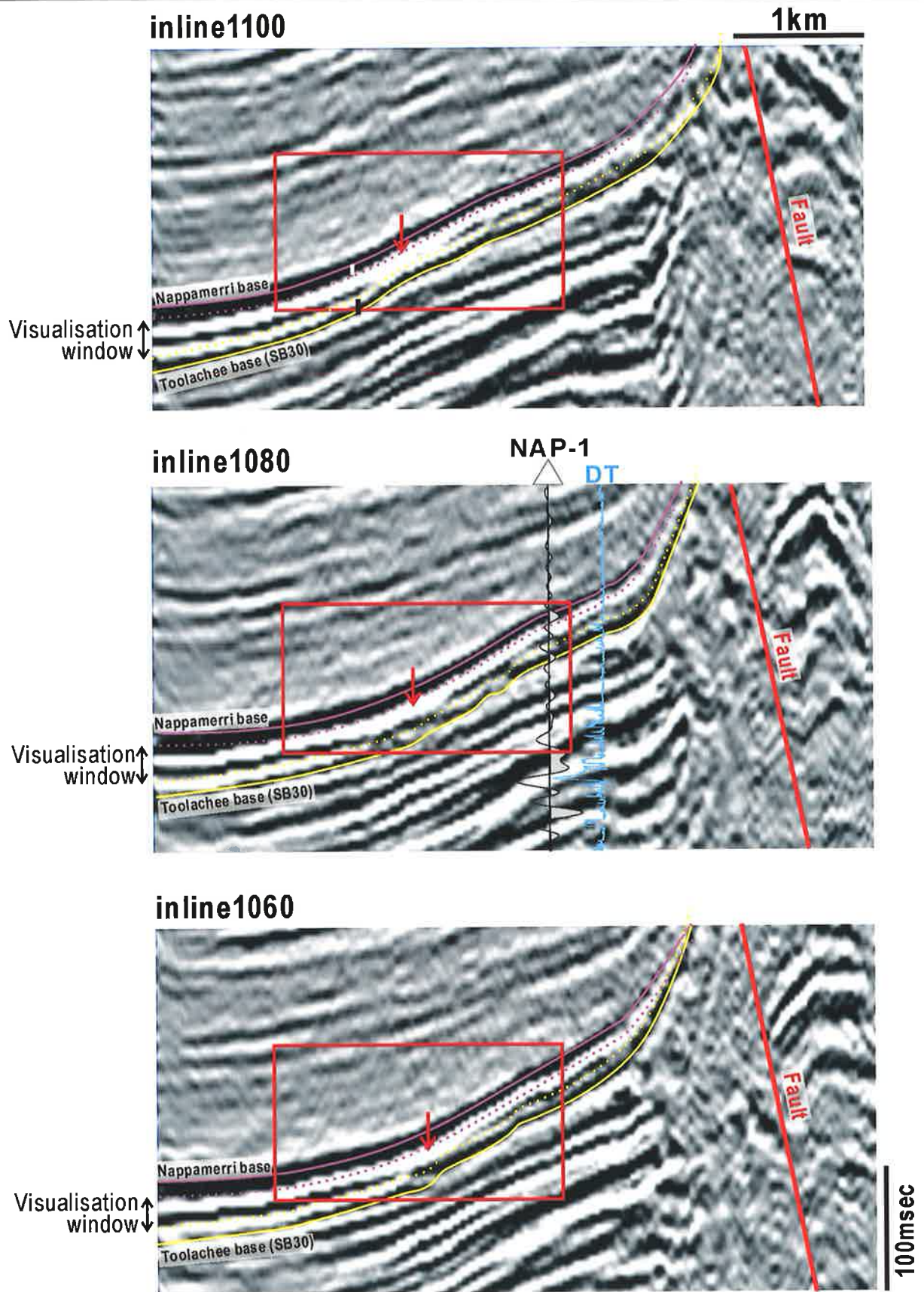


Figure 6.3.3. Amplitude variation corresponding to the coal distribution in TST of the Toolachee Formation on the downthrown block. Channel features with the amplitude variation can be identified (red arrow). The horizon-keyed window (dot lines) was set 12msec above SB30 to 8msec below the Nappamerri base to visualise the amplitude variation in Figure 6.3.4. See the locations of the sections in Figure 6.3.4.

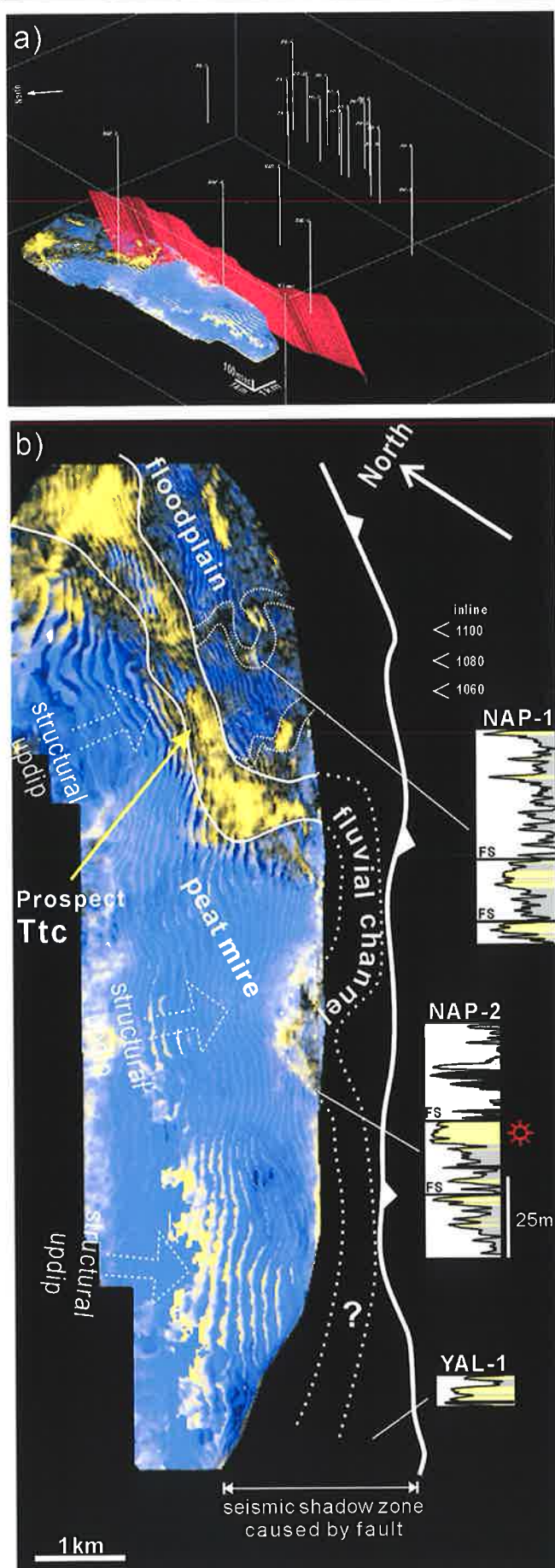


Figure 6.3.4. a) & b) Seismic amplitude distribution in the visualisation window set 12msec above SB30 to 8msec below the Nappamerri base corresponding to TST of the Toolachee Formation on the downthrown block (also see Figure 6.3.39). Respectively, yellow, black and blue shows negative amplitude, nearly zero and positive amplitude. The elongate and sinuous pattern of negative amplitude distribution is interpreted as a fluvial channel belt surrounded by floodplain and coal. On the east side of the channel belt smaller size sinuous patterns suggest a crevasse splay channel on the floodplain. The well log facies of the Toolachee Formation, which interval is approximately corresponding to the seismic visualisation window, are consistent with the interpretation of a fluvial channel belt, and the gas accumulation in Napowie-2 suggests a stratigraphic trap opportunity in an isolated fluvial channel belt sandstone (prospect Ttc).

6.4 Prospect extraction in Poolowanna Formation

6.4.1 Sedimentary facies analysis

Four sedimentary facies are recognised in the Poolowanna Formation with a similar facies definition as in the Permian interval (figures 6.4.1 and 6.4.2; see the facies definitions in section 5.3.1). The facies include fluvial channel (stacked and amalgamated sandstone with a sharp base), crevasse splay channel (interbedded sandstones with sharp bases and shale), floodplain-crevasse splay complex (interbeds of fine-grained sandstones and shales) and floodplain.

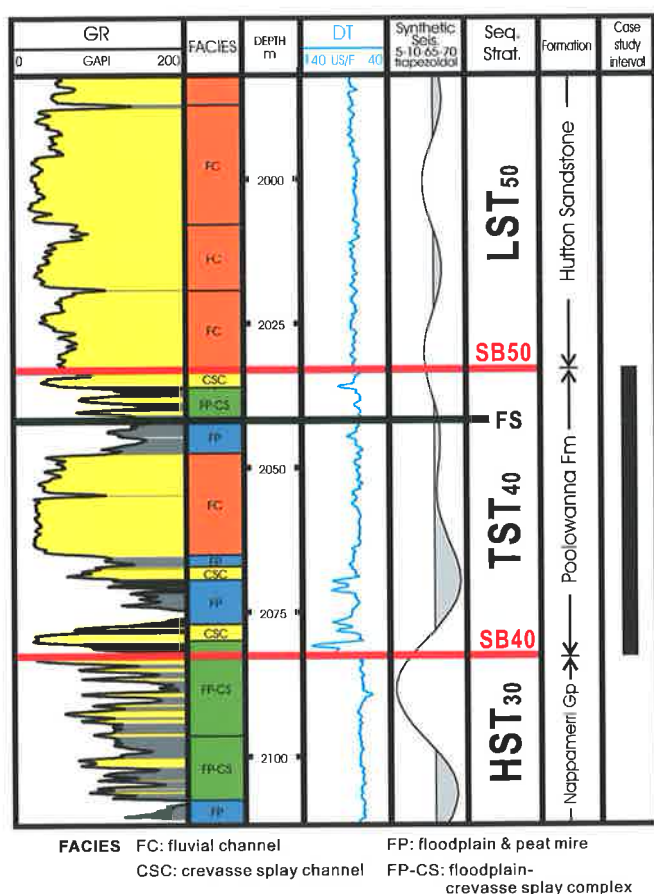


Figure 6.4.1. Sedimentological and sequence stratigraphic interpretation of the Poolowanna Formation based on well data in Nardu-1.

6.4.2 Sequence stratigraphy

The Poolowanna Formation lies at the base of the Jurassic-Cretaceous Eromanga Basin, unconformably overlying the Permian-Triassic Nappamerri Group. The sequence boundary (SB40) of the base of the Poolowanna Formation is a regional erosional surface characterised by an irregular topography of an incised valley system (Wiltshire 1982; Alexander & Sansome 1996). The Poolowanna Formation is overlain by the Jurassic Hutton Sandstone, a

thick succession of stacked fluvial channel sandstone. Well log data and 3D seismic data suggest that the base of Hutton Sandstone is also a sequence boundary (SB50) which erodes both the Poolowanna Formation and the Nappamerri Formation (figures 6.4.2 and 6.4.3). Consequently, the distribution of the Poolowanna Formation is controlled by both the basal Jurassic incised topographic relief and the degree of the Hutton Sandstone erosion (this will be discussed later).

The Poolowanna Formation comprises fluvial channel and floodplain deposits (Figure 6.4.1). The fluvial channel facies changes laterally into crevasse splay and floodplain deposits (Figure 6.4.2). The thickness of each fluvial channel is less than the depth of the basal Jurassic incision and multiple fluvial channels and associated floodplain deposits filled the topographic relief of the incised valley. The laterally discontinuous fluvial sediments above the sequence boundary of the basal Jurassic incision were deposited during increasing alluvial accommodation produced by the rising of relative base level, and are assigned to a transgressive systems tract (TST40).

Within the Poolowanna Formation, laterally continuous shale-prone or coaly intervals are identified that lie on top of abandoned fluvial channel successions or the correlative floodplain deposits (Figure 6.4.2). The widespread development of the shale-prone and coaly interval above the abandoned channels is identified as a flooding surface resulting from rapidly rising relative base level or channel-avulsion.

The seismic expression of the sequence boundary at the base of the Poolowanna Formation is limited because the high amplitude reflection is controlled by the contrast in acoustic impedance between coals and non-coal successions. The coal in the Poolowanna Formation is not always sitting on the sequence boundary, hence mapping the coal does not necessarily show the topographic features of the surface. However, in this case, the spatial distribution of the Poolowanna coal does outline an incised valley complete with fluvial axis and associated tributary drainage (Figure 6.4.4). In the seismic data, the typical amplitude peak and trough combination can be tied to the Poolowanna coaly interval, and the amplitude trough is then picked as the intra-Poolowanna horizon showing the base of the coaly interval (figures 6.4.1 and 6.4.3). This horizon is characterised by terminations of the underlying amplitude peaks

and troughs of the Nappamerri Group. The base of the Hutton Sandstone is picked as an amplitude trough which truncates the amplitude peak of the Poolowanna coal interval and merges with the intra-Poolowanna horizon (figures 6.2.5 and 6.4.3).

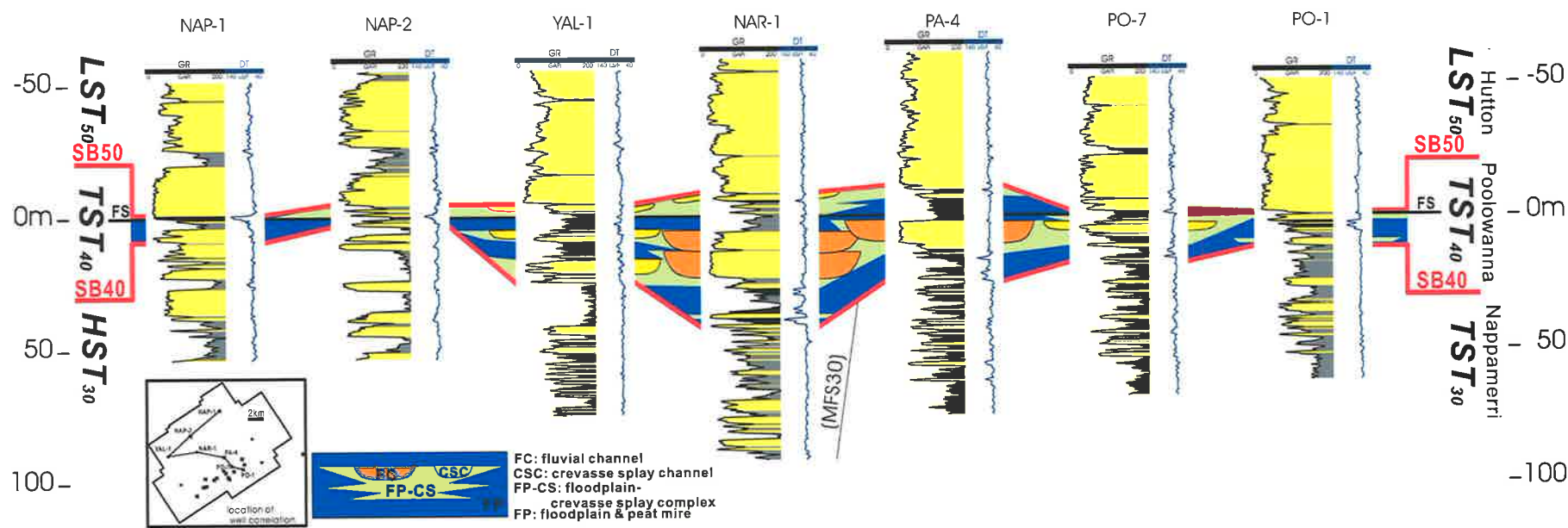


Figure 6.4.2. Sequence stratigraphic correlation of the Poolowanna Formation across the Pondrinie structural high, showing the facies distribution and incised valley interpretation with TST fill.

6.4.3 3D seismic data visualisation and prospect extraction

Prospect Tpc: Isolated fluvial channels in transgressive systems tract filling incised valley

Visualisation

The high amplitude distribution (red in Figure 6.4.4) of the intra-Poolowanna horizon is interpreted as a proxy for the distribution of the coaly interval in the Poolowanna Formation. The distribution of the coaly interval is characterised as mainly a NE-SW elongated pattern with wedge-shaped tributary patterns on both sides filling the topographic low area of the intra-Poolowanna horizon. Away from the main elongated area, the widths of the tributaries tend to narrow and the amplitude becomes weak (yellow, green and blue in Figure 6.4.4). The well log motif and the amplitude distribution show that the relatively thick Poolowanna interval coincides with a high amplitude area. The spatial thickness variation of the Poolowanna Formation according to the well log motifs and the amplitude distribution suggest the existence of the incised valley over the Pondrinie area. The tributary amplitude pattern suggests small valleys being etched into the margins of the main incised valley (Blum, 1993; Schumm, 1992; Wescott, 1993; Posamentier & Allen, 1999). Following the relative base level fall which made this incision, the transgressive systems tract comprising fluvial deposits of the Poolowanna Formation back-filled the incised valley with sandstone, shale and coal. The fluvial channel sands were concentrated and preserved in the valley centre. The erosion by the Hutton Sandstone is the other factor which determines the thickness of the Poolowanna Formation. However, the undulation of the erosion surface is broad, as seen in the well correlation and the seismic data (figures 6.4.2 and 6.4.3), hence the Poolowanna incised valley outline is probably illustrated by the amplitude distribution of the Poolowanna coaly interval.

Possible stratigraphic trap

The transgressive fluvial channel sandstones in the incised valley could be a stratigraphic trap prospect in the Poolowanna Formation. However, none of the wells (Nardu-1, Packsaddle-4, Pondrinie-3, 4) which intersected the fluvial channel sand of the Poolowanna Formation in this area have discovered economic hydrocarbon accumulations. A possible reason for failure of this potential Poolowanna Formation trap could be hydrocarbon leakage through the

contact between the Poolowanna sandstone and the Hutton Sandstone caused by the Hutton erosion. A potentially prospective area is the northeastern part of the survey area where the thick Poolowanna interval has not yet been drilled (Prospect Tpc, Figure 6.4.4). However, the Hutton erosion in the updip side of this area remains a key hydrocarbon leakage risk.

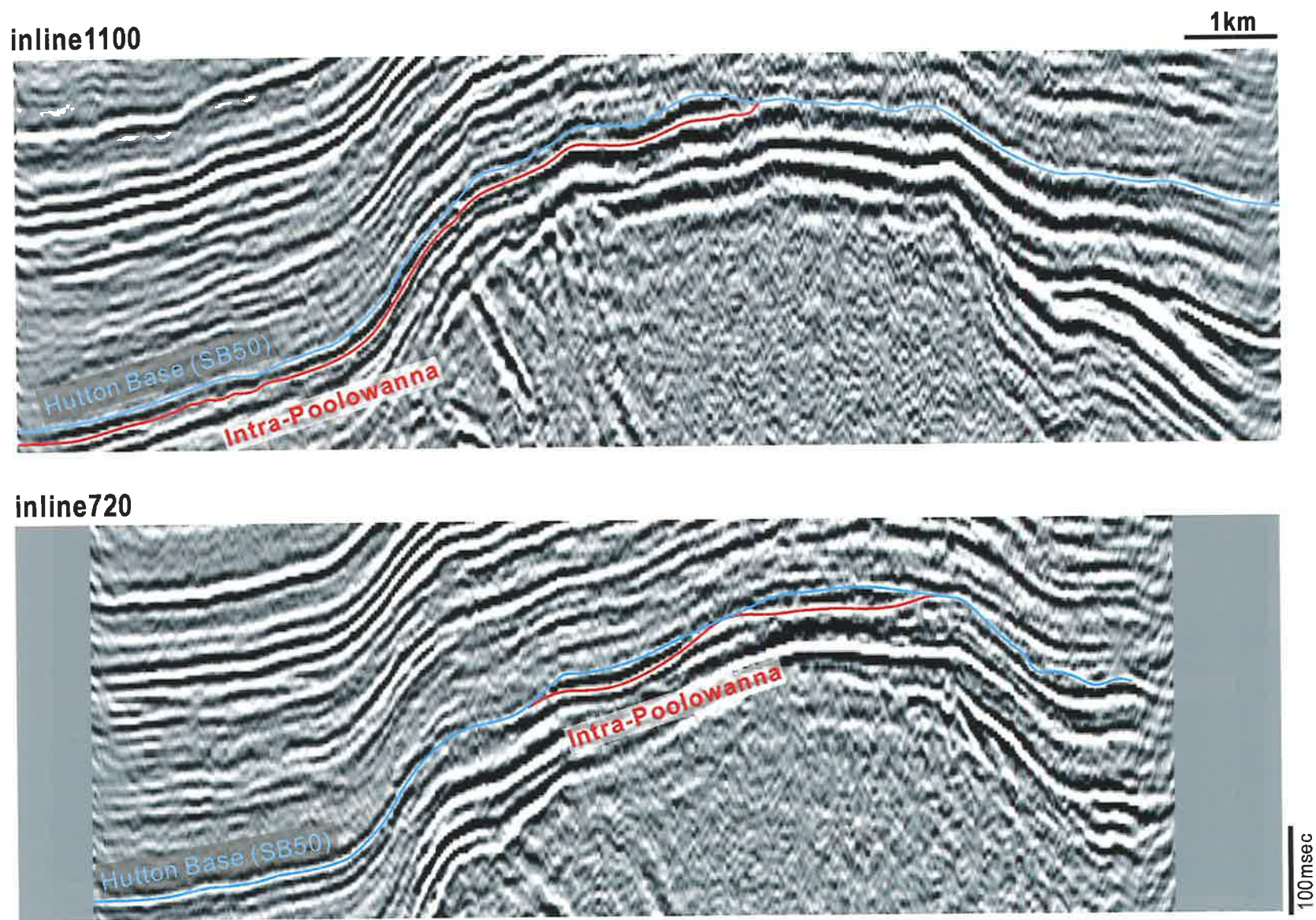


Figure 6.4.3. Amplitude variation corresponding to the coaly interval between the intra-Poolowanna horizon and the base of the Hutton Sandstone (see the seismic locations in Figure 6.4.4).

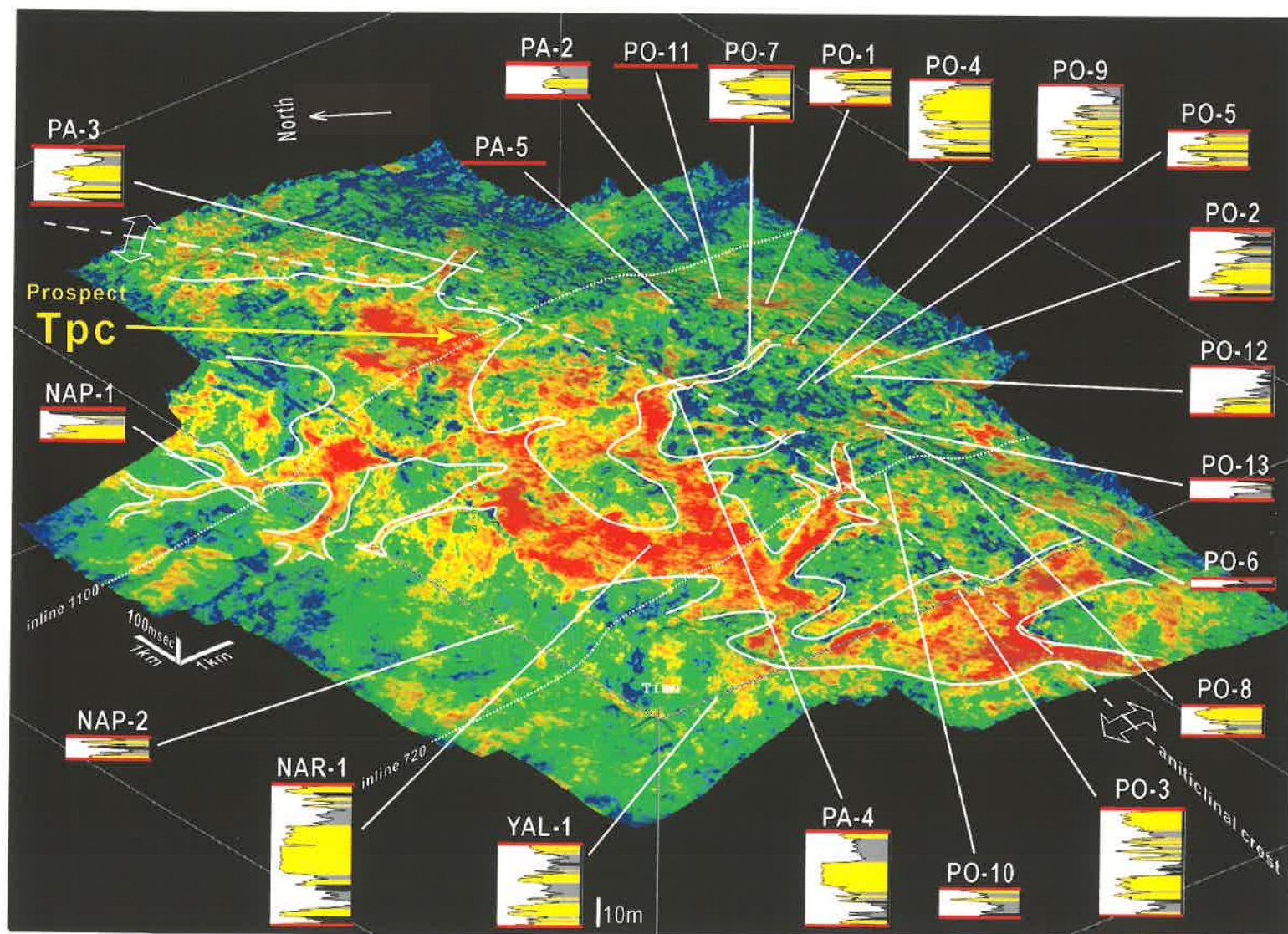


Figure 6.4.4. Amplitude pattern of the intra-Poolowanna horizon (red: high, blue: low) showing the distribution of the coaly interval of the Poolowanna Formation. High amplitude shows relatively thick coaly interval. The elongated distribution of high amplitude with wedge-shaped tributary patterns on both sides is filling the topographic low area (outlined by white lines) of the intra-Poolowanna horizon suggesting that the coaly interval filled the incised valley at the base of the Poolowanna Formation. The well log motif shows fluvial channel sandstones in the TST interval tended to be deposited and preserved in the centre of the incised valley. A potentially prospective area is the northeastern part of the survey where the thick Poolowanna interval has not yet been drilled (Prospect Tpc). However, the Hutton erosion in the updip side of this area remains a hydrocarbon leakage risk.

Chapter 7

Case Study 3: Merrimelia 3D Seismic Survey Area

7.1 Introduction

The difficulty of producing hydrocarbons from the Birkhead Formation is generally caused by the reservoir discontinuity due to the nature of fluvial succession. In this case study, the Birkhead interval, in which oil accumulates in the Merrimelia Field area is selected to visualise the complex spatial arrangement of the reservoir and seal rocks in the fluvial system (Figure 7.2.2). A new effective stratigraphic trap prospect has not been extracted and there is no contribution from this case study to construct a portfolio of stratigraphic trap explorations in the final stage of this research. However, the result is considered to be important for the future exploration and development of stratigraphic trap play of the Birkhead Formation in the Eromanga Basin.

7.2 Fields in the Merrimelia 3D seismic survey area

7.2.1 Merrimelia/ Meranji/ Pelican fields

The Merrimelia 3D seismic survey area is located in northeastern South Australia in the

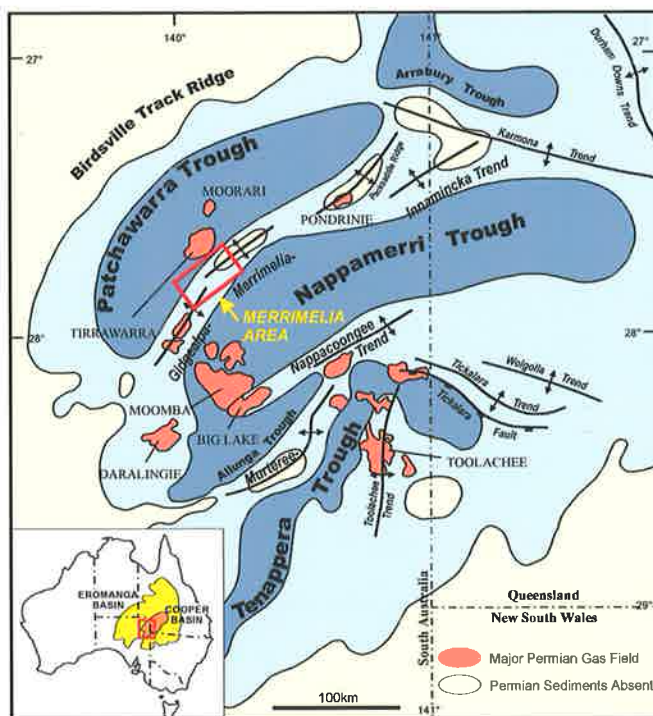


Figure 7.2.1. Major structural elements of the southern Cooper Basin (modified after Thornton, 1979; Apak et al., 1997) and the location of the case study area.

middle part of the Gidgealpa-Merrimelia-Innaminka structural high trend (GMI trend) of the southern Cooper Basin (Figure 7.2.1). The seismic survey covers the locations of the Merrimelia, Meranji and Pelican fields.

The Merrimelia Field is an anticline with a four-way dip closure, bounded to the northwest at Early Permian level by a NE striking, southward dipping reverse fault produced by inversion tectonics (Apak et al., 1997; figures 7.2.4 & 7.2.5). At the Jurassic to Cretaceous level, conjugate normal faults trending NE-SW are located near the Merrimelia structural crest (figures 7.2.3, 7.2.4 & 7.2.5). The first four Merrimelia wells were sited on early seismic, gravity and magnetic mapping. The discovery of commercial gas in the Toolachee Formation at Merrimelia 5 in 1970 followed the results of the 1970 Merrimelia seismic survey (Smith, 1983). Thirty-seven exploration and development wells had been penetrated by 1997 and discovered oil accumulations in the Nappamerri Group, Poolowanna Formation, Hutton Sandstone, Birkhead Formation and Namur Sandstone, and gas accumulations in the Tirrawarra Sandstone, Toolachee Formation and Nappamerri Group.

The Meranji and Pelican fields are located in the saddle between the Gidgealpa and Merrimelia structural highs (figures 7.2.1 & 7.2.3). These fields are two of a number of anticlinal structures which are bounded to the west by the reverse fault extending from the Merrimelia high. In the Meranji Field, seventeen wells had been penetrated by 1998 and discovered gas accumulation in the Tirrawarra Sandstone, Patchawarra Formation, Epsilon Formation and Toolachee Formation, and oil accumulation in the Namur Sandstone. In the Pelican Field, six wells had been drilled by 1991 and discovered gas accumulation in the Tirrawarra Sandstone, Patchawarra Formation and Toolachee Formation. Around the Merrimelia, Meranji and Pelican fields, some gas discoveries exist in the Permian successions in the fault block in the flank area of the structural high trend (Narie-1, Massy-1, Ficus-1, Bindah-1).

