2.2.4 SOUTH VENTURE FIELD

2.2.4.1 Field History

In 1983, the discovery well South Venture O-59 was drilled to a total depth of 6176 metres. Multiple, vertically stacked hydropressured and overpressured sandstone gas accumulations were encountered, testing at flowrates up to 509 E3M3/d. Hydropressured reservoir horizons occur from 3926 to 4266 metres in the O-59 well. Overpressured gas accumulations occur between 4746 and 5054 metres. **Figure 2.2.4.1.1** illustrates the South Venture Sand 2 depth structure map.

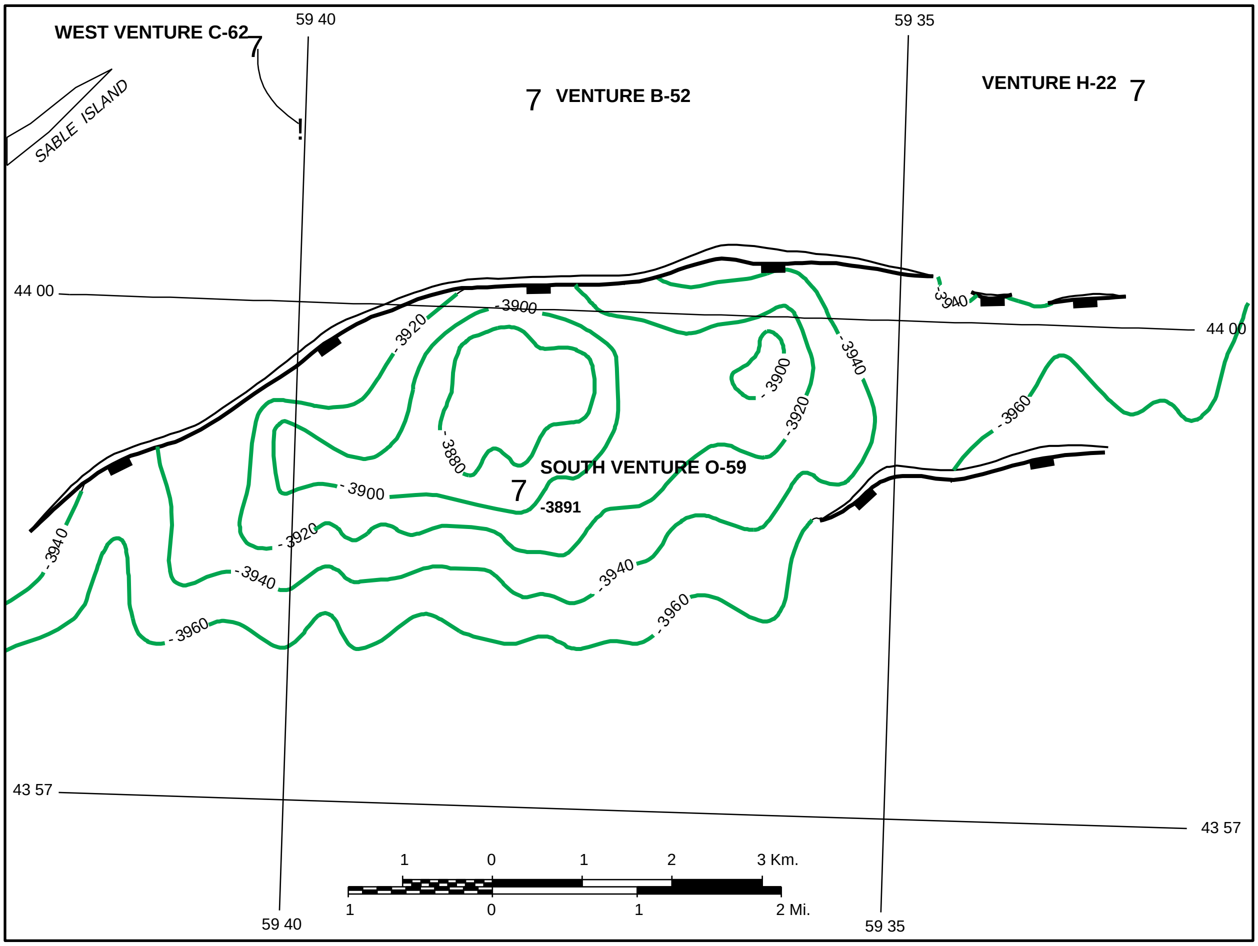

Figure 2.2.4.1.1: South Venture Field - Top Sand 2 Structure Map
Contour Interval: 20 Metres

2.2.4.2 Structural Configuration

The South Venture structure is a low relief rollover anticline situated on the downthrown side of a major east-west trending growth fault. At the top Sand 2 hydropressured horizon, the structure is approximately eight kilometres by three kilometres, encompassing an area of 23 square kilometres, with 70 metres of vertical closure. Gross closure is established by structural saddle spillpoints to the east and west of the South Venture structure.

2.2.4.3 Geology

The South Venture reservoir section consists of interbedded shales, siltstones, sandstones, and occasional limestones or highly calcareous sandstones. As in the Venture Field, this cyclic sedimentation is interpreted to be the result of delta progradations of Late Jurassic and Early Cretaceous age, the deposits of which are assigned to the Mic Mac and Lower Missisauga formations.

Hydropressured gas was tested in five independent reservoir horizons. **Figure 2.2.4.3.1** is a net pay map of one of these horizons, the Sand 2 reservoir. Net pay in the O-59 well at this horizon is 14.5 metres. The free water level elevation estimate of 3936 metres subsea is based on an assumed 80 percent fillup volume. Gas is inferred to be trapped by a combination of rollover closure and fault closure **(DPA - Part 2 Ref. # 2.2.4.3.1).**

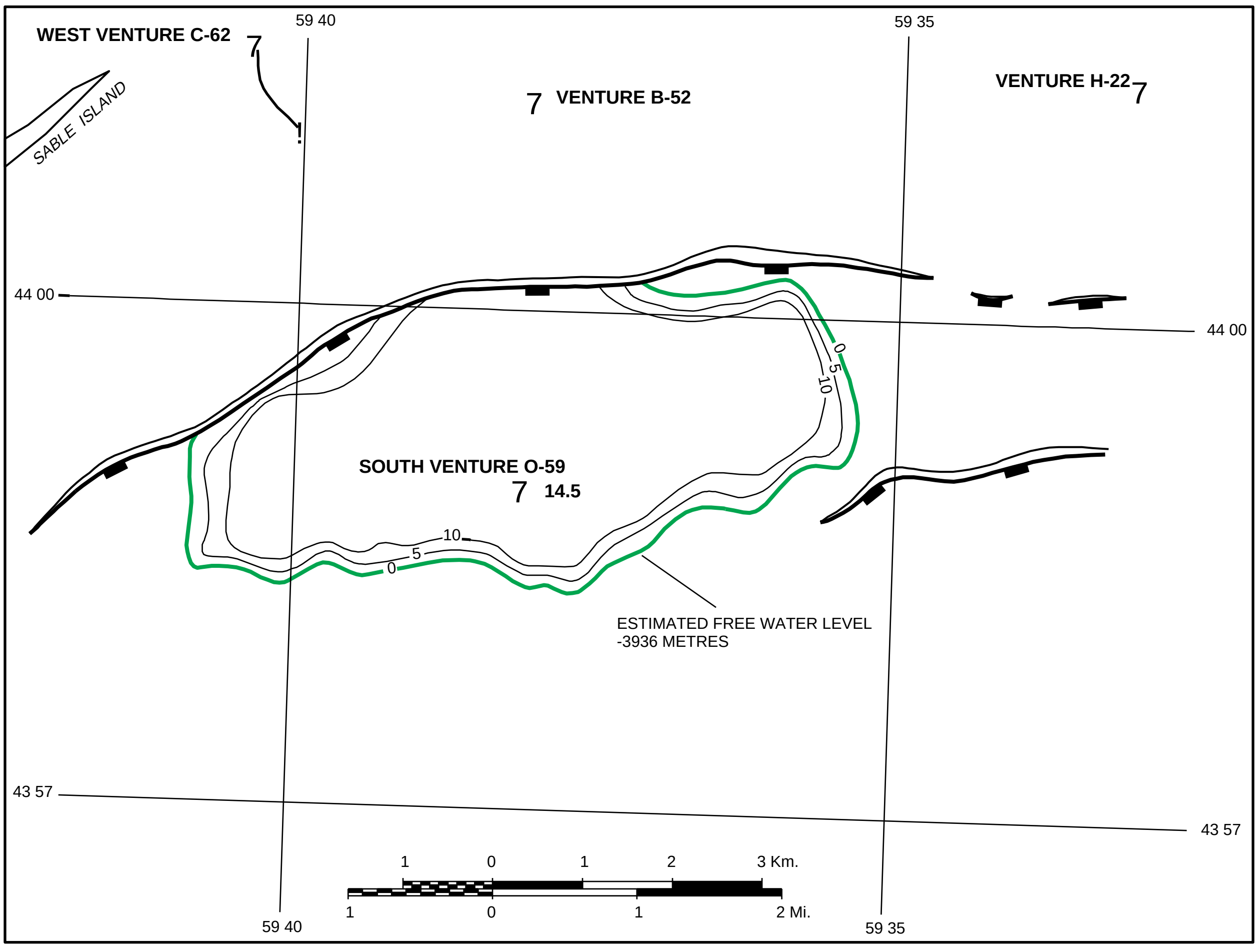

Figure 2.2.4.3.1 South Venture Field - Sand 2 Net Pay Thickness Map
Contour Interval: 5 metres

Two overpressured sandstone horizons, sands 7 and 8, tested gas in the 0-59 well. These horizons have low porosity as demonstrated by wireline logs, and exhibited significant pressure drawdown during drillstem testing. These deep overpressured accumulations are not currently included in the Project. There were no cores taken in the O-59 well, and attempts to recover Repeat Formation Test (RFT) data were unsuccessful, largely due to tool seating problems.

2.2.4.4 Reservoir Zonation

Using O-59 wireline log response, and correlations to the Venture Field wells, the hydropressure section was subdivided into sandstone packages, and numbered from zero to six. Reservoir sandstones in the South Venture hydropressure section are younger than the Venture Field reservoirs. Based on these correlations to Venture and continuous seismic reflectors within the South Venture structure, sandstone continuity in the hydropressured section is anticipated to be favourable. The reservoir nomenclature for South Venture is shown in **Figure 2.2.4.4.1**.

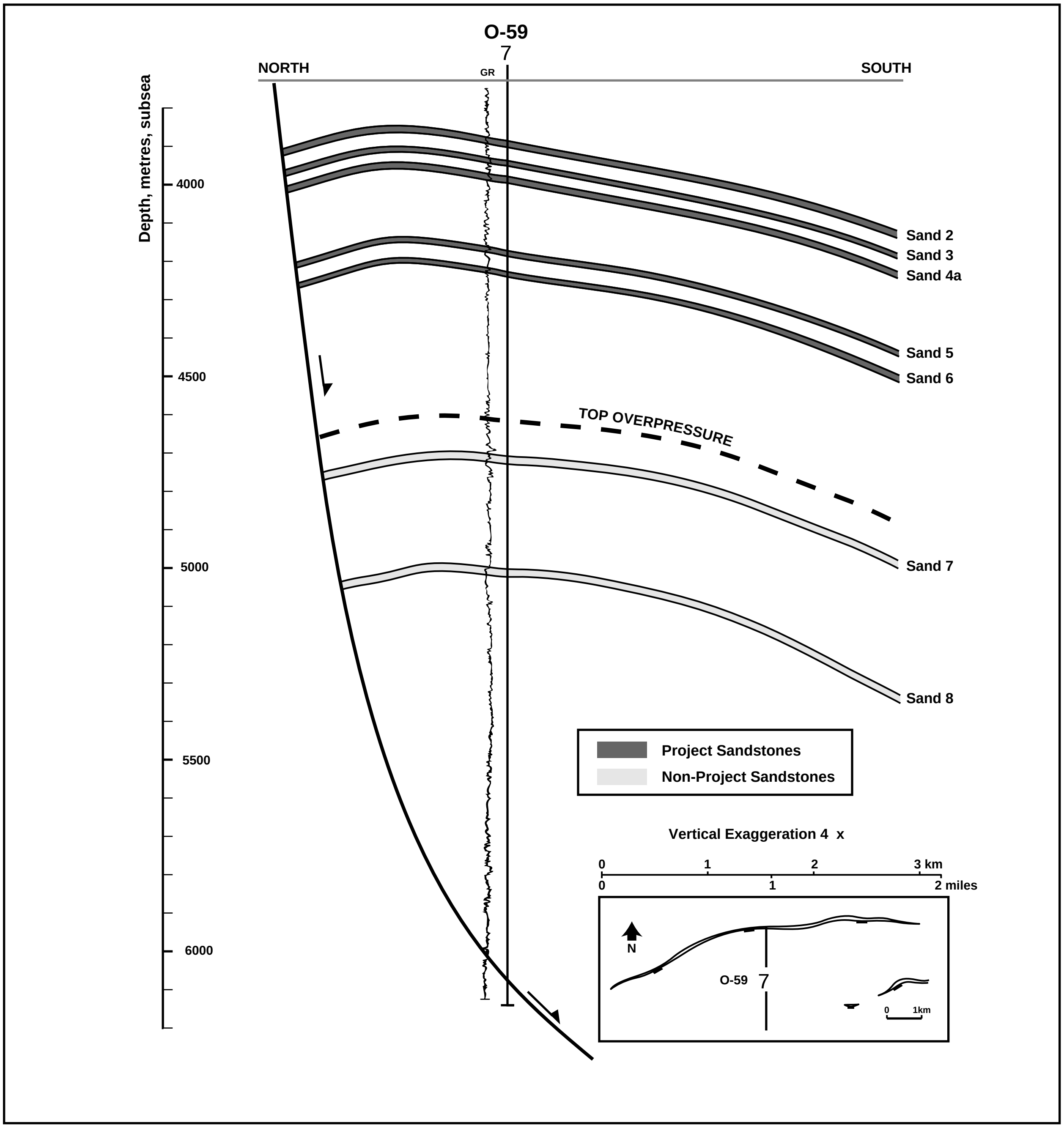

Figure 2.2.4.4.1: South Venture Schematic Structural Cross-section

2.2.4.5 Geophysics

2.2.4.5.1 Seismic Database

The South Venture Field is covered by essentially the same vintages of seismic data as the Venture Field. A summary of acquisition and processing details for several of these datasets is included in **Table 2.2.4.5.1.1**. The data density and quality at the normal pressured level sands is good to very good. There is only one strike line. The synthetic seismogram from the O-59 ties very well with the seismic at both mapped horizons. In the overpressured section, frequency content and horizon continuity has decreased but mapping confidence remains quite high. The depth structure maps used for gas in place estimates are based on the 2D seismic data illustrated in **Figure 2.2.4.5.1.1.**

