3.0 RESERVOIR ENGINEERING

Reservoir engineering activities continue throughout the Project. They are aimed at the generation and continual refinement of the physical descriptions of the reservoir for the optimization of economic recovery. At the early project stages prior to development, the subsurface emphasis is on the detailed seismic interpretation combined with reservoir characterization and geologic models for which cores, modern wireline logs and production test information supplements the regional geology and seismic knowledge. These reservoir geological models, developed from the integration of all the subsurface information, provide the input for numerical reservoir simulation studies.

Early simulation activity is aimed at establishing viable project development options and must be inherently flexible to allow for the integration of new data, project scope changes and advancements in new technology. Later in the life of the field, necessary adjustments are made to the reservoir simulators to history match the actual field performance. The reservoir depletion plans must be flexible enough to allow for the implementation of contingency plans should surveillance information prompt revisions to the production scheme.

The following sections describe the data used in the development of a description of the reservoir for the purpose of individual field simulations studies. The fundamental building blocks and the tools used in the development of a production forecast are described, as well as, some of the simulated alternative development options. The chapter ends with a discussion on reservoir management , from development through to operations.

3.1 Reservoir Data

3.1.1 Reservoir Mapping

More than 40 hydrocarbon bearing sands have been identified within the six Project fields. Of these sands, 32 have been identified as having sufficient volume and producibility to form the basis of the production forecast. The sands included in the development of the Project (Project Sands) consist of seven in Thebaud, 12 in Venture, one in North Triumph, five in South Venture, three in Alma and four in Glenelg. These sands have been tested, mapped and incorporated, to varying degrees, into the reservoir modelling work completed to date. The Project Sands and their associated gas in place estimates are shown in **Table 3.1.1.1**.

The shallow sands in all fields will be penetrated with wells targeted for deeper horizons. The relatively small volumes associated with these sands may be produced towards the end of the Project but have not been incorporated into the production forecast. The deeper horizons, Sands 11 and 13 in Venture, and Sands 7 and 8 in South Venture are not included in this development plan because the small volumes and associated high drilling and producing costs render them currently uneconomic. The gas volume associated with these sands is shown in the line entitled *Minor Sand Total* in **Table 3.1.1.1.** Part Two of the Development Plan (**DPA - PART 2, Ref. # 3.1.1.1**) includes a detailed discussion of the viability of the minor sand accumulations.

Table 3.1.1.1 Gas In Place Summary - Project Sands

Field	Reservoir Sandstone	P90 OGIP E9M3	P50 OGIP E9M3	P10 OGIP E9M3	Mean OGIP E9M3
Thebaud	A	6.4	11.9	20.6	12.8
	B	0.7	1.7	3.3	1.8
	F1	0.3	0.9	2.2	1.1
	F3	1.1	2.7	6.0	3.2
	G2	0.5	1.2	2.8	1.5
	G3	1.0	2.3	5.4	2.9
	H2	0.8	2.3	4.8	2.7
	Total	**10.8**	**23.0**	**45.1**	**26.0**
Venture	2	2.5	6.2	12.2	7.0
	A	0.2	0.8	2.1	1.0
	B	0.5	1.4	3.3	1.7
	3	2.9	5.8	11.1	6.6
	4a	0.4	1.0	3.0	1.4
	4c	0.5	1.4	3.7	1.9
	4d	0.3	1.0	3.5	1.6
	5	1.8	5.0	12.2	6.2
	6u	4.7	9.1	16.8	10.1
	6m	2.2	4.8	10.1	5.6
	7	1.0	2.4	5.5	2.9
	8	1.2	2.9	6.2	3.4
	Total	**18.2**	**41.8**	**89.7**	**49.4**
North Triumph	**Total**	**6.2**	**14.2**	**25.2**	**15.2**
South Venture	2	1.3	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
	Total	**3.3**	**10.4**	**20.5**	**11.3**
Alma	A	8.6	11.5	14.4	11.4
	B	2.5	3.1	3.9	3.1
	C	0.4	0.3	0.4	0.5
	Total	**11.5**	**14.9**	**18.7**	**15.0**
Glenelg	B	2.8	6.4	10.8	6.7
	C1	3.0	3.9	4.9	3.9
	C2	0.3	0.5	0.5	0.5
	F	1.0	1.3	1.6	1.3
	Total	**7.1**	**12.1**	**17.8**	**12.4**
Project Total		**57.1**	**116.4**	**217.0**	**129.3**
Minor Sand Total		**1.9**	**6.7**	**18.0**	**8.9**

Note: Mean values have been summed arithmetically.
P90 = 90 % Probability of exceeding posted value.
P10 = 50 % Probability of exceeding posted value.
P10 = 10 % Probability of exceeding posted value.
OGIP = Original Gas In Place

3.1.2 Well Test Data

Data obtained from Drill Stem Tests (DST) for the Project fields have been compiled and is presented in Table 3.1.2.1. The interpretations associated with the highlighted DST's can be found in Part 2 of this submission **(DPA - Part 2, Ref. # 3.1.2.1)**.

The flowing times during cleanup and subsequent production periods varied significantly for all the DST's, ranging from 15 minutes in some of the earlier wells (Venture D-23) to 24 hours in the later wells (North Triumph G-43). The short flow and buildup periods for the earlier wells coupled with the use of mechanical gauges with low pressure sensitivities, leads to some uncertainty in the interpretations. The recent wells used electronic gauges which offered a higher degree of accuracy.

Table 3.1.2.1 Drillstem Test Summary

Well	DST No.	Sand	Top Interval (M-KB)	BHSP (MPa)	BHST (C)	Max. Gas Rate (E3m3/d)	Cond. Ratio (m3/E6m3)	Water Rate (m3/d)	Water Ratio (m3/E6m3)	Cum. Flow Time (hr)	KH (md-m)	Skin	Draw Down (MPa)	Remarks
THEBAUD														
P-84	1OH	2	2935	30	93	300	11	6.6	22	2	—	—	1	
P-84	1	D3	4027	60	126	0	0	0	0	3	—	—	16	
P-84	2	D3	4020	52	—	0	0	1	N/A	3	—	—	29	Tbg load rate
P-84	3	D3	4020	—	117	0	0	3	N/A	7	—	—	—	Tbg load rate
P-84	***4***	***A***	***3830***	***—***	***104***	***—***	***—***	***—***	***—***	***—***	***—***	***—***	***—***	***Misrun***
P-84	***5***	***A***	***3830***	***53***	***111***	***596***	***0***	***0***	***0***	***—***	***—***	***—***	***3***	
P-84	***6***	***A***	***3830***	***52***	***104***	***—***	***—***	***0***	***—***	***—***	***—***	***—***	***—***	
P-84	***7***	***6a2***	***3402***	***34***	***102***	***195***	***134***	***0***	***0***	***4***	***—***	***—***	***—***	
P-84	***8***	***6a1***	***3364***	***34***	***103***	***88***	***N/A***	***—***	***0***	***1***	***—***	***—***	***16***	***Misrun***
P-84	***9***	***6a1***	***3364***	***—***	***99***	***—***	***—***	***—***	***—***	***—***	***—***	***—***	***—***	***Misrun***
P-84	***10***	***6a1***	***3364***	***34***	***—***	***147***	***162***	***0***	***0***	***3***	***—***	***—***	***7***	
P-84	***11***	***4***	***3213***	***33***	***91***	***150***	***116***	***0***	***0***	***3***	***—***	***—***	***2***	
P-84	***12***	***3C***	***3139***	***31***	***85***	***0***	***TSTM***	***0***	***TSTM***	***1***	***—***	***—***	***—***	
I-94	***1OH***	***A***	***3769***	***—***	***—***	***—***	***—***	***—***	***—***	***—***	***—***	***—***	***—***	***Misrun***
I-94	***2***	***A***	***3769***	***52***	***—***	***387***	***165***	***0***	***0***	***4***	***299***	***47***	***—***	
I-93	1	G3	4652	90	137	0	0	0	0	4	—	—	43	No flow
I-93	2	G1	4614	87	134	0	0	0	0	4	—	—	41	No flow
I-93	3	E1	4318	—	—	—	—	—	—	—	—	—		Misrun
I-93	4	E1	4318	75	127	TSTM	0	0	0	7	—	—	62	
I-93	5	D3	4080	62	117	est. @ 0.8	0	TSTM	0	26	—	—	23	Rec. 103M ppm water
I-93	6	C	3997	54	116	TSTM	0	13	N/A	25	—	—	10	190000 ppm
I-93	***7***	***A***	***3931***	***53***	***114***	***746***	***149***	***3.0***	***4***	***44***	***526***	***37***	***12***	***Tbg load rate***
I-93	***8***	***A***	***3912***	***53***	***114***	***167***	***137***	***0***	***0***	***15***	***676***	***2.9***	***1***	
I-93	9	8	3711	38	110	0	0	0	0	18	—	—	6	54000 ppm
I-93	***10***	***6a1***	***3453***	***35***	***104***	***0***	***0***	***0***	***0***	***6***	***—***	***—***	***0.3***	***107000 ppm***
C-74	1	J1	5016	100	153	0	0	0	0	4	—	—	42	No flow
C-74	***2***	***H2***	***4748***	***89***	***131***	***1333***	***22***	***0***	***0***	***22***	***664***	***21***	***13***	
C-74	3	H1	4682	88	136	741	55	37.1	50	19	75	10	40	Tbg load rate
C-74	***4***	***GL***	***4508***	***—***	***142***	***872***	***57***	***15.7***	***18***	***14***	***—***	***—***	***—***	***Misrun-tbg load rate***
C-74	***5***	***GL***	***4508***	***84***	***143***	***1348***	***46***	***10.8***	***8***	***16***	***22***	***-1***	***12***	***Tbg load rate***
C-74	***6***	***F3***	***4405***	***83***	***141***	***1314***	***41***	***0***	***0***	***31***	***131***	***1***	***17***	
C-74	***7***	***F1***	***4311***	***80***	***129***	***184***	***47***	***0***	***0***	***8***	***2***	***-3***	***56***	
C-74	***8***	***B***	***3914***	***53***	***116***	***51***	***121***	***0.0***	***0***	***35***	***1712***	***-2***	***1***	
C-74	***9***	***A***	***3865***	***52***	***113***	***878***	***108***	***5.3***	***6***	***51***	***761***	***0***	***5***	***Tbg load rate***

Well	DST No.	Sand	Top Interval (M-KB)	BHSP (MPa)	BHST (C)	Max. Gas Rate (E3m3/d)	Cond. Ratio (m3/E6m3)	Water Rate (m3/d)	Water Ratio (m3/E6m3)	Cum. Flow Time (hr)	KH (md-m)	Skin	Draw Down (MPa)	Remarks
VENTURE														
D-23	1	6u	4899	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	2	6u	4899	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	3	6u	4899	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	***4***	***6u***	***4899***	***84***	***140***	***283***	***87***	***4.5***	***16***	***8***	***138***	***-2***	***3***	***4400 ppm***
D-23	5	5	4829	80	135	—	—	—	—	—	—	—	—	Misrun
D-23	6	5	4829	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	7	5	4829	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	8	3a	4643	70	—	628	81	0	0	8	568	2	2	
D-23	9	2	4414	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	9A	2	4414	—	—	—	—	—	—	—	—	—	—	Misrun
D-23	***9B***	***2***	***4414***	***44***	***—***	***328***	***85***	***0***	***0***	***5.5***	***—***	***—***	***3***	***Poor gauge data***
B-13	1	10	5168	98	142	3.7	0	192.4	52000	5	—	—	48	
B-13	***2***	***8***	***5056***	***—***	***145***	***17***	***0***	***190.4***	***11200***	***2.5***	***—***	***—***	***—***	***No gauge data***
B-13	***3***	***6u***	***4949***	***85***	***140***	***524***	***5***	***0***	***0***	***7.5***	***725***	***-1***	***1***	***32000 ppm***
B-13	***4***	***4c***	***4882***	***82***	***139***	***128***	***0***	***246.4***	***1925***	***6***	***152***	***5***	***2***	
B-13	***5***	***4b***	***4853***	***80***	***127***	***0***	***N/A***	***73***	***N/A***	***7***	***0.003***	***2***	***26***	***Tbg load rate***
B-13	***6***	***B***	***4572***	***51***	***—***	***81***	***47***	***3.8***	***47***	***8***	***4***	***3.5***	***41***	***13000 ppm***
B-13	7	3a	4714	—	—	—	—	—	—	—	—	—	—	Misrun
B-13	8	3a	4714	—	—	—	—	—	—	1	—	—	—	Misrun Pkr Leak *
B-13	***9***	***A***	***4531***	***51***	***125***	***194***	***197***	***18.0***	***93***	***8***	***6***	***-3***	***32***	***4300 ppm***
B-13	***10***	***2l***	***4495***	***47***	***123***	***433***	***75***	***17.3***	***40***	***5.5***	***109***	***0***	***6***	***42000 ppm***
B-13	***11***	***2u***	***4478***	***47***	***126***	***527***	***116***	***4.7***	***9***	***6***	***2313***	***16***	***1***	***790 ppm***
B-13	12	—	4418	47	123	386	120	0	0	5	—	—	2	21900 ppm
B-13	13	1l	4126	43	116	0	0	17	N/A	8	—	—	4	87000 ppm
B-13	14	1u	4107	43	118	0	0	190	N/A	1	—	—	0.1	107000 ppm
B-13	15	—	4068	43	117	0	0	350	N/A	1.5	—	—	0.06	175000 ppm
B-13	16	—	3755	38	108	0	0	300	N/A	3	—	—	0	148000 ppm
B-43	1	13	5510	107	153	0	0	16	N/A	8	—	—	47	Tbg load rate
B-43	2	13	5479	107	161	261	69	139.0	533	7	49	13	24	
B-43	3	11	5279	100	151	447	96	6.3	14	8	81	1	9	
B-43	***4***	***8***	***5090***	***86***	***148***	***418***	***0***	***0***	***0***	***1***	***—***	***—***	***7***	***18000 ppm***
B-43	***5***	***8***	***5090***	***86***	***140***	***139***	***202***	***0***	***0***	***8***	***70***	***-1***	***2***	***19000 ppm***
B-43	***6***	***7***	***5036***	***84***	***137***	***280***	***78***	***5.3***	***19***	***6***	***—***	***—***	***0.4***	***600 ppm***
B-43	***7***	***6***	***4953***	***84***	***138***	***300***	***153***	***7.8***	***26***	***11***	***1017***	***-1***	***0.6***	***700 ppm***
B-43	***8***	***5***	***4883***	***80***	***132***	***390***	***330***	***0***	***0***	***6***	***664***	***1***	***1***	
B-43	***9***	***4a***	***4788***	***79***	***129***	***178***	***138***	***0***	***0***	***6***	***12***	***2***	***12***	***2100 ppm***
B-43	***10***	***3a***	***4680***	***70***	***127***	***162***	***71***	***0***	***0***	***12***	***639***	***12***	***2***	***3600 ppm***
B-43	11	C	4607	—	—	—	—	—	—	—	—	—	—	misrun
B-43	12	C	4607	62	127	0.5	TSTM	0	N/A	15	—	—	—	
B-43	13	B	4543	—	125	—	—	—	—	—	—	—	—	misrun
B-43	14	B	4543	—	—	—	—	—	—	—	—	—	—	misrun
B-43	***15***	***B***	***4543***	***—***	***125***	***0***	***0***	***0***	***N/A***	***5***	***—***	***—***	***—***	
B-43	16	—	4251	44	119	75	94	28.7	382	13	—	—	35	
B-43	17	—	3700	39	108	TSTM	TSTM	0	N/A	8	—	—	1	
H-22	1	18	5692	114	155	0	0	0	0	8	—	—	63	No flow
H-22	2	Y	5520	110	151	0	0	0	0	7	—	—	56	No flow
H-22	3	11	5246	94	142	0	0	0	0	5	—	—	41	No flow
H-22	***4***	***8***	***5056***	***85***	***140***	***113***	***0***	***95.0***	***841***	***5***	***—***	***—***	***24***	***187000 ppm***
H-22	***5***	***7m***	***5021***	***84***	***140***	***164***	***56***	***232.7***	***1419***	***8***	***50***	***2***	***4***	***183000 ppm***
H-22	***6***	***6m***	***4976***	***83***	***139***	***698***	***71***	***103.3***	***148***	***22***	***72***	***-1***	***25***	***189000 ppm***
H-22	***7***	***6u***	***4957***	***82***	***139***	***1081***	***61***	***42.2***	***39***	***64***	***67***	***-2***	***22***	***172000 ppm***
H-22	***8***	***4b***	***4837***	***—***	***—***	***—***	***—***	***0***	***—***	***—***	***—***	***—***	***—***	***Misrun***
H-22	***9***	***4b***	***4837***	***77***	***132***	***0***	***0***	***0***	***N/A***	***22***	***5***	***-2***	***21***	***69000 ppm***
B-52	1	18	5800	—	—	13	0	1.9	143	15	—	—	—	Recorders failed

Well	DST No.	Sand	Top Interval (M-KB)	BHSP (MPa)	BHST (C)	Max. Gas Rate (E3m3/d)	Cond. Ratio (m3/E6m3)	Water Rate (m3/d)	Water Ratio (m3/E6m3)	Cum. Flow Time (hr)	KH (md-m)	Skin	Draw Down (MPa)	Remarks
VENTURE cont'd														
B-52	2	17	5725	115	161	311	3	9.0	29	13	—	—	77	44000 ppm
B-52	3	13	—	—	—	—	—	—	—	—	—	—	—	Misrun
B-52	4	13	—	—	—	—	—	—	—	—	—	—	—	Misrun
B-52	5	13	5453	108	152	0.7	0	271	N/A	7	63	-6	32	Tbg load rate
B-52	6	11	5284	99	—	1393	23	20.9	15	36	57	-3	28	16000 ppm
B-52	7	7	5126	86	142	0.8	0	231	N/A	6	494	1	4	199000 ppm
B-52	8	6m	5065	—	142	1.1	0	83	N/A	9	—	—	—	209000 ppm
B-52	9	6u	5043	84	140	2	0	851	N/A	6	399	-5	13	268000 ppm
B-52	10	6U	5031	83	—	1	0	379	N/A	5	—	—	24	231000 ppm
B-52	11	6u	5023	84	143	0.6	0	335	N/A	2	68	-3	17	246000 ppm
B-52	12	5	4963	82	142	3.3	TSTM	76	N/A	10	—	—	43	155000 ppm
B-52	13	4d	4920	81	138	44	TSTM	129	N/A	7	1	-1	49	238000 ppm
B-52	14	4a	4848	76	135	0	0	14	N/A	16	—	—	26	159000 ppm
B-52	15	3a	4711	70	133	12	TSTM	363	N/A	7	245	-4	8	257000 ppm
NORTH TRIUMPH														
G-43	1	A	3835	39	118	994	26	4.0	4	24	1061	-4	1	
G-43	2	A	3795	38	115	1045	31	6.3	6	24	1475	-5	0	
B-52	1		3810	—	118	0	0	3	N/A	2	—	—	—	186000 ppm
B-52	2	A	3795	38	119	TSTM	0	9	N/A	1	—	—	—	185000 ppm
B-52	3	A	3771	—	117	0	0	—	—	—	—	—	—	Misrun
B-52	4	A	3771	39	118	774	26	3.9	5	24	529	-7	1	
SOUTH VENTURE														
O-59	1	—	5925	—	163	—	—	—	—	—	—	—	—	Misrun
O-59	2	—	5925	—	161	0	0	0	0	1	—	—	—	No flow
O-59	3	—	5849	—	161	0	—	—	—	5	—	—	—	Misrun
O-59	4	—	5667	105	154	0	0	0	0	4	—	—	41	No flow
O-59	5	8u	5035	93	141	183	58	0	0	9	37	57	61	
O-59	6	—	4865	61	137	0	0	0	0	4	—	—	14	No flow
O-59	7	7m	4747	73	134	224	211	1.6	7	9	20	15	48	
O-59	8	—	4602	—	130	—	—	—	—	—	—	—	—	Misrun
O-59	9	—	4603	71	133	0	0	0	0	5	—	—	32	No flow
O-59	10	6	4255	44	122	379	301	6.1	16	7	501	7	2	19000 ppm
O-59	11	5	4209	43	116	391	187	5.1	13	7	62	5	15	41000 ppm
O-59	12	4a	4020	41	114	515	165	8.8	17	5	1216	25	3	9900 ppm
O-59	13	3	3985	40	112	484	198	5.8	12	6	124	-6	1	4000 ppm
O-59	14	2	3926	40	111	46	3130	14.9	323	5	420	0	2	90000 ppm
ALMA														
F-67	1	C	3026	—	—	—	—	0	—	—	—	—	—	Misrun - aborted
F-67	2	C	3026	31	104	48	0	61.3	1278	8	6	15	21	77000 ppm
F-67	3	C	3016	—	103	0	0	0	0	—	—	—	—	Aborted
F-67	4	C	3016	30	106	0	0	0	0	2	—	—	—	40000 ppm
F-67	5	B	2978	31	103	522	55	0	0	34	103	-5	14	
F-67	6	A	2911	30	101	319	77	0	0	10	1774	-2	18	
F-67	7	A	2872	30	101	846	70	0	0	39	1242	-1	2	
K-85	1	F	3073	33	102	370	6	0	0	31	—	—	21	
K-85	2	D	3020	31	100	459	76	0	0	17	—	—	16	
K-85	3		2950	31	98	595	59	0	0	31	141	3	9	
K-85	4	B	2931	30	97	272	0	0	0	9	126	9	20	
K-85	5	A	2843	30	97	855	69	0	0	30	655	3	4	
GLENELG														
J-48	1	VC	5075	97	163	0	0	11	N/A	2	—	—	44	332000 ppm
J-48	2	Miss.	3950	43	121	127	0	0	TSTM	10	—	—	24	48000 ppm
J-48	3	Miss.	3806	39	121	0	0	6	N/A	9	—	—	1	159000 ppm
J-48	4	G	3767	39	120	125	0	88.0	704	11	—	—	2	233000 ppm

Well	DST No.	Sand	Top Interval (M-KB)	BHSP (MPa)	BHST (C)	Max. Gas Rate (E3m3/d)	Cond. Ratio (m3/E6m3)	Water Rate (m3/d)	Water Ratio (m3/E6m3)	Cum. Flow Time (hr)	KH (md-m)	Skin	Draw Down (MPa)	Remarks
GLENELG cont'd														
J-48	**5**	**G**	**3746**	**39**	**120**	**801**	**18**	**0**	**—**	**10**	**—**	**—**	**8**	
J-48	6	F	3608	—	113	8	TSTM	0	TSTM	8	—	—	—	Inconclusive
J-48	***7***	***F***	***3608***	***37***	***112***	***99***	***0***	***0***	***TSTM***	***8***	***17***	***0***	***11***	
J-48	***8***	***C2***	***3491***	***36***	***110***	***594***	***56***	***19.0***	***32***	***15***	***219***	***-1***	***7***	
J-48	9	LC	3062	30	98	850	77	0	—	10	—	—	3	
E-58A	1	E	3072	37	113	663	93	0	0	31	—	—	21	
E-58A	***2***	***C1***	***3567***	***36***	***111***	***252***	***TSTM***	***0***	***0***	***12***	***309***	***-1***	***24***	
N-49	1	D	3598	37	117	596	34	0	0	8	—	—	2	
N-49	***2***	***C1***	***3476***	***36***	***109***	***871***	***26***	***0***	***0***	***24***	***404***	***-2***	***0***	
N-49	***3***	***B***	***3391***	***35***	***109***	***483***	***22***	***0***	***0***	***14***	***44***	***-1***	***13***	

* - Recovered formation water in tubing-tail fluid. Rate of cushion flow indicated inflow rate of up to 380m3/d (with leaking packer)

Highlighted well tests indicate sands that are incorporated within the present project scope

Table Notes:
- All DST's that were performed are represented
- All tests considered Misruns are indicated but are not detailed as to specific equipment failure
- Where available, all representative gauge data is presented
- KH and Skin values were determined only for the zones that produced gas
- Flow times represented are cumulative (includes clean-up and multiple flow periods)
- Water and condensate rates are based on the flow period during which they were recovered
- Water rates for non-gas producing tests are recorded in 'Remarks' column
- Water volumes recovered (rec'd) by reverse-circulating tubing on non-flowing tests are noted in remarks column as 'tbg load rates'
- Water of condensation ratios range from approximately 17 to 28 m3/E6m3 (3 - 5 bbl/MMscf)
- TSTM = Too small to measure
- All interval depths are measured depths
- VC = Verrill Canyon
- Miss. = Missisauga undifferentiated
- LC = Logan Canyon
- 4400 ppm = 4400 parts per million NaCl equivalent

The Summary, **Table 3.1.2.1**, includes the shut-in bottom hole static pressures (BHSP) and the shut-in bottom hole static temperatures (BHST) for each of the tests. These data, together with Repeat Formation Testing (RFT) data, was used to define temperature and pressure gradients for the fields.

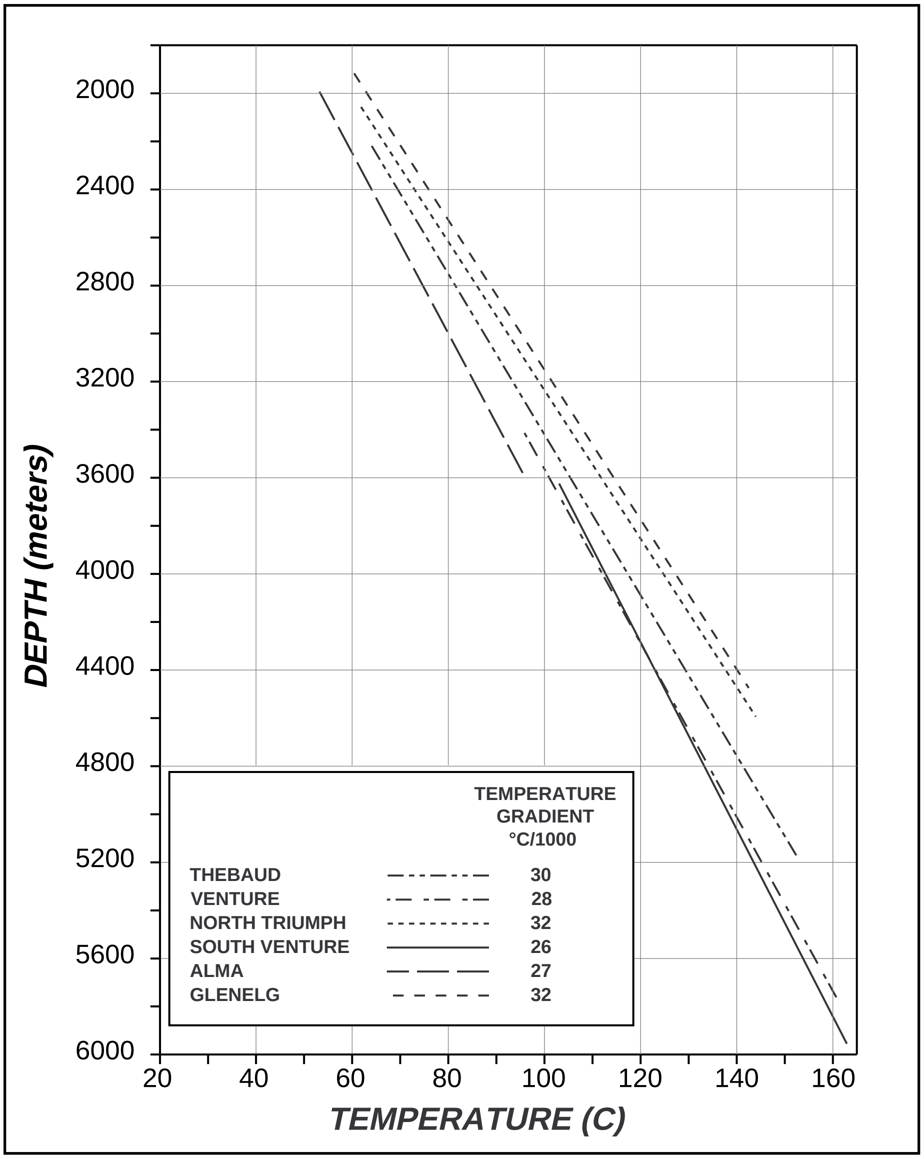

Figure 3.1.2.1 Reservoir Temperature Profile

Reservoir pressure obtained from RFT's and DST's is plotted in **Figure 3.1.2.2** for all fields. Detailed discussions of the data for each well are contained in Part Two of this document **(DPA - Part 2, Ref. # 3.1.2.2)**. Where possible, pressure depth data was used to assist in the location of the free water level for gas in place determination.

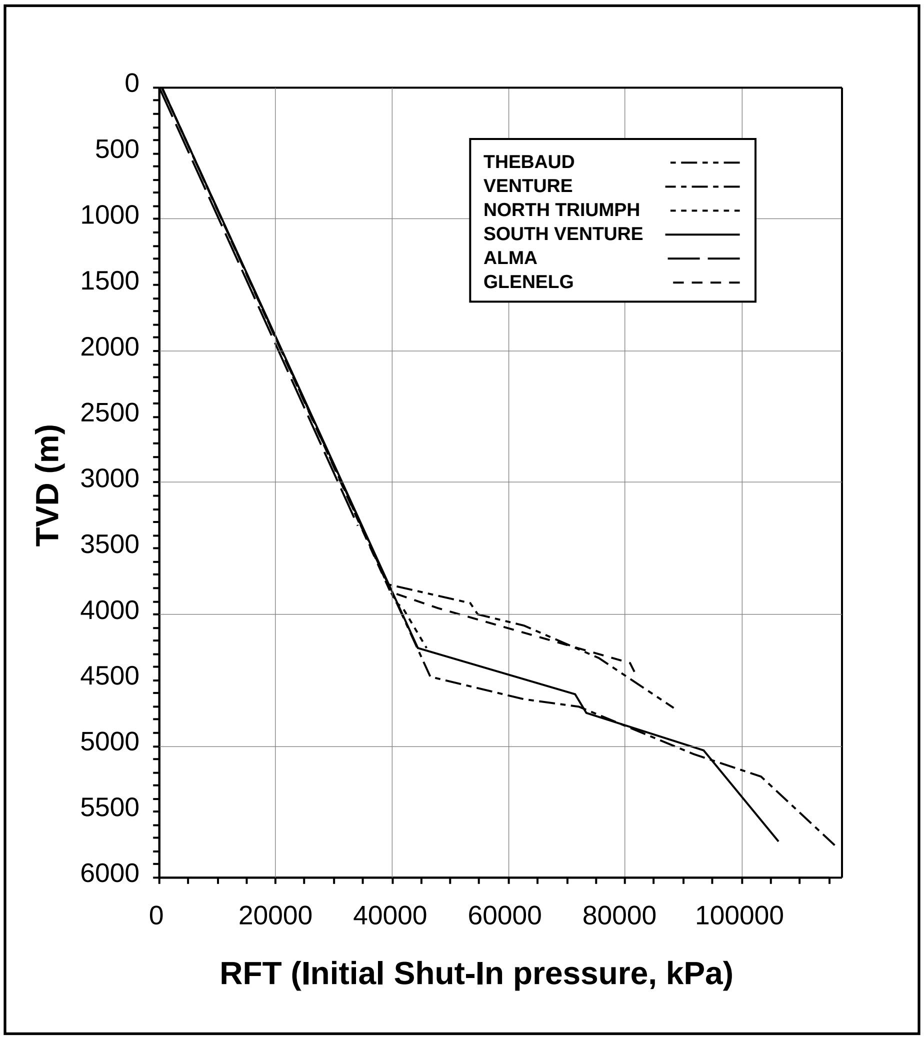

Figure 3.1.2.2 Reservoir Pressure Profile

The gas rates presented in the tables are the maximum observed rates for that test. The gas rates were generally high for all fields, with more than 1000 E3M3/d recorded for Venture (B-52 DST #6) and North Triumph (G-43 DST #2). However, drawdown pressures were, on average, only five to 10 percent of initial pressure.

Estimates of the future well performance, including consideration of various tubing configurations, have been developed from history matched models of the field DST performance. A detailed discussion regarding well deliverability and reference data tables is included in Part Two of this document **(DPA - Part 2, Ref. # 3.1.2.3)**.

The measured condensate ratios vary considerably between fields and between individual sands. In Thebaud, there is a significant difference in the A sand at 165 M3/E6M3 compared with the H and J sands at 22 and 0 M3/E6M3, respectively. For North Triumph, the condensate ratio is approximately 25 M3/E6M3, about half that of Alma and Glenelg. There is also a marked difference in the Venture sands where the condensate ranges from a low of 23 M3/E6M3 in B-52 (DST #6 - Sand 11) to a high of 330 M3/E6M3 in B-43 (DST #8 - Sand 5). There does not appear to be a correlation or specific relationship governing the variation in condensate ratio (In this context, the term condensate refers to the liquid stream from the produced fluids at the test separator temperature and pressure).

Formation water production was observed in some of the DST's, as noted in **Table 3.1.2.1**. In updip wells such as Venture D-23 and North Triumph G-43, little or no water was observed. NaCl equivalent salinity associated with these DST's was less that 5000 ppm, indicative of water of condensation. Downdip wells such as Venture B-52 and North Triumph B-52 have NaCl equivalent salinity values greater than 150000 ppm, indicative of formation water.

There is considerable variability in the permeability thickness product (kh) estimates between the pools in the fields. This data is presented in **Table 3.1.2.1**. The DST interpreted permeabilities were the main source of permeability input to the reservoir simulation models that have been constructed for the individual fields.

The wellbore skin, included in **Table 3.1.2.1**, indicates the zones are slightly enhanced with Skins of -2 to slightly damaged with Skins of +2. Certain wells, such as South Venture O-59, consistently show a significant positive Skin. This indicates zone damage, perhaps from drilling.

3.1.3 Special Core Analysis

Special core analysis has been completed for four of the six fields. **Table 3.1.3.1** presents a summary of the number of plugs taken and the type of analysis completed. All reservoir parameters have been extrapolated to reservoir conditions using the overburden relationship developed from the special core work. Water saturations calculated within the models use the capillary pressure data. In addition, trapped gas saturation and steady-state relative permeability data obtained from core analysis have been used in the reservoir modelling. In sands/fields where data was not available, analogous information from these analyses, has been used for modeling purposes and is included in Part Two of this document (**DPA - Part 2, Ref. #'s 3.1.3.1 through 3.1.3.6**).

Table 3.1.3.1 Special Core Analysis

Type of Analysis	Number of Samples Analyzed													
	Venture				Thebaud		Alma		N.Triumph		Glenelg			
	B-13	**B-43**	**B-52**	**H-22**	**I-93**	**C-74**	**F-67**	**K-85**	**B-52**	**G-43**	**N-49**	**E-58**	**H-38**	**J-48**
Porosity and Permeability Effects at Overburden Pressures	14	20	20	33	5	18	46	-	34	50	-	-	-	-
Overburden Permeability (Air) at Irreducible Water Saturation	-	10	20	30	11	19	-	-	-	-	-	-	-	-
Capillary Pressure (Air-Mercury)	14	20	10	33	-	-	29	1	36	58	-	-	-	-
Capillary Pressure (Air-Brine)	14	20	25	33	5	21	-	-	-	-	-	-	-	-
Cation Exchange Capacity	-	18	30	46	5	13	6	-	-	-	-	-	-	-
Pore Throat Size Distribution	14	20	10	33	-	-	-	-	-	-	-	-	-	-
Rock Pore Volume Compressibility	14	20	-	-	-	-	-	-	-	-	-	-	-	-
Uniaxial Compressive Strength	-	-	-	-	-	7	-	-	-	-	-	-	-	-
Triaxial Compressive Strength	-	7	-	15	-	-	-	-	-	-	-	-	-	-
Particle Size Analysis (Sieve)	-	-	-	15	-	-	-	-	-	-	-	-	-	-
Relative Permeability Study	-	-	-	6	-	6	-	-	-	-	-	-	-	-
Waterflood Displacement Trapped Gas Study	-	8	13	22	5	13	-	-	-	-	-	-	-	-
Permeability (Air) as a Function of Flow Rate	-	-	6	-	-	-	-	-	-	-	-	-	-	-
Brinell Hardness - Sand Strength	-	-	62	57	-	-	-	-	-	-	-	-	-	
Hunidy/Oven Dried Porosity	-	-	6	45	8	27	-	-	-	-	-	-	-	-
Permeability as a Function of Throughput Fluid	-	-	6	-	-	-	-	-	-	-	-	-	-	-
Formation Factor at Atmospheric and Overburden Pressure	14	20	25	33	5	21	33	-	10	11	-	-	-	-
Formation Resistivity Index at Atmospheric & Overburden Pressure 14	20	25	33	5	21	33	-	11	2	-	-	-	-	
Thin Section Studies	-	-	-	-	45	49	15	20	17	26	37	17	5	-
X-Ray Diffraction	-	-	-	-	22	21	4	4	4	4	8	3	1	-
Electron Microscope Scanning (air-brine)	-	-	-	-	25	28	4	6	4	4	8	4	1	-

3.1.4 Reservoir Fluid Properties

Surface gas samples, as well as separator liquids, were obtained during DST operations. These samples were recombined analytically at the measured producing conditions to predict the behaviour of an equivalent single phase gas at reservoir conditions. In addition, during testing of the Venture H-22 well, single phase surface samples were obtained at flowing pressures in excess of the anticipated dew point pressure.

The produced gas from the six fields in question has been determined to be sweet gas with traces of H_2S and relatively low levels of CO_2. For most of the gas samples, Venture, South Venture and Thebaud the heptane plus (C7+) hydrocarbon fractions are approximately 1.5 to 2 mole percent. The C7+ hydrocarbon fractions for Alma, Glenelg and North Triumph are considerably lower in the range of 0.5 to 0.8 mole percent. The gas compositions used in the reservoir simulations are as compiled in **Table 3.1.4.1**.