The play type of the discoveries in the Merrimelia, Meranji and Pelican field area are categorised by two types; pre- and post-Daralingie uplift plays. In the structurally high area, the Early Permian succession misses being bounded by the fault and eroded by the base of the Toolachee Formation. The gas accumulations in the Early Permian succession occur in the

fault traps and pinch-out traps due to the erosion. In the Late Permian, Triassic to Jurassic successions, the oil and gas accumulations occur in domed four way dip closures. However, the Toolachee Formation and the Birkhead Formation have a combination with a stratigraphic trap due to the lateral thinning of sandstones in the formations.

AGE		STRATIGRAPHY		PALYNOLOGICAL ZONE	BASIN	Sequence boundaries in this study	Objective interval in case study 3
CRETACEOUS	LATE	MARREE SUBGROUP	Winton Fm	PK7	EROMANGA BASIN		
	EARLY		Mackunda Fm	PK6			
			Oodnadatta Fm	PK5.2			
			Aliana Mudstone	PK5.1			
			Toolebuc Fm	PK4			
			Coorikiana Sandstone	PK3.2			
			Wallumbilla Fm	PK3.1			
			Bulldog Shale	PK2.2			
			Wyandra Sandstone Member	PK2.1			
	Cadna-owie Fm		PK1.2				
Murta Fm	PK1.1						
JURASSIC	LATE	NAPPAMERRI GROUP	Namur Sandstone	PJ6.2	EROMANGA BASIN		
	MIDDLE		McKinlay Member	PJ6.1			
			Westbourne Fm	PJ5.1			
			Adori Sandstone	PJ5		SB60	
	EARLY		Algebuckina Sandstone	PJ4.2			
			Hutton Sandstone	PJ4.1			
				PJ3.3		SB50	
			Poolowanna Fm	PJ3.2			
				PJ3.1			
				PJ2.2			
		PJ2.1	SB40				
TRIASSIC	LATE	GIDGEALPA GROUP	Cuddapan Fm	PJ1	COOPER BASIN		
	MIDDLE			PT5			
				PT4			
	EARLY		Tinchoo Fm	PT3			
						PT2	
						PT1	
PERMIAN	LATE	GIDGEALPA GROUP	Callamurra Member	PP6	COOPER BASIN		
	EARLY		Toolachee Fm	PP5		SB30	
				PP4.3			
				PP4.2			
			Daralinga Fm	PP4.1			
			Roseneath Shale	PP3.3			
			Epilina Fm	PP3.2			
			Murtree Shale	PP3.1			
				PP2.2.3		SB20	
			PP2.2.2				
		PP2.2.1					
	Patchawarra Fm	PP2.1					
	Tirrawarra Fm	PP1.2.2	SB10				
	Merrimella Fm	PP1.2.1					
CARBON-IFEROUS	LATE			PP1.1			

Figure 7.2.2. Generalised stratigraphic column of the Cooper-Eromanga Basin in northeast South Australia (modified after Moussavi-Harami, 1996; Alexander, 1998) and objective intervals in this case study.

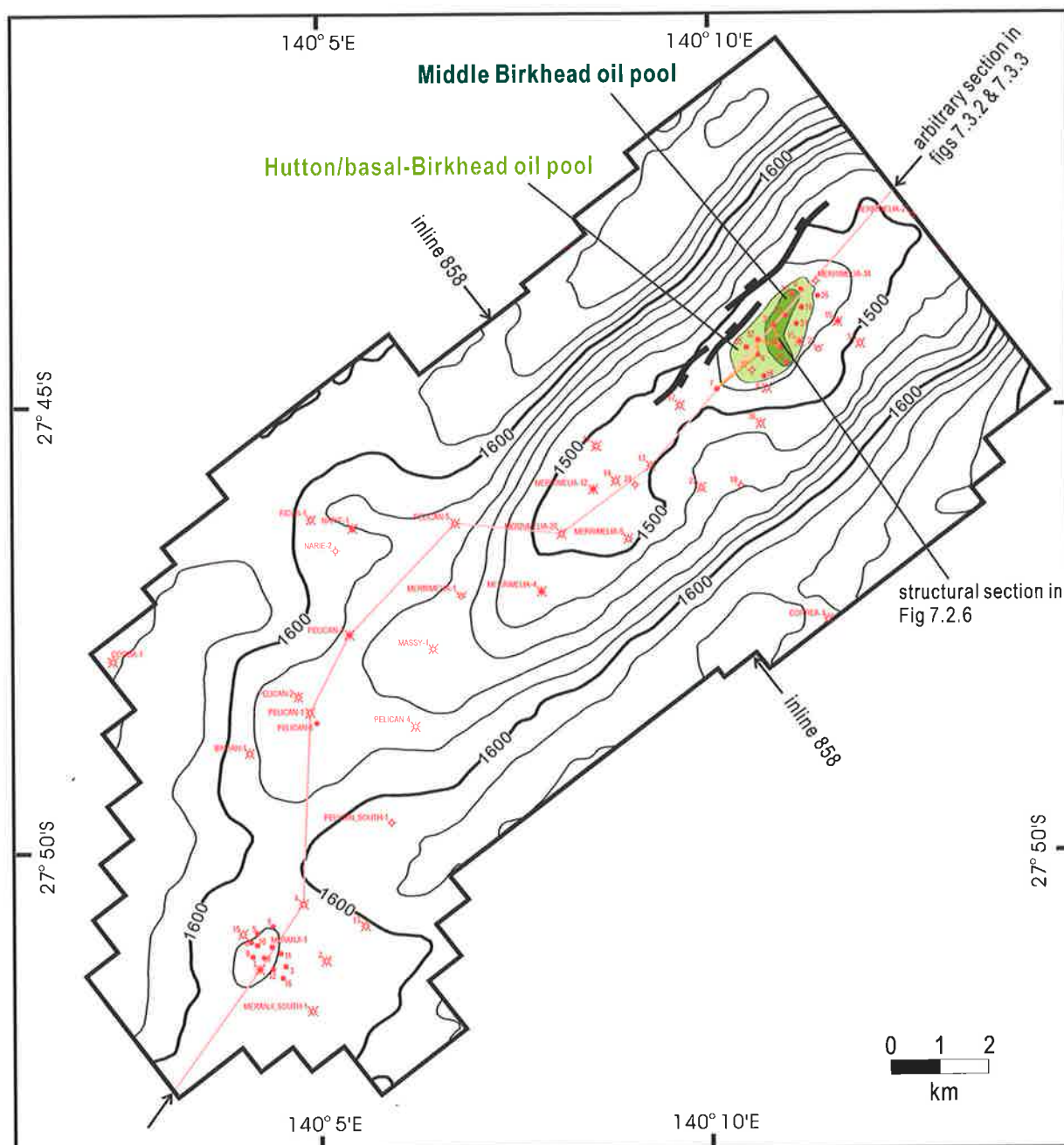


Figure 7.2.3. Two-way-time structure map of the top-Birkhead horizon in the Merrimelia and Meranji fields area. Conjugate normal faults trending NE-SW are located on the northeastern flank of the Merrimelia structural crest. (also see figures 7.2.4 and 7.2.5).

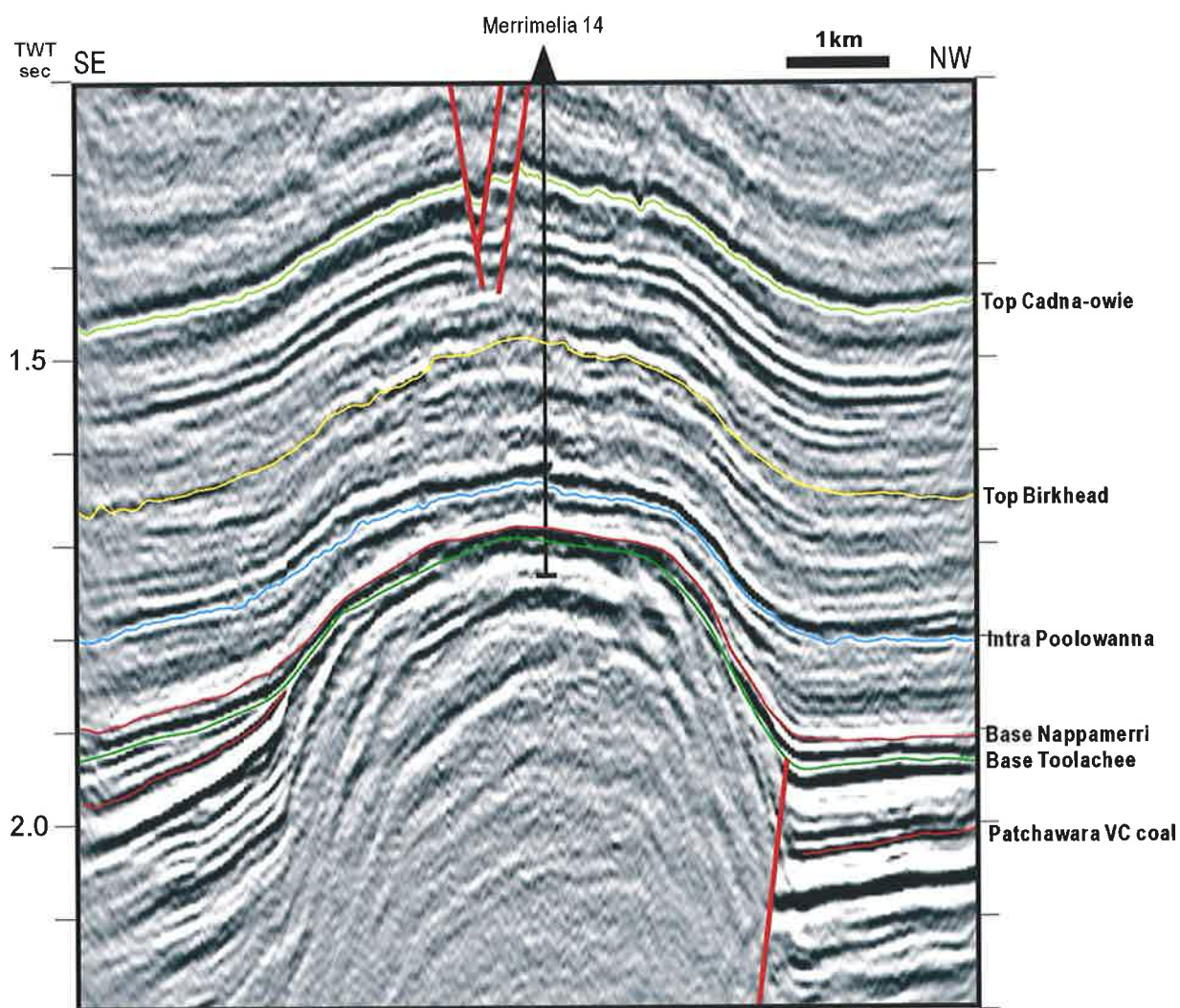


Figure 7.2.4. Seismic section across Merrimelia Field (inline 858, see the location in Fig. 7.2.3)



7.2.2 The Birkhead and Hutton oil reservoirs in the Merrimelia Field

The oil accumulations exist in the Hutton Sandstone and the Birkhead Formation in the Merrimelia Field. The distribution of the accumulation is restricted in the top of the Merrimelia high (Figure 7.2.3). The oil pools are distinguished into two intervals, the Hutton/basal-Birkhead reservoir and the middle Birkhead reservoir (Figure 7.2.6).

Although the distribution of the basal-Birkhead reservoir is scattered, the reservoir comes in contact with the massive Hutton Sandstone reservoir. A common oil-water contact also suggests that basal-Birkhead and the Hutton Sandstone act as one reservoir. Consequently, the distribution of the oil accumulation in the Hutton/basal-Birkhead is basically controlled by the topographic feature of the Merrimelia structural high.

The middle Birkhead reservoir shows significant lateral facies change from sandstone to shale with thin coal beds. Sandstones in the interval in the same depth level do not always have oil accumulations (for example middle Birkhead reservoir equivalent in Merrimelia-6 well, Figure 7.2.6). This suggests that the reservoir sandstone is laterally isolated within the middle Birkhead interval. The free water level of this reservoir has not been confirmed; however, water bearing sandstones above and below the middle Birkhead interval indicate that this interval is also statically disconnected with the lower and upper Birkhead intervals which are divided by correlative shaly intervals recognised as flooding surfaces (this will be discussed later). Consequently, the oil accumulation in the middle Birkhead reservoir is recognised as a stratigraphic trap which is produced as a reservoir rock thinning out within the top, lateral and bottom seal rocks.

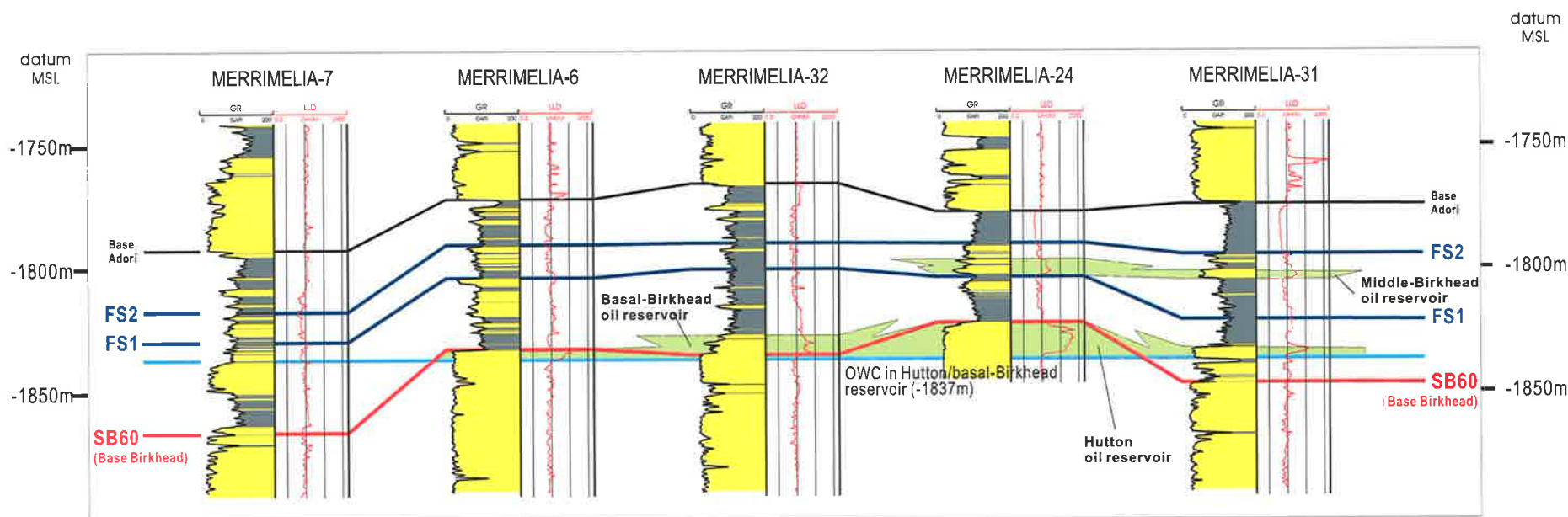


Figure 7.2.6. Structural cross section of the Hutton and Birkhead oil reservoir intervals in the Merrimelia Field area. Two oil pools, the Hutton/basal-Birkhead reservoir and the middle Birkhead reservoir, are recognised. The middle Birkhead reservoir is statically isolated from the upper and lower Birkhead intervals by correlative shaly zones recognised as flooding surfaces. SB60 was interpreted as changes from low gamma Hutton to increasing gamma volcanoclastic Birkhead Formation (see text). See the location in Fig. 7.2.3.

7.3 Distribution of the upper and middle Birkhead reservoirs

7.3.1 Sedimentary facies analysis

Four sedimentary facies are recognised in the Birkhead Formation with a similar facies definition as in the previous case studies (figures 7.4.1 and 7.4.2; see the facies definitions in section 5.3.1). The facies include fluvial channel (stacked and amalgamated sandstone with a sharp base), crevasse splay channel (interbedded sandstones with sharp bases and shale), floodplain-crevasse splay complex (interbeds of fine-grained sandstones and shales) and floodplain.

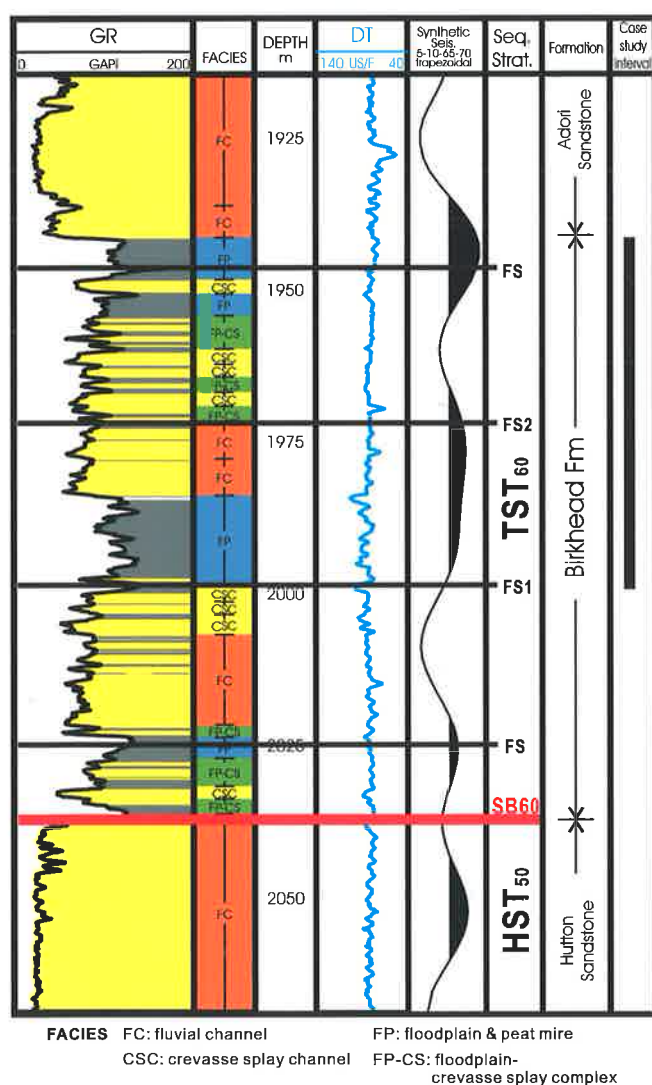


Figure 7.3.1. Sedimentological and sequence stratigraphic interpretation based on well data, Pelican-5, showing systems tracts. The uppermost Hutton Sandstone can be interpreted as HST whereas the basal succession is valley filling and interpreted as an amalgamated sheetlike LST.

7.3.2 Sequence stratigraphy

The Birkhead Formation comprises fluvial deposits consisting of sandstones and shales with minor coal layers (figures 7.3.1 and 7.3.2). The formation lies on the massive stacked fluvial channel sandstone of the Hutton Sandstone. The boundary of the Birkhead Formation and the Hutton Sandstone is practically recognised as a shift of a gamma ray response from sandy to shaly. The undulation of the topographic feature suggests that the base of the Birkhead Formation is an erosional surface forming the valley incising the Hutton Sandstone (SB60; it will be discussed again later). The top of the Birkhead Formation is identified as the boundary between the shaly interval of the Birkhead Formation and the massive fluvial channel sandstone of the Adori Sandstone.

The Birkhead Formation comprises fluvial channel and floodplain deposits. The fluvial channel facies laterally changes into crevasse splay and floodplain deposits. The laterally discontinuous fluvial sediments suggest that these sediments were deposited during increasing fluvial accommodation caused by the rising of the relative base level, and are assigned to a transgressive systems tract (TST60).

Within TST60, laterally continuous shale-prone intervals are identified that lie on top of a fining upward abandoned channel succession or its correlative floodplain deposits. The extensive abandonment of the fluvial channels suggests a widespread, elevated relative base level leading to the development of the shaly interval that is identified as a flooding surface.

The well correlation, flattened on the flooding surface, demonstrates the topographic feature at TST60 sedimentation (Figure 7.3.2). The magnitude of the incision of the base of TST60 into the Hutton Sandstone was at least fifty meters in depth. The lower part of TST60, topped by FS1, filled the topographic low area of the incised valley, onlapping the wall of the valley following the relative base level rise. Continuous base level rise produced the middle and upper part of TST60 inundating the incised valley and widely covering the Merrimelia and Meranji area.

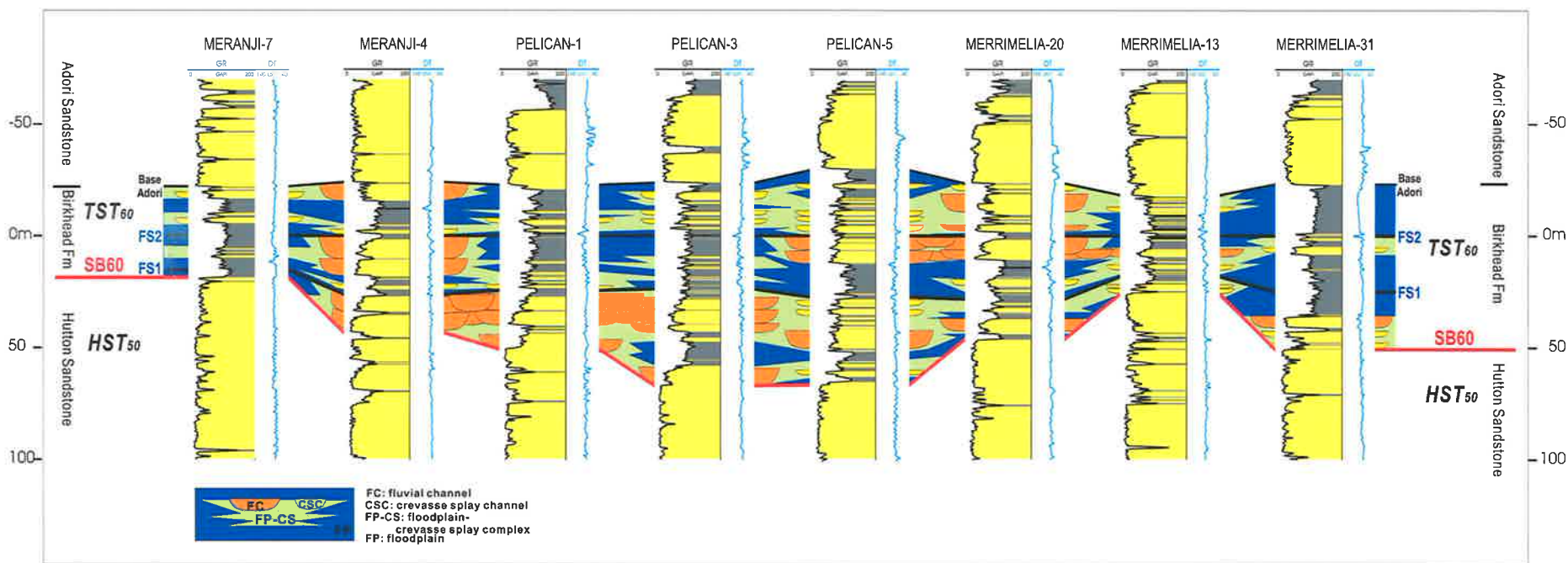


Figure 7.3.2. Sedimentary facies distribution and sequence stratigraphic correlation of the Birkhead Formation. See the location of the section in Figure 7.3.5.

Boult et al.(1998) described the sequence stratigraphic setting of this interval in the Gidgealpa Field and the Moorari Field areas and showed the incised valley system of the Birkhead Formation filled by lowstand systems tract and transgressive systems tract. In the Merrimelia area, however, the lower part of the Birkhead Formation filling the incised valley, does not show laterally continuous stacked fluvial channel sandstone, which is expected as evidence of a lowstand and stable base level stage associated with a regression and a new alluvial accommodation space within the incised valley. Hence, the lowstand systems tract is considered not to be deposited in this area except for the lag deposits just above the bottom of the incised valley. There is a possibility that the late stage of a lowstand systems tract was deposited in the increasing fluvial accommodation resulting from slow relative base level rising and still regression (presumably Boult et al.(1998) interpreted their lowstand systems tract as this in the Moorari field area). However as it is practically difficult to identify a transgressive surface bounding the lowstand systems tract and the transgressive systems tract, then the whole Birkhead Formation was interpreted as the transgressive systems tract in the Merrimelia area. In the flattened correlation on the flooding surface, the base of the Adori Sandstone lying on the Birkhead Formation is almost flat and shows no significant incision.

The top of the TST60 can be tied approximately into the amplitude peak (figures 7.3.1 and 7.3.3), although the amplitudes laterally vary. The rock property of the Adori Sandstone is almost homogeneous (except the local cemented portion in the crest of the Merrimelia high area; this will be discussed later), and then the amplitude variation around the top Birkhead horizon is corresponding to the facies variation of the middle and upper part of the TST60 (FS1 to the top of the Birkhead Formation).

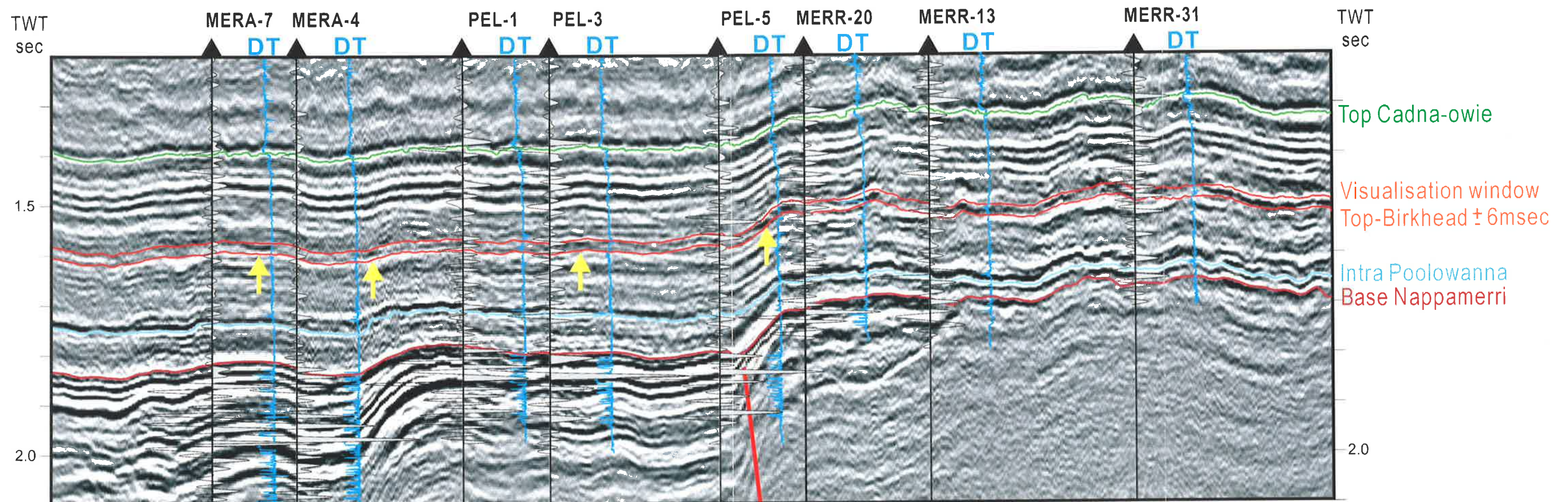


Figure 7.3.3. Interpreted key surfaces on an arbitrary seismic section with sonic logs and synthetic seismogram of key wells. The wavelet is zero phase with a 5-10-65-70 Hz trapezoidal bandpass. See the location of the section in Fig. 7.3.5. The visualisation window was set for the middle and upper Birkhead interval as 6msec above and below the top-Birkhead horizon. Scattered positive high amplitudes (yellow arrows) are observed on the top-Birkhead horizon, which are represented as meandering patterns in the seismic volume visualisation in the transgressive systems tract (TST60, see Fig. 7.3.5).

7.3.3 3D seismic data visualisation

Scattered positive high amplitudes appear on the top-Birkhead horizon in seismic sections (yellow arrows in Figure 7.3.3). The seismic volume visualisation sets a window of 6msec above and below the top-Birkhead horizon (the thickness of the window is consequently 12msec) to show the positive amplitude variation and demonstrates the meandering patterns of the amplitude (figures 7.3.4 and 7.3.5). The seismic amplitude variation of this seismic volume corresponds approximately to the middle to upper Birkhead interval (from FS1 to the top of the Birkhead Formation).

Although in the crestal area of the Merrimelia high, there is also an extensive high amplitude distribution, the carbonate cemented portion of the Adori Formation (which appears as high resistively and high velocity in well logs-red-squares in Figure 7.3.5) affects the seismic amplitude and it is not representative of the facies variation of the Birkhead interval (Smith, 1983).

In the Meranji Field area (western side of the 3D seismic survey area), the meandering pattern of the positive amplitude divides the sedimentary facies of the upper Birkhead interval (FS2 to Base of the Adori Sandstone) interpreted in well log motifs. The fluvial channel facies exists inside of the meandering pattern and crevasse splay and floodplain facies dominant outside of the meandering pattern. Meranji-15 well intersected the narrow high amplitude meandering pattern and represents the shaly and coaly interval of floodplain deposits. The meandering patterns are interpreted as an abandoned channel plugged by fine sediments as the final stage of the lateral migration of the meandering fluvial channel. The inside of the meandering pattern suggests the lateral accretion of point bars (point bar M in Figure 7.3.5), which are represented as fluvial channel facies in well log motifs in the upper Birkhead interval.

In the middle of the survey area (near Pelican-5), the distribution of positive amplitude shows a meandering channel pattern that corresponds to the fluvial facies variation within the middle Birkhead interval (FS1 to FS2), although the blurring of the seismic data is due to the effect of the cemented portion of the overlying Adori Formation. The fluvial channel sand facies is located inside the point bar loop (point bar P in Figure 7.3.5). Along the northern edge of the

survey areas, the edge of a channel belt is inferred, where floodplain sediments were deposited (Narie-1, 2 and Ficus-1).

The southern margin of the distribution of the fluvial channel facies in the middle and upper Birkhead intervals suggests the possible edge of the fluvial channel belt, which elongates southwest to northeast. The northern margin of the channel belt was merged with the limitation of the abandoned channel pattern, which is extending southwest to northeast along with the southern margin.