Table 2.2.4.5.1.1: South Venture Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
2D	8624-M003-047E	Yes	1983	Marine	1983-84	356	60 fold Decon before and after stack, FD migration	Generally good to very good quality. Deteriorating with depth
2D	8620-5014-006R	No	1983	Marine	1983-84	31	60 fold Desig, Decon after stack FD migration	Fair to good quality
2D	8624-M003-041E	No	1981	Marine	1981-82	2	72 fold Desig, Decon after stack, FD migration	Good quality data, lower frequency
2D	8624-M003-035E	No	1980	Marine	1980-81	80	48 fold Desig, Decon after stack, FD migration	Generally good quality data, lower frequency
2D	8624-M003-033E	No	1979	Marine	1979-80	72	60 fold DBS, Decon after stack, FD migration	Fair to good quality

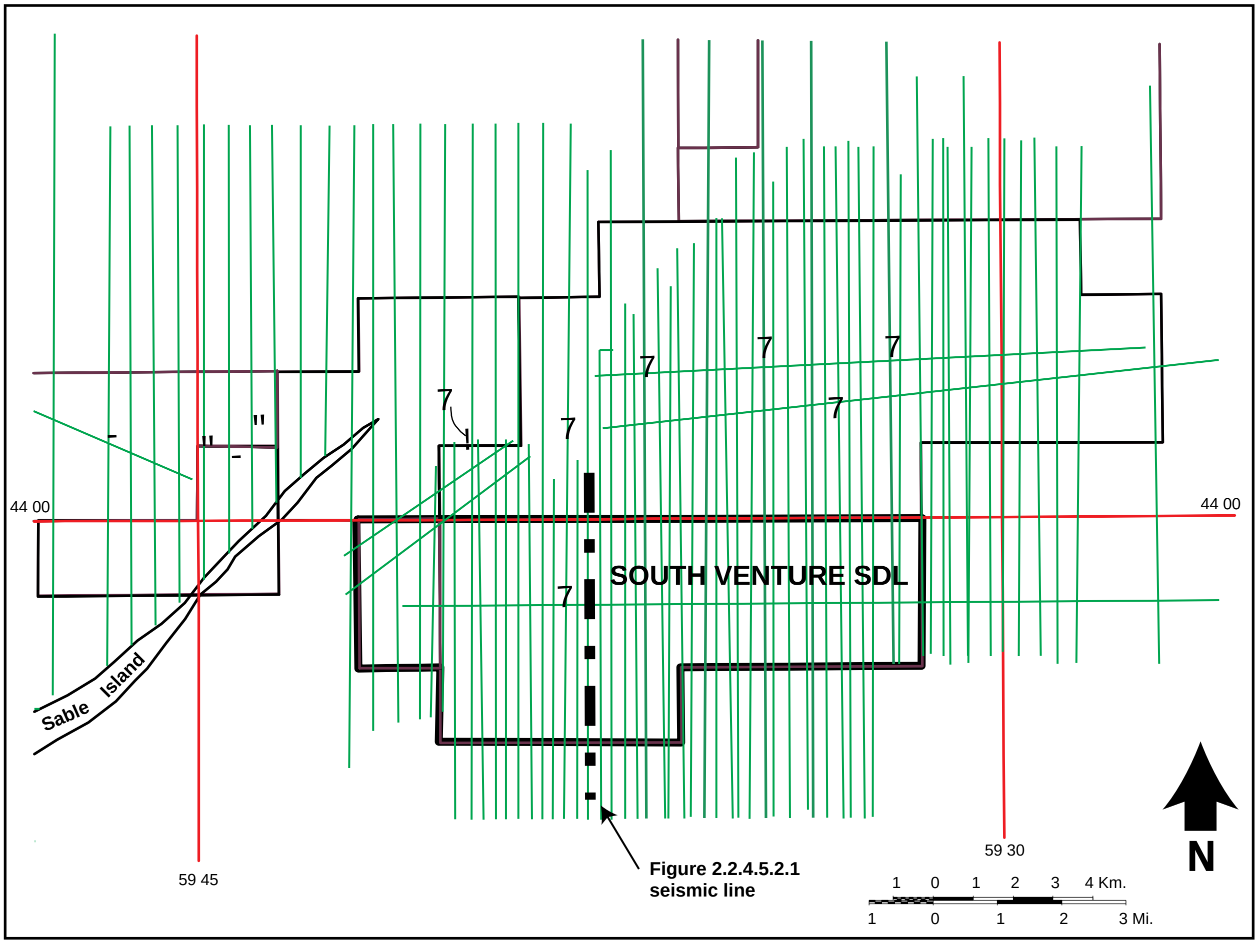

Figure 2.2.4.5.1.1: South Venture Seismic Database Map

2.2.4.5.2 Time Interpretation

The maps used for the gas in place calculations at South Venture are based on time and depth structure maps made from the 1983 data. The entire 1983 survey consists of 52 lines for a total length of 356 line kilometres. There is only one strike line in the survey that crosses the South Venture Field. This line runs from east to west, just south of the crest of the structure in the hydropressured section and through the O-59 well. The dip lines have an east to west line spacing of approximately 300 metres over the crest and flanks of the structure. A seismic line representative of the data quality and illustrating the field geometry is included as **Figure 2.2.4.5.2.1** and its location is shown as a bold dashed line in **Figure 2.2.4.5.1.1**.

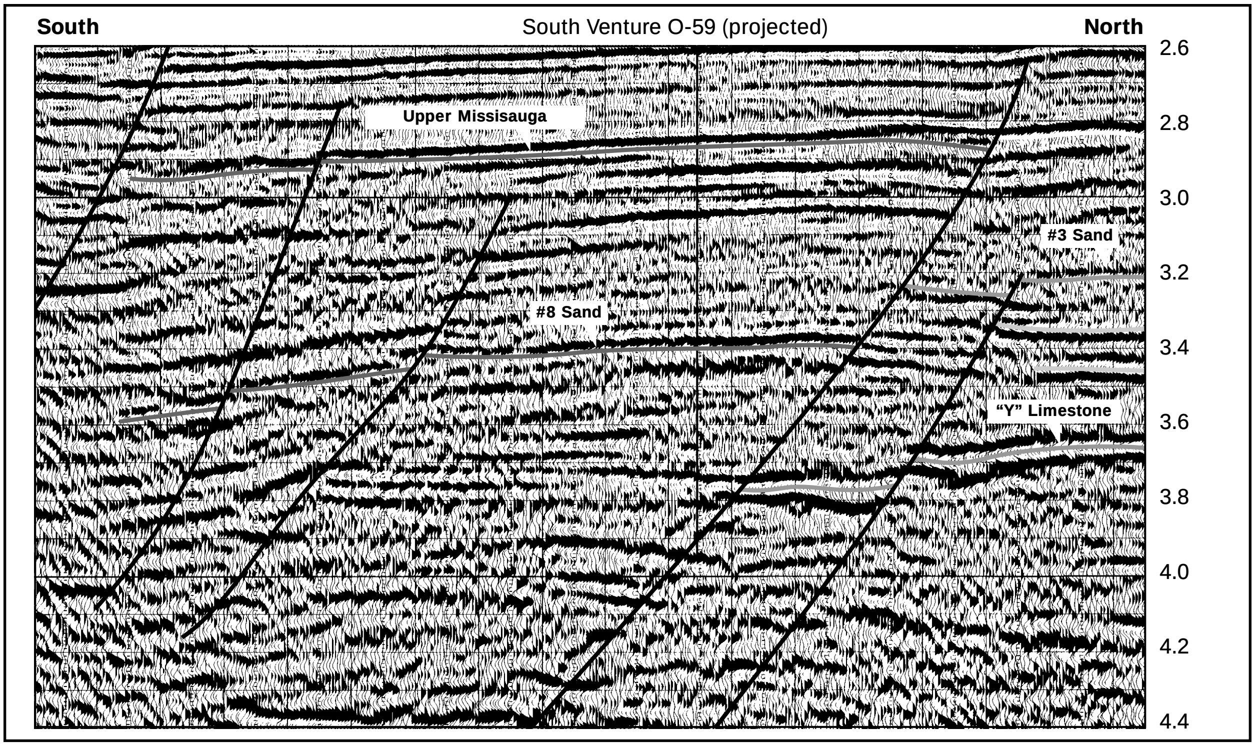

Figure 2.2.4.5.2.1: South Venture Seismic Line

The South Venture interpretation was generated on paper sections that were hand timed, posted and contoured. A checkshot survey corrected synthetic seismogram, generated at the O-59 well by convolving a minimum phase wavelet with an acoustic impedance series derived from the wireline log sonic and density information, was used to tie well lithology to the seismic data.

Two horizons were mapped in the hydrocarbon bearing portion of the field; one in the hydropressured section and one in the overpressured section. The Upper Missisauga Event corresponds to the top of the South Venture Sand 2 and was used to generate maps for Sands 2, 3, 4, 5 and 6. The second time event mapped, corresponds to the top of overpressured South Venture Sand 8 at O-59. The mapping horizons are illustrated in **Table 2.2.4.5.2.1.** Detailed maps are included in Part Two **(DPA - Part 2, Ref. # 2.2.4.5.2.1)**.

Table 2.2.4.5.2.1: South Venture Mapping Horizons

FIELD	SOUTH VENTURE 0-59	
MAP HORIZON	**Depth (M, ss)**	**TWT (sec)**
UPPER MISSISAUGA	-3890.6	2867
#8 SAND	-4999.0	3400

2.2.4.5.3 Depth Conversion

The depth conversion at South Venture used the same technique and velocity database as that described in Venture **Section 2.2.2.5.3**. Time structure maps for two horizons; the Upper Missisauga (Top of Sand 2), and the Top of Sand 8, were digitized and gridded. Intermediate depth maps were generated from the interval thickness encountered in the O-59 well (**DPA - Part 2, Ref. # 2.2.4.5.3.1**). The velocity surveys for South Venture are illustrated in **Table 2.2.4.5.3.1** .

Table 2.2.4.5.3.1: South Venture Velocity Surveys

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
South Venture O-59	1982	Yes	Vertical	No	NA
Venture D-23	1979	Yes	Vertical	No	NA
Venture B-13	1981	Yes	Vertical	No	NA
Venture B-43	1982	Yes	Vertical	No	NA
Venture B-52	1983	Yes	Vertical	Yes	Vertical
Venture H-22	1984	Yes	Vertical	No	NA
West Venture C-62	1985	Yes	Deviated Well	No	NA
Olympia A-12	1983	Yes	Vertical	No	NA

The South Venture structure has been penetrated by only one well. Stacking velocity data from the 1983 dataset was used in the same manner as at Venture, to supplement and constrain the applied velocity field. This is a reasonable approach at Venture given the well velocity data's areal distribution, but greater opportunity for error exists in the South Venture depth conversion, due to the limited well control.

2.2.4.6: Petrophysics

A detailed petrophysical evaluation of the multiple reservoir sands, hydropressured and overpressured, has been conducted on the South Venture O-59 well. The interpretation methodology and parameters are included in Part Two of this document **(DPA - Part 2, Ref. # 2.2.4.3.1)**. The results of this evaluation are illustrated in **Table 2.2.4.6.1**.

Table 2.2.4.6.1: South Venture Reservoir Parameter Summary

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
2	3926.0	3960.0	-3890.6	-3924.6	34.0	14.5	14.7	47.2	-
3	3977.0	3992.0	-3941.6	-3956.6	15.0	4.3	13.4	21.1	-
4a	4016.0	4034.0	-3980.6	-3998.6	18.0	5.8	13.3	30.7	-
5	4201.0	4217.0	-4165.6	-4181.6	16.0	2.3	14.0	39.0	-
6	4255.0	4266.0	-4219.6	-4230.6	11.0	4.9	14.0	24.0	-

* not calculated

The methodologies used in the analysis of the O-59 well relied heavily on those established for similar reservoirs of the Venture Field. This was necessary because no cores were cut in the O-59 well, and all sands encountered in the well, are interpreted to be either gas bearing or tight. Due to the lack of core data, water sands, and formation water samples in South Venture, petrophysical parameters derived in similar reservoirs of the Venture Field supported the interpretation.

Zonal average porosity ranges from seven to 15 percent in the O-59 well. Porosity was calculated from the raw density measurement using matrix density values determined from crossplots and lithologic descriptions. Water saturation for values used in the estimation of gas in place was calculated using the Archie equation. Cementation and saturation exponents correspond to those used in similar reservoirs of the Venture Field. True formation resistivity was determined from the deep induction measurement. In the absence of formation water samples, formation water resistivity was estimated from Venture Field data and log data.

The calculation of net porous sand thickness was found to be quite sensitive to the porosity cutoff value. In general, a porosity cutoff value of 10 percent was used. Lower porosity cutoff values of six to seven percent were applied in low porosity overpressured sands which had favourable gas flowrates on drillstem tests. The water saturation cutoff value used was 70 percent.

2.2.4.7 Gas In Place

Gas in place estimates for the South Venture Field have been generated using deterministic and probabilistic methods. The probabilistic assessment of gas in place was conducted in 1995 (**DPA - Part 2, Ref. # 22.2.4.7.1**). The summation of mean values from the output expectation curves generated for the five hydropressured Project sands is 11.3 E9M3. Results of this probabilistic assessment for the each of the Project sands are shown in **Table 2.2.4.7.1**.

Table 2.2.4.7.1: South Venture Probabilistic Estimates of Gas In Place, E9M3

Reservoir Sandstone	P90	P50	P10	Mean
2	1.4	4.8	7.9	**4.8**
3	0.5	1.5	3.1	**1.6**
4a	0.6	1.6	3.7	**1.9**
5	0.3	0.8	2.0	**1.0**
6	0.6	1.7	3.8	**2.0**
Project Total	3.4	10.4	20.5	**11.3**

A deterministic assessment of gas in place was generated in 1985. The methodology used to generate the maps and gas in place estimates is described in Part Two of this document (**DPA - Part 2 Ref. # 2.2.4.7.2**). Deterministic gas in place estimates for Project sands are shown in **Table 2.2.4.7.2** and represent unrisked volumes.

Table 2.2.4.7.2: South Venture Deterministic Estimates of Gas In Place, E9M3

Reservoir Sandstone	Gas in Place
2	4.4
3	2.2
4a	2.6
5	1.0
6	2.6
Total	12.8

2.2.5 GLENELG FIELD

2.2.5.1 Field History

The Glenelg Field was discovered in 1983 (**DPA - Part 2, Ref. # 2.2.5.1.1 through 2.2.5.1.3**). The discovery well, Glenelg J-48, encountered stacked, hydropressured, gas pay in a number of separate pools in the lower Logan Canyon Formation and throughout the Missisauga Formation. During drillstem testing, gas flowed at rates of up to 849 E3M3/d. Three subsequent wells, one of which was whipped, were drilled to delineate the accumulation. **Figure 2.2.5.1.1** illustrates the top B pool structure (near top Missisauga level) at Glenelg.

