Capital employed

End Q4/01 to end Q1/02

Capital employed end Q1/02 was $25.2 bn. (end Q4/01 was $24.6 bn).

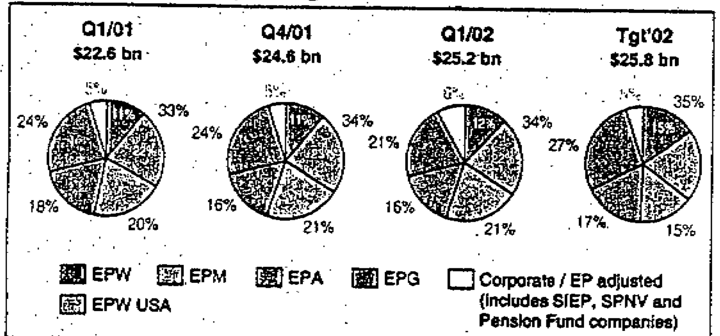
- Capex of $1.6 bn mainly in the USA ($0.3 bn), Canada ($0.3 bn), Nigeria ($0.3 bn), and UK ($0.2 bn).
- Deprecation of $1.0 bn mostly in the USA ($0.3 bn), UK ($0.2 bn) and Oman GISCO and New Zealand ($0.1 bn each).
- Other Investments of $0.2 bn relate to China IPO revaluation and the Weatherford warrants from grant of manufacturing & marketing rights of expandable tubular technology.
- Divestments of $0.1 bn primarily in New Zealand (On shore assets).
- Provision of $0.4 bn mainly in Norway (deferred tax on Draugen acquisition).

End Q1/02 actual vs end full year Target

Capital employed end Q1/02 of $25.2 was $0.6 bn (3%) lower than the full year target of $25.8 bn.

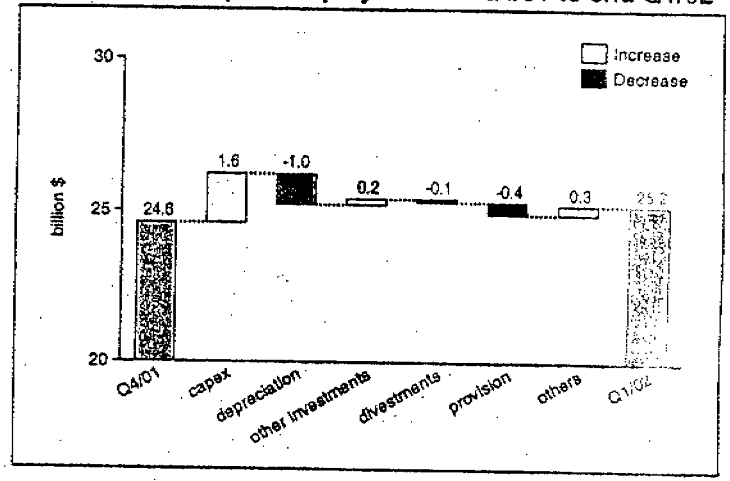
The decreases were in Canada ($0.7 bn - timing of investment), Netherlands ($0.6 bn - working capital), Nigeria (0.6 bn - timing of investment), Norway ($0.3 bn - Draugen acquisition offset by working capital and deferred tax provision), Denmark ($0.2 bn - timing of investment and working capital), Malaysia (0.2 bn - timing of investment) and Kazakhstan ($0.2 bn - working capital). These were partly offset by increases in Russia ($1.2 bn - mostly Sakhalin), USA ($0.4 bn - lower investment offset by depreciation) and Oman ($0.3 bn GISCO). The full year target includes some $0.7 bn of capital employed mainly for strategic options under "EP specials".

Capital employed per region

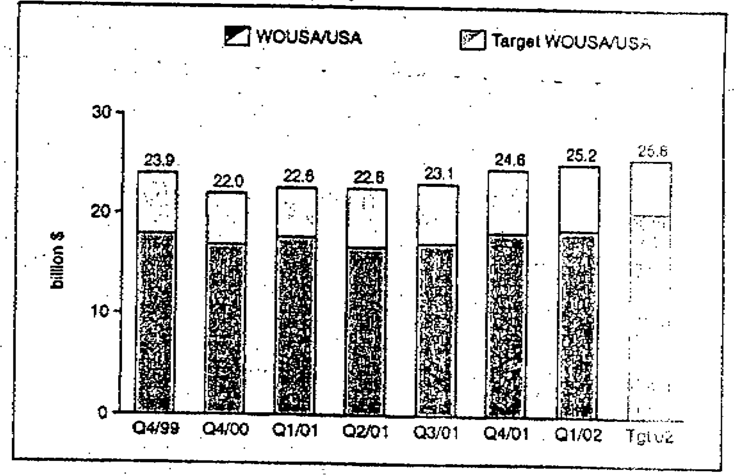


EP sector results Q1/02

Movements in capital employed - end Q4/01 to end Q1/02



End Q1 2002 capital employed



EPF-211s23 page 23

ROACE (rolling 4 quarters)

Note: Normalised ROACE based on new methodology as from 01/01/02.

Q1/02 vs end 2001
Q1/02 ROACE (calculated on a rolling 4-quarter basis) at 33.2% was 7.1 percentage points lower than end 2001 ROACE (40.3%).
The decrease was due to lower NIBIAT coupled with higher ACE.

- $1.3 bln lower NIBIAT contributed to 6.4 percentage points hurt mainly due to lower prices ($1.1 bn) and higher depreciation charges ($0.1 bn).
- $0.5 bln higher ACE (used to calculate ROACE - see definition below) contributed to 0.8 percentage points hurt. Major increases in ACE were in Nigeria ($0.3 bn) working capital movements and in New Zealand ($0.4 bn) as impact of Fletcher acquisition in Q1/01was fully reflected in the ACE.

Adjusted Q1/02 ROACE excluding Special items was 32.8% compared to adjusted end 2001 ROACE of 40.4%.