As a consequence of the integration of the sequence stratigraphy and 3D seismic visualisation, a Birkhead fluvial channel belt system can be demonstrated. After infilling the incised valley, the Birkhead fluvial system inundated the Merrimelia and Meranji fields area. Within the channel belt, meandering channels made a complex of laterally accreting point bars and crevasse splay deposits. The meandering channel was finally abandoned and plugged by fine sediments. Outside of the channel belt, occasionally flooding occurred and resulted in the crevasse splay channel and crevasse splay delta complex comprising thin alternations of sandstone, shale and minor coal. The fluvial system was aggraded corresponding to the relative base level rising with several experiences of extensive avulsion (FS 1, 2), and caused the laterally discontinuous fluvial channel and floodplain complex.

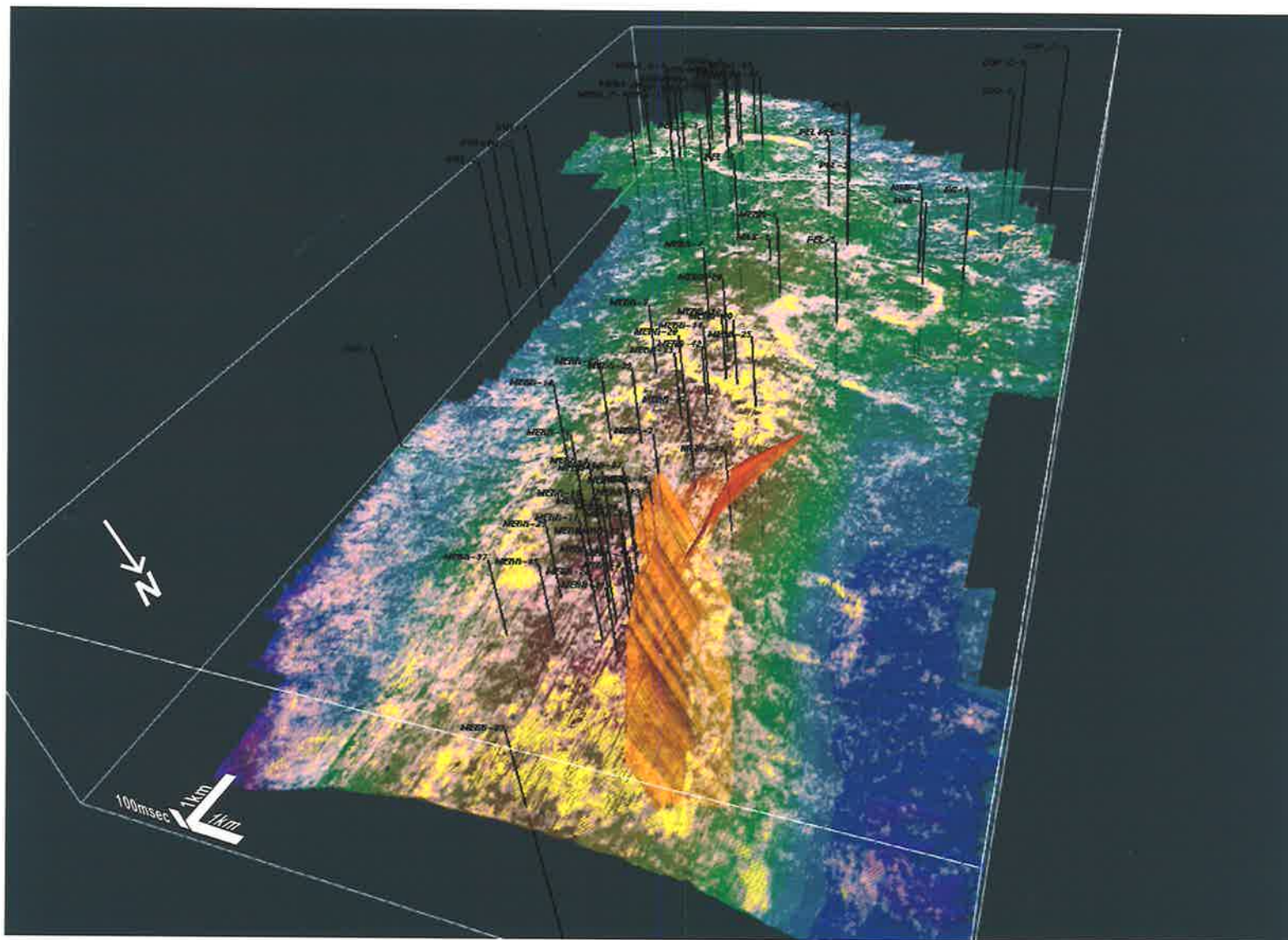


Figure 7.3.4. Seismic amplitude variation within the seismic volume extracted from 6msec above and below the top-Birkhead horizon. Cloudy patterns coloured in pink to yellow show the positive amplitude distribution. The horizon is contoured in TWT to represent the structural trend. The amplitude distribution shows a meandering pattern in the middle and upper Birkhead interval. Around the top of the structure, the very high amplitude is affected by the cemented portion of the Adori Sandstone which does not show internal features of the Birkhead Formation.

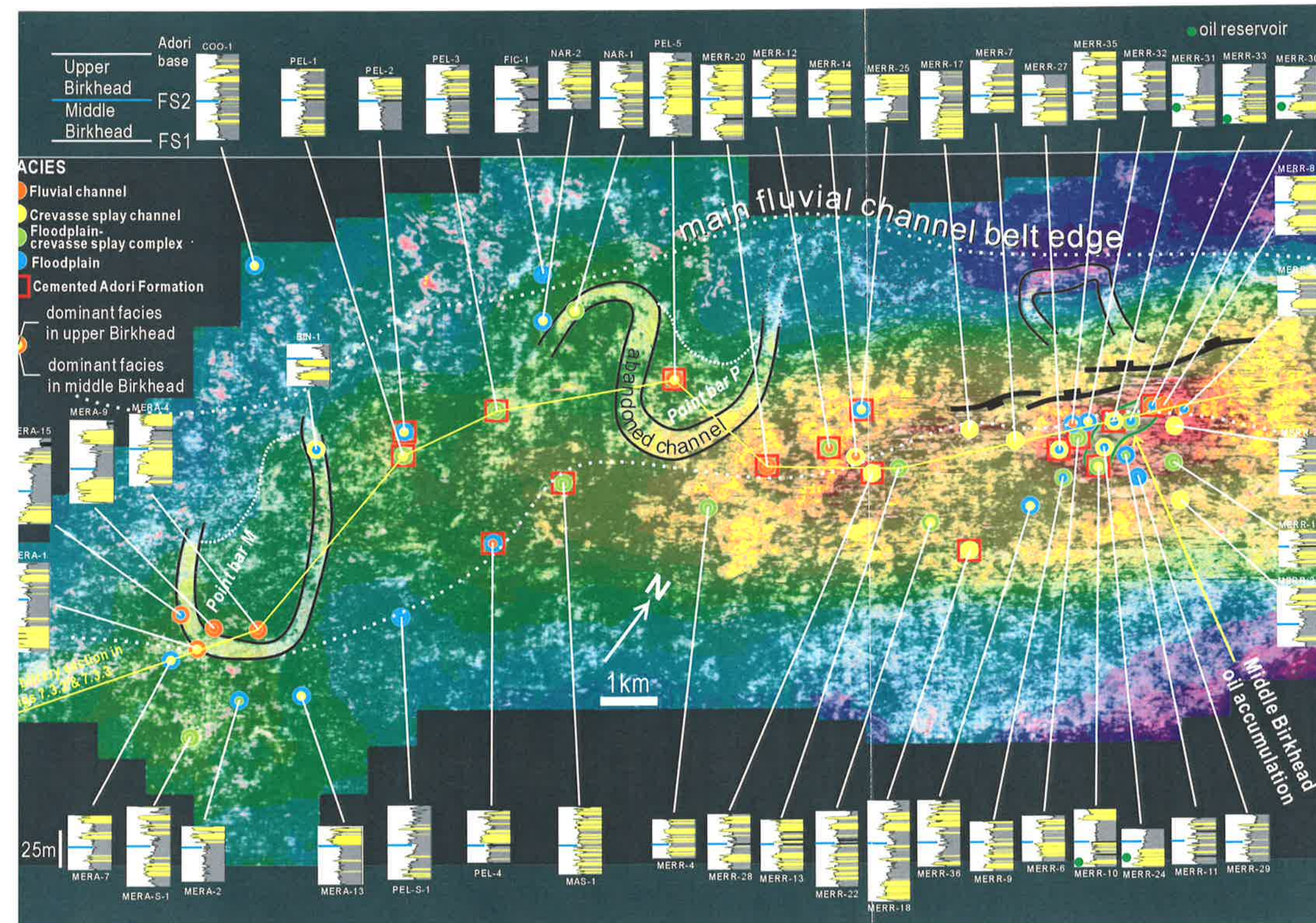


Figure 7.3.5. Sedimentary facies in well log motifs in the middle and upper Birkhead Formation (FS1 to the top of the Birkhead Formation) and seismic amplitude variation within the seismic volume extracted from 6msec above and below the top-Birkhead horizon. Cloudy patterns show the positive amplitude distribution. The amplitude distribution shows a meandering pattern in the middle and upper Birkhead interval. Around the crest of the structure, the very high amplitude is affected by the carbonate cemented portion of the Adori Sandstone which does not show internal features of the Birkhead Formation. In the Meranji Field area (western side of the 3D seismic survey area), the meandering pattern of the positive amplitude divides the sedimentary facies of the upper Birkhead interval (FS2 to Base of the Adori Sandstone) interpreted in well log motifs. The fluvial channel facies exists inside of the meandering pattern and crevasse splay and floodplain facies dominant outside of the meandering pattern. Meranji-15 well intersected the narrow high amplitude meandering pattern and represents the shaly and coaly interval of floodplain deposits. The meandering patterns are interpreted as an abandoned channel plugged by fine sediments as the final stage of the lateral migration of the meandering fluvial channel. The inside of the meandering pattern suggests the lateral accretion of point bars (point bar M), which are represented as fluvial channel facies in well log motifs in the upper Birkhead interval. In the middle of the survey area (near Pelican-5), the distribution of positive amplitude shows a meandering channel pattern that corresponds to the fluvial facies variation within the middle Birkhead interval (FS1 to FS2), although the blurring of the seismic data is due to the effect of the cemented portion of the overlying Adori Formation. The fluvial channel sand facies is located inside the point bar loop (point bar P). Along the northern edge of the survey areas, the edge of a channel belt is inferred, where floodplain sediments were deposited (Narie-1, 2 and Ficus-1). The southern margin of the distribution of the fluvial channel facies in the middle and upper Birkhead intervals suggests the possible edge of the fluvial channel belt, which elongates southwest to northeast. The northern margin of the channel belt was merged with the limitation of the abandoned channel pattern, which is extending southwest to northeast along with the southern margin.

7.3.4 Reservoir and seal rock distribution

The meandering pattern of the positive amplitude suggests the distribution of the possible reservoir rocks of point bar sandstones. The sandstones are enveloped by floodplain shale on the top and bottom, and laterally by the shale plugging the abandoned channel. The location where the edge of the point bar up-dips towards the abandoned channel can be an efficient stratigraphic trap. The main targets of these point bar sandstones, however, have been penetrated and confirmed their non-hydrocarbon accumulation (Pelican 5, Meranji 4 and 9).

The oil accumulation in the Birkhead Formation in the Merrimelia Field area is controlled by the distribution of reservoir and the structural contour. The oil-bearing reservoirs are almost less than 5m thick, because all these reservoirs are located out of the fluvial channel belt and consist of crevasse splay channel and crevasse splay delta facies. The restricted accumulation on the top of the structural high perhaps indicates a breach of the seal rocks and juxtaposing reservoir rocks due to the tectonic movement associated with the conjugate faults which cut the Birkhead Formation. In fact the interpreted point bar sandstone of the middle Birkhead interval represented by the meandering positive pattern in the northern flank of the Merrimelia high, is considered as to be juxtaposed with the oil bearing Hutton/basal-Birkhead reservoir along the conjugate faults. The other possibility of the restricted oil accumulation is that the oil migrated only from the Nappamerri Trough side (southern side of the Merrimelia high); hence the possible stratigraphic trap of the point bar sand and abandoned channel shale combination has not been located on the oil migration path.

7.3.5 Capacity of the point bar sandstone reservoir

To demonstrate the impact of a reservoir potential of the middle Birkhead interval, the capacity for oil reserves of the point bar sandstone is calculated. The point bar sandstones have been penetrated by wells and confirmed water-wet, therefore the reserve size calculations are not real. However, it can be useful to gain a sense of the magnitude of the possible capacity of the point bar sandstone as oil reservoirs for the future exploration in this interval.

Two point bars (point bar M and P) represented as a result of integration of sequence stratigraphy and seismic data visualisation were selected to calculate the oil reserve capacity.

The reserve size is calculated such as:

(structurally and stratigraphically closed point bar area) x (net sandstone thickness of the fluvial channel facies) x (average porosity) x (1 - average water saturation) x (formation volume factor).

This reserve size indicates the possible in-place reserve size of oil in the point bar sandstone. The closed point bar areas were measured as a place closed by the outline of the meandering amplitude pattern and time contour of the top-Birkhead horizon (Figure 7.3.5). Confirmed net sandstone thickness of the fluvial channel facies in well data was applied (for point bar M, the average of net sandstone thickness in the upper Birkhead interval in Meranji-4 and 9, for point bar P, the net sandstone thickness in the middle Birkhead interval in Pelican-5, were used). Porosity was derived from sonic data (80μsec/ft) in the fluvial channel facies interval. The equation and constants for log-derived porosity for fluvial point bar sandstone (Gravestock and Alexander, 1986) are as follows:

$$\phi = \frac{\Delta t_{\log} - \Delta t_{mo}}{\Delta t_f - \Delta t_{mo}}$$

Where $\Delta t_{\log}$ = sonic log transit time (μ sec/ft)

Δt_{mo} = matrix material transit time (μ sec/ft) = 51

Δt_f = fluids transit time (μ sec/ft) = 189

For the average oil saturation and formation volume factor, the data from oil production achieved in the Hutton/basal-Birkhead reservoir in the Merrimelia Field was used. As a result, the possible capacity (in place) for oil accumulation were calculated as 25.6 million bbl for the point bar M and in 12.6 million bbl for the point bar P.

	Area	Net sand thickness	Porosity	Sw	FVF	Reserves (in place)
Point bar M	4.7 km2	9.5 m	21%	50%	1.152	25.6 MMbbl
Point bar P	2.0 km2	11.0 m	21%	50%	1.152	12.6 MMbbl

Table 7.3.1. Parameters to calculate possible reserves for point bar M and P.

The implication for the development of the Birkhead Formation reservoir in other areas is the compartmentalisation of reservoir rocks resulting from the complexity of fluvial channel geometry corresponding to relative base level rising in this interval. To develop the Birkhead

Formation reservoir effectively, the expectation of the distribution of the point bar sandstone by employing the integration of the sequence stratigraphic concept and 3D seismic data visualisation, can diminish the uncertainty of the reservoir distribution.

Chapter 8

Implications for Sequence Stratigraphy in the Cooper-Eromanga Basin

8.1 Introduction

In the preceding chapters, sequence stratigraphic concepts have been applied to extract a series of stratigraphic trap prospects for case study areas used in this research. In this process, facies variations of each genetic interval were identified according to the different stratigraphic locations. Such variation reflects the subtle differences of the tectonic setting, accommodation and sediment supply where the sediments were deposited. Although comparable intervals to describe spatial variations in this research are limited (i.e. the Permian and the basal Jurassic successions in the Moorari and the Pondrinie highs), the implications of the spatial variation of facies and systems tracts help us to construct sequence stratigraphic framework of practical use for exploration in the Cooper-Eromanga Basin. Before discussing the quantitative risk assessment for the extracted stratigraphic trap prospects (the main aim of this research), the sequence stratigraphic framework of the Permian to the basal Jurassic successions in the Moorari and the Pondrinie highs and sequence stratigraphic implications for the other areas of the Cooper-Eromanga Basin are discussed.

8.2 Sequence stratigraphic framework for the case study areas

Four second-order sequences (sequence 10, 20, 30 and 40) were identified in the Permian, Triassic and the basal Jurassic successions in the Moorari and the Pondrinie area (Figure 8.2.1). The sequential naming of the sequences in this research project does not imply that all the sequences in the Cooper-Eromanga Basin are represented, because it is recognised that higher resolution sequences (third or fourth order) can be identified, and also significant parts of the successions have been removed by erosion or have not been deposited in these areas. The main reason for this is because the case study areas were paleo-topographically high.

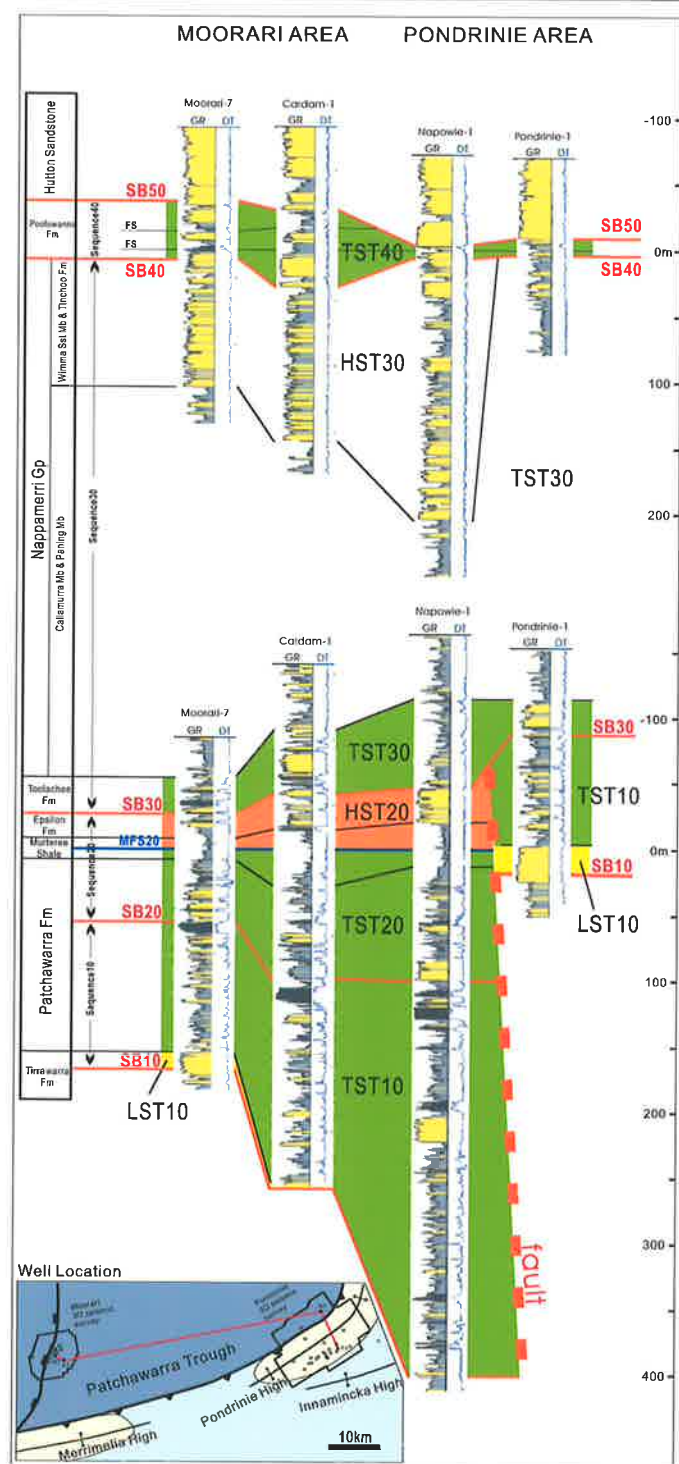


Figure 8.2.1. Sequence stratigraphic framework for the Permian and the basal Jurassic successions in the Moorari and the Pondrinie area. The dual datum is hung on MFS20 for the Permian and on a FS for the basal Jurassic respectively.

Sequence 10 comprises the top of the Tirrawarra Sandstone and the lower Patchawarra Formation, consisting of fluvial deposits. Sequence 10 is divided into a lowstand systems tract (LST10) and a transgressive systems tract (TST10). LST10 comprises stacked and amalgamated fluvial channel fill sandstones of the upper Tirrawarra Sandstone. The sandstone is laterally continuous and is interpreted as amalgamated fluvial channel deposits accumulated during a period of relatively low accommodation compared to sediment supply. TST10 consists of floodplain and crevasse splay deposits of the lower Patchawarra Formation.

Sequence 20 includes the upper Patchawarra Formation, the Murteree Shale and Epsilon Formation (Figure 8.2.1). The base of sequence 20 (SB20) is marked by the absence of palynostratigraphic unit PP2.2.2. typically above a coaly interval in the middle Patchawarra Formation (VC coal) in the structurally high area (also see Figure 4.1.2). The top of the sequence is defined by sequence boundary (SB30), which is the unconformity at the base of the Toolachee Formation (Figure 4.1.2), following the Daralingie uplift. Sequence 20 is divided into a transgressive systems tract (TST20) and a highstand systems tract (HST20), separated by a widespread maximum flooding surface (MFS20). MFS20 is characterised by the finest-grained, laterally continuous lacustrine shale interval which makes the extensive Murteree palaeo-lake. TST20 comprises fluvial deposits in the lower portion and lacustrine deposits in the upper portion. The fluvial deposits include fluvial channel, crevasse splay and floodplain facies. The fluvial deposits are overlain by lacustrine deposits, consisting of lacustrine delta sandstones and shales, which show a retrogradational stacking pattern followed by increasing fluvial accommodation topped by MFS20 (maximum lacustrine flooding). HST20 consists of a coarsening-upward succession of sandstones, shales and coals associated with the lacustrine delta progradation of the Epsilon Formation. The coal at the top of the coarsening-upward succession is interpreted as peat deposition on the emergent inter-distributary zone of the lacustrine delta plain. Over the structurally high area, the upper section of the delta was eroded by SB30; hence the relatively thick section is preserved only on the flank area of the structural high (see figures 5.3.2 and 6.3.2). The interplay of the lacustrine environments is reflected by the Roseneath Shale and Daralingie Formation in the southern Cooper Basin, but in the Moorari and Pondrinie areas these units were also eroded by SB30.

Sequence 30 in the study areas comprises fluvial sandstones, floodplain shales and laterally continuous coals of the Toolachee Formation, which overlies SB30 immediately below TST30 (Figure 8.2.1). The fluvial channel facies is relatively thick but laterally discontinuous. The lateral discontinuity of the fluvial channel deposits on the sequence boundary, suggests that this section is the transgressive systems tract overlying the sequence boundary, produced by increasing accommodation associated with rising relative base level (Lang et al., 2001), inundating the structural high. For the purposes of this thesis, the upper part of sequence 30 includes the Nappamerri Group; however it is recognised that this could be subdivided in

other sequences, but this is the subject of future work.

Sequence 40 comprises laterally discontinuous fluvial deposits of the basal Jurassic Poolowanna Formation. The base of the sequence is recognised as a sequence boundary (SB40) characterised by an incised valley that eroded the Nappamerri Group. Particularly in the upthrown block of the Pondrinie high, the Wimmera Sandstone Member of the Nappamerri Group, which is interpreted as sandy fluvial deposits associated with high and stable base level (HST30), was eroded by an incised valley (figures 4.1.2, 6.4.2 and 8.2.1). The incised valley fill comprises fluvial channel, crevasse splay and floodplain deposits with thin coal deposited during rising relative base level, and is assigned to a transgressive systems tract (TST40). In this location, a LST is not recognised, although logically it should exist down depositional dip. TST40 is overlain unconformably by the Jurassic Hutton Sandstone, a thick succession of stacked fluvial channel sandstone incised into the Poolowanna Formation.

8.3 Some implications for the sequence stratigraphy in the other areas of the Cooper-Eromanga Basin

Possible distributions of LST20 (Patchawarra Formation)

Well data in the case study areas indicate that sequence 20 includes the transgressive systems tract, consisting of laterally discontinuous fluvial deposits (TST20) and the highstand systems tract, comprising laterally continuous lacustrine delta succession (HST20), and a lowstand systems tract is missing in this interval. The distribution of the lowstand systems tract is possibly restricted to the structurally low area. This is because fluvial systems would have tended to lie in the paleo-topographic low areas during the low accommodation stage, especially as relative base level was falling leading to the SB20 unconformity. In the selected case studies, the palaeo-topographic features are still reflected by the structural highs and lows, except where younger inversion is involved (Apak et al., 1997).

In the Moorari 3D seismic data, the lower part of the sequence 20 interval is onlapping and thinning against SB20 (amplitude trough onlapping on SB20 approximately represented as the reflection of the top of the Patchawarra VC coal), and suggests the existence of LST20 in the structural low area (see figures 5.3.7, 5.3.8 and 5.3.9). LST20 represents a low accommodation interval relative to sediment supply and hence stacked fluvial sand bodies can

be expected. This lowstand systems tract is identified as prospect L20E and L20SW in the Moorari area. The missing highstand systems tract in sequence 10 may represent the sandy interval deposited on the high and during the stable base level stage as the upper part of the sequence 10 (i.e. progradational lacustrine delta succession like HST20 or stacked fluvial channel succession) was eroded and reworked by the unconformable event that made SB20. This event could result in provide sand intervals being released during low accommodation especially in the topographically low. The stacked fluvial channel sandstones in the low accommodation space are expected to be relatively thick and laterally continuous; hence LST20 is predicted to contain good reservoirs. Although the distributions are restricted in the structurally low area and they are located relatively deeply, the effective porosity can be preserved in deep locations because of the primary reservoir porosity of the fluvial channel facies (Figure 9.4.1. this will be discussed in Chapter 9).

The potential reservoirs of LST20 tend to be located in the structurally low areas and are expected to be deposited towards the basin centre of the Patchawarra Trough. The potential reservoirs should be a key to the new exploration play type in the basin centre area (e.g. basin centre gas play; Hillis et al., 2001).

Variation of accommodation rate controlled by a fault activity in TST30 (Toolachee Formation)

Three of case study areas, TST30 generally comprises laterally discontinuous fluvial deposits. However, the interval in the upthrown block of the Pondrinie high shows a relatively high continuity of fluvial channel facies (see Figure 6.3.2). For the same reason as in the case of sequence 20 described above, a lowstand systems tract can exist in the base of sequence 30; however, from the correlation of well and seismic data, the continuous fluvial channel interval is recognised as the genetic interval which was deposited at the same time as TST30 in the downthrown block; hence the laterally continuous fluvial deposits are not assigned to the lowstand systems tract, but are mapped as TST deposits.

The variation in the lateral continuity in the transgressive systems tract interval is caused by differences in the rate of increasing accommodation resulted from fault movement (described in Chapter 2, see figures 2.2.2 and 2.2.3). The movement of the fault bounding the Pondrinie

high and the Patchawarra Trough resulted in a differential rate of the increase of accommodation space over these areas. Subsidence in the downthrown block resulting in a high rate of increasing accommodation reflected in increasingly isolated fluvial deposits. In the upthrown block, a reduced rate of relative base level rise resulted in low sediment accommodation in contrast to the downthrown block, although both sides of the fault ultimately subsided.

The variation of the facies continuity in TST30 suggests that the reservoir characteristics of the transgressive systems tract vary according to the tectonic setting. In the downthrown block, discontinuous fluvial channel sandstones isolated in floodplain shales result in a stratigraphic trap (this type was identified as prospect T30 and Ttc, see Chapter 5 and 6). In the upthrown block, equivalent transgressive systems tract comprising laterally continuous fluvial channel sandstones may envelop the structural high and make relatively simple dip-closure targets (this play is an actual gas reservoir in the upthrown block in the Pondrinie Field). Therefore, even though the targets are recognised as being the same genetic interval, the strategy of the exploration and development should be applied according to the specific location relative to the tectonic setting.

Variation of paleo-topography above the base of the Poolowanna Formation (SB40)

The paleo-topography of the base of the Eromanga Basin (i.e. SB40) changes depending on the location of the basin. In the Pondrinie area, coal distribution represented in the seismic data demonstrates the existence of an infilled incised valley, which is mainly NE-SW elongated with wedge-shaped tributary valleys on both sides (see Figure 6.4.4). The well data shows significant thickness changes of the incised valley fill deposits (TST40) onlapping the wall of the paleo-valley. The incised valley extends along the trend of the fault bounding the northwest of the Pondrinie high. This location may suggest that the valley was preferably incising the weak trend along the fault surface.

In the Moorari area, the paleo-topographic feature of SB40 is broad and does not appear as an incised valley. The thickness change of TST40 interval is relatively gentle. The seismic data demonstrates the fluvial channel and floodplain complex of TST40 and the sedimentary process of the interval seems not to be restricted within a valley-like topographic feature (see

figures 5.4.4, 5.4.5 and 5.4.6).

The paleo-topography of SB40 varies according to different tectonic locations around the basin. On the basin margin, the relative base level fall resulted in significant incising of the topographic high. Incision was focussed along the weak trends in the region affected by the paleo-fault movement. In the centre of the basin, the rate of the incision was gentle and made a broad erosional surface, because of the differential uplift delineating the outline of the basin (Figure 2.2.2; Posamentier & Allen, 1999). Fault movement in the early Jurassic along a northwest trend adjacent to the Pondrinie high (actually a series of faults bounding the northwest of the GMI trend) constructed the outline of the basin margin. The uplift mainly occurred along the fault trend, and in the Moorari area was located in the relatively stable basin centre. This basin outline closely matches the map of the basal Eromanga Basin described by Wiltshire (1982).

One implication for exploration in the TST40 interval (Poolowanna Formation) is that the play type will depend on the location in the basin. Near the basin margin, TST40 would be deposited as incised valley fill, and accordingly the exploration targets should be fluvial channel sandstone restricted within the valley (recognised as Tpc prospect introduced earlier, and also oil accumulations in the Chookoo, Cooroo and Karri fields can be identified as this play type; Green et al., 1989). In the basin centre, the fluvial channel and floodplain sediments deposited in the open fluvial environment can be objectives for exploration in TST40 (recognised as T40 prospect in this research). Importantly, the seal effectiveness of the overlying Hutton Sandstone should control the distribution of the hydrocarbon accumulation in the TST40 (discussed below).

Erosional surface of the base of the Hutton Sandstone (SB50)

In the western area of the Eromanga Basin where the case study areas are located, the well log motifs show that the base of the stacked fluvial channel Hutton Sandstone lie sharply over the fluvial channel and floodplain complex interval of the Poolowanna Formation (see figures 5.4.2 and 6.4.2). The well correlations, of which the datum is hung on one of the lacustrine flooding surfaces, demonstrate that the depth of erosion of the base of the Hutton Sandstone is at least 25 meters deep. The seismic data representing the features of the incision (Figure 5.4.3C) and the truncation (Figure 6.4.3) into the Poolowanna Formation and the Nappamerri

Group interval, also support the interpretation that the base of the Hutton Sandstone is characterised as an erosional surface and recognised as a sequence boundary (SB50).