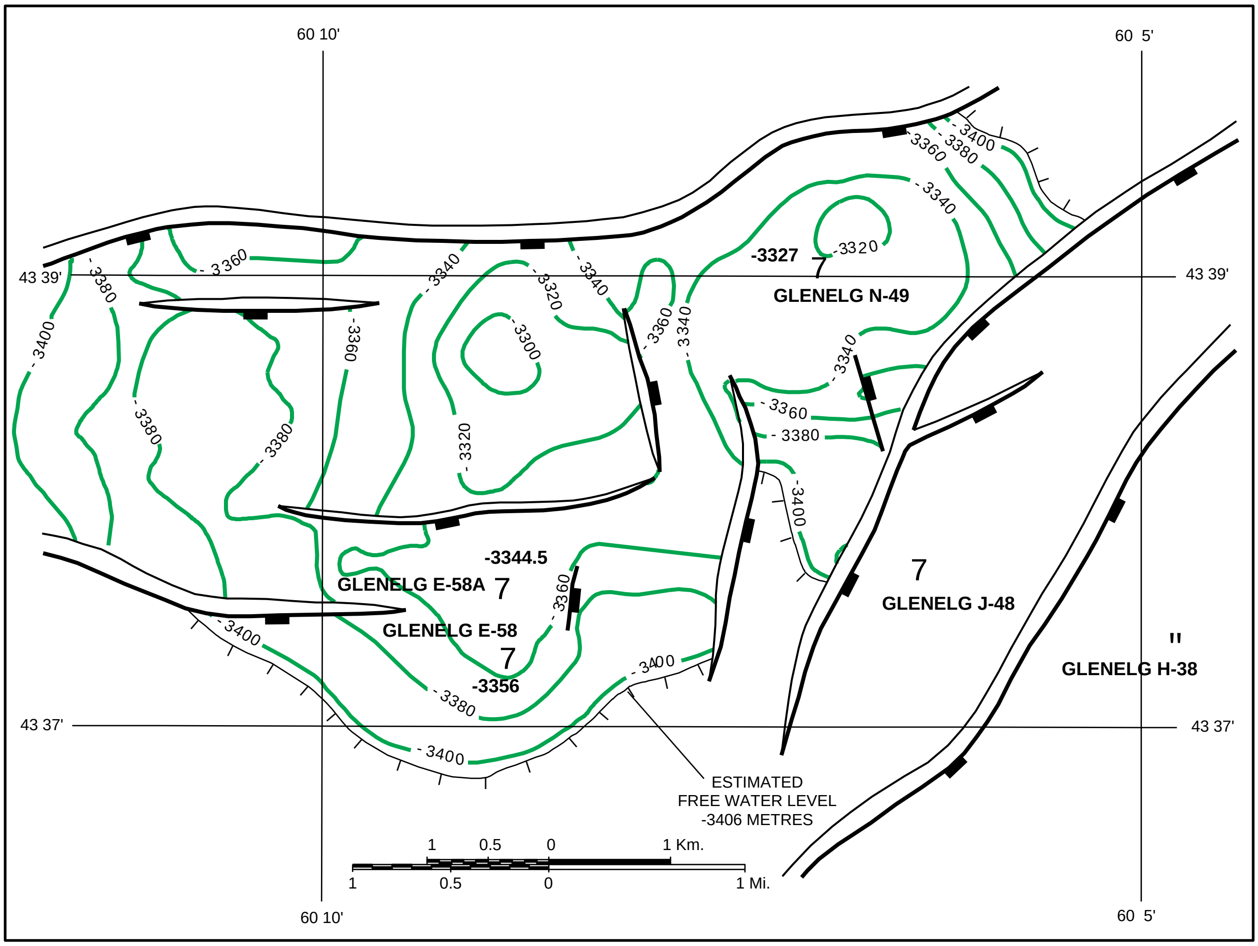

Figure 2.2.5.1.1: Glenelg - Top Missisauga (Top B Pool) Depth Structure Map
Contour Interval: 20 metres

2.2.5.2 Structural Configuration

The Glenelg feature is a large rollover anticlinal structure bounded to the north and southeast by major listric normal faults, and to the northeast, south and west by dip closure. Internally, the rollover anticline is partially dissected by a number of lesser normal faults, some of which exhibit significant throws. The field is at an average depth of 3470 metres subsea and covers an area of some 25 square kilometres.

2.2.5.3 Geology

The Glenelg area is located toward the southernmost extension of sands of the Sable Delta complex. Approximately 550 metres of Missisauga Formation is present there. The Missisauga Formation contains a lower sand/shale ratio than in more northern wells. It exhibits significant thicknesses of shale-dominated section between the interbedded sandstones and shales more typical of the Missisauga Formation.

The lower 300 metres of the Missisauga Formation at Glenelg is composed of coarsely interlayered sandstone and shale. Sandstone intervals approximately 50 metres thick, dominated by sharp-based sandy channel fill successions, are interbedded with shaley intervals of similar thickness. The channel sands exhibit variable development across the Glenelg structure. The upper 250 metres of the Missisauga Formation is composed of stacked coarsening-upward cycles of shale to sandstone, deposited by successive delta-lobe progradations into the area. These cycles are correlatable across the Glenelg structure. The individual sands capping these cycles exhibit north-south variation in thickness and log character; this is associated with variation in reservoir quality (**DPA - Part 2, Ref. # 2.2.5.1.1, 2.2.5.1.3 & 2.2.5.3.1**).

Hydropressured gas has been encountered in a number of separate pools within the Logan Canyon and Missisauga formations. Three of the pools within the Missisauga Formation, B, C and F, are considered of sufficient size to be developed. The gas pools tend to be restricted to specific stratigraphic horizons within a single structural block. The C pool is an exception, being hydrodynamically continuous across a fault separating the N-49 and J-48 wells, with gas reservoired in different stratigraphic levels in each structural block. As a result of different reservoir qualities on either side of this fault, the C accumulation is subdivided into two substituent pools, C1 and C2. This is illustrated in **Figures 2.2.5.3.1(a), 2.2.5.3.2(b) & 2.2.5.4.1**; and presented in further detail in Part Two (**DPA - Part 2, Ref. # 2.2.5.1.1**).

The B, C1/C2 and F pools are all reservoired in sands which occur in the uppermost 250 metres of the Missisauga Formation. The distribution of the various reservoir sands in this stratigraphic interval are modelled as north to south tapering wedges. This model combines the effects of a northerly source for the sands with syndepositional downward movement on the northern bounding growth fault; the latter acts to trap most of the reservoir quality sand in the northern portion of the structure. According to this model, reservoir thickness is at a maximum adjacent to the northern bounding fault, and thins systematically southward to the southern boundaries of the field. The B and C2 pools are reservoired in the same stratigraphic interval, namely in the uppermost sands of the Missisauga Formation. The C1 and F pools are reservoired in an older stratigraphic unit (informally termed the Glenelg Sand). Consequently, these gas pools may be represented by two reservoir development models.

Convolution of the appropriate reservoir development model with structure maps and gas/water contacts for each of the pools permits construction of net pay maps. Net pay maps are then used for gas in place determination. **Figure 2.2.5.3.1(a-b)** shows the structural configuration for the Glenelg C1/C2 and F pools; **Figure 2.2.5.3.2(a-c)** are net pay maps for the Glenelg B, C1/C2, and F pools.

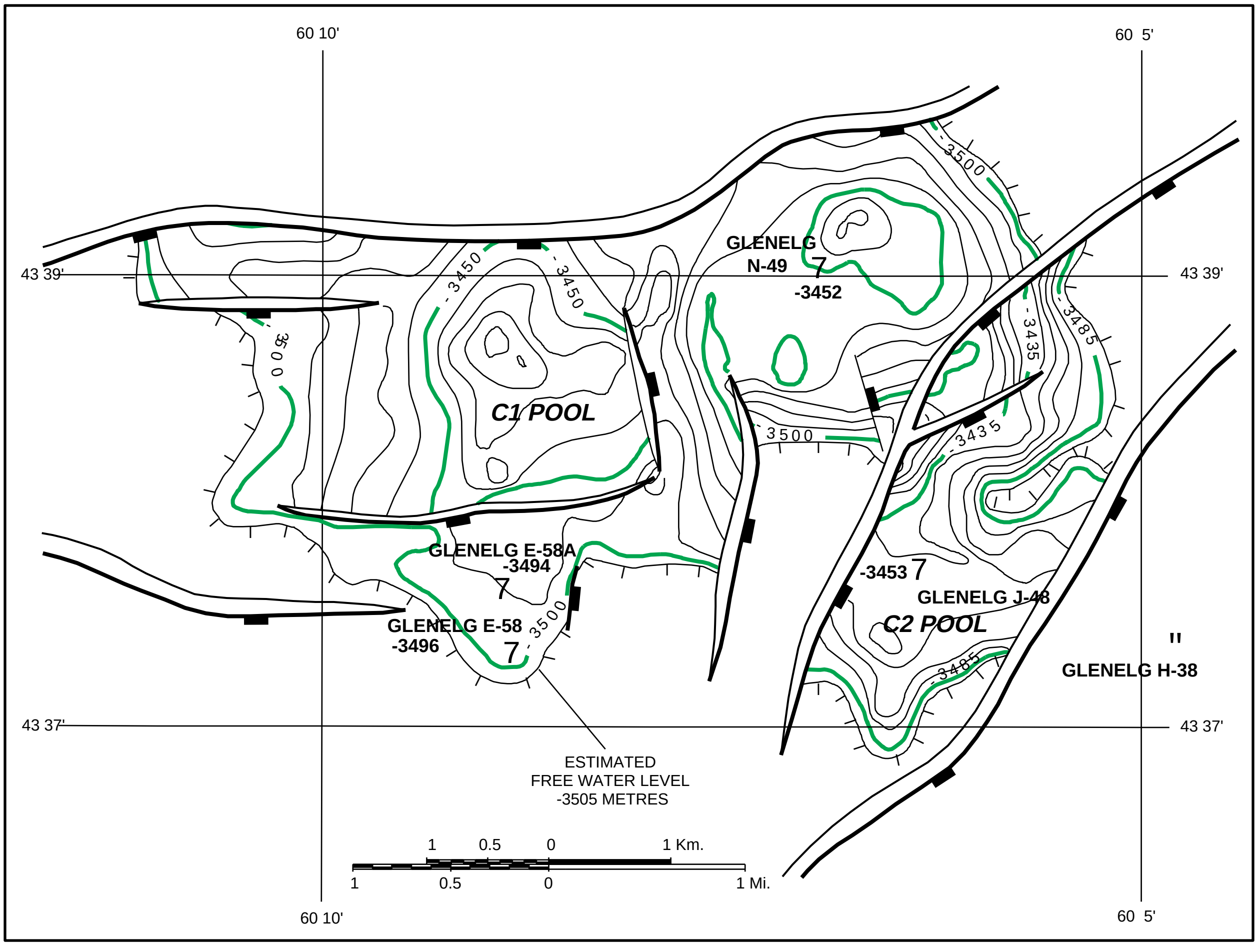

Figure 2.2.5.3.1 (a): Glenelg - C1/C2 Pools, Depth Structure Map
Contour Interval: 10 metres

Note: Change of mapping horizon between J-48 and N-49 fault blocks. Refer to text and structural cross-section (Figure 2.2.5.4.1).

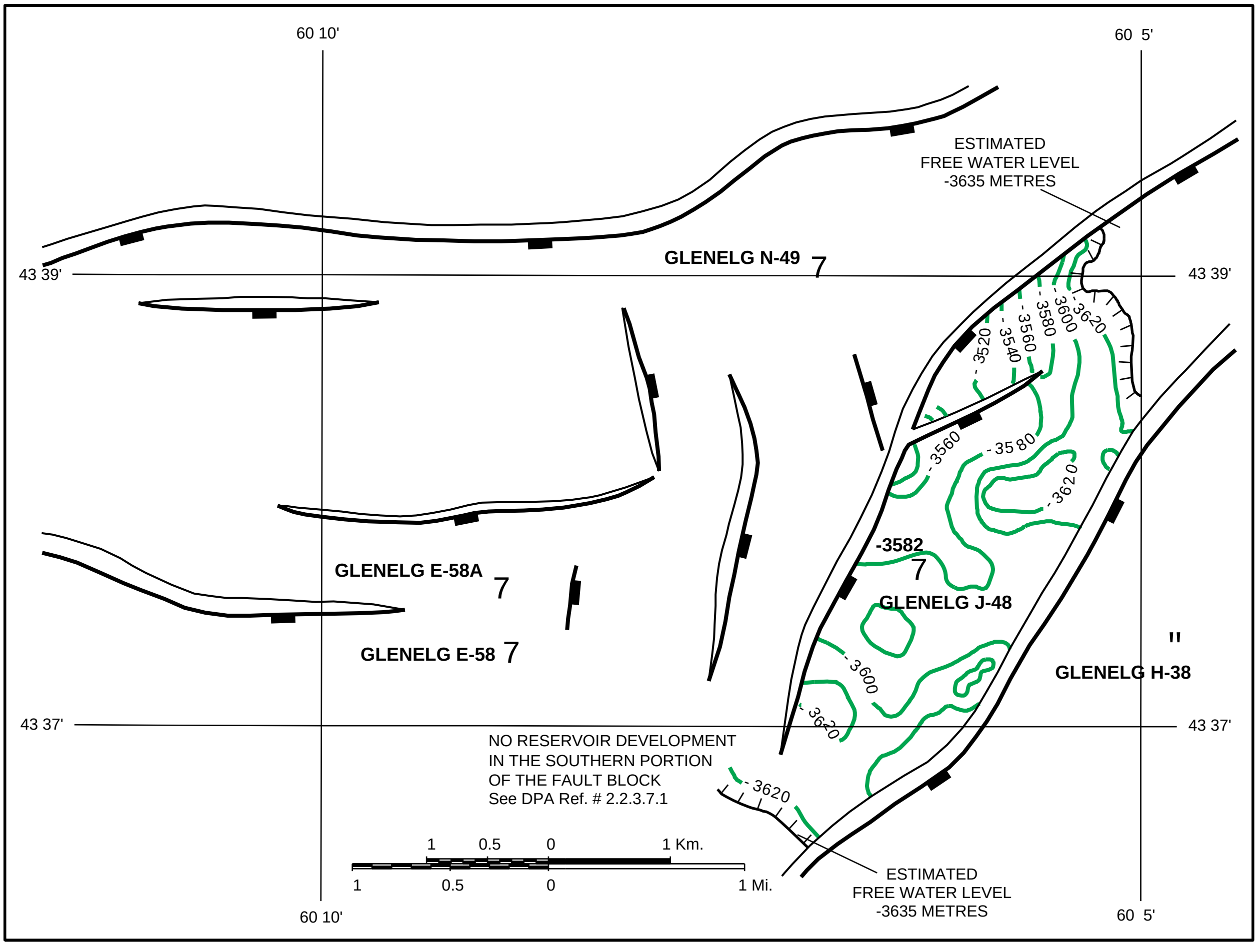

Figure 2.2.5.3.1 (b): Glenelg - F Pool, Depth Structure Map
Contour Interval: 20 metres