Normalised ROACE @$16/bbl was 18.5% compared to the external promise of 18%.

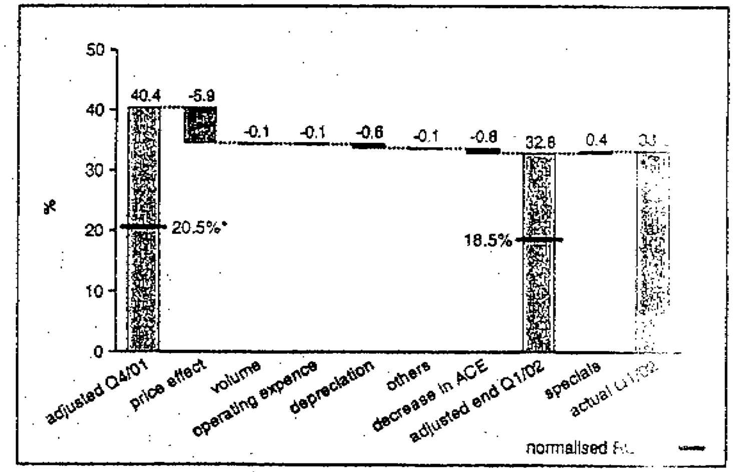
Q1/02 vs Q1/01
Q1/02 ROACE decreased by 17.5 percentage points from end Q1/01 of 50.7% as NIBIAT decreased by $3.7 bln partly offset by decrease in ACE of $0.3 bn.
The decrease in NIBIAT was mainly price related, as average Brent price and gas realisation (on 4-quarter rolling) was 17% and 19% lower, respectively.

• *ROACE formula :*

- *Numerator (NIBIAT): NIAT (excl. minority interests) + After Tax Interests (excl. interest on associates' third party debt, excl. minority interests).*
- *Denominator (ACE): Net Assets (excl. minority interests) + Debt (excl. Group loans to associates, excl. third party debt to associates.*

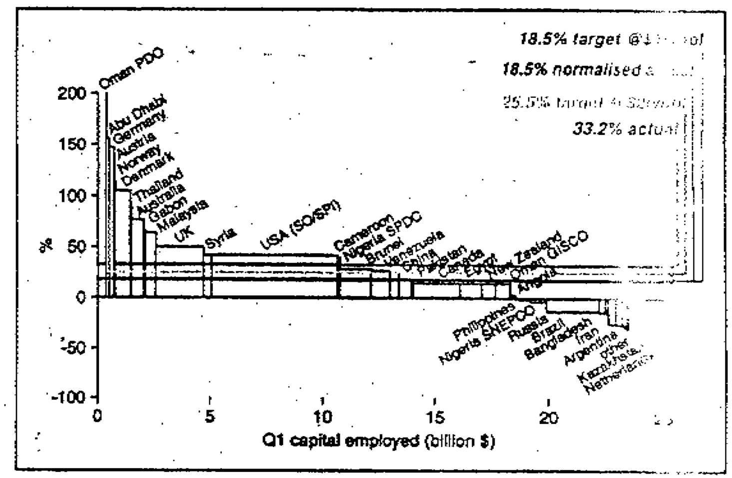
• *Price sensitivity: Any increase in realised oil and equivalent gas prices by $1/boe has a weighted impact of some $360 mln (for oil) and $266 mln (for gas) on full year NIAT.*

ROACE end Q1/02 vs 2001 (rolling 4 quarter)



* restated based on new methodology ... reported originally in 2001 as 15% normalised @$14/bbl

ROACE 2001



Cash surplus

Q1/02 vs Q1/01
Q2/01 Cash surplus of $1.1 bn was $0.9 bn lower than last year.
The changes were mainly due to a decrease in operational cash flow ($1.5 bn) partly offset by decreased capital investments ($0.6 bn).

- Decreases: USA ($0.9 bn; mainly lower income from operations and movement of long term assets), Corporate ($0.5 bn; pension fund reclassifications), Canada ($0.2 bn; increased investment activities Athabasca), Germany ($0.2 bn; mainly working capital movements), Netherlands ($0.2 bn; mainly lower income from operations and working capital movements), Denmark, Russia and Malaysia ($0.1 bn each).
- Increases: New Zealand ($0.9 bn; Fletcher acquisition in Q1/01), China ($0.2 bn; sale of CNOOC shares), Nigeria and Oman ($0.1 bn each).

Cash flow from operations ($2.7 bn) is $1.5 bn lower than Q1/01 as a result of lower net income ($1.2 bn; mainly in the USA and the UK) and unfavourable movements in working capital ($0.6 bn; USA, New Zealand, Germany and the Netherlands) partly offset by movements in investment activities ($0.6 bn) from other operations ($1.2 bn; Netherlands and Russia).

YTD vs YTD target
Cash surplus of $1.1 bn is $0.2 bn below target of $1.3 bn.

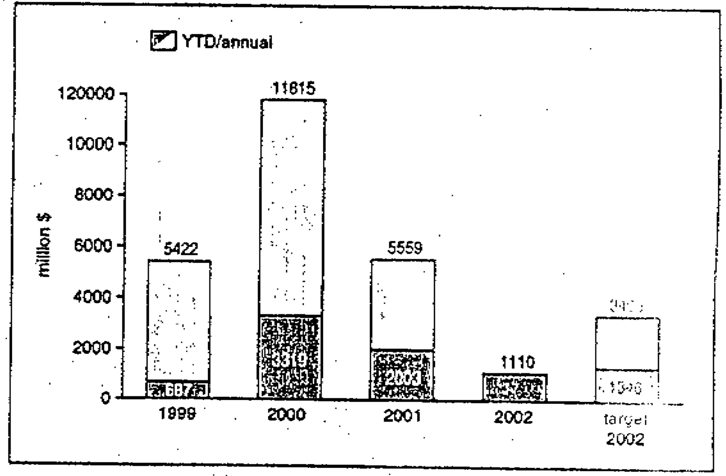
Cash flow

$mln	End 2001	Q1 2001	Q1 2002	Change*	Tgt 2002 ($20/bbl)
Cash from operations	12,731	4,224	2,631	(1,593)	9,148
Investments (capex/expex/inv. ass)	(7,304)	(2,244)	(1,667)	577	(5,831)
Divestments	132	23	146	123	86
Cash surplus/(deficit)	5,559	2,003	1,110	(893)	(3,403)
Cash used in financing activities	(5,976)	(1,657)	(1,058)	599	(3,553)
Free cash flow	(417)	346	52	(294)	(150)