Wiltshire (1982 & 1989) suggested that in the Surat Basin and the eastern edge of the Eromanga Basin, the transition from the Evergreen Formation (the equivalent of the Poolowanna Formation) to the Hutton Sandstone is observed as gradual, from lake shoreface to distributary channel and fluvial channel sandstones, with no significant erosional event evident.

From the observations of the base of the Hutton Sandstone in the western and eastern of the Eromanga Basin, basinal tectonic tilting in this time can be suggested. The western basinal uplift is associated with widespread erosion (SB50) of the fluvial channel and floodplain in the Eromanga Basin area. In the Surat Basin, an increased sediment supply from the western erosion resulted in a conformable transition from the lake to the fluvial environment. The western shift of uplift, probably made a new accommodation in the erosional area and the massive fluvial channel sandstone of the Hutton Sandstone overlay the erosional surface (SB50) in the Eromanga Basin area. The fluvial systems extended into the Surat Basin and continuously deposited the Hutton Sandstone.

The erosional contact between the Hutton Sandstone and the underlying Poolowanna Formation provides a significant seal risk with the Poolowanna exploration play in the western Eromanga Basin. In the eastern Eromanga Basin and the Surat Basin, the seal risk may be less than in the western Eromanga Basin because of the relatively conformable contact.

Chapter 9

Quantitative Risk Assessment for Prospect Inventory

9.1 Introduction

Petroleum exploration is an investment and the aim is a profitable return. However, there are many aspects that introduce uncertainty and therefore increase the risk of losing capital. In order to control the profitable return, many oil companies are recently assessing their petroleum exploration projects with quantitative risk analysis.

One of the ways to diversify the risk capital is globally investing in many projects which have positive expected net present values. However, it is often difficult for many corporations to deal effectively with many projects in a situation where opportunity is limited (e.g. a non-accessible area for the corporation, lack of funds). The other way for diversifying the risk is an investment into as many play types of exploration opportunities as possible in the limited area including stratigraphic traps.

Recent geoscience improvements, especially sequence stratigraphy and 3D seismic data visualisation technique, have been remarkable, and has greatly contributed to diminishing geologic uncertainty in stratigraphic trap exploration. If the stratigraphic trap prospects can effectively be identified at the same stage as extracting the other conventional play types, the same effects as global investments for diversifying risk capital, should be expected.

In this chapter, play types of eight stratigraphic trap prospects extracted in the Moorari and Pondrinie area are summarised, and quantitative risk assessment is then conducted. This includes estimating the chance of geologic success and calculating probabilistic reserves distributions for each stratigraphic trap prospect, depending on the sequence stratigraphic context. Finally, a risk-reward optimisation is conducted for determining an efficient frontier and an appropriate portfolio of stratigraphic traps.

9.2 Play type of prospects

Eight stratigraphic trap prospects were identified in the Moorari and Pondrinie 3D seismic survey areas by linking the depositional systems tracts to specific seismic intervals aided by 3D visualisation. Prospects are located in the TST10, LST20, TST20, HST20 and TST30 intervals of the Permian succession and in the TST40 interval of the basal Jurassic succession (Figure 9.2.1 and 9.3.2)

9.2.1 Moorari 3D seismic survey area

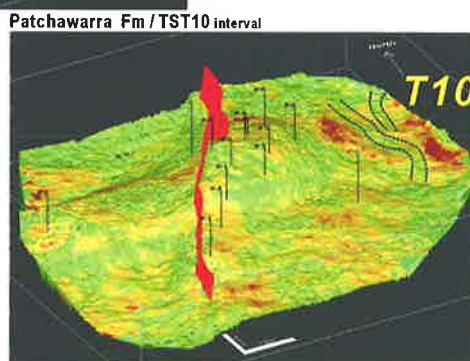
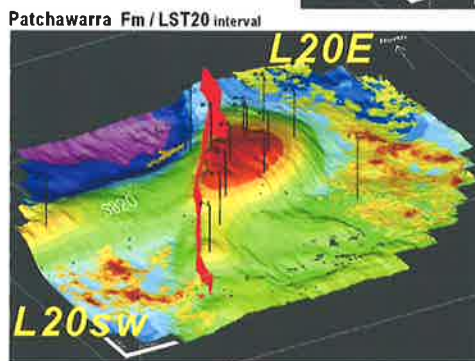
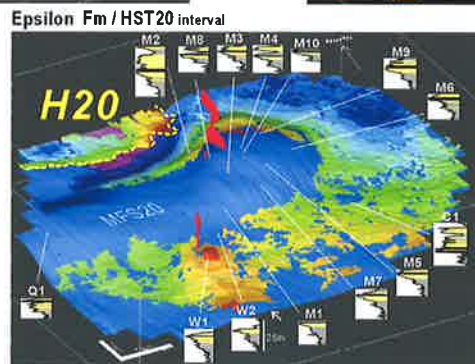
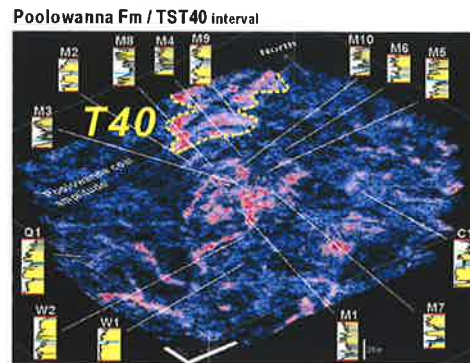
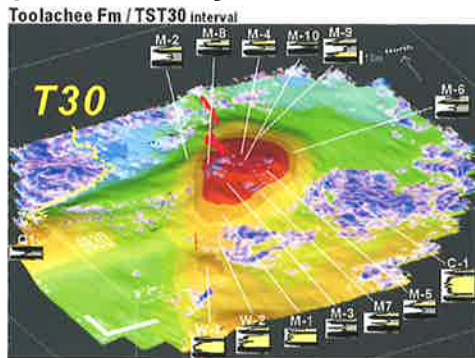
Prospect T10

Prospect T10 comprises an isolated fluvial channel sandstone reservoir and floodplain shale seal in TST10 on the eastern flank of the Moorari structural high. Figure 9.2.1b-6 shows the amplitude distribution of the amplitude trough in TST10. The low amplitude area (green), which represents thin coal distribution, is sinuously elongated north to south. The high amplitude areas (yellow to red) show thick coal, and are sitting on both sides of the elongated low-amplitude area. The amplitude pattern suggests the existence of a fluvial channel within the floodplain or under the peat mire in the transgressive systems tract. The channel could have aggraded in response to the increasing base level, resulting in an isolated sand body enveloped by floodplain shale in TST10 (prospect T10 in Figure 9.3.2).

The southern extension (structurally up-dip) of the fluvial channel is outside the 3D seismic data. Uncertainty in the geometry of the channel presents a risk of hydrocarbon leakage along the sand body extending southwards. However, a gas accumulation in a crevasse splay sandstone in the equivalent interval has been confirmed at a well beside the prospect (Cardam-1) and this suggests the possibility that a gas accumulation may exist in the channel sandstone on the flank of the Moorari high.

a) Prospect inventory

Moorari area



Pondrinie area

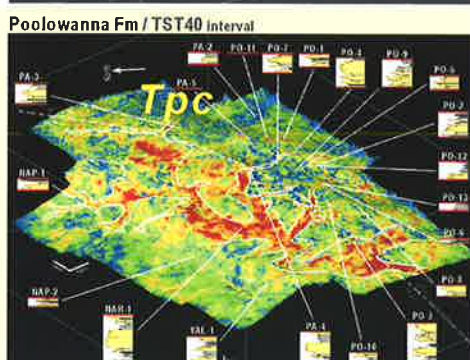
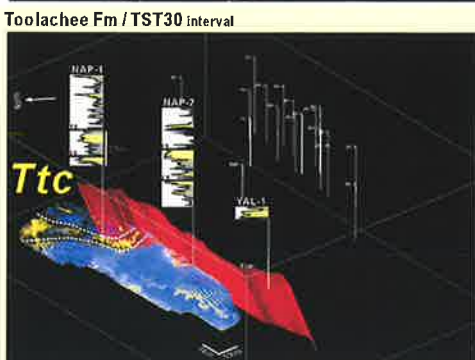
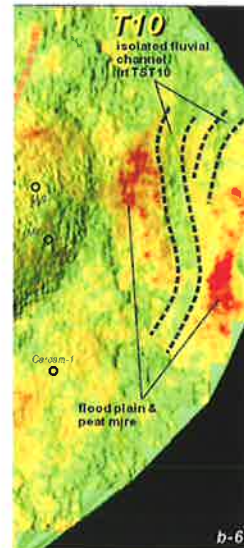
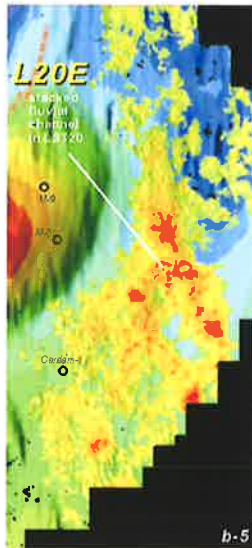
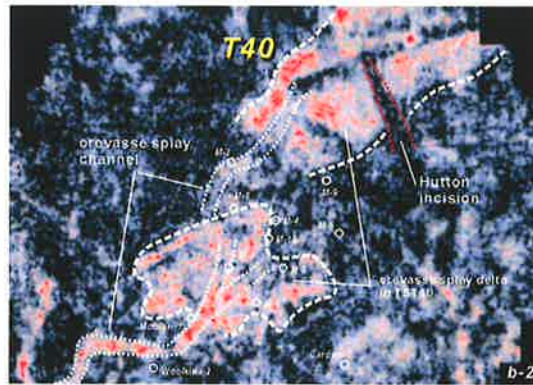
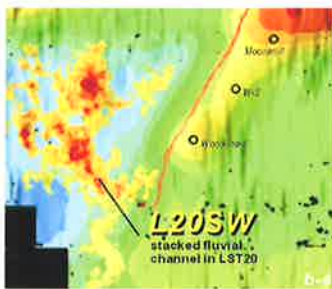
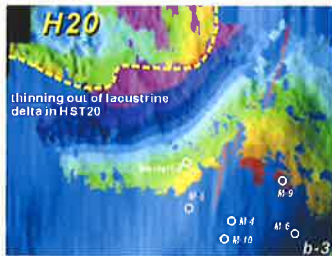
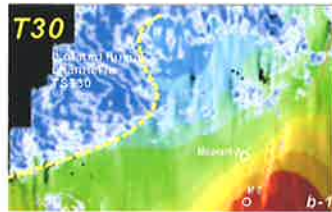
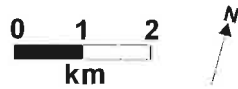


Figure 9.2.1a. Summary of prospect inventory from the Moorari and Pondrinie 3D seismic survey area. Bird's eye view images of the prospect inventory, b) plan view details of prospects for spatial comparison of sedimentary environments.

b) Plan view details for prospect inventory

Moorari area



Pondrinie area

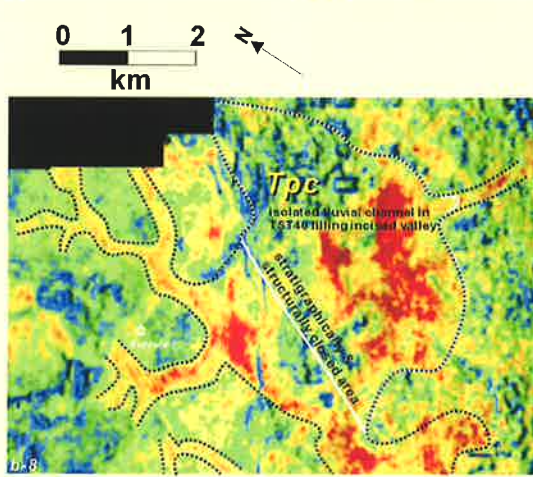
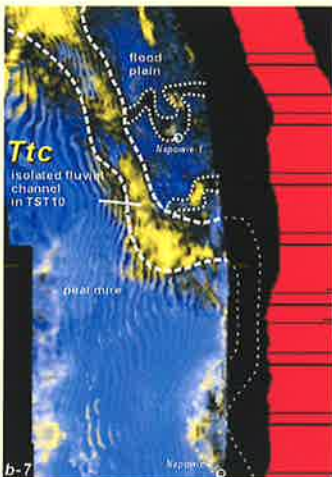


Figure 9.2.1b. Summary of prospect inventory from the Moorari and Pondrinie 3D seismic survey area. Plan view details of prospects for spatial comparison of sedimentary environments.

Prospects L20SW and L20E

Prospects L20SW and L20E comprise stacked fluvial sand reservoirs in LST20 on the southwestern and the eastern flanks of the Moorari structural high. The LST20 amplitude trough is onlapping on the high and restricted to the low areas above SB20 on the southwestern and eastern flanks of the Moorari high (figures 9.2.1b-4 and 9.2.1b-5). Although no well has penetrated the interval, LST20 is interpreted as a low accommodation interval relative to sediment supply and hence stacked fluvial sand bodies can be expected. The LST20 intervals are enveloped by the floodplain shale of the transgressive systems tracts above and below (TST10 and TST20, see prospects L20SW and L20E in Figure 9.3.2), which is expected to act as a seal.

On the southwestern flank of the Moorari high, LST20 appears to be isolated and dipping up towards the structural high (prospect L20SW, Figure 9.2.1b-4). LST20 on the eastern flank of the Moorari high (prospect L20E, Figure 9.2.1b-5) is dipping northwards. The southern extension (structurally up-dip) of LST20 is outside the 3D seismic data area, hence there is an uncertainty in the trapping geometry. However, a gas accumulation in a crevasse splay sandstone of TST20 close to SB20 has been confirmed at a well (Cardam-1) and it suggests a possible gas accumulation in the LST20 interval.

Prospect H20

Prospect H20 comprises a progradational lacustrine sandstone reservoir and lacustrine shale seals within the HST20 interval on the northwestern flank of the Moorari high. Figure 9.2.1b-3 shows the coal amplitude peak distribution associated with the Epsilon delta progradation above MFS20. The apparent thinning out of the amplitude peak on the northwestern flank of the Moorari high suggests that the Epsilon lacustrine delta and coal were eroded by SB30. The Epsilon delta sandstone eroded by SB30 on the northwest flank of the Moorari high may represent a possible stratigraphic trap (prospect H20 in Figure 9.3.2).

The top and the bottom of the delta sandstone are sealed by lacustrine shales. However, the delta sandstone may be in contact with the fluvial sandstones of the Toolachee Formation (TST30) above the SB30 and this represents a hydrocarbon leakage risk through the juxtaposition of the sandstones.

Prospect T30

Prospect T30 comprises an isolated fluvial channel sandstone reservoir and floodplain shale seals on the northwestern flank of the Moorari high. A lenticular negative amplitude is identified above SB30 (Figure 9.2.1b-1). The amplitude trough corresponds to the fluvial channel sandstones among the floodplain shales and coal in TST30 of the Toolachee Formation, which appears in wells (Cardam-1, Woolkina-1 and 2) in the southern of the Moorari high. The lenticular negative amplitude appears also on the northwestern side of the Moorari high and it suggests the existence of fluvial channel sandstones (prospect T30, Figure 9.3.2). The fluvial sandstones could be enveloped and sealed by the floodplain shales and coal of TST30. However, it is difficult to confirm the isolation of the sand body because the negative amplitude extends beyond the limits of the seismic survey.

Prospect T40

The seismic amplitude distribution and well data in TST40 suggests that a crevasse splay channel and a crevasse splay delta complex exists on the floodplain (Figure 9.2.1b-2). All wells in the study area penetrate the TST40 interval, but no hydrocarbons of economic interest have been discovered. A possible reason for this failure could be hydrocarbon leakage through the contact between the TST40 and the Hutton Sandstone.

In the northeastern area of the Moorari 3D seismic survey, the sheet-like positive amplitude corresponding to the crevasse splay delta has not been penetrated by a well. The crevasse splay delta sandstone can be enveloped by floodplain shale of the TST40 (prospect T40). However, the incision by the Hutton Sandstone on the crevasse splay delta suggests a high risk of hydrocarbon leakage.

9.2.2 Pondrinie 3D seismic survey area

Prospect Ttc

Prospect Ttc comprises an isolated fluvial channel sandstone reservoir and floodplain shale seals of TST30 lying in the downthrown fault block to the northwest of the Pondrinie high. Figure 9.2.1b-7 shows the amplitude distribution within TST30 in the downthrown block. The

area of negative amplitude (yellow) represents thin coal distribution, and is sinuous, elongate, and trends northeast to southwest along the fault. The positive amplitude areas (blue) indicate coal distribution and are sitting on the western side of the elongated negative amplitude area. On the eastern side of the negative amplitude area, a smaller scale sinuous pattern is represented by variable amplitude. The amplitude patterns imaged in Figure 9.2.1b-7 suggest the existence of a fluvial channel belt surrounded by splay complexes and the floodplain accumulated in TST30. The channel belt probably aggraded in response to an increasing base level, resulting in an isolated sandbody among the floodplain and peat mire deposits (prospect Ttc).

This channel belt seems to be orientated parallel to the fault, although in the seismic shadow zone of the fault there is uncertainty regarding the channel geometry and the relationship between the channel and the fault. However, a gas accumulation in the fluvial channel sandstone (Napowie-2) suggests that gas has accumulated in the isolated fluvial channel sandstone in the downthrown fault block.

Prospect Tpc

Prospect Tpc comprises an isolated fluvial channel sandstone reservoir and floodplain shale seals of TST40 filling the topographic feature of the incised valley of the basal Jurassic Poolowanna Formation (SB40). The high amplitude distribution within the Poolowanna interval (red in Figure 9.2.1b-8) is interpreted as a proxy for the distribution of the coaly interval in TST40. The distribution of the coaly interval is characterised as mainly a NE-SW elongated pattern with wedge-shaped tributary patterns on both sides. The spatial thickness variation based on the well log motifs and the amplitude distribution, suggests the existence of an incised valley over the Pondrinie area in TST40. The transgressive fluvial channel sandstones in the incised valley could be a stratigraphic trap prospect within TST40. However, none of the wells which intersected the fluvial channel in this area have discovered economic hydrocarbon accumulations. A possible reason for failure may be hydrocarbon leakage through the contact between the TST40 sandstone and the overlying Hutton Sandstone. A potentially prospective area is the northeastern part of the survey area where the thick TST40 interval has not yet been drilled (prospect Tpc, Figure 9.2.1b-8), although the Hutton erosion on the updip side of this area remains a key hydrocarbon leakage risk.

9.3 Chance of geologic success

9.3.1 Geologic chance factors for stratigraphic traps

A chance of geologic success of a prospect is defined as the chance that an exploration well encounters an accumulation of mobile hydrocarbons. A practical proxy for this case is “encountering enough reservoir oil or gas to sustain flow”. Geologic success does not imply economic success (Rose, 2001). For a subsurface accumulation of hydrocarbons, five geologic chance factors must exist: thermally mature source rock, hydrocarbon migration, reservoir rock, structural or stratigraphic closure and hydrocarbon containment. These geologic chance factors are independent of each other. The chance of geologic success is calculated from the multiplication of the estimated confidence values of all five factors, which expresses the probability of the existence of each factor as a value from 0 to 1.

In this chapter, to simplify issues in relation to the estimation of the chance of geologic success in stratigraphic traps, the focus is on reservoir, seal rock and appropriate spatial arrangement of reservoir and seal. These factors are corresponding respectively to geologic chance factors: “reservoir rocks”, “effectiveness of hydrocarbon containment” and “stratigraphic closure” in the definition outlined in Chapter 2. It is recognised that “thermally mature source rock”, “hydrocarbon migration” and “preservation from subsequent spillage” must also be considered in estimating the chance of geologic success.

The concept of a depositional systems tract provides a predictive framework for the spatial distribution of sedimentary facies. Sequence stratigraphy can therefore be used to evaluate the distribution of reservoirs and seals more systematically and with less uncertainty than lithostratigraphic approaches. In this thesis, the reservoir and seal factors are categorised based on depositional systems tracts and the confidence values are estimated for each geologic chance factor.

An effective stratigraphic trap requires the existence of three geologic factors: reservoir, seal, and an appropriate spatial arrangement of the reservoir and seal (stratigraphic closure). The seals in the systems tract for the stratigraphic trap can be categorised as top seal, lateral seal,

and bottom seal (Figure 9.3.1). The top, lateral and bottom seals are defined by the sealing potential of the rocks which were deposited after, contemporaneously, and before deposition of the reservoir facies in a given systems tract. The seal effectiveness of other systems tracts is also critical, because erosion by the overlying systems tract can remove or partially penetrate the top or lateral seal (e.g. the incision by an overlying lowstand systems tract may increase the risk of destruction of the top seal in the underlying transgressive or highstand systems tract). In another case, the sand content of the underlying systems tract can have an effect on the bottom seal potential (e.g. a sand-rich highstand systems tract below the onlap of a transgressive sandstone reservoir may increase the risk of hydrocarbon leakage). These multiple-seal factors are geologically independent of each other. All the geologic factors must be favourable for the geologic success of a stratigraphic trap to occur. However, if some of them are obviously not related to the stratigraphic trap component, the factor can be excluded (for example, if the trap is confined with a single systems tract, then the overlying systems tract does not affect the confidence value).

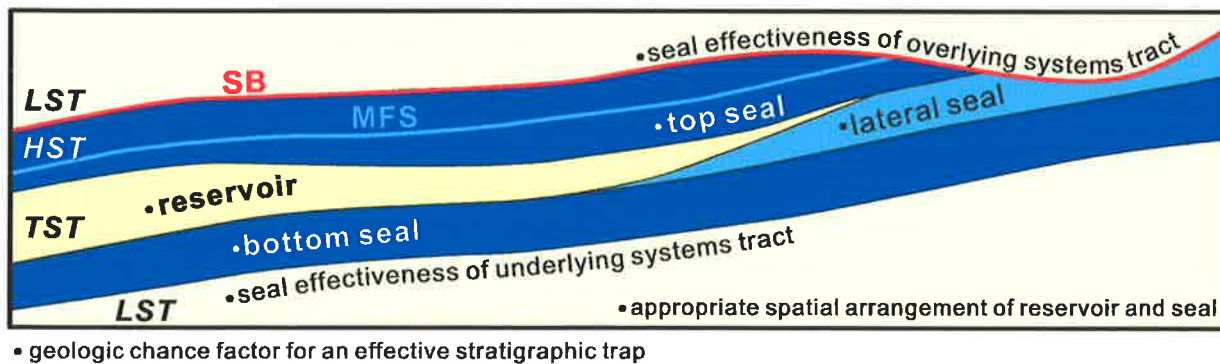
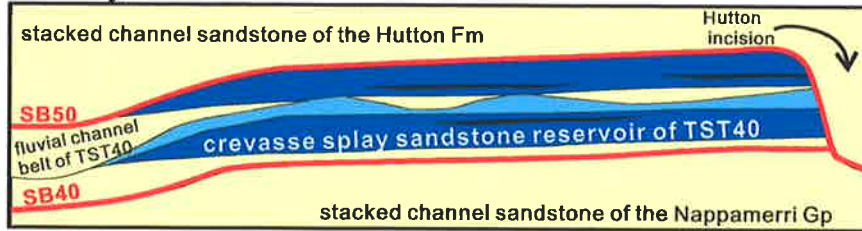


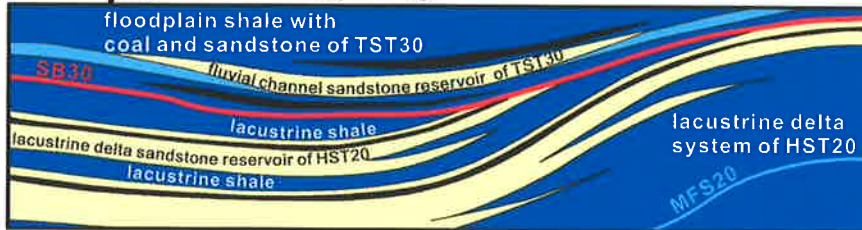
Figure 9.3.1. Schematic section showing geologic chance factors which are required for an effective stratigraphic trap.

Moorari area

Prospect T40



Prospects T30 & H20



Prospects L20_{sw} & L20_E

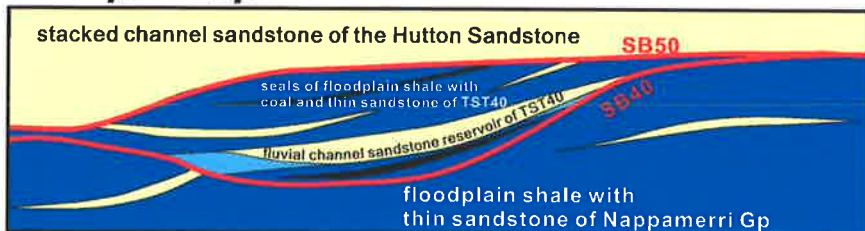


Prospect T10



Pondrinie area

Prospect Tpc



Prospect Ttc

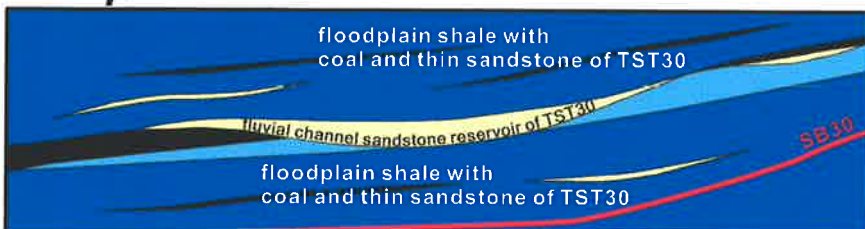


Figure9.3.2. Schematic sections of play concepts for the prospect inventory (not to scale).

9.3.2 Chance of geologic success of prospect inventory

To estimate the chance of geologic success of a stratigraphic trap, a confidence value for each geologic factor has to be allocated. Figure 9.3.3 shows an index for the subjective expressions of confidence in the existence of a geologic factor (modified after Rose, 2001; Nakanishi & Lang, 2002). The confidence value should be assessed by the expression of the existence of the geologic factors, resulting from geologic interpretation (a good scenario versus bad scenario) and the quality and quantity of information supporting the geologic interpretation (enough or poor).

expression of the existence of the geologic chance factors

		expression of the existence of the geologic chance factors				
		very bad	bad	even	good	very good
quality & quantity of information	plentiful	0.00	0.25		0.75	1.00
	enough	0.13	0.31		0.69	0.88
	moderate	0.25	0.38	0.50	0.63	0.75
	poor	0.38	0.44	0.50	0.56	0.63
	very poor			0.50		

Figure 9.3.3. Index for the subjective expressions of confidence in the existence of the geologic chance factors (modified after Rose, 2001; Nakanishi and Lang, 2002). Also see the criteria for the expression of the existence of the geologic chance factors, and the quality and quantity of information in Figure 9.3.4. Very good expression supported by plentiful information is evaluated as 1.00 for a confidence value. Very poor information, which implies no data and no geological idea (see criteria in Figure 9.3.4b), is evaluated as a confidence value of 0.5 (i.e. a coin toss). Plentiful and enough information is evaluated as confidence value of either, more than even, or less than even.

Figures 9.3.4a and 9.3.4b list the criteria for expression of the existence of the geologic factors categorised by systems tract, and the quality and quantity of information supporting the geologic interpretation. Figure 9.3.5 summarises the estimates of the chance of geologic success for a range of play types.

The lowstand systems tract plays (L20SW and L20E) show high chances of success. This high expectation is caused by the fact that confidence in the existence of a seal is high. Lateral and bottom seals for the lowstand systems tract are provided by the transgressive systems tract underneath (TST10), which demonstrates the high seal potential of the shales. The top of the lowstand systems tract is sealed by shales of TST20. The expectation of a high concentration of sandstone in the lowstand systems tract also results in a high chance. Low chances of success were estimated in prospects T40 and Tpc in TST40. These estimations result from the high confidence in the incision by the overlying systems tract (Hutton stacked channel sandstone), with the result of a high risk of a hydrocarbon leakage.

a) Criteria for the expression of the existence of the geologic chance factors

Systems Tract	Expected Geologic Objective	Expression of Geologic Chance Factor's Existence
Reservoir		
HST	Laterally continuous lacustrine delta sandstone	very good
TST	Laterally discontinuous crevasse splay delta sandstone & isolated fluvial channel sandstone	good
LST	Stacked fluvial channel sandstone	very good
Top seal		
HST	Laterally continuous lacustrine offshore shale	very good
TST	Floodplain shale	good
LST	Top seal is not expected in the lowstand systems tract	---
Lateral seal		
HST	Lateral seal is not expected in the highstand systems tract	---
TST	Floodplain shale	good
LST	Lateral seal is not expected in the lowstand systems tract	---
Bottom seal		
HST	Laterally continuous lacustrine offshore shale	very good
TST	Floodplain shale	good
LST	Bottom seal is not expected in the lowstand systems tract	---
Seal effect of the overlying systems tract		
Hutton Sst on TST40	Stacked fluvial channel sandstone of Hutton Sandstone on SB50 incising to TST40	bad
TST30 on HST20	Isolated fluvial channel sandstone of TST30 on SB30 contacts with HST20	bad
TST20 on LST20	Floodplain shale of TST20 overlying LST20 as the top seal	good
Seal effect of the underlying systems tract		
Nappamerri Gp under TST40	Floodplain shale of Nappamerri Gp under TST40	good
TST10 under LST20	Floodplain shale of TST10 under LST20 as the top and lateral seal	good
Appropriate spatial arrangement of reservoir & seal		
HST	Updip part of the lacustrine sandstone is sealed by lacustrine shale of the HST and TST30	good
TST	Crevasse splay delta & isolated fluvial channel sandstone enveloped by floodplain shale	good
LST	Stacked fluvial channel sandstone of the LST enveloped by floodplain shale of TST	good

b) Criteria for quality and quantity of information

plentiful	There are well and seismic data which proved the existence or non-existence of the geologic chance factor near the prospect
enough	There are well and seismic data suggesting the existence or non-existence of the geologic chance factor which has not been proved by well
moderate	Existing well and seismic data are not enough to support the expression of the geologic chance factor's existence
poor	There is no well and seismic data and the expression of the geologic factor's existence comes from the general geological concept of the region
very poor	No data and no geological idea

Figure 9.3.4. Criteria for chance of geologic success estimation for the prospect inventory. a) criteria for the expression of the existence of the geologic chance factors resulting from sequence stratigraphic concepts. b) criteria for quality and quantity of information supporting the interpretation.