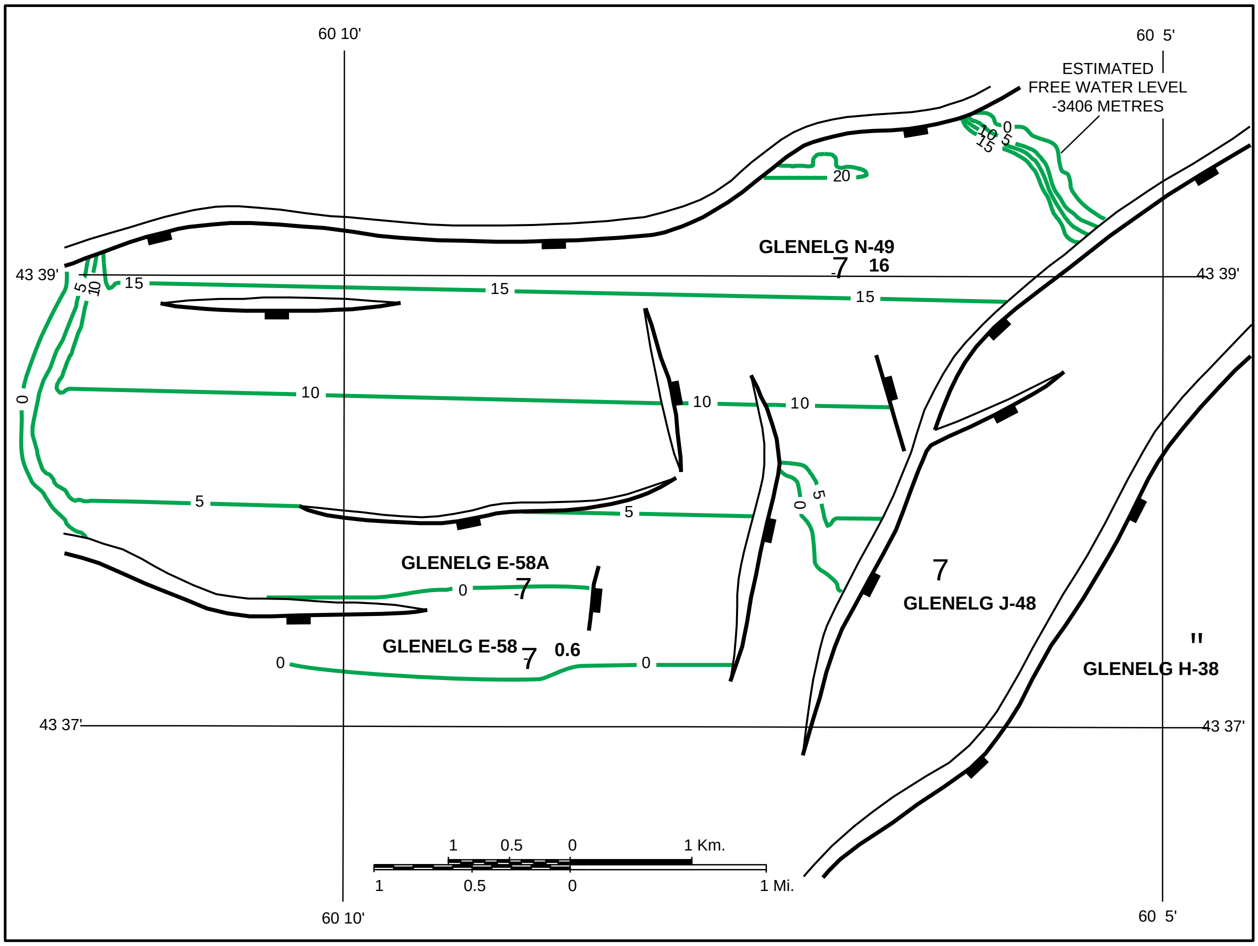

Figure 2.2.5.3.2 (a): Glenelg - B Pool, Net Pay Map
Contour Interval: 1 metre

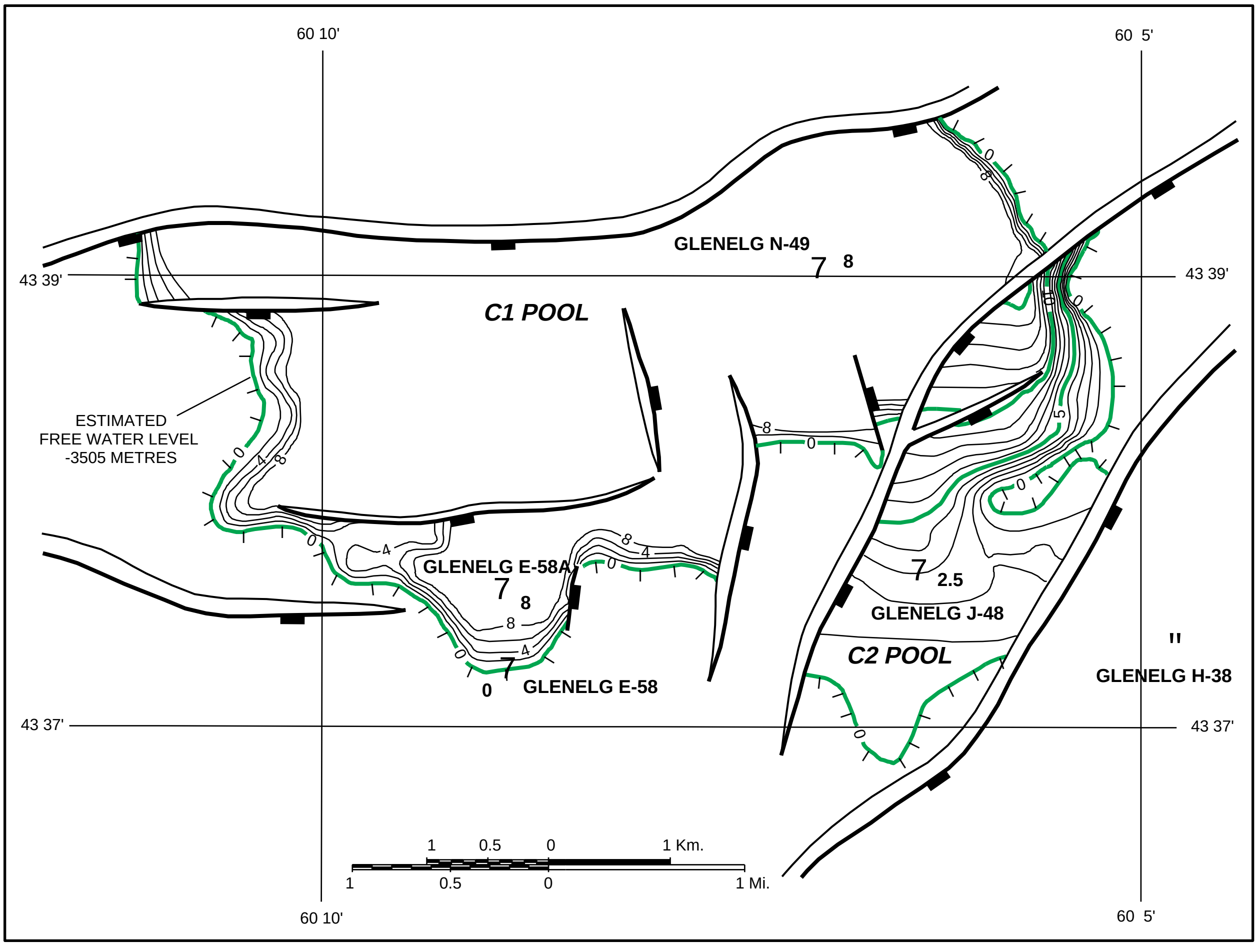

Figure 2.2.5.3.2 (b): Glenelg - C1/C2 Pool, Net Pay Map
Contour Interval: Variable, 1 - 2 Metres

Note: Change of mapping horizon between J-48 and N-49 fault blocks. Refer to text and structural cross-section (Figure 2.2.5.4.1).

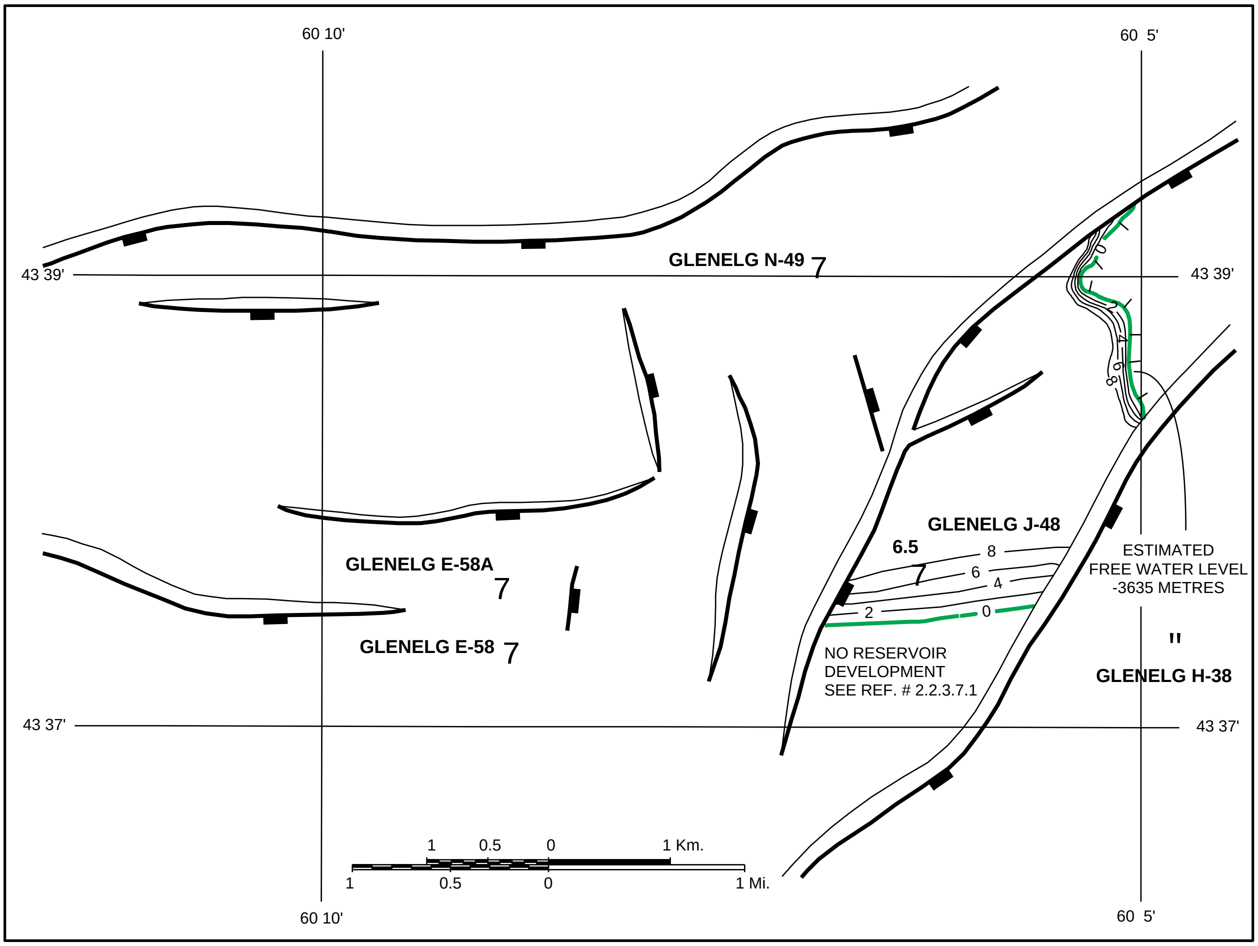

Figure 2.2.5.3.2 (c): Glenelg - F Pool, Net Pay Map
Contour Interval: 2 metres

2.2.5.4 Reservoir Zonation

The presence of hydrodynamically separate, stacked, gas accumulations in the Glenelg Field is indicated by pressure data and the intersection by the wells of several discrete gas/water contacts. This necessitates division of the reservoir interval into a number of zones. Zone boundaries are taken at the base of shale intervals believed, on the basis of pressure work, to be seals to gas migration. Each reservoir zone has, for the purpose of initial modeling of recoverable gas reserves, been treated as a single flow unit (**DPA - Part 2, Ref. # 23.1.3.5**). **Figure 2.2.5.4.1** illustrates a Glenelg schematic structural cross-section.