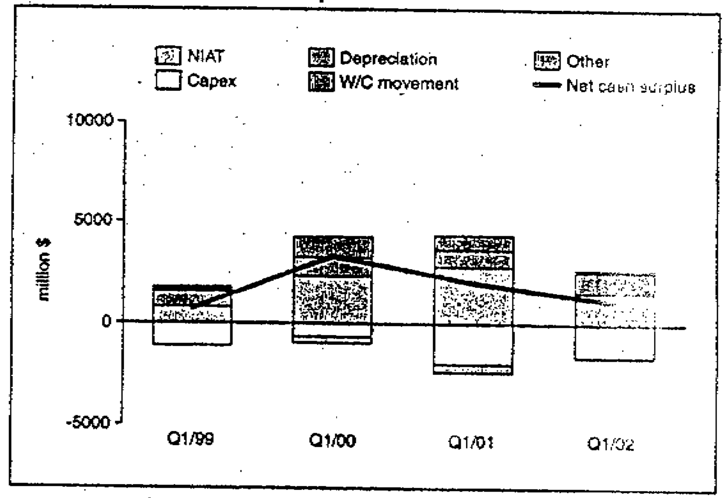
* Q1/02 less Q1/01

EP sector results Q1/02

Cash surplus



Components of cash surplus



EPF-211828 page 25

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DB 29400

Independent financial management (IFM)

Net Cash Return to Shareholders (NCR)

Q1/02 NCR was $1,272 mln, which consisted of $843 mln dividend, $583 mln net equity repayments and $24 mln Intra-group interest income partly offset by $178 mln net quasi-equity injections. Q1/02 NCR was 22% of Business Plan target at $20/bbl of $5,761 mln.

Dividends

- Dividend contributions came from 9 out of the 19 dividend paying countries. The main contributors were Norway ($200 mln), Denmark ($150 mln), USA ($100 mln), Netherlands ($149 mln), UK ($143 mln) and Malaysia ($116 mln).
- Q1/02 dividends pay-out was 47% ($748 mln) lower than dividends paid in Q1/01 ($1,591 mln) mainly due to lower prices with major decreases in the USA ($400 mln) and the UK ($378 mln). Q1/02 dividends were 14% of Business Plan target at $20/bbl of $6,156 mln.

Quasi-equity and equity

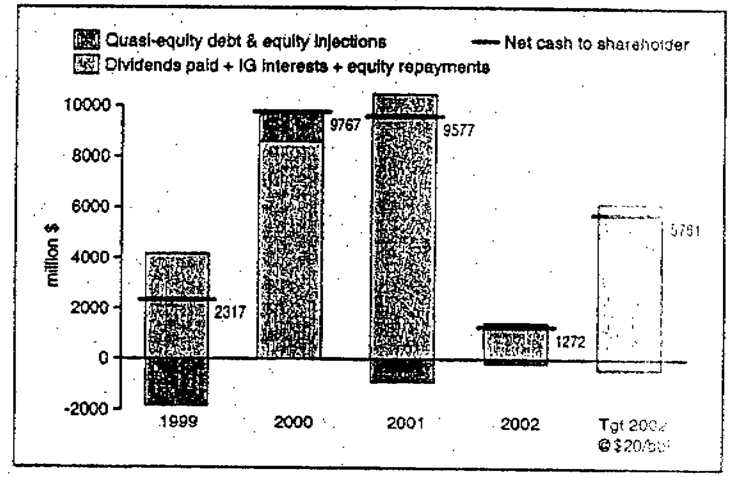
- Additional quasi-equity injections were mainly in Sakhalin ($86 mln) and Nigeria SNEPCO ($50 mln), Namibia ($19 mln) and Kazakstan ($16 mln).
- Net equity repayments were mainly from New Zealand ($200 mln), Oman-GISCO ($156 mln) and Germany ($126 mln).
- Quasi-equity debts balance increased by $892 mln from end Q4/01 balance to $3,884 mln principally resulting from the transfer of quasi-equity receivable balances (related to the corporate offshore entities i.e.Barbados and Netherlands Antilles) previously reported in New Zealand ($630 mln), correction in reporting for the quasi-equity loans in Abu Dhabi ($110 mln) and additional quasi-equity injections this quarter.

Gearing

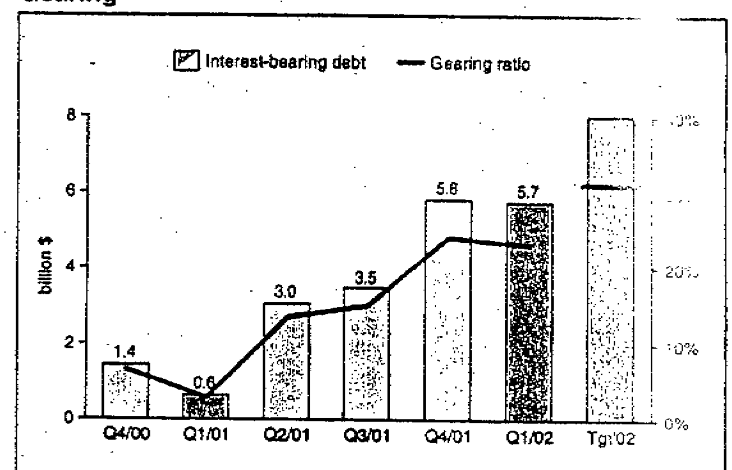
- EP Gearing level decreased slightly to 23% from end Q4/01 gearing of 24%. This compares to 2002 Business Plan target @$20/bbl of 31%.
- Interest-bearing debt balances decreased by $118 mln from end Q4/01 to $5,750 mln. Main decreases were due to increases in deposits in Netherlands ($440 mln - due to timing of tax payments), Norway ($144 mln) and Australia ($110 mln) offset by New Zealand ($200), Nigeria ($230 mln) and Canada ($160 mln).