Play type concept

Prospect	systems tract	expected reservoir	expected seal	seal effect of the other systems tracts	depth (m)
T40	TST40	Laterally discontinuous crevasse splay delta sandstone	Floodplain shale enveloping crevasse splay delta	Hutton Sandstone contacts with the prospect interval on SB50	2368 - 2473
T30	TST30	Isolated fluvial channel sandstone	Floodplain shale enveloping fluvial channel		2826 - 2862
H20	HST20	Laterally continuous lacustrine delta sandstone	Laterally continuous lacustrine offshore shale	Fluvial sandstone of TST30 contacts with the prospect interval on SB30	2883 - 2899
L20 _{SW}	LST20	Stacked fluvial channel sandstone	Floodplain shale of TSTs above and below this LST		3022 - 3039
L20 _E	LST20	Stacked fluvial channel sandstone	Floodplain shale of TSTs above and below this LST		2936 - 3075
T10	TST10	Isolated fluvial channel sandstone	Floodplain shale enveloping fluvial channel		3037 - 3137
Tpc	TST40	Isolated fluvial channel sandstone	Floodplain shale enveloping fluvial channel	Hutton Sst & Nappamerri shale contact with the prospect interval	1871 - 2041
Ttc	TST30	Isolated fluvial channel sandstone	Floodplain shale enveloping fluvial channel		2602 - 2845

Chance of geologic success

reservoir	top seal	lateral seal	bottom seal	overlying systems tract	underlying systems tract	spatial arrangement of reservoir & seal	chance of geologic success
G M	G PL	G PL	G PL	B PL	- -	G M	0.04
G E	G PL	G PL	G PL	- -	- -	G M	0.18
VG E	VG E	- -	VG PL	B E	- -	G E	0.17
VG E	- -	- -	- -	G PL	G PL	G E	0.34
VG E	- -	- -	- -	G PL	G PL	G M	0.31
G E	G PL	G PL	G PL	- -	- -	G M	0.18
G PL	G PL	G PL	G PL	B E	G PL	G E	0.05
G PL	G PL	G PL	G PL	- -	- -	G M	0.20

Expression of geologic chance factor's existence
VG: very good
G: good
E: even
B: bad
VB: very bad

Quality & quantity of information
PL: plentiful
E: enough
M: moderate
P: poor
VP: very poor

Probabilistic reserves estimation

Prospect	productive area (km ²) P10, Pmean, P90	average net pay thickness (m) P10, Pmean, P90	average porosity (%) min, mode, max	average Sw (%) min, mode, max	FVF min, mode, max	recoverable factor (%) min, mode, max	recoverable reserves (gas equivalent, bcf) P10, Pmean, P90	reality check P10/P90 ratio P99, P1 (bcf)
T40	3.1 1.8 0.9	9.4 5.9 3.2	14.7 10.1 5.5	60 50 30	0.91 0.89 0.85 (for oil)	67 30 5 (for oil)	13.3 6.4 1.7	7.7 0.7, 28.6
T30	2.6 1.6 0.8	12.8 8.3 4.9	13.1 10.6 7.9				10.3 5.6 2.2	4.7 1.3, 18.9
H20	2.2 1.4 0.8	15.9 9.0 3.8	10.1 7.6 4.8				7.8 3.9 1.3	6.2 0.6, 15.2
L20 _{SW}	2.6 1.6 0.8	19.7 11.5 5.3	10.1 8.8 7.6		243.3 225.9 208.5 (for gas)	83 81 78 (for gas)	12.7 6.5 2.3	5.6 1.2, 24.6
L20 _E	6.4 3.3 1.1	19.7 11.5 5.3	10.5 9.1 7.7				29.5 13.5 3.3	8.9 1.5, 68.8
T10	2.3 1.5 0.8	12.8 8.3 4.7	9.5 8.6 7.6	55 37 16			7.8 4.4 1.8	4.3 1.1, 13.8
Tpc	5.7 3.0 1.1	12.8 8.3 4.7	22.8 15.3 6.3	60 50 30	0.91 0.89 0.85 (for oil)	67 30 5 (for oil)	47.0 21.2 4.6	10.2 1.9, 111.7
Ttc	2.9 1.7 0.9	12.8 8.3 4.7	13.3 10.7 8.1	59 37 13	173.0 168.3 163.6 (for gas)	83 81 78 (for gas)	8.8 4.6 1.7	5.0 0.9, 16.3

P10: 10% probability the occurrence is equal to or more than this value
P90: 90% probability the occurrence is equal to or more than this value
Pmean: mean value
P90 < Pmean < P10

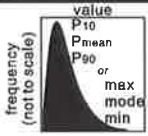


Figure 9.3.5. Playtype concepts and chance of geologic success estimation for the prospect inventory. For estimating chance of success, the criteria (figures 9a & b) and the index for the confidence in the existence of the geologic chance factors are used (see Figure 9.3.3).

Figure 9.3.6. Probabilistic reserves estimation for the prospect inventory. For the reserves estimates, geologically reasonable ranges were given to each parameter and these parameters were multiplied by Monte Carlo simulation to calculate probabilistic reserves distributions.

9.4 Probabilistic reserves estimation

The estimation of the prospect's reserves must be assessed as a range, because prospect reserves are the products of many factors with their own uncertainty. Any scientific approach has to take into account the uncertainty. The probabilistic reserves distribution is the product of several parameters: productive area, average net pay thickness, average porosity, average hydrocarbon saturation ratio, recoverable ratio and formation volume factor. The Monte Carlo simulation is employed for multiplying these parameters to make the probabilistic reserves distribution. The probabilistic distributions given to each parameter and the reserves estimation result are shown in Figure 9.3.6 and Appendix A.

9.4.1 Parameter estimation

P90, Pmean and P10

The following definitions are used; P10: 10% probability the occurrence is equal to or more than this value, P90: 90% probability the occurrence is equal to or more than this value, Pmean: mean value.

Productive area

The maximum case of a productive area was set as the maximum possible distribution of the expected reservoir within the 3D seismic survey area. The reservoir distribution was estimated from seismic amplitude distribution corresponding to the sedimentary facies interpretation (for example, the entire possible fluvial channel area in prospect Ttc, Figure 9.2.1b-7). The maximum productive area is also considered to be the area updip of any dry holes which have penetrated the reservoir interval with the expected reservoir area. For example, the possible productive area is a structurally closed area of the incised valley fill of prospect Tpc, not including the area confirmed to be dry. The minimum case of a productive area was practically assigned to 0.5km². This is an area just large enough to reserve hydrocarbons to sustain a flow that comprises a geologic success. A lognormal distribution was used for the estimation, in order to reflect the nature of the productive area which is a natural multiplication of independent, random variables (Capen, 1992; Rose, 2001).

Average net pay thickness

The maximum case of the net pay thickness was estimated as the maximum net sand thickness of the objective facies and the interval in the well data in these study areas. In the case of the absence of well data, the thickness of the reservoir interval was derived from the seismic data using assumed isopach and net-gross ratio. The minimum case of net pay thickness used the definitions of sedimentary facies expected in the reservoir play (i.e. fluvial channel; 3m, crevasse splay delta; 2m, lacustrine delta; 2m, see the definition of the facies in the former chapters). The reservoir thickness is also recognised as just enough to reserve hydrocarbons to sustain the flow that constitutes a geologic success. The lognormal distribution is used to calculate net pay thickness.

Average porosity

The core porosity-depth plot of the Patchawarra and Toolachee formations in the southern Cooper Basin is illustrated in Figure 9.4.1c. In Figure 9.4.1d, porosity data were extracted from the Patchawarra Trough and the GMI trend where the study areas are located. The average core porosity values in the study areas are displayed with a sedimentary facies analysis. Comparing Figures 9.4.1c and 9.4.1d, there are no apparent differences in the trend of the reducing porosity with increasing depth in between the whole southern Cooper Basin and the Patchawarra Trough/GMI trend. As expected, the core porosities of the fluvial channel facies in the high porosity area are distinct from the crevasse splay channel and crevasse splay delta facies, because of the difference in initial porosity. Importantly, rate of porosity reduction is less in the fluvial channel facies than in the other facies. The porosity range of the fluvial channel facies is used for estimating the porosity of the fluvial channel prospects in the Permian succession. The core data, showing preserved porosity even deeper than 3200m, suggests that the estimation of the possible porosity range is reasonable. In the study areas, insufficient core data is available from the Epsilon and Poolowanna formations to apply facies analysis; hence the core porosity range from P90 to P10 in the interval where data are available for the southern Cooper Basin (see the investigation window in figures 9.4.1a and b), are considered reasonable for the average porosity estimation for the prospects H20, T40 and Tpc (see the definitions of P90 and P10 above). For calibration from ambient to overburden porosity, 0.95 was used as a correction factor (Morton, 1989; Alexander, 1996; Gravestock et al., 1998).

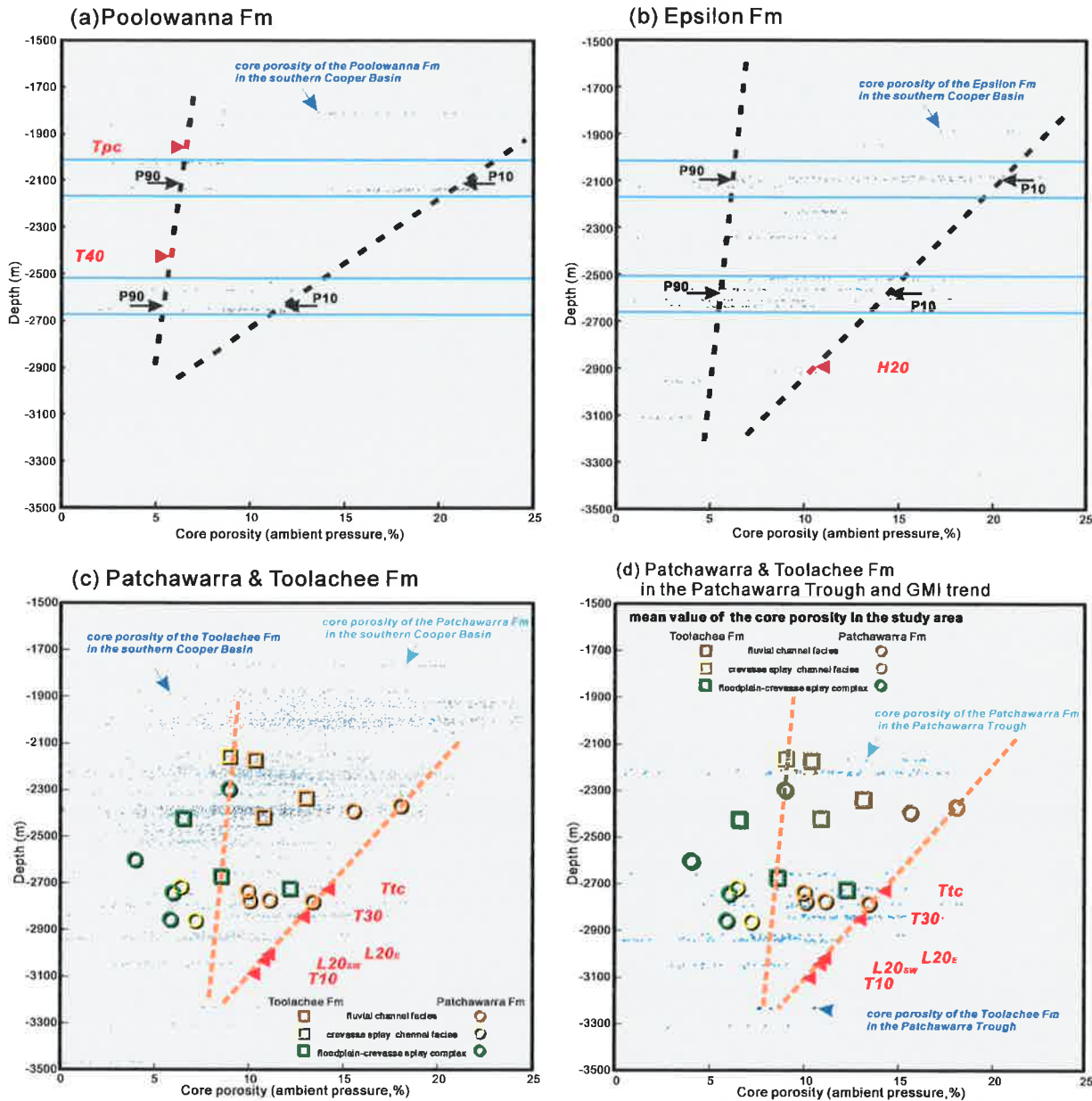


Figure 9.4.1. The trend of reducing core porosity with increasing depth. (a) the Poolowanna Formation in the southern Cooper Basin. (b) the Epsilon Formation in the southern Cooper Basin. (c) the Patchawarra and Toolachee formations in the southern Cooper Basin. (d) the Patchawarra and Toolachee formations in the Patchawarra Trough and GMI trend. In figures (a) and (b), the core porosity range from P90 to P10 (see the definitions of P90 and P10 in the text) in the interval where considerable amount of data are available (blue lined windows in figures), was used as a reasonable range of the average porosity estimate for prospects H20, T40 and Tpc in the Poolowanna and Epsilon formations play. In figures (c) and (d), coloured symbols reflect different sedimentary facies. The range and reducing trend of the porosity of the fluvial channel facies (orange dotted lines) are used for the porosity estimation of the fluvial channel play prospects in the Permian succession (T30, L20SW, L20E, T10 and Ttc).

Average water saturation

For the prospects in the Permian succession, water saturation information from net pay intervals in the Moorari / Woolkina and Pondrinie / Packsaddle fields was applied. There is no net pay in the Poolowanna Formation in these areas; hence the water saturation range generally used for reserve size estimation (e.g. Morton, 1996) was used for prospects T40 and Tpc.

Hydrocarbon type

From the known discoveries surrounding the study areas, it is expected that gas and condensate accumulations will be found in the Permian prospects and oil accumulations in the basal Jurassic prospects. The formation volume factor (and recovery factor for the gas reservoirs were assumed to be similar to those from the Moorari/Woolkina and Pondrinie/Packsaddle fields. For the prospects of the Poolowanna Formation, the typical range for oil reservoirs were applied (e.g. Morton, 1996).

9.4.2 Reserves estimation results

The oil reserves estimations for the prospects T40 and Tpc were converted to gas equivalent (gas equivalent (cf) = oil (bbl) x 6000) in order to simplify comparison of results.

Minimum case (P99 case) of reserves estimates range from 0.6 to 1.9bcf (Figure 9.3.6) and can be recognised as reasonable as a gas accumulation just enough to be a geologic success. P10/P90 ratio of each estimate (4.3 to 10.2) should be realistic as prospects adjacent to producing fields in a matured exploration basin (Table 2.1.1, Chapter 2). The maximum cases may be too pessimistic because of the 3D seismic survey areas not covering the whole prospect area and therefore P10/P90 ratio may be larger.

The comparison of the mean reserve size, the incised valley fill play (Tpc) is ranked highest, followed by the lowstand systems tract play (L20E and L20SW). These results reflect the possible extent of the potential productive area and relatively thick reservoirs of these prospects. The isolated channel play prospects (T10 and Ttc) are ranked relatively low because of the restricted distribution of the possible productive area. It is possible that the 3D seismic survey area does not cover the total area of prospects T30 and H20; hence the productive area for these prospects may be underestimated.

9.5 Efficient exploration frontier

As in common stock business or financial ventures, a risk-reward optimisation can be applied to oil and gas exploration to determine an appropriate exploration portfolio (Bernstein, 1996; Rose, 2001). In financial ventures, the standard deviation of profitability of each possible portfolio is often used to express risk. In this chapter, instead, the chance of geologic success is used as a measure of risk, because the nature of the exploration business is such that there is a low chance of discovering hydrocarbons, so managing the chance of geologic success is a key factor in portfolio management.

9.5.1 Efficiency of single exploration wells

Figure 9.5.1 illustrates the variation of the chance of geologic success vs. the mean reserves estimate of single exploration wells in the prospect inventory. Two combinations of prospects, L20E+T10, and T30+H20, are each drillable by a single well from one location. For these exploration wells targeting dual prospects, the chance of geologic success is given as the chance of success for at least one of the two prospects (chance of success of L20E only, T10 only, or both L20 and T10). Accordingly, the mean value of the reserves is shown as a mean value of all possible discovery cases of two prospects (not the simple summation of the reserves means of two prospects).

Of all the prospects identified, prospect Tpc has the highest reserves estimate (Figure 9.5.1); however the chance of success is the second lowest, hence it can be identified as a high-risk/high-return prospect. Conversely, prospect L20SW has the highest chance of success, but it has a relatively low reserves estimate, hence it can be identified as a low-risk/low-return prospect. Prospect L20E is located between prospect Tpc and L20SW in terms of chance of geologic success and mean reserves, and it is considered a moderate-risk/moderate-return prospect. However, the comparison by risked reserves, which is used to demonstrate the efficiency of exploration, is calculated from the chance of geologic success multiplied by the reserves mean, and indicates that prospect L20E has the highest efficiency. By comparison with three prospects above (L20E, L20SW and Tpc), the risked reserves for the other prospects is low (T10, H20, T30, T40 and Ttc).

The risked reserves for dual prospect exploration (L20E+T10, T30+H20) shows that the

efficiencies are improved, compared with single-prospect exploration. This suggests that multi-prospect exploration enhances exploration efficiency, as long as the drilling cost is not significantly different in single versus multi-prospect exploration. Consequently, for a single exploration well, prospects L20E+T10 constitutes the most efficient exploration campaign and prospects L30+H20 are the fourth most efficient.

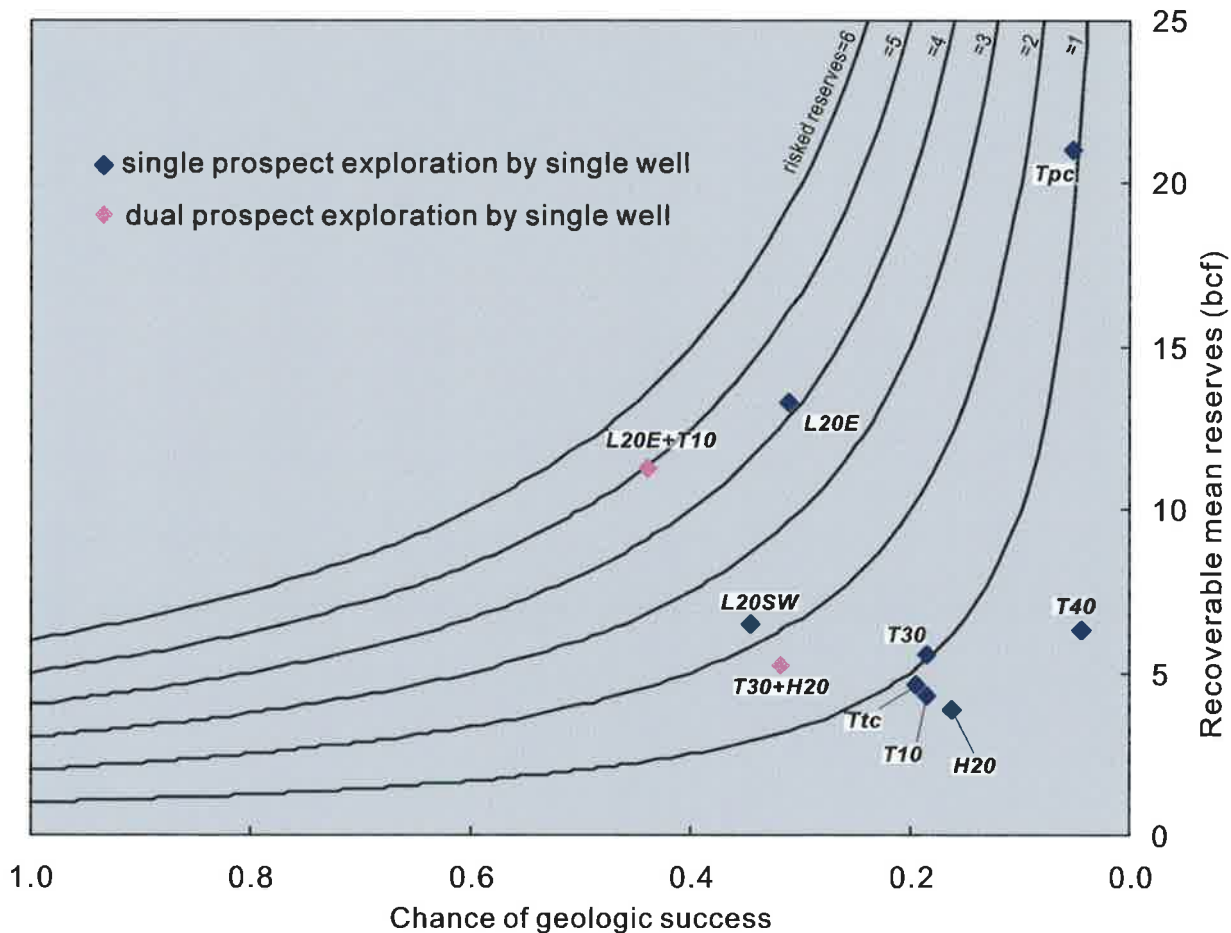


Figure 9.5.1. The variation of the chance of geologic success vs. the mean reserves estimate of single exploration wells in the prospect inventory. Two combinations prospects, L20E+T10, and T30+H20, are drillable by a single well from one location. For these single-well explorations targeting dual prospects, the chance of geologic success is given as the chance of success for at least one of two prospects. Accordingly, the mean value of the reserves is shown as a mean value of all possible discovery cases of two prospects. The risked reserves (chance of geologic success times mean reserves) for dual prospect exploration shows that the efficiencies are improved from the single prospect exploration.

9.5.2 Efficient exploration frontier of multiple exploration wells

Diversifying risk capital into multiple investment opportunities is one of the best ways to minimise risk. This concept can be applied to the exploration business by sharing with the investment partners the cost of multiple exploration wells. The variation of the chance of geologic success vs. the mean reserves estimate of multiple exploration wells for the prospect inventory is illustrated in Figure 9.5.2. The chance of geologic success for the multiple exploration wells is shown as the chance of at least one of the multiple wells encountering a

geologically successful prospect. The reward must be shared according to the share rate of the investment. The calculations are simplified so that the number of the investment partners to share the well costs is equal to the number of the exploration wells; hence the mean reserves estimate is divided by the number of exploration wells. Consequently, the plots in Figure 9.5.2 show the efficiency of the possible exploration cases in the prospect inventory, where a corporation with a budget to drill one exploration well, drills multiple wells sharing the costs with investment partners.

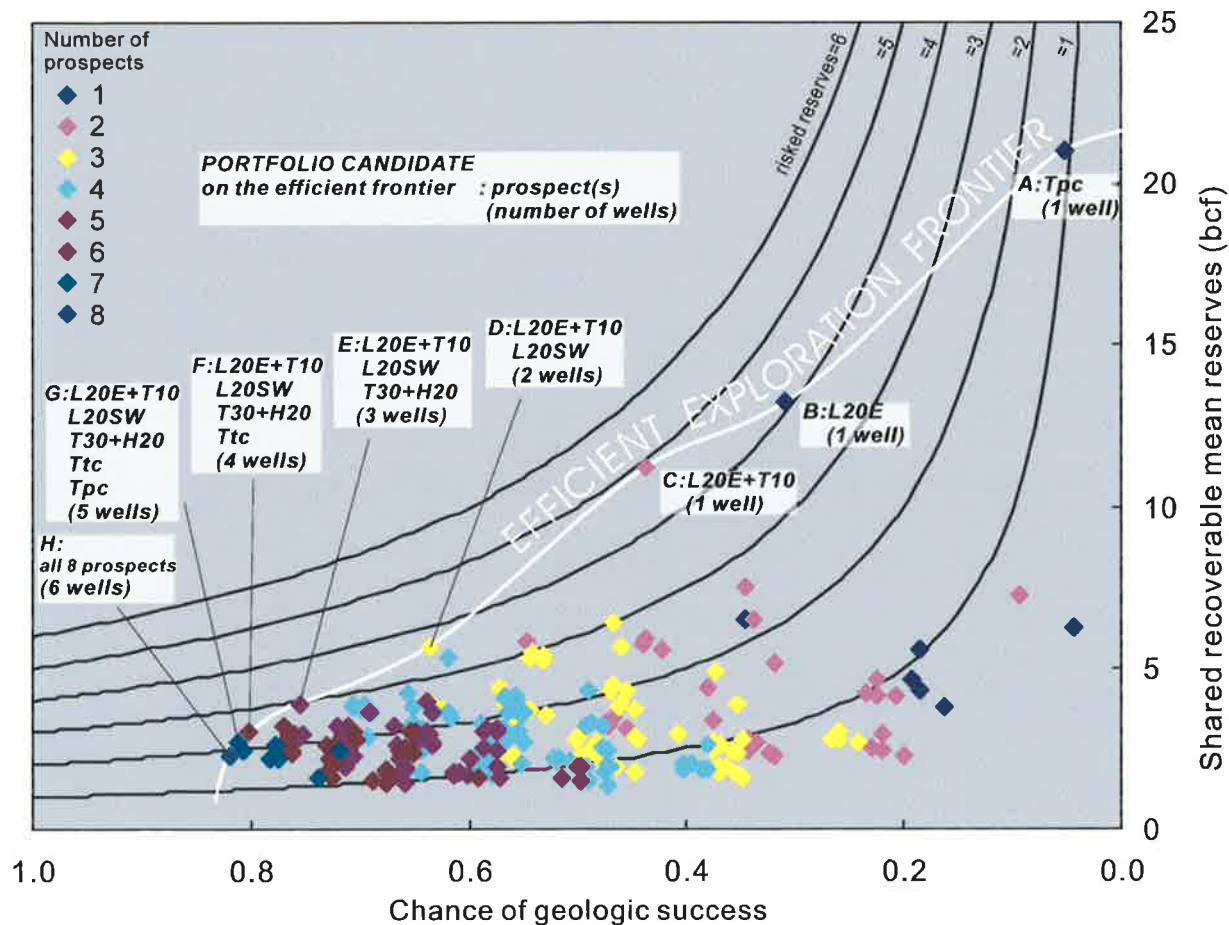


Figure 9.5.2. The variation of the chance of geologic success vs. the mean reserves estimate of multiple exploration wells for the prospect inventory. Monte Carlo simulation was employed to calculate the chance of success and reserves mean value of each exploration case. The chance of geologic success is shown as the chance of at least one of the multiple wells encountering a geologically successful prospect. The mean reserves size divided by the number of exploration wells provides the shared mean reserves with the investment partners. This plot shows an efficient exploration frontier where no plot can cross over into the high risked reserves area (high efficiency area). The exploration portfolio of the corporation should be selected from exploration cases plotted on the efficient frontier, because the portfolio candidate on the efficient frontier has the highest risked reserves when compared with the other exploration cases with the same chance of success or the same mean reserves estimate.

Increasing the number of wells tends to make the chance of geologic success higher, but lowers the shared mean reserves. However, exploration opportunities involving the same number of wells have variations of risked reserves corresponding to the association of target prospects. Plotting all exploration cases shows a frontier delineating the limit of risked

reserves for the exploration portfolios (Figure 9.5.2). The exploration portfolio of a corporation should be selected from exploration portfolio candidates plotted on the efficient frontier, because they have the highest risked reserves compared to other candidates with the same chance of success or the same mean reserves. On the efficient frontier, the portfolio candidates might be categorised as high-risk/high-return (portfolio A and B), moderate-risk/moderate-return (portfolio C and D) and low-risk/low-return (portfolio E, F, G and H). The selection of the actual portfolio from the portfolio candidates on the efficient frontier depends on the policy of the corporation. If the corporation is interested in a chance of success higher than 40% and the mean reserves size higher than 3 bcf, the portfolio should be selected from candidate C, D or E.

9.6 Expected net present value analysis for portfolio candidates

The risk-reward optimisation should be managed not in terms of reserve size but in terms of monetary value, because as mentioned earlier the ultimate aim of exploration is not to discover hydrocarbons but to make a profitable return. Many corporations now use expected net present value (ENPV) to manage exploration investments (Rose, 1992a; Alexander & Lohr, 1998; McMaster, 1998; Johns et al., 1998; Kubota et al., 1999; Nakanishi, 2000; Rose, 2001). ENPV is the summation of the products of the chance of success and the monetary mean value of the case of success, and the chance of failure and the monetary mean value in the case of failure (Figure 9.6.1). Investment in a project of which the ENPV is more than zero is usually recognised as a reasonable decision.

ENPV(expected net present value)=

- Chance of geologic failure x Exploration cost NPV in geologic failure
- +Chance of geologic success and economic failure x
Exploration cost NPV in geologic success and economic failure
- +Chance of economic success x Profit NPV mean

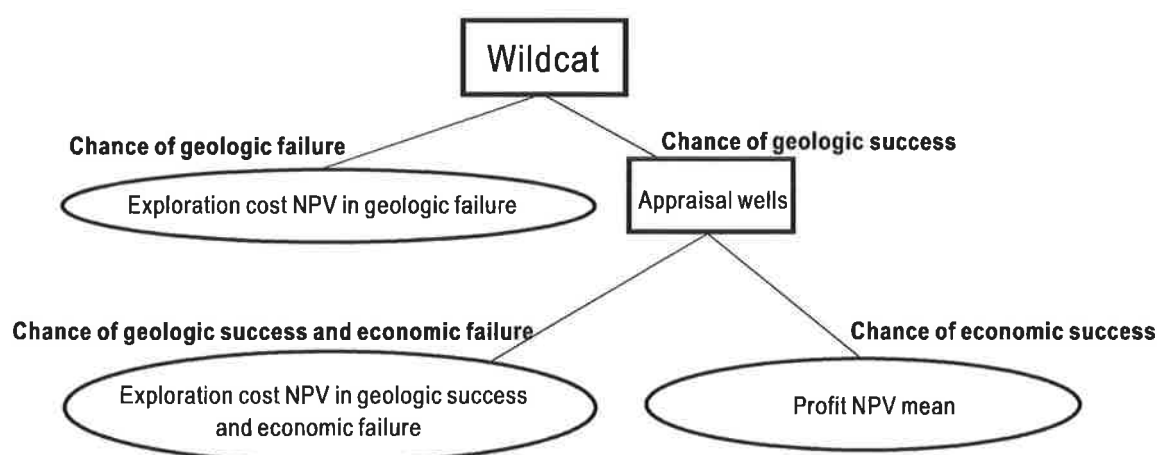


Figure 9.6.1. The concept of ENPV.