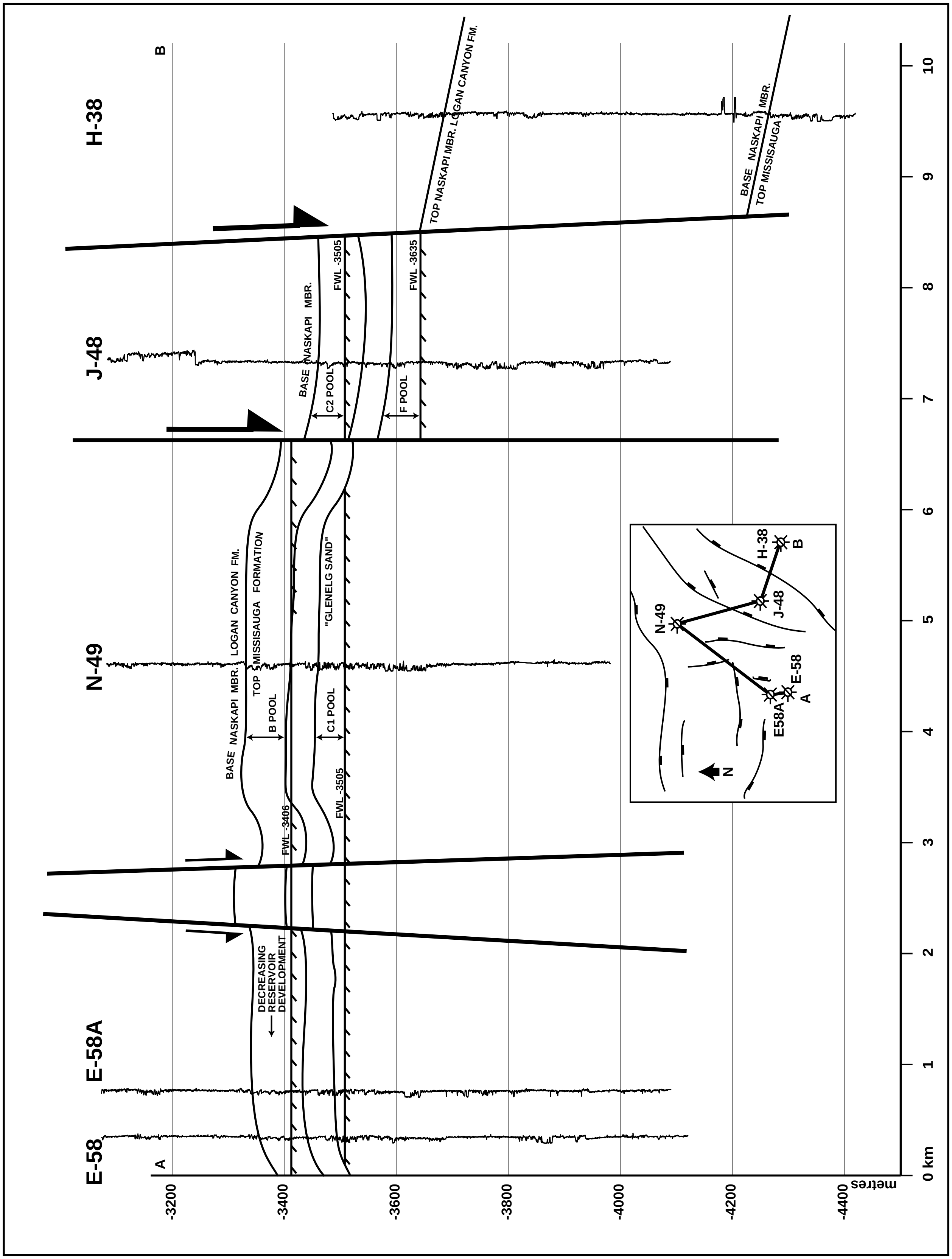

Figure 2.2.5.4.1: Glenelg Schematic Structural Cross-section

2.2.5.5: Geophysics

2.2.5.5.1: Seismic Database

The depth structure map used for gas in place estimates is based on a 3D seismic dataset covering 333 square kilometres (illustrated in **Figure 2.2.5.5.1.1**) and was acquired in 1984-1985. Acquisition and processing details are illustrated in **Table 2.2.5.5.1.1**. Seismic data quality is good down to the objective level Top Missisauga.

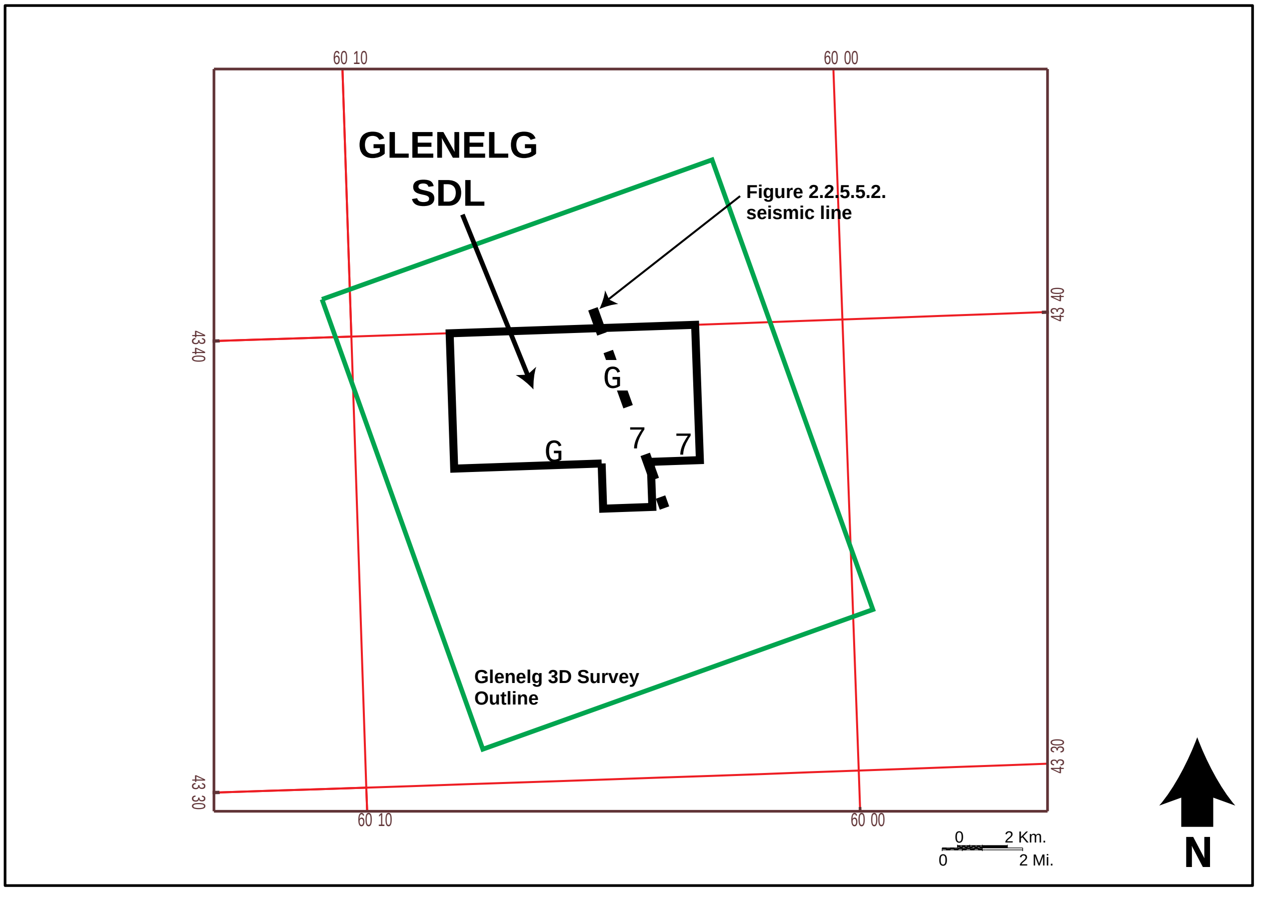

Figure 2.2.5.5.1.1: Glenelg Seismic Database Map

Table 2.2.5.5.1.1: Glenelg Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
3D	041E	Yes	1984-85	Marine	1895-86	333km2	40 Fold, Desig, FK Migration	Generally good data quality
2D	048E	No	1985	Marine	1986	201	60 Fold, Desig, FK Migration	Generally very good data quality
2D	033E	Yes	1982	Marine	1983	783	54 Fold, Desig, FD Migration	Generally poor to fair data quality
2D	027E	Yes	1981	Marine	1981	320	60 Fold, Desig, FD Migration	Generally poor data quality
2D	023E	Yes	1980	Marine	1980	315	48 Fold, Desig, FD Migration	Generally poor to fair data quality
2D	020E	No	1976	Marine	1976	108	24 Fold, No Mig	Generally poor data quality

2.2.5.5.2 Time Interpretation

Interpretation of the Glenelg 3D seismic dataset commenced in 1986 on a Landmark III™ workstation. Time structure maps for the Wyandot, Top Lower Logan Canyon, Naskapi, and Top Missisauga horizons were created, and are included in Part Two of this document (**DPA - Part 2, Ref. # 2.2.5.1.2**). The Top Missisauga Event, correlated from well control (**Table 2.2.5.5.2.1**), was selected as the main mapping horizon and used to define this large complex structure. In order to produce structure maps for the four main pools (B, C1, C2 and F), it was assumed that sands within the Missisauga Formation (eg. the Glenelg Sand) parallel the Top Missisauga marker (**DPA - Part 2, Ref. # 2.2.3.7.1**). A representative seismic line from the 3D survey is illustrated in **Figure 2.2.5.5.2.2.**

Table 2.2.5.5.2.1: Glenelg Horizon Markers

FIELD	Glenelg															
	H-38				J-48				N-49				E-58			
MAP HORIZON	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)
Wyandot Chalk	1673	1673	-1649	1.642	1646	1646	-1622	1.612	1571	1571	-1548	1.559	1586	1586	-1562	1.574
Top L.Logan Can.	2458	2440	-2416	2.142	2302	2302	-2278	2.044	2280	2280	-2257	2.030	2247	2247	-2223	2.009
Naskapi	3702	3699	-3675	2.804	3135	3135	-3111	2.513	3056	3056	-3033	2.476	3103	3103	-3079	2.500
Missisauga	4268	4262	-4238	3.104	3491	3491	-3467	2.702	3350	3350	-3327	2.635	3380	3380	-3356	2.649
Verrill Canyon	4495	4489	-4465	3.212	3982	3982	-3958	2.940	3670	3670	-3647	2.792	3905	3905	-3881	-
Jurassic “S”	-	-		-	4760	4760	-4736	3.400	-	-		-	-	-		-
TD	4865				5148				4040					4154		

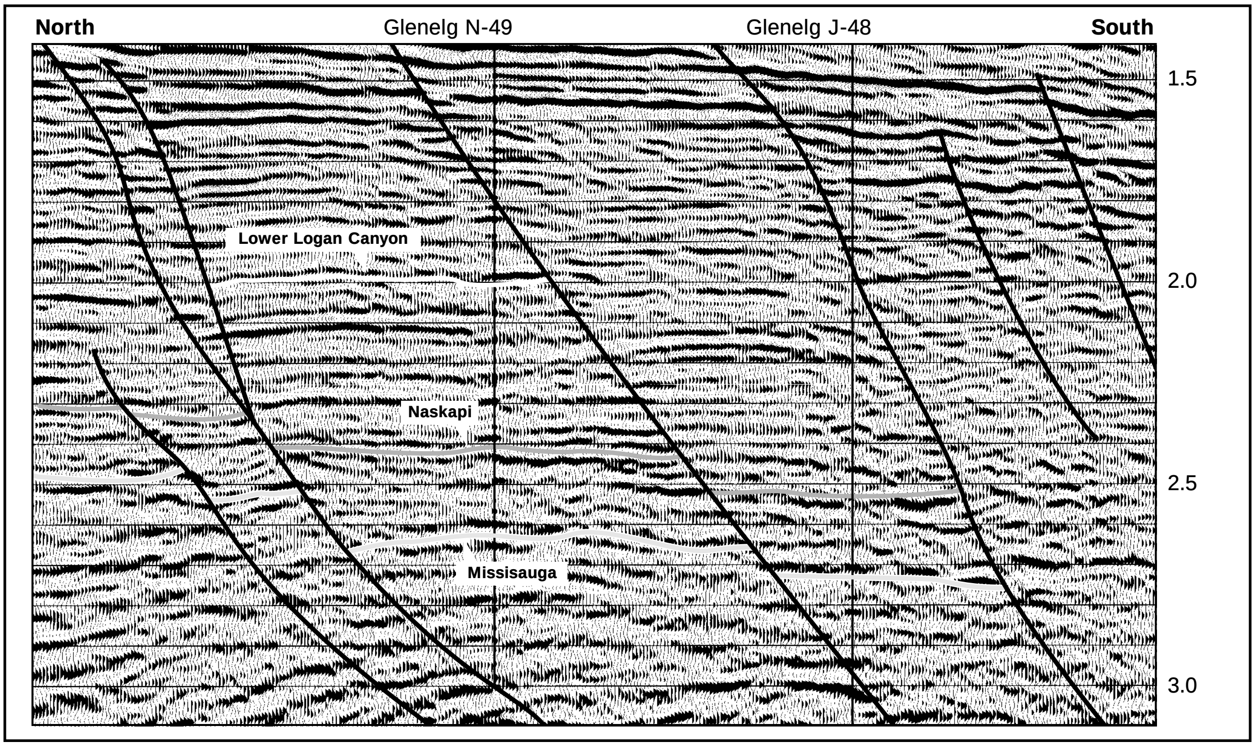

Figure 2.2.5.5.2.1: Glenelg Seismic Section

2.2.5.5.3 Depth Conversion

Utilization of time-depth functions derived from well control was found to be a more satisfactory method of depth conversion than relying on smoothed average stacking velocities. Time structure maps were generated and time-depth functions derived from the well control were used to generate depth maps (**DPA - Part 2, Ref. # 2.2.5.5.2.1**).

Table 2.2.5.5.3.1: Glenelg Well Velocity Data

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
Glenelg J-48	1983	Yes	Vertical	No	NA
Glenelg E-58	1984	Yes	Vertical	Yes	Vertical
Glenelg H-38	1985	Yes	Vertical	No	NA
Glenelg N-49	1986	Yes	Vertical	Yes	Vertical

2.2.5.6 Petrophysics

Petrophysical evaluation of the four Glenelg wells used all available log data, conventional core analysis data and pressure data. A detailed summary of the interpretation parameters and methodology is included in Part Two of this document (**DPA - Part 2, Ref. # 2.2.5.6.1**). Given the lack of special core analyses on Glenelg core, and the perceived similarities between reservoirs in the Glenelg and Alma fields, Alma special core analyses results were used for examination of the Glenelg Field. The results of this evaluation are illustrated in **Table 2.2.5.6.1**.

Tables 2.2.5.6.1: Glenelg Reservoir Parameter Summary

Glenelg E-58 K.B. 24 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
B	3380	3468	-3356	-3444	88	0.6	11.3	0.51	-
C1	3520	3573	-3496	-3549	53	1.6	15.2	0.56	-

Glenelg E-58A K.B. 24 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
B	3413	3506	-3346	-3436	91.5	-	-	-	-
C1	3566.0	3626.0	-3494.0	-3552.0	58.0	8.0	14.0	40.0	1.8

Glenelg N-49 K.B. 23 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
B	3350.0	3426.0	-3327.0	-3403.0	76.0	16.5	16.0	24.0	5.0
C1	3476.0	3523.0	-3453.0	-3552.0	68.0	8.0	15.0	21.6	-

Glenelg J-48 K.B. 24 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
C2	3477.0	3557.0	-3453.0	-3533.0	80.0	2.5	20.0	17.0	30.0
F	3606	3629	-3582	-3605	23	6.5	15.0	22.0	1.8

* Estimated from DSTs

Average porosity ranges from 14 to 18 percent in the four major gas bearing zones. The primary control on porosity is average grain size. Irreducible water saturations, as calculated from logs, range from 17 to 60 percent. Porosity was calculated from density calibrated to stressed core porosity measurements. Water saturation values used in the estimation of gas in place was calculated using the Archie equation. Cementation and saturation exponent values were based on special core analysis from the Alma Field. Formation water resistivity was derived from RFT and DST fluid sample analysis. A formation temperature gradient was determined from bottom hole temperature measurements. Net pay cutoff criteria were based on core analysis data.