Note : NCR = Dividend payments + net movements in quasi-equity or equity + 90% of Intra-group interest Payment

Net cash to shareholder



Gearing



EPF-211a26 page 26

EP sector results Q1/02

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DB 29401

Profit & loss and balance sheet (GA basis)

PROFIT & LOSS ($ mln MOD)	Q1 2001	Q1 2002	Q1 Change	YTD 2001	YTD 2002	YTD Change	2002 target	% target
Proceeds	7,393	5,178	(2,215)	7,393	5,178	(2,215)	21,190	24
Royalties	(521)	(364)	158	(521)	(364)	158	(1,443)	25
Production costs (opex)	(721)	(727)	(6)	(721)	(727)	(6)	(3,237)	22
Miscellaneous opex	(168)	(28)	140	(168)	(28)	140	37	-74
Feasibility expenses	(19)	(112)	(93)	(19)	(112)	(93)	(488)	23
Site restoration costs	(45)	(80)	(35)	(45)	(80)	(35)	(259)	31
Depreciation	(861)	(877)	(16)	(861)	(877)	(16)	(4,376)	[illegible]
Exploration expense	(163)	(168)	(5)	(163)	(168)	(5)	(886)	[illegible]
Other costs *	(63)	(101)	(38)	(63)	(101)	(38)	(605)	17
Associates P/L	524	310	(215)	524	310	(215)	1,250	-5
Operating profit	5,357	3,031	(2,326)	5,357	3,031	(2,326)	11,185	27
Interest/other income	50	36	(14)	50	36	(14)	(197)	-18
Interest expense	(26)	(38)	(12)	(26)	(38)	(12)	(441)	9
D.I.E. / other	12	0	(12)	12	0	(12)	(0)	-98
Taxation	(2,541)	(1,463)	1,079	(2,541)	(1,463)	1,079	(5,195)	[illegible]
Income after tax	**2,851**	**1,566**	(1,285)	2,851	**1,566**	(1,285)	**5,352**	29
Minority interests in net income	*69*	*6*	*(63)*	*69*	*6*	*(63)*	*71*	[illegible]
Income after minority interest	**2,783**	**1,561**	(1,222)	2,783	**1,561**	(1,222)	**5,280**	[illegible]
Special	0	(115)	(115)	0	(115)	(115)	16	[illegible]
Adjusted income	**2,783**	**1,446**	(1,337)	2,783	**1,446**	(1,337)	**5,296**	27

BALANCE SHEET ($ mln MOD)	YTD 2001	YTD 2002	$ variance	%	2002 target	% variance
Tangible fixed assets (PP&E)	26,208	31,080	4,872	19	29,226	106
Investments & other long term assets	6,679	5,744	(935)	-14	7,171	80
Current assets	4,823	3,806	(1,017)	-21	3,545	[illegible]
Current liabilities	(7,106)	(6,540)	566	-8	(5,362)	[illegible]
Total assets less curr. liab.	30,603	34,089	3,485	11	34,580	[illegible]
LT liabilities	(5,641)	(10,186)	(4,545)	81	(13,958)	73
Deferred taxes	(5,018)	(5,346)	(328)	7	(4,824)	111
Other provisions	(2,696)	(3,031)	(334)	12	(3,153)	96
Group net assets before MI	**17,248**	**15,526**	**(1,722)**	**-10**	**12,645**	123
Add back debt	*5,336*	*9,612*	*4,276*	*80*	*13,157*	73
Capital employed at period end	**22,585**	**25,138**	**2,553**	**11**	**25,802**	97

* *For upstream, this line includes cost of sales for the purchase of excess cost oil, and purchases for overlifts.*

Cash flow statement

CASH FLOW STATEMENT ($ mln MOD)	Q1 2001	Q1 2002	Q1 Change	YTD 2001	YTD 2002	YTD Change	2002 target	% target
Total net income (after M.I.)	2,783	1,561	(1,222)	2,783	1,561	(1,222)	5,280	30%
Depreciation	861	877	16	861	877	16	4,376	20%
Provision addns	73	491	418	73	491	418	51	868%
Acc receivable	170	332	163	170	332	163	321	103%
AP & accr liab	(186)	(462)	(276)	(186)	(462)	(276)	(146)	315%
Tax payable	734	206	(527)	734	206	(527)	(609)	-34%
Other	(23)	(36)	(13)	(23)	(36)	(13)	11	-321%
Movements in working capital	694	41	(653)	694	41	(653)	(423)	[illegible]
Other	(186)	(257)	(70)	(186)	(257)	(70)	(136)	[illegible]
Cash from operations	**4,224**	**2,713**	(1,511)	**4,224**	**2,713**	**(1,511)**	**9,148**	[illegible]
Exploration expense	163	168	5	163	168	5	886	[illegible]
Cash from production operations	**4,387**	**2,882**	(1,506)	**4,387**	**2,882**	**(1,506)**	**10,034**	[illegible]
Exploration expenditure	(283)	(298)	(15)	(283)	(298)	(15)	(1,487)	20%
Production capex	(1,823)	(1,457)	366	(1,823)	(1,457)	366	(5,668)	26%
Divestments	23	146	123	23	146	123	88	[illegible]
Other investments	(359)	(107)	252	(359)	(107)	252	0	-
New investments	(48)	(54)	(6)	(48)	(54)	(6)	43	-126%
Disp investment	111	(0)	(111)	111	(0)	(111)	(140)	0%
Net investments associates/other	(296)	(161)	135	(296)	(161)	135	372	-43%
Other	(8)	(5)	3	(8)	(5)	3	163	-3%
Cash surplus/deficit	**2,003**	**1,109**	(895)	**2,003**	**1,109**	**(895)**	**3,403**	33%
Cash used in financing activities	*(1,658)*	*(1,080)*	*577*	*(1,658)*	*(1,080)*	*577*	*(3,552)*	30%
Dividends paid	*(1,591)*	*(867)*	*724*	*(1,591)*	*(867)*	*724*	*(6,156)*	14%
Movements in cash	*(1,246)*	*(839)*	*407*	*(1,246)*	*(839)*	*407*	*(6,306)*	13%