It is important to note the limitations for assessing ENPV, which are mentioned in the following chapter. For simplicity, only one pre-tax cash flow model for gas development in the Cooper Basin was adopted (Figure 9.6.3) using the feasibility study by McDonough (1997). According to this cash flow model, the minimum economic reserve size is 6bcf. A cost of one exploration well was assumed as a failure cost for the economic failure case, because the minimum economic reserve size is small enough to make a decision for

developing the field. Therefore the ENPV is simplified as;

ENPV(expected net present value)=

$$\begin{aligned} &\text{Chance of economic failure} \times \text{Exploration cost NPV in economic failure} \\ &+ \text{Chance of economic success} \times \text{Profit NPV mean} \end{aligned}$$

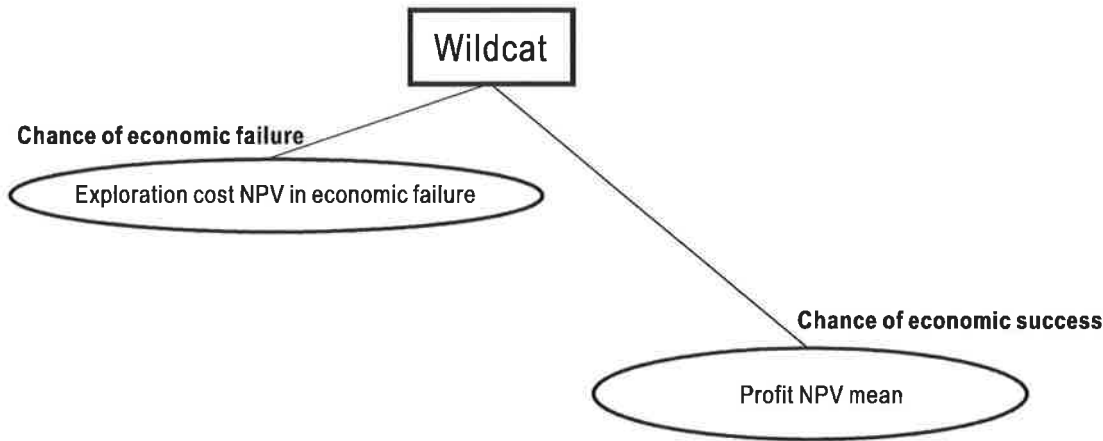


Figure 9.6.2. Simplified ENPV

According to the cash flow model, the relationship between reserves and NPV is linear (Figure 9.6.3), therefore the chance of economic success and the profit NPV mean in the economic success case are calculated as the product of the chance of geologic success and the probability of more than minimum economic reserves, and the NPV in the mean reserves case respectively (see the section of chance of economic success, profit NPV mean in the economic success case in Chapter 2). Figure 9.6.4 shows an example of a categorisation of success and failure in the portfolio candidate C (L20E+T10). The chance of economic success is the chance of geologic success multiplied by the economic success area within the reserves distribution. For portfolio candidate C, the chance of economic success is calculated as 26%. The mean value of reward in the case of economic success is \$13.6 million, resulting from discovery of 16.6 bcf of mean reserves. The chance of economic failure is calculated as 74% (100-26%) with a loss in this case of \$1.75million (i.e. for one dry hole). Consequently, the ENPV for the portfolio candidate C (L20E+T10) is calculated as \$2.2 million.

Table 9.6.1 shows the ENPV results of all the portfolio candidates on the efficient frontier. The ENPV of portfolio A (single Tpc prospect) is negative; hence investment in prospect Tpc alone is not recommended. The highest ENPV is estimated in the portfolio C (L20E+T10), however the chance of economic success is 26%. If the corporation prefers a higher chance of

economic success, other candidates with positive ENPV and relatively high reward estimates can be chosen (portfolio candidate D, E or F). The risk-reward optimisation outlined above helps to identify an appropriate exploration portfolio suited to the policy of the organisation.

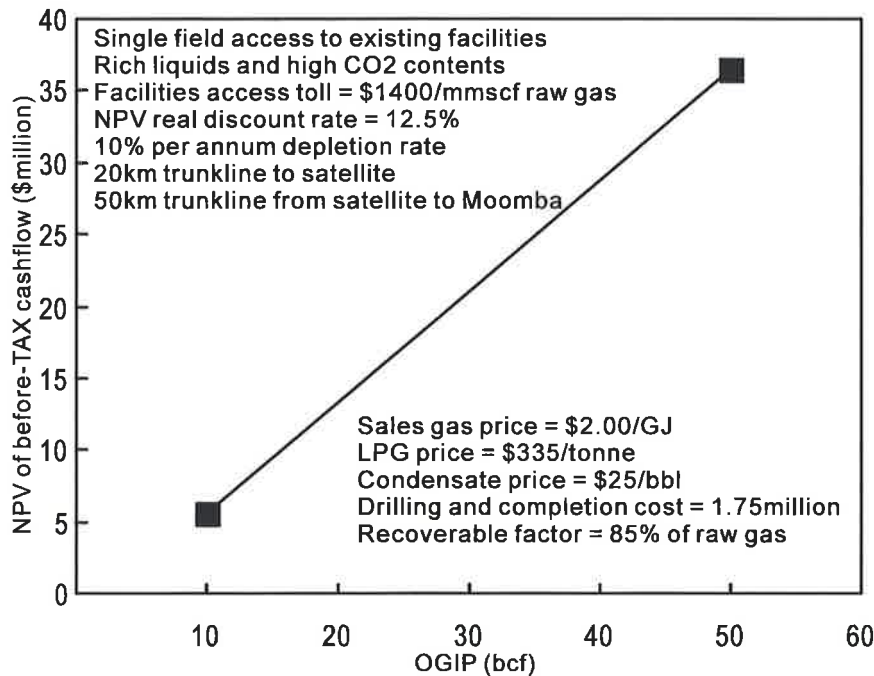


Figure 9.6.3. Correlations between reward and gas reserve size in a particular case in the Cooper Basin (McDonough, 1997).

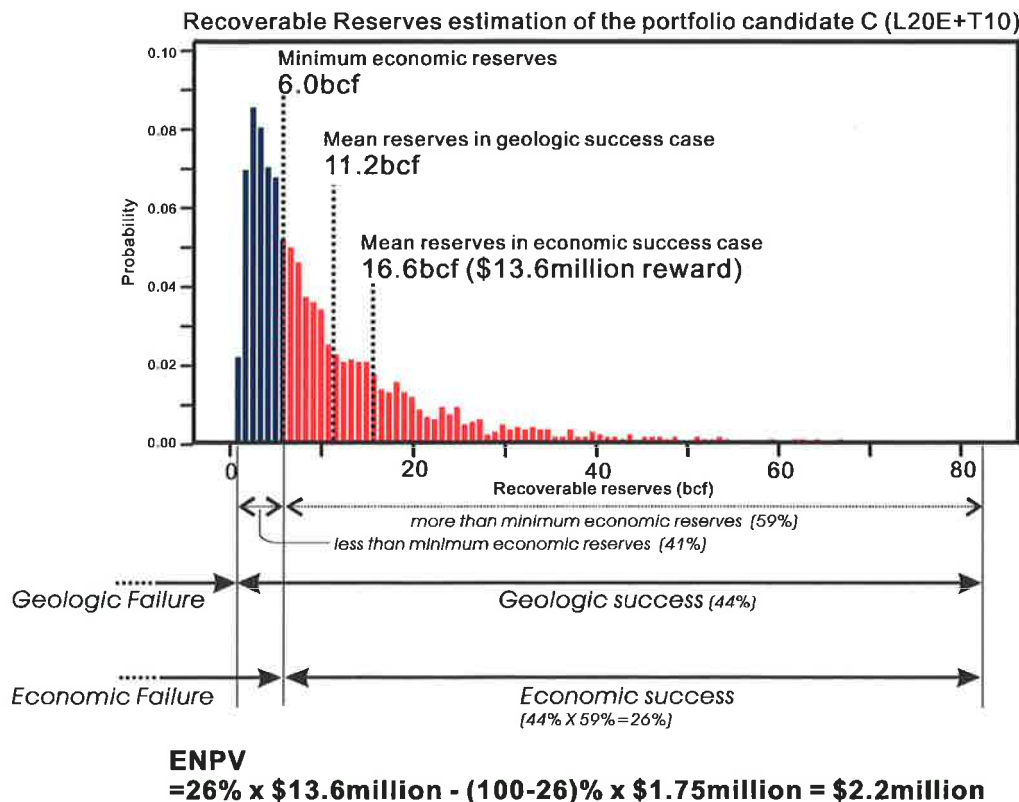


Figure 9.6.4. Categorisation of success and failure in the portfolio candidate C (L20E+T10) and ENPV.

Table 9.6.1. Assessment results of chance of economic success, reward and ENPV for portfolio candidates on efficient exploration frontier.

Portfolio candidates	Number of exploration wells (number of partners)	Chance of geologic success	Chance of economic success	Mean reserves in economic success (bcf)	Shared mean reserves in economic success	Reward in economic success (\$million)	Shared reward in economic success (\$million)	Exploration cost (\$million)	ENPV (\$million)	Shared ENPV (\$million)
A: Tpc	1	5%	4%	24.0	24.0	20.7	20.7	1.75	-0.8	-0.8
B: L20E	1	31%	22%	17.0	17.0	14.1	14.1	1.75	1.8	1.8
C: L20E+T10	1	44%	26%	16.6	16.6	13.6	13.6	1.75	2.2	2.2
D: L20E+T10,L20SW	2	64%	39%	15.8	7.9	12.9	6.5	3.50	3.0	1.5
E: L20E+T10,L20SW,T30+H20	3	76%	49%	16.0	5.3	13.1	4.4	5.25	3.7	1.2
F: L20E+T10,L20SW,T30+H20,Ttc	4	80%	55%	16.1	4.0	13.3	3.3	7.00	4.0	1.0
G: L20E+T10,L20SW,T30+H20,Ttc,Tpc	5	81%	58%	17.5	3.5	14.6	2.9	8.75	4.7	0.9
H: All	6	82%	59%	17.7	2.9	14.7	2.5	10.50	4.3	0.7

Chapter 10

Limitations

There are several limitations in the evaluation procedure established in this research.

10.1 Geologic chance factors

For the estimation of the chance of geologic success, the geologic chance factors of “thermally mature source rock”, “hydrocarbon migration”, and “preservation from subsequent spillage” are not dealt with in the case studies. These geologic factors must ultimately be incorporated to estimate the chance of geologic success. Confidence values for these chance factors should be assessed by the expression of the existence of the geologic factors, resulting from geologic interpretation and the quality and quantity of information supporting the geologic interpretation (see Chapter 9) and be multiplied by the other confidence values to calculate the chance of geologic success. For assessing the thermally mature source rock and hydrocarbon migration, sequence stratigraphy can be a powerful tool to give confidence values systematically and with consistency.

However, in the case study areas, there is no doubt that matured source rocks exist (e.g. shales and coals of the Patchawarra Formation and highly carbonaceous shales of the Poolowanna Formation in the Patchawarra and Nappamerri trough area; Jenkins, 1989; Michaelsen & McKirdy, 1996; see Chapter 4). Hydrocarbon accumulations including producing fields in these areas suggest the high potential of the hydrocarbon migration and the seal preservation. Therefore, the risks of a lack of thermally mature source rock, hydrocarbon migration, and preservation from subsequent spillage are considered as low or non-risk (i.e. confidence values for these factors were effectively assessed as 1.0), and then the values assessed for the prospect inventory in the case studies can be recognised as the chance of geologic success.

10.2 Dependencies in multiple prospects

Dependencies regarding the chance of geologic success among multiple prospects have not been considered in the case studies. For example, if the first well for prospect L20E finds that the seismic amplitude interpreted as the lowstand systems tract is not a stacked fluvial channel

sandstone, re-evaluation for the prospect L20SW with the same expectation in the reservoir as L20E should be needed. If the thermally mature source rock and hydrocarbon migration factors are considered, the dependency of these potentially common factors on the prospects should be evaluated.

The other type of dependency among multiple prospects is the dependency regarding development, production plans and economics. If multi-fields are discovered in the prospect inventory, the development and production plan must be optimised to maximise the profitability from the fields. However, the cash flow model used in this research is one simple model which has a linear function between reserves size and profit. To assess a more realistic economic impact of the exploration for the prospect inventory, a variety of cash flow models according to optimised development and production plans are needed, but this is beyond the scope of this thesis.

10.3 Estimation of maximum case of reserves distribution

As for the reserves estimates for the stratigraphic traps, the whole possible reservoir area appearing in the 3D seismic survey was included as a maximum case for reserves calculation. This contains both an optimistic and a pessimistic view. For the maximum case, it has been assumed that the seal capacity was sufficient to hold back the entire gas column; however this may be too optimistic. Because the seal capacity data for the Permian succession was not available, seal capacity data from floodplain shale of the Triassic, Nappamerri Group in the Merrimelia area has been used, that could hold back a 297 to 608m gas column (Dragomirescu et al., 2001). If the seal capacity of the Permian shales is similar to the Triassic, it could be sufficient to contain the gas column for a maximum case (the highest column is 263m in prospect Ttc (structural height + reservoir thickness)). In contrast, for the maximum case, the reservoir area have been restricted to the confines of 3D seismic survey area. This is probably pessimistic as the reservoirs may extend significantly outside the limit of the 3D seismic survey.

10.4 Cash flow model

Only one cash flow model for the monetary value estimation has been used for all portfolio candidates in this thesis. Further consideration of the cash flow model is required to

realistically match the actual exploration business in terms of producing area, depth, hydrocarbon type, communication of the existing facilities, pipeline tally, gas price, discount rate of the cash flow and so on. The range of the hydrocarbon recovery factor should also be estimated when considering economically positive production in cash flow models.

Importantly, the cash flow model prepared for this research does not evaluate tax and royalty. In order to estimate the net gain with consideration of tax and royalty, the optimisation of development and a production plan in the case of a multi-discovery should be reflected as the effects of tax synergy in the cash flow model. To roughly demonstrate the impact of the tax and royalty on the portfolio candidates, however, the reward in the economic success case of each candidate was simply reduced by the tax and royalty rate (30% and 10% in South Australia, respectively), and ENPV was calculated (Table 10.1).

Portfolio candidate	Reward in economic success (\$million)	Shared reward in economic success (\$million)	ENPV (\$million)	Shared ENPV (\$million)
A: Tpc	12.4	12.4	-1.1	-1.1
B: L20E	8.4	8.4	0.5	0.5
C: L20E+T10	8.2	8.2	0.8	0.8
D: L20E+T10,L20SW	7.8	3.9	0.9	0.5
E: L20E+T10,L20SW,T30+H20	7.8	2.6	1.2	0.4
F: L20E+T10,L20SW,T30+H20,Ttc	8.0	2.0	1.2	0.3
G: L20E+T10,L20SW,T30+H20,Ttc,Tpc	8.7	1.7	1.3	0.3
H: All	8.8	1.5	0.8	0.1

Table 10.1. Reward and ENPV of portfolio candidates with rough consideration of tax and royalty. The reward in the economic success case of each candidate was simply reduced by the tax and royalty rate (30% and 10% in South Australia, respectively), and ENPV was calculated. Note that the detailed cash flow models with the optimisation of development and a production plan in the case of multi-discovery, and non-linear relationship between reserves and NPV must be evaluated (see text).

The reserves distribution is converted to monetary value distribution by employing the cash flow model to determine the chance of economic success, the mean monetary value in the economic success case and ENPV (see figures 9.6.2 and 9.6.3). The relationship of the reserves size and the monetary value in the cash flow model in this research has been assumed to be linear; hence the mean monetary value in the economic success case is identical to the monetary value in the mean reserves size in the economic success case (i.e. the mean reserve

size of more than the minimum economic reserves size). However, if more realistic cash flow models are established including the dependencies of multi-discovery cases or tax synergy, then the relationship of the reserves size and the monetary value may not be linear. In this case, therefore, the mean monetary value in the economic success case should be calculated after converting the reserves distribution to monetary distribution (see Figure 2.1.7). Also the efficient exploration frontier should be merged, not in terms of the chance of geologic success and reserves mean, but the chance of economic success and the mean monetary value in the economic success case, because the efficiency may be reversed by using the non-linear cash flow model.

10.5 Reward estimation as the mean value of many projects

To control profitability in the exploration business, corporations should deal with as many prospects as possible, using a portfolio construction approach. This is because the reward estimates are derived from the mean values, calculated statistically from the assessments, and the mean value of the future reward from many exploration activities will reach this point.

10.6 Post audit

All estimations need to be reviewed against actual exploration results. A comparison between estimates and results will lead to appropriate modification of criteria for assessment of geologic chance of success and reserves distribution. This quantitative comparison helps us to identify geotechnical weak points in the organisation and appropriate investments to develop them. Several ways for the post audit are represented in Chapter 2.

Chapter 11

Conclusions

11.1 Summary

This study aimed to demonstrate an evaluation procedure for portfolio construction designed for stratigraphic trap exploration in fluvial-lacustrine successions, using several case studies from the Cooper-Eromanga Basin. The approach is listed as follows:

1. Constructing a sequence stratigraphic framework, using key surfaces and stacking patterns to identify depositional systems tracts.
2. Integrating sequence stratigraphic concepts with 3D seismic data visualisation.
3. Extracting a series of stratigraphic trap prospects each categorised by a depositional systems tract.
4. Estimating the chance of geologic success and reserves distribution for each prospect.
5. Plotting all exploration cases in terms of the chance of geologic success *vs.* reserves estimate and determining an efficient exploration frontier.
6. Calculating ENPV for portfolio candidates on the efficient exploration frontier.

The key conclusions are summarised as follows:

The role of risk management in the petroleum exploration business was reviewed including the recognition of the uncertainty versus risk, differences of the risk in the exploration and development stage, the diversification of risk capital, and the concept of risk-reward optimisation. Examples of fields which include stratigraphic trap components were outlined, and the advantages of placing stratigraphic trap prospects into the exploration inventory to diversify risk capital was explained.

The key tools used for this research were quantitative risk analysis, sequence stratigraphy and 3D seismic visualisation. Quantitative risk analysis, as is now being adopted by corporations such as JNOC, was evaluated in this research. The analysis is divided into estimations of the chance of geologic success and probabilistic reserves distribution, development and

production planning, cash flow modelling, estimations of the chance of economic success and reward, and calculation of ENPV. Effective extraction and characterisation of the stratigraphic trap prospects lie in developing a genetic-stratigraphic framework, using sequence stratigraphic concepts as applied to non-marine basins. 3D seismic data visualisation is based on the voxel technique which allows the interpreter to deal with the seismic data as a volume seismic attribute. The integration of sequence stratigraphy and the 3D seismic data visualisation significantly enhances the recognition of stratigraphic trap prospects with reduced uncertainty.

3D seismic data set areas, the Moorari, Pondrinie and Merrimelia 3D seismic surveys in the Cooper-Eromanga Basin, were selected as case study areas. To achieve the aim of the research, the criteria for selecting the case studies were set as: areas where hydrocarbons have already been discovered, in order to concentrate subjects in the reservoir and seal, particularly for stratigraphic traps and to avoid the issue of hydrocarbon generation and migration risks; areas which has field developments to obtain a relatively realistic cash flow model; the areas with good well control enough to conduct sedimentary facies analysis and wireline-based sequence stratigraphy; areas with good quality 3D seismic survey, in order to apply the visualisation technique; and finally areas with well and seismic data that were open file (not confidential) in order to be published.

The overall geologic setting and petroleum systems of the southern Cooper-Eromanga Basin were outlined from the previous studies, and the selected case study areas are located on the GMI structural high trend and in the Patchawarra Trough. The objectives of this research are non-marine successions of the Permian Patchawarra Formation, the Murteree Shale, the Epsilon Formation and the Toolachee Formation, the basal Jurassic Poolowanna Formation, and the middle to late Jurassic Birkhead Formation. Many fields include combined structural and stratigraphic trap components, however hydrocarbon potential of the basin has largely been addressed by drilling the crest of the major anticlines. The matured source rocks and hydrocarbon migration paths were considered as low risk.

In case study 1, the Moorari and Woolkina field areas, six sedimentary facies were interpreted in the Patchawarra Formation, the Murteree Shale, the Epsilon Formation and the Toolachee

Formation, based on wireline logs, cuttings and core descriptions. Three second-order sequences (sequence 10, 20 and 30) were recognised from the spatial relationship among the sedimentary facies. The genetic surfaces from the sequence stratigraphy were tied into the 3D seismic data by employing synthetic seismograms, and each systems tract was visualised as seismic amplitude variation to represent stratigraphic features in each interval. Five stratigraphic traps were extracted from estimations of potential reservoir and seal rocks distributions represented in the seismic amplitude variation. The extracted stratigraphic trap prospects are listed as follows:

- **T10:** Isolated fluvial channels in a transgressive systems tract of the lower Patchawarra Formation.
- **L20E and L20W:** Fluvial sand bodies in low accommodation intervals in a lowstand systems tract of the upper Patchawarra Formation.
- **H20:** Highstand lacustrine delta of the Epsilon Formation below the regional sequence boundary at the base of the Toolachee Formation.
- **T30:** Isolated fluvial channels in the transgressive systems tract of the Toolachee Formation.

Four sedimentary facies were interpreted in the basal Jurassic Poolowanna Formation, and this interval was interpreted as a sequence (sequence 40) comprising transgressive systems tract following the erosional event of the base of the Eromanga Basin. The flooding surface characterised by correlative shaly and coaly interval was tied into the 3D seismic data and a fluvial channel and floodplain complex was represented. One stratigraphic trap prospect was extracted from the interval.

- **T40:** Crevasse splay channels and crevasse splay delta complex of the transgressive systems tract of the Poolowanna Formation.

In case study 2, the Pondrinie and Packsaddle field areas, six sedimentary facies were interpreted in the Patchawarra Formation, the Murteree Shale, the Epsilon Formation and the Toolachee Formation. Two second-order sequences (sequence 20 and 30) were recognised. In the downthrown fault block, the Toolachee Formation including transgressive systems tract of

the sequence 30 was tied into the 3D seismic data and a fluvial channel belt surround by peat mire and floodplain was represented. One stratigraphic trap was extracted from the Toolachee interval:

- **Ttc:** Isolated fluvial channel belt in a transgressive systems tract of the Toolachee Formation.

In the basal Jurassic Poolowanna Formation, four sedimentary facies were recognised and this interval was interpreted as sequence 40, consisting of a transgressive systems tract following the erosional event of the base of the Eromanga Basin. The flooding surface characterised by correlative shaly and coaly interval was tied into the 3D seismic data and the seismic amplitude variation suggested an incised valley on the base of the Jurassic. One stratigraphic trap prospect was extracted from the interval:

- **Tpc:** Transgressive fluvial channel in the incised valley of the Poolowanna Formation.

In case study 3, the Merrimelia, Meranji and Pelican field areas, four sedimentary facies were recognised in the Birkhead Formation. This interval was interpreted as sequence 60 comprising a transgressive systems tract following an erosional event on the top of the Hutton Sandstone. The interval was represented as an amplitude variation in the 3D seismic data and demonstrated meandering channel patterns. Although possible stratigraphic traps could not be recognised in this interval, the volumes of the point bars, which were confirmed as water-wet by wells, were calculated to show the possible amount of oil contained as a stratigraphic trap of 25.6 and 12.6 million barrels in place.

The implications for sequence stratigraphy used in the case study areas included:

- Possible distributions of LST20 (Patchawarra Formation)
- Variation of increasing accommodation rate controlled by a fault activity in TST30 (Toolachee Formation)
- Variation of topographic feature of SB40 (base of the Poolowanna Formation)
- Possible erosional surface of the base of the Hutton Sandstone (SB50)

To estimate a chance of geologic success for a stratigraphic trap, geologic chance factors were addressed, such as reservoir, top seal, lateral seal, bottom seal within a systems tract, seal effectiveness of overlying and underlying systems tract, and an appropriate spatial arrangement of the reservoir and seal. The confidence value for the existence of the geologic chance factors should be assessed by the expression of the existence of the geologic factors, resulting from geologic interpretation, and the quality and quantity of information supporting this geologic interpretation. To assess the confidence values, an index for the subjective expressions of confidence in the existence of a geologic factor was prepared. The criteria for assessing the confidence values were allocated systematically, based on the sequence stratigraphic context, and the chance of geologic success for each prospect was calculated. The highest chance was assessed for L20SW (34%) and the lowest in T40 (4%). Geologically reasonable ranges were given for each parameter which determines the recoverable reserves size, and probabilistic reserves distributions for the prospects were calculated using Monte Carlo simulation. The highest reserves size is evaluated in Tpc (21.2 bcf in mean value) and the lowest in H20 (3.9 bcf in mean value).

The prospect inventory was plotted in terms of chance of geologic success vs. mean reserves and characterised as high-risk/high-return and low-risk/low-return prospects. The efficiency improvement achieved by intersecting multi-prospects by one well was demonstrated in the plot. On plots regarding multi-well exploration by sharing the well costs with partners, an efficient exploration frontier was merged. The exploration cases on the frontier were selected as portfolio candidates for stratigraphic trap exploration in the prospect inventory. The probabilistic reserves distributions for the portfolio candidates on the efficient exploration frontier were converted to NPV distribution by employing one simple cash flow model. Chance of economic success, NPV mean in the economic success case and ENPV were calculated for the portfolio candidates. The highest ENPV was assessed for portfolio C (L20E+T10, ENPV=\$2.2million, chance of economic success=26%). If a corporation prefers a higher chance of economic success, other candidates with positive ENPV and relatively high reward estimates may be chosen (portfolio candidate D, E or F).

Several limitations to be appreciated in the evaluation procedure established in this research were discussed, in particular regarding geologic chance factors, dependencies in multiple

prospects, estimation of maximum case of reserves distribution, cash flow model, reward estimation as mean value of many projects and post audit.

11.2 Concluding statement

The key to managing the exploration business is how to reduce the uncertainty and how to manage the remaining uncertainty in order to minimise risk. The integration of sequence stratigraphy and 3D seismic data visualization reduces the uncertainty of the spatial distribution of reservoir and seal rocks and helps to distinguish effective stratigraphic trap prospects from within what are normally considered high-risk plays. Effectively extracting the stratigraphic traps allows us to increase investment opportunities additionally with conventional traps and to diversify risk capital. By employing quantitative risk assessment and performing a risk-reward optimisation with the prospect inventory, the most effective portfolio can be identified in which a corporation should invest. The evaluation procedure for stratigraphic trap exploration outlined in this thesis should be made consistent with conventional play types to enable a portfolio analysis of all exploration opportunities, thus assisting the risk management of the exploration business.

References

ALEXANDER, E.M. AND SANSOME, A., 1996 – Lithostratigraphy and Environments of Deposition. In: Alexander E.M. and Hibburt J. (ed) Petroleum Geology of South Australia Vol 2: Eromanga Basin. Mines and Energy South Australia, 49-86.

ALEXANDER, E.M., 1996 – Reservoirs and Seals. In: Alexander E.M. and Hibburt J. (ed) Petroleum Geology of South Australia Vol 2: Eromanga Basin. Mines and Energy South Australia, 141-148.

ALEXANDER, E.M., 1998 – Lithostratigraphy and Environments of Deposition. In: Gravestock D.I., Hibburt J.E. & Drexel J.F. (ed) Petroleum Geology of South Australia Vol 4: Cooper Basin. Mines and Energy South Australia, 69-116.

ALEXANDER, J.A. AND LOHR, J.R., 1998 – Risk Analysis: Lessons Learned, SPE 49030, Society of Petroleum Engineers Annual Meeting, New Orleans.

ALLEN, G.P., LANG, S.C. MUSAKTI, O. AND CHIRINOS, A., 1996 – Application of Sequence Stratigraphy to Continental Successions: Implications for Mesozoic Cratonic Interior Basins of Eastern Australia. In: Mesozoic Geology of the Eastern Australia Plate Conference, GSA, Extended Abstract No. 43, Queensland, Australia, 22-26.

AL-SHAIEB, Z., SHELTON, J.W. AND PUCKETTE, J.O., 1989 – Sandstone Reservoirs of the Mid-Continent: Oklahoma City Geological Society Syllabus for Short Course. AAPG Mid-continent section meeting, Oklahoma City.

APAK, S.N., 1994 – Structural Development and Control on stratigraphy and sedimentation in the Cooper Basin, Northeastern South Australia and Southwestern Queensland. NCPGG PhD thesis, University of South Australia (unpublished).

APAK, S.N., STUART, W.J. AND LEMON, N.M., 1993 – Structural-Stratigraphic Development of the Gidgealpa-Merrimelia-Innaminka Trend with Implications for Petroleum Trap Styles, Cooper Basin, Australia. APEA Journal, 33, 94 -104.

APAK, S.N., STUART, W.J., LEMON, N.M. AND WOOD G., 1997 – Structural Evolution of the Permian-Triassic Cooper Basin, Australia: Relation to Hydrocarbon Trap Styles. AAPG Bulletin, 81, 533-555.

BERNSTEIN, P.L., 1996 – Against the Gods, The Remarkable Story of Risk. John Wiley and Sons, New York, 383p.

- BLUM, M.D., 1993 – Genesis and Architecture of Incised Valley Fill Sequences: A Late Quaternary Example from the Colorado River, Gulf Coastal Plain of Texas. In: Weimer P. and Posamentier H.W. (ed) *Siliciclastic Sequence Stratigraphy – Recent Developments and Applications*. AAPG Memoir 58, 259-287.
- BOREHAM, C.J. AND HILL, A.J., 1998 – Source Rock Distribution and Hydrocarbon Geochemistry. In: Gravestock D.I., Hibburt J.E. and Drexel J.F. (ed) *Petroleum Geology of South Australia Vol 4: Cooper Basin*. Mines and Energy South Australia, 129-142.
- BOULT, P.J., LANZILLI, E., MICHAELSEN, B.H., McKIRDY, D.M. AND RYAN, M.J., 1998 – A New Model for the Hutton/Birkhead Reservoir/Seal Couplet and the Associated Birkhead-Hutton (!) Petroleum System. *APPEA Journal*, 38, 724 – 744.
- BOWERING, O.J.W. AND HARRISON, D.M., 1986 – The Merrimelia Oil and Gas Field – a case history. In: Gravestock, D.I., Moore, P.S. and Pitt, G.M. (ed) *Contributions to the geology and hydrocarbon potential of the Eromanga Basin*. Geological Society of Australia. Special Publication, 12, 183-194.
- BROWN, A.R., 1999 – Interpretation of Three-Dimensional Seismic Data, 5th edition. AAPG Memoir 42 and SEG Investigations in Geophysics No.9, 514p.
- CANDIDO, A. AND CORA, C.A.G., 1992 – The Marlim and Albacor Giant Fields, Campos Basin, Offshore Brazil. In: Halbouty M.T. (ed) *Giant Oil and Gas Field of the Decade 1978 to 1988*, AAPG Memoir 54, 123-135.
- CAPEN, E.C., 1992 – Dealing with Exploration Uncertainties. In: Steinmetz, R. (ed) *The Business of Petroleum Exploration*. AAPG Treatise of Petroleum Geology, Handbook of Petroleum Geology, 29-61.
- CLEMENT, W.A., 1991 – East Clinton Field-U.S.A., Anadarko Basin, Oklahoma. In: Foster N.H. and Beaumont E.A. (compilers) *Stratigraphic Traps II*, AAPG Treatise of Petroleum Geology / Atlas of Oil and Gas Fields, 207-268.
- DEIGHTON, I. AND HILL, A.J., 1998 – Thermal and Burial History. In: Gravestock D.I., Hibburt J.E. and Drexel J.F. (ed) *Petroleum Geology of South Australia Vol 4: Cooper Basin*. Mines and Energy South Australia, 143-155.
- DRAGOMIRESCU, R., KALDI, J., LEMON, N. AND ALEXANDER, E., 2001 – Triassic Seals in the Cooper Basin, South Australia. *Proceedings of the Eastern Australasian Basin Symposium 2001*, PESA, 311-320.
- DUNLOP, E.C., BROWNE, N.V. AND TADIAR, E.F., 1992 – Depletion of Gas Reservoirs by Molecular Diffusion – a case study. *APPEA Journal*, 32, 369-390.