Net pay thickness was determined based on a permeability cutoff of 1.0 mD to air at ambient conditions. This was found to correspond to an in situ porosity value of 10 percent and a water saturation cutoff of 70 percent.

2.2.5.7 Gas in Place

The ranges of uncertainty of the parameters utilized in the probabilistic assessment of gas in place are detailed in Part Two (**DPA - Part 2, Ref # 2.2.5.7.1**). The results for the main pools in the Glenelg Field are presented in **Table 2.2.5.7.1**.

Deterministic gas in place estimates, performed in 1990 and 1991, used average reservoir porosity and water saturation values determined from well petrophysics and average net pay values. The latter were determined from convolving the reservoir development model with what was then considered the 'most likely' structure maps for the area of the B, C1/C2, and F pools. This information is presented in detail in Part Two (**DPA - Part 2 Refs. # 2.2.3.7.1 and # 2.2.3.7.2**). The results are presented in **Table 2.2.5.7.2**. The deterministic volumes are similar to the P50 and Mean values obtained from the probabilistic method.

Table 2.2.5.7.1: Glenelg Field Probabilistic Estimates of Gas In Place

Reservoir Sandstone	P90	P50	P10	Mean (E9M3)
B	2.8	6.5	10.8	**6.7**
C1	2.9	3.9	4.9	**3.9**
C2	0.3	0.4	0.6	**0.4**
F	1.0	1.3	1.6	**1.3**
Project Total	7.1	12.1	17.8	**12.4**

Table 2.2.5.7.2: Glenelg Field Deterministic Estimates of Gas In Place

Reservoir Sandstone	Gas in Place (E9M3)
B	6.3
C1	3.9
C2	0.5
F	1.1
Project Total	11.8

2.2.6 ALMA FIELD

2.2.6.1 Field History

The Alma Field was discovered in 1984 (**DPA - Part 2, Ref. # 2.2.6.1.1**). The discovery well, Alma F-67, encountered stacked, hydropressured, gas pay in a number of separate pools in the uppermost 200 metres of the Missisauga Formation. During drillstem testing, gas flowed at rates of up to 842 E3M3/d. Follow-up drilling consists of one well, Alma K-85. This well encountered gas pay throughout the Missisauga Formation. A depth structure map for the top Missisauga Formation at Alma is shown in **Figure 2.2.6.1.1**.

Figure 2.2.6.1.1: Alma - Top Missisauga (Top A Pool), Depth Structure Map
Contour Interval: 25 metres

2.2.6.2 Structural Configuration

The Alma structure consists of a rollover anticline bound to the north and south by major listric faults. The crestal portion of the rollover anticline is divided into two highs within which each of the wells were drilled. It is complicated by a number of northeast/southwest striking normal (possibly growth) faults with minor down-to-east throws. The field lies at an average depth of 2940 metres and covers an area of some 32 square kilometres.

Separate structural maps have to be constructed for each reservoir zone because of lateral and temporal variation in growth and sedimentation along the northern bounding fault. **Figure 2.2.6.2.1(a-b)** shows the structural configuration at the tops of the B and C Sands, respectively.

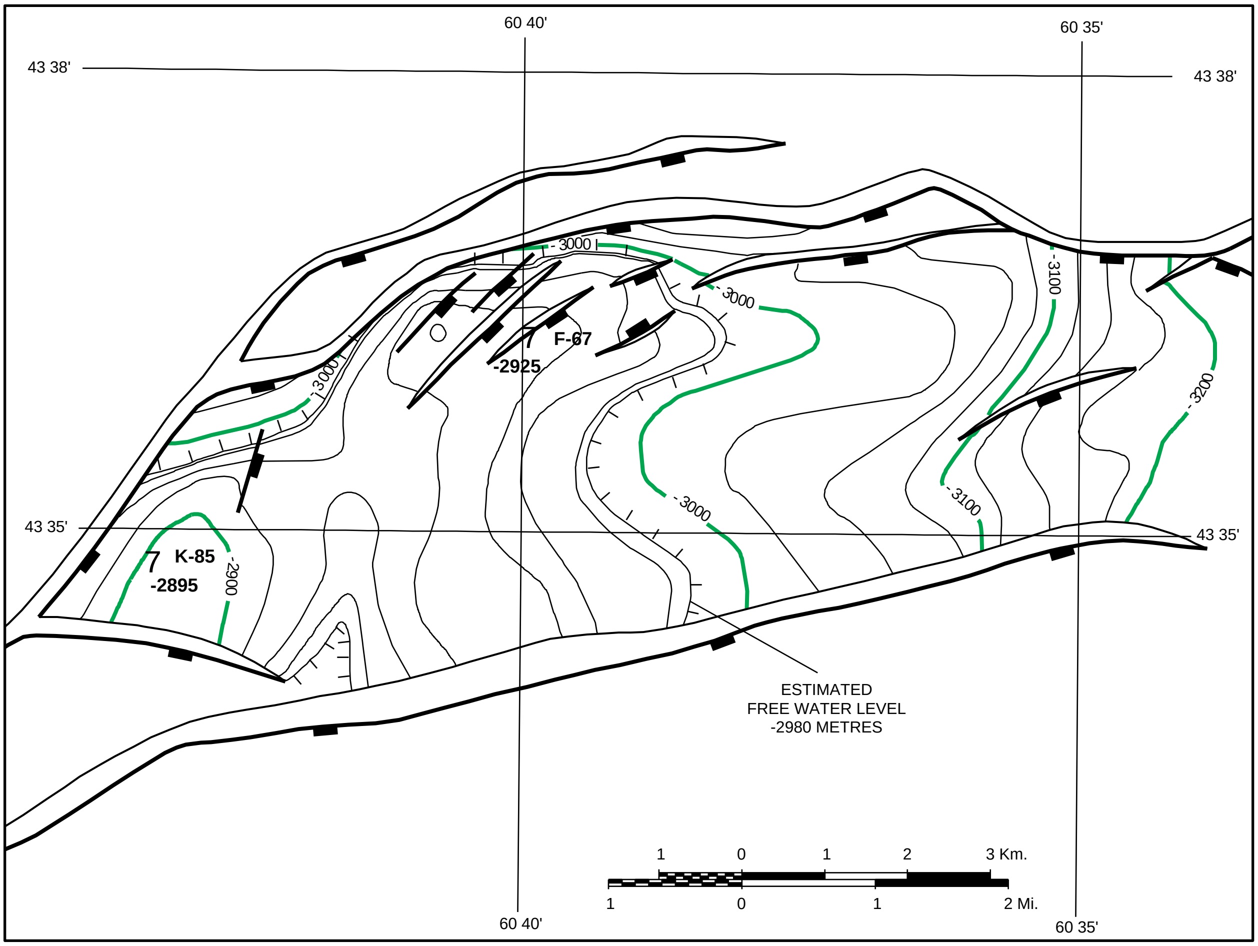

Figure 2.2.6.2.1(a): Alma - Top B Sand, Depth Structure Map
Contour Interval: 25 metres

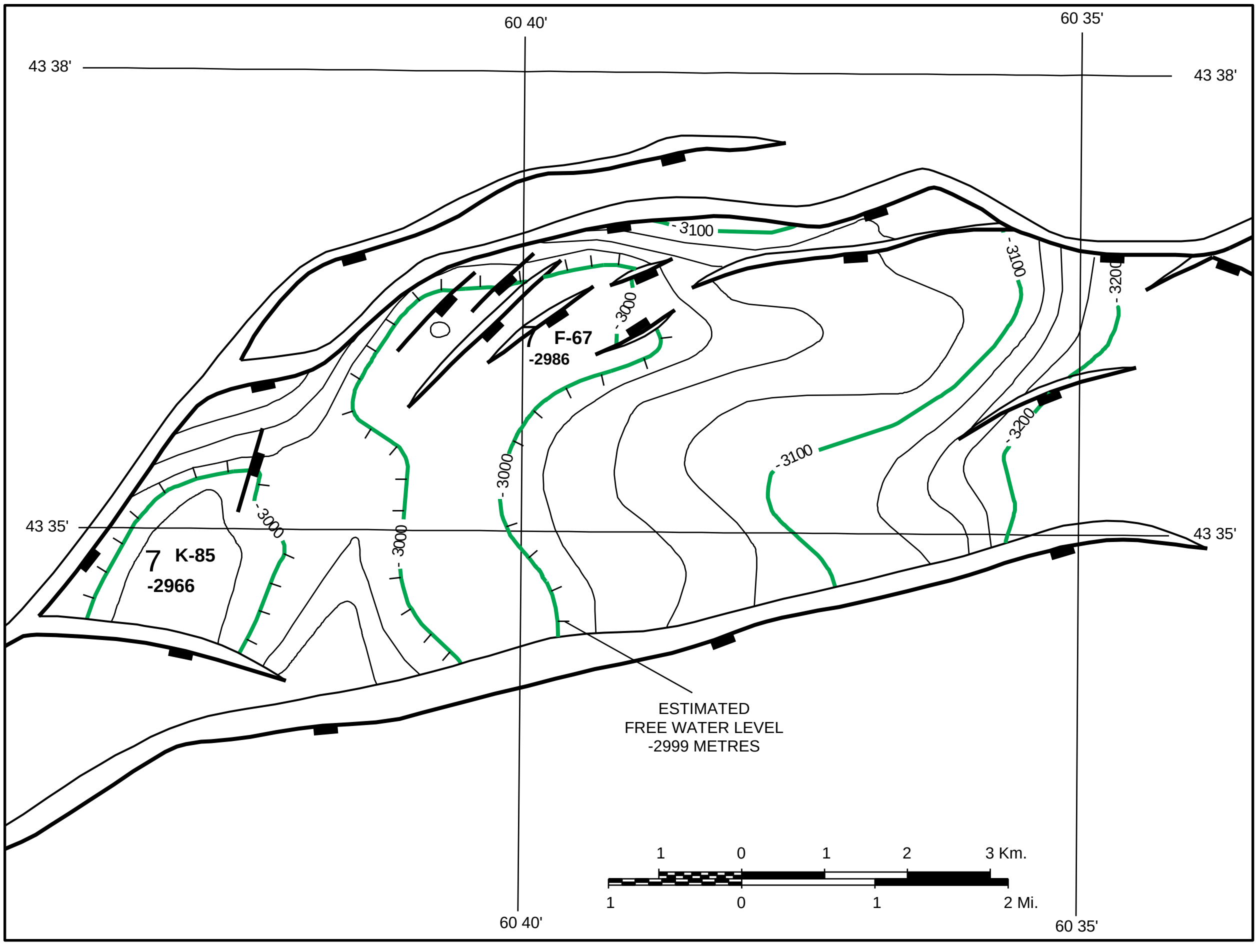

Figure 2.2.6.2.1(b): Alma - Top C Sand, Depth Structure Map
Contour Interval: 25 metres

2.2.6.3 Geology

The Alma Field is located near the southernmost extension of sands at the top of the Sable Delta complex. The sandy reservoir section (Missisauga Formation) is approximately 300 metres thick in this area.

Hydropressured gas was encountered throughout the Missisauga Formation in the K-85 well, and in the upper part of the formation in the F-67 well. Five separate pools are recognized. Three of these, A, B, and C, have significant volumes of gas.

The three main pools show simple closure to the east due to the plunge of the rollover anticline. Cross-fault seal is provided to the north by juxtaposition of the reservoir units with shales of the Verrill Canyon Formation, and to the south and west by their juxtaposition with Naskapi and lower Logan Canyon shales.

The Missisauga Formation at Alma is made up of a number of stacked coarsening-upward shale-to-sandstone deltaic cycles. Extensive coring has enabled sedimentological analysis of the reservoir section, much of which is interpreted as delta-fringe sediments. These were deposited on the shelf, several kilometres seaward of the actual shoreline, in shallow waters affected by tidal currents, as well as flood- and storm-generated flows, which carried silt and sand offshore. The uppermost sand unit in Zone A is interpreted, on the basis of sedimentary structures, as being deposited in a more tidally influenced estuarine setting (**DPA - Part 2, Ref. # 2.2.6.3.1**).

Changes in both thickness and sedimentology occur within the reservoir section between the two wells. The succession thins, and becomes less sand-rich in a southwestward direction. This is associated with a degradation in reservoir quality (see Alma: Petrophysics). The reservoir development model used for gas in place determination for the three pools at Alma is one of a north to south tapering wedge. This model combines the effects of a northerly source for the sands with syndepositional downward movement on the northern bounding growth fault; the latter acts to trap most of the reservoir quality sand in the northern portion of the structure. According to this model, reservoir thickness is at a maximum adjacent to the northern bounding fault, and thins systematically southward through the F-67 and K-85 wells, to the southern boundary of the field. Accompanying this trend in reservoir thickness is a southward decrease in grain size, and hence porosity development.

Convolution of this reservoir development model with structure maps and gas/water contacts for each of the pools permits construction of net pay maps. Net pay maps are then used for gas in place determination. **Figure 2.2.6.3.1(a-c)** illustrates the variation in net pay distribution across the Alma structure in the three main pools.