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EP information by country

	NIBIAT* ($ million)		Net income ($ million)			Dividend paid		Cash surplus ($ million)		Effective tax rate (%)			Average C.E. ($ million)		ROACE (%)	
	YTD'01	YTD'02	YTD'01	YTD'02	%Tgt	YTD'02	Target	YTD'01	YTD'02	YTD'01	YTD'02	Target	YTD'02	Target	YTD'02	Target
Netherlands	291	250	291	251	43%	149	563	766	585	47%	46%	47%	(109)	594	NA	194
UK	376	210	373	202	22%	143	825	557	596	41%	36%	30%	2,288	3,147	50	41
Norway	45	33	46	35	23%	153	215	332	241	81%	75%	72%	181	466	114	43
Denmark	203	164	198	163	31%	108	669	323	174	36%	34%	29%	605	806	105	68
Germany	91	60	79	59	57%	2	215	226	67	41%	38%	42%	206	311	147	56
Austria	1	(1)	2	(1)			112	1	(1)			0%	8	5	130	120
Nigeria - SPDC	95	69	95	68	21%		350	(355)	(180)	76%	67%	67%	1,290	1,402	29	26
Nigeria - SNEPCO	(3)	(2)	(3)	(2)				(43)	(71)	30%	41%		530	526		
Gabon	23	20	23	20	34%		73	2	(12)	69%	59%	64%	69	93	66	122
Cameroun	8	10	8	10	41%	24		38	(1)	66%	46%	52%	119	151	40	26
Angola	(8)	(4)	(8)	(3)				(29)	(7)		12%		151	74	3	NA
Rest of EPG	(8)	(7)	(8)	(7)				(2)	(15)				34	7	17	NA
EPG	1,114	797	1,097	790	31%	578	3,021	1,813	1,350	53%	48%	48%	5,380	12,396	65	40
USA (SO/SPI)	902	228	909	221	15%	76	1580	1,145	215	35%	38%	38%	5,257	5,234	42	41
Canada	157	48	158	47	22%	13	59	(10)	(211)	43%	40%	33%	1,823	1,833	15	9
Venezuela	27	25	29	25	18%		107	54	18	1%	1%	1%	404	380	26	31
Argentina	(1)	1	(5)	(1)				(24)	15	35%	85%		347	420		
Brazil	(7)	(9)	(11)	(12)			18	(24)	(38)	35%	30%	36%	246	125		
Rest of EPW		(1)		(1)				73	(1)	111%			7	71	20	
EPW	1,077	292	1,080	281	18%	110	5,208	1,139	(3)	36%	36%	71%	8,085	22,708	29	30
Oman PDO	82	67	82	68	26%		198	84	(11)	79%	77%	77%	362	374	625	79
Oman Gisco	40	25	42	25	25%	22	64		210	49%	50%	50%	958	1,108	11	16
Oman Offshore															104	
Abu Dhabi	10	8	10	8	24%		34	(3)	8	94%	93%	93%	127	136	156	[illegible]
Egypt	25	38	28	38	24%		159	12	16				929	961	15	[illegible]
Syria	64	38	61	37	27%	44	163	49	32				389	436	42	[illegible]
Russia	(23)	(61)		(63)			9	(40)	(135)	29%	30%	44%	1,736	1,146		
Kazakhstan	(5)	(10)	(5)	(10)	16%			(8)	(16)				100	106		
Iran	(4)	(20)	(3)	(20)				(34)	(70)	-			220			
Rest of EPM	(1)	(1)	(1)	(1)				(2)	(1)				2	226		
EPM	187	81	190	79	16%	66	627	51	29	72%	60%	73%	4,877	4,742	14	[illegible]
Australia	158	81	154	84	34%		415	129	92	32%	33%	30%	515	657	77	43
Brunei	67	63	67	53	27%	51	159	(90)	58	72%	71%	72%	821	692	27	25
New Zealand	16	7	17	1	11%			(829)	89	33%	23%	25%	750	42	11	7
Malaysia	93	71	93	71	40%	116	179	178	127	39%	41%	40%	463	610	64	26
Thailand	18	11	18	11	22%		39	40	18	41%	39%	39%	57	63	90	61
Philippines	(3)	8	6	6		(10)		(4)	(8)	30%		29%	589	626		3
China	28	16	29	30	36%		79	(186)	(15)	32%	17%	31%	533	145	18	17
Pakistan	2		2					(1)	(24)				74	34	16	
Bangladesh	4	4	4	4	98%			(8)	19				175	218		2
Rest of EPA	(60)		(60)					(3)	(1)	18%		134%	22		36	2
EPA	328	249	337	280	34%	156	671	(865)	355	49%	47%	51%	3,998	2,835	27	19
Corporate/Other	140	36	147	157		(68)	(3571)	(135)	(622)		11%	95%	1,521	870	1	36
EP Adjustment														838		
EP World (incl Oil Sands)	2,847	1,455	2,851	1,566	29%	843	6,156	2,003	1,109	47%	48%	49%	23,861	25,128	33.2	25.5
Canada Oil Sands								(167)				40%		725		
EP World (excl. Oil Sands)	2,847	1,455	2,851	1,566	29%	847	6,156	2,171	1,109	47%	48%	49%	23,861	24,401		25.5
WOUSA	1,945	1,192	1,941	1,205	31%	743	4,575	873	967	51%	52%	53%	18,127	19,892	31.2	22.7
USA	903	263	910	361	24%	100	1,580	1,130	142	35%	27%	37%	5,734	5,234	41.1	[illegible]