Table 3.1.4.1 Fluid Analysis Summary

Thebaud

Sand	**SAND A**	**SAND B**	**F1**	**F3**	**G2**	**G3**	**H2**
Technique	**Dense Phase**	**Dense Phase**	**Recomb.**	**Dense Phase**	**Dense Phase**	**Dense Phase**	**Dense Phase**
Well	**C-74**	**C-74**	**C-74**	**C-74**	**C-74**	**C-74**	**C-74**
Sample(s)	**9-23**	**8-31**	**7-31/7-32**	**6-10**	**4-17**	**4-17**	**2-21**
He	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N2	0.16	0.15	0.22	0.16	0.08	0.08	0.14
CO2	1.53	1.60	2.07	2.30	2.47	2.47	3.09
H2S	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	86.01	85.22	86.67	86.94	86.94	86.94	88.20
C2	6.82	6.99	6.85	6.52	6.42	6.42	5.63
C3	2.38	2.58	2.07	1.87	1.82	1.82	1.37
iC4	0.36	0.41	0.37	0.37	0.34	0.34	0.30
nC4	0.53	0.65	0.47	0.46	0.41	0.41	0.31
iC5	0.17	0.23	0.19	0.21	0.18	0.18	0.16
nC5	0.15	0.21	0.15	0.16	0.13	0.13	0.10
C6	0.21	0.14	0.16	0.11	0.17	0.17	0.08
C7+	1.68	1.82	0.78	0.90	1.04	1.04	0.62
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Pc 1	4602	4602	4631	4636	4637	4637	4667
Tc 2	695	695	677	676	677	677	664
Sg 3	0.718	0.718	0.678	0.679	0.687	0.687	0.662
Z 4	1.209	1.219	1.586	1.608	1.614	1.614	1.694
Bgi 5	324.4	323.8	363.4	383.0	383.9	383.9	392.3

1. Specific Gravity
2. Pseudo-Critical Pressure (kPa)
3. Pseudo-Critical Temperature (Deg. K)
4. Compressibility
5. Formation Volume Factor(sm3/m3)

Table 3.1.4.1 Fluid Analysis Summary continued

Venture

Sand	SAND 2u	A	B	SAND 3a	4	SAND 5	SAND 6u	SAND 6m	SAND 7	SAND 8
Technique	Recomb.	Recomb.	Recomb.	Recomb.	Recomb.	Recomb.	Dense Phase	Dense Phase	Dense Phase	Dense Phase
Well	B-13	B-13	B-13	B-43	B-43	B-43	H-22	H-22	H-22	H-22
Sample(s)	11-2,11-10	9-3/9-7	6-3/6-8	10-15,10-23	9-6/9-8	8-15,8-9	7-14	6-92	5-18	4-49
He	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
N2	0.29	0.27	0.58	0.27	0.34	0.27	0.15	0.16	0.15	0.16
CO2	1.85	1.55	1.52	0.85	1.19	1.38	1.92	1.68	1.68	1.58
H2S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C1	83.25	82.10	84.98	85.46	82.20	79.11	86.37	86.80	87.85	88.11
C2	7.33	7.07	7.23	7.28	7.62	7.87	6.29	6.18	5.73	5.73
C3	3.46	3.53	2.93	2.91	3.74	4.47	2.24	2.16	1.89	1.84
iC4	0.52	0.56	0.46	0.46	0.63	0.75	0.39	0.37	0.36	0.30
nC4	0.95	1.24	0.74	0.74	1.11	1.48	0.56	0.53	0.56	0.59
iC5	0.31	0.41	0.27	0.26	0.39	0.51	0.22	0.20	0.22	0.22
nC5	0.27	0.42	0.20	0.20	0.34	0.46	0.17	0.14	0.18	0.17
C6	0.30	0.40	0.22	0.21	0.32	0.43	0.23	0.27	0.22	0.17
C7+	1.46	2.45	0.87	1.35	2.12	3.27	1.46	1.51	1.16	1.13
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Pc 1	4604	4567	4611	4586	4567	4539	4617	4610	4617	4617
Tc 2	702	719	687	693	716	742	686	685	677	676
Sg 3	0.731	0.773	0.695	0.704	0.759	0.822	0.702	0.699	0.683	0.678
Z 4	1.141	1.19	1.193	1.441	1.555	1.601	1.624	1.626	1.644	1.651
Bgi 5	296.8	306.6	308.7	347.8	359.8	357.6	352.7	352.7	349.9	348.5

1. Specific Gravity
2. Pseudo-Critical Pressure (kPa)
3. Pseudo-Critical Temperature (Deg. K)
4. Compressibility
5. Formation Volume Factor(sm3/m3)

Table 3.1.4.1 Fluid Analysis Summary continued

SOUTH VENTURE							**TRIUMPH**	**ALMA**	**GLENELG**
Sand	**SAND 2**	**SAND 3**	**SAND 4A,4E**	**SAND 5**	**SAND 6**	**Sand**	**A**	**A**	**C1**
Technique	**Recomb.**	**Recomb.**	**Recomb.**	**Recomb.**	**Recomb.**	**Technique**	**Recomb.**	**Recomb.**	**Recomb.**
Well	**O-59**	**O-59**	**O-59**	**O-59**	**O-59**	**Well**	**G-43**	**K-85**	**N-49**
Sample(s)	**14-31,14-36**	**13-48,13-53**	**12-34,12-32**	**11-55,11-60**	**10-56,10-51**	**Sample(s)**	**2-64,2-61**	**5-47,5-46**	**2-27,2-23**
He	0.01	0.01	0.01	0.01	0.01	He	0	0	0
N2	0.54	0.52	0.49	0.68	0.60	N2	0.25	0.51	0.28
CO2	1.63	1.78	1.84	1.92	1.80	CO2	2.09	1.38	2.04
H2S	0.00	0.00	0.00	0.00	0.00	H2S	0	0	0
C1	79.02	82.56	83.28	79.22	78.09	C1	91.13	88.19	90.58
C2	6.01	6.61	6.57	7.10	7.94	C2	3.84	4.92	4.17
C3	5.18	3.99	3.61	5.38	5.41	C3	1.41	2.48	1.52
iC4	1.05	0.57	0.52	0.80	0.72	iC4	0.18	0.35	0.19
nC4	1.82	1.10	0.99	1.50	1.40	nC4	0.32	0.59	0.35
iC5	0.61	0.32	0.31	0.40	0.40	iC5	0.11	0.19	0.12
nC5	0.55	0.30	0.28	0.34	0.42	nC5	0.11	0.19	0.11
C6	0.87	0.30	0.47	0.55	0.73	C6	0.12	0.26	0.14
C7+	2.71	1.94	1.63	2.10	2.48	C7+	0.44	0.94	0.5
Total	100.00	100.00	100.00	100.00	100.00	Total	100	100	100
Pc 1	4531	4632	4593	4567	4557	Pc 1	4646	4602	4644
Tc 2	700	681	680	704	698	Tc 2	654	676	656
Sg 3	0.83	0.75	0.74	0.79	0.81	Sg 3	0.64	0.684	0.642
Z 4	1.05	1.05	1.07	1.09	1.10	Z 4	1.033	0.939	1.003
Bgi 5	281.4	289.6	284.5	289.1	290.1	Bgi 5	284.1	241.3	271.5

1. Specific Gravity
2. Pseudo-Critical Pressure (kPa)
3. Pseudo-Critical Temperature (Deg. K)
4. Compressibility
5. Formation Volume Factor(sm3/m3)

Pressure, Volume, Temperature (PVT) analysis, including both dense phase and recombination analysis, has been conducted on all of the six fields. **Table 3.1.4.1** also summarizes the critical properties used to characterize the fluid phase behaviour.

Detailed Equation of State (EOS) analysis was completed on the Venture H-22 Sand 6U sample. The EOS suggests that Venture reservoir fluids are lean, to very lean gas-condensates, with a maximum liquid saturation under Constant Volume Depletion (CVD) of less than one volume percent at 10 MPa at a reservoir temperature of 140°C. This is unlike a typical rich gas condensate which is characterized by liquid saturations in excess of 20 to 30 percent under CVD. The H-22 sample was selected for detailed EOS analysis because it represents the most reliable PVT sample. The flow rate was stabilized and the wellhead pressures were well above the dew point pressure. The dew point pressure for the various gas samples range from a low of 18.4 MPa at Venture H-22 (DST #4) to a high of 39 MPa at Thebaud I-93 (DST #7).

Condensate recovery in the reservoir is a function of overall gas recovery, initial liquid content of the gas, and critical condensate saturation. Critical condensate saturation and relative permeability to gas at critical condensate saturation are active areas of investigation by the Proponents, their affiliates and the industry in general. The variability associated with these parameter estimates can be significant in predicting overall condensate recovery. Initial indications, using a compositional model, show condensate recovery in the range of 50 to 70 percent may be anticipated. The lean nature of the Project reservoir fluids and the low

SABLE OFFSHORE ENERGY PROJECT

dew point pressures suggest that liquid drop-out throughout the entire reservoir occurs at pressures close to abandonment pressures. The reinjection of gas for enhanced liquids recovery is not currently viewed as an opportunity for increasing project value. A detailed discussion regarding the fluid properties associated with all sands is included in Part Two of this document **(DPA - Part 2, Ref. # 3.1.4.1)**. The study with the EOS model mentioned previously is also included in Part Two of this document **(DPA - Part 2, Ref. # 3.1.4.2)**.

3.2 Reservoir Simulation

All reservoir simulation studies for the Sable Offshore Energy Project were conducted using Pegasus/Prevue, a proprietary simulator developed by the Mobil Exploration and Production Technical Centre in Dallas. The Pegasus simulators capable of modeling full field scale non-thermal reservoir engineering processes and has a feature that allows for the integration of surface and gas contractual constraints. Prevue is an interactive preprocessor and postprocessor, designed to simplify the preparation of input simulator data and provides several tools for the display and analysis of the simulation results.

The wellbore hydraulics, or the flow characteristics for each of the wellbores within the simulators are externally modelled using a commercially available Wellbore Evaluation Model (WEM) program and mimicked within Pegasus through the use of flow tables **(DPA Part 2 ref #3.2.1)**. Similarily, when modeling the surface interactions on the reservoir performance, it is a two step approach. The surface model is first studied external to Pegasus and then the surface facility constraints are mimicked within Pegasus, using flow tables.

3.2.1 Individual Field Simulation

Multi-sand, non-compositional simulation models were developed for each of the six fields. The Sable Offshore Energy Project fields are currently at different stages of appraisal. The appraisal and follow up technical investigations conducted since discovery have primarily focused on Venture, Thebaud and North Triumph. Data on these fields include high level geological concepts, such as regional and detailed geology, stratigraphy, sedimentology and structural diagnostic data. As a result, the individual field reservoir models developed for Thebaud, Venture and North Triumph are more complex than the Glenelg, Alma and South Venture models. Refinement of all the numerical models is an ongoing process as more information becomes available. Early sources of new information include the proposed 3D seismic program and any test data obtained from the initial Project wells.

These initial field simulation studies have two primary objectives. The first objective is to investigate the key resource uncertainties related to reservoir performance. As a second objective, the models provide one of the components required for the total integration of the surface and the subsurface systems for the study of various development options.

At this stage in the project, the early individual field reservoir models provide a tool for the assessment of reserve uncertainty and the study of various depletion plans. Included in the assessment of resource uncertainty are issues such as residual gas saturation and aquifer strength. A depletion plan includes the individual field production forecast, well offtake rates, the number of wells, well location and completion details, and the overall recovery efficiency on a sand by sand basis. The early simulation input is based on the most likely reservoir characterization. Conducting resource characterization scenarios through multiple reservoir simulation sensitivity studies provides a means of acquiring further insights into possible field performance outcomes. These simulation sensitivity studies are ongoing. One example was the focused investigation of the possible reservoir fluid compositional ranges and the examination of its effect on field performance.

The results of this study are reported in **DPA Part 2, ref 3.3.2.2.** Another scenario currently under investigation involves the study of water production during production operations. The individual field models are also being used for focused technical investigations. Two such examples involve the study of commingled wellbores and the effects of wellbore geometry on performance.

3.2.2 Integrated Surface-Subsurface Simulation

The integrated surface and subsurface simulation model, referred to as Pegasus-ISF combines multiple field reservoir simulations constrained by both the surface facilities and a sales gas rate at a prescribed pressure. Early in the development of the project this model functions as a tool for assessing various development alternatives. Later in the life of the project , the tool has utility in ongoing reservoir management activities. In either application the output from the model is the Project forecast under various development plans, with full account for the system constraints, from the subsurface through to the surface and the market sales gas rate.

Figure 3.2.2.1 illustrates the network that is being modeled within Pegasus-ISF. The model assumes an onshore gas plant and a central platform at Thebaud. As stated previously, Pegasus - ISF models the surface system constraints through the use of flow tables, describing the pressure drop and rate relationships within each pipeline and the modeled surface equipment. The flow table information has been generated using a combination of commercially available and proprietary simulators. Further details are reported in **DPA Part 2, ref 3.2.1.**

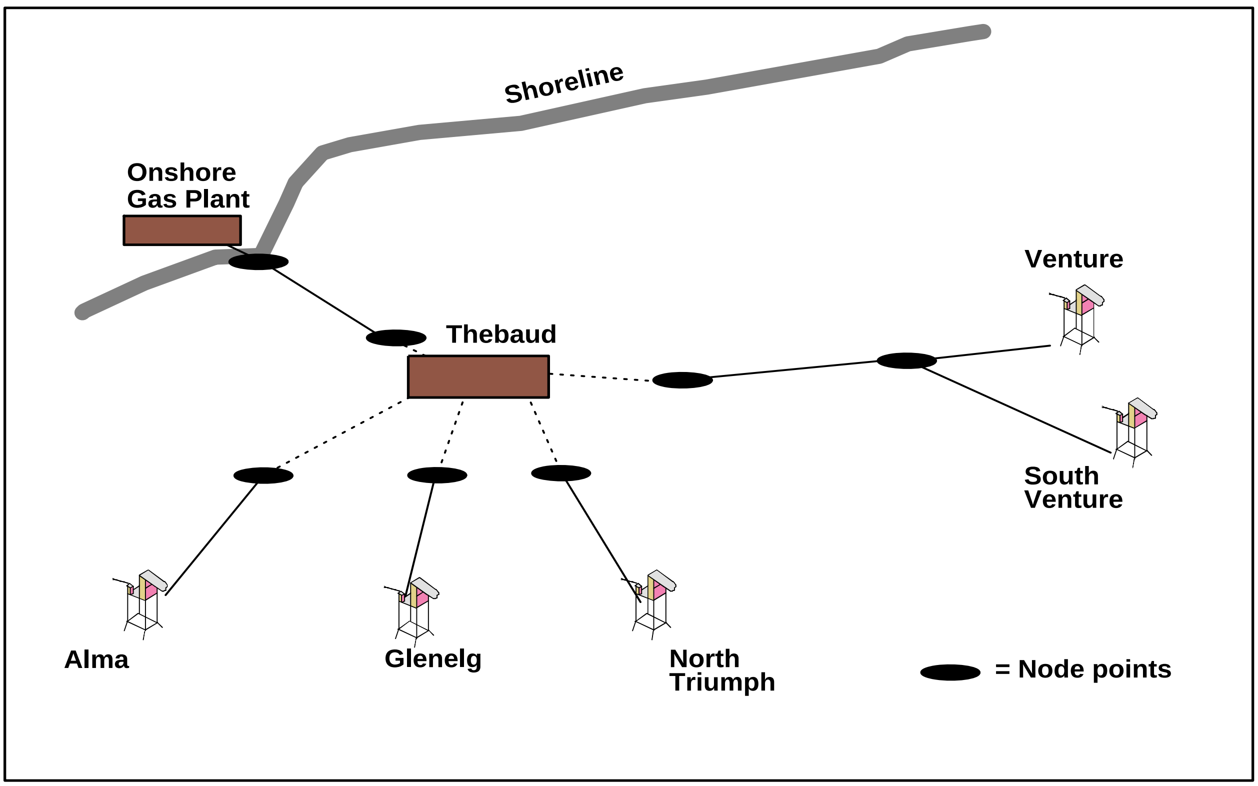

Figure 3.2.2.1 ISF Network Schematic

The node points on the diagram, represented by shaded ovals, are the data capture points for the model information. These data points provide an accounting function, capturing simulated pressures as a function of time along the pipelines and the assigned input gas/condensate ratios for the fields. The gas/condensate ratios that are captured at these points are the user supplied values on an individual reservoir basis and are consistent with non-compositional modeling assumptions.

3.3 Project Plan Development

The current Project plan has been developed through multiple iterations on the Pegasus-ISF model. The challenge is to identify field development scenarios that provide sufficient flexibility to respond to the introduction of new information, technology and/or discoveries throughout the project life.

3.3.1 Assumed Project Constraints

As a first step, the integrated model was run to develop a realistic prediction of the physical performance of the entire system for the life of the Project under a set of constraints. The constraints employed for the early predictions were a target sales gas rate of 11.3 E6M3/d for a period of no less than 15 years and an inlet pressure at the onshore gas plant of 7.2 MPa.

Within these constraints, individual models were linked with the surface network to design potential Project alternatives. The alternatives focused around field sequencing, sales gas rates and individual field platform rates. As a result of these alternative studies, the current development plan has the system constraints described in **Table 3.3.2.1.** Other than the constraints reported in this table , the central compressor, located at Thebaud has been modeled with a minimum suction pressure of 2.8 MPa.

To achieve the 15 year flat life, wells and fields were phased, while maintaining the required Project production rate. The required production rate is comprised of the sales gas rate and a deliverability excess volume, built into the design to offset the performance risk of individual wells and fields. The desired level of deliverability for Sable Offshore Energy Project is still under investigation.

Table 3.3.1.1 System Constraints

Field	Platform Design E6M3/d	Maximum Rate Limitation E6M3/d per well	Minimum Rate Limit E6M3/d per well	Condensate Gas Ratio M3/E6M3
Thebaud	6.2	1.7	0.1	148
Venture	7.1	1.7	0.1	201
North Triumph	3.7	1.7	0.3	46
South Venture	1.8	1.7	0.3	201
Alma	3.7	1.7	0.3	104
Glenelg	3.7	1.7	0.3	60

3.3.2 The Constrained Project Plan

The current plan generated under these constraints begins with production from the Thebaud, Venture and North Triumph fields, and phases in the other fields, as required, to maintain the production rate at 11.3 E6M3/d. **Figure 3.3.3.1** provides the raw gas forecast for the plan using the following field sequencing: Thebaud, Venture, North Triumph, South Venture, Alma, and Glenelg.

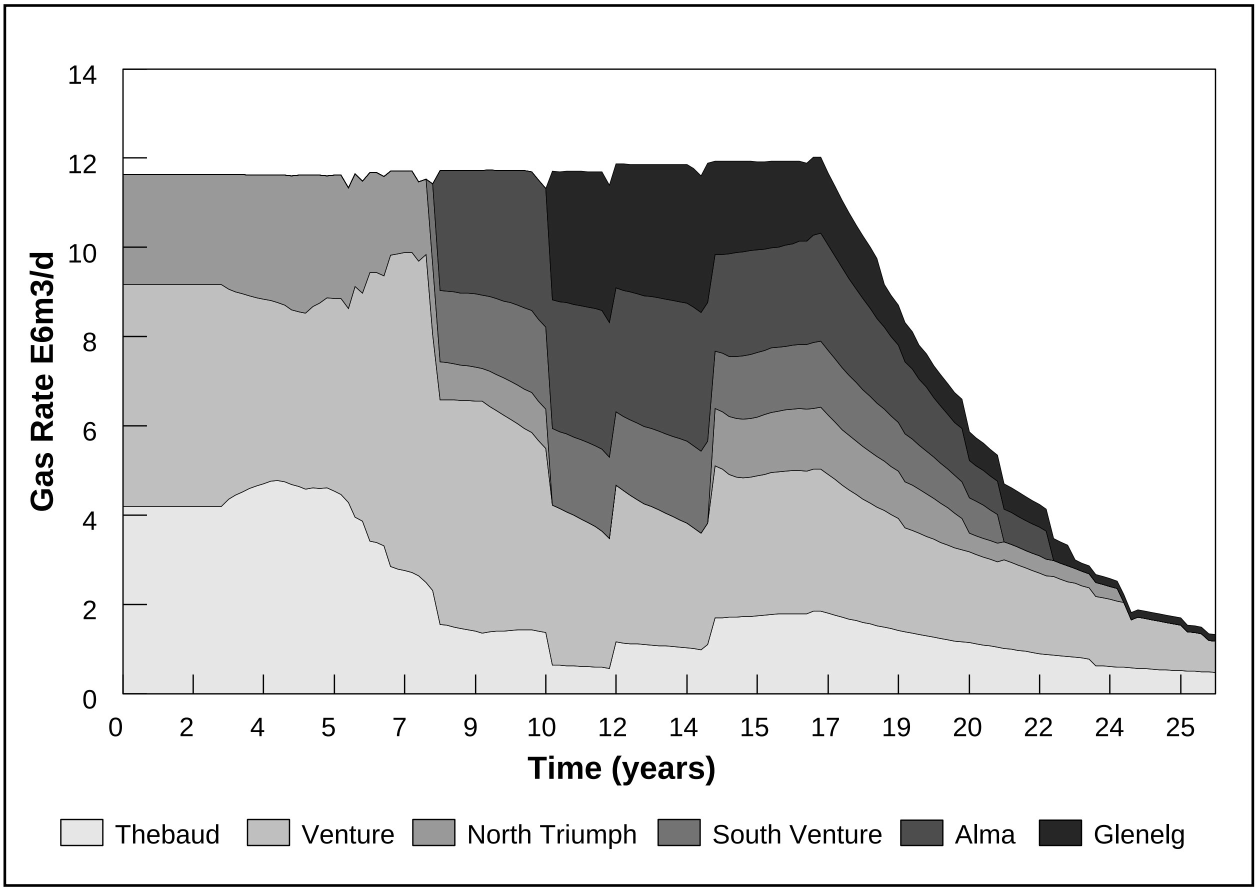

Figure 3.3.2.1 Raw Gas Production Forecast

The aquifer volumes associated with each of the models varies with the information available. In the Venture and Thebaud fields, the aquifers are considered to be limited in extent due to their overpressured nature. In the hydropressured (normally pressured) fields such as North Triumph, Alma, South Venture and Glenelg, the aquifer size is still under investigation. An objective of the reservoir management plan is to attempt to reduce the uncertainty in the size and responsiveness of the aquifers through analysis of regional geology, laboratory studies and production data.

The water production forecast associated with this Project plan is provided in **Figure 3.3.2.2**. This diagram is primarily a reflection of the Venture individual model input. The water production from a single well in the Venture field causes the production spike in years two through four. The pressures associated with these overpressured sands enables the well to lift significant volumes of water. This enhances the recovery of some of the minor sands which are commingled with this major sand.

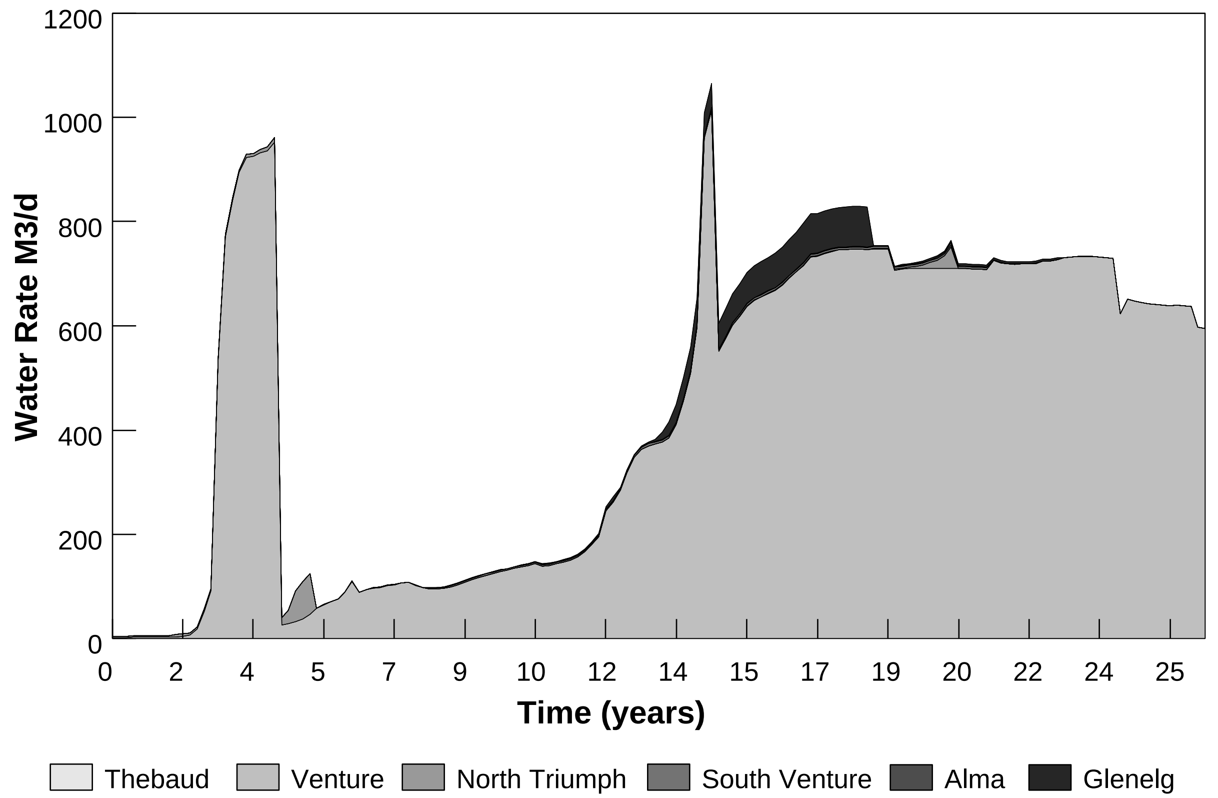

Figure 3.3.2.2 Water Production Estimate

Water production forecasts are heavily dependant on the relative permeability curves used to describe the ease with which water moves in a gas reservoir. The relative permeability curves obtained from core data were input for the Venture and Thebaud fields. This information currently does not exist for the other four fields. To accommodate this uncertainty in water production rates, the facilities design includes some flexibility to expand water handling capacity.

The total system deliverability is 50 percent higher than the required sales gas rate in the early stages of the Project, when there is a high degree of uncertainty of individual field deliverability. The system deliverability, at any point in time, is calculated as the sum of the maximum well rates, as determined from Pegasus - ISF. Total system deliverability is illustrated in **Figure 3.3.3.3**.

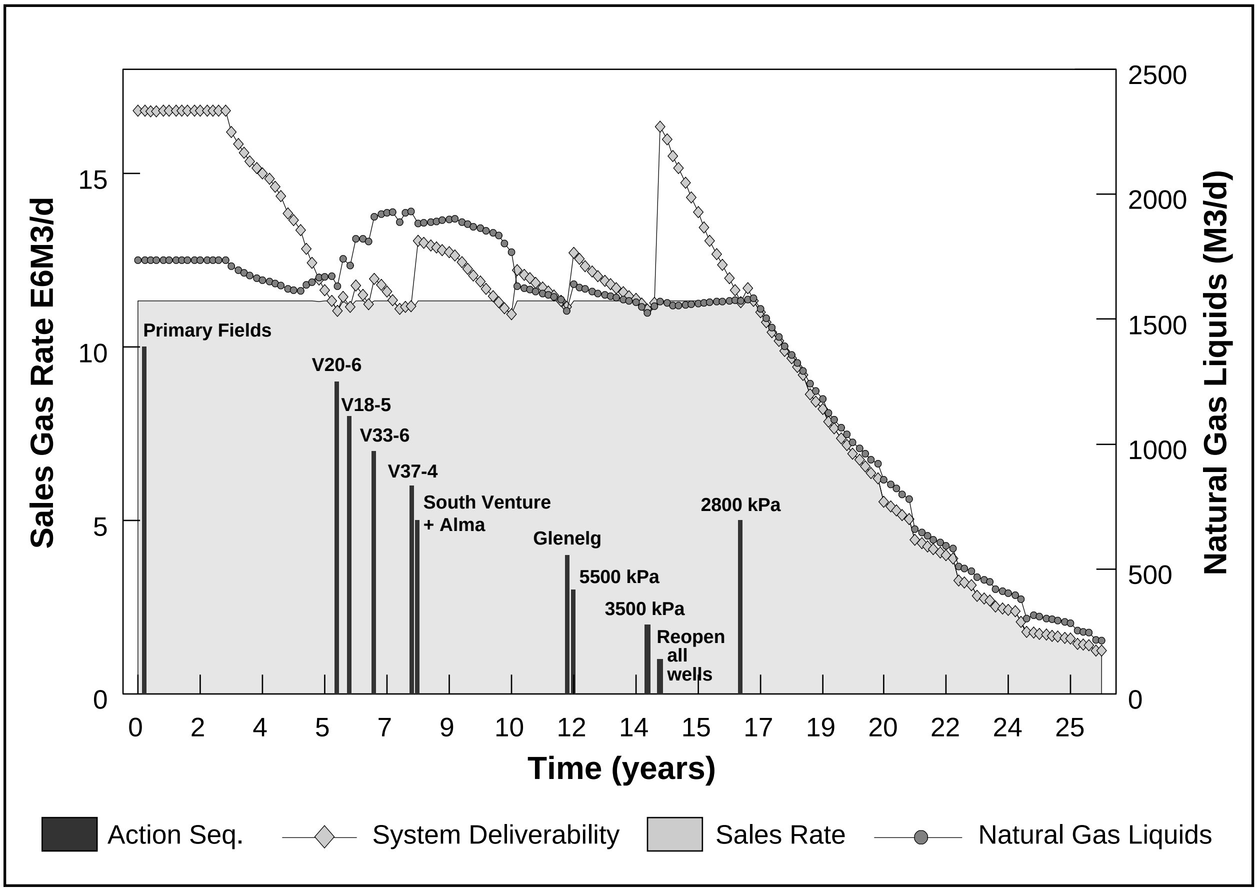

Figure 3.3.2.3 Sales Gas Forecast

The natural gas liquids rate shown on the right of **Figure 3.3.2.3** ranges from a high of 1.9 E3M3/d to a low of 1.5 E3M3/d during the sales gas flat life. This natural gas liquids forecast was based on a non-compositional simulation model with the CGR constraints as outlined in **Table 3.3.1.1**

The simulated event sequences depicted in **Figure 3.3.2.3** indicates an initial high level of activity for the start of production, with five Venture wells, four Thebaud wells and three North Triumph wells assumed to be predrilled.

In production years five through eight, the remaining four Venture wells, two wells in South Venture and five wells in Alma are added, as required, to maintain the desired level of sales gas in the simulation. The remaining five wells in Glenelg are not predicted to be required until year 10 of the project.

Following the field phasing stage of development, the first stage of compression (5.5 MPa suction pressure) is predicted to be required in year 12 of production. In years 15 and 16, the final re-staging of compression to a minimum suction pressure of 2.8 MPa completes the simulated sequence of events. The resulting average reservoir abandonment pressure ranges from a low of 7 MPa in the high deliverability, primary reservoirs to a high of 41 MPa in the lower permeability reservoirs. This simulated depletion strategy also provides for the optional recompletion of the wellbores to maintain deliverability later in the life of the field. This sequence of activities yields a plateau sales gas rate of 11.3 E6M3/d for 16 to 17 years.

The overall recovery efficiency predictions for each field are presented in **Table 3.3.2.1**.

Table 3.3.2.1 ISF - Recoverable Volumes

Field	Gas in Place E9M3	Recoverable Volume E9M3	Recovery Factor %
Thebaud	26.6	19.5	73.3
Venture	49.7	32.9	66.2
North Triumph	15.0	10.8	72.0
South Venture	9.2	7.2	77.2
Alma	15.0	11.8	78.6
Glenelg	11.9	8.1	68.1
Overall	127.4	90.2	70.9

Wells were located within the model to minimize gas trapped at the crest of the structure and for maximum areal drainage. All wells are assumed to be directionally drilled from field platforms as shown in **Figure 3.3.2.4.**

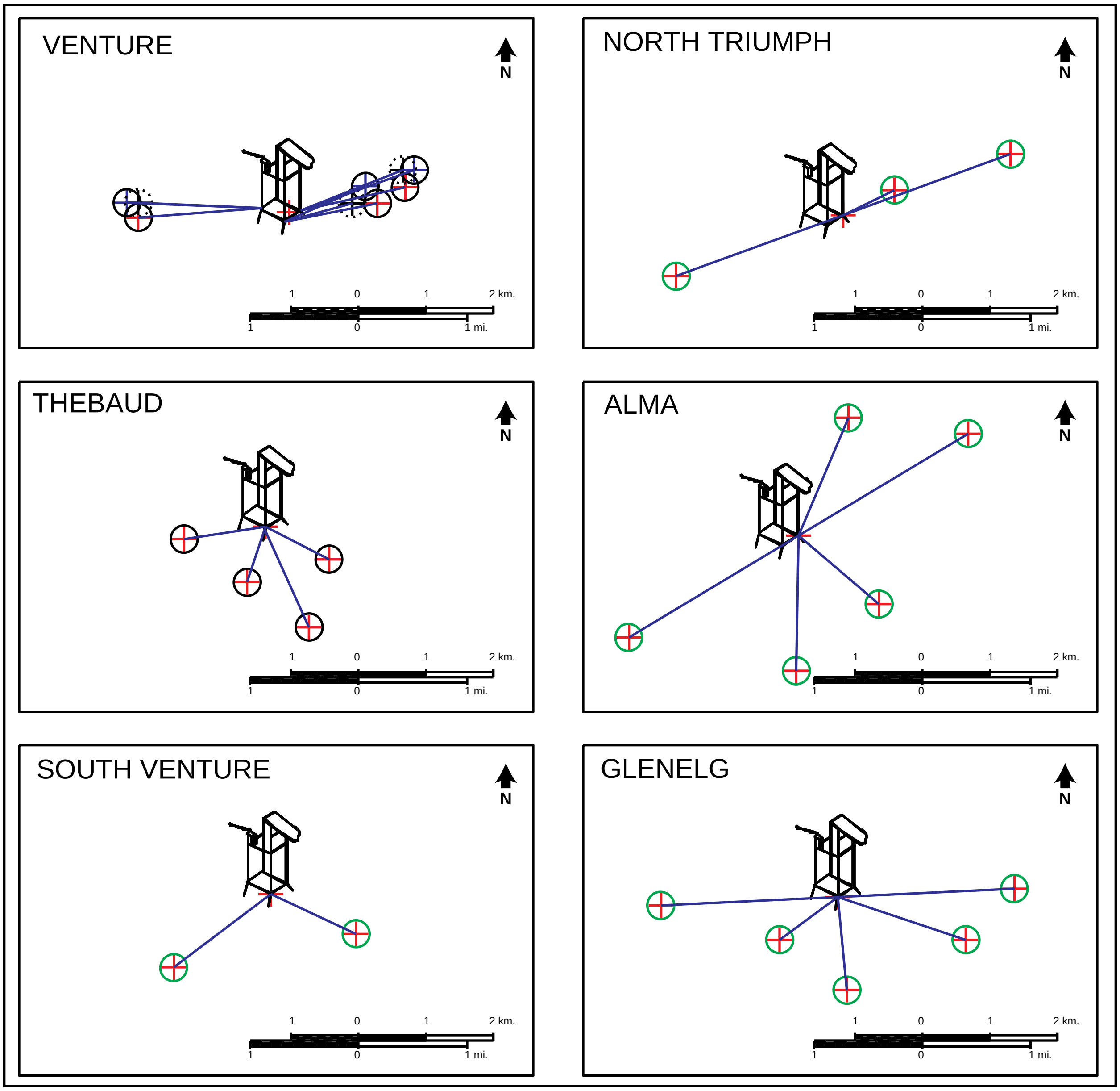

Figure 3.3.2.4 Well and Platform Location Schematic

The current simulated well completion strategy has a major sand commingled with two or three minor sands of similar pressure. The benefits of commingling are a reduction in costs and mechanical risks, while improving the recovery from the minor sands which would not be economically viable, if developed on their own. A more extensive discussion outlining the advantages, disadvantages and reasons for commingled production is included in Part Two of this document **(DPA - Part 2, Ref. # 3.3.2.1)**.

The first three wells drilled in Venture were to target the deeper horizons (Sands 6u, 6m, 7 and 8). The next three wells targeted the intermediate zones (Sands 4a, 4c, 4d and 5). The remaining three wells in the simulation were assumed to be completed in the shallowest formations of Sands 2, A, B, and 3a. **Figure 3.3.2.5** demonstrates the simulated completion strategy for the Venture Field.