- GALLOWAY, W.E., 1989 – Genetic Stratigraphic Sequences in Basin Analysis I: Architecture and Genesis of Flooding-surface Bounded Depositional Units. AAPG Bulletin, 73, 125-142.
- GRAVESTOCK, D.I. AND ALEXANDER, E.M., 1986 – Porosity and Permeability of Reservoirs and Caprocks in the Eromanga Basin, South Australia. APPEA Journal, 26, 202-213.
- GRAVESTOCK, D.I. AND JENSEN-SCHMIDT, B., 1998 – Structural Setting In: Gravestock D.I., Hibburt J.E. and Drexel J.F. (ed) Petroleum Geology of South Australia Vol 4: Cooper Basin. Mines and Energy South Australia, 47-68.
- GRAVESTOCK, D.I., 1982 – Jurassic to Lower Cretaceous Stratigraphy of the Eromanga Basin – Problems and Progress with Subsurface Correlation. In: Moore, P.S. and Mount, T.J. (compilers), Eromanga Basin Symposium, Adelaide. Summary Papers. PESA, GSA, 79-91.
- GRAVESTOCK, D.I., 1996 – Traps. In: Alexander E.M. and Hibburt J. (ed) Petroleum Geology of South Australia Vol 2: Eromanga Basin. Mines and Energy South Australia, 149-152.
- GRAVESTOCK, D.I., ALEXANDER, E.M., MORTON, J.G.G. AND SUN, X., 1998 – Reservoir and Seals. In: Gravestock D.I., Hibburt J.E. and Drexel J.F. (ed) Petroleum Geology of South Australia Vol 4: Cooper Basin. Mines and Energy South Australia, 157-169.
- GREEN, P.M., BRAIN, T.J. AND JOHN, B.H., 1989 – Possible Stratigraphic Controls on Hydrocarbon Distribution within the Jurassic-Early Cretaceous Rocks, Eromanga Basin, Southern Queensland. In: O'Neil, B.J. (ed.) The Cooper and Eromanga Basins, Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG (SA Branches), 251-264.
- HEATH, R., MCINTYRE, S. AND GIBBINS, N., 1989 – A Permian Origin for Jurassic Reservoired Oil in the Eromanga Basin. In: O'Neil, B.J. (ed.) The Cooper and Eromanga Basins, Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG (SA Branches), 405-416.
- HILL, A.J. AND GRAVESTOCK, D.I., 1995 – Cooper Basin. In: Drexel, J.F. and Preiss, W.V. (ed) The Geology of South Australia. Vol 2, The Phanerozoic. GSSA Bulletin 54, 78-87.
- HILLIS, R.R., MORTON, J.G.G., WARNER, D.S. AND PENNEY, R.K., 2001 – Deep Basin Gas: A New Exploration Paradigm in the Nappamerri Trough, Cooper Basin, South Australia. APPEA Journal, 41, 185-200.

- HOWELL, J.A. AND FLINT, S.S., 1996 – A Model for High Resolution Sequence Stratigraphy within Extensional Basins. In: Howell J.A. & Aitken J.F. (ed.) High Resolution Sequence Stratigraphy: Innovations and Applications. Geological Society, London, Special Publications, 104, 129-138.
- HUNT, J.W., HEATH, R.S. AND MCKENZIE, P.F., 1989 – Thermal Maturity and Other Geological Controls on the Distribution and Composition of Cooper Basin hydrocarbons. In: O'Neil, B.J. (ed.) The Cooper and Eromanga Basins, Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG (SA Branches), 510-523.
- JENKINS, C.C., 1989 – Geochemical Correlation of Source Rocks and Crude Oils from the Cooper and Eromanga Basins. In: O'Neil, B.J. (ed.) The Cooper and Eromanga Basins, Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG (SA Branches), 525-540.
- JOHNS, D.R., SQUIRE, S.G. AND RYAN, M.J., 1998 – Measuring Exploration Performance and Improving Exploration Predictions- with Examples from Santos' Exploration Program 1993-96. APPEA Journal, 38, 559-569.
- KIDD, G.D., 1999 – Fundamentals of 3-D Seismic Volume Visualization. The Leading EDGE, 18, 702 - 709.
- KUBOTA, H., MIYANAGA, M. AND NAKANISHI, T., 1999 – A Review of Risk Analysis for Oil and Gas Exploration by JNOC and companies in USA, JNOC Oil and Gas Review 1999 (2), 60-79.
- KUYKENDALL, M.D. AND MATSON, T.E., 1992 – Glenn Pool Field-U.S.A, Northeast Oklahoma Platform, Oklahoma. In: Foster N.H. and Beaumont E.A. (compilers) Stratigraphic Traps III. AAPG Treatise of Petroleum Geology / Atlas of Oil and Gas Fields, 155-188
- LANG, S.C., CEGLAR, N., FORDER, S., SPENCER, G. AND KASSAN, J., 2002 – High Resolution Sequence Stratigraphy, Reservoir Analogues, and 3D Seismic Interpretation – Application to Exploration and Reservoir Development in the Baryulah Complex Cooper Basin, Southwest Queensland. APPEA Journal, 42, 511-522.
- LANG, S.C., GRECH, P., ROOT, R., HILL, A. AND HARRISON, D., 2001 – The Application of Sequence Stratigraphy to Exploration and Reservoir Development in the Cooper-Eromanga-Bowen-Surat Basin System. APPEA Journal, 41, 223-250.

- LANG, S.C., KASSAN, J., BENSON, J.M., GRASSO, C.A. AND AVENELL, L.C., 2000 – Applications of Modern and Ancient Geological Analogues in Characterisation of Fluvial and Fluvial-Lacustrine Deltaic Reservoirs in the Cooper Basin. *APPEA Journal*, 40, 393-416.
- LE FEVER, R.D. AND LE FEVER, J.A., 1991 – Newburg and South Westhope Fields-U.S.A, Williston Basin, North Dakota. In: Foster N.H. and Beaumont E.A. (compilers) *Stratigraphic Traps II*, AAPG Treatise of Petroleum Geology / Atlas of Oil and Gas Fields, 161-188.
- LEGARRETA, L. AND ULIANA, M.A., 1998 – Anatomy of Hinterland Depositional Sequences: Upper Cretaceous Fluvial Strata, Neuquen Basin, West-Central Argentina. In: Shanley, K.W. and McCabe, P.J. (ed) *Relative Role of Eustasy Climate, and Tectonism in Continental Rocks*. SEPM Special Publication, 59, 83-92.
- LEGARRETA, L., ULIANA, M.A., LAROTONDA, C.A. AND MECONI, G.R., 1993 – Approaches to Nonmarine Sequence Stratigraphy-Theoretical Models and Examples from Argentine Basins in *Proceedings of Institute Francais du Petrole*. In: Eschard R. & Doliez B. (ed) *Conference on Exploration and Production: Subsurface Reservoir Characterization from Surface Observations*, April 12-17, 1992, Scarborough, England, Publ. IFP, Technip Methuen, London, New York.
- MACKENZIE, D.B., 1972 – Primary Stratigraphic Traps in Sandstone. In: *Stratigraphic Oil and Gas Fields*, AAPG Memoir 16, 47-81.
- MACKIE, S.I. AND GUMLEY, C.M., 1995 – The Dirkala South Oil Discovery: Focussing on Cost-Efficient Reservoir Delineation. *APEA Journal*, 35, 65-78.
- MCCABE, P.J., 1984 – Depositional Environments of Coal and Coal-Bearing Strata. In: Rahmani, R.A. and Flores, R.M. (ed) *Sedimentology of Coal and Coal-bearing Sequences*. IAS Spec. Publs, 7, 13-42.
- MCDONOUGH, R., 1997 – Economics of Gas Gathering and Processing in the Cooper Basin. *Mines and Energy South Australia*, 11p.
- MCMASTER, G.E., 1998 – New Trends in Exploration Risk Analysis, New Technologies in Hydrocarbon Exploration and Production and Their Impact on World Oil Reserves. Repsol Foundation Madrid Spain, April 1998.
- MEGILL, R.E., 1984 – *An Introduction to Exploration Risk Analysis*, 2nd edition. PennWell Publishing Co., Tulsa, Okla., 273p.
- MIALL, A.D., 1992 – Alluvial Deposits. In: Walker, R.G. and James, N.P. (ed) *Facies Models*. 119-142. Geological Association of Canada.

- MICHAELSEN, B.H. AND McKIRDY, D.M., 1996 – Source Rock Distribution and Hydrocarbon Geochemistry. In: Alexander E.M. and Hibburt J. (ed) Petroleum Geology of South Australia Vol 2: Eromanga Basin. Mines and Energy South Australia, 101-110.
- MITCHUM, R. M., 1977 – Seismic Stratigraphy and Global Changes of Sea Level, Part 11: Glossary of Terms Used in Seismic Stratigraphy. In: Payton C.E. (ed) Seismic Stratigraphy: Applications to Hydrocarbon Exploration, AAPG Memoir 26, 205-212.
- MOORE, P.S., HOBDAI, D.K., MAI, H. AND SUN, Z.C., 1986 – Comparison of Selected Non-marine Petroleum-bearing Basins in Australia and China. APPEA Journal, 26, 285-309.
- MORTON, J.G.G., 1989 – Petrophysics of Cooper Basin reservoirs in South Australia. In: O'Neil B.J. (ed.) The Cooper and Eromanga Basins Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG, 153-63.
- MORTON, J.G.G., 1996 – Undiscovered Petroleum Resources. In: Alexander E.M. and Hibburt J. (ed) Petroleum Geology of South Australia Vol 2: Eromanga Basin. Mines and Energy South Australia, 181-185.
- MOUSSAVI-HARAMI, R., 1996 – Burial History. In: Alexander E.M. and Hibburt J. (ed) Petroleum Geology of South Australia Vol 2: Eromanga Basin. Mines and Energy South Australia, 125-140.
- NAKANISHI, T. AND LANG, S.C., 2001a – The Search for Stratigraphic Traps Goes On-Visualisation of Fluvial-Lacustrine Successions in the Moorari 3D Survey, Cooper-Eromanga Basin. APPEA Journal, 41, 115 – 137.
- NAKANISHI, T. AND LANG, S.C., 2001b – Visualisation of Fluvial Stratigraphic Trap Opportunities in the Pondrinie 3D Survey, Cooper-Eromanga Basin. Proceedings of the Eastern Australasian Basin Symposium 2001, PESA, 301-310.
- NAKANISHI, T. AND LANG, S.C., 2002 – Towards an Efficient Exploration Frontier: Constructing a Portfolio of Stratigraphic Traps in Fluvial-lacustrine Successions, Cooper-Eromanga Basin. APPEA Journal, 42, 131-150.
- NAKANISHI, T., 2000 – Quantitative Geologic Risk Evaluation and Expected Net Present Value Evaluation in JNOC's Projects. Journal of the Japanese Association for Petroleum Technology, 65 (3), 217-228.
- PASSMORE, V.L., 1989 – Petroleum Accumulations of the Eromanga Basin: A Comparison with Other Australian Mesozoic Accumulations. In: O'Neil, B.J. (ed.) The Cooper and Eromanga Basins, Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG (SA Branches), 371-389.

- PATON, I.M., 1986 – The Birkhead Formation — a Jurassic Petroleum Reservoir. In: Gravestock, D.I., Moore, P.S. and Pitt, G.M. (ed) Contributions to the geology and hydrocarbon potential of the Eromanga Basin. GSA. Special Publication, 12, 195-201.
- PERES, W.E., 1993 – Shelf-Fed Turbidite System Model and Its Application to the Oligocene Deposits of the Campos Basin, Brazil. AAPG Bulletin, 77, 81-101.
- PLINT, A.G. AND NUMMEDAL, D., 2000 – The Falling Stage Systems Tract: Recognition and Importance in Sequence Stratigraphic Analysis. In: Hunt, D. and Gawthorpe, R.L. (ed) Sedimentary Responses to Forced Regressions. Geological Society, London, Special Publications, 172, 1-17.
- POSAMENTIER, H.W. AND ALLEN, G.P., 1999 – Siliciclastic Sequence Stratigraphy – Concepts and Applications. SEPM Concepts in Sedimentology and Paleontology #7, 210p.
- POSAMENTIER, H.W. AND CHAMBERLAIN, C.J., 1993 – Sequence-stratigraphic analysis of Viking Formation lowstand beach deposits at Joarcam Field, Alberta, Canada. In: Posamentier, H.W., Summerhayes, C.P., Haq, B.U. and Allen, G.P. (ed) Sequence Stratigraphy and Facies Associations. Spec. Publs., Int. Ass. Sediment, 18, 469-485.
- POSAMENTIER, H.W. AND MORRIS, W.R., 2000 – Aspects of the Stratal Architecture of Forced Regressive Deposits. In: Hunt, D. and Gawthorpe, R.L. (ed) Sedimentary Responses to Forced Regressions. Geological Society, London, Special Publications, 172, 19-46.
- POSAMENTIER, H.W. AND VAIL, P.R., 1988 – Eustatic Controls on Clastic Deposition II, Sequence and Systems Tract Models. In: Wilgus, C.K., Hastings, B.S., Kendall, C.G.St.C., Posamentier, H.W., Ross, C.A. and Van Wagoner, J.C. (ed) Sea-Level Changes: An Integrated Approach. SEPM Special Publication, 42, 125-154.
- POSAMENTIER, H.W., ALLEN, G.P., JAMES, D.P. AND TESSON, M., 1992 – Forced Regressions in a Sequence Stratigraphic Framework: Concepts, Examples, and Exploration Significance. AAPG Bulletin, 76, 1687-1709.
- POSAMENTIER, H.W., JERVEY, M.T. AND VAIL, P.R., 1988 – Eustatic Controls on Clastic Deposition I, Conceptual Framework. In: Wilgus, C.K., Hastings, B.S., Kendall, C.G.St.C., Posamentier, H.W., Ross, C.A. and Van Wagoner, J.C. (ed) Sea-Level Changes: An Integrated Approach. SEPM Special Publication, 42, 109-124.
- ROSE, P.R., 1987 – Dealing with Risk and Uncertainty in Exploration: How Can We Improve? AAPG Bulletin, 71, 1-16.

- ROSE, P.R., 1992a – Chance of Success and Its Use in Petroleum Exploration. In: Steinmetz, R. (ed) *The Business of Petroleum Exploration*. AAPG, *Treatise of Petroleum Geology, Handbook of Petroleum Geology*, 71-86.
- ROSE, P.R., 1992b – Risk Behaviour in Petroleum Exploration. In: Steinmetz, R. (ed) *The Business of Petroleum Exploration*. AAPG, *Treatise of Petroleum Geology, Handbook of Petroleum Geology*, 95-104.
- ROSE, P.R., 1997 – Risk Analysis of Petroleum Exploration Ventures by Modern Corporations, a report commissioned by JNOC (unpublished).
- ROSE, P.R., 1998 – Exploration Plays: Risk Analysis and Economic Assessment, a report commissioned by JNOC (unpublished).
- ROSE, P.R., 2001 – Risk Analysis and Management of Petroleum Exploration Ventures. AAPG, *Methods in Exploration* 12, 164p.
- SALTER, D.J., 1998 – 3D Seismic Interpretation of the Moorari/Woolkina Field: Stratigraphic and Structural Analyses of the Basal Jurassic, Toolachee and Epsilon Intervals; Cooper Basin, South Australia. NCPGG Honours thesis, University of South Australia (unpublished).
- SCHLAGER, W., 1993 – Accommodation and Supply – A Dual Control on Stratigraphic Sequences. *Sedimentary Geology*, 86, 111-136.
- SCHUMM, S.A., 1992 – River Response to Baselevel Change: Implications for Sequence Stratigraphy. *The Journal of Geology*, 101, 279-294.
- SEGGIE, R.J., 1997 – Reservoir Characterisation of the Moorari/Woolkina Field Complex, Cooper Basin. *APPEA Journal*, 37, 70-86.
- SHANLEY, K.W. AND McCABE, P.J., 1994 – Perspectives on the Sequence Stratigraphy of Continental Strata. *AAPG Bulletin*, 78, 544-568.
- SHELTON, J.W., 1973 – Models of Sand and Sandstone Deposits: A Methodology for Determining Sand Genesis and Trend, *Oklahoma Geological Survey Bulletin*, 118, 122p
- SMITH, B.L., 1983 – Seismic Investigation of the Merrimelia Field. *APEA Journal*, 23, 192-202.
- STANMORE, P.J. AND JOHNSTONE E.M., 1988 – The Search for Stratigraphic Traps in the Southern Patchawarra Trough, South Australia. *APEA Journal*, 28, 156-166.

- STANMORE, P.J., 1989 – Case Studies of Stratigraphic and Fault Traps in the Cooper Basin, Australia. In: O'Neil, B.J. (ed.) The Cooper and Eromanga Basins, Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG (SA Branches), 361-369.
- TAYLOR, S., SOLOMON, G., TUPPER, N., EVANOCHKO, J., HORTON, G., WALDECK, R. AND PHILLIPS, S., 1991 – Flank Plays and Faulted Basement: New Directions for the Cooper Basin . APEA Journal, 31, 56 - 73.
- THORNTON, R.C.N., 1979 – Regional Stratigraphic Analysis of the Gidgealpa Group, Southern Cooper Basin, Australia. GSSA, Bulletin, 49, 134p.
- VAIL, P.R., MITCHUM, R.M. AND THOMPSON, S.,III, 1977 – Seismic Stratigraphy and Global Changes of Sea Level, Part 3: Relative Changes of Sea Level from Coastal Onlap. In: Payton C.E. (ed) Seismic Stratigraphy: Applications to Hydrocarbon Exploration, AAPG Memoir 26, 63-97.
- VAN WAGONER, J.C., MITCHUM, R.M, CAMPION, K.M. AND RAHMANIAN, V.D., 1990 – Siliciclastic Sequence Stratigraphy in Well logs, Cores, and Outcrops. AAPG Methods in Exploration Series, 7, 55p.
- VAN WAGONER, J.C., POSAMENTIER, H.W., MITCHUM, R.M, VAIL, P.R., SARG, J.F., LOUIT, T.S. AND HARDENBOL, J., 1988 – An Overview of Sequence Stratigraphy and Key Definitions In: Wilgus, C.K., Hastings, B.S., Kendall, C.G.St.C., Posamentier, H.W., Ross, C.A. and Van Wagoner, J.C. (ed) Sea-Level Changes: An Integrated Approach. SEPM Special Publication, 42, 39-45.
- WATTS, K.J., 1987 – The Hutton Sandstone–Birkhead Formation Transition, ATP 269(P), Eromanga Basin. APEA Journal, 27, 215-227.
- WEIMER, P. AND POSAMENTIER, H.W., 1993 – Recent Developments and Applications in Siliciclastic Sequence Stratigraphy. In: Weimer, P. and Posamentier, H.W. (ed) Siliciclastic Sequence Stratigraphy – Recent Developments and Applications, AAPG Memoir 58, 3-12.
- WESCOTT, W.A., 1993 – Geomorphic Thresholds and Complex Response of Fluvial Systems – Some Implications for Sequence Stratigraphy. AAPG Bulletin , 77, 1208-1218.
- WHITFORD, D.J., HAMILTON, P.J. AND SCOTT, J., 1994 – Sedimentary Provenance Studies in Australian Basins Using Neodymium Model Ages. APEA Journal, 34, 320-329.
- WILLIS, A.J. AND MOSLOW, T.F., 1994 – Stratigraphic Setting of Transgressive Barrier-Island Reservoirs with an Example from the Triassic Halfway Formation, Wembley Field, Alberta, Canada. AAPG Bulletin, 78, 775-791.

WILTSHIRE, M.J., 1982 – Late Triassic and Early Jurassic Sedimentation in the Great Artesian Basin. In: Moore, P.S. and Mount, T.J. (compilers), Eromanga Basin Symposium, Adelaide, 1982. Summary papers. PESA, GSA, 279-291.

WILTSHIRE, M.J., 1989 – Mesozoic Stratigraphy and Palaeogeography, Eastern Australia. In: O'Neil, B.J. (ed.), The Cooper and Eromanga Basins, Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG (SA Branches), 279-291.

WRIGHT, V.P. AND MARRIOTT, S.B., 1993 – The Sequence Stratigraphy of Fluvial Depositional Systems: the Role of Floodplain Sediment Storage. *Sedimentary Geology*, 86, 203-210.

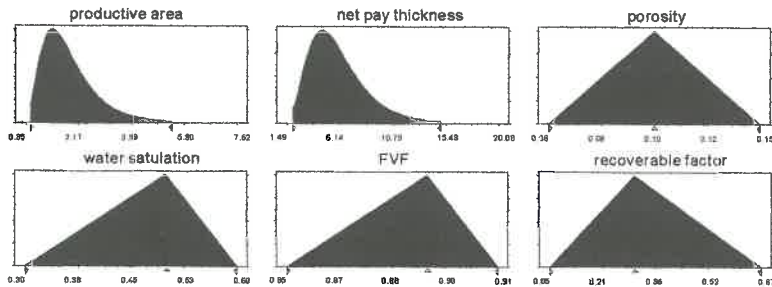
YEW, C.C. AND MILLS, A.A., 1989 – The Occurrence and Search for Permian Oil in the Cooper Basin, Australia. In: O'Neil B.J. (ed.) The Cooper and Eromanga Basins Australia. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. PESA, SPE, ASEG, 339-359.

APPENDIX A

Prospect: T40

Chance of geologic success: 0.04

Input Data	Unit	Shape	P99/min	P90	P50	P10	P1/max	mode	mean
productive area	km2	Lognormal	0.50	0.87	1.64	3.09	5.40	1.40	1.84
net pay thickness	m	Lognormal	2.00	3.21	5.48	9.36	15.00	4.26	5.91
porosity		Triangular	0.06	0.08	0.10	0.13	0.15	0.10	0.10
water saturation		Triangular	0.30	0.38	0.47	0.55	0.60	0.50	0.47
FVF		Triangular	0.85	0.87	0.88	0.90	0.91	0.89	0.88
recoverable factor		Triangular	0.05	0.17	0.33	0.52	0.67	0.29	0.34



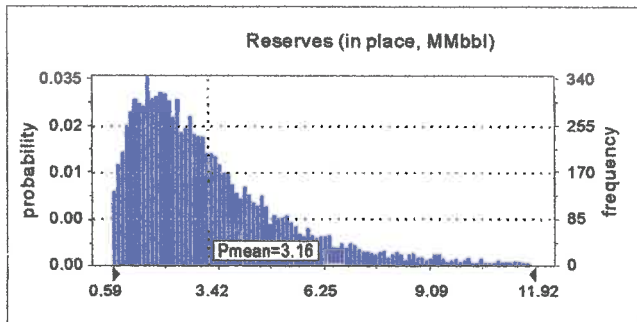
Result

		PmeanPr @mean	PmodePr @mode	P10/P90	
in place	MMbbl	3.16	39	1.55	78
recoverable reserves	bcf	6.40	37	2.82	76

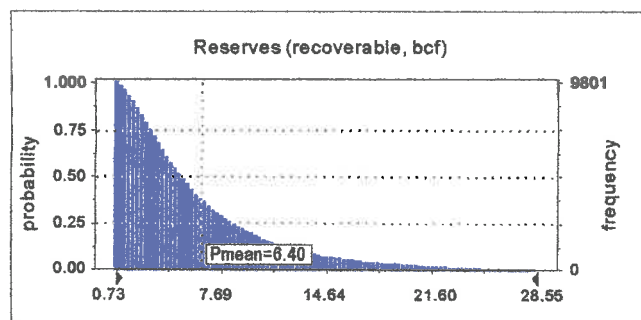
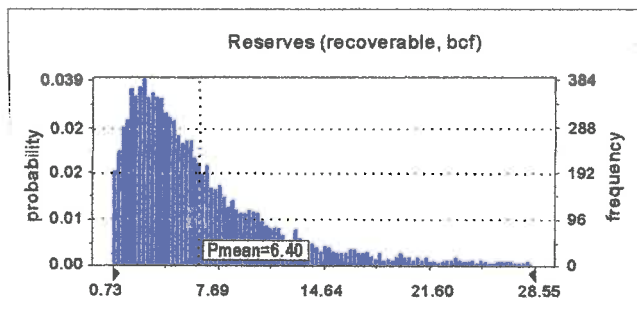
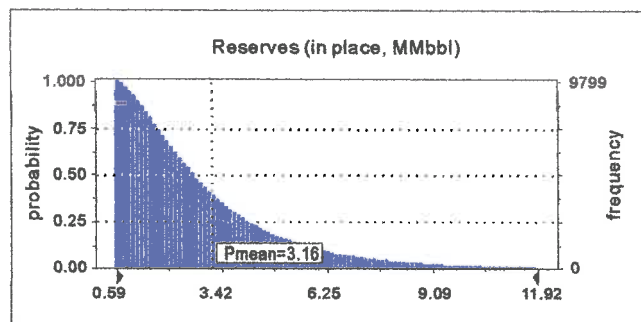
gas equivalent (cf)=oil(bbl) x 6000

		P99	P90	P80	P70	P60	P50	P40	P30	P20	P10	P1
in place	MMbbl	0.59	1.09	1.48	1.84	2.21	2.65	3.11	3.73	4.61	6.12	11.92
recoverable reserves	bcf	0.73	1.74	2.52	3.29	4.09	5.00	6.09	7.53	9.70	13.29	28.55

Frequency distribution



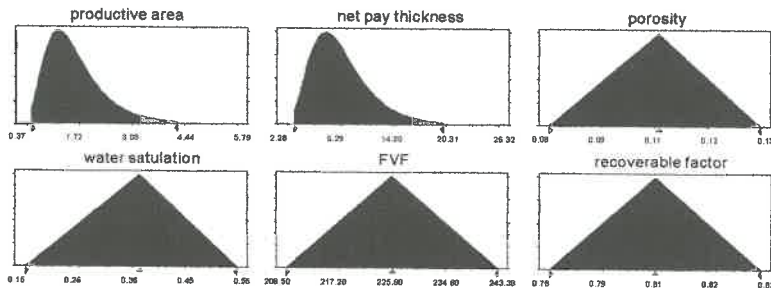
Reverse cumulative distribution



Prospect: T30

Chance of geologic success: 0.18

Input Data	Unit	Shape	P99/min	P90	P50	P10	P1/max	mode	mean
productive area	km2	Lognormal	0.50	0.83	1.46	2.58	4.25	1.27	1.60
net pay thickness	m	Lognormal	3.00	4.88	7.75	12.83	20.00	7.53	8.29
porosity		Triangular	0.08	0.09	0.11	0.12	0.13	0.11	0.11
water saturation		Triangular	0.16	0.25	0.36	0.47	0.55	0.36	0.36
FVF		Triangular	208.50	216.28	225.90	235.52	243.30	226.40	225.92
recoverable factor		Triangular	0.78	0.79	0.81	0.82	0.83	0.80	0.80

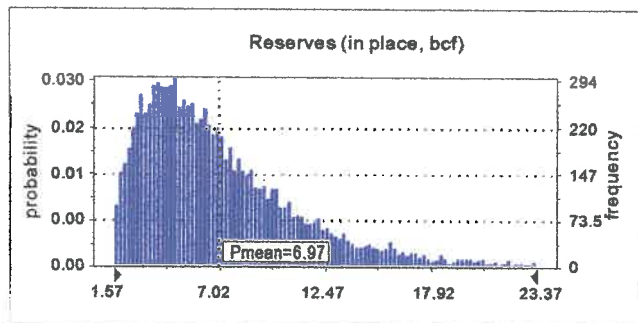


Result

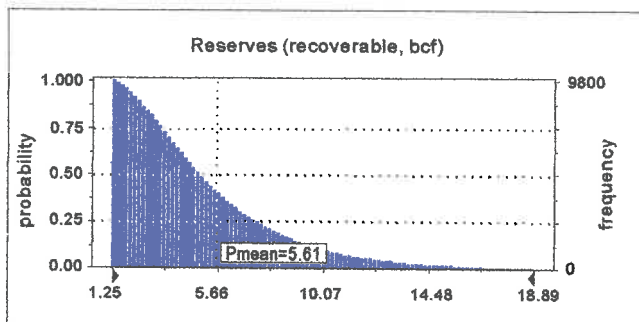
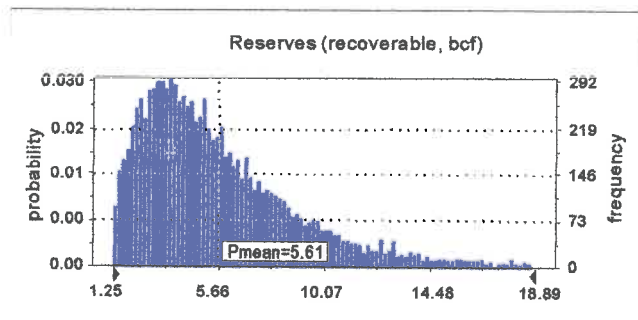
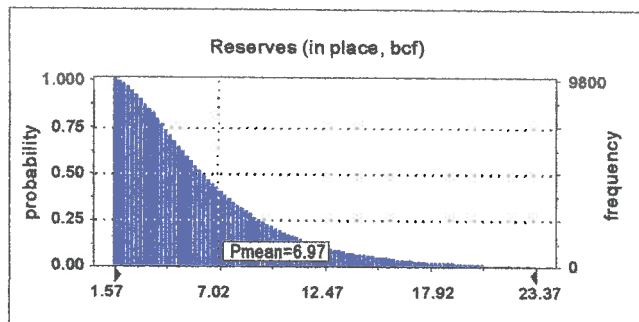
		PmeanPr @mean	PmodePr @mode	P10/P90	
in place	bcf	6.97	40	4.73	65
recoverable reserves	bcf	5.61	40	3.63	68