EP sector results Q1/02

* No OU targets available for NIBIAT

EP information by country (A1) against full year target

* $/bbl, sales + transfers
** $/MMBtu, inland trade + export

	Unit operating cost ($/boe)				Unit depreciation ($/boe)				Adjusted unit NIAT ($/boe)				Oil/NGL prod (kbd)			Net gas production (mrd m³)			Unit proceeds Oil*	Unit proceeds Gas**
	YTD'01	YTD'02	Tgt'02	%Tgt	YTD'01	YTD'02	Tgt'02	%Tgt	YTD'01	YTD'02	Tgt'01	%Tgt	Q1/01	Q1/02	%Tgt	Q1/01	Q1/02	%Tgt	Q1/02	Q1/02
Netherlands	0.9	1.0	1.7	60%	1.1	1.0	1.6	62%	7.5	7.0	5.8	121%	13	9	100%	6.2	5.8	36%	18.30	2.48
UK	3.0	2.9	4.0	72%	4.4	5.1	4.6	110%	7.2	4.4	5.3	83%	334	302	106%	3.6	3.0	28%	17.82	[illegible]
Norway	3.5	4.2	4.2	100%	2.9	3.4	3.6	93%	4.1	3.2	3.5	90%	88	91	106%	0.5	0.5	25%	21.13	[illegible]
Denmark	1.2	1.5	1.7	86%	2.4	1.6	2.5	67%	11.0	9.0	7.9	114%	136	144	111%	0.9	0.9	27%	20.67	[illegible]
Germany	2.6	1.9	2.4	81%	1.8	1.5	1.8	83%	10.4	6.3	3.6	174%	5	5	109%	1.2	1.5	33%	20.41	[illegible]
Austria	4.1	2.9			3.0				6.0	(2.5)	6.0	-41%			73%	0.0	0.1	29%	34.58	
Nigeria - SPDC	2.2	3.2	2.1	154%	1.7	2.1	2.3	90%	3.6	3.2	3.1	102%	256	201	81%	0.6	0.6	27%	20.93	0.34
Nigeria - SNEPCO																			0.00	
Gabon	3.2	3.6	4.1	88%	2.6	2.4	3.0	80%	4.5	4.8	3.4	142%	59	48	98%				20.40	
Cameroun	5.1	4.3	5.8	74%	3.4	3.3	3.5	95%	4.6	6.0	4.5	134%	20	18	113%				18.33	
Angola																				
Rest of EPG	4.9	4.4			(1.0)	2.1			(28.0)	(25.3)			3	3					19.67	
EPG	2.2	2.4	2.9	84%	2.6	2.8	3.0	91%	6.8	5.3	4.8	112%	914	822	99%	13.1	12.2	32%	19.76	2.55
USA (SO/SPI)	3.9	3.2	3.0	106%	4.3	4.9	5.2	94%	14.9	3.8	5.1	70%	406	417	89%	4.0	4.0	21%	17.74	[illegible]
Canada	3.1	3.1	3.5	86%	2.0	2.3	2.5	92%	10.7	3.1	3.5	88%	57	60	98%	1.6	1.6	26%	15.05	2.23
Venezuela	3.0	2.8	2.7	102%	3.2	2.5	3.2	78%	7.7	5.9	7.2	81%	42	48	92%				0.00	
Argentina	14.2	2.5	3.1	81%	3.3	5.8	8.9	65%	(12.3)	(2.3)	(24.2)	10%	3	0	69%			18%	11.20	0.57
Brazil	0.1	2.9	1.5	186%	4.5	4.4	4.9	90%	(16.8)	(13.8)	(10.3)	135%	2	2	103%	0.1	0.1	32%	12.50	1.99
Rest of EPW																				
EPW	3.7	3.2	3.1	102%	3.9	4.3	4.7	91%	13.4	3.4	4.7	72%	509	527	90%	5.7	5.8	23%	17.08	2.31
Oman PDO	1.0	1.6	1.2	127%	2.7	1.9	3.0	61%	3.2	2.8	2.6	109%	286	270	96%				20.72	
Oman Gisco	0.2	0.1	0.2	61%	2.5	5.3	5.7	94%	3.0	1.3	1.1	116%	61	66	85%	1.5	2.3	22%	18.38	0.80
Oman Offshore																			0.00	
Abu Dhabi	0.8	0.9	0.8	109%	0.8	0.9	1.0	89%	1.0	0.9	0.9	95%	109	97	101%				21.00	
Egypt	1.3	1.0	1.9	52%	1.9	2.7	4.7	58%	5.6	6.9	8.1	65%	14	14	124%	0.6	0.7	27%	20.13	[illegible]
Syria	1.9	2.0	2.2	91%	1.0	1.4	1.4	96%	12.5	7.6	6.4	118%	52	52	93%			19%	20.05	[illegible]
Russia			6.1				2.8				(5.6)									
Kazakhstan																				
Iran		2.6				1.3								23	138%					
Rest of EPM																				
EPM	1.1	1.3	1.2	110%	2.2	2.8	3.6	78%	3.2	1.2	6.1		512	523	92%	2.2	3.0	23%	20.34	1.22
Australia	0.4	1.0	0.9	102%	2.8	1.4	1.8	77%	10.4	5.9	4.6	127%	104	94	112%	0.9	1.0	26%	15.26	1.69
Brunei	2.1	2.2	2.5	88%	1.5	1.7	2.0	88%	4.1	3.0	2.9	104%	98	102	100%	1.2	1.4	28%	13.00	1.87
New Zealand	1.0	1.4	1.3	103%	1.1	5.9	3.5	166%	5.4	0.1	0.4	39%	8	26	108%	0.4	1.2	30%	20.46	[illegible]
Malaysia	0.7	0.9	1.2	71%	1.2	1.2	1.4	86%	6.5	4.3	2.6	163%	58	56	92%	1.5	1.9	25%	21.25	[illegible]
Thailand	3.0	3.0	3.5	86%	1.8	2.2	1.7	133%	7.8	5.5	5.6	99%	18	15	88%	0.1	0.1	25%	18.22	2.16
Philippines		12.9	7.4	173%		2.5	3.2	79%		5.1	(0.8)	-670%		9	384%		0.1	12%	19.14	[illegible]
China	2.6	3.0	1.1	263%	1.5	2.4	1.0	245%	12.0	7.0	10.4	67%	27	26	119%				19.22	
Pakistan			8.0				2.3		5.0		(8.9)					0.1				
Bangladesh	2.9	3.2	5.0	64%	7.3	6.7	8.0	84%	6.6	6.2	1.7	357%				0.1	0.1	27%		2.89
Rest of EPA											(0.3)									
EPA	1.3	1.7	1.7	99%	1.8	2.2	2.0	112%	6.2	3.8	3.1	125%	313	328	104%	4.3	5.7	26%	18.76	1.41
Corporate/Other			31.2				7.5													
EP Adjustment																				
EP World (incl Oil Sands)	2.2	2.1	2.2	93%	2.7	2.6	3.4	77%	8.0	4.0	3.8	107%	2,248	2,199	97%	25.3	28.6	27%	19.21	2.14
WOUSA	1.8	1.8	2.0	91%	2.4	2.2	2.9	74%	6.6	3.7	3.4	106%	1,842	1,782	99%	21.2	22.6	29%	19.50	[illegible]
USA	3.9	3.2	3.0	106%	4.3	4.9	5.2	94%	14.9	5.8	5.2	113%	405	417	89%	4.0	4.0	21%	17.74	[illegible]