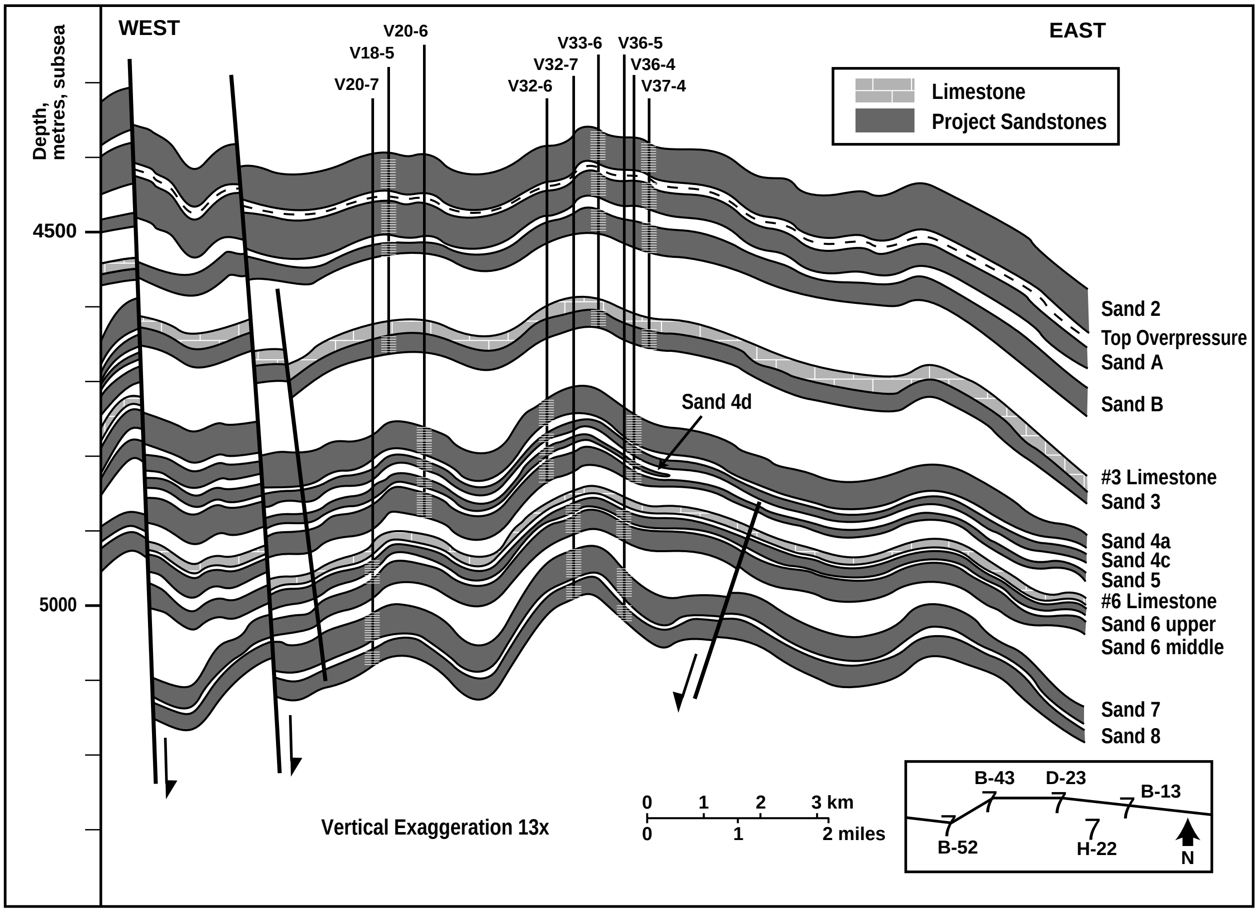

Figure 3.3.2.5 Venture Simulated Completion Strategy

Two wells in the Thebaud structure were simulated to target the deeper horizons and the remaining two wells targeted Sands A and B. This is similar to the methodology simulated in Venture. The deep wells of Thebaud were simulated to be perforated sequentially uphole, as each zone was depleted to the pressures of the upper zone. Within a relatively short time, all zones were open and producing in a commingled fashion, as shown in **Figure 3.3.2.6**.

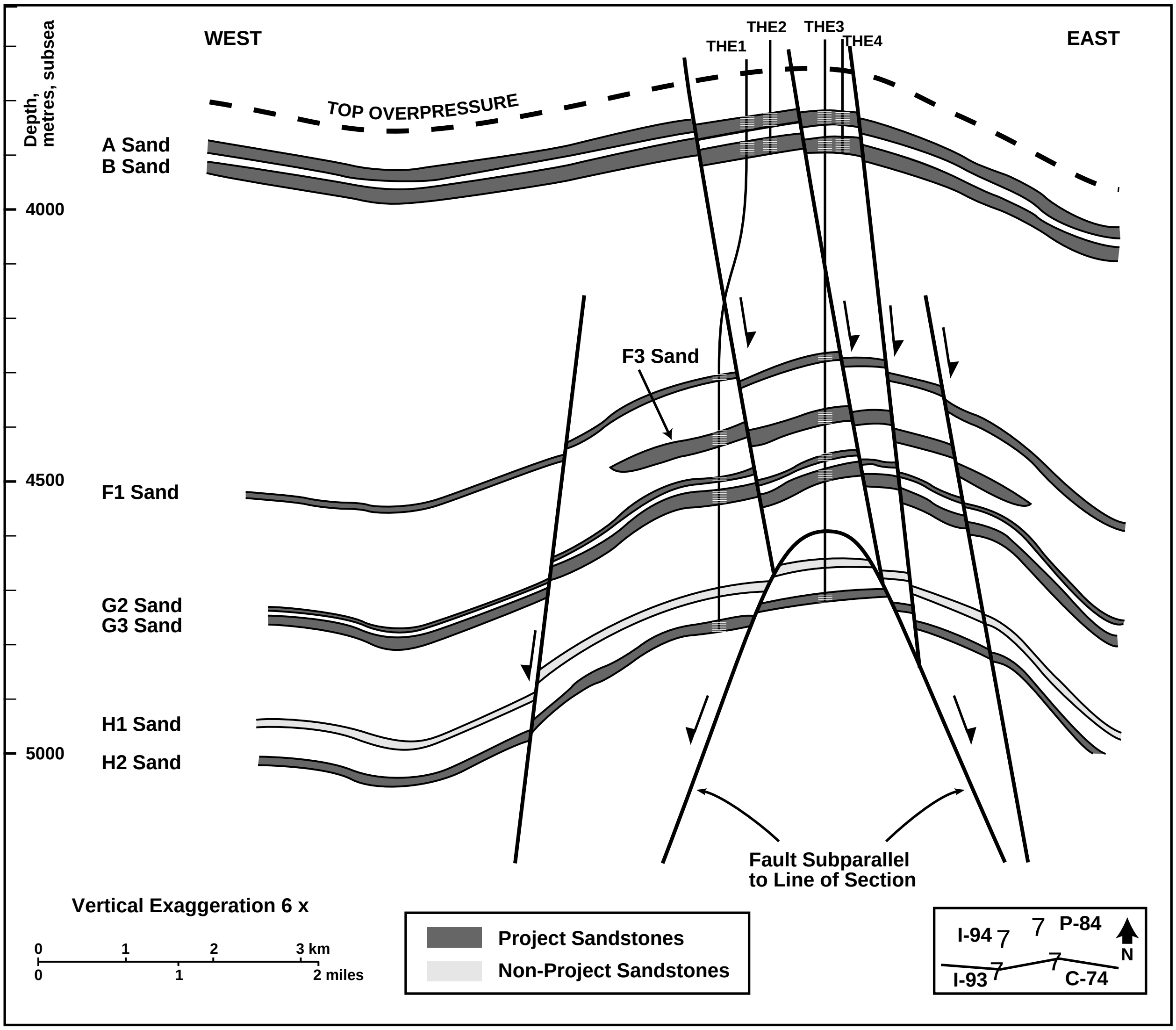

Figure 3.3.2.6 Thebaud Simulated Completion Strategy

Within the South Venture structure, the simulated two wells are targeted for the hydropressured sands, 2, 3a, 4, 5 and 6. These zones are similar in pressures and were simulated in a commingled production. This completion practice was also employed in the Alma and Glenelg simulations.

Within the simulations, all wells in Venture (shallow and intermediate horizons), North Triumph, South Venture, Alma and Glenelg were initially completed with 127 mm tubing. The two wells in Thebaud A and B sands were also simulated with 127 mm tubing. The tubing was changed to 102 mm during the simulated life of these wells. The wells in Venture and Thebaud targeted for the deeper horizons were completed with 102 mm size tubing. The optimized tubing sizes are currently under study.

To summarize, the presented simulated depletion scenario has 12 wells predrilled; five in Venture, four in Thebaud and three in North Triumph. The Venture field requires four additional wells to maintain deliverability and for adequate drainage. The remaining fields are predicted to require two wells at South Venture and five wells each for Alma and Glenelg to provide sufficient deliverability and, ultimately, drainage. The development of an optimized depletion scenario is ongoing as new data becomes available.

3.3.3 Alternative Depletion Scenarios

Several alternatives to the preferred depletion plan have been examined by the Proponents and were eliminated. In addition to these studies, there was a study commissioned by the Nova Scotia Department of Natural Resources, conducted by Indeva Energy Consultants **(DPA - Part 2, Ref. # 3.3.3.1)** which helped to screen the wide range of options for the six field development.

Two additional alternatives currently under review are discussed below:

(1) Alternative Field Sequencing

In this simulated study, field sequencing was modified. The simulation constraints were the same as those presented in **Table 3.3.1.1**. The first simulated fields on production, Venture and Thebaud are followed by North Triumph, South Venture, Alma and Glenelg prior to the onset of the compression phase. A notable feature of this study is the reduction in excess deliverability to approximately 20 percent of the sales gas rate. Compression assumptions are consistent with the case presented in the previous section which results in a similar recovery. **Figure 3.3.3.1** shows the action sequence to maintain the sales gas rate and the overall system deliverability.

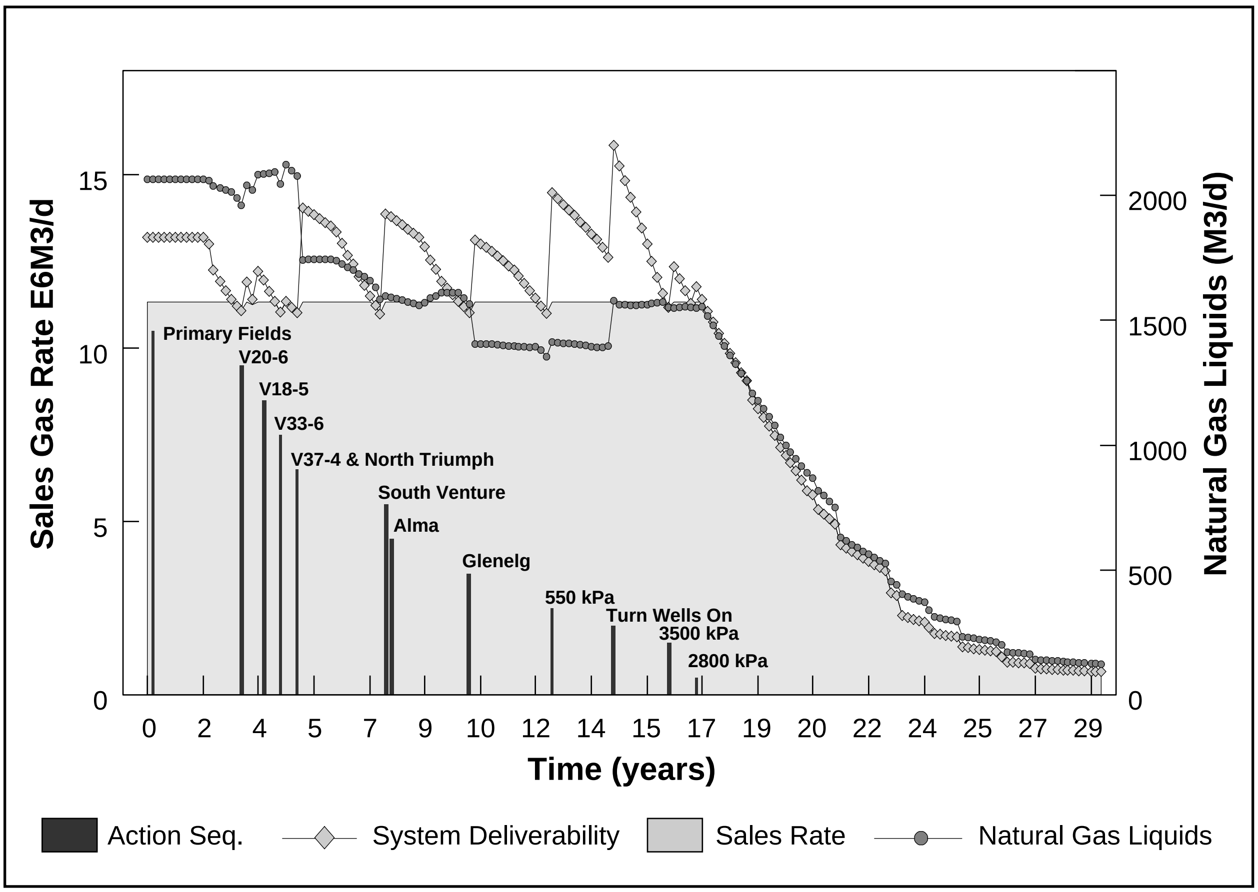

Figure 3.3.3.1 Sales Gas Forecast - Defer North Triumph Start-up

(2) Increased Sales Gas Rate

This alternative maintains the simulated field sequencing and compression assumptions outlined in **Section 3.3.2** and has an increased sales gas rate from 11.3 to 17 E6M3/d. The major impact is the reduction of the flat life from 16 years to eight years, demonstrating the dependency of the plateau life on the sales gas rate. This alternative is illustrated in **Figure 3.3.3.2**.

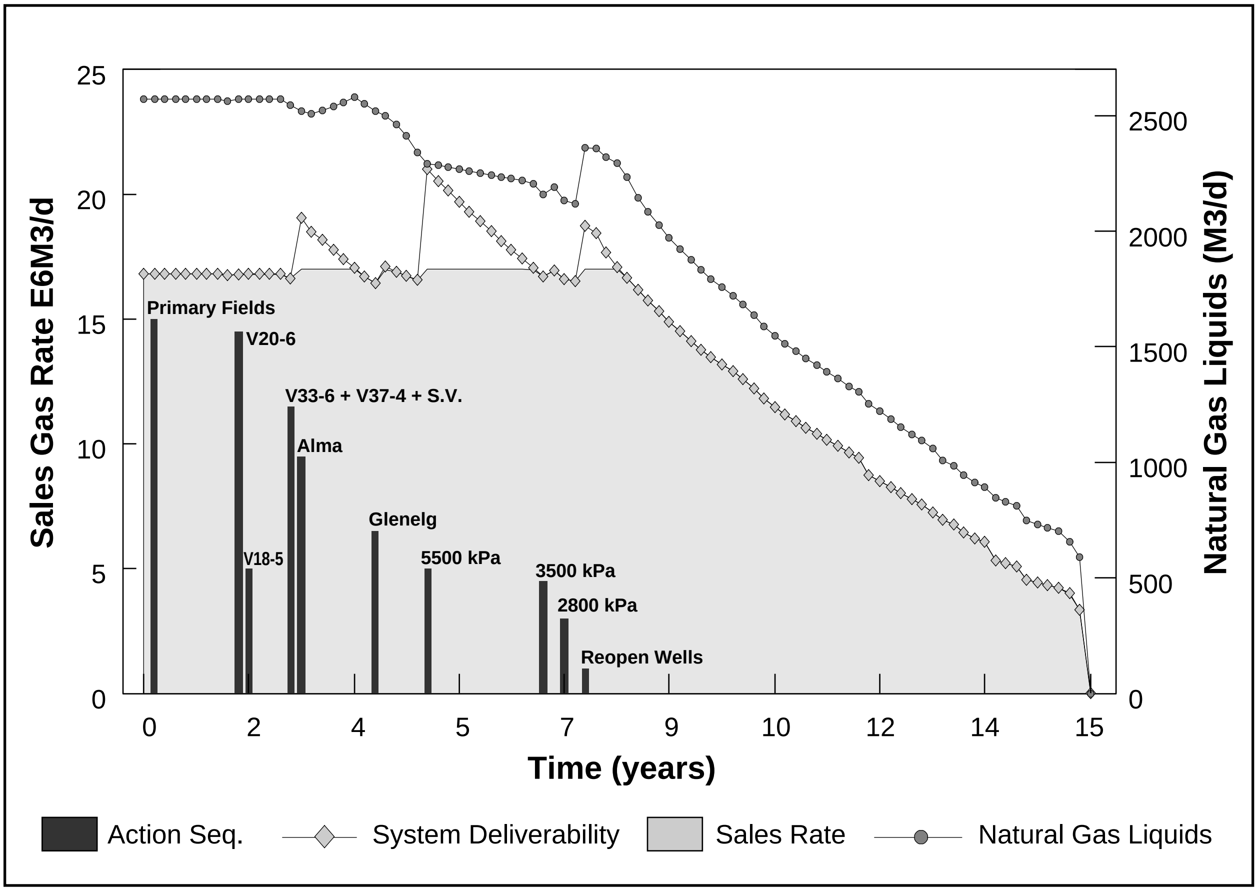

Figure 3.3.3.2 Sales Gas Forecast - Increased Gas Rate

Work to validate and screen production options is ongoing and is discussed further in Part Two of this document **(DPA - Part 2, Ref. # 3.3.3.2)** and will continue as new data becomes available.

3.4 Reserves

The recovery factors from the simulated option represented in **Section 3.3.2** have been incorporated into a probabilistic estimate of Project reserves. **Table 3.4.1** provides the recoverable reserve estimates at three different probability ranges and at the expected value for each field. A more detailed breakdown to the individual sand level is included in Part Two of this document **(DPA - Part 2, Ref. # 3.4.1)**.

Table 3.4.1 Probabilistic Reserves

Field	OGIP Ev E9M3	P90 Raw Recoverable E9M3	P50 Raw Recoverable E9M3	P10 Raw Recoverable E9M3	Mean Raw Recoverable E9M3	Mean Condensate Recoverable E6M3
Thebaud	26.0	6.4	14.4	30.3	16.9	2.4
Venture	49.4	11.9	27.1	58.6	32.2	6.2
North Triumph	15.2	4.0	9.1	17.3	10.2	0.4
South Venture	11.3	2.0	7.2	15.5	7.8	1.4
Alma	15.0	4.8	9.4	10.9	9.4	1.0
Glenelg	12.4	3.2	7.3	12.5	7.8	0.5
Total	129.3	32.3	74.5	145.1	84.3	11.9

Note: Mean values have been summed arithmetically.
P90 = 90 % Probability of exceeding posted value.
P10 = 50 % Probability of exceeding posted value.
P10 = 10 % Probability of exceeding posted value.
Ev = Expected Value or Mean Value.
OGIP = Original Gas In Place

Condensate recovery, reported in **Table 3.4.1**, was predicted using EOS, compositional and analytical models. The input data was obtained from compositional analysis and saturation pressure (dew point) measurements conducted on both **Sable Offshore Energy Project** fluid and analogous North Sea samples. **Table 3.4.1** summarizes the predicted condensate recovery at abandonment pressures for each field. The overall recovery of condensate is high and is characteristic of the lean nature (low dew point) of the reservoir fluids and the high initial reservoir pressures. Detailed discussion of the methodology and results, by sand, can be found in Part Two of this document **(DPA - Part 2, Ref. # 3.4.2).**

3.5 Reservoir Management Philosophy

Reservoir Management is a continuous process, which begins at exploration planning and is completed at the point of project abandonment. At this phase of the **Sable Offshore Energy Project** reservoir management, all existing data have been employed in a multidisciplinary approach to design a simulation tool for the generation of the development plan as presented in **Section 3.3.2.** As described in this section, the simulations at this stage vary in complexity with each field, spanning the range from simple tank type models to large scale three dimensional models.

The integral components of a reservoir management plan during the production phase include data surveillance, ongoing history matching of reservoir performance and updating of field and zonal depletion planning.

The surveillance plan is comprised of both routine and non-routine activities. The routine surveillance activities involve the collection, validation, storage and analysis of data. The type of data collected routinely may include daily production, fluid compositions, pressures and temperatures. Examples of non-routine data used for surveillance include production tests, RFT and DST tests, open and cased hole logs, as well as seismic surveys.

Other than the field surveillance plan, another key reservoir management tool is the well by well, zone by zone depletion plan. The focus of the depletion plan is for the optimization of wellbore utilization and economic recovery. For the commingled wellbores the plan could identify zonal targets and fluid contact monitoring techniques. Additional opportunities such as sidetrack or recompletion candidates could also be identified through the collection and analysis of this specific data.

It is important during the early stages of the project to recognize that most of the resource database has been obtained under static conditions and reservoir simulation provides the opportunity to predict early dynamic performance, under an initial set of assumptions. During the production phase new data will be integrated into the reservoir simulators as it becomes available. Ongoing history matching using routine well data and the more infrequent well test and possible production logging will assist in the validation of the initial reservoir performance assumptions.

One goal of the depletion plan is to identify when a focused subsurface review is required to update the field depletion plan. This identification is usually triggered when field simulations are not predicting performance within adequate target ranges. Through this non-routine reservoir recharacterization and subsequent larger simulation updating, the reservoir predictability is maintained, while honouring all the data. Such a comprehensive review would be a separate activity in addition to the ongoing depletion planning.

In summary, efficient development at **Sable Offshore Energy Project** requires a multidisciplinary reservoir management plan that will be developed in the next phase of work.

4.0 DRILLING COMPLETIONS AND WORKOVERS

4.1 Strategy

The development of drilling, completion and workover plans for the **Sable Offshore Energy Project** are guided by a desire to minimize the initial and future costs of all wells during production operations. Any technological developments that could enhance the Project, will be considered as the Front End Engineering Design (FEED) stage of the Project progresses. There may be modifications to this development plan proposal as the Front End Engineering Design (FEED) progresses. Some future options include horizontal wells (both conventional and multi-lateral), and extended reach wells. Additional studies are underway to determine the effect on formation integrity with pressure depletion. The results of this work will be shared with the **CNSOPB** when finalized.

All wells for the **Sable Offshore Energy Project** will be drilled with Cantilever Jackup rigs which have a water depth capability of up to 90 metres, and use 103 MPa Blowout Preventers (BOPs). The 100 year storm criteria establishes minimal acceptable rig design and thus limits selection. Preliminary criteria are outlined in **Section 5.6** of **Chapter 5.0: Production and Export Systems** of this document. All completion and workover operations will utilize either the rig, or equipment such as coiled tubing or wireline units, present and certified on the rig. The only exception would be skid-mounted wireline units that would be mounted on the platforms. Identical operating and certification requirements will be followed.

Contracting strategy for the Project drilling, tubular, wellhead and mudline suspension systems and services will likely be based on integrated services and enhanced supplier relationships. Synergy may be possible with contractors and suppliers already operating off the East Coast, for items such as workboats and helicopters. It would be optimal to utilize only one rig contractor for both drilling rigs, and rig contracting inquiries will be approached on a two rig basis.

Additional selection criteria for drilling contractors will be experience with high pressure offshore wells, technical ability and cost.

Specific safety issues for drilling are addressed in **Section 10.2** of **Chapter 10.0: Safety Plan** of this document. They include the development of procedures to be followed during simultaneous drilling and production.

Relief well drilling capability will be ensured in the initial phase of drilling by having two 103 MPa rigs drilling in the Sable area. During other segments of drilling, completion and workover operations, only one jackup rig may be operating in the Sable area. Agreements will be established with the Proponents to make an appropriate drilling unit immediately available for relief well drilling, if necessary. This unit would most likely be mobilized from the North Sea or the Gulf Coast, but does not preclude available units identified by the combined worldwide resources of the Proponents' affiliates. Casing, wellhead and mudline suspension equipment will be available for use, if necessary.

All manuals, drilling programs and approvals will be complete by the proposed drilling date for the Project. A tentative schedule has been developed to reference the timing and completion of the activities, and the acquisition of critical components for drilling. **Table 4.1.1** illustrates a tentative drilling development schedule.

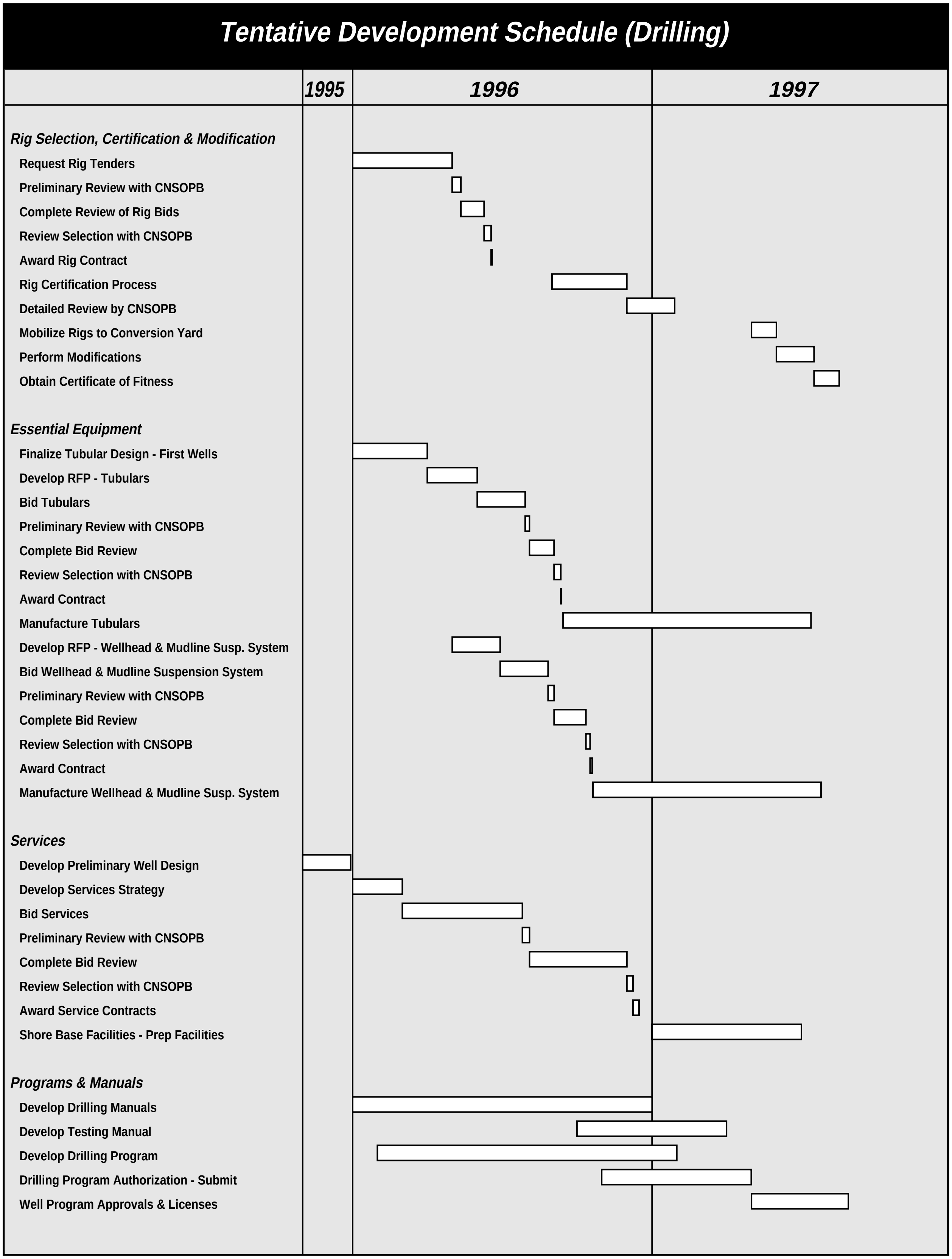

Table 4.1.1: Tentative Development Schedule (Drilling)

4.2 Projected Drilling Schedule

The target date for the start of gas produciton from the **Sable Offshore Energy Project** dictates that drilling must commence no later than September, 1997. To accomplish this goal, a number of wells will have to be completed and ready for production by that date. The number of wells required for start-up will be determined by individual well deliverability and required project deliverability.

The jackup drilling rigs will be brought in to Halifax harbour in the summer of 1997. The process for upgrades and/or inspections for **CNSOPB/CCG** Certificates of Fitness (COF) to operate in the waters off Nova Scotia will commence prior to their arrival and be completed in the Halifax harbour. There will be pre-drilling of wells using templates and mudline systems in the Venture, Thebaud and North Triumph fields. A total of five Venture wells, three North Triumph and four Thebaud wells are expected to be pre-drilled in accordance with the simulated development plan discussed in Chapter 3.

One of the rigs will begin operations after the template has been positioned on the seabed at the Venture field. This rig would require a working water depth of 30 metres, with allowance for 100 year storm criteria. It is likely that the rated water depth of the rig will be substantially greater than this requirement. The Venture jacket is planned for installation in May of 1999. A September 1997 startup of operations guarantees that up to five wells will be drilled and completed by the end of 1999. If the startup of drilling is delayed until the following April, due to rig availability or other unforeseen factors, only three wells could be completed by May of 1999 and the drilling and completion of the last two wells would be at risk for the November 1, 1999 startup. The first rig will be released once the last well at Venture is tied back.

The second jackup drilling rig will require a water depth capability of up to 90 metres. This rig will have to meet the same 100 year storm criteria as the first unit. A template will be set at Thebaud prior to drilling in September of 1997. Four wells will be drilled at Thebaud in 1997/98. The rig will then be moved to North Triumph in November and three wells will be drilled, again through a template. Once the platform is completed at Thebaud, the rig will move back to this location and tie back the wells. While this work is ongoing, the platform for North Triumph will be installed. Once the installation is complete, the rig will return to North Triumph to tie back and complete the three previously drilled wells at this location. This work is expected to end in the third quarter of 1999. Ongoing exploration and drilling activities should ensure the second rig remains in the area until the year 2004, when it will be used for the second phase of development.

In the spring of 2004, the remaining four Venture wells of the anticipated nine well program will be drilled. Once they are completed, the rig will be moved to the South Venture platform to drill two wells. In October, the rig will move to Alma to drill up to five wells. By June of 2007, these wells will be completed and the rig will be moved to the Glenelg platform to drill the remaining wells. Any additional drilling and recompletion work will commence after this period. The projected drilling schedule by year is outlined in **Table 4.2.1**.

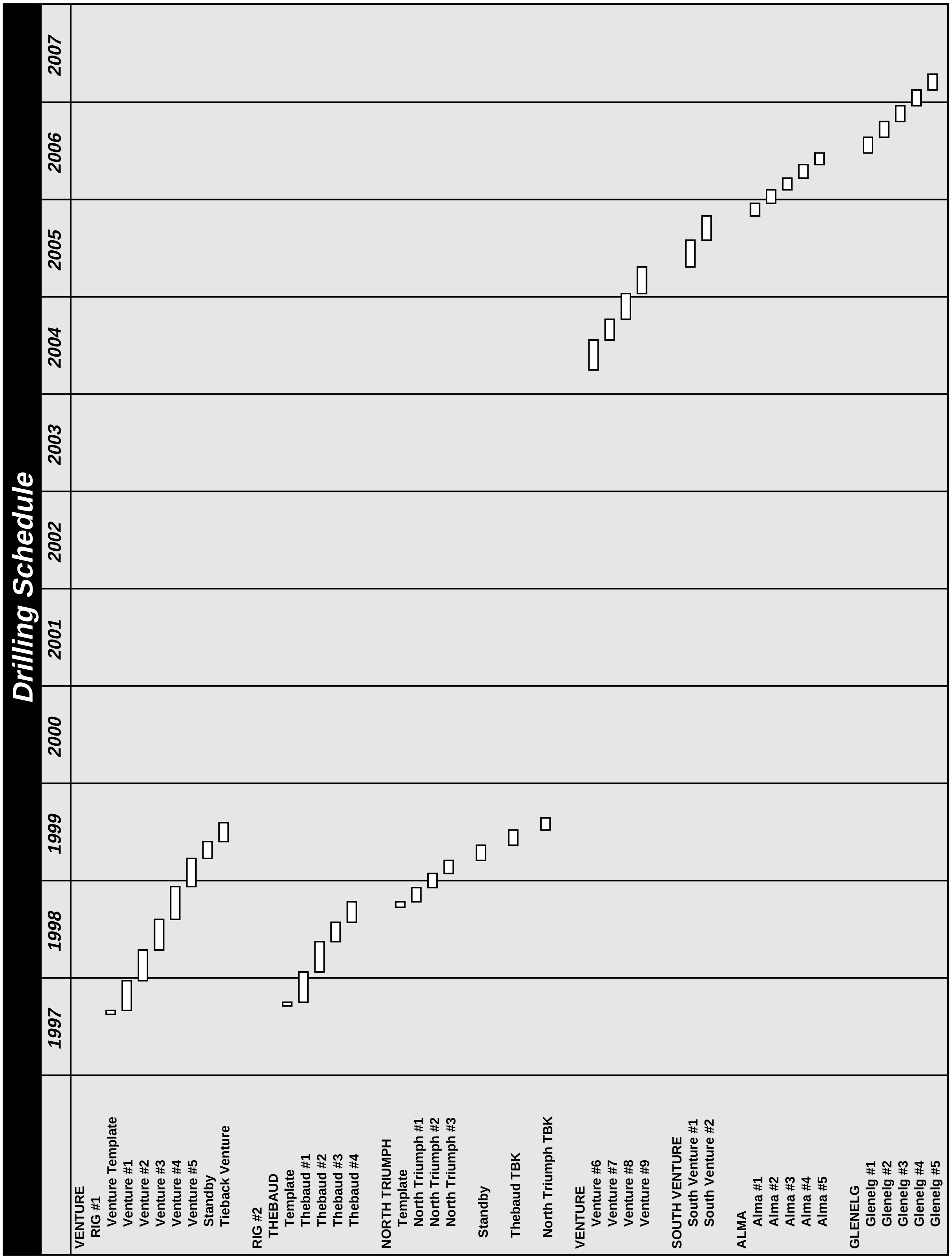

Table 4.2.1: Drilling Schedule

4.3 Equipment Selection

4.3.1 Drilling Rigs and Services

The rigs will be a minimum of a CFEM T-2005-C design, or equivalent, and have 103 MPa pressure control equipment. One rig would require a working water depth of 30 metres, in accordance with the 100 year storm criteria. It is likely that the rated water depth of that rig will be greater than required. The second jackup drilling rig will require a water depth capability of up to 90 metres. Possible modifications to the rigs selected include changes in the handling of oil based drilling fluids. These modifications will be further defined as the Project progresses.

4.3.2 Mud Handling System

All wells will have a dual water and Low Toxicity Mineral Oil (LTMO) mud system. The use of LTMO based mud provides hole stability and lubrication, which are both important for directional drilling. Conductor and surface hole will be drilled with sea water based drilling mud. The first intermediate interval will be drilled with a water based mud for holes greater than 343 millimetres (mm) in diameter. Dependent on the angle of the hole in this section, some 343 mm holes will be drilled with LTMO mud. All holes below 343 mm, will be drilled with LTMO mud. Cuttings and cleaning equipment for LTMO based drilled solids will meet or exceed **CNSOPB** regulations for oil based cuttings. Gas and water log identification may be enhanced by the use of LTMO mud in the production zone.

4.3.3 Directional Surveying

Both in-house and commercial directional survey models will be evaluated for their applicability and reliability in planning directional wells from the templates and platforms. A directional surveying manual based on North Sea experiences will be developed to address well interference, directional control, tool reliability and directional well planning and surveying procedures. The manual will also discuss areas of responsibility, precautions to avoid intersections and procedures to be followed for well paths that approach existing wellbores too closely.

4.4 Well Casing and Completion Plans

4.4.1 Casing Design

Casing designs are based on **CNSOPB** drilling regulations. Work for the casing design, using Mobil's Load Resistance Factor Design (LRFD) method, is underway at the time of filing. The LFRD method determines the actual stresses and limitations of the tubulars. This design work has the potential to reduce the overall casing and tubing costs, and provides a greater level of reliability than conventional methods. Further details are included in Part Two of this document (**DPA Part 2 - Ref. # 4.4.1.1**).

Casing points have been selected to provide sufficient kick tolerance and prevent excessive mud weights in the intermediate hole section of each well. L-80 and C-90 grades of pipe are suggested for the production casing to compliment the premium connections. Examples of completion designs for the Project wells are included in **Figure 4.4.1.1** and **Figure 4.4.1.2**.