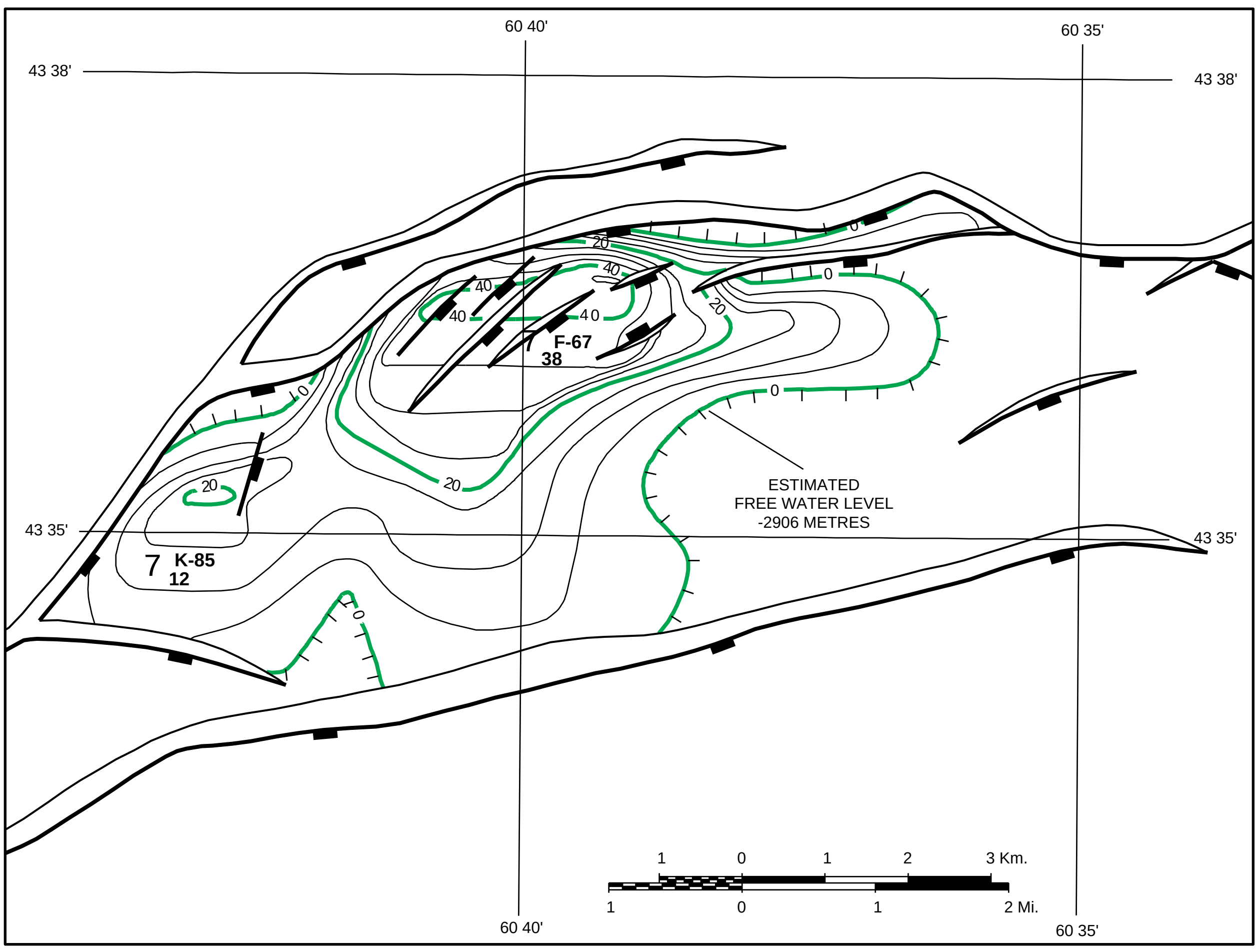

Figure 2.2.6.3.1(a): Alma - A Pool, Net Pay Map
Contour Interval: 5 metres

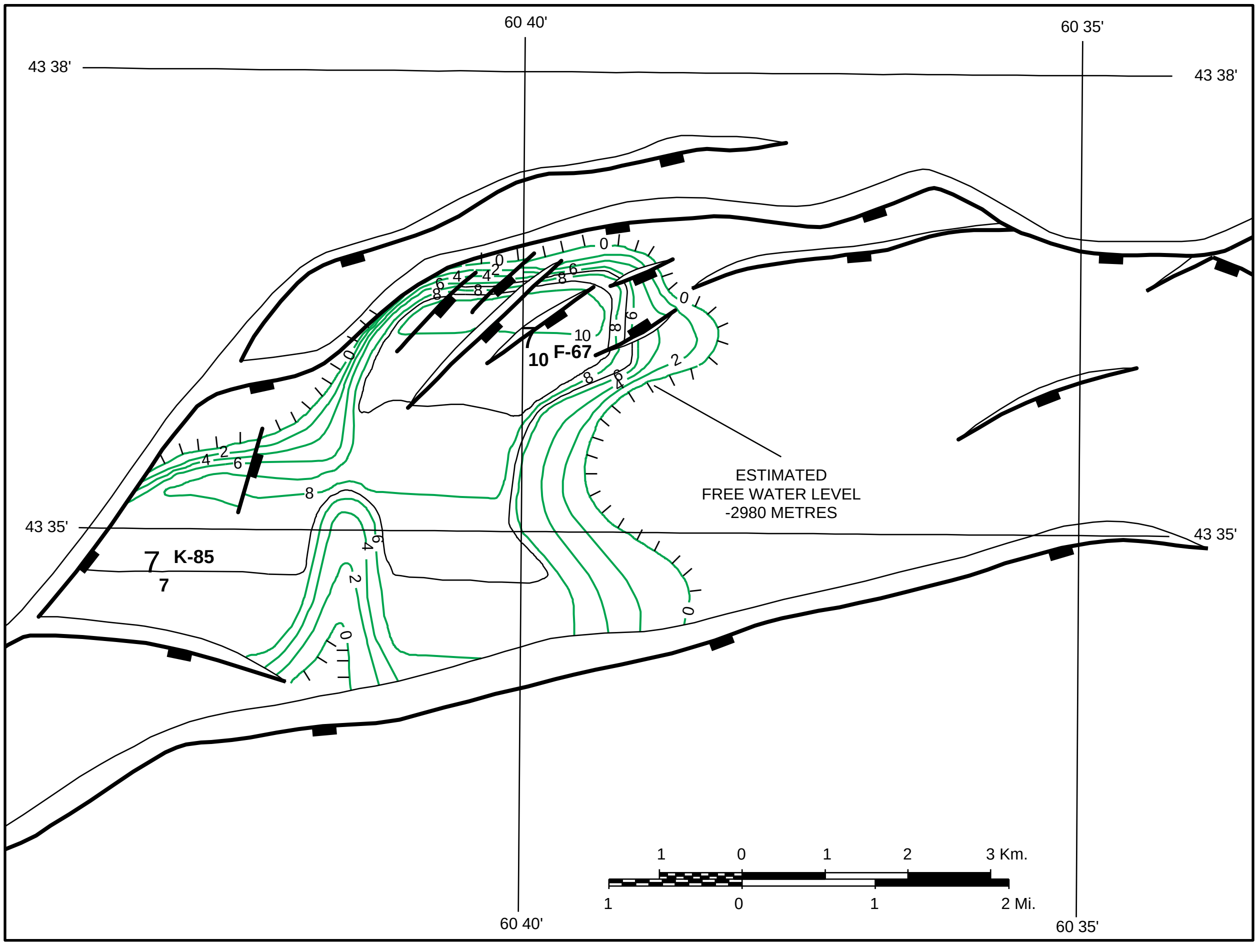

Figure 2.2.6.3.1(b): Alma - B Pool, Net Pay Map
Contour Interval: 2 metres

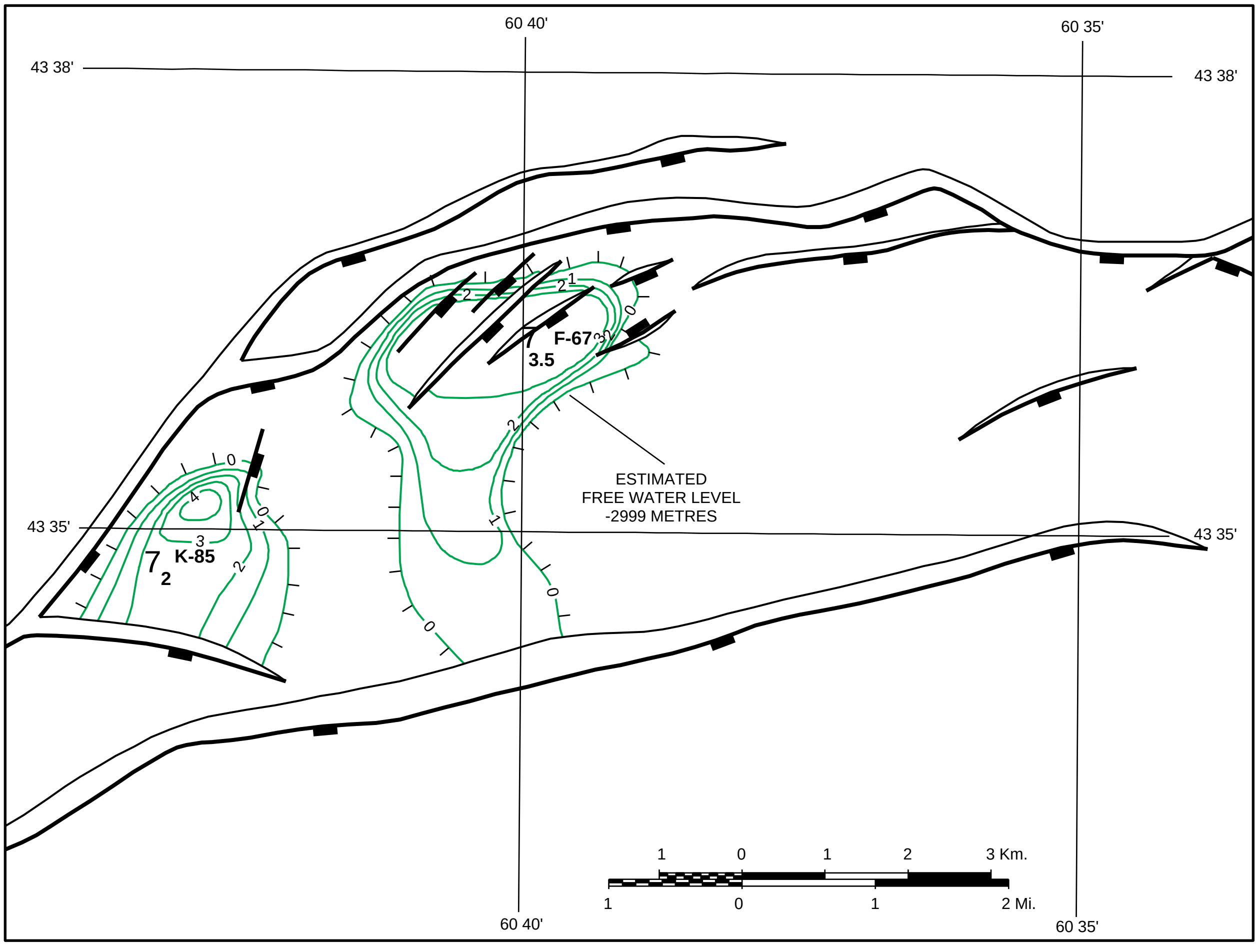

Figure 2.2.6.3.1(c): Alma - C Pool, Net Pay Map
Contour Interval: 1 metre

Log correlatability and reservoir pressure analysis indicate continuity of shales and reservoir intervals between the two wells in the upper two-thirds of the Missisauga Formation. Correlation is more problematic in the lower 75 to 100 metres of the Missisauga. This probably indicates syndepositional growth fault activity between the two wells, which has affected sand distribution patterns.

2.2.6.4 Reservoir Zonation

The Alma reservoir section is divided into five zones in order to reflect the presence of stacked, hydrodynamically separate gas accumulations (**DPA - Part 2, Ref. #2.2.6.4.1**). These separate gas pools are indicated by pressure data and the intersection by the wells of a number of discrete gas/water contacts. Their zone names correspond to the names of the associated gas pool. Zone boundaries are taken at the base of shale intervals believed, on the basis of pressure work, to be seals to gas migration. Each reservoir zone has, for the purpose of initial modeling of recoverable gas reserves, been treated as a single flow unit (**DPA - Part 2, Ref. # 2.3.1.3.6**).

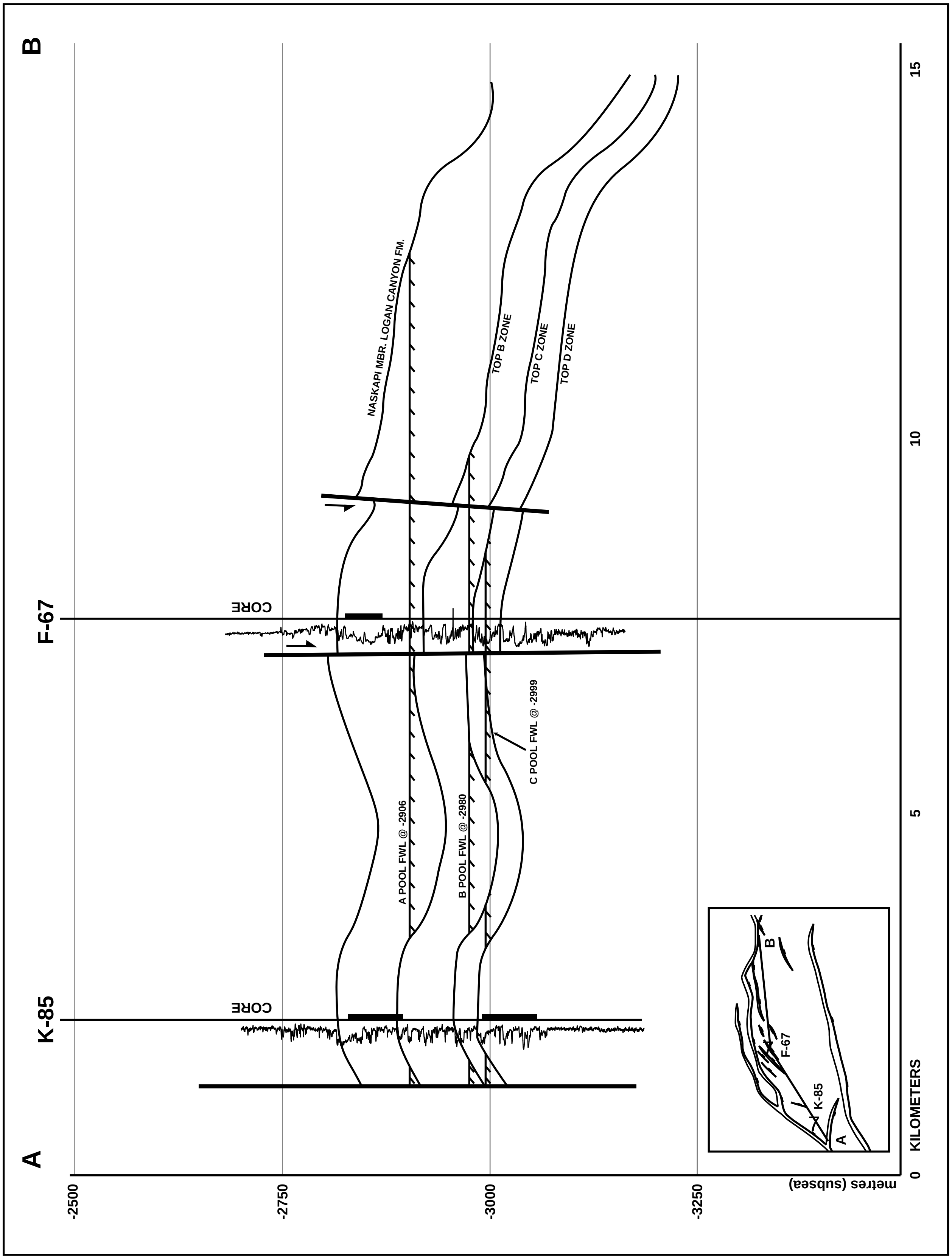

Figure 2.2.6.4.1: Alma Schematic Structural Cross-section

2.2.6.5 Geophysics

2.2.6.5.1 Seismic Database

The depth structure maps used to appraise reserves in Alma are based on a 2D seismic dataset consisting of lines acquired throughout the period 1981-1984. This is illustrated in **Figure 2.2.6.5.1.1**. Seismic data quality is generally fair to good to the objective level. A summary of acquisition and processing details is given in **Table 2.2.6.5.1.1.**