EP sector results Q1/02

EPF-211[illegible] page 30

FOIA Confidential
Treatment Requested

V00300656

DB 29405

EP information by country (A2) against full year target

*Operational Account basis

	Operating cost (mln $)				Depreciation (mln $)				Production capex* (mln $)			Exploration expenditure* (mln $)		
	YTD'01	YTD'02	Target	%Tgt	YTD'01	YTD'02	Target	%Tgt	YTD'02	Target	%Tgt	YTD'02	Target	%Tgt
Netherlands	34	36	156	23%	43	36	135	26%	37	166	22%	5	30	18%
UK	155	131	680	19%	229	232	791	29%	211	591	36%		28	3%
Norway	40	46	178	26%	33	37	156	24%	122	111	110%	1	29	36%
Denmark	21	27	117	23%	43	30	164	18%	49	272	18%	11	14	10%
Germany	20	18	69	27%					3	26	11%	1	2	9%
Austria										3			1	15%
Nigeria - SPDC	57	69	217	32%	46	45	240	19%	141	627	22%	13	40	32%
Nigeria - SNEPCO		2	6	32%					75	645	12%	44	73	61%
Gabon	17	15	72	21%	14	10	54	19%	11	44	26%	6	11	53%
Cameroun	9	7	34	21%	6	5	21	27%	2	6	28%		1	8%
Angola									7	40	18%	5	47	10%
Rest of EPG	4	3			0	1			1	16	3%	21	56	[illegible]
EPG	357	355	1,529	23%	413	396	1,561	25%	657	2,545	26%	108	331	33%
USA (SO/SPI)	128	132	597	22%	238	274	1,385	20%	369	1155	32%	85	282	[illegible]
Canada	45	46	213	22%	30	34	148	23%	245	619	40%	44	122	[illegible]
Venezuela	11	12	52	23%	12	11	61	18%	9	65	13%			
Argentina	5	1	6	14%	1	2	16	11%	2	26	8%	2	1	[illegible]
Brazil		2	4	58%	3	4	13	28%	1	6	10%	18	55	32%
Rest of EPW												1	2	38%
EPW	190	193	871	22%	284	325	1,623	20%	625	1,872	33%	150	462	32%
Oman PDO	96	63	441	19%					41	291	14%	13	45	30%
Oman Gisco	2	3	22	13%	35	105	514	20%	20	143	14%			
Oman Offshore														5%
Abu Dhabi									11	50	21%		1	27%
Egypt	17	14	49	29%	24	38	120	31%	28	43	65%	8	19	40%
Syria	38	34	152	23%	19	23	98	24%	9	85	10%			
Russia		16	52	31%			18	-2%	39	137	29%			
Kazakhstan												19	108	18%
Iran		14	53	25%		7	35	20%	49	270	18%	2		
Rest of EPM												3		
EPM	153	164	769	21%	78	172	784	22%	188	1,020	19%	48	171	27%
Australia	4	9	30	29%	24	11	62	19%	17	105	16%	16	58	27%
Brunei		1				4			22	178	12%	1	12	6%
New Zealand	3	13	44	30%	3	55	114	48%	3	25	11%	2	7	32%
Malaysia	23	28	184	15%	42	41	217	19%	37	305	12%	4	40	9%
Thailand	7	6	30	19%	4	4	14	30%	7	37	18%		1	35%
Philippines		17	50	33%		3	21	15%	3	4	66%		1	24%
China	7	7	24	30%	7	6	22	28%	5	19	25%	1	6	3%
Pakistan			4	7%			1	2%	11	37	29%		8	1%
Bangladesh	2	2	11	18%	5	4	18	23%		7		1	4	24%
Rest of EPA			8				16			11			7	-2%
EPA	48	84	385	22%	85	128	485	26%	104	727	14%	24	144	17%
Corporate/Other	(25)	(70)	(318)	22%	1	(145)			22	310	7%	(3)	394	-1%
EP Adjustment							135						89	
EP World (incl Oil Sands)	721	727	3,237	22%	881	877	4,378	20%	1,604	6,474	25%	324	1,590	20%
Associates	169	117	497	24%	79	71	306	23%						
PSC Costs	(52)	(57)	(286)	20%	(56)	(59)	(248)	24%						
Oman/Germ	(69)	(45)	(317)	14%	82	59	364	16%						
OA number	768	742	3,131	24%	866	943	4,798	20%						