		P99	P90	P80	P70	P60	P50	P40	P30	P20	P10	P1
in place	bcf	1.57	2.74	3.60	4.36	5.14	6.04	7.01	8.26	9.98	12.76	23.37
recoverable reserves	bcf	1.25	2.20	2.89	3.51	4.14	4.86	5.65	6.66	8.03	10.29	18.89

Frequency distribution



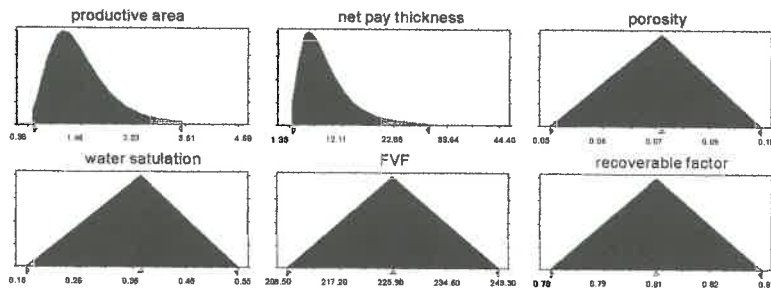
Reverse cumulative distribution



Prospect: H2O

Chance of geologic success: 0.17

Input Data	Unit	Shape	P99/min	P90	P50	P10	P1/max	mode	mean
productive area	km2	Lognormal	0.50	0.79	1.33	2.24	3.53	1.09	1.44
net pay thickness	m	Lognormal	2.00	3.77	7.75	15.92	30.00	4.61	8.97
porosity		Triangular	0.05	0.06	0.08	0.09	0.10	0.08	0.08
water saturation		Triangular	0.16	0.25	0.36	0.47	0.55	0.36	0.36
FVF		Triangular	208.50	216.28	225.90	235.52	243.30	226.40	225.92
recoverable factor		Triangular	0.78	0.79	0.81	0.82	0.83	0.80	0.80

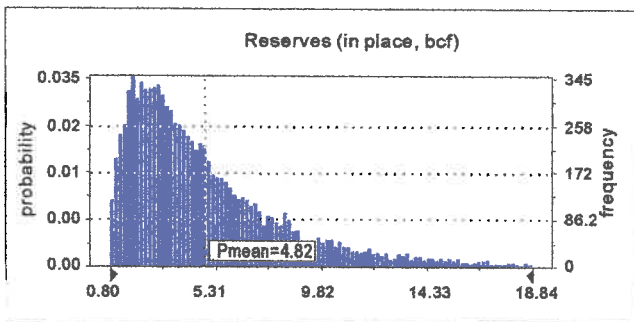


Result

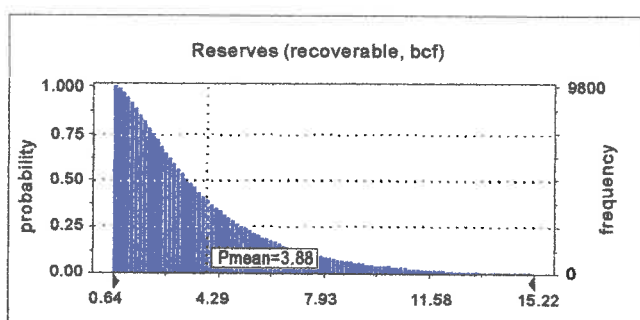
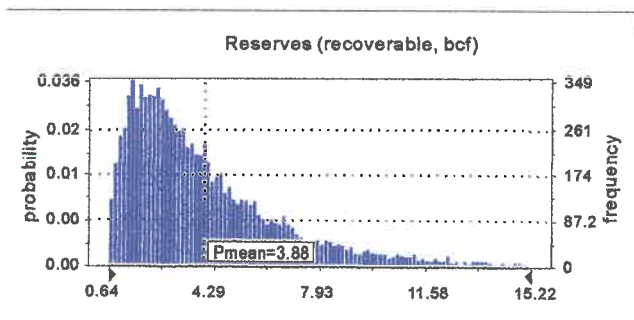
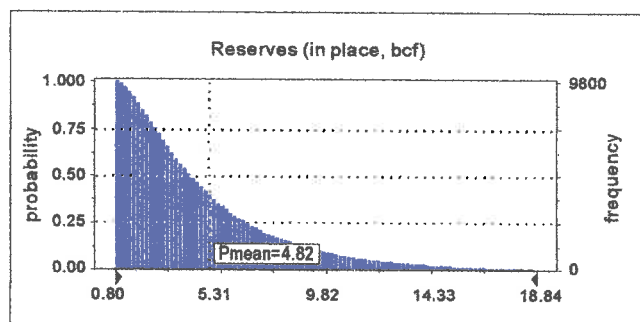
		PmeanPr @mean	PmodePr @modeP10/P90
in place	bcf	4.82 39	1.79 86
recoverable reserves	bcf	3.88 39	1.44 86

		P99	P90	P80	P70	P60	P50	P40	P30	P20	P10	P1
in place	bcf	0.80	1.57	2.13	2.68	3.24	3.91	4.70	5.68	7.11	9.67	18.84
recoverable reserves	bcf	0.64	1.26	1.72	2.15	2.61	3.15	3.78	4.57	5.72	7.80	15.22

Frequency distribution



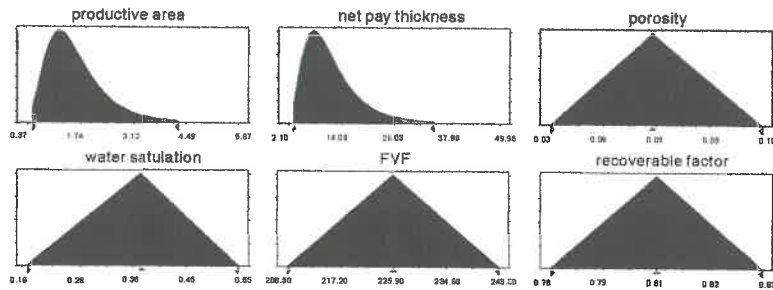
Reverse cumulative distribution



Prospect: L20SW

Chance of geologic success: 0.34

Input Data	Unit	Shape	P99/min	P90	P50	P10	P1/max	mode	mean
productive area	km2	Lognormal	0.50	0.83	1.47	2.60	4.30	1.27	1.61
net pay thickness	m	Lognormal	3.00	5.33	10.25	19.69	35.00	9.88	11.49
porosity		Triangular	0.08	0.08	0.09	0.10	0.10	0.09	0.09
water saturation		Triangular	0.16	0.25	0.36	0.47	0.55	0.36	0.36
FVF		Triangular	208.50	216.28	225.90	235.52	243.30	226.40	225.92
recoverable factor		Triangular	0.78	0.79	0.81	0.82	0.83	0.80	0.80

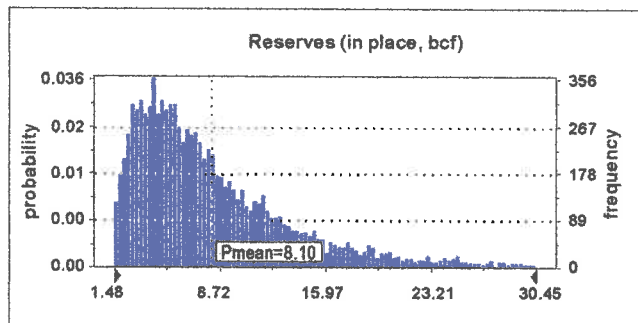


Result

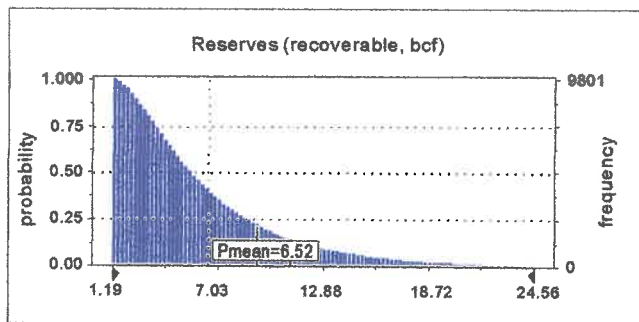
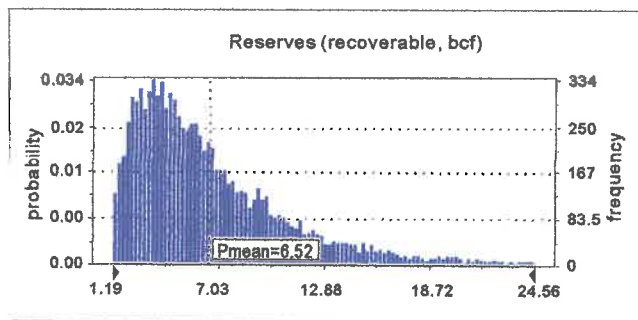
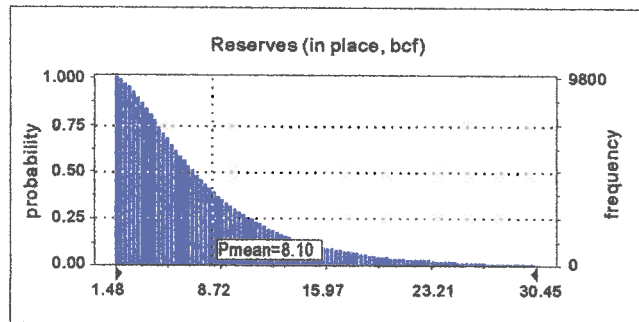
		PmeanPr @mean	PmodePr @mode	P10/P90
in place	bcf	8.10	39	4.23
recoverable reserves	bcf	6.52	39	3.41

		P99	P90	P80	P70	P60	P50	P40	P30	P20	P10	P1
in place	bcf	1.48	2.80	3.75	4.67	5.62	6.71	7.95	9.58	11.87	15.71	30.45
recoverable reserves	bcf	1.19	2.25	3.01	3.76	4.51	5.41	6.40	7.72	9.57	12.67	24.56

Frequency distribution



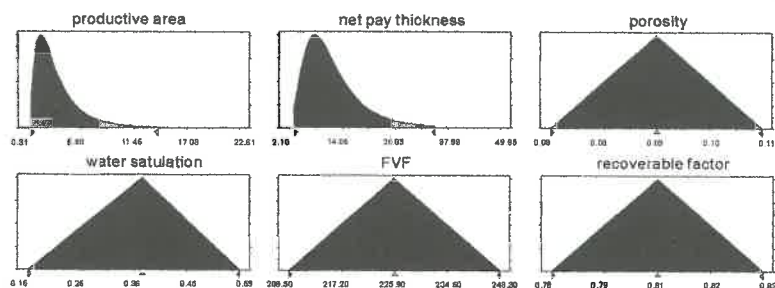
Reverse cumulative distribution



Prospect: L20E

Chance of geologic success: 0.31

Input Data	Unit	Shape	P99/min	P90	P50	P10	P1/max	mode	mean
productive area	km2	Lognormal	0.50	1.09	2.65	6.41	13.97	2.15	3.30
net pay thickness	m	Lognormal	3.00	5.33	10.25	19.69	35.00	9.88	11.50
porosity		Triangular	0.08	0.08	0.09	0.10	0.11	0.09	0.09
water saturation		Triangular	0.16	0.25	0.36	0.47	0.55	0.36	0.36
FVF		Triangular	208.50	216.28	225.90	235.52	243.30	226.40	225.92
recoverable factor		Triangular	0.78	0.79	0.81	0.82	0.83	0.80	0.80

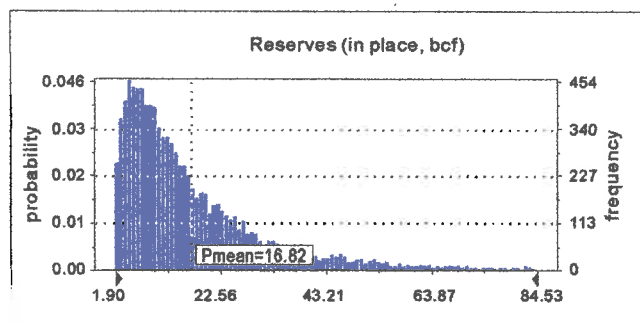


Result

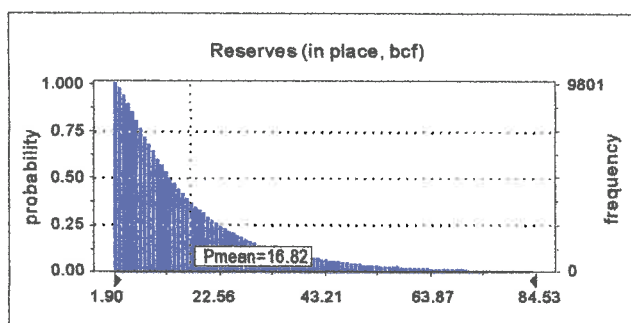
		PmeanPr @mean	PmodePr @mode	P10/P90
in place	bcf	16.82	36	4.79
recoverable reserves	bcf	13.54	36	3.88

		P99	P90	P80	P70	P60	P50	P40	P30	P20	P10	P1
in place	bcf	1.90	4.14	6.00	7.94	10.03	12.55	15.50	19.72	25.56	36.63	84.53
recoverable reserves	bcf	1.53	3.32	4.83	6.38	8.06	10.07	12.48	15.82	20.55	29.50	68.76

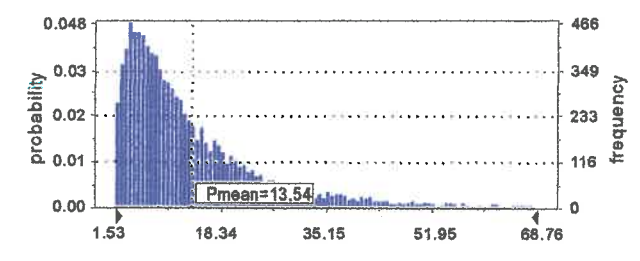
Frequency distribution



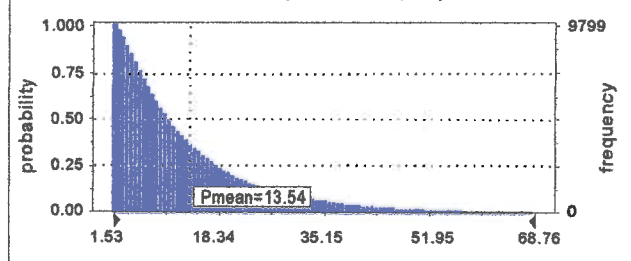
Reverse cumulative distribution



Frequency distribution



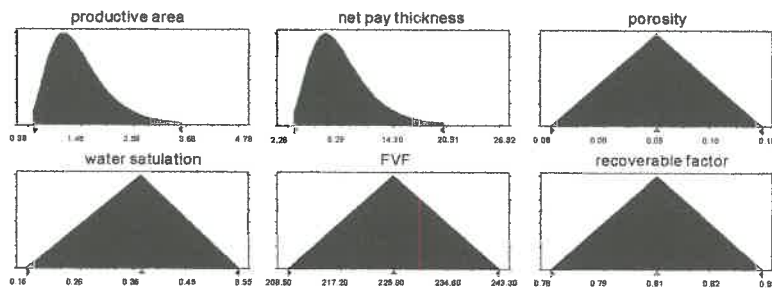
Reverse cumulative distribution



Prospect: T10

Chance of geologic success: 0.18

Input Data	Unit	Shape	P99/min	P90	P50	P10	P1/max	mode	mean
productive area	km2	Lognormal	0.50	0.79	1.34	2.27	3.60	1.19	1.45
net pay thickness	m	Lognormal	3.00	4.68	7.75	12.83	20.00	7.53	8.29
porosity		Triangular	0.08	0.08	0.09	0.10	0.10	0.09	0.09
water saturation		Triangular	0.16	0.25	0.36	0.47	0.55	0.36	0.36
FVF		Triangular	208.50	216.28	225.90	235.52	243.30	226.40	225.92
recoverable factor		Triangular	0.78	0.79	0.81	0.82	0.83	0.80	0.80

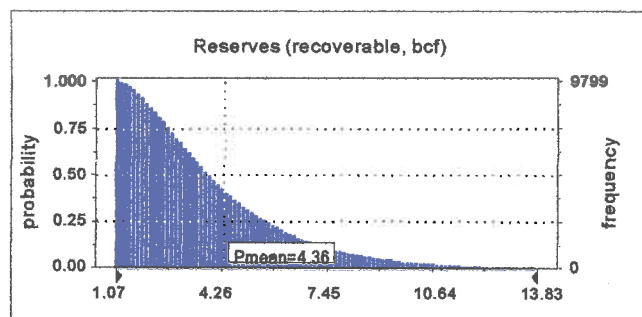
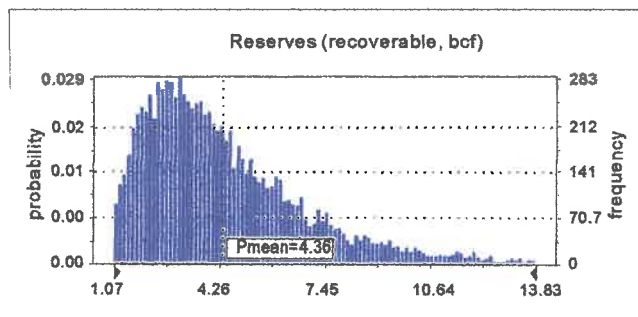
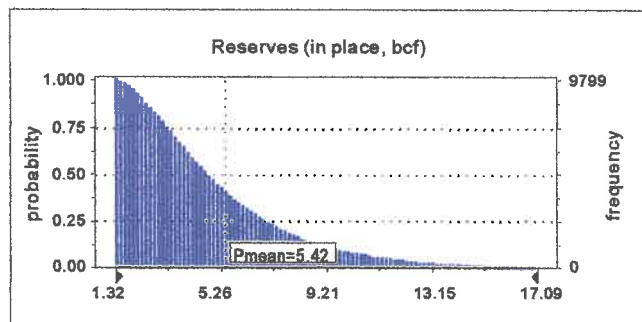
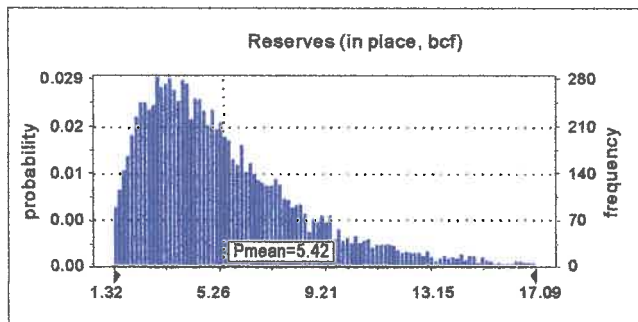


Result

		PmeanPr @mean		PmodePr @mode		P10/P90						
in place	bcf	5.42	41	2.98	79	4.32						
recoverable reserves	bcf	4.36	41	3.04	65	4.32						
		P99	P90	P80	P70	P60	P50	P40	P30	P20	P10	P1
in place	bcf	1.32	2.25	2.91	3.47	4.08	4.73	5.47	6.41	7.64	9.72	17.09
recoverable reserves	bcf	1.07	1.81	2.34	2.80	3.28	3.81	4.40	5.16	6.15	7.81	13.83

Frequency distribution

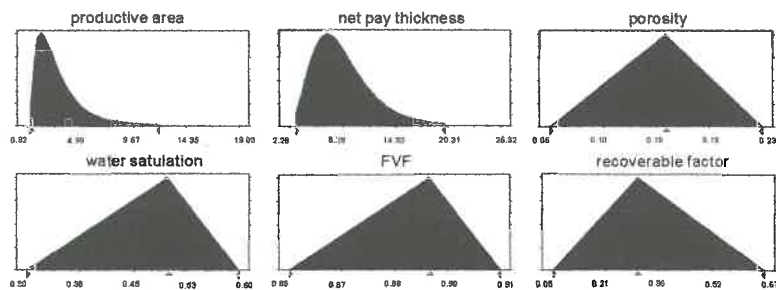
Reverse cumulative distribution



Prospect: Tpc

Chance of geologic success: 0.05

Input Data	Unit	Shape	P99/min	P90	P50	P10	P1/max	mode	mean
productive area	km2	Lognormal	0.50	1.05	2.45	5.70	12.01	1.49	2.99
net pay thickness	m	Lognormal	3.00	4.68	7.75	12.83	20.00	7.53	8.29
porosity		Triangular	0.06	0.10	0.15	0.19	0.23	0.15	0.15
water saturation		Triangular	0.30	0.38	0.47	0.55	0.60	0.50	0.47
FVF		Triangular	0.85	0.87	0.88	0.90	0.91	0.89	0.88
recoverable factor		Triangular	0.05	0.17	0.33	0.52	0.67	0.29	0.34



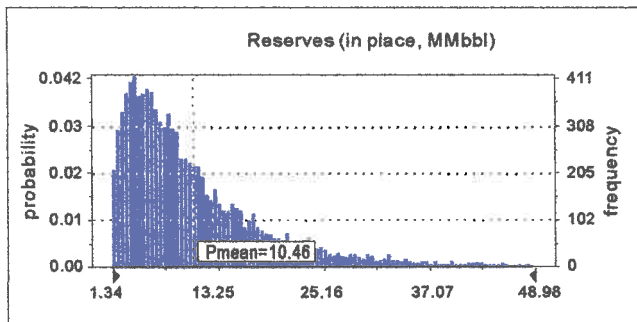
Result

		PmeanPr @mean	PmodePr @mode	P10/P90	
in place	MMbbl	10.46	37	3.96	81
recoverable reserves	bcf	21.17	36	7.91	76

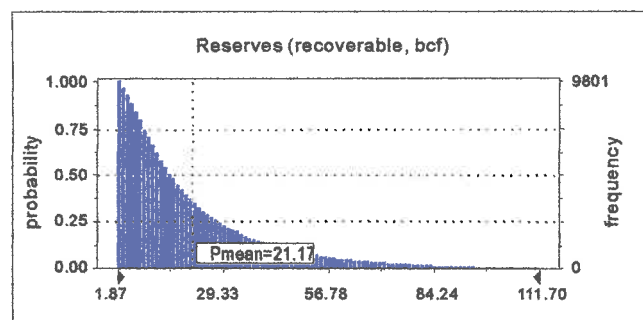
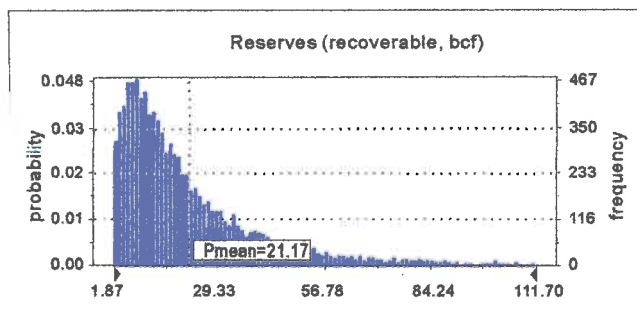
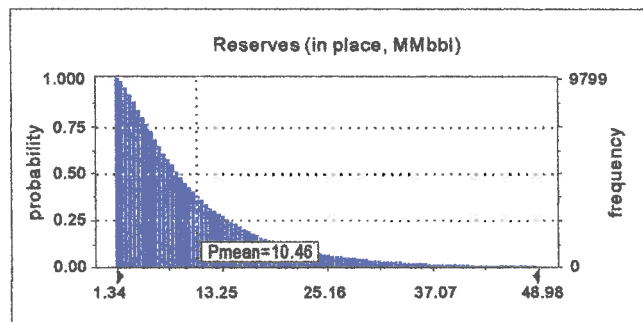
gas equivalent (cf)=oil(bbl) x 6000

		P99	P90	P80	P70	P60	P50	P40	P30	P20	P10	P1
in place	MMbbl	1.34	2.84	4.03	5.30	6.61	8.14	9.93	12.29	15.87	22.09	48.98
recoverable reserves	bcf	1.87	4.62	7.10	9.51	12.21	15.30	19.20	24.45	32.69	47.04	111.70

Frequency distribution



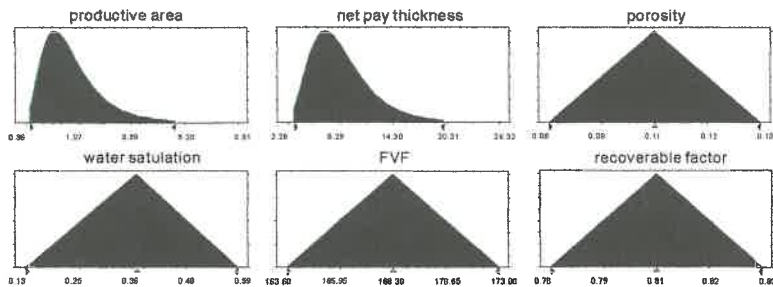
Reverse cumulative distribution



Prospect: Ttc

Chance of geologic success: 0.20

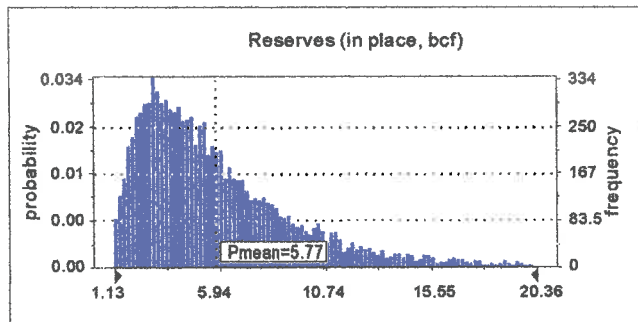
Input Data	Unit	Shape	P99/min	P90	P50	P10	P1/max	mode	mean
productive area	km2	Lognormal	0.50	0.86	1.57	2.88	4.90	1.11	1.74
net pay thickness	m	Lognormal	3.00	4.68	7.75	12.83	20.00	5.88	8.34
porosity		Triangular	0.08	0.09	0.11	0.12	0.13	0.11	0.11
water saturation		Triangular	0.13	0.24	0.36	0.49	0.59	0.36	0.36
FVF		Triangular	163.60	165.70	168.30	170.90	173.00	167.85	168.31
recoverable factor		Triangular	0.78	0.79	0.81	0.82	0.83	0.80	0.80



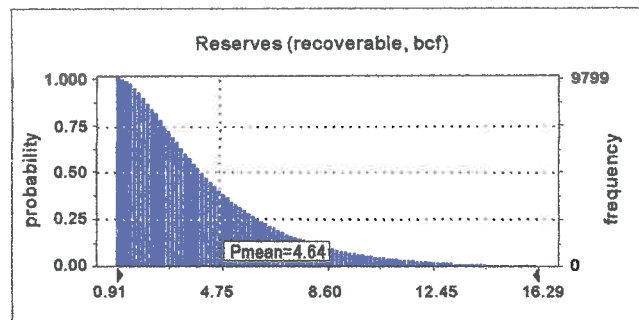
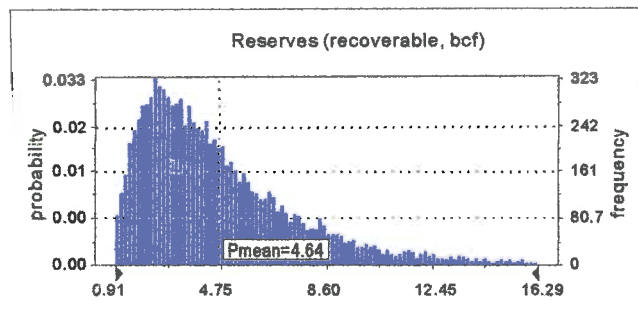
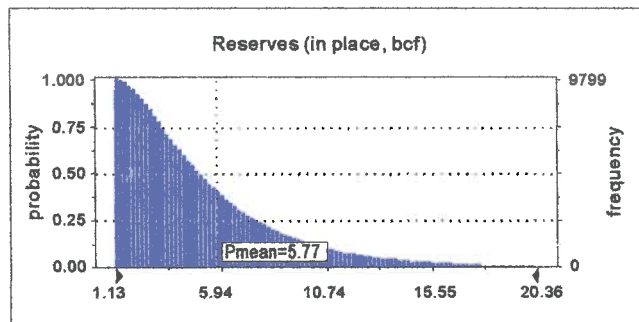
Result

		PmeanPr @mean	PmodePr @mode	P10/P90								
in place	bcf	5.77	40	2.96	78	5.04						
recoverable reserves	bcf	4.64	40	2.37	78	5.03						
		P99	P90	P80	P70	P60	P50	P40	P30	P20	P10	P1
in place	bcf	1.13	2.16	2.84	3.46	4.14	4.88	5.74	6.83	8.34	10.91	20.36
recoverable reserves	bcf	0.91	1.74	2.29	2.79	3.34	3.93	4.62	5.50	6.71	8.75	16.29

Frequency distribution



Reverse cumulative distribution



APPENDIX B

Nakanishi, T., (2000) Quantitative geologic risk evaluation and expected net present value evaluation in JNOC's projects.

Journal of the Japanese Association for Petroleum Engineering, v. 65 (3), pp. 217-228.

NOTE:

This publication is included in the print copy
of the thesis held in the University of Adelaide Library.

It is also available online to authorised users at:

<http://dx.doi.org/10.3720/japt.65.217>

APPENDIX C

Nakanishi, T., and Lang, S.C., (2001) The search for stratigraphic traps goes on-
visualisation of fluvial-lacustrine successions in the moorari 3D survey, Cooper-
Eromanga Basin.
The APPEA Journal, v. 41 (1), pp. 115-137.

NOTE:

This publication is included in the print copy
of the thesis held in the University of Adelaide Library.

APPENDIX D

Nakanishi, T., and Lang, S.C., (2001) Visualisation of fluvial stratigraphic trap opportunities in the pondrinie 3D survey, Cooper-Eromanga Basin.
Eastern Australian Basin Symposium, pp. 301-310.

NOTE:

This publication is included in the print copy
of the thesis held in the University of Adelaide Library.

APPENDIX E

Nakanishi, T., and Lang, S.C., (2002) Towards an efficient exploration frontier: constructing a portfolio of stratigraphic traps in fluvial-lacustrine successions, Cooper-Eromanga Basin.
The APPEA Journal, v. 42 (1), pp. 131-150.

NOTE:

This publication is included in the print copy
of the thesis held in the University of Adelaide Library.

APPENDIX F

Timetable (Takeshi Nakanishi)

[illegible]