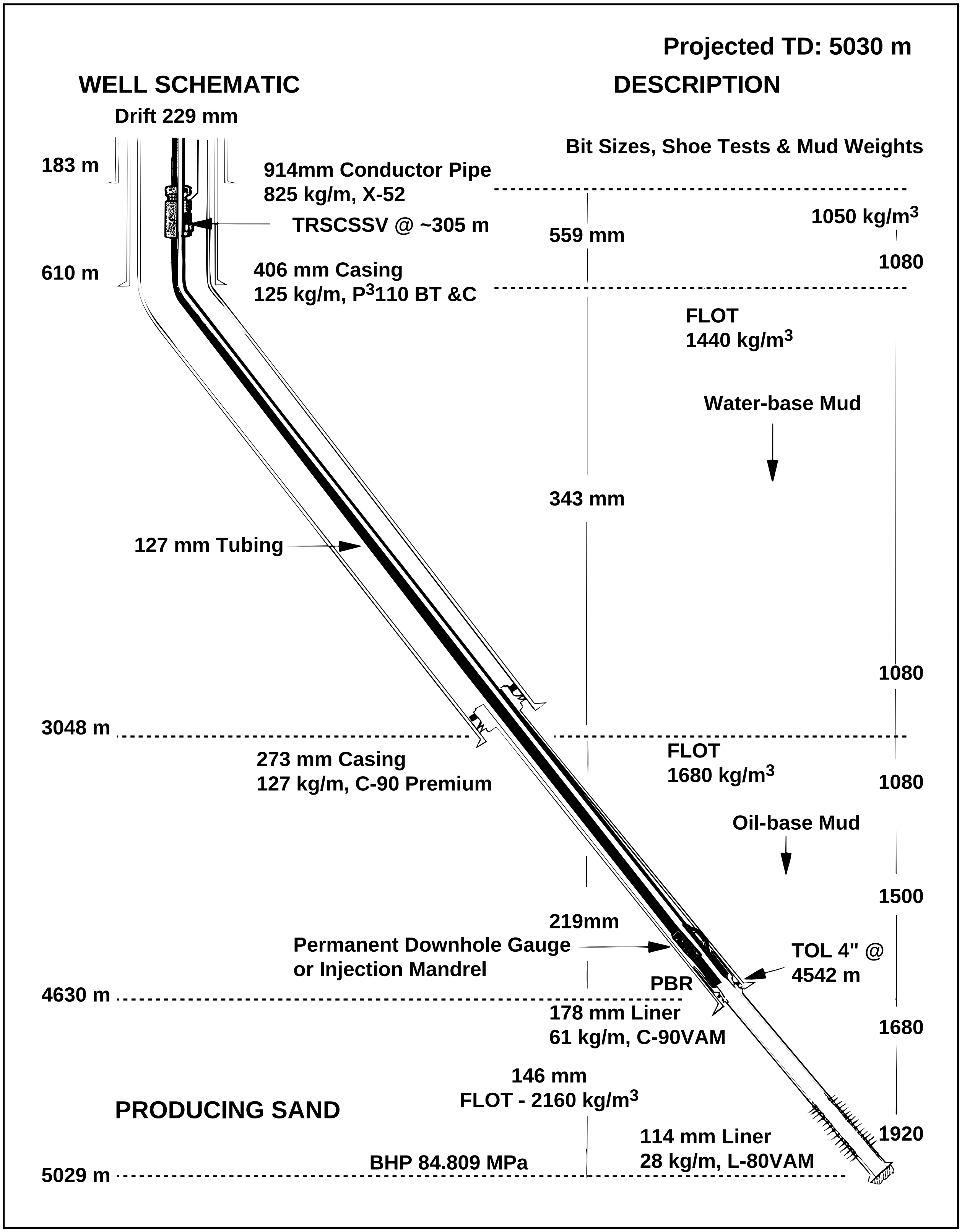

Figure 4.4.1.1: High Pressure Completion Designs

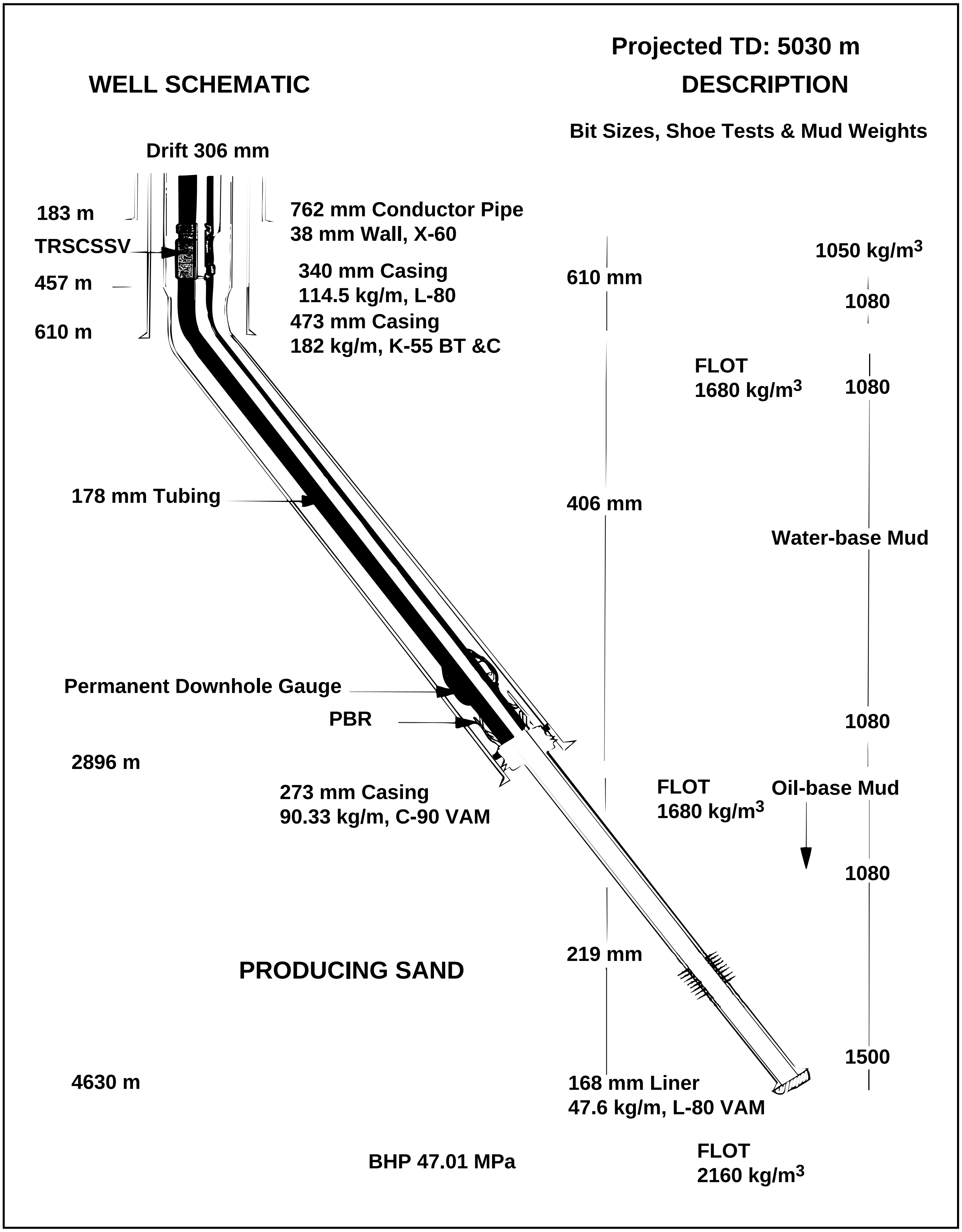

Figure 4.4.1.2: Low Pressure Completion Designs

4.4.2 Completion Design

4.4.2.1 Design Philosophy

Completion systems must be simple, reliable and economic, and meet all requirements for a high temperature, high pressure (HTHP) environment. The completions are designed on a step-monobore concept where the liner becomes part of the flow conduit presently proposed. Although the current base-case for the field simulations use 102 mm tubing, the size of tubing string will most likely be 178 millimetres (mm) for shallow and 127 mm for deep completions. In deeper sands and thus higher pressure applications, 127 mm tubing is necessary for design pressure limitations and subsurface safety valve geometries. A completion design will be used that provides the flexibility to increase the size of the tubing to a larger string without jeopardizing wellbore or equipment integrity.

Production objectives considered, but not limited to, in the design are:

- Ensure operational safety.
- Keep completions as simple as possible.
- Schedule workovers to minimize downtime.
- Maintain a surplus in deliverability to mitigate production downtime due to workovers or suspended wells.
- Minimize the number of wells for each field while maximizing recovery and effectively depleting the reserves.
- Maintain the flat-life production of the Project as long as possible, to minimize compression requirements.
- Select producing intervals to maximize individual well rates while minimizing effects of cross-flow, condensate deposition and sand production.
- Recomplete zones from bottom-up.
- Maximize drawdown on low-productivity sands.
- Allow commingling of sands.

4.4.2.2 Metallurgy

Careful consideration will be given to the materials used for tubulars, wellhead and/or downhole equipment because of exposure to corrosive fluids. Due to the presence of H_2S (albeit small) and CO_2, an alloy steel may be required for tubulars and downhole equipment, and a corrosion resistant cladding may be required for wellhead equipment.

The Proponents are undertaking a study to determine the corrosion potential of the producing environment, and to determine optimal material and operational guidelines. The results of this study will be shared with the **CNSOPB** when it is finalized.

4.4.2.3 Tubing Design

With a possible completion strategy that includes commingling to maximize productivity, maximizing the tubing size is necessary so that wellbore deliverability is not tubing constrained. The major deterrent to large wellbore size is the production casing burst limit with respect to shut-in tubing head pressure (SITHP). The tubing size is limited by the size of the Outside Diameter (OD) of the subsurface safety valve (SSSV) that will fit in the production casing. The tubing design must provide a flow conduit consistent with the inflow performance of the completed sands.
A field-by-field summary of maximum anticipated shut-in tubing head pressures, and allowable bottomhole static pressures for casing weights with the maximum setting depths for conventional casings for each field is included in Part Two of this document (**DPA - Part 2, Ref.# 4.4.2.3.1 and 4.4.2.3.2**).

The design of the tubing connections will likely incorporate the following:

- primary metal-to-metal seals
- multiple seals
- internal flush bore to prevent turbulence and corrosion
- high strength to withstand combined stresses
- minimum outside diameter
- proven reliability with make-up / break-out history, particularly with respect to the design metallurgy

Where practical, one size, weight, grade and connection will be used for each tubing / casing string. This will minimize inventory and prevent the use of improper materials. Design limits for production tubing will meet or exceed the minimum tolerances of burst, tension and collapse, as calculated for the influence of combined stress under normal operating conditions. Final selection of the tubular connection will adhere to a connection qualification program that meets industry standards.

4.4.2.4 Downhole Equipment

The use of downhole tools will be minimized to reduce workover complexity and requirements. High temperatures and pressures, coupled with the potentially corrosive environment, may reduce the performance of any equipment in the wellbore.

The current design has tubing retrievable SSSV's installed, and all wells are equipped with a Polished Bore Receptacle (PBR) system to facilitate tubing change-out. The liner hanger design incorporates a packer assembly above the slips to ensure positive pressure integrity. The selection of sealing method and elastomer type will incorporate the results of future corrosion studies.

The maximum anticipated pressure will be contained safely and effectively through the selection of appropriate wellhead and production tree equipment. Full-bore access to the tubing will allow for well-kill operations and be integrated with an operating and emergency control and shutdown system, both manual and hydraulic. Due to the operating environment, the wellhead and tree will most likely be clad in a corrosion/erosion resistant material. The tubing bonnet will be ported to allow capability to handle downhole injection and control lines, and the hydraulic valves will be capable of cutting both wireline and coiled tubing.

The present completion strategy allows for the integration and use of any anticipated downhole equipment including flow control nipples, chemical injection and mandrels for real-time pressure read-out.

4.4.2.5 Completion, Workover and Packer Fluids

Finalization of the fluid types and requirements will be dependent on the final completion design. Laboratory testing on field core samples will quantify the potential for formation damage and ensure stability with time at high temperature and pressure.

In general, all workover fluids will ensure well operations are carried out in an overbalanced condition, and that the fluid, potentially inhibited fresh or salt water for normal or depleted pressure environments, will be non-damaging to the formation. It is the intent that under normal circumstances, all environmentally sensitive fluids will be collected for disposal or re-use. The **CNSOPB** guidelines for handling and disposal of fluids as they apply to the drilling operation will be applied in these circumstances.

5.0 PRODUCTION FACILITIES

5.1 Development Plan

The present **Sable Offshore Energy Project** development plan includes the six offshore natural gas fields: Thebaud, Venture, North Triumph, South Venture, Glenelg and Alma; and extends onshore to gas processing facilities in the Country Harbour area and to liquids processing facilities in the Point Tupper area (see Figure 5.1.1). The six fields are anticipated to deliver a sales gas volume of 11.3 E6M3/d to markets in Canada and the eastern United States.

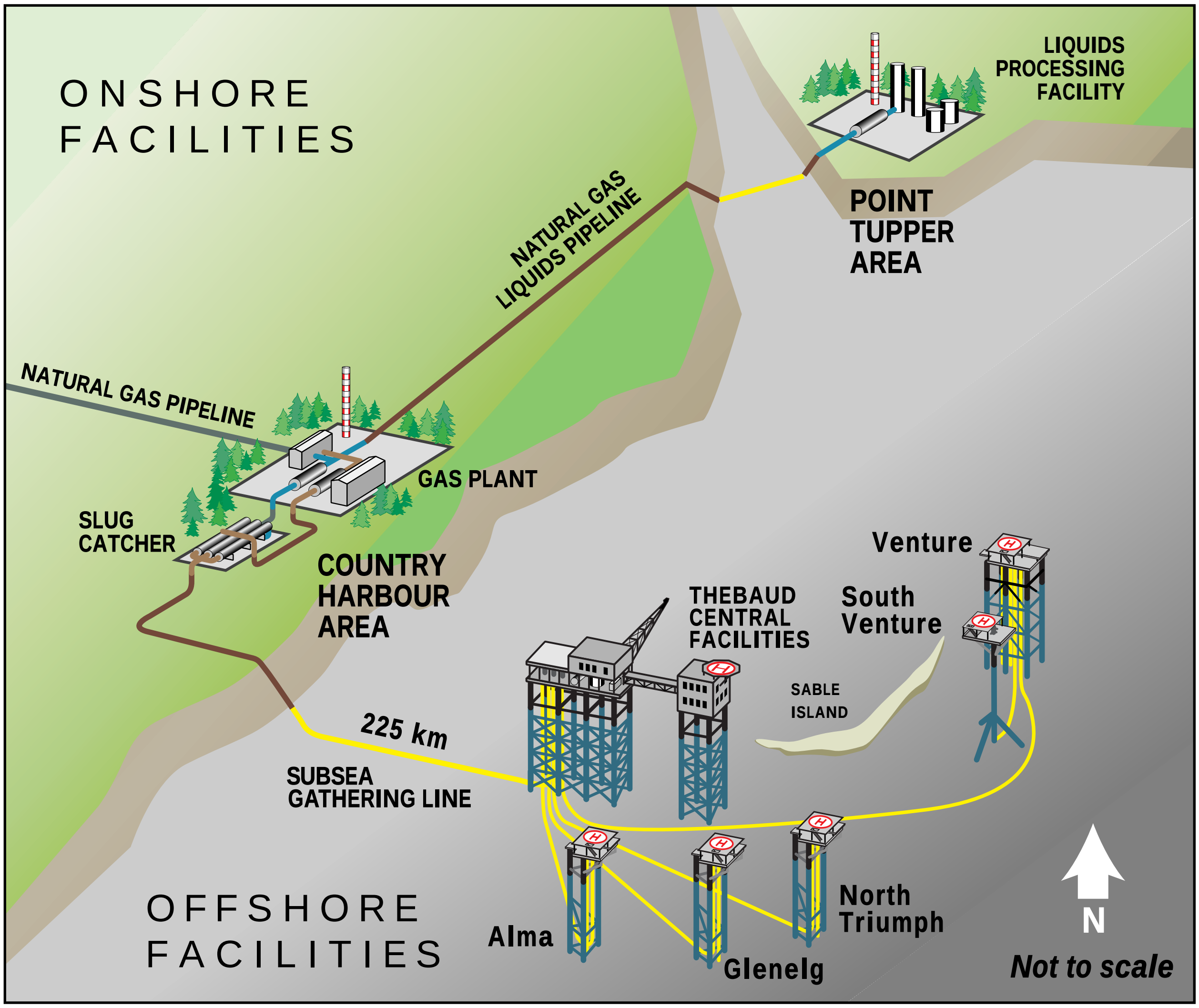

Figure 5.1.1: Production Facilities

The scope of the Production and Export Systems for the Project include:

- Offshore Facilities (production platforms and subsea pipelines)
- Onshore Facilities (gas and liquids processing facilities and liquids pipeline)

For the gas product the Project will extend to the gas plant outlet flange where processed gas will enter **The Maritimes and Northeast Pipeline**. For natural gas liquids products (Liquified Petroleum Gas and Condensate), the Project will extend to the point of loading at, or near, the Statia Terminal in Point Tupper. The project may also make use of salt caverns for gas and/or liquids storage to enhance marketing reliability. Salt cavern development would be subject to a separate development plan.

When fully developed, the **Sable Offshore Energy Project** will include up to six production platforms and an accommodation platform. The central facilities at Thebaud will be continuously manned, and include wellheads, production and processing equipment and an adjacent accommodation platform. The other fields will be developed with satellite platforms. These satellites will be normally unmanned and support wellheads and minimal processing facilities. These platforms will be equipped with emergency shelters. The satellite platforms will be tied-back to the Thebaud platform via subsea interfield flowlines. A single subsea production gathering pipeline will transport the gas from Thebaud to an onshore natural gas processing plant, with its related facilities, in the Country Harbour area. Natural gas liquids extracted from the produced gas will be fed by buried pipeline to liquid processing, storage, and shipping facilities in the Point Tupper area.

The Proponents believe that this plan is currently the most effective development plan for the resources. Their choice is based on definition engineering, environmental, economic and socio-economic (including public consultation) factors. Front End Engineering Design (FEED), the results of ongoing technical investigations and technical advances, market outlook, the acquisition and interpretation of 3D seismic, and early development drilling results will result in modifications to, and optimization of, this plan. The project development process is illustrated in **Section 1.2** of **Chapter 1.0: Project Overview** of this document.

5.1.1 Development Plan Philosophies

5.1.1.1 Facility Expansion

The design basis for the Project presented in Section 5.5 of this chapter references a raw gas design capacity for the central facilities (Thebaud Platform, Production Gathering Pipeline, Slugcatcher, Gas Plant, Liquids Pipeline, and Liquids Processing Facilities) of 12.7 E6M3/d. This rate coincides with production expectations from the current Project depletion plan in **Chapter 3.0: Reservoir Engineering**. The difference between the 12.7 E6M3/d raw gas rate and the 11.3 E6M3/d sales gas rate referred to throughout the DPA represents shrinkage from liquids production and fuel usage plus a 10% design allowance. However, there may be future expansion due to increased reserves in the base project or new discoveries in the area. An investigation of facility expansion, by up to 50 percent, to a throughput of 19 E6M3/d (raw gas inlet) has been conducted and is included in Part Two of this document (**DPA - Part 2, Ref. # 5.1.1.1.1**).

The Proponents' philosophy on facility expansion is summarized as follows:

- To prebuild expansion capacity, where it is economically justifiable.
- To provide space and weight allocations, as appropriate, in the base design to facilitate future expansion where prebuilding capacity cannot be economically justified.

5.1.1.2 Third Party Access To Facilities

The Proponents' philosophy on third party access to the facilities is as follows:

- The Proponents are prepared to permit Third Party Access to the facilities in accordance with normal regulatory practice. The Proponents believe that the appropriate terms and conditions relating to Third Party Access should reflect the appropriate allocation of cost and risk borne by the owners, particularly in the event of facilities expansions.

5.1.1.3 Measurement

The Proponents' philosophy on measurement systems is as follows:

- Measurement systems of suitable accuracy and precision will be installed consistent with the fiscal and commercial terms that are negotiated.

- Measurement systems will be installed consistent with an expectation to provide a material balance across the facilities and a basis for reservoir management.

- Measurement systems will be designed consistent with applicable regulatory requirements.

- Measurement technology will be selected consistent with Proponent goals to minimize capital and operating costs and with reference to such standards as the latest revision of the *American Petroleum Institute Manual of Petroleum Measurement Standards*.

The most common measurement systems utilized in the gas industry are orifice metering for gas and positive displacement or turbine metering for liquids. It is envisioned that meters of these types will be used at custody transfer locations such as the outlets of the onshore facilities.

New technologies continue to be developed and old technologies continue to be enhanced to improve their accuracy and precision. Multiphase flow measurement offers a significant opportunity to simplify offshore metering while providing acceptable accuracy. These **Development Alternatives** will be addressed during FEED.

5.2 Offshore Production Facilities

5.2.1 Platform Structures

The Project platforms are expected to be fixed steel jacket-type platforms. These are preferred for their lower cost, easier construction and established safe performance record. The steel jacket platform has a long history of successful operation in environments similar to the Sable Island area. Any variations in platform design resulting from FEED will not affect their environmental performance. **Figure 5.2.1.1** illustrates a typical jacket structure in the fabrication yard.

Figure 5.2.1.1: Typical Jacket Structure

Floating systems were eliminated as an alternative because they are not appropriate for use in the shallow waters and frequent severe storms of the Sable Island area. The seasonal effects of extreme storm, wind and wave conditions would make the production system susceptible to disconnect, interrupting production during the time of year when market demand for gas is highest. There are loading restrictions on floating structures, and it would be difficult to design an adequate mooring system for the shallow water depths.

Concrete structures, while not eliminated as an option, are not considered to be cost competitive. They will be investigated further in the FEED stage of Project development.

5.2.2 Well Facilities

Wellheads will be installed on the central processing platform at Thebaud and the satellite platforms. Any wells drilled prior to the installation of a platform will require the setting of a well template to serve as a conductor guide during drilling. These wells will be completed with tie-backs from the sea bottom, installed by a jackup rig once the platforms are in place. A Development Alternative would include setting of wellhead jackets prior to drilling. Wellheads suitable for the shut-in wellhead pressures of each particular field will also be installed at that time. **Chapter 4.0: Drilling, Completions and Workovers** contains further information on the wells.

5.2.3 Satellite Platform Facilities

The satellite platforms will be designed as normally unmanned, minimal processing facilities. This practice is consistent with the offshore natural gas experience of both Mobil and Shell, and their affiliates, in the North Sea and the Gulf of Mexico. A visit frequency to each of these platforms of once every one or two weeks should be attainable, if not bettered. Emergency shelters will be located at these platforms for safe refuge in emergencies and accommodation when inclement weather unexpectedly prevents helicopter access. The satellite platforms will be connected by pipeline to the central production platform at Thebaud.

Gas, condensate and water produced from the wells at the Venture, North Triumph, Glenelg and Alma fields will be separated in a three-phase group separator equipped with gas and liquid metering. The group separator will be paralleled with a test separator to facilitate individual well tests. Produced water will be treated through a hydrocyclone separator, followed by a degasser, and then discharged overboard through a caisson extending below the water surface. Gas and condensate will be recombined and sent to the central production platform at Thebaud for further processing. Monoethylene glycol (MEG) and corrosion inhibitors will be injected into the pipeline at the satellites to prevent hydrates and corrosion. A small methanol (MeOH) injection tank and pump will be provided for use on a contingency basis to deal with the infrequent formation of hydrates.

South Venture wells will be developed from a simple wellhead support structure, or possibly directionally drilled from Venture. Further measurement and treatment, other than MEG injection at the wellhead, will be done at the Venture platform.

Development Alternatives for the satellite platforms include the addition of an inlet production cooler (seawater or aerial) and the use of wet gas measurement, which would eliminate the need for a test separator. **Figure 5.2.3.1** illustrates a typical satellite platform in the UK sector of the southern North Sea.

Figure 5.2.3.1: Typical Satellite Platform

The preliminary platform site coordinates are as follows (UTM NAD27 Zone 20):

Venture	44^{o} 02.12' N	59^{o} 34.96'W
South Venture	44^{o} 00.00' N	59^{o} 37.00'W
North Triumph	43^{o} 41.91' N	59^{o} 51.40'W
Alma	43^{o} 35.69' N	60^{o} 40.92'W
Glenelg	43^{o} 39.35' N	60^{o} 08.51'W

The platform locations are illustrated in **Figure 5.2.3.2**. Preliminary designs for satellite support facilities are outlined in the following sections.

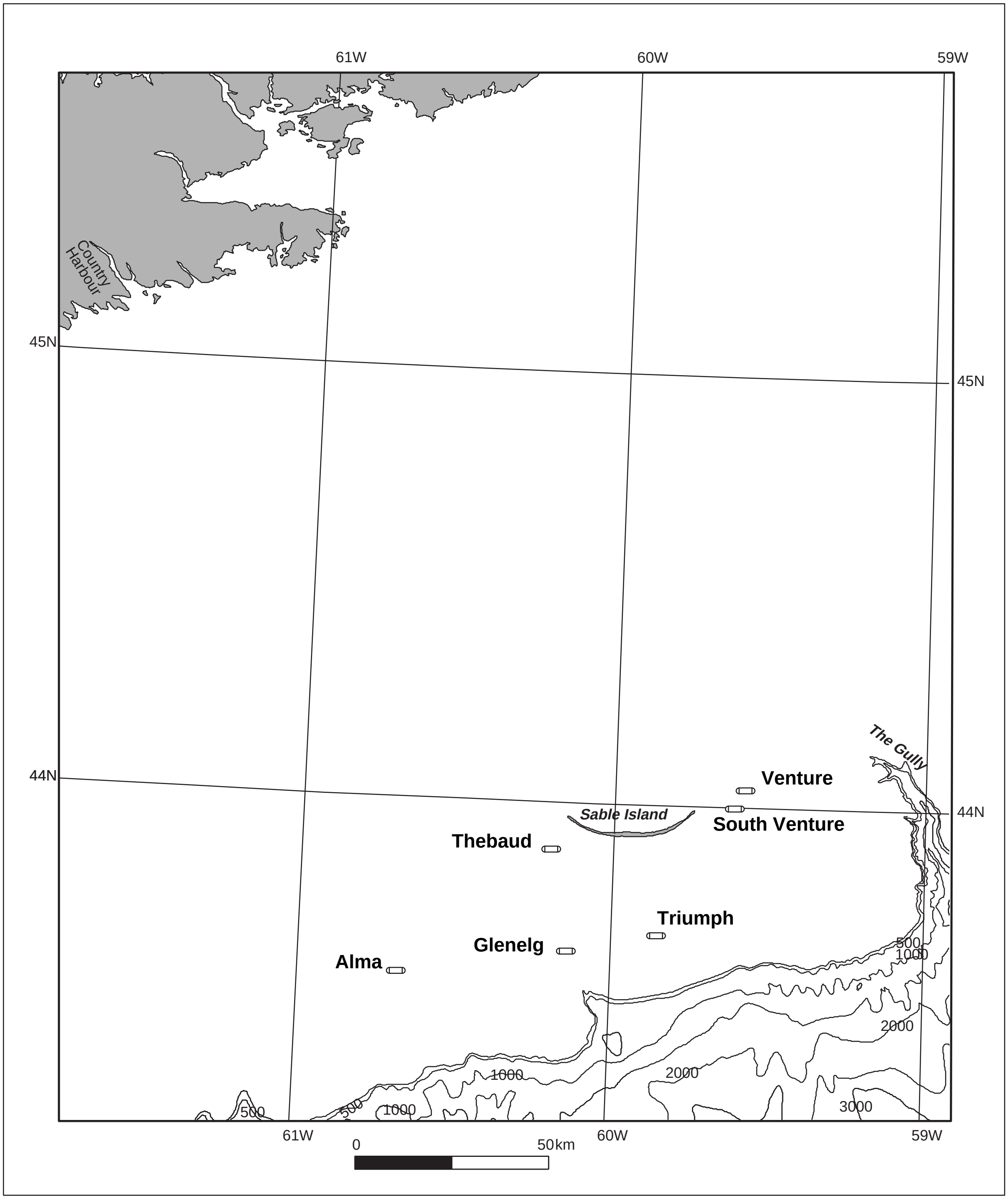

Figure 5.2.3.2: Preliminary Platform Locations

5.2.3.1 Electrical Power Generation and Distribution

Electrical power generation for each satellite platform will be provided by multiple redundant diesel generating sets. Battery back-up will be provided for essential services. Power distribution by subsea cable from Thebaud is a **Development Alternative**. However, it is currently viewed as uneconomic due to the distances involved. This option will be investigated further in the FEED stage of the project.

5.2.3.2 Service Water Supply

Service water for wash water use will either be filtered seawater or collected rainwater.

5.2.3.3 Treatment of Produced Water

Produced water will be treated using a hydrocyclone separator and a degasser to meet the draft *Guidelines for the Treatment and Disposal of Wastes from Petroleum Drilling and Production Installations on Canada's Frontier Lands*. Continuous on-line monitors will be used to ensure water quality before the water is discharged to the sea at each satellite platform. Hydrocarbon liquids separated from the water in the hydrocyclone will be pumped back in to the pipeline to the Thebaud Platform.

Hydrocyclone technology has been chosen for its design simplicity, low maintenance and proven performance. Hydrocyclone separators have no moving parts. They rely on centrifugal forces generated by a pressure drop and the difference in density between the produced water and hydrocarbons to achieve separation. The operating conditions of the Project (low viscosity, ample available pressure drop and high differential density) favour the use of this technology. Mobil has successfully used hydrocyclone separation technology in environmentally sensitive areas within the Gulf of Mexico since 1982.

A Development Alternative is the application of Corrugated Plate Interceptors or Parallel Plate Interceptors for produced water treatment. Future review in FEED will determine if this Development Alternative is acceptable.

On-line monitoring will be used to assist in compliance with applicable regulatory standards. Grab samples will be used only for calibration and testing. This protocol is similar to that accepted in offshore Australia facilities where Mobil has a working interest. At these facilities the operator has four years of successful experience in reportable monitoring of overboard water using Sigrist photometers. Recently, the Starscan monitor, licensed by Houston Photonics, has been approved by the U.S. Minerals Management Service for offshore applications. The approval was granted after examination of several successful field applications. The operator may now substitute on-line monitoring for the grab samples required at other platforms.

While current on-line monitoring technology is available and used successfully, the Proponents will consider any new developments during the FEED process. The most appropriate equipment will be selected at that time.

5.2.3.4 Closed Drain and Open Drain Effluent

Liquids coming from closed drains, caisson skimmers, and equipment drip trays will be collected and pumped to the hydrocyclone separator.

5.2.3.5 Relief and Blowdown System

Pressure relief and blowdown capability will be provided by emergency venting facilities that can be activated for either scheduled or unscheduled reasons. Scheduled activation will occur during planned tests of the system and inspection or maintenance work. Unscheduled activation will take place if there are overpressure conditions detected in the system, if there is a hazardous condition such as a fire or gas detection, or if the emergency shutdown (ESD) system is activated. Activation for any of these purposes will be infrequent.

When the system is activated, hydrocarbons will be safely directed to a cold vent at a controlled rate. The hydrocarbons will be routed through an appropriate high or low pressure knockout drum. Future FEED and safety analysis will determine if separate high and low pressure knockouts are required.

The vent will be designed so that a gas plume does not impact the helideck under worst-case wind conditions. The design will also consider maximum heat radiation conditions at the deck level to allow escape to shelter in case the gas plume ignites. Visual alarms will be provided on the helideck to warn outgoing or incoming helicopters of an impending release.

The flow capacity of the cold vent will accommodate the largest single source supplying the vent. Future safety analysis will determine the basis for the design flowrate.

5.2.3.6 Compressed Air for Instrument Use

Instrument air will be supplied from multiple electrically driven air compressors. Redundancy will be appropriate for service.

An alternative would be the use of separated and filtered produced gas for instrumentation, in which case instrument vents would be collected and directed away from the facilities. Future FEED and safety analysis will determine if this **Development Alternative** is acceptable.

5.2.3.7 Fire Protection and Safety Systems

The design basis for the fire protection and safety systems for the satellite support facilities will be developed within the Concept Safety Analysis/Evaluation (CSE) of the Project. This is outlined in **Section 10.5** of **Chapter 10.0: Safety Plan**.

Safety systems and devices will be designed to meet Project standards, the requirements of all applicable standards and codes, and local regulations. Where there is a conflict, the more stringent requirements will take priority. In all instances, however, local regulations will be met, unless exemptions are sought for alternatives that will provide an equivalent level of safety.

Relatively small unmanned platforms, with less equipment and fewer hazards, will generally require fewer protective measures. The following systems and devices are used in similar offshore developments, and are planned for this Project.

- physical barriers and/or passive fire protection to protect safe havens from the effects of fire, smoke and blast (e.g.. fireproofing, spacing, blast walls, fire walls)
- ventilation and pressurization
- shutdown, relief, and depressuring systems (including ESD)
- gas, smoke and fire detection systems in hazardous locations and at strategic locations throughout the platform
- temperature and pressure monitoring and control
- hand-portable and wheeled fire extinguishers
- high pressure and high level shut downs on process vessels
- a lifeboat capacity of 100 percent of platform capacity
- survival suits for 100 percent of platform capacity
- safe refuge/emergency quarters sized for platform capacity

For the normally unmanned satellite platforms, the provision of fire water systems (ring main distribution system, sprinkler/spray system, fixed monitor system, hose reels/hydrants, foam system) is not expected to be necessary. This will be confirmed by an evaluation of fire risks, facility value, loss of production potential and maintenance requirements.

5.2.3.8 Helicopter Deck

A helicopter deck will be situated on or above the top deck of each satellite platform. The helideck will be designed to accommodate a Sikorski 61N, or equivalent, helicopter, in accordance with *Transport Canada Recommended Practice TP4414*. The deck will be heat-traced to prevent ice buildup, and slightly cambered for drainage.

5.2.3.9 Potable Water and Sewage Systems

Water will be supplied to closed storage facilities on the satellite platforms by supply boat. The sewage system will consist of either a chemical toilet or maceration. Disposal to the sea will be in accordance with the *Guidelines for the Treatment and Disposal of Wastes from Petroleum Drilling and Production Installations on Canada's Frontier Lands.*

5.2.4 Thebaud Production and Processing Platform Facilities

The Thebaud production and processing platform will support production from the Thebaud field wells and provide central dehydration facilities for the Project. The Thebaud platform is described in detail in an initial definition engineering study in Part Two of this document (**DPA - Part 2, Ref. # 5.2.4.1**).

The preliminary location of the Thebaud Platform is 43^{o} 53.5' N, 60^{o}12'W.

Gas, condensate and water produced from the Thebaud wells will be cooled in an inlet cooler and separated in a three-phase inlet group separator equipped with gas and liquid metering. The inlet group separator will be paralleled with a test separator to facilitate individual well tests. Production from these separators will be combined with production from the satellite platform inlet separators.

There will be two three-phase inlet separators installed on the Thebaud platform for production from the satellite platforms. One will be sized to become a low pressure inlet separator for future booster compression. These separators are presently sized on the basis of projected production from the Venture and North Triumph fields. Their design and the timing of installation will be optimized during the FEED stage of the Project.

The central processing facilities at Thebaud will include triethylene glycol (TEG) gas dehydration and condensate dewatering. The combined gas stream from the inlet separators will be fed to two TEG contactor trains where the bulk of the water vapour in the gas will be removed. The TEG will be regenerated by boiling off the water absorbed from the gas and recycling the TEG to the contactors. There will also be a separate regenerator for the monoethylene glycol (MEG) produced from the satellite field inlet separators. The water vapour and trace amounts of glycol and hydrocarbons from the regenerators will be vented to the atmosphere (see **Volume 3, Environmental Impact Statement**). Condensate from the inlet separators will be combined and fed to a condensate coalescer and stripper. Dewatered condensate will be pumped into the gas stream from the TEG contactors. The recombined gas and condensate will be fed through the production gathering pipeline to the onshore gas processing facilities. Water from the coalescer and other platform sources will be fed to a water separation and treatment system and then discharged into the sea.

Expansion capability will be provided at the Thebaud platform. Sufficient space and weight allocations will be incorporated into the design of the deck and jacket to accommodate additional processing facilities. Individual pieces of equipment will be critically examined during the FEED stage to determine if this additional capacity can be installed during initial construction for low incremental cost, thereby optimizing prebuilt capacity.

When gas production begins to decline from the satellite platforms, a compression facility will be installed at Thebaud to maintain production. The compression equipment will consist of gas turbine driven centrifugal compressors. Sufficient space and weight allocations for future compression will be included in the platform design.

As in the selection of type of platform, the central processing facilities at Thebaud may be modified as the FEED stage of the Project progresses. **Development Alternatives** include a separate Thebaud wellhead platform, and dedicated inlet separation and measurement for each interfield pipeline inlet. As an **Alternative development** option to test separation, wet gas metering may be installed. Also, a **Development Alternative** with respect to future compression is the installation of a separate compression platform. **Figure 5.2.4.1** illustrates a typical central processing platform. Preliminary designs for Thebaud support facilities are outlined in the following sections.

Figure 5.2.4.1: Typical Central Processing Platform

5.2.4.1 Electrical Power Generation and Distribution

Electrical power generation will be provided by multiple sets. Redundancy will be appropriate for the service. The generators will be powered by gas turbines capable of running on natural gas or diesel. The diesel capability will be primarily for startup and commissioning duties.

5.2.4.2 Fuel Gas System

Fuel gas for onboard consumption will be supplied from dehydrated produced gas. The fuel gas system will have its own metering facilities.

5.2.4.3 Service Water Supply

Service water for process and utility systems will be filtered seawater.

5.2.4.4 Treatment of Produced Water

Produced water from the Thebaud wells and water from the condensate coalescer will be treated using a hydrocyclone separator and a degasser to meet the *Guidelines for the Treatment and Disposal of Wastes from Petroleum Drilling and Production Installations on Canada's Frontier Lands*. A continuous on-line monitor will be used to ensure water quality before the water is discharged into the sea. Hydrocarbon liquids separated in the hydrocyclone will be pumped back in to the main production stream to feed the pipeline to the onshore gas plant.

A Development Alternative is the application of Corrugated Plate Interceptors or Parallel Plate Interceptors for produced water treatment. Future review in FEED will determine if this Development Alternative is acceptable.

On-line monitoring will be used to assist in compliance with applicable regulatory standards. Grab samples will only be used for calibration and testing.

While current on-line monitoring technology is available and used successfully, the Proponents will consider any new developments during the FEED process. The most appropriate equipment will be selected at that time.

5.2.4.5 Closed Drain and Open Drain Effluent

Liquids from closed drains, caisson skimmers, and equipment drip trays will be collected and pumped to either the hydrocyclone separator or separate treatment equipment.

5.2.4.6 Relief and Blowdown System

Pressure relief and blowdown capability will be provided by emergency venting facilities that can be activated for either scheduled or unscheduled reasons. Scheduled activation will occur during planned tests of the system and inspection or maintenance work. Unscheduled activation will take place if there are overpressure conditions detected in the system, if there is a hazardous condition such as a fire or gas detection, if there is a need to depressure an interfield flowline due to a leak, or if the ESD system is activated. Activation for any of these purposes will be infrequent.

When the system is activated, hydrocarbons will be safely directed at a controlled rate to a cold vent. The hydrocarbons will be routed through an appropriate high or low pressure knockout drum. Future FEED and safety analyses will determine if separate high and low pressure knockouts and/or a flare are required. The vent will be designed so that a gas plume will not impact the helideck and living quarters in worst-case wind conditions. Maximum heat radiation conditions at the deck level will be considered to allow escape to shelter if the gas plume ignites. Visual alarms will be provided on the helideck to warn outgoing or incoming helicopters of an impending release. The flow capacity of the cold vent will be designed in accordance with future safety analysis.