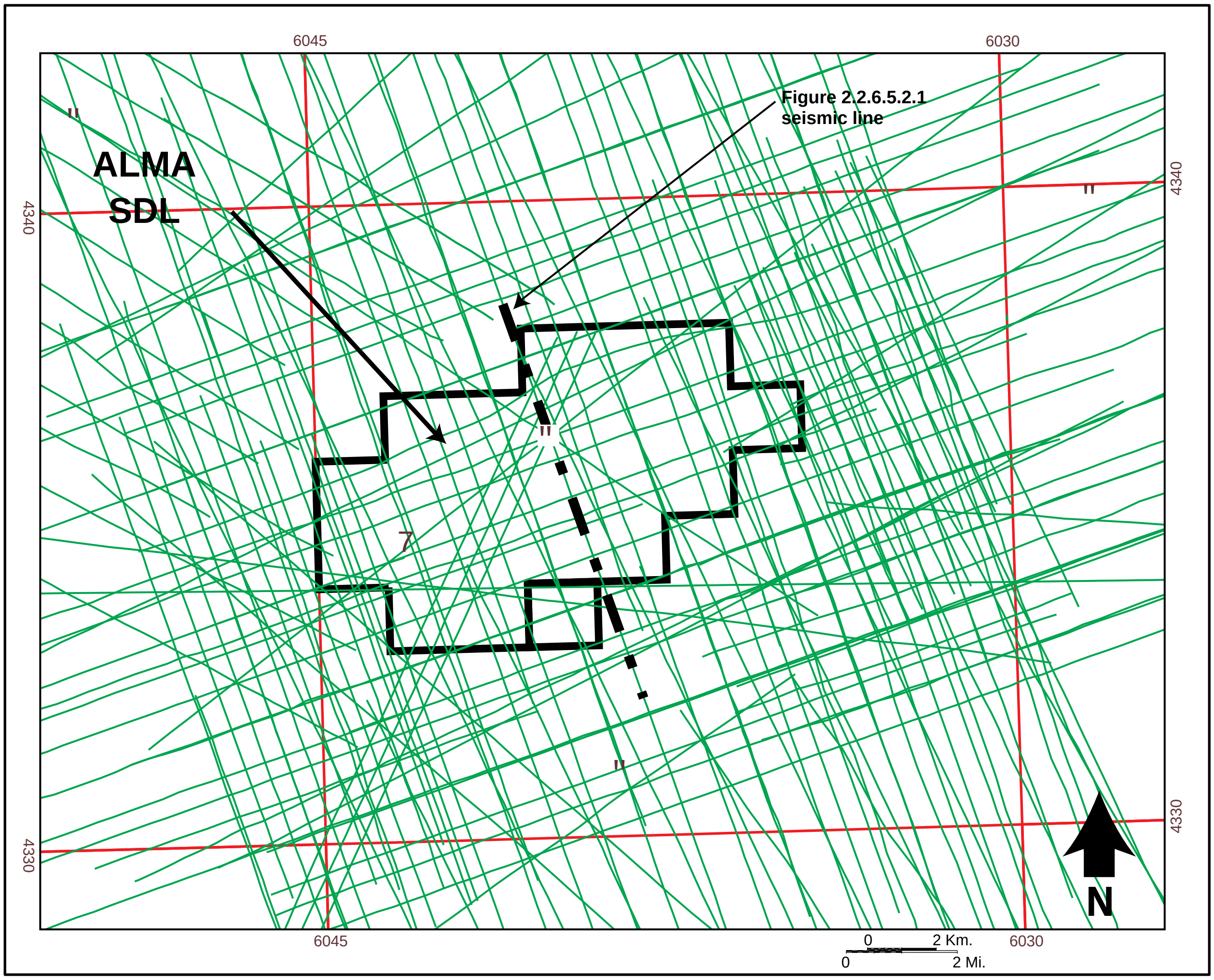

Figure 2.2.6.5.1.1: Alma Seismic Database Map

Table 2.2.6.5.1.1: Alma Acquisition and Processing Summary

Data Type	Survey Name	Incorp. In Study	Acq. Date	Acq. Style	Proc. Date	Field Kms	Proc. Details	Comments
2D	8624-s006-048E	No	1985	Marine	1985	376	60 Fold, Desig, FK Migration	Generally good quality data.
2D	8624-S006-043E	Yes	1984	Marine	1984	212	60 Fold, Desig, FD Migration	Generally fair to good data quality.
2D	8624-S006-037E	Yes	1983	Marine	1983	56	80 Fold, Desig, FK Migration	Generally fair to good data quality.
2D	8624-S006-037E	Yes	1983	Marine	1983	156	54 Fold, Desig, FD Migration	Generally fair to good data quality.
2D	8624-S006-033E	Yes	1982	Marine	1982	266	50 Fold, Desig, FD Migration	Generally good data quality.
2D	8624-S006-027E	Yes	1981	Marine	1982	571	60 Fold, Desig, FD Migration	Generally fair to good data.
2D	8624-S006-020E	No	1976	Marine	1973	19	24 Fold, No Mig	Generally poor data quality.

2.2.6.5.2 Time Interpretation

The 2D seismic data were interpreted manually and time structure maps were made for the Wyandot, Base Sable Shale, Naskapi, and Top Missisauga horizons. The Top Missisauga Event, correlated from well control (**Table 2.2.6.5.2.1**), was used as the main mapping horizon. Alma contains three main sand units which thin in a distal direction. The A Sand is assumed to be conformable to the Top Missisauga. However, the B and C Sand surfaces are not subparallel to the Top Missisauga and so new structure maps were created for these sands by summing wedges equal to the isopach thicknesses for the well tops of Sands A to B and tops A to C, respectively. This information is include in Part Two (**DPA - Part 2, Ref. # 2.2.3.7.1**).

Table 2.2.6.5.2.1: Alma Horizon Markers

FIELD	ALMA							
	F-67				K-85			
MAP HORIZON	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)	Depth MD (m)	Depth TVD (m)	Depth (Mss)	TWT (sec)
Wyandot Chalk	1312	1312	-1288	1.317	1323	1323	-1299	1.332
Top L. Logan Can.	1878	1878	-1854	1.711	1877	1877	-1853	1.720
Naskapi	2543	2543	-2519	2.108	2523	2525	-2501	2.106
Missisauga	2843	2842	-2818	2.270	2843	2843	-2819	2.287
Verril Canyon	3107	3107	-3083	2.384	3111	3106	-3082	2.428
TD	5054				3602			

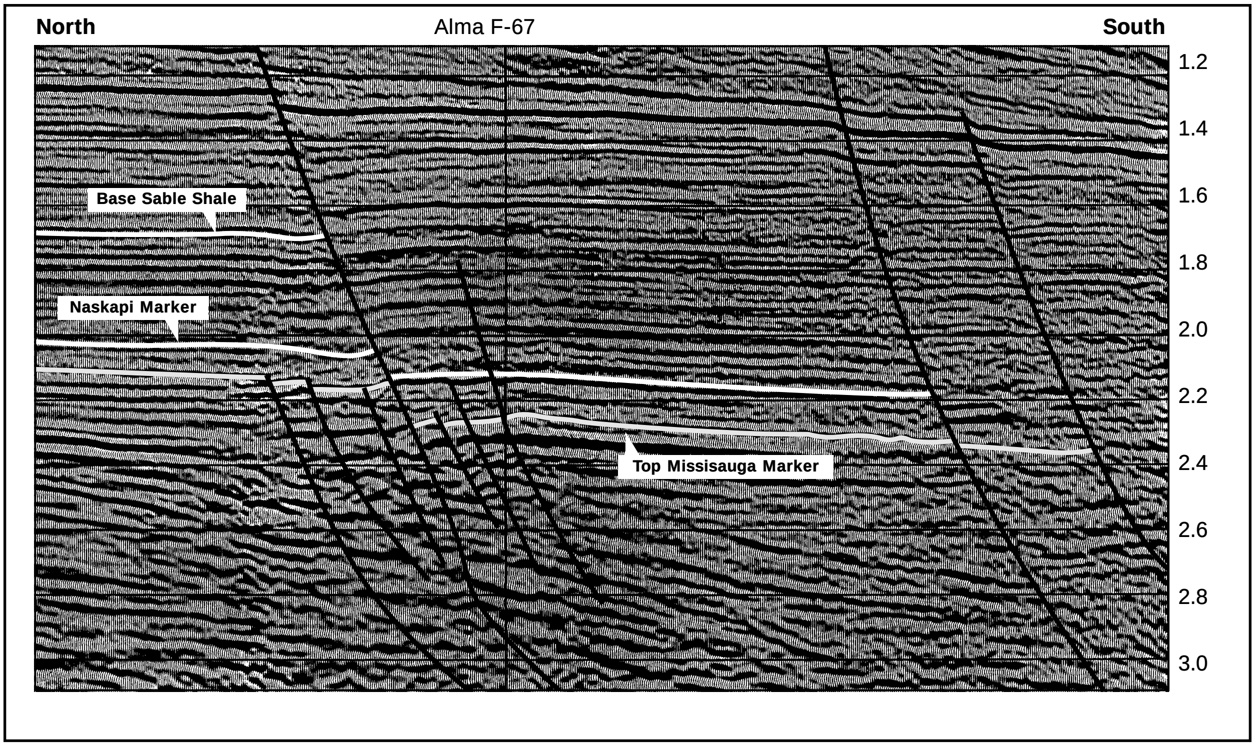

Figure 2.2.6.5.2.1: Alma Seismic Section

2.2.6.5.3 Depth Conversion

In a manner similar to the depth conversion work at Glenelg, a replacement velocity was used for the water layer; and time-depth tables, derived from the well control, were used to produce depth maps from the respective horizon time structure maps as illustrated in **Table 2.2.6.5.3.1** (**DPA - Part 2, Ref. # 2.2.6.5.3.1**).

Table 2.2.6.5.3.1: Alma Well Velocity Data

Well	Year Acquired	Checkshot Available	Checkshot Type	VSP Available	VSP Type
Alma F-67	1984	Yes	Vertical	No	NA
Alma K-85	1985	Yes	Vertical	No	NA

2.2.6.6 Petrophysics

A detailed petrophysical evaluation of the two wells in the Alma reservoir has been conducted using all available wireline log data, conventional and special core analysis data and pressure data. A detailed summary of the interpretation parameters and methodology is included in Part Two (**DPA - Part 2, Ref. # 2.2.6.6.1**). The results of this evaluation are illustrated in **Table 2.2.6.6.1**.

Table 2.2.6.6.1: Alma Reservoir Parameter Summaries

Alma F-67 K.B. 2.40 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	2842.0	2949.0	-2818.0	-2925.0	107.0	38.2	15.0	42.0	6-54
B	2949.0	3010.0	-2925.0	-2986.0	61.0	10.1	18.0	49.0	5-15
C	3010.0	3045.0	-2986.0	-3021.0	35.0	3.5	14.0	48.0	2

Alma K-85 K.B. 24.0 Metres

Sand Unit	Measured Depth Top (m)	Measured Depth Base (m)	Elevation Top (m ss)	Elevation Base (m ss)	Gross Thickness (m)	Net Pay (m)	Average Porosity (%)	Average Sw (%)	Average Permeability* (mD)
A	2843.0	2919.0	-2819.0	-2895.0	76.0	12.1	16.0	27.0	60
B	2919.0	2990.0	-2895.0	-2966.0	71.0	7.0	15.0	39.0	10-67
C	2990.0	3017.0	-2966.0	-2993.0	57.0	2.0	14.0	56.0	3-20

*Estimated from DSTs

The bulk of reserves in the Alma Field are contained in three separate hydropressured reservoirs, with individual gas/water contacts. Average porosity ranges from 15 to 18 percent with the primary control on porosity being average grain size. Irreducible water saturations, as calculated from logs, range from 10 to 60 percent. Porosity was calculated from density logs calibrated to stressed core porosity measurements. Water saturation values used in the estimation of gas in place were calculated using the Archie equation. Cementation and saturation exponent values were based on special core analysis stressed formation resistivity factor and resistivity index measurements. Formation water resistivity was derived from RFT and DST fluid sample analysis. A formation temperature gradient was determined from bottom hole temperature measurements. Net pay cutoff criteria were based on core analysis data. Net pay thickness was determined based on a permeability cutoff of 1.0 mD to air at ambient conditions. This was found to correspond to an in situ porosity value of 10 percent and a water saturation cutoff of 60 percent.

2.2.6.7 Gas in Place

The ranges of uncertainty of the parameters utilized in the probabilistic assessment of gas in place are detailed in Part Two (**DPA - Part 2, Ref # 2.2.5.7.1**). The results for the three main pools in the Alma Field are presented in **Table 2.2.6.7.1**.

Deterministic gas in place estimates were performed in 1990 and 1991. Average reservoir porosity and water saturation values were determined from well petrophysics and average net pay values. These were determined from the net pay maps, and what was then considered the ‘most likely’ structure maps for the area of the three pools. The methodology of this deterministic gas in place determination is presented in detail in Part Two (**DPA - Part 2, Refs. #2.2.3.7.1 and #2.2.3.7.2**); the results are presented in **Table 2.2.6.7.2**. The deterministic volumes are similar to the P50 and Mean values obtained from the probabilistic method.

Table 2.2.6.7.1: Alma Probabilistic Estimates of Gas In Place, E9M3

Reservoir Sandstone	P90	P50	P10	Mean
A	8.8	11.4	14.3	11.5
B	2.4	3.1	3.9	3.1
C	0.3	0.4	0.5	0.4
Project Total	11.5	14.9	18.7	15.0

Table 2.2.6.7.2: Alma Deterministic Estimates of Gas In Place, E9M3

Reservoir Sandstone	Gas in Place
A	11.3
B	3.4
C	0.4
Project Total	15.1

Two other pools, D and E, were encountered deeper in the K-85 well. Correlative sands in the F-67 well are wet, indicating either limited gas columns, sand pinchout, or the presence of a sealing fault between the wells. Current interpretation indicates that the reserves contained in these deeper sands in K-85 are too small to warrant inclusion in the **Sable Offshore Energy Project** development.