5.2.4.7 Inert Gas System

The Thebaud facilities may be equipped with a supply of nitrogen to purge hazardous locations such as vessels, removing combustible vapours and making the equipment safe for entry and inspection. Prior to facility start-up, it may also be used to purge air out of vessels and piping before gas is introduced. In addition, nitrogen may be used as a blanket in glycol and other storage tanks to provide pressurization or to reduce the corrosion effects at the liquid-vapour interface. Safety analyses during the FEED stage will determine the nitrogen requirements.

5.2.4.8 Compressed Air for Instrument/Utility Use

Instrument and utility air will be supplied from multiple electrically driven air compressor sets. Redundancy will be appropriate for service.

5.2.4.9 Fire Protection and Safety Systems

The design basis for the fire protection and safety systems for the central facilities at Thebaud will be developed within the CSE for the Project outlined in **Chapter 10.0: Safety Plan**, of this document.

Safety systems and devices will be designed to meet Project standards, the requirements of all applicable standards and codes, and local regulations. Where there is a conflict, the more stringent requirements will take priority. In all instances, however, local regulations will be met, unless exemptions are sought for alternatives that will provide an acceptable level of safety.

The central facilities at Thebaud will incorporate a number of detection and suppression systems in accordance with the requirements noted above and modifications that may result from a series of hazards assessment studies planned to address these system requirements. A combination of ventilation, pressurization, fire detection, gas detection, fire systems (sprinkler, water spray, foam, gaseous and dry chemical) and manual systems (hose reel, dual agent, monitor) typically apply to normally manned platforms. The fire protection and safety systems will vary by location on the central platform.

The following systems and devices are used in similar offshore developments, and are planned for this Project:

- physical barriers and/or passive fire protection to protect safe havens from the effects of fire, smoke and blast (e.g.. fireproofing, spacing, blast walls, fire walls)
- ventilation and pressurization
- shutdown, relief and depressuring systems (including ESD)
- gas, smoke and fire detection systems in hazardous locations and at strategic locations throughout the platform
- overpressure protection
- temperature and pressure monitoring and control
- hand-portable and wheeled fire extinguishers
- high pressure and high level shut downs on vessels
- lifeboats
- survival suits
- ventilation to prevent build-up of hazardous vapours
- safe refuge locations

In support of the systems/devices listed above, the following primary systems are planned for the central facilities at Thebaud:

a) A firewater hydrant system using seawater for general deluge, water monitor and fire-fighting applications will be utilized. Firewater pumps will supply seawater to a ring main system. Associated equipment will include filters, strainers and jockey pumps. Hose reels, monitors and portable extinguishers will be situated at strategic locations around the platform.

b) An Aqueous Film-Forming Foam system (AFFF) to fight hydrocarbon-based fires will be included. The AFFF ring main will supply foam to dual-agent hose reels and fire monitors located throughout the platform.

c) An inert gas fire suppression system will be used in confined spaces such as turbine enclosures, electrical switch gear rooms and control rooms.

d) A fixed fire-extinguishment system utilizing carbon dioxide or pressure water spray for machinery, hydrocarbon liquid pump, and flammable liquid storage spaces will be used.

5.2.5 Thebaud Accommodation Facilities

The present development plan includes accommodation facilities that are connected by a steel truss bridge to the production and processing platform at Thebaud. The living quarters will accommodate up to 40 people. The Development Alternative of incorporating the accommodation facilities with the process platform will be examined during FEED. The systems that will be located on the accommodation platform are described as follows:

5.2.5.1 Living Quarters

Most of the living quarters will consist of double berth rooms. Facilities will include a recreational area, cafeteria and galley, locker area, office areas, laundry room and a medical facility.

5.2.5.2 Storage Areas

Bulk storage will be provided for safety equipment and spare parts. Separate storage will be provided for food supplies.

5.2.5.3 Helicopter Deck

A helicopter deck will be situated above the accommodation facilities at Thebaud. The helideck will be designed to accommodate a Sikorski 61N, or equivalent, helicopter in accordance with *Transport Canada Recommended Practice TP4414*. The deck will be heat-traced to prevent ice buildup and slightly cambered for drainage.

5.2.5.4 Emergency Power

Emergency power for the complex will be provided by a diesel generator set located on the accommodation platform. This unit will only be used for the living quarters and life support systems.

5.2.5.5 Potable Water System

The potable water system at Thebaud will be supplied either from watermakers with seawater desalination systems or brought from the mainland on supply boats.

5.2.5.6 Sewage Treatment System

Sewage treatment will consist primarily of maceration. The system will be designed to comply with the *Guidelines for the Treatment and Disposal of Wastes from Petroleum Drilling and Production Installations on Canada's Frontier Lands.*

5.2.5.7 Fire Protection and Safety Systems

The living quarters at Thebaud will be the primary safe haven where platform personnel can take one or more of the following actions:

- assemble during an emergency
- take refuge from fire, smoke and other hazards
- initiate emergency actions (including requirements to have secure communication)
- effect safe and orderly platform evacuation

In addition to being physically remote from hazardous areas containing hydrocarbons, the accommodations will be protected from the effects of fire, smoke and blast through the use of physical barriers and/or passive fire protection. The actual level of protection for the accommodation platform will be determined based on Project standards, codes, local regulations and a determination by hazard assessment techniques. Accommodations on a separate bridge-connected platform typically require less physical barrier protection because of the increased distance from hazards.

The following fire protection and safety systems are planned for the accommodation facilities:

- non-combustible construction
- fire rated construction (minimum one-hour duration)
- explosion overpressure protection, if required
- heating, ventilation, and air conditioning (HVAC) system capable of maintaining a positive pressure
- fire detection, smoke detection and alarm
- HVAC inlets incorporating gas detection and alarm
- platform emergency shutdown capability
- internal and external communication capabilities
- emergency lighting
- two means of egress
- alternate means of escape (lifeboats, life rafts, helideck, etc.)
- survival suits
- hand-portable and wheeled fire extinguishers
- hose reel and sprinkler fire water system

5.2.5.8 Heating, Ventilating and Air Conditioning Systems

The living quarters will have stand alone heating and air conditioning systems, separate from those on the production and processing platform.

5.2.6 Offshore Pipelines

5.2.6.1 Subsea Interfield Pipelines

Produced gas and condensate from the satellite platforms will be transported to the central processing platform at Thebaud via carbon steel pipelines. Steel lines are suitable, providing that produced formation water is removed at the satellite platforms and a corrosion inhibition program is followed. The use of MEG injection for hydrate inhibition in offshore gas pipelines is a common and proven practice. Also, the condensate content in the **Sable Offshore Energy Project** gas stream will serve as a natural inhibitor for both hydrates and corrosion. Corrosion modelling for the interfield lines indicates extremely low corrosion rates will occur if a corrosion inhibition program is followed. The potential for Stress Corrosion Cracking is considered to be insignificant due to plans for a corrosion prevention program and appropriate external protection. General corrosion and loss of wall thickness is the primary focus for corrosion prevention. Further laboratory experiments during FEED to confirm the results of the modelling will form the basis for final design. The subsea interfield pipeline corridor is shown in **Figure 5.2.6.1.1**.

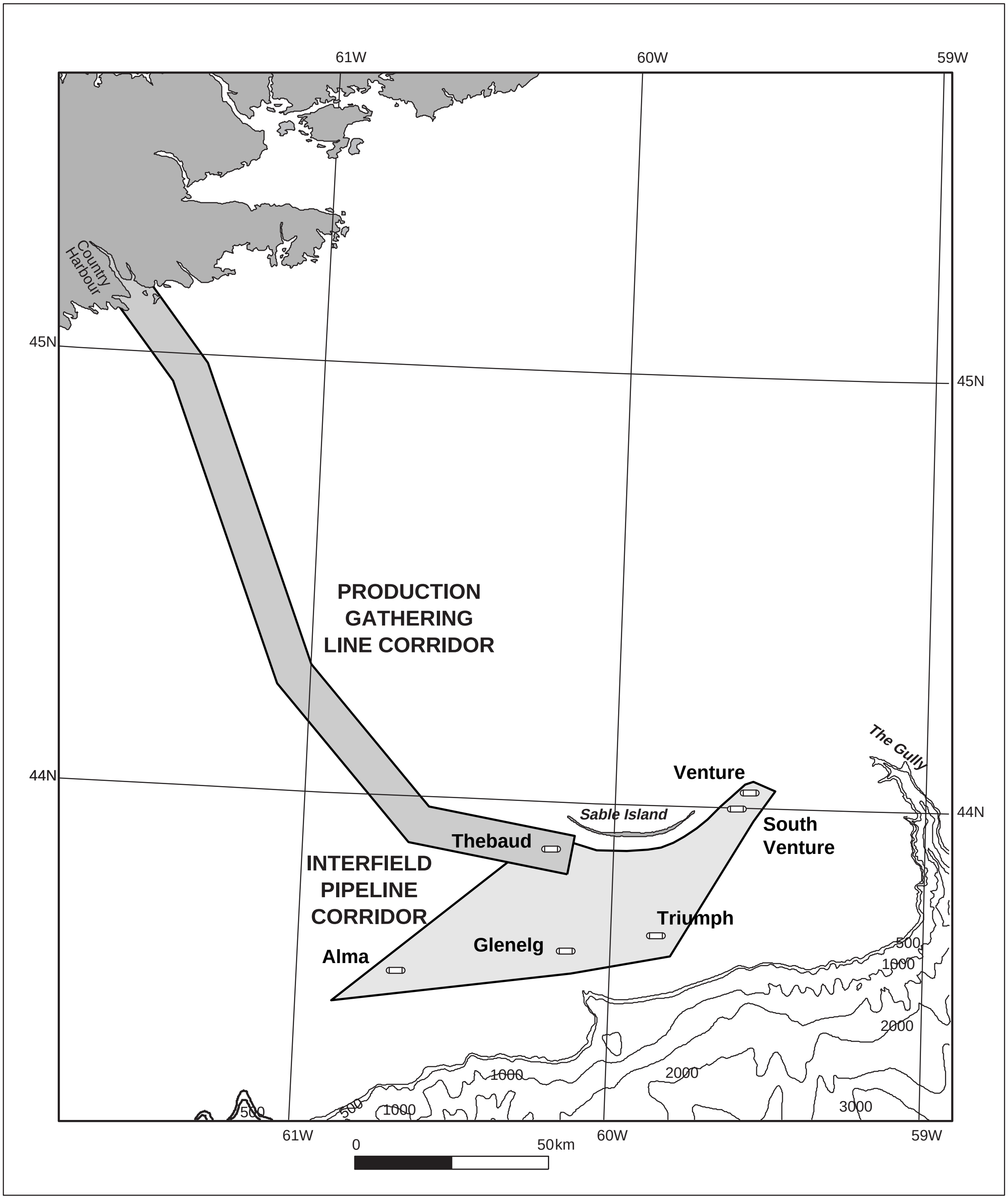

Figure 5.2.6.1.1: Pipeline Corridors

The routing of the interfield pipelines will be addressed in FEED. Route selection will be based on the optimum combination of route length, terrain variation, water depth and suitability of substrate materials.

Further data for the interfield pipeline corridor is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.1**).

The subsea interfield flowlines are presently sized as follows:

- Venture to Thebaud — 54 kilometres, 457 mm OD, 12.7 mm WT
- North Triumph to Thebaud — 35 kilometres, 324 mm OD, 12.7 mm WT
- South Venture to Venture — 5 kilometres, 219 mm OD, 12.7 mm WT
- Glenelg to Thebaud — 32 kilometres, 324 mm OD, 12.7 mm WT
- Alma to Thebaud — 50 kilometres, 324 mm OD, 12.7 mm WT

These sizes and lengths are subject to change during the FEED stage.

Sizing of the interfield pipelines was determined by optimizing the trade-off between pressure drop and liquid holdup for each line. This was done to minimize slugging to the Thebaud platform and to avoid the requirements of a regular pigging program. This analysis is included in Part Two of this document (**DPA Part 2, Ref. # 5.2.6.1.2**). The pipelines will be designed to be capable of pigging, if required. Appropriate leak detection and emergency shutdown and blowdown equipment will be installed on each interfield line in accordance with applicable codes and standards.

The pipelines will be externally coated for corrosion protection and concrete coated for negative buoyancy and to provide on-bottom stability. They will be trenched, where necessary, into the seafloor. Present assumptions are that all interfield lines will be trenched and will self bury. These assumptions will be refined during FEED by the geotechnical studies referenced in Section 5.7 of this chapter.

The maximum operating pressure of the interfield lines, except the South Venture line, is expected to be 13.8 MPag, corresponding to a design pressure of 14 MPag per ANSI 900 Rating. The maximum operating pressure for South Venture is expected to be 14.1 MPag. At these design pressures, the wall thickness for all pipelines larger than 559 mm is governed by internal pressure. For smaller pipe sizes, a minimum pipe wall thickness of 12.7 mm is required, as determined by mechanical pipelay requirements. The wall thickness will be verified during FEED. Each interfield pipeline will be installed with an 88.9 mm OD line strapped to it for MEG delivery from Thebaud. Strapping an MEG line of this size to a gas pipeline is common practice in the southern North Sea.

Development Alternatives for the interfield pipelines include the use of corrosion resistant alloys rather than steel and the use of flexible pipe or insulated steel pipe for the South Venture tie-in. These alternatives will be evaluated during FEED.

5.2.6.2 Subsea Production Gathering Pipeline

The production gathering pipeline is currently sized as 609 mm OD, 15.88 mm WT for a length of 225 kilometres. The Maximum Operating Pressure (MOP) of this pipeline would be approximately 11.7 MPag, corresponding with the Project design production rate of 12.7 E6M3/d and a plant inlet pressure of 7240 KPag. The design pressure for this line would be 13.5 MPag as per *CSA Standard Z662-94* specifications. At this design pressure, the wall thickness for the pipeline will be governed by internal pressure containment requirements, plus a corrosion allowance, rather than mechanical pipelay requirements.

The production gathering pipeline sizing of 609 mm was determined by optimizing the trade-off between pressure drop and liquid holdup. The goal was to minimize slugging and avoid the requirements of a regular pigging program, while not substantially increasing future booster compressor requirements. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**). A regular pigging program may be required at rates below 75 percent of design capacity to maintain a manageable liquid holdup in the line. The pipeline will be designed for pigging, when required. It will be equipped with a pig sender at the Thebaud platform and a pig receiver at the onshore slugcatcher. Appropriate leak detection and emergency shutdown and blowdown equipment will be installed on the production gathering pipeline, in accordance with applicable codes and standards.

A production group line of 609 mm, when operated at maximum design pressure, is capable of carrying a maximum flowrate of about 15.9 E6M3/d. This flowrate could only be attained if considerable compression is installed earlier than planned. High backpressure would otherwise be applied to the wells. Future expansion capability equivalent to the above rate could also be achieved by preinvesting in a 660 mm OD, 17.48 mm WT pipeline, without increasing the MOP. Future expansion capability of up to 19 E6M3/d could be obtained at the same MOP by installing a 711 mm OD, 19.05 mm WT pipeline. Information to support these line sizes is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**). The installation of a larger diameter pipeline has implications for both slugcatcher sizing and pigging requirements, as outlined in Section 5.3.1 of this chapter, when the pipeline is operated at the Project design rate of 12.7 E6M3/d. The optimum sizing of this line will be determined during FEED.

The production gathering pipeline will be carbon steel. The potential for internal corrosion in this line is insignificant because the gas will be dehydrated at the Thebaud platform to near sales pipeline specifications and no water will condense in the pipeline. The potential for Stress Corrosion Cracking is considered to be negligible due to the lack of a corrosive environment internally and appropriate external protection. The cool operating temperature of the pipeline further reduces the potential.

The subsea production gathering pipeline corridor was selected based on the optimum combination of distance, slope and water depth and to avoid unsuitable substrate materials. Further data relative to the production gathering pipeline corridor is outlined in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.1**). Sensitive coastal issues such as aquaculture sites, ocean dumping sites, parks and conservation areas were also included in the evaluation. Input obtained from the fishery community during the public consultation process was particularly useful in highlighting significant fishing areas that have been avoided by the selected corridor. The subsea production gathering pipeline corridor is shown in **Figure 5.2.6.1.1**.

The pipeline will be externally coated for corrosion protection and concrete coated for negative buoyancy and to provide on-bottom stability. The line will be trenched in shallow water depths and is expected to self bury. The design criteria for burial will be refined by future geotechnical studies as described in Section 5.7 of this document. The line will be routed, where possible, to avoid extreme water depths in order to simplify lay barge requirements and avoid rock outcrops and severe slopes. The routing will be further defined in the FEED process.

5.3 Onshore Facilities

5.3.1 Scope of Facilities

The onshore facilities will include a slugcatcher and natural gas processing plant located in the Country Harbour area and a natural gas liquids processing facility in the Point Tupper area. The gas plant will produce specification sales gas and unstabilized liquids products. The unstabilized liquids will be shipped by pipeline to Point Tupper where production and loading of specification liquefied petroleum gases (propane and butane) or Liquified Petroleum Gas (LPG) mix and stabilized condensate will occur. **Figure 5.3.1.1** illustrates the process block flow for the onshore facilities.

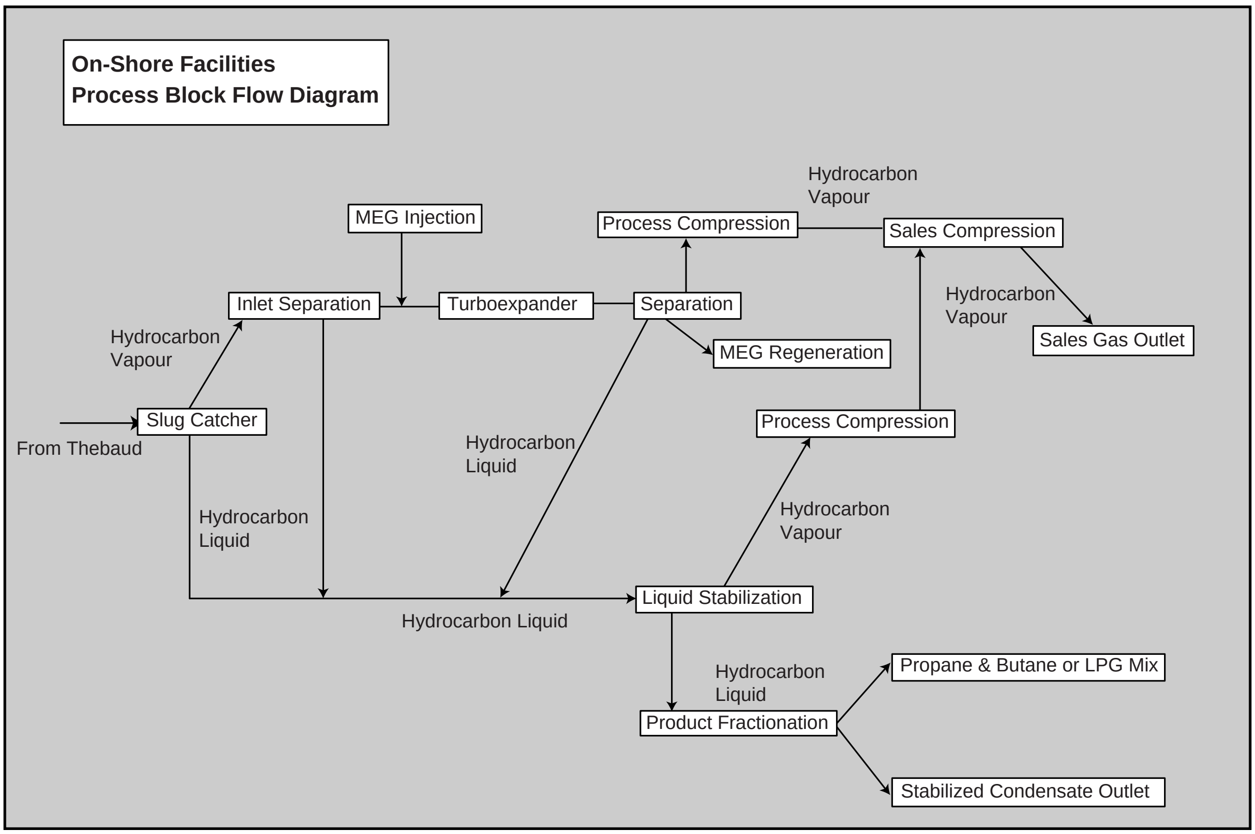

Figure 5.3.1.1: Process Block Flow Diagram

5.3.2 Slugcatcher

An inlet slugcatcher will be installed near the pipeline landfall. The slugcatcher will occupy an area of about five hectares. It will separate out hydrocarbon liquids that are reinjected into the pipeline at Thebaud or condensed from the gas as it travelled through the production gathering pipeline to shore. It will consist of a series of large diameter (up to 1220 mm OD) pipes that are up to 200 metres each in length. These pipes will be inclined downward across their length from the inlet end to the liquid outlet end. Gas will be removed through connecting piping into a header located across the top of the slugcatcher near the inlet end. Gas and liquids will be fed separately from the slugcatcher into the plant. A typical slugcatcher is illustrated in **Figure 5.3.2.1**.

Photo Courtesy: Taylor Forge

Figure 5.3.2.1: Typical Slugcatcher

As gas and liquids are sent to shore, temperature and pressure decrease and additional liquids condense in the production gathering pipeline. For a given flow rate the gas and liquid velocities in the pipe may be different. The liquid tends to flow along the bottom of the pipeline and typically collects in low spots or in uphill sections of the pipeline. When the flow rate in the pipeline is increased, some liquids will be swept out and an incremental flow of liquid or a liquid 'slug' will exit the pipeline. The slugcatcher will be designed to provide sufficient capacity to address expected changes in flow and normal operating slug sizes. This information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**).

A regularly scheduled pipeline pigging program will be required when significant changes in flow are made or when the pipeline throughput decreases below a level where the normal slug size could exceed the capacity of the slugcatcher without pigging. A pipeline pig is typically either a rubber sphere or a series of rubber disks on a shaft. It has the same diameter as the pipeline and is inserted in the gas flow through the line to remove accumulated liquids. Pigging helps prevent accumulation of unmanageable liquid slugs, reduces pipeline pressure drop, and reduces the risk of corrosion which could result from any inadvertent water accumulation in the pipeline.

The diameter of the pipeline is one of the key factors in defining the volume of liquids that will accumulate in the pipeline. Although the pressure drop for a given flow rate is less in larger diameter pipelines and less compression is required, the velocity is lower and the liquid slug volume is larger. Consequently, a larger slugcatcher is required.

Based on transient flow analysis, a 609 mm OD production gathering pipeline would be optimal for the 12.7 E6M3/d Project design basis. The required slugcatcher capacity for this line size is about 2400 M3. For a 660 mm OD pipeline, the slugcatcher would need to be 50 percent larger. If a 711 mm production gathering pipeline was installed to facilitate future expansion up to 19 E6M3/d, a slugcatcher capacity of about 4800 M3 would be required to operate at the Project design flow rate of 12.7 E6M3/d. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**). The implementation of a regular pigging program from the outset of the Project could help reduce the slugcatcher sizing. The optimum balance of pipeline size, slugcatcher size, pigging program, and future compression requirements will be determined during FEED.

5.3.3 Country Harbour Gas Plant

A typical gas plant is illustrated in **Figure 5.3.3.1**.

Figure 5.3.3.1: Typical Gas Plant

The gas plant will be located immediately downstream of the slugcatcher. It will require approximately 20 hectares of land; 25 hectares in total including the slugcatcher **(DPA - Part 2, Ref. #5.3.3.1)**.

The plant will have an operating pressure of approximately 6900 KPag. The inlet feed, gas and liquids, will enter the plant through separate pipelines from the slugcatcher. Any liquid collecting in the gas inlet separator will be discharged into the hydrocarbon liquid flash drum.

The gas from the inlet separator will be cooled in the feed gas/residue gas heat exchanger. Any liquids formed during gas cooling will be separated in the turboexpander inlet separator. After expansion, to 5516 KPag, the resulting two-phase stream will be separated in the low temperature separator. The expander outlet gas will be used to chill the feed gas in the feed gas/residue gas exchanger. The gas will then be compressed to 5998 KPag in the expander compressor and mixed with the compressed overhead vapours from the hydrocarbon liquids flash drum. The combined stream will be further compressed to 9963 KPag in the sales gas compressors and cooled to 38^{o}C in the discharge compressor aftercooler. It will then be routed through the sales gas pipeline metering station located at the plant fence into the export pipeline.

The hydrocarbon liquid streams from the slugcatcher, the inlet separator, the turboexpander inlet separator and the low temperature separator will be sent to the hydrocarbon liquid flash drum operated at 1035 KPag. The liquids will then be transported via a 219 mm OD, 6.35 mm WT pipeline to Point Tupper for further processing. The inlet pressure to the pipeline will be 6550 KPag.

Joule-Thompson (JT) valve operation will be used as a back-up to the turboexpander process. The feed gas/residue gas exchanger will be sized to maximize the flow during JT operation. The JT operation can achieve approximately 80 percent of the plant capacity, and for this reason, only one 100 percent capacity turboexpander will be installed.

In order to prevent hydrate formation in the outlet from the turboexpander, MEG will be injected in the feed gas upstream of the feed gas/residue gas exchanger. A small MEG regeneration package is required. Water vapour and trace amounts of glycol and hydrocarbons from this system will be vented (see **Volume 3, Environmental Impact Statement**).

Expansion of the gas plant will likely be accommodated through pre-investment in larger inlet facilities and a turboexpander that is larger than the one currently specified in Part Two of this document (**DPA - Part 2, Ref. # 5.3.3.1**). This will permit the addition of a separate processing train at a later date.

The selection of a turboexpander process for the onshore gas plant is based on early definition engineering. Process alternatives, including propane refrigeration and solid bed adsorption, will be evaluated during FEED.

5.3.4 Point Tupper Liquid Facilities

The liquid handling facilities will require up to 10 hectares of land. The hydrocarbon liquids pumped from the Country Harbour area will enter the facility through the liquids feed drum at 2760 KPag and feed the deethanizer tower at 2586 KPag. The hydrocarbon liquid will be further stabilized by removing methane and ethane from the feed stream for use as facility fuel. The bottoms from the deethanizer will feed an additional fractionation tower or towers depending on whether an LPG mix or specification propane and butane is produced in conjunction with stabilized condensate. Storage and shipping facilities will include truck, rail and/or barge for the LPG's. The condensate will be shipped by tankers.

Pre-investment to accommodate future expansion will likely be limited because the liquids content of new discoveries will drive the liquid handling requirements. A "lean" gas could require little additional liquids capacity while a "rich" gas could require disproportionately more capacity. During FEED, individual pieces of equipment will be critically examined to determine if additional capacity can be installed at low incremental cost. Expansion alternatives for the liquid facilities range from utilizing lower efficiency tower trays in the base design, with later replacement by higher efficiency tower packing, to completely pre-built facilities. The 219 mm liquids pipeline from Country Harbour has sufficient capacity to handle future expansion.

Development Alternatives for the Point Tupper facilities range from a simple condensate transfer facility (LPG's deethanized and extracted at Country Harbour) to third party purchase and shipment of an unstabilized NGL stream. These alternatives will be examined in the FEED process, following market studies. The final scope for the liquid facilities will be driven by market forces.

5.3.5 Onshore Support Facilities and Services

5.3.5.1 Power

A survey will be carried out to ascertain the power available and the reliability of the available grid system in both locations. However, preliminary design calls for gas turbine driven power generation facilities to be installed at Country Harbour to make it self-sustaining. This facility will also have a diesel powered emergency generator. Diesel generator capability to power essential systems will be used only for plant startup or during major disruptions in the gas supply.

Preliminary design for the Point Tupper facilities assumes that power will be provided by the local grid. An emergency power generator capable of consuming Diesel fuel, LPG or Deethanizer overheads as a fuel will also likely be required.

5.3.5.2 Instrument Air

Instrument air for plant control functions and valve operators will be provided by multiple packaged air compressor units, with all ancillary equipment and dryers, at both locations.

5.3.5.3 Fire Protection and Safety Systems

The design basis for the fire protection and safety systems for the onshore facilities will be developed within the Concept Safety Analysis for the Project described in **Chapter 10.0: Safety Plan**, of this document.

Safety systems and devices will be designed to meet Project standards, the requirements of all applicable standards and codes, and local regulations. Where there is a conflict, the more stringent requirements will take priority. In all instances, however, local regulations will be met, unless exceptions are sought for alternatives that will provide an equivalent level of safety.

The onshore facilities will incorporate a number of detection and suppression systems in accordance with the requirements noted above and modifications that may result from a series of hazards assessment studies planned to address these system requirements. A combination of ventilation, pressurization, fire detection, gas detection, fire systems (sprinkler, water spray, foam, gaseous and dry chemical) and manual systems (hose reel, dual agent, monitor) are typically employed at manned plants.

The following systems and devices are typically used in onshore gas plant/liquid handling facilities:

- emergency shutdown and depressuring system to progressively isolate hydrocarbon inventory, and depressure and shutdown the process system
- fire and gas detection systems
- heat and smoke detection systems
- fixed fire main and hydrant system
- foam/sprinkler deluge systems
- hand-portable and wheeled fire extinguishers
- ventilation and pressurization
- an inert gas system for turbine enclosures, control rooms and electrical switch-gear room

5.3.5.4 Relief and Blowdown Systems

The relief and blowdown systems are emergency venting facilities that can be activated for scheduled and unscheduled reasons. Scheduled activation will occur during planned tests of the system, and inspection or maintenance work. Unscheduled activation will take place if there are overpressure conditions detected in the system, if there is a hazardous condition such as a fire, if there is a need to depressure a pipeline due to a leak, or if the ESD is activated. Activation for any of these purposes will be very infrequent.

Both locations will be equipped with flare systems. Both ground flare and flare stack alternatives will be investigated during the FEED process.

5.3.5.5 Water Supply

Potable water for the facilities near Country Harbour will likely be sourced from a well. The Point Tupper facility will be connected to the local municipal supply. Supply alternatives will be reviewed during the FEED process and will be consistent with all applicable codes.

5.3.5.6 Sewage Disposal

Sewage disposal for both locations will be determined during FEED and will be consistent with all applicable codes. Self-contained septic systems are the most likely alternative for both locations.

5.3.6 Onshore Natural Gas Liquids Pipeline

The natural gas liquids will be transported from the gas plant near Country Harbour to facilities near Point Tupper via a buried 219 mm OD carbon steel pipeline. The design pressure of the pipeline will be 6895 KPag. The pipeline will be constructed in accordance with *CSA Standard Z662-94*.

A detailed pipeline routing survey will be initiated following the final selection of the gas plant and liquid handling sites. On completion of the survey, a route will be selected that considers population density, environmental considerations, acidic slate potential, terrain, mining activity, quarries, forestry activities, and pipeline length. The pipeline corridor under investigation is shown in **Figure 5.3.6.1**.

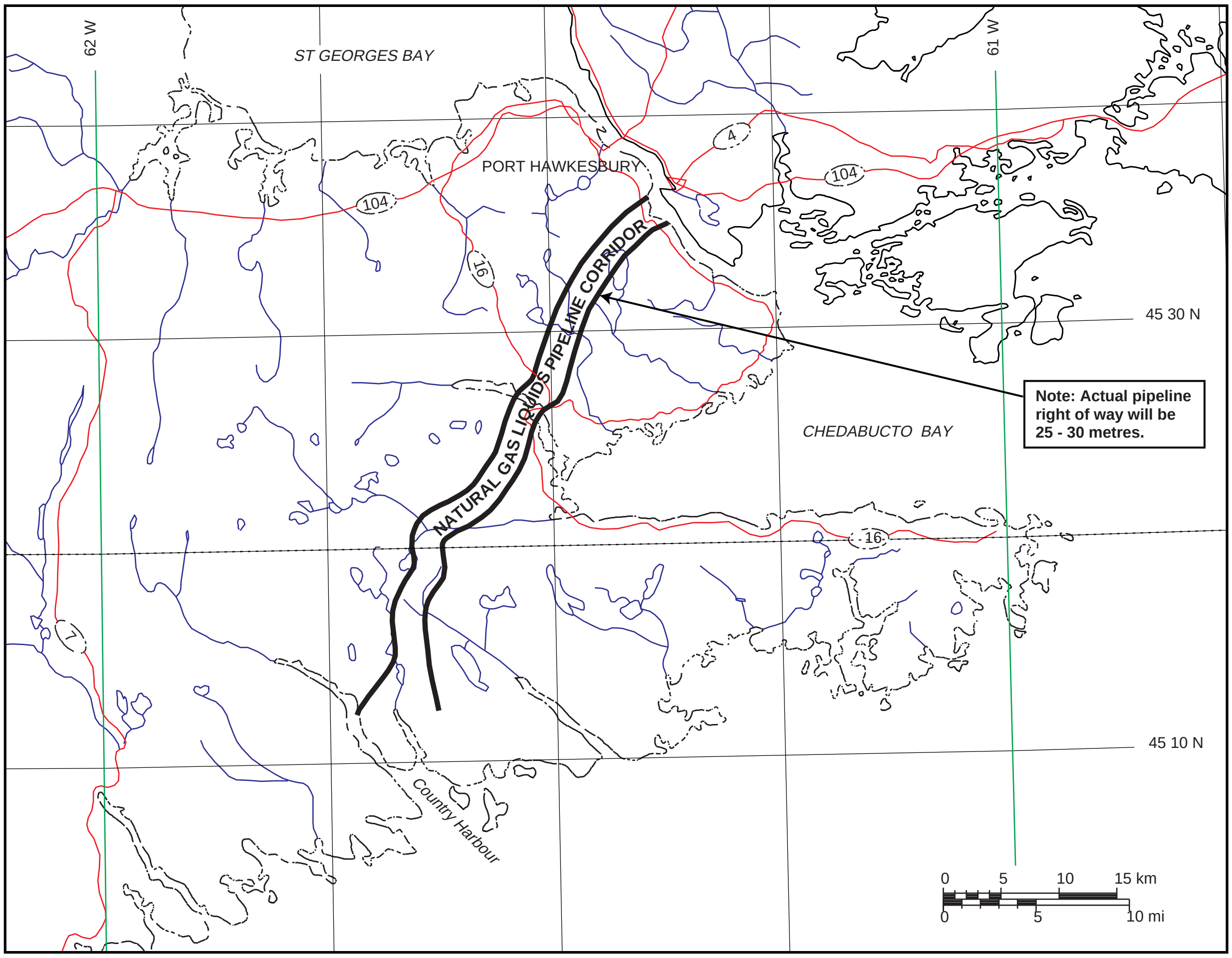

Figure 5.3.6.1: Preliminary Liquids Pipeline Corridor

The pipeline will require a major crossing of the Strait of Canso. Preliminary analysis indicates this can be achieved by either directional drilling or cut trench, as outlined in Part Two of this document (**DPA - Part 2**, **Ref.# 5.3.6.1**). The pipeline will involve several other water crossings. Depending on the facility locations and the route selected, the crossings may include Country Harbour River, Seal Harbour River, Salmon Harbour River, Clam Harbour River and Guysbourough Harbour River at Guysbourough Harbour. Determination of the appropriate method(s) for the water crossings will be completed following final route selection and FEED.

5.4 Production Operations

Detailed operating and maintenance procedures will be prepared during the detailed engineering design and construction phase of the Project. The current plans for operations and maintenance are based on previous experience of the Proponents and their affiliates in Canada, the North Sea and the Gulf of Mexico.

5.4.1 Operations Monitoring and Maintenance

The following operations monitoring and maintenance systems are envisioned:

- process monitoring and control
- fire and gas detection and protection
- rotating equipment bearing monitoring systems
- structural and foundation monitoring system
- essential services monitoring system
- compliance monitoring system
- corrosion monitoring system

5.4.2 Inspection Procedures

Regular, comprehensive visual and non-destructive testing (NDT) inspections will be an integral part of the management program. The inspection requirements for each Project component will depend on the service, manufacturers' recommendations, data obtained from monitoring systems, the operating environment and previous experience. Corrosion monitoring will include intelligent pigging, NDT testing, corrosion probes, and sample coupons.

5.4.3 Logistics

Support logistics for the offshore operation will be provided by helicopters and workboats. Workboats will meet Canada Coast Guard requirements and be suitable for the environmental conditions of the Sable Island area. An opportunity to synergize the level of logistics support may exist while drilling operations are in progress.

Initially, a daily helicopter flight will likely be required for personnel movement and satellite platform work. The schedule may be reduced as operations proceed, particularly with respect to the frequency of satellite platform visits.

Two to three workboats will be required for normal operations. One workboat will make supply trips between the shorebase and the Thebaud platform. A second workboat will be on standby at the Thebaud platform. A third workboat, or acceptable alternative, will be required when the supply workboat is unavailable to provide standby service on helicopter trips to the satellite platforms. All of these vessels will be equipped with full lifesaving and rescue capabilities in compliance with Canadian Coast Guard requirements.

5.4.4 Communications

Reliable communications systems will be installed offshore to ensure efficient operations. A combination of microwave and satellite communication systems is envisioned, but fibre optic cables are also a potential alternative.

5.4.5 Control and Monitoring Systems

The **Sable Offshore Energy Project** will have a reliable distributed control system (DCS) at both the Thebaud platform and the onshore facilities. While the satellite platforms will likely be equipped with individual programmable logic controllers (PLC's) for local control, a SCADA (Status, Control and Data Acquisition) system will also be provided to link with manned operations at Thebaud.

5.4.6 Pipeline Control/Leak Detection System

A leak detection system which meets the requirements of the *CSA Standard Z662-94 Oil and Gas Pipeline Systems* will be provided for the subsea pipeline network. The system that is currently planned will compare the mass flow in and out of pipeline segments over time. Alternatives to this system will be evaluated during FEED.

During the regular transportation of personnel between platforms, the helicopter will overfly the pipeline routes, providing an additional means of checking pipeline integrity.

5.5 Design Criteria

5.5.1 Production Facility Preliminary Design Criteria

Table 5.5.1.1 presents the preliminary design criteria for the Project facilities that are outlined in this Development Plan Application. They include: satellite platforms, interfield pipelines, Thebaud Platform, production gathering pipeline, slugcatcher, gas conditioning plant, liquids pipeline and liquids handling facility.

Table 5.5.1.1: Preliminary Production Facility Design Criteria

Equipment	MOP (kPag)	Pressure Rating	Design Range & Operating (_C)	Flowrate (E3M3/D)	Water (M3/D)	Comments
Venture Platform	13800	Ansi 900#	-20 to 120 / 110	7363	1590	
South Venture Platform	14140	Ansi 1500#	-20 to 120 / 110	1840	397	
North Triumph Platform	13200	Ansi 900#	-20 to 120 / 110	3680	397	
Glenelg Platform	13200	Ansi 900#	-20 to 120 / 110	3115	397	
Alma Platform	13200	Ansi 900#	-20 to 120 / 110	3115	397	
Thebaud Inlet	13200	Ansi 900#	-20 to 120 / 110	6230	555	
Thebaud Platform	12760	Ansi 900#	-20 to 93 / 30	12750	800	

Equipment	MOP (kPag)	Pressure Rating (kPag)	Design Range & Operating (_C)	Length (KM)	Size (mm OD/WT)	Comments
Venture Flowline	13800	14366	-20 to 120 / 100	54	457 / 12.7	Carbon Steel
South Venture Flowline	14140	29979	-20 to 120 / 100	5	219 / 12.7	Carbon Steel
North Triumph Flowline	13200	20264	-20 to 120 / 100	35	324 / 12.7	Carbon Steel
Glenelg Flowline	13200	20264	-20 to 120 / 100	32	324 / 12.7	Carbon Steel
Alma Flowline	13200	20264	-20 to 120 / 100	50	324 / 12.7	Carbon Steel
Thebaud to Shore	11725	13467	-20 to 93 / 20	225	609 / 15.88	Carbon Steel
Slugcatcher	8275	Ansi 600#	-20 to 93/0-20		1220	Carbon Steel
Plant Inlet	8275	Ansi 600#	-20 to 93/0-20			Carbon Steel
Low Temp. Process	6900	Ansi 600#	-45 to 93/ -30			Carbon Steel
Plant Gas Outlet	9930	Ansi 600#	-20 to 49 / 35			Carbon Steel
Hydrocarbon Liquids Pipeline - Pt. Tupper	6900	15108	-20 to 50 / 15	67	219 / 6.4	Carbon Steel
Liquid Fac. Inlet	2800	Ansi 300#	-20 to 93/0-20			Carbon Steel

5.5.2 Regulation, Codes, Standards and Certification

5.5.2.1 Design Philosophy

Where Nova Scotia or Canadian regulations or standards exist (i.e.: CSA) they will be met by the Project design. Where such standards do not exist, the Project design will meet accepted international standards (i.e. American Petroleum Institute(API), Deutsches Industries Normen, (DIN) British Standards (BS)). Where no specific standards exist the **Sable Offshore Energy Project** Proponents' own corporate standards will be met, following the tenets of 'good oilfield practice.'

A list of all known applicable regulations, codes and standards for engineering design and project construction is included in Part Two of this document (**DPA - Part 2, Ref. # 5.5.2.1.1**).

5.5.2.2 Certifying Authority

The *Nova Scotia Offshore Area Petroleum Production and Conservation Regulations* require that a Certifying Authority (CA) be employed by the Proponents to independently assess the compliance of the production facilities and structures with the regulations and other applicable codes and standards. The Project will be subject to a number of regulatory bodies, not all of which require a CA. However, it is anticipated that the CA scope will encompass all of the offshore facilities. The CA will assess design, methods of construction, transportation and installation, and provide material and construction inspections to ensure that the Project is designed and constructed in accordance with applicable regulations, codes and standards. ‘Certificates of Fitness’ will be issued by the CA when it is satisfied that the requirements outlined in the regulations and other standards have been met. The certificates will be issued prior to the application to the **CNSOPB** and other regulatory bodies, where applicable, for final approval of various elements of the Project.

The CA for the **Sable Offshore Energy Project** will be selected from the list in Schedule I of the *Nova Scotia Offshore Certificate of Fitness Regulations*. They will be selected by the Proponents through a tendering process. While effective communication between the project design team and the CA will be critical to the success of the project, the CA will be an independent third party.

5.6 Environmental Criteria

5.6.1 Preliminary Environmental Criteria

Existing data has been compiled to determine the preliminary environmental design for the Project. This data comes from two sources; The *Venture Preliminary Physical Environment Criteria* prepared by Mobil (**DPA - Part 2, Ref. # 5.6.1.1**), describes the physical environment that characterizes the Venture and Thebaud field areas, and the *Sable Gas Preliminary Environmental Study* (**DPA - Part 2, Ref. # 5.6.1.2**) commissioned by Shell includes specific environmental criteria for the North Triumph, Glenelg, and Alma field areas. The preliminary environmental design criteria for the Project is featured in **Table 5.6.1.1**.

Table 5.6.1.1: Preliminary Environmental Design Criteria

Waves and Water levels (100-year return period values)

Parameter	Venture	South Venture	Thebaud	Alma	Glenelg	North Triumph
Chart water depth (m)	20	22	30	70	80	80
Storm tide (m)	0.5	0.5	0.5	0.5	0.5	0.5
Astronomical tide (m)	1.6	1.6	1.6	1.6	1.6	1.6
Storm still water level (m)	22.1	24.1	32.1	72.1	82.1	82.1
Significant wave height (m)	14.7	13.2	12.6	12.6	12.6	12.6
Maximum wave height (m)	17.2	18.8	23.4	23.4	23.4	23.4
Period range (max waves) (s)	14-19	14-19	14-19	14-19	14-19	14-19
Maximum crest elevation (m) above storm still water	14.0	15.4	18.9	14.3	13.8	13.8

Wind (10 m above mean sea level)

Wind Parameter	100-year return period value (m/s)
1 hour mean	41.6
10 minute mean	43.7
1 minute mean	48.7
15 second gust	51.7
5 second gust	54.6
3 second gust	55.7

Current (reference d/D, ratio of depth to total depth below surface)

Reference Depth (d/D)	100-year return period current (cm/s)
0.00	230
0.10	190
0.25	162
0.50	116
0.75	109
0.90	107

The following sections outline the plans for updating and finalizing the environmental design criteria for engineering design.

5.6.2 Environmental Criteria for Engineering Design

5.6.2.1 Meteorological Conditions

The database on meteorological conditions will be updated with, and extended to include, more recent measurements and information from the area. Much, if not all, of this update will come from work summarized in the Environmental Impact Statement prepared for the Project: **Sable Offshore Energy Project**, **Environmental Impact Statement**, **Volume 3.** The design parameters that will be refined are listed below:

- Seasonal Wind Conditions
- Precipitation
- Air Temperature
- Relative Humidity
- Temperature and Salinity
- Sea Ice
- Icebergs
- Sea Spray Icing and Atmospheric Icing
- Operational Winds
- Visibility

5.6.2.2 Tides

Tide modelling for the area has been well developed. Earlier work completed on this subject is sufficient and no further development studies are planned.

5.6.2.3 Extreme Wave Conditions

Earlier studies for Venture used wave models which are now outdated, particularly for the modelling of shallow water wave mechanisms. A recent hindcast study commissioned by the Canadian government, (**DPA Part 2 - Ref. # 5.6.2.3.1**) on a limited number of storm events, used a state-of-the-art third generation wave model which predicts the shallow water wave physics properly. In recent years, a number of severe storms have occurred in this area. This has increased estimates of design level wave conditions. These storms will be included in the hindcast storm population.

A comprehensive wind and wave hindcast study will be performed for the area to produce wind and wave design criteria for the Project. This study will include a state-of-the-art shallow water wave model. It may also be necessary to perform very fine grid computer simulations of wave propagation because of the complex bathymetry in the area. The **Sable Offshore Energy Project** hindcast study will build upon the government study by adding recent storms to the government's hindcast data base. This will be completed through a cooperative exchange of information.

Present estimates of the design wave heights, which are limited by depth-induced wave breaking, are expected to be correct for the 20 to 30 metre water depth locations (Venture, South Venture, and Thebaud). In these locations the storm water depth (the combination of astronomical tide, storm surge, and water depth referenced to a tidal datum) is critical because the design wave height is directly proportional to depth. The storm surge estimates will be revised with information from the new hindcast study. The combination of the spring tidal range and the peak storm surge leads to a conservative design estimate of the deepest water depth. However, for structure design in shallow water it will be equally important to consider a low water level/high wave height condition, as has been done by Mobil in the southern North Sea gas fields. Under these conditions the water depth will be lower and the wave height will also be somewhat lower, but the nature of the shallow water waves may cause the forces exerted on the structure to be larger.

For the 70 to 80 metre water depth sites (North Triumph, Glenelg, and Alma) the wave heights will not be limited by depth-induced breaking. The water depth changes dramatically to deepwater in this area. The shallow water wave attenuation mechanisms are likely to be less effective in decreasing wave heights at these locations than they would be in areas having a more gradual change in water depth. The design criteria for these sites will be based on studies which include the most recent severe storms. This will include the “Halloween Storm” of 1991, where significant wave heights of over 17 metres were measured in deepwater off the Scotian Shelf.

5.6.2.4 Operational Wave Conditions and Normal Wave Conditions

This information will be updated with recent data gathered for the EIS for the Project, and by the results of an earlier Canadian government hindcast study (**DPA - Part 2, Ref. # 5.6.2.4.1**).

5.6.2.5 Wind Speeds

The wind speeds given in the *Venture Preliminary Environmental Criteria* are considerably higher than those found in the Canadian government-sponsored study. The 100 year return period hourly wind speeds at 10 metre elevation presented in these references were 143 and 96 kilometres per hour, respectively. This discrepancy is likely due to the joint probability approach used in the Venture work, where extreme wind and wave conditions were assumed to occur simultaneously. An ‘associated’ wind approach, where less severe winds occur in conjunction with the extreme wave conditions, was used in the government work. Differences of this magnitude will be resolved to establish detailed design criteria for the Project. This will be accomplished by using the wind hindcast results derived in the extreme wave hindcast study discussed above.

5.6.2.6 Currents

Existing design current values for the Project are considered too high for a number of reasons. First, they were determined by vectorially adding the extreme tidal currents, extreme background currents and wind-driven currents calculated from the extreme wind speed values. The likelihood of all these conditions occurring at the same point in time is quite small. Second, current values are independent of the wave conditions and therefore extreme currents are not necessarily the currents associated with peak wave conditions. The Proponents’ experience in other parts of the world and in recent computer modelling of currents, indicates that extreme waves and extreme currents do not occur simultaneously. Third, the current speeds change significantly with depth at the same location. Using the given surface speeds will lead to an unnecessarily high design value.

To address these issues, a current model study to develop design criteria values will be performed. This will likely build on existing current modelling work done by the Bedford Institute of Oceanography in Dartmouth, Nova Scotia.

5.6.2.7 Ice and Icebergs

As with the meteorological and oceanographic information, the ice data bases need to be updated. The existing database was compiled in the late 1970s and early 1980s. Although the International Ice Patrol reports higher iceberg counts off the East Coast of Canada in the period between 1984 and 1993, the probability of occurrence of icebergs in the Project area is very low. They will not be considered as a design criteria, but will be addressed under operational contingency planning. A design criteria for sea ice will be specified.

5.6.2.8 Tsunamis

Earlier work indicated that this phenomenon will not control design. No further work is anticipated.

5.6.2.9 Marine Fouling

A study will be performed to define the design fouling levels. Data available from the existing Cohasset-Panuke operation will be analyzed and incorporated.

5.7 Geotechnical Criteria

5.7.1 Preliminary Geotechnical Criteria

Existing data has been compiled to determine the preliminary geotechnical design criteria for the Project. This data comes from two sources; The *Venture Preliminary Geotechnical Criteria* prepared by Mobil (**DPA - Part 2, Ref. # 5.7.1.1**), describes the geotechnical data that characterizes the Venture and Thebaud field areas, and the *Sable Gas Preliminary Geotechnical Study*, (**DPA - Part 2, Ref. # 5.7.1.2**), commissioned by Shell includes specific criteria for the North Triumph, Glenelg, and Alma field areas. The preliminary geo-technical design criteria for the Project is featured in **Table 5.7.1.1**.

Table 5.7.1.1: Preliminary Geotechnical Design Criteria

Sediment Transport (30-year design life)

Location	Component	Local Scour (m)	Dishpan Scour (m)	Sand Ridge Migration (m)	East Bar Migration (m)	Megaripples & Sand Waves (m)	Total Scour (m)
Venture	Legs	2.8	6.0	1.3	0.6	1.0	11.7
	Risers	1.5	6.0	1.3	0.6	1.0	10.4
	Conductors	1.5	6.0	1.3	0.6	1.0	10.4
South Venture	Legs	2.8	6.0	0.5	0.6	1.0	10.9
	Risers	1.5	6.0	0.5	0.6	1.0	9.6
	Conductors	1.5	6.0	0.5	0.6	1.0	9.6
Thebaud	Legs	2.8	6.0	1.0	-	1.0	10.8
	Risers	1.5	6.0	1.0	-	1.0	9.5
	Conductors	1.5	6.0	1.0	-	1.0	9.5

Earthquake Peak Ground Motions (all platform locations)

	Acceleration (m/s^2)	Velocity (cm/s)	Displacement (cm)
Operating Level Earthquake	0.4	2	0.6
Safety Level Earthquake (Near-field)	1.47	12	3
Safety Level Earthquake (Far-field)	1.47	20	16

The Proponents will update and finalize the geotechnical design criteria for FEED in the following ways.

5.7.2 Geotechnical Conditions and Seismicity

The geotechnical conditions on the Sable Island Bank are relatively uniform. The surficial geology of the bank top consists of Sable Island sand and gravel with occasional interbedded clays. A number of boreholes have been drilled, primarily for oil and gas exploration and also for scientific research. These boreholes are relatively uniform from location to location. All existing, publicly available data on Sable Bank surficial geology has been compiled in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.1**).

A localized field boring program was conducted around Venture and this data is considered to be indicative of this area. This information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.7.2.1**). Information has also been obtained for the Thebaud P-84 well, which is close to the planned central platform site. The sea bottom at all planned platform sites is expected to be dense sand with excellent bearing capacity. In fact the soil borings at Venture and Thebaud consisted almost entirely of sands and gravels with the exception of a few thin clay layers below 40 metres penetration.

If site specific geotechnical data is not available for each platform site, a soil boring and analysis program will be performed prior to detailed design. Site specific data will be necessary to properly design jacket piles, and evaluate pile and conductor driveability, as well as, jacket stability (mudmat capacity). This will be done prior to driving the piles. As part of these studies, the regional seismic data will be reviewed to incorporate any advances in site seismicity characterization.

5.7.3 Bathymetry, Scour and Sediment Transport

The approximate water depth at each of the platform sites is as follows:

Field	Water depth (metres)
South Venture	20
Venture	22
Thebaud	30
North Triumph	80
Alma	70
Glenelg	80

Figure 5.7.3.1 illustrates the Sable Island area bathymetry. Detailed bathymetric surveys have been conducted across the Scotian shelf for oil and gas exploration and for scientific research. The seabed is known to be dynamic in many areas around the island with evidence of storm-current generated sand ridges, sand waves and megaripples. Conversely, some of these features could also be relict (inactive/ancient). All existing, publicly available data on Sable Bank bathymetry has been compiled in Part Two of this document (**DPA - Part 2, Ref. 5.2.6.1.1**).

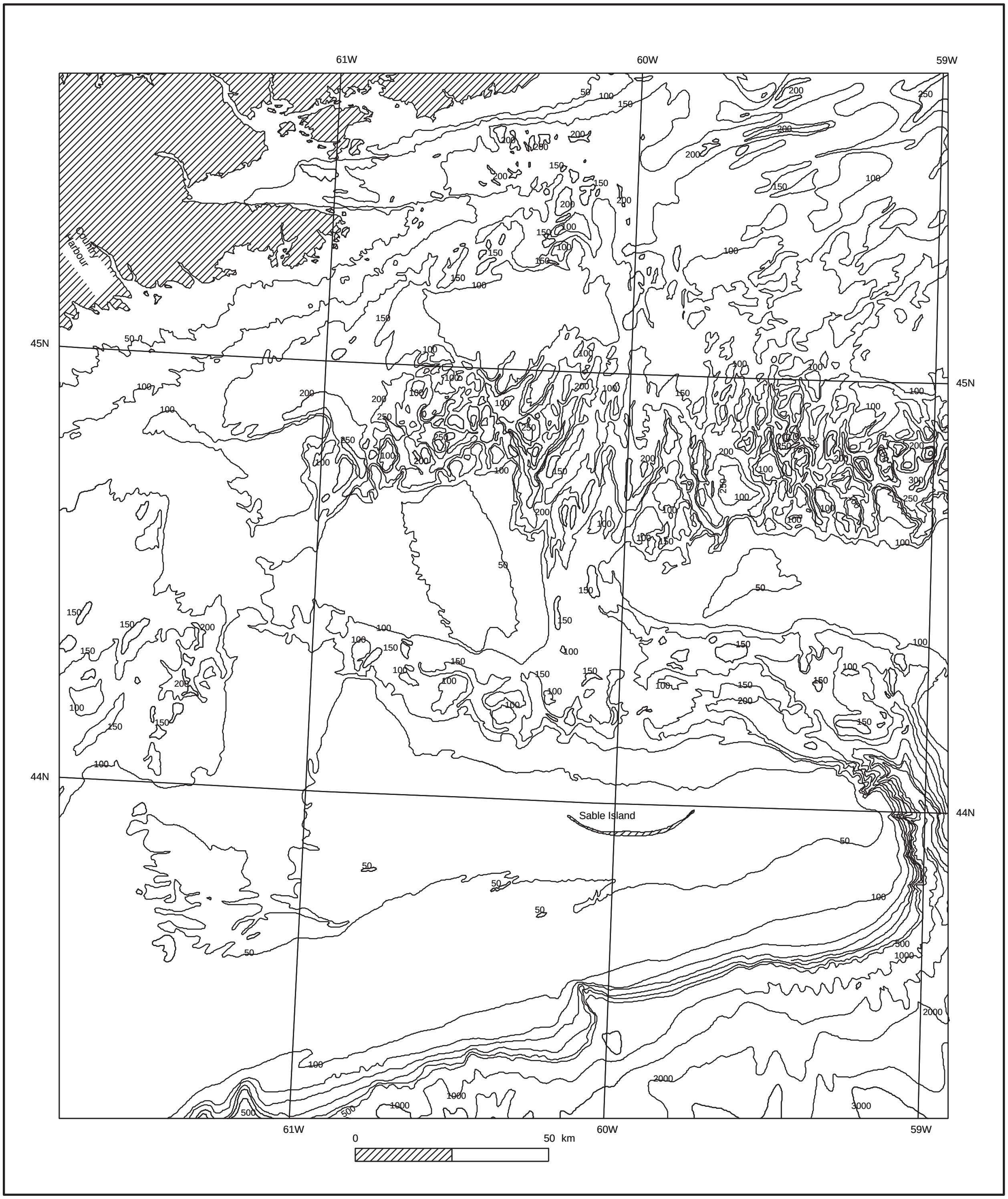

Figure 5.7.3.1: Sable Bathymetry Map

Most existing bathymetry data was obtained prior to 1985. Navigation techniques at that time were less precise than presently available. As a result, accurate rates of sand ridge and sand wave migration could not be determined. Due to advances in water depth measuring technique (Swath), and positioning technology (differential global positioning systems (DGPS)), all platform sites and the intrafield pipeline routes will be resurveyed prior to detailed final design of the pipelines. An overview of the planned survey activities in the next two years is as follows:

5.7.3.1 Baseline Swath Mapping

This survey was completed in the fall of 1995 and the results will establish an accurate swath bathymetric data set for comparative purposes with future surveys. This will accurately determine the extent of bottom feature movement over time. The Thebaud to Venture interfield pipeline corridor was the main focus of the survey. This area is characterized by numerous sand ridges, sand waves and megaripple fields. Corridors in three different water depth ranges were surveyed to determine whether feature migration diminishes with increasing water depth.

5.7.3.2 Other 1995 Swath Survey Objectives

A Country Harbour approach area of approximately three and a half by eight kilometres, located approximately 20 kilometres offshore, has been surveyed to help define a clear route through outcropping bedrock. Previous surveys indicated that a continuous channel is probable. However, the results were not definitive because of the survey technology available at the time. Swath and backscatter data will be utilized to locate an open corridor and define the best pipeline route.

The near-shore approach to Country Harbour/Issac's Harbour has been surveyed to better define local bathymetry and to confirm the lack of rock outcrops and other hazards. Previous surveys emphasized Betty's Cove as the preferred landfall. Other areas within the harbour approach have less coverage. This survey is expected to provide complete bathymetric detail and define rock outcrops.

The preferred pipeline route identified in the mid-1980's has been resurveyed with Swath to improve the bathymetric data density and better identify any rough bottom areas with potential for free spans. This was completed while the survey vessel was in transit between Country Harbour, the Country Harbour approach, and the Thebaud field.

5.7.3.3 Seabed Scour Monitoring

The **Sable Offshore Energy Project** is participating in a joint research program with the Atlantic Geoscience Centre (AGC), of the Bedford Institute of Oceanography to deploy their 2D DODO (Depth of Disturbance Observatory) system near Sable Island. A 3D DODO system is also being developed during fall and winter of 1995/96. The device is a seabed frame with multiple instruments to monitor scouring of the seabed through sector scanning sonar, wave and current meters and sand suspension backscatter equipment. The equipment will be deployed in an active sand wave area near the existing Cohasset-Panuke facilities, where previous data has been gathered by AGC. Further insight into seabed dynamics, particularly during storm conditions, will be gained by this study.

5.7.3.4 Swath Re-Survey, Subbottom Data Gathering

The baseline survey areas will be resurveyed after the winter storm season (spring 1996) to assess movement of large seabed features. Sidescan sonar and subbottom profiling equipment will also be deployed to determine if the depth of the mobile sediment layer can be determined by geophysical means. Cone penetration tests (CPT's) may also be attempted to resolve this question. CPT's directly measure density state whereas geophysical profiling represents an economic means to extrapolate CPT results, providing that a reasonable correlation can be established. The depth of the mobile layer will influence pipeline burial depth requirements.

Potential for pipeline erosion will also depend on sand grain size, density state and permeability. Loose sediment may be subject to liquefaction or suspension during severe storms. Thus, geotechnical data is required to define both the sediment type and density state along the entire pipeline corridor. Accurate geotechnical data, as well as wave and current data, will be required to define the amount of weight coating required for pipeline on-bottom stability and to define the extent and depth to which the pipeline will be buried.

5.7.3.5 Swath and Subbottom Follow-up Resurveys

After reviewing the repeat Swath data, additional surveying may be required to check seabed conditions immediately following a severe storm (i.e. allowing no time for backfill or return to equilibrium), or after a second complete winter season to evaluate how seabed features change from year to year. The need for such surveys, which would be conducted during the winter of 1996/97, will be evaluated after review of the first repeat survey data. Additional surveys may also be required for reconfigured or rerouted pipelines or to better define possible platform installation impediments at their proposed locations.

5.7.4 Local and Dishpan Scour

In addition to regional sediment transport mechanisms described above, local and dishpan scour can occur about jacket structures. A study included in Part Two of this document (**DPA - Part 2, Ref. # 5.7.4.1**), concluded that sediment transport about foundation piles would be significant. Design scours of 9.1 to 11.7 metres were predicted to occur around vertical members ranging from 0.76 to 1.4 metres in diameter. This was a combination of local, dishpan, sandridge and East Bar migration, plus megaripples and sandwaves. These design values will be checked against more recent experience with the Cohasset-Panuke project structures and accounted for in platform design. Scour mitigation techniques used in the North Sea, as well as at the Cohassett-Panuke project, will also be reviewed.

5.8 Assessment of Alternative Development Plans

5.8.1 Eliminated Alternatives

Although many alternatives have been suggested, five of the most promising alternative development plans were screened for the **Sable Offshore Energy Project**, prior to the selection of this Preferred Development Plan. The **Eliminated Alternatives** are listed below:

- Electric power generation
- LNG (Liquified Natural Gas)
- LHG (Liquified Heavy Gas)
- Natural Gas conversion technologies
- Offshore Gas Plant

5.8.1.1 Electrical Power Generation

Three alternative electrical power schemes have been evaluated by the Nova Scotia Department of Natural Resources, Nova Scotia Power and TransAlta/Pan-Alberta. (**DPA - Part 2, Ref. # 5.8.1.1.1**). They used coal/natural gas or gas as fuel. The electrical power would have been delivered to, and sold in, the New England market. These proposals were based on significant growth in electrical demand in northeastern American markets but did not anticipate the level of cogeneration plant development which has occurred in the region.

Installing export power generation facilities in Nova Scotia presumes that electrical generation is more economical in Nova Scotia than in the northeastern United States. Economies of scale for plant construction in the northeastern states result in, at best, a neutral cost advantage. The cost of transmission facilities (gas or electric) are roughly the same. However, natural gas transmission has efficiencies approaching 98 percent (the 2% loss represents fuel gas used for compression) while electrical schemes are about 95 percent efficient. There are stronger business and efficiency advantages to providing gas to the marketplace and letting the local customers decide on usage. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.8.1.1.1**).

5.8.1.2 Liquified Natural Gas (LNG)

The manufacturing of Liquified Natural Gas (LNG) offshore, and transportation of the LNG and condensate to markets by tanker has also been studied as an alternative.

Offshore manufacturing of LNG is a complex process that would substantially increase the size of the Thebaud platform, and thus Project cost. Offshore storage and loading facilities would also be required. LNG projects generally require high production rates (over 28 E6M3/d) to support the large capital investments required. LNG makes sense if the gas is to be shipped over long distances. The comparatively short distance from the **Sable Offshore Energy Project** to the North American gas pipeline grid makes it attractive to tie into this system by pipeline, both for immediate utility and future growth. LNG is not currently competitive in the North American market except for limited peak shaving opportunities. More detail on the LNG alternative is included in Part Two of this document (**DPA - Part 2, Ref. # 5.8.1.2.1**).

5.8.1.3 Liquified Heavy Gas (LHG)

In this alternative, Liquified Heavy Gas (LHG) would be manufactured offshore and transported by custom-built tankers to markets. A propane solvent must be recycled by tanker to the field as part of this process.

Mobil investigated the application of LHG technology for the Venture Development Project. Unlike LNG, which relies on cryogenic temperatures, LHG relies on refrigeration at a higher temperature and pressure to reduce the volume of gas to be shipped. This pressure is high enough to require that the gas be shipped in a specially constructed tanker. While LHG production facilities would result in net savings through the elimination of the production gathering line, slugcatcher, gas plant, natural gas liquids pipeline and future compression; the cost of constructing LHG storage, shipping and receiving facilities would be substantially higher than the savings identified. The economies of scale of an LHG project are likely similar to LNG. LHG development has not been pursued since 1989. This study is included in Part Two (**DPA - Part 2, Ref. # 5.8.1.3.1**).

5.8.1.4 Natural Gas Conversion Alternatives

Other alternatives for conversion of gas have been investigated by Mobil and Shell, and their affiliates, for projects of similar scale elsewhere in the world. This work comes to the same conclusion about other gas conversion technologies as that drawn for LNG and LHG. This information is included in Part Two (**DPA - Part 2, Ref. # 5.8.1.4.1**).

5.8.1.5 Offshore Gas Plant Location Alternatives

In addition to the Preferred Development Plan, two alternatives to an onshore gas processing location were investigated. The two eliminated alternatives are:

- Offshore natural gas processing plant;
- Natural gas processing plant on an artificial island or Sable Island.

A brief description of each processing alternative follows.

5.8.1.5.1 Offshore Gas Plant Platform

An offshore gas plant would involve consolidating all gas processing to the central production platform at Thebaud. Sales gas and NGL's would be transported to shore in separate pipelines. The comparison of this case to the onshore base case was made on the basis of the same landfall for both. The offshore plant alternative appears, within estimating accuracy, to have essentially the same capital and operating cost profile as the onshore plant.

While the offshore plant and onshore plant were equivalent for most of the selection criteria evaluated, the following key criteria favoured the onshore plant:

- Reliability/Availability/Maintenance
- Operating Flexibility (Compositional)
- Ease of Expansion
- Safety Considerations
- Nova Scotia-Canada Benefits

An offshore plant is difficult to maintain and operate at a high level of reliability, primarily due to access restrictions. If gas composition varies considerably from the design basis, the modifications that must be made to the plant would be much more difficult and costly to undertake offshore. Similarly, space for expansion is constrained offshore. The risks associated with an offshore plant are always higher than those for an onshore plant, given the number of options for escape from an onshore plant. Finally, an onshore plant assures a significant level of Nova Scotia and Canada benefits that cannot be guaranteed with an off-shore plant. Further information is included in Part Two (**DPA - Part 2, Ref. # 5.8.1.5.1.1**).

5.8.1.5.2 Processing Plant on Artificial or Sable Island

Previous studies assessed the feasibility of constructing an artificial island in the Sable Island area for gas processing facilities. While technically feasible, environmental concerns and costs eliminate this plan as a **Development Alternative**. There have also been studies on developing an area of Sable Island itself, with the construction of a wharf and breakwater. This alternative was also eliminated because of environmental concerns related to physical disturbance of the island. Furthermore, the project principles also eliminate this alternative. This information is included in Part Two (**DPA - Part 2, Ref. # 5.8.1.5.2.1**).

5.8.2 Pipelines

A number of pipeline developments were investigated prior to the selection of the Preferred Development Plan. A list of the eliminated alternatives follows:

- The transportation of gas and condensate through a single, dense phase subsea pipeline to Nova Scotia.

- The transportation of dehydrated gas and unstabilized condensate through separate subsea pipelines to Nova Scotia.

- The transportation of dehydrated gas by subsea pipeline to a landfall at Boston, and the transportation of gas condensate by tanker to markets.

- The transportation of dehydrated gas and condensate to Nova Scotia by separate subsea pipelines.

A discussion of each of these eliminated alternatives follows below:

5.8.2.1 Single Subsea Dense Phase Pipeline

The transportation of dense rich gas involves significant compression. This must be installed at initial start-up at a considerable capital and operating cost penalty. The only capital savings occur with the elimination of the slugcatcher. This alternative has only proven attractive in the North Sea where substantial reinjection compression, and the capability to remove condensate and ship separately, already exist. This is not the case for the **Sable Offshore Energy Project**. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.2.6.1.2**).

5.8.2.2 Separate Subsea Gas and Unstabilized Condensate Pipelines

This alternative would require a smaller slugcatcher facility on the gas line at the landfall to separate liquids condensing from the gas stream. Slugging could occur on the unstabilized condensate line, unless it was pumped to avoid flashing. The use of two pipelines offers little technical advantage over the Preferred Development Plan, but costs considerably more (**DPA - Part 2, Ref. # 5.8.2.2.1**).

5.8.2.3 Single Subsea Sales Gas Pipeline to Boston

This alternative would have an offshore sales gas pipeline route direct to Boston. It would be dependent on an offshore gas plant and would preclude marketing of gas in Nova Scotia and New Brunswick. Offshore condensate storage and tanker loading is required. While technically feasible, and the shortest pipeline route to markets in the northeastern United States, the cost estimating accuracy for this option is not equivalent to other options. Very little is known about the prospective pipeline route, which runs just to the north of George's Bank. Transportation of condensate by tanker presents a greater environmental risk than by pipeline. The required storage and loading system would increase the offshore costs considerably, particularly when a separate LPG product is considered. While capital cost is competitive on a total project basis, the gas marketing implications of bypassing Nova Scotia, New Brunswick and Maine rule this option out. Further information is included in Part Two of this document **(DPA - Part 2, Ref. # 5.8.2.2.1**).

5.8.2.4 Separate Subsea Sales Gas and Stabilized Condensate Pipelines

This pipeline option is connected to the offshore gas plant option discussed in the previous section. At landfall, the gas line ties-in to the transmission pipeline. The condensate is routed through a buried pipeline overland to Point Tupper. This option is not required with the elimination of the offshore plant option. Further information is included in Part Two of this document (**DPA - Part 2, Ref. # 5.8.1.5.1.1**).

5.8.3 Satellite Platform Development Alternatives

The Project design philosophy for the satellite platforms is to minimize both capital and operating costs by minimizing processing at the satellites. The main challenge is to effectively deal with produced formation water.

Alternative separation technologies were considered for water treatment. These included centrifuge separators, induced gas flotation cells, caisson pipe separators and Plate Interceptors (Parallel and Corrugated). Centrifuge separators may produce marginally better effluent but require a higher level of maintenance and operator attention than is practical for unmanned operations. Induced gas flotation cells are more complex than hydrocyclone separators but produce an effluent of no better quality. They also require high levels of operator attention and maintenance. Pipe caisson separators, a simple standpipe with a hydrocarbon pump off, do not consistently achieve the same level of hydrocarbon removal as do hydrocyclone separators. Plate Interceptors, Parallel and Corrugated, have been effectively applied in the Gulf of Mexico. Potential concerns are that they are most effective with larger hydrocarbon droplet sizes, higher gravity hydrocarbons and relatively clean water. Droplet shearing associated with large pressure drop across production chokes may preclude utilization of this technology.

Development Alternatives that were considered included collection and treatment of water at the central production platform at Thebaud and treatment on-shore. Treatment at the central production platform or onshore would require very large volumes of hydrate and corrosion inhibition injection at the satellite platforms and would result in an increased pressure drop in the pipelines. The gas also cools in the pipeline and treatment at the lower temperature would be less effective. Although treatment by a single, larger hydrocyclone unit may be marginally less costly, the lower efficiency at the lower temperature offsets this advantage. Further information is provided in Part Two of this document (**DPA - Part 2, Ref. # 5.8.3.1**).

Separate gas and liquid (water/condensate) pipelines from each satellite were also reviewed. All water would be treated at the central production platform. The water treatment issues previously discussed, additional pipeline cost and serious concerns of corrosion in the gas pipeline make this alternative unattractive. The separation of hydrocarbon liquids from the gas has a detrimental effect on any corrosion inhibition program as they are expected to act as a buffer from corrosion by providing a stable film and acting as a carrying agent for corrosion inhibitors. The presence of condensed water from the cooling of the gas would still require both hydrate and corrosion inhibition in the gas line. Further information is provided in Part Two of this document (**DPA - Part 2, Ref. # 5.8.3.2**).

Hydrate inhibition using methanol or kinetic hydrate inhibitors was also reviewed. Methanol injection presented special challenges for recovering the injected volume from the gas, hydrocarbon liquids and condensed water. Vaporization and liquid hydrocarbon losses tend to be high from methanol whereas monoethylene glycol (MEG) has extremely low solubility levels in these phases. Methanol is normally the inhibitor of choice at temperatures below -40°C, due to viscosity concerns for glycol, but this is of little benefit offshore. A recovery process would require installation of a refrigeration system at Thebaud and, without a suitable source of cooling, this was not found to be economical. Kinetic hydrate inhibitors, while required in less volume than MEG, are non-recoverable and therefore not currently cost competitive. The corrosion concerns outlined above remain with these alternatives. Further information is provided in Part Two of this document (**DPA - Part 2, Ref. # 5.8.3.1**).

5.8.4 Landfall Alternatives

There were three landfall and onshore facility site alternatives investigated prior to the selection of the Preferred Development Plan. Background information on these alternative sites is included in Part Two of this document (**DPA - Part 2, Ref. # 5.8.4.1**). The two eliminated alternatives are described below:

- Landfall: Country Harbour/Gas Plant: Point Tupper

- Landfall: Port Richmond/Gas Plant: Point Tupper

The alternative offshore pipeline corridors are shown in **Figure 5.8.4.1**. These alternatives were eliminated in favour of the Country Harbour landfall / Country Harbour Gas Plant / Point Tupper Liquids Processing Facilities for the following reasons:

- The pipeline route to Country Harbour is the shortest practical route from Thebaud to shore. This results in the lowest cost offshore pipeline option for the Project. The Preferred Development Plan remains the most cost effective alternative even when the cost of the liquids line to Point Tupper, and the capital credit for the use of existing infrastructure that could be accessed by a gas plant located there, are considered.

- The seabed profile and bottom conditions of the Country Harbour route also reduce the cost of the pipeline relative to the Point Tupper route.

- The cost of the Preferred Development Plan is less than the cost of an offshore pipeline to Country Harbour with a pipeline that continues overland to a plant site at Point Tupper. In this case the entire pipeline from Thebaud to Point Tupper would have to be one pipe size larger.

- The Country Harbour route avoids several offshore fishing banks and shellfishing areas. The pipeline is routed along less sensitive fisheries areas between Sable Island and the landfall than the offshore route to Point Tupper. This conclusion is based on input from fisheries groups and bathymetric mapping.

- The risk of anchors from large ships contacting the offshore pipeline is lower with the Country Harbour route. Also, the Chedabucto seismic fault line (presently inactive) along the Point Tupper offshore route will be avoided. This gives the Country Harbour route a safety advantage.

- Having the processing facilities split between Country Harbour and Point Tupper will take advantage of the local infrastructure at Point Tupper. The existing marine terminal and liquids storage capacity at Point Tupper facilitate liquid product disposition.

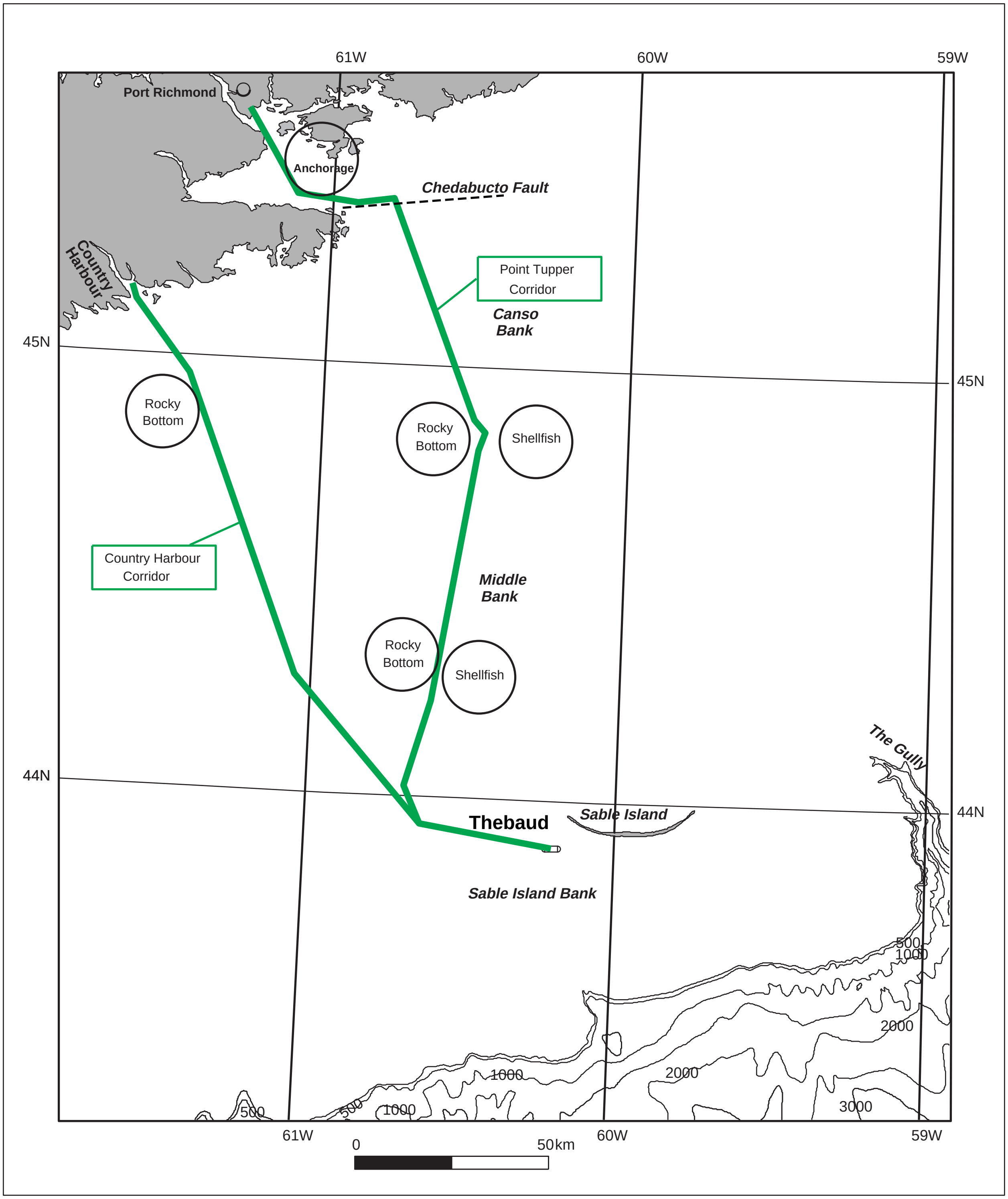

Figure 5.8.4.1: Alternative Offshore Pipeline Corridors

6.0 CONSTRUCTION AND INSTALLATION

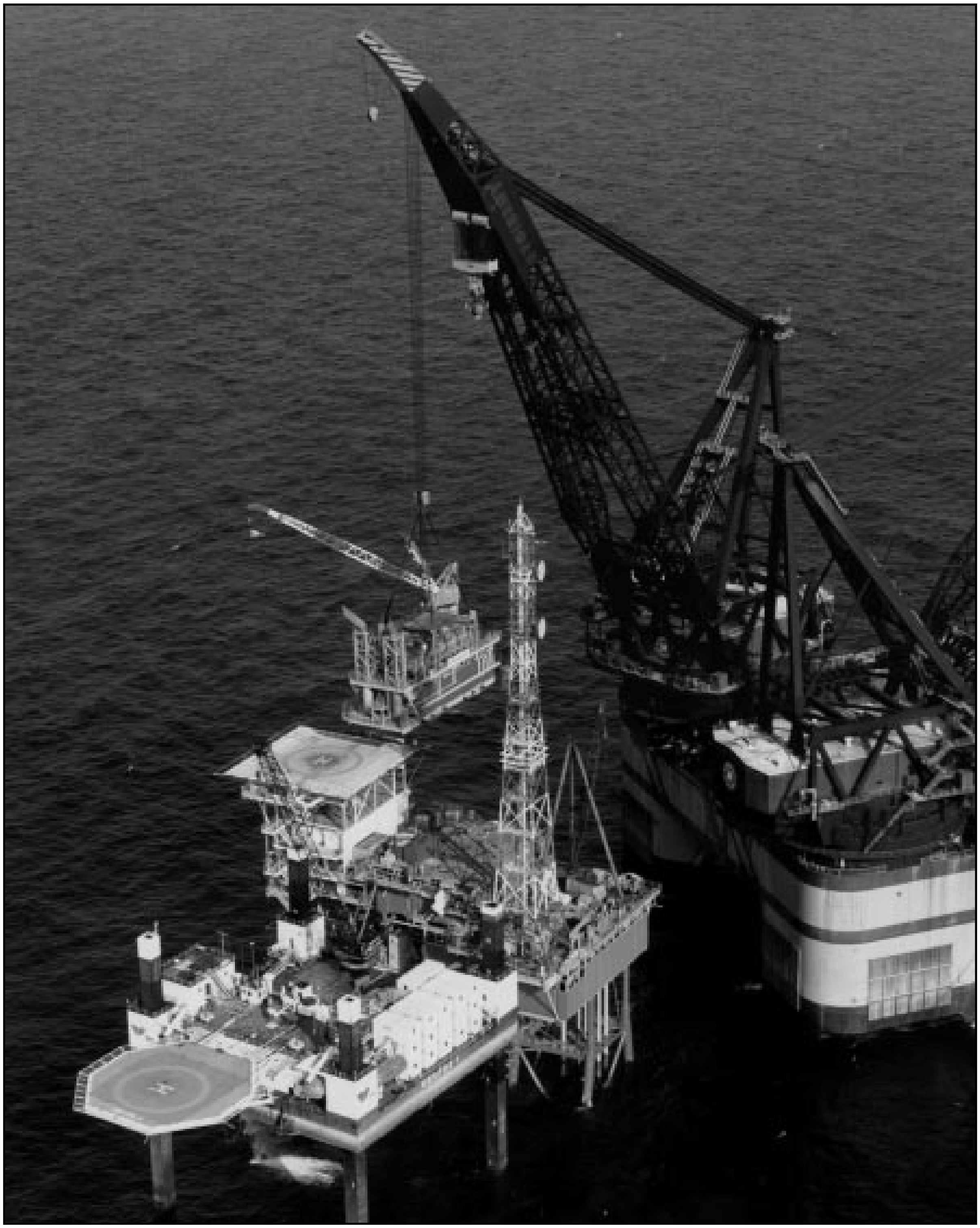

Photo Courtesy: J. Ray McDermott

Figure 6.0.1: A Heavy Lift Vessel Installing a Compressor Module At An Offshore Platform. In the foreground is a construction support jack-up.

6.1 Management Philosophy

Sable Offshore Energy Project management philosophy is based upon the belief that a successful outcome can best be achieved by harnessing the skills and experience of employees of the Project Proponents and participating contractors to create a close team with common goals. The objective is to establish a management structure and Project execution plan that will assure a quality product at low cost within an acceptable schedule. A primary activity leading up to the submission of the Development Plan Application (DPA) has been a series of dialogues between Project Proponents and prospective contractors. The Proponents have also discussed the procedures for recently contracted projects with other major operators, to take advantage of their experience in the continuously evolving contracting market. A concept of ‘risk and reward’ sharing between the Proponents and their contractors is being developed to identify benefits to the Project.

The Proponents of the **Sable Offshore Energy Project** recognize that a high standard of compliance with the regulatory requirements for safety and environment is inherent to any project execution and management structure plan, and will honour the benefits provisions in the *Accord Acts*. Technical excellence in design and construction, and full compliance with the appropriate regulatory and industry codes is a Project goal.

6.2 Construction Schedule

Commencement of the Front End Engineering Design (FEED) is planned to occur in 1996. The Project construction is projected to take place between July 1997 and November 1999. Construction phases are as follows:

Commencement of Front End Engineering Design (FEED)	Mid 1996
Commencement of Detailed Engineering, Fabrication and Construction	July 1997
Commissioning and Start-Up	September - October 1999
Production	01 November 1999

There is little contingency time in this schedule. In the FEED period, prior to the Development Phase decision, some ‘long lead’ items may require early purchase in order to preserve the schedule. The **Sable Offshore Energy Project** Proponents would be exposed to cancellation charges should the project not proceed. The commencement of FEED is not likely to be approved until Regulatory and Fiscal terms and conditions are fully defined, and reasonable certainty of approval of the DPA is assured. Completion of project construction by the end of 1999 is based upon a determination of the markets in 1997 for produced gas. The Proponents assume the requirements of the U.S. Federal Energy Regulatory Commission (FERC) for the export pipeline can be satisfied within the projected time-frame. Further refinement of the schedule will continue after construction begins.

6.3 Contracting Philosophy

The initial production phase of the current plan involves the construction of three offshore platforms, interfield pipelines, production gathering pipeline feeding the gas plant, an onshore gas plant and a natural gas liquids handling facility. The preferred contract strategy is to enter into a contract with a highly competent and experienced engineering contractor to provide engineering, project management and procurement services through the Front End Engineering Design (FEED) stage. Provisions in the contract will allow the services to continue through the Construction phase into the first few years of Production should the **Sable Offshore Energy Project** receive Proponent approval to go ahead.

Competitive selection processes or bids are scheduled to be issued for various construction and installation facilities during the latter stages of FEED. Selected bidders may be invited to participate in an 'alliance.' They will be invited to take part in an exercise to improve project engineering and execution plan, and to establish a project 'target cost.' This target cost will be one of the main factors in the Proponents' decision to go forward with the Project. An alliance, for these purposes, is an agreement by the Proponents and the contractors to share the financial risks and rewards of the Project. A sum of money, funded from potential project savings accrued by virtue of the 'alliance' approach, will be set aside and shared according to construction outcome. The agreed reward formula will also encompass quality, safety and performance. All parties will benefit from a cost underrun if the Project meets the targeted schedule; all will lose if there are delays or cost overruns. The net effect is to reward team work and encourage efficient practices.

The onshore portion of the work may be split away from the offshore portion and issued as a separate contract.

These decisions have not been made at this point in time. The Proponents will continue to define an agreed upon development plan basis and undertake further dialogues with prospective contractors. The objective is to determine the greatest benefit to the Project, in terms of both cost and schedule; and to comply with the benefit provisions of the *Accord Acts*.

A questionnaire to prospective engineering contractors has been issued, inviting them to qualify for the FEED, project management and procurement portions of the Project. Engineering contractors were selected based on recent experience with similar work, corporate strength, and their degree of interest in undertaking work on behalf of the Project in an Alliance. The questionnaire is a means of determining these qualifications; as well as other important issues such as safety and environmental record, quality control, and Nova Scotia/Canadian content. Their responses to the questionnaires are analyzed, and further discussions with contractor(s) have taken place, and a contractor is being selected. Front End Engineering Design (FEED) is planned to commence on Stage 3 approval by the Proponents. At that time, the framework for the alliance structure and compensation package will also be formulated.

All contracts for fabrication, supply and installation during construction will be offered for tender to prequalified contractors on the basis of free, open and international competition. The combination of quality, safety performance and management, cost and delivery, representing 'best value' is the most important criteria for contract award. Potential contractors will be made fully aware of the Project criteria and must demonstrate their compliance with the Project policies.

6.4 Project Team

An integrated team of qualified personnel from the Proponents and the selected engineering contractor will lead the development of the Project through FEED to completion. As the Project proceeds and the scope expands, the team will expand to include other engineering specialists, fabricators, construction contractors and suppliers. Executive and technical roles will be determined on a "best person for the job" basis.

The **Sable Offshore Energy Project** team will be augmented, as required, with specialists from the areas of Environmental Affairs, Loss Prevention and Operations. Input from these disciplines is required at all stages of project design and execution to ensure that our standards of Environmental, Health and Safety are maintained. The specialists will be involved in Hazard and Operability (HAZOP) reviews, Process And

Instrumentation Diagrams (P&ID) reviews, and Operational Accessibility and Maintenance studies. Team members and visiting specialists will be nominated on the basis of skill, experience and availability.

The make-up of the Construction phase team will depend upon the strategy of the Construction contract. A larger contribution of personnel by the Proponents will be required than in the FEED stage. The principles of an integrated team, and the Proponents' high standards, will remain the same.

6.5 Project Execution Plan

The Drilling and Construction stage of the Project will begin with one or two drilling rigs at the proposed platform locations. Development wells are most likely to be drilled through templates or wellhead jackets placed on the sea floor. The templates are put in place to ensure the correct spacing of the well casings where the platforms will be installed. The uncompleted wells will be temporarily suspended with casings detached above the sea floor. At the time of installation, steel jackets with casing guides, spaced to match that of the casings, will be positioned over the wells and piled to the sea floor. Should wellhead jackets be used, then the wells will be suspended by plugging downhole and at the surface, and the wellheads left in place.

While drilling is in progress, engineering design, procurement and fabrication will begin on the facilities to be installed offshore. Under the current Development Plan, the central platform to be placed at Thebaud will consist of an eight-pile steel jacket and an integrated deck, estimated, at this time, to weigh about 4500 tonnes. The Venture platform will have six piles and a deck-weight of about 2500 tonnes. A minimal facilities platform at North Triumph will have a deck weight of about 1100 tonnes. **Figure 6.5.1** illustrates an example of offshore platforms that are similar to those proposed for the satellite fields.

Figure 6.5.1: Example of Offshore Platforms

There will be competitive tenders issued on the international market for construction of the platforms and jackets. Consequently, they may be built in various locations throughout the world. The various components of the facilities may, depending on market forces, be constructed in several places as well. The Thebaud deck is the largest and most complicated unit. It will require a large, fairly sophisticated waterside yard for fabrication. There is generally more flexibility for the construction of the other units, although covered construction space is required to fabricate and outfit the integrated decks. Open yard space is suitable for jacket construction; with the requirement that sufficient crane lift and height capacity are in place to erect the jackets. **Figure 6.5.2** illustrates an example of jacket erection. **Figure 6.5.3** illustrates module deck construction while **Figure 6.5.4** illustrates a heavy lift barge installing a living quarters module.

Figure 6.5.2: Jacket Erection

Figure 6.5.3: Module Deck Construction

Upon completion, the jackets and decks are planned to be sea-fastened to ocean-going barges and towed to the Sable Island area. The barges may standby offshore or be held in a Nova Scotian port to await the arrival of a 'heavy-lift' barge. Lifts of 4500 tonnes and 2500 tonnes can be made in the shallow water depths existing at Thebaud and Venture with modern-day barges. There are no applicable water depth limitations for lifts in the other fields.

Photo Courtesy: J. Ray McDermott

Figure 6.5.4: Heavy Lift Barge Installing Living Quarters

One alternative method for installation of the offshore facilities is a 'float over' approach. The decks would be floated on barges over the jackets and then jacked into final position. This method will be investigated in the FEED stage, although sea conditions on the Scotian Shelf may be too severe for its use.

The decks should be virtually complete when they are installed because of the integrated deck design applied during fabrication. The final steps of installation will be to re-enter and complete the wells and to pipe the wells to the production manifolds. This will require minimal offshore labour. Minimal offshore labour is the key to a cost-effective construction program for the Project. Work done offshore is estimated to cost at least three times the work performed in onshore construction yards.

Pipe-laying work on the 609 mm OD, 225 kilometre line from the Country Harbour area to Thebaud will begin while the platforms are being installed. Interfield lines are planned to be laid at the same time. **Figure 6.5.5** illustrates a semi-submersible pipe-laying barge.

Photo Courtesy: J. Ray McDermott

Figure 6.5.5: Pipe-laying Barge

A pipe-lay barge with anchor handling boats, supply boats and barges will perform the work. The pipe material will be pre-coated on the outside for corrosion control, and concrete-weight coated for bottom stability and then stored for delivery to the barge at the appropriate time. The linepipe for the pipeline may be supplied from a large number of mills worldwide, including those in Canada. Corrosion and weight coats can be applied at or near the mills, or after delivery to the Project area. An 88.9 mm OD pipe will be "piggy-backed" to the interfield lines to supply Monoethylene Glycol (MEG) to prevent hydrates from occurring in the interfield lines between the Thebaud platform and the Venture and North Triumph platforms.

The 609 mm OD pipeline will be laid on the seabed, and will be trenched in shallow water. Future studies will determine the likelihood of self burial by the pipeline, and identify places where sand movement or bottom terrain may cause instability in the line. The line may be trenched in areas of concern by one of several possible methods: mechanical trenching, ploughing, jetting or dredging. The appropriate method will be chosen to conform to bottom conditions and ecological concerns. For example, if a shellfishery is important in the area, methods that stir up a large volume of silt would be avoided.

The 'heavy lift' and 'pipe-lay' barges are special purpose, multi-million dollar vessels of which there are very few in the world. There are no Canadian operators or owners of these barges. They are primarily operated by international contractors in Europe and the United States. The vessels come fully crewed and will require little assistance beyond provision of supplies to the worksite. The high operating cost and the world-wide demand for these vessels means they work to a very tight schedule. Standby time would be very costly to the Project. Every effort will be made to ensure the most efficient use is made of barge time. The Project Proponents and the vessel operator will ensure that the appropriate clearances for working in Canadian waters are obtained from the Canadian Coast Guard.

Onshore construction of the gas plant, pipelines and natural gas liquids handling facility will proceed at the same time as construction for the offshore facilities. All facilities are scheduled to be completed during the third quarter of 1999, to allow for commissioning during September and October in preparation for first gas sales in early November of that year.

The pipeline from Thebaud will make landfall in the vicinity of Country Harbour, Nova Scotia. The pipeline will be buried in the shallow water approach and through the beach area. The landfall could be bored, if inshore conditions are suitable. The pipeline will continue inland a short distance to the gas plant and slugcatcher site.

Contractual division between onshore work and offshore work will be decided as the Development Phase of the Project progresses. The engineering, procurement and construction contract for the gas plant will be awarded through international competition. The most likely scenario for construction is that the site will be cleared and the foundations poured, with the majority of the equipment erected there. Some of the equipment will be skid mounted and some of the piping prefabricated. It is possible that the plant could be partially constructed elsewhere in several modules and be brought to the site by barge or road. This will depend on site access and the costs involved. In either case, there should be significant opportunities for local civil, mechanical, electrical and general building trades to bid for work at the site.

From the gas plant, a 67 kilometre, 219 mm OD pipeline will be trenched and buried to carry gas liquids to the Point Tupper area. As the pipeline crosses the Strait of Canso, it will either be trenched and buried, or horizontally bored (directionally drilled). This decision will depend on future engineering, geological, environmental and economic studies. An experienced inland pipeline contractor will be hired to construct this pipeline. Considerable reliance on local trades, equipment and labour is likely. **Figure 6.5.6** illustrates an onshore pipeline construction spread.

Photo Courtesy: Fluor Daniel

Figure 6.5.6: Onshore Pipeline Construction Spread

A natural gas liquids handling facility will be built at Point Tupper, Nova Scotia to stabilize the condensate and process the natural gas liquids. The condensate will then be shipped, either through the Statia Terminals, or through other facilities. The decision for shipping arrangements has not been made at the time of filing. Construction of the natural gas liquids handling facility and construction of the gas plant will most likely be under the same contract. Local construction skills are again anticipated to be needed at Point Tupper.

The total construction of Project facilities will be of modern design and incorporate well established engineering practices. Technology developed in the North Sea and the Gulf of Mexico will be applied to the offshore work, and technology developed in Western Canada will be applied to the onshore work. There are no concerns that the technological applications will cause cost or re-engineering delays.

The scenario presented here is subject to change as Front End Engineering Design (FEED) progresses and new ideas are developed. However, there are not likely to be any significant changes to the general sequence and scope of this construction scenario.

7.0 PROVISIONS FOR FACILITIES DECOMMISSIONING AND ABANDONMENT

There will be three **Sable Offshore Energy Project** facility sites which require decommissioning and abandonment once the Project is finished: the offshore facilities, the onshore gas plant and natural gas liquids pipeline, and liquids handling facilities.

Decommissioning and abandonment activities will be undertaken in accordance with the regulatory requirements applicable at the time of such activities. The following description outlines the decommissioning and abandonment activities that are currently anticipated for the Project. As there is a long period of time between construction and abandonment, industry practice, technological and regulatory requirements may change in this period. The abandonment plan will be submitted to the appropriate regulatory authorities for approval prior to abandonment.

Special consideration to the removal process will be given during the design of the facilities. Eventual abandonment of the offshore platforms and jackets is planned by cutting off the jacket legs and/or piles below the mudline and transporting the jackets and platforms to a suitable site for recovery and disposal. Due consideration will be given to any potential contaminants that could present a hazard during recovery and transportation of the facilities. Reuse of the platforms and jackets will be considered in terms of economic benefits as the time for abandonment approaches.

Wells will be abandoned according to standard industry practices, in compliance with applicable drilling regulations.

Offshore pipelines will be abandoned 'in place' after they are flushed internally and filled with seawater. Their ends will be capped. The lines will be surveyed, and any pipelines or parts of lines presenting an environmental or commercial hazard will be recovered and scrapped.

The onshore gas plant will be removed and the land restored to a state similar to that which existed before construction began. Onshore pipelines, where buried, will, in general, be flushed internally, capped and abandoned in place. The right-of-way will be revegetated and allowed to return by natural succession. Any above ground structures associated with onshore pipelines will be removed.

Prior to the commencement of production from the Project, the Proponents will provide evidence of financial responsibility to the regulatory authorities to address decommissioning and abandonment regulatory requirements applicable at the time of such activities.

8.0 PROJECT ECONOMICS

The **Sable Offshore Energy Project** has been analyzed using discounted cash flows together with a computer modelled risk analysis for Project costs from January 1995 forward. The results are a function of the Project specific input data, from the risk assessment and the economic assumptions.

The risk analysis combined technical and non-technical issues associated with the Project, assessed the ranges of input assumptions, quantified the outcomes and identified Project risk areas for mitigation.

Economic parameters, such as cash flows (before and after tax), rate of return, Project payout and net present value, have been used to assess the effect of various fiscal and regulatory scenarios and determine Project viability.

The range of input data and related assumptions for the economic model are included in Part Two of this Development Plan Application (**DPA - Part 2, Ref. # 8.1**). More detail on economic benefits can be found in **Volume 4, The Socio Economic Impact Statement, Section 8.2**.

9.0 LIABILITY AND COMPENSATION

9.1 Liability

Liability may be imposed upon a party that is responsible for an incident or activity that has impacted the environment while conducting offshore operations. The Accord legislation currently provides that liability may be imposed on a party for spills or debris attributable to offshore work or activity, such as the **Sable Offshore Energy Project**. In addition, fisheries legislation may impose liability for any action that must be taken to clean up spills and debris, or any adverse effects of deleterious substances on the fisheries. Shipping legislation in Canada may also provide a basis for statutory liability in connection with offshore operations. Civil liability may be imposed on a ship owner for damage and clean up measures caused by oil pollution and debris from a ship not specifically engaged in exploration, drilling, production, conservation or processing of oil or gas. Voluntary compensation plans may also apply to the Project, such as the industry compensation plan for fishermen who suffer loss or damage to their vessels and fishing equipment, in certain circumstances. Additional liabilities from statute, legislation, government policy or voluntary agreement may apply to the Project when offshore operations commence. The current liability regime, as applicable to the Project, is summarized below.

The Accord legislation provides a statutory liability regime under which a party carrying out offshore work or activity may be strictly liable, without proof of fault or negligence, up to a prescribed limit, for actual loss or damage and costs reasonably incurred in taking any action in respect of spills and debris which may be attributable to the work or activity. A limit of liability, in the amount of $30 million, has been established by regulation. In addition, the Accord legislation provides that the statutory liability regime does not suspend or limit liability or remedies, that may be available at law, by reason only that the incident gives rise to liability under the Accord legislation.

Fisheries legislation also provides potential statutory joint and several strict liability for parties that own, or have charge, management or control of deleterious substances. Liability may arise for reasonable costs incurred by government to remedy adverse effects as a result of a deposit of such substances in water frequented by fish, as well as, for loss of income of licensed fishermen to the extent that the loss can be established to have been incurred as a result of the deposit or a prohibition to fish resulting therefrom. In addition, there may be joint and several liability for such costs and loss of income imposed according to the respective degrees of fault or negligence on those who cause or contribute to the cause of the deposit. The legislation also provides that the liability provisions do not affect or suspend available civil remedies or limit the right of a party to recourse that the party may have to another that is liable under the legislation.

Shipping legislation in Canada may also provide a basis for statutory liability for incidents or activities in connection with offshore operations for the Project. The *Canada Shipping Act* provides for civil liability on the part of a ship owner for damage and clean up measures caused by oil pollution and debris that emanates from a ship not specifically engaged in exploration, drilling, production, conservation or processing of oil or gas.

In addition to compensation available by statute, voluntary compensation plans may have application and provide a further basis for compensation for loss arising from conducting offshore operations for the Project. For example, the Canadian Association of Petroleum Producers' Fishermen's Compensation Policy may provide for compensation to fishermen for damage or loss to vessels and fishing equipment caused by debris of unknown origin.

At the time offshore operations are conducted for the Project, there may be additional or other liability obligations and provisions for compensation prescribed by statute or regulation, as well as the application of government policy or voluntary agreement for any losses that arise.

9.2 Strategy

The **Sable Offshore Energy Project** strategy to address compensation, environmental degradation community concerns and financial responsibility matters for offshore operations is as follows:

9.2.1 Compensation

A fisheries compensation plan will be filed with the appropriate regulatory authorities during activities leading up to construction of facilities for the Project. Consultation with the fisheries industry is ongoing in connection with the preparation of the fisheries compensation plan. The general policy for compensation, the scope of potential claimants and the extent of claims, and the outline for the procedures to make and assess claims, as well as the consequences of making a claim will be included in the fisheries compensation plan.

9.2.2 Environmental Community Concerns

Community concerns relating to the environment, including those of the fishing and aquaculture industries, have been recorded as part of the pre-filing public consultation program. The concerns expressed are summarized in the Socio-Economic Impact Statement (SEIS) for the Project (**The Sable Offshore Energy Project, Socio-Economic Impact Statement, Volume 4**) and have been used by the Proponents as input in certain Project decisions. In addition, the Environmental Protection Plan (EPP) to be filed with the appropriate regulatory authorities will take into consideration remaining concerns that have been raised and, where appropriate, will address such concerns.

In addition to community concerns relating to the environment, the results of studies conducted on the environmental impact of the Project will form a basis for the preparation of the EPP for the Project (**DPA - Part 2, Ref. # 9.2.2.1**).

9.2.3 Financial Responsibility

As a condition for the approval of work or activities in the offshore, the Accord legislation requires evidence of financial responsibility to address the liability obligations referred to in Section 9.1, above. The *Nova Scotia Offshore Area Petroleum Drilling Regulations* also contemplate the provision of evidence of financial responsibility to meet financial liabilities that may be incurred in the conduct of an offshore drilling program.

Different forms of evidence of financial responsibility may be acceptable to satisfy the financial responsibility requirements under the Accord legislation and the *Nova Scotia Offshore Area Petroleum Drilling Regulations*, as well as for other obligations that may be applicable, such as platform abandonment. The Proponents will provide evidence of financial responsibility to address such requirements prior to commencement of the specific offshore activity in respect of which the applicable financial requirement relates. Consideration will be given to financial instruments such as a letter of credit, a financial institution guarantee or an indemnity bond, as well as to the provision of financial statements or insurance where appropriate, to address such requirements.

10.0 SAFETY PLAN

10.1 Introduction

The Safety Plan will be part of a comprehensive Environmental, Health and Safety Management (EHSM) system for the Project. This is a framework for managing and improving operations, in terms of personnel and public safety and protection of the environment. The Proponents of the **Sable Offshore Energy Project** have comprehensive EHSM systems in place. The management system and Safety Plan will be built from these foundations.

A description of Mobil's EHSM System (Operation Assurance (OA)) is on file with the **CNSOPB**. The 12 elements of OA (listed in **Section 10.4**) are similar to those found in the management systems of the other Proponents. OA will provide the basis for the policies, standards and practices of the Project. OA, while developed for Western Canadian land based operations, is based on Mobil's North Sea Environmental, Health and Safety Management System. The existing system will be modified and further developed to incorporate additional onshore and offshore experience from the Project Proponents. The Safety Plan components will be designed to address, in a comprehensive manner, onshore and offshore safety issues. Activities will be planned, organized, executed and maintained in a manner that achieves safety and protects the environment, in accordance with the various acts and regulations.

Each of the specific safety plan requirements noted in the **CNSOPB Guideline No. 3150.002 OPERATOR'S SAFETY PLAN** (**DPA - PART 2, Ref. # 210.1.1**) are contained in Operation Assurance. They will be further defined as the specific Safety Plan for this Project is developed. In addition to the general safety plan requirements for all projects, the Safety Plan will reflect the recommendations developed from the Project's Concept Safety Analysis/Evaluation (CSE). The various studies initiated from this analysis, the Preliminary Hazard Assessments (PHAs), the Hazard and Operability (HAZOP) reviews, Safety Reviews, and Safety Audits will be conducted as the engineering and procurement stages move forward.

The Safety Plan will be developed as the Project progresses. It will include an outline for the decision making process and a complete Environmental, Health and Safety Organizational Structure. The preliminary Nova Scotia organization for the **Sable Offshore Energy Project** is illustrated in **Figure 10.1.1**. As indicated in this figure, Environment, Health and Safety will report directly to the **Sable Offshore Energy Project** Operations Manager.

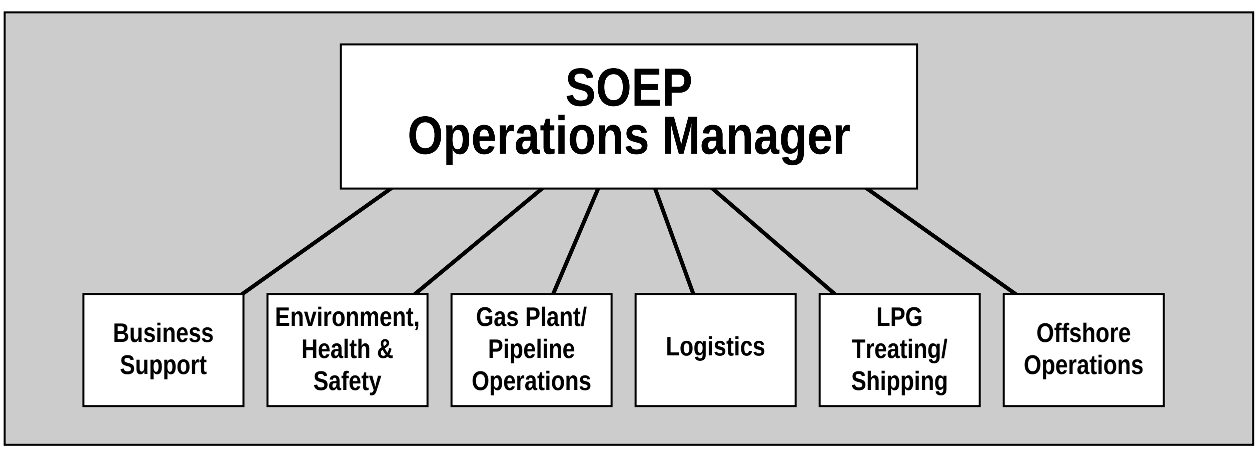

Figure 10.1.1: Preliminary Nova Scotia Organization

The development process for environmental, health and safety documentation, manuals, programs and procedures, with key activities highlighted, is illustrated in **Table 10.1.1**.

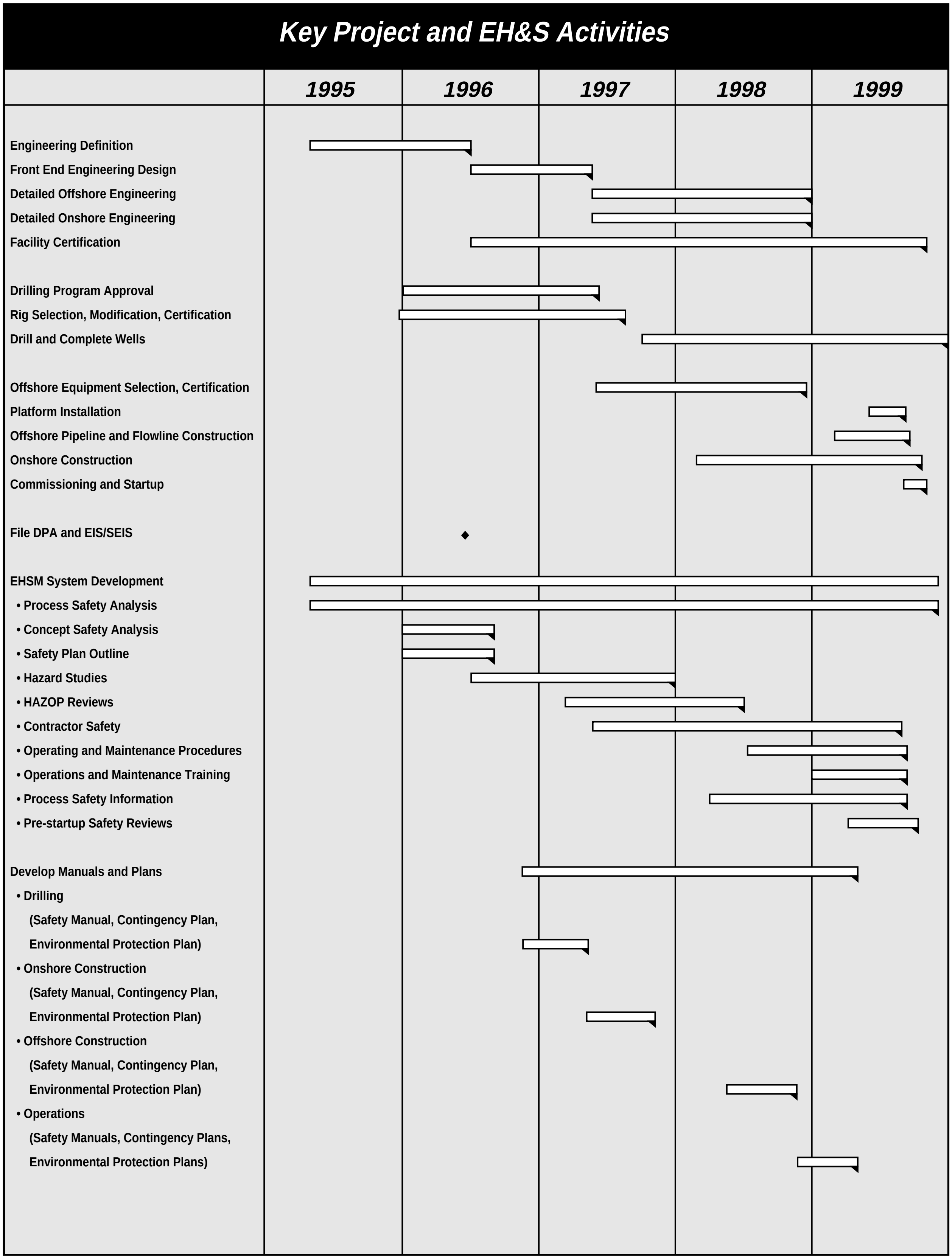

Table 10.1.1: Key Project and Environmental, Health and Safety Activities

An annotated outline of the Safety Plan and a schedule for the development of the Project's EHSM System will be provided to the regulatory authorities at the time the CSE is filed. The CSE will proceed concurrently with the Design Basis Specifications for both the offshore and onshore Front End Engineering Design (FEED), and will be filed near the beginning of FEED.

10.2 Hazard Management

Key EHSM system activities relating to hazard management are closely linked to the Project schedule (Table 10.1.1). In Engineering Definition, Front End Engineering Design (FEED) and Detailed Engineering, the **Sable Offshore Energy Project** is applying a deliberate, systematic and efficient approach to Project hazard identification, analysis and control.

Early in FEED, at the completion of Engineering Definition, the Project Concept Safety Analysis/Evaluation (CSE) will be completed. The initial step in the CSE is the definition of Target Levels of Safety to be applied throughout the life of the Project. These targets apply to the risk to life and the risk of damage to the environment from major hazards that apply to all activities associated with each phase of the life of the Project. A suitable criterion for the Target Levels of Safety will be developed based on the Proponents' experience, industry recommended practice, accepted Codes of Practice and worldwide industry experience. These targets will be reviewed over the life of the Project and modified and improved, as appropriate.

Potential and major safety and environmental hazards associated with the Project installations (platforms, pipelines, gas plant, liquids processing facility) will be assessed in the CSE, including: blowout, explosion, fire (and smoke), structural failure, collision, helicopter crash, earthquake, extreme weather, pipeline rupture, platform spills, simultaneous drilling and construction, simultaneous drilling and production. An assessment of the effects on key safety systems (evacuation systems, safe refuge systems, control systems, emergency shut-down systems), personnel, the public and the environment will be made. The likelihood of occurrence and the potential consequences of these hazardous events will be estimated and be used in the assessment. The CSE will also address contingency plans to avoid, mitigate or withstand these potential hazards.

The Concept Safety Analysis/Evaluation, prepared by recognized experts in this type of analysis, will consist of the following:

- Hazard identification
- Assessment of major hazard risk levels
- Assessment of major hazard consequences
- Assessment of prevention, control and mitigation
- Assessment of rescue and evacuation
- Assessment of Levels of Safety achievable
- Specification of updating and tracking procedures
- Recommended design improvements and studies

Based upon the results of these analyses, plans and measures will be developed for the **Sable Offshore Energy Project** to assure that the Target Levels of Safety specified for the Project will not only be met, but improved upon where practicable by embracing the principle of As Low As Reasonably Practicable (ALARP) design. A series of specific safety and environmental studies will follow the CSE. These will incorporate recommendations from the CSE and provide necessary additional analysis required for the Detailed

Engineering of the Project. These could include recommendations for additional fire risk analysis, ventilation and gas detection studies, and various quantitative risk assessments.

The studies, recommended in the CSE, will support other components of process hazard analysis conducted during the FEED and Detailed Engineering. Key environmental, health and safety components during engineering will include:

- The Hazard Management Plan at the start of FEED
- The Process Hazard Reviews of process flow and general arrangement drawings in FEED
- The Detailed Hazard Reviews (using check lists, what if analysis and HAZOPs) of process flow and instrumentation in FEED
- Final HAZOP Reviews of process flow and instrumentation in Detailed Engineering
- Environmental, Health and Safety Audits, in both FEED and Detailed Engineering

This work will support the updating of the Concept Safety Analysis and contribute to the Safety Plan for the Project.

10.3 Drilling

Environmental, Health and Safety initiatives will be designed to compliment existing OA procedures and standards, while developing specific drilling safety plan details and procedures (Table 10.1.1) for this Project.

The drilling contractor will be required to have a comprehensive safety program in place. This program must meet or better all applicable industry, government and Proponent standards. The contractor safety program will be evaluated by Loss Prevention personnel familiar with offshore drilling installations prior to acceptance of the drilling unit. The Loss Prevention personnel involve specialists from the Proponents, Project team and contractors and will ensure that sufficient training, information and equipment is made available to the workforce.

Survival equipment, emergency procedures and training are a major focus of the Safety Plan. Emergency drills, procedures for evacuation and abandonment, fire fighting, stability control, man overboard, well control and spill response will be reviewed, further developed and approved. These procedures will be further modified to align with the offshore installation when the structure is in place.

The general Drilling Safety Program from the operating company will be utilized for the Project to encompass both drilling and workover operations. This program, which forms part of the Quality Management System, will facilitate continuous improvement and safe and environmentally responsible drilling, completion and workover activities. Internal safety audits will be held at a sufficient frequency to ensure the success of the safety program.

Proven operator safety programs from the North Sea and Gulf Coast will be incorporated into the development of a Simultaneous Drilling and Production Operations Manual and a specific Drilling Operations Manual. Within the second manual, limits and procedures to deal with close proximity well bores will be defined.

Procedures will be established for the early detection and control of hazardous well conditions in the Drilling Operations Manual. These procedures include, but are not limited to, tripping speeds, flow checks, well-kill procedures and testing of casing and well control equipment. Data logging units will be used to continuously monitor all drilling parameters.

10.4 Construction

The Safety Plan for construction incorporates two elements: the protection of life and materials during the physical act of construction, and the safety features designed into the facilities.

Safety during construction is a team effort between Proponents and contractors. The roles vary however, according to the stage and location of the work. In off-site locations, for example, the Proponents monitor the work and manage safety improvements in co-operation with the contractor. The Proponents' Offshore Manager has direct responsibility for all activities that are undertaken within the Proponents' Licence.

The contractor's safety management system and safety record is part of the qualification criteria used to determine contractor suitability to participate in the Project. Contractor's safety manuals, organization and performance will be audited prior to contract award. Corrective action will be required of the contractor where necessary, prior to qualification. Compliance with Project environmental, health and safety standards, and those of the country of jurisdiction where the construction activity is taking place, will be a contractual requirement. The contract will also contain the Proponents' Environmental, Health and Safety rules which will form part of the basis for the Project's Safety Plan. The Project Manager's team will monitor performance in the construction yards and arrange audits by the Proponent's Loss Prevention Specialists.

The Proponents' Offshore Manager is responsible for the safety of all work undertaken within the Licence. A Loss Prevention organization will be in place during the construction stage of the Project. 'Work Permitting' procedures, an element of the EHSM system, will be the normal method of work authorization. These procedures will ensure that the requirements for safe work are in place. The Loss Prevention organization will be pro-active in the education of the workforce. Safety will have first priority at the work site.

Technical Safety is built into the engineering design by compliance with the appropriate regulatory requirements, the application of industry standards and active Quality Assurance/Control reviews of all aspects of the design. HAZOP reviews, Loss Prevention reviews, and Access/Maintenance reviews will be periodically held to ensure the integrity of the design. These reviews will involve the Proponents' corporate loss prevention and operations experts, as well as Project and contractor personnel.

10.5 Operations

The Proponents recognize the need for safe operations, and the hazards which are inherent in the operations of the proposed Project. The **Sable Offshore Energy Project** Safety Program is being designed to reduce risks As Low As Reasonably Practicable (ALARP). This will be accomplished through a combination of qualitative and quantitative risk assessment procedures.

Project environmental, health and safety philosophy is based upon the following beliefs:

- all environmental, health and safety incidents are preventable.
- environmental, health and safety objectives must never be sacrificed for expediency.
- environmental, health and safety objectives are an integral part of operations objectives.

The Environmental, Health and Safety program will consist of 12 key elements:

- Leadership, Responsibility and Accountability
- Personnel Training, Awareness and Motivation
- Personnel Health and Safety
- Drilling and Well Servicing Safety
- Process and Facility Safety
- Operations and Maintenance
- Management of Change
- Environmental Protection
- Emergency Preparedness
- Community Relations
- Incident Investigation, Reporting and Analysis
- Compliance Assurance and Improvement

The Proponents will require all employees and contractors for the Project to follow this Safety program.

The following safety tools will be used in the various hazard reviews/studies for this Project: Preliminary Hazard Assessments (PHAs), HAZOP reviews, and Quantitative Risk Assessment (QRA).

Preliminary Hazard Assessments are used to identify risk and consequences associated with safety hazards, such as a small or large gas leak, explosions, and fires. PHA's can be used to focus remedial work during the design stage, or to eliminate obvious hazards before construction. This tool is also invaluable for managing change and to assess existing operations.

HAZOP reviews require the availability and use of Process and Instrument Diagrams and the assistance of experienced design and operations personnel. HAZOPs are very effective in the later stages of design to identify safety issues and to provide alternative designs and operating procedures.

Quantitative Risk Assessment is a tool used to understand the relative levels of risk associated with different safety procedures and emergency equipment. It is helpful in selecting life saving equipment, determining the best locations for this equipment and predicting the optimum arrangement of safety equipment.

10.5.1 Routine Operations

Routine operations are predicated on the following principles: a well trained and experienced staff, Operations Assurance, Continuous Improvement and Risk Management. These operations include logistical support operations using helicopters and work boats, as well as routine operations and maintenance activities.

The Proponents propose the use of a training computer for both onshore and offshore operations staff to familiarize them with the equipment and procedures. It is a learning tool for plant and equipment operation used prior to actual “hands on” training and operations. Operations and maintenance personnel will also be exposed to continuous updating and review training through a computer based, self-paced program. All personnel are required to set objectives for, and complete, yearly training reviews.

Offshore operations staff will be selected on a hierarchical basis by their experience in the following areas: previous offshore gas production experience, previous land based oil and gas production experience and previous marine experience. In addition to the offshore operations training, survival training, first aid and other safety training will be required.

All new staff members will be indoctrinated in Project operations as a condition of employment. Each employee will be required to function as part of an operating team, with both individual and shared objectives based on Operation Assurance. Managers and leaders within the organization are required to demonstrate leadership by practising safe performance themselves, and to recognize this achievement in those they lead. Managers and leaders are also required to demonstrate commitment to OA.

Continuous Improvement (CI) is a powerful safety management tool. It can be used to measure safety performance, to identify causes of variation in safety performance and to develop and test solutions to these causes. This philosophy is directed at fixing the problems by eliminating the causes. The Proponents will implement a strong organizational culture which recognizes and rewards the commitment and follow-through of employees who strive to eliminate variation in safety performance on a day-by-day basis.

10.5.2 Management Of Change

The Management of Change is a key Safety Plan element supporting continuous improvement in risk management. The Proponents will develop procedures to identify, report and consider **all** changes within the operation. Initially, these procedures will be derived from current Proponent practices, onshore and offshore. This will be followed up with CI to measure the effectiveness of the process, identify variations and implement improvements in the process. This process will have a strong documentation element to allow for follow up measurements and identification of root causes of variation.

Management of Change is an element of the Environmental, Health and Safety Management (EHSM) system and will receive continuous development, assessment and improvement, as outlined in this application.

10.5.3 Well Servicing Operations

The safety program for well servicing operations will be developed in conjunction with the drilling safety program. It will include the elements of a total loss prevention and control program in conjunction with the EHSM system initiatives. The Proponents will develop a manual to describe specific elements of the program as they apply to the well servicing operation, in order to minimize all types of accidental losses. The standards established will reflect technology with a high level of safety applicable for local conditions, and will take full advantage of technical advancements in equipment, materials and operational techniques. The standards will adhere to industry and regulatory requirements. This will be reviewed by the **CNSOPB** prior to final implementation.

As with the drilling program, contractors will be required to demonstrate a comprehensive program to track all accidents, incidents and near misses. They will be required to ensure all Government and industry standards are met, as well as standards of safety training similar to those of the drilling program.

10.5.4 Emergency Preparedness

The Project Proponents have extensive experience with Emergency Preparedness. Monthly safety drills, including realistic emergency exercises, will be conducted in both the onshore and offshore facilities. In the offshore, weekly lifeboat drills, man overboard exercises and fire drills will be conducted. A major annual emergency exercise will mobilize staff to the emergency command centre. The exercise will act out evacuation, verify and improve emergency procedures, and test communication systems.

The facilities and equipment will be operated to keep risk at a minimum. Operations and management personnel will be trained and drilled to handle all identified emergencies. The Proponents will prepare Alert/Emergency Response Plans (ERPs) (**Chapter 12.0: Contingency Plans**), to outline identified emergencies, establish responsibilities and accountability for these events and lay out notification and response procedures.

An assessment of safe havens for offshore personnel and the provision of QRA for specified events will also be part of the overall emergency preparedness program.

11.0 ENVIRONMENTAL PROTECTION PLAN

11.1 Introduction

The Proponents are committed to stewardship of the environment in which they seek to operate, and will design this Project to eliminate or minimize impacts on the environment (See **Volume 3: Environmental Impact Statement**). Environmental protection, an important element of the Proponents' overall Environmental, Health and Safety Management (EHSM) system, will be managed to ensure that utilizing resources and the environment today will not impair prospects for future generations. This goal will be achieved through a balanced approach that recognizes the mutual long term dependence of a healthy environment and a healthy economy. The Proponents consider protection of the environment essential to the integrity of ecosystems, human health and the well-being of society. This will be a measure of the success of this development over its Project life of 25 years or more.

An Environmental Protection Plan (EPP) will be developed to provide detailed guidance, particularly for project personnel, on how to eliminate or minimize and mitigate adverse environmental effects from the Project. The EPP will provide a practical framework for implementation of the environmental requirements of development.

The Proponents will prepare an EPP, in a timely manner, for the management of Project-related impacts. The EPP will consolidate all the proposed environmental mitigation and monitoring procedures for construction (offshore and onshore), drilling, production, decommissioning and abandonment. The EPP will be an integral part of the overall Operational Plan and a reference document for the life of the Project. The EPP will, by necessity, reflect the activities of the Project and will be phased so that protection measures will be in place prior to each stage of activity.

Environmental performance will be the subject of yearly reviews by all personnel for the design, construction, operation, decommissioning and abandonment of this Project. Performance measures will be established. Continuous Improvement of these performance measures will be equally as important as the economic indicators which impact the operation.

The EPP, as part of the overall comprehensive EHSM system, will consist of the following elements:

- Environmental Policy
- Standards and codes of practice
- Mitigation/Operating procedures (construction, drilling, production, decommissioning and abandonment)
- Environmental education, training and orientation procedures/programs
- Chain of command (mechanisms for environmental decision-making)
- Environmental Effects Monitoring (EEM) practices and reporting
- Environmental Compliance Monitoring (ECM) practices and reporting
- Reference Laws, Regulations, Guidelines, Licenses, Permits and Approvals
- Waste Management Plan (WMP)
- Atmospheric Release Management Plan
- Effluent Release Management Plan
- Accidental Discharge Contingency Plan
- Contractual commitments, including special environmental clauses
- Environmental inspection and audit procedures

- Interaction with landowners and compensation procedures
- Interaction with the fishing industry and compensation procedures
- Special conservation plans, where appropriate (example: Sable Island)
- Environmental Management Continuous Improvement

The EPP will reflect the commitments the Proponents have made in this Development Plan Application, the Environmental Impact Statement, Socio-Economic Impact Statement, Review Panel Conditions of Approval, and other regulatory requirements for the Project. Additional detail is provided in **The Sable Offshore Energy Project Environmental Impact Statement, Volume 3, Biophysical Environment, Section 8.0 Environmental, Health and Safety Management System.**

One component of the EPP will be the Environmental Effects Monitoring (EEM) program. Effects monitoring will detect changes to the environment caused by a specific activity or development. The EEM program will provide an early warning of undesirable changes in the environment. The EEM program, where applicable, would address the following issues: Are changes being caused in the receiving environment? What is the size of the area affected? What biological components are affected? How severe are the impacts? What is the significance of the impacts? Are corrective measures necessary?

The other major monitoring component will be Environmental Compliance Monitoring (ECM). Part of this ECM is directly related to regulatory environmental surveillance and the conditions associated with licenses, permits and approvals. For example, this would include conformance with legislated spill reporting requirements. The other part of ECM is self-imposed, and is used to monitor performance standards developed for this Project by the Proponents.

There will also be a provision for specific EPPs on an 'as needed' basis in support of specialized activities such as future seismic work.

11.2 Construction

Each element noted above will be addressed in the EPP section on Construction. This will include offshore platforms, interfield pipelines, production gathering pipeline, onshore slugcatcher, onshore pipelines, gas plant and liquids processing facility. The EPP will be an Action Plan to guide inspectors and contractors during construction. It will contain construction specifications relevant to environmental protection, codes of practice for protecting sensitive features of the environment during construction, and mechanisms for dealing with an environmental emergency or unplanned occurrences.

Compliance with the EPP will be a mandatory element within each construction contract. The contractors' environmental practices and specific Waste Management Plan (WMP) will be among the criteria for contract award. In terms of the offshore, the Proponents will have in place, within the Offshore License, an Offshore Manager who has responsibility for ensuring that all discharges and emissions are within statutory limits. The WMP will be based upon the elimination of accidental spills and discharge of waste into the sea. Responsible waste disposal, in consultation with the local authorities, will be the mode of operation for all aspects of construction. Specific elements of the EPP relating to construction are presented in the **Sable Offshore Energy Project Environmental Impact Statement, Volume 3, Section 8.3.3**. These will be modified as a result of the EIS review. The EPP section on Construction will be presented in final draft to the appropriate regulatory authorities at least six months prior to commencement of major physical construction activities.

11.3 Drilling, Completions and Workovers

The Proponents fully acknowledge the environmental significance of the Sable Island and the Gully areas, and will conduct operations in a way that will address all potential impacts on those environments. Policies and procedures to eliminate or minimize environmental impacts will be established. The Proponents will meet or better all applicable regulations, corporate policies and environmental obligations. A Waste Management Program for drilling and workover operations to minimize waste, to recycle, to establish waste handling procedures and ensure regulatory compliance will be established. An accurate system of monitoring areas of environmental concern will also be established.

Qualified personnel, equipment and procedures will be in place in the event of an environmental incident, in order to correct the situation as soon as possible and to limit any damage. A reporting system will be established to record any incidents, regardless of size, and to record any near miss incidents and report these as required to the appropriate authorities. This information will be used to improve procedures and reduce incidents.

11.4 Operations

Each element noted above will be addressed in the EPP section on Operations. A combination of ECM and EEM programs will be established to monitor and report on the following, as well as other possible situations as they develop over the Project life:

Examples for Offshore Platforms

Flaring/venting (durations, volumes and causes)
Spill causes and volumes, with a zero tolerance threshold (all spills no matter how small will be reported)
Waste volumes and sources including:
- Process and well treating chemicals
- Produced water treatment and disposal (oil content)
- Sewage discharges (volumes, BOD, suspended solids)

Hazardous materials inventories, use and disposal
Heat losses to the atmosphere
Noise emissions

Examples for Offshore Gathering Systems

Flow rates and pressures
Periodic external inspections
Periodic internal inspections
Hydrostatic test fluid disposal

Examples for Onshore Facilities

Gas plant emissions
Gas plant effluent
Noise emissions
Flowline route revegetation
Flowline stream crossings
Hydrostatic test fluid disposal
Gas liquids processing emissions
Gas liquids processing effluent
Storage and shipping

The details of these programs will be established at the early stages of the Project, in response to requirements associated with Project activities. Additional detail is provided in the **Sable Offshore Energy Project Environmental Impact Statement, (Volume 3, Section 8.3.3)**. The EPP section on Operations will be presented to the regulatory authorities at least six months prior to the commissioning of the facilities. It will be an ongoing Continuous Improvement (CI) guide for management, operations and maintenance personnel to minimize wastes and emissions. Management will endorse written environmental policies and procedures for operations. The underlying philosophy of the Operations Plan will be Continuous Improvement: measuring and reporting on environmental issues, identification and elimination of ‘root’ causes of variation, and achievement of ‘excellence’ in environmental operations.

11.5 Decommissioning and Abandonment

The EPP section on decommissioning and abandonment will address the elements noted above. Matters relating to decommissioning and abandonment of facilities are addressed in **Section 7.0 Decommissioning and Abandonment** of this DPA.

12.0 CONTINGENCY PLANS

12.1 Introduction

The objective of the contingency plans is to ensure the safety of Project personnel and the public, and to protect both the environment and the Proponents' investment. The Mobil Field Support Emergency Response Plan (Field ERP) is currently being used for the **Sable Offshore Energy Project**. This is to ensure effective mobilization of personnel, facilities, and resources in the event of an accident or incident related to Project work. This plan provides information on Levels of Alert, Notification Structure, key response team duties, Emergency Control Centre (ECC) support teams, emergency telephone lists, and various forms and checklists. A copy of the Field ERP is on file with the **CNSOPB** and will be filed with other regulatory authorities as required. As Project activities increase, there will be a need for other contingency plans. These will deal with the response to, and mitigation of, accidental events affecting the safety of personnel and the public or the integrity of the facilities, and the response to, and mitigation of, accidental release of hazardous substances. Existing ERPs will be reviewed and updated on an annual basis.

Emergency Response Plans (ERPs) for the **Sable Offshore Energy Project** will be developed in compliance with the Canadian Association of Petroleum Producers (CAPP) *Guidelines for the Preparation of Emergency Response Plans* and *CAN/CSA-Z731-95 Emergency Planning for Industry*. They will be a logical extension of present plans used by the Proponents in similar onshore and offshore projects.

The Offshore Alert/Emergency Response Plan (**Offshore ERP**) will be quite similar to Offshore Alert/Emergency Response Plans the Proponents had in place while drilling off Nova Scotia in the 1980's; and to the *LASMO Nova Scotia Limited Alert/Emergency Response Contingency Plan* currently on file with the **CNSOPB**. The **Offshore ERP** will address construction, operation, drilling, decommissioning and abandonment activities associated with the offshore components of the project (platforms, pipelines, vessels, aircraft).

The Onshore Alert/Emergency Response Plan (**Onshore ERP**) will be quite similar to the ERPs the Proponents have in place for their Western Canadian facilities. The **Onshore ERP** will address construction, operation, decommissioning and abandonment activities associated with the onshore components of the project (gas plant, slugcatcher, pipelines, liquids processing facility).

The process for development of the ERPs will include hazard identification and assessment, environmental sensitivities, consultation with government agencies to ensure regulatory compliance, incorporation of industry Codes of Practice and consultation with local and other emergency resources. The plans will take into account the availability of existing industry and government emergency equipment and facilities.

The Proponents' contingency plans will incorporate the appropriate government agencies and other operating companies. This will be addressed, not only in planning, but also in coordinated exercises and drills. The goal will always be to reduce the impact from an emergency situation through the rapid and appropriate response of available resources, knowledge, and experience. The Proponents plan to become a member of the Regional Environmental Emergencies Team (REET) and Point Tupper Marine Services (PTMS). The Proponents will cooperate and interact with several other cooperative bodies. These include: Department of National Defence Rescue Coordination Centre (RCC) and Search and Rescue (SAR), the East Coast Response Corporation (ECRC) and the Emergency Measures Organization (EMO).

12.2 Offshore ERP

The **Offshore ERP** will be filed with the regulatory authorities at least six months prior to the commencement of Project activities (construction, drilling, operation, decommissioning and abandonment). The following topics will be addressed in the **Offshore ERP**:

1. **Administration**
   Introduction, policy, purpose and scope
   Manual Organization
   Definitions
   Amendment sheet and distribution list

2. **Organization**
   Internal emergency organizations
   External emergency organizations

3. **Roles and Responsibilities**
   Emergency Task Force Members (offshore, onshore, administrative)
   Description of key roles and responsibilities

4. **Communications**
   Alert and Emergency Notifications (charts, lists)

5. **Emergency Response** (actions by positions, onshore and offshore, specific hazard/emergency action plans)

   Offshore Installation Emergency
   - Loss Of Well Control
   - Gas Leak
   - Fire/Explosion
   - Structural Failure/Damage
   - Offshore Flowline Failure/Damage
   - Severe Weather

   Transportation Emergency
   - Overdue/Lost (vessel, aircraft)
   - Collision Avoidance (infringement of Safety Zones)
   - Severe Weather

   Personnel Emergency
   - Serious Injury/Fatality
   - Medevac Plan
   - Man Overboard
   - Abandon Platform
   - Diving Emergency

   Security Alert/Emergency
   - Criminal Acts
   - Act of terrorism/sabotage (includes bomb threats)

Environmental Alert/Emergency
Spill Incident (formation fluids, fuels, oils, lubricants, chemicals, gas/condensate, bulk products)

6. **Resources**
Personnel/equipment
Contractor resources
Government and mutual aid resources
Contact lists

7. **Training**
Employees and contractors
Drills and emergency exercises
Continuous Improvement system

8. **Appendixes**
Logs
Procedures
Severe weather criteria
Communication system overview

Additional information is provided in subsequent sections on Loss of Well Control, Pipeline Breaks, Platform Incidents, Collision, Marine Incidents, Aviation Incidents, and Force Majeure.

12.3 Loss Of Well Control (Drilling & Well Servicing)

A diverter system will be used for drilling below the conductor casing on all **Sable Offshore Energy Project** wells. This policy corresponds with **CNSOPB** requirements. The system will be designed with lines that are as straight as possible and have a minimum line size of 254 mm.

Once surface casing is set, either a 34 or 69 MPa blowout preventer (BOP) will be installed prior to drilling out. Pressure test requirements will be developed to meet government and Operator standards. This will include test pressures, test times, documentation, type of test and test frequency.

At intermediate casing point, a BOP of suitable pressure rating to reach total depth will be installed. In a number of cases, this will be a 103 MPa BOP. The choke manifold system and additional well control equipment will be designed to work with the 103 MPa working pressure BOP. The BOP working pressure requirements will be determined by the maximum possible surface pressure and will meet, or better, **CNSOPB** requirements

Procedures for well control and equipment, and procedures for early kick detection, will be formalized in the **Sable Offshore Energy Project** Drilling Operations Manual. This will include, but is not limited to, shallow gas, lost circulation, kicks and underground flows. Those procedures will be referenced and extracted, as necessary, to address Loss of Well Control during drilling. Similarly, procedures relating to Well Servicing operations will be supported in the **Offshore ERP** sections relating to Loss of Well Control.

During workover and completion operations, a minimum two-barrier well control philosophy will be strictly adhered to. This will ensure redundancy for well control against all predictable occurrences. This will include combinations of kill fluid, downhole plugs, BOPs, wellhead and safety valves. Safety procedures will be developed and implemented to ensure compliance with **CNSOPB** regulations and identification of critical operations. The safety procedures will adhere to Proponents' safe operating practices guidelines.

Where possible, all contingency plans will be developed in cooperation with other operators on the East Coast to maximize response capability and reduce duplication. This approach will help minimize the negative effects of any incident. During segments of drilling, completion and workover operations, only one Project jackup rig may be operating in the Sable area. Agreements will be established with the Project Proponents to make an appropriate drilling unit immediately available for relief well drilling, if required. This unit would most likely be mobilized from the North Sea or the Gulf Coast, but does not preclude available units identified by the combined worldwide resources of the Proponents. Casing, wellhead and mudline suspension equipment will be available for use, if necessary. Experienced personnel from other operating areas will be identified for well control or relief well operations. These individuals will be mobilized immediately in the event of a major well control incident.

12.4 Gathering Line Breaks

Contingency plans for gathering line breaks will be included in the **Offshore ERP** and its supporting documentation. These will include:

- Isolation procedures for ruptured or broken flowlines; which include 'securing the area' and preventing vessels from approaching the hazard area.'
- Containment and clean up of spilled hydrocarbons, with on-site and special hired equipment.
- Repair procedures including mobilization of necessary equipment and services.
- Inspection procedures for assessing the damage, adequacy of repairs and restart of operations.
- Compensation procedures for damage caused by flowline incidents.
- Documentation procedures to report and monitor spill causes, and to meet regulatory requirements.

12.5 Platform Incidents

Contingency plans for platform incidents will be included in the **Offshore ERP** and its supporting documentation. These incidents would include: injury to personnel from operational or environmental hazards, sickness of personnel, death, structural failure from environmental or operational forces, gas leak, fire/explosion, severe weather (storm winds and/or waves, pack ice, icebergs, superstructure icing), man overboard, diving emergency, and abandon platform.

12.6 Collision

To a large extent, fixed facilities in the open sea are reliant on the skill and vigilance of mariners to avoid collision. With proper procedures and the provision of special equipment, the risk of collision can be reduced to a very low and acceptable level. The **Sable Offshore Energy Project** has commissioned work around this contingency which is contained in Part Two of this document (**DPA - Part 2, Ref. # 12.6.1**).

A ‘safety zone’ will be established 500 metres all around the facilities rising above the sea surface. This ‘safety zone’ is mandated in offshore regulations. Standby boats and other vessels of the Proponents will be instructed to warn other vessels trespassing within the zone. The Canadian Coast Guard will also be requested to prohibit vessel anchoring within 200 metres of any Project subsea flowline.

Where appropriate, the Proponents will install active and passive navigational aids, such as radar reflectors, fog horns and lights on all surface facilities. In addition, anti-collision radar will operate in the producing area. This will give early warning to the personnel on platforms and standby boats of a potential collision hazard. This will give time for the vessel concerned to be warned and diverted. If the vessel cannot be diverted, prior to collision there will be time to secure the production and/or drilling equipment, and evacuate personnel in a safe and orderly manner. Operations and emergency procedures will be prepared and practiced to handle this contingency.

The platforms are protected from damage in normal day-to-day dealings with supply boats and other vessels by guards and bumpers. The mariners on these vessels will be made familiar with the facilities to reduce the risk of accidental contact and damage.

12.7 Marine Incidents

Guidelines for the safe and effective operation of **Sable Offshore Energy Project** vessels will form the basis of a marine operations manual. It will outline Project procedures for both routine and emergency marine applications. Emergency procedures relating to marine incidents (overdue, missing, damaged, sinking, or sunk vessels) will be detailed in the **Offshore ERP**.

12.8 Aviation Incidents

Sable Offshore Energy Project facilities will be designed to minimize the number of personnel involved in the operation of the offshore manned facilities, and to also minimize the number of visits required to service the normally unmanned facilities.

Helidecks will be designed to fully meet the standards, in size and equipment, required by regulatory authorities and aviation advisors to the Project. Helicopter operating companies with experience in offshore operations and experienced pilots and ground staff will be contracted. Maintenance, safety and operations records will be audited by the aviation specialists.

The Proponents will develop Procedures in Operations (for example, flight following), and emergency manuals to cover crash landings on the facilities and in the sea (late, missing, downed, or damaged aircraft). These will involve platform personnel, standby boats, other marine vessels and aircraft. Canada Coast Guard and other government services will be included when appropriate.

Personnel using helicopter transportation will receive training on how to react in the event of a helicopter accident. Frequent users will also receive ‘ditching at sea’ training. Training for the use of, and the wearing of survival protection gear will be mandatory.

12.9 Force Majeure

Force Majeure is, by definition, an occurrence beyond the control of the Project. The timing and magnitude of these occurrences are never predictable. Force Majeure basically falls into two categories: Acts of Nature; such as storms and earthquakes; and Human Induced; such as war, insurrection or strikes.

All the facilities are constructed with the most recent meteorological, climatological, oceanographic and geotechnical data available to the designers. The design allows for natural occurrences that can reasonably be expected within the vicinity of the facilities. A risk management program will be developed to address financial exposure in the event of injury, death, damage or loss of the facilities from natural disasters and human acts.

The operations and emergency procedures of the Project will address most of the effects from Force Majeure. These are generally: fire, hydrocarbon spills, rescue at sea, or stoppage of work or production. All these incidents will be covered by recommended action plans, training programs and periodic drills.

12.10 Onshore ERP

The **Onshore ERP** will be filed with the regulatory authorities at least six months prior to the commencement of Project activities (construction, operations, decommissioning and abandonment). The following topics will be addressed in the **Onshore ERP**:

1. **Administration**
   Introduction, policy, purpose and scope
   Manual Organization
   Definitions
   Amendment sheet and distribution list

2. **Organization**
   Internal emergency organization
   External emergency organizations

3. **Roles and Responsibilities**
   Emergency Task Force Members (onshore, administrative)
   Description of key roles and responsibilities

4. **Communications**
   Alert/Emergency Notifications (charts, lists)
   Resident Notification/Emergency Planning Zones (EPZs)

5. **Emergency Response (actions by positions, specific hazard/emergency action plans)**
   Onshore Facility Emergency
      Gas Leak
      Fire/Explosion
      Structural Failure/Damage (gas plant, slugcatcher, natural gas liquids handling facility)
      Onshore Flowline Failure/Damage
      Evacuation (personnel and residents)

Personnel Emergency
- Serious Injury/Fatality
- Medevac Plan

Security Alert/Emergency
- Criminal Acts
- Act of terrorism/sabotage (includes bomb threats)

Environmental Alert/Emergency
- Spill Incident (fuels, oils, lubricants, chemicals, gas/condensate, bulk products)

6. Resources

Personnel/equipment
Contractor resources
Government and mutual aid resources
Contact lists

7. Training

Employees and contractors
Drills and emergency exercises
Continuous Improvement system

8. Appendixes

Logs
Procedures
Communication system overview
Maps (residence, environmental features)

Additional information on certain topics is provided in subsequent sections on Fire/Explosion, Serious Injury/Fatality, and Spills.

12.11 Fire/Explosion

The **Onshore ERP** will be address all levels of fires and explosions, including:

- small fires in a non-critical area of a facility;
- fires that can be controlled with on site personnel and equipment; and
- fires that are out of control that will cause major equipment losses, could cause a release of an explosive mixture, could cause a unconfined vapour cloud expansion (UVCE) or could cause a boiling liquid expanding vapour explosion (BLEVE).

12.12 Serious Injury/Fatality

The **Onshore ERP** will provide the Project with procedures to deal effectively with incidents involving serious injury and/or death. Such an incident could occur during a fire or explosion, or as a result of an accident during normal operations, an automobile or similar incident involving **Sable Offshore Energy Project** personnel and contractors, or from natural causes.

12.13 Spills

The **Onshore ERP** will contain specific information how the Proponents will respond to a major spill or flowline rupture. Small spills or line breaks will be treated in other procedures outlined in the Environmental Protection Plan (EPP).

DEVELOPMENT PLAN APPLICATION
PART TWO: BIBLIOGRAPHY

Mobil Oil Canada Properties, for itself and on behalf of the Proponents of the Sable Offshore Energy Project, hereby declares that certain designated material contained in Part Two of the **Sable Offshore Energy Project** Development Plan Application contains financial, commercial, scientific or technical information which:

a) is **CONFIDENTIAL** under the terms of the Access to Information Act (Canada) and is not to be released or made public except as provided in the Act;

b) is **CONFIDENTIAL** under the terms of the Freedom of Information and Protection of Privacy Act (Nova Scotia) as disclosure would affect the continued access to such information, would affect the competitive position of the Proponents and result in undue financial loss and access thereto should be refused pursuant to the Act;

c) is **PRIVILEGED** under Section 122(2) of the Canada/Nova Scotia Offshore Petroleum Resources Accord Implementation Act (Canada) and is not to be released or made public except as provided in the Act; and

d) is **PRIVILEGED** under Section 121(2) of the Canada/Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act and is not to be released or made public except as provided in the Act.

Any notices regarding this matter should be sent to:

Mobil Oil Canada Properties
P.O. Box 800
Calgary, Alberta
T2P 2J7

Attention: Vice President, Frontier Development

Legend

Canada-Nova Scotia Offshore Petroleum Board: **CNSOPB**
Mobil Oil Canada Properties: **Mobil**
Shell Canada Limited: **Shell**
Sable Offshore Energy Project: **SOEP**

1.0 EXECUTIVE SUMMARY

Ref.#	Report Title / Source	Year	Status
1.2.5.1	Venture Development Plan Mobil	1984	

2.0 GEOLOGY, GEOPHYSICS AND PETROPHYSICS

Ref.#	Report Title / Source	Year	Status
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2.1.1.2	East Coast Basin Atlas Series: Scotian Shelf. Atlantic Geoscience Centre, Geological Survey of Canada	1991	
2.1.1.3	MacLean, B.C. and J.A. Wade, Seismic Markers and Stratigraphic Picks in Scotian Basin Wells. Geological Survey of Canada and East Coast Basin Atlas Series	1993	
2.1.1.4	MacLean, B.C. and J.A. Wade, Aspects of the geology of the Scotian Basin from recent seismic and well data. In: The Geology of the Southeastern Margin of Canada Geology of Canada, No. 2. Geological Survey of Canada (M. Keen and G.L. Williams Eds.). Chapter 5, pp. 190-238	1990	
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2.1.3.1	Powell, T. Petroleum Geochemistry of the Verrill Canyon Formation: a source for Scotian Shelf Hydrocarbons. Bulletin of Canadian Petroleum Geology Vol. 30, pp. 167-179	1982	
2.1.3.2	Williamson, M.A. and Smyth, C. Timing of Gas and Overpressure Generation in the Sable Sub-basin, Offshore Nova Scotia: Implications for Gas Migration Dynamics. Bulletin of Canadian Petroleum Geology, Vol. 40, No. 2, pp. 151-169	1992	
2.1.3.3	Williamson, M.A. Overpressures and Hydrocarbon Generation in the Sable Sub-basin, Offshore Nova Scotia. Basin Research Vol. 7, pp. 21-34	1995	
2.1.3.4	Williamson, M.A., and DesRoches, K. A Maturation Framework for Jurassic Sediments in the Sable Sub-basin, Offshore Nova Scotia. Bulletin of Canadian Petroleum Geology, Vol. 41, pp. 244-257	1993	
2.1.4.1	Reservoir Geology of the Overpressured Reservoirs of Thebaud Mobil	1988	Confidential
2.1.5.1	Stratigraphic Analysis of Reservoir Geometry and Reservoir Quality, MicMac and Missisauga formations, Scotian Shelf. Mobil	1995	Confidential
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3.1.2.1	Well Test Analyses for the SOEP Fields SOEP	1995	Confidential
3.1.2.2	RFT Data Analyses for the SOEP Fields SOEP	1995	Confidential
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3.1.3.5	Memorandum on the Reservoir Simulation Aspects of Glenelg SOEP	1995	Confidential
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3.1.4.1	Individual Sand Fluid Composition Data SOEP	1995	Confidential
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3.2.1	Well Evaluation Model (WEM) P.O. Moseley and Associates	1992	
3.2.1.1	Radial Compositional Modelling Study for SOEP SOEP		
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3.3.3.2	An Early Investigation of Depletion Alternatives for the Sable Offshore Energy Project SOEP	1995	Confidential
3.4.1	Probabilistic Reserve Estimates for the SOEP Fields SOEP	1995	Confidential
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5.2.4.1	SIGP Gas Plant Options Study Fluor Daniel	1995	Confidential
5.2.6.1.1	SOEP Preliminary Pipeline Corridor Data Review Seabed Exploration	1995	
5.2.6.1.2	SIGP Multiphase Flow Study Mobil	1995	Confidential
5.3.3.1	Venture Preliminary Geotechnical Survey: West Side of Country Harbour Mobil	1985	
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5.6.1.1	Venture Preliminary Physical Environment Criteria Mobil	1987	

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8.1 SOEP Economic Input Assumptions
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9.0 LIABILITY AND COMPENSATION

9.2.2.1 Environmental Impact Studies
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10.0 SAFETY PLAN

10.1.1 CNSOPB Guideline No. 3150.002 Operator’s Safety Plan
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12.0 CONTINGENCY PLAN

12.6.1 Collision Avoidance For Sable Offshore Energy Project Facilities
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