EP sector results Q1/02

EPF 21 (31) page 31

FOIA Confidential Treatment Requested

V00300657

DB 29406

EP information by country (B1) against YTD target

	Unit operating cost ($/boe)				Unit depreciation ($/boe)				Adjusted unit NIAT ($/boe)				Oil/NGL production (kbd)				Net gas production (mrd m³)			
	YTD'01	YTD'02	Tgt'02	%Tgt	YTD'01	YTD'02	Tgt'02	%Tgt	YTD'01	YTD'02	Tgt'02	%Tgt	YTD'01	YTD'02	Tgt'02	%Tgt	YTD'01	YTD'02	Tgt'02	%Tgt
Netherlands	0.9	1.0	1.1	87%	1.1	1.0	1.4	72%	7.5	7.0	5.2	134%	13	9	11	83%	6.2	5.8	5.9	88%
UK	3.0	2.9	1.6	182%	4.4	5.1	2.0	251%	7.2	4.4	3.3	136%	334	302	308	98%	3.8	3.0	3.1	89%
Norway	3.5	4.2	1.7	240%	2.9	3.4	1.4	240%	4.1	3.2	1.4	222%	88	91	87	104%	0.5	0.5	0.6	78%
Denmark	1.2	1.5	0.7	207%	2.4	1.6	1.1	156%	11.0	9.0	3.2	283%	136	144	130	111%	0.9	0.9	0.9	99%
Germany	2.6	1.9	1.9	105%	1.8	1.5	1.7	88%	10.4	6.3	3.5	180%	5	5	5	107%	1.2	1.5	1.3	113%
Austria	4.1	2.9			3.0				6.0	(2.5)					1	73%	0.0	0.1	0.1	122%
Nigeria - SPDC	2.2	3.2	0.8	424%	1.7	2.1	0.8	247%	3.6	3.2	1.1	278%	256	201	250	81%	0.6	0.6	0.5	109%
Nigeria - SNEPCO																				
Gabon	3.2	3.6	1.2	267%	2.6	2.4	0.9	261%	4.5	4.8	1.2	409%	59	48	53	90%				
Cameroun	5.1	4.3	1.9	224%	3.4	3.3			4.6	6.0	1.5	406%	20	18	16	111%				
Angola																				
Rest of EPG	4.9	4.4			(1.0)	2.1			(28.0)	(25.3)			3	3						
EPG	2.2	2.4	1.2	194%	2.6	2.8	1.4	196%	6.8	5.3	2.7	200%	914	822	861	95%	13.1	12.2	12.3	99%
USA (SO/SPI)	3.9	3.2	1.4	231%	4.3	4.9	2.3	210%	14.9	3.6	2.3	158%	405	417	477	87%	4.0	4.0	4.7	84%
Canada	3.1	3.1	2.0	151%	2.0	2.3	1.4	161%	10.7	3.1	2.0	154%	57	60	62	97%	1.6	1.6	1.6	103%
Venezuela	3.0	2.8	0.9	306%	3.2	2.5	1.1	232%	7.7	5.9	1.8	326%	42	46	49	98%				
Argentina	14.2	2.5	3.9	64%	3.3	5.8	10.3	56%	(12.3)	(2.3)	(20.3)	11%	3			94%				98%
Brazil	0.1	2.9	1.0	299%	4.5	4.4			(16.6)	(13.9)	(8.2)	170%	2	2	2	101%	0.1	0.1	0.1	123%
Rest of EPW																				
EPW	3.7	3.2	1.4	218%	3.9	4.3	2.1	200%	13.4	3.4	2.1	162%	509	527	590	89%	5.7	5.8	6.4	[illegible]
Oman PDO	1.0	1.6	0.4	377%	2.7	1.9	1.0	182%	3.2	2.8	0.9	323%	286	270	277	98%				
Oman Gisco	0.2	0.1	0.1	101%	2.5	5.3	3.3	161%	3.0	1.3	0.7	191%	51	66	78	85%	1.5	2.3	2.6	88%
Oman Offshore																				
Abu Dhabi	0.8	0.9	0.3	332%	0.8	0.9	0.3	302%	1.0	0.9	0.3	288%	109	97	98	99%				
Egypt	1.3	1.0	1.5	68%	1.9	2.7	3.4	79%	5.6	6.9	4.4	155%	14	14	12	114%	0.8	0.7	0.7	100%
Syria	1.9	2.0	0.8	267%	1.0	1.4	0.5	270%	12.5	7.8	2.1	355%	52	52	57	92%				77%
Russia																				
Kazakhstan									-	-	-									
Iran		2.6				1.3								23	20	116%				
Rest of EPM																				
EPM	1.1	1.3	0.5	246%	2.2	2.8	1.5	184%	3.2	1.2	0.4	334%	512	523	542	97%	2.2	3.0	[illegible]	90%
Australia	0.4	1.0	0.5	195%	2.6	1.4	0.8	169%	10.4	5.9	2.0	287%	104	94	72	130%	0.9	1.0	[illegible]	106%
Brunei	2.1	2.2	1.1	195%	1.5	1.7	0.9	204%	4.1	3.0	1.3	235%	98	102	108	95%	1.2	1.4	1.4	99%
New Zealand	1.0	1.4	1.1	128%	1.1	5.9	2.3	258%	5.4	0.1	0.3	44%	8	26	24	108%	0.4	1.2	[illegible]	100%
Malaysia	0.7	0.9	0.8	109%	1.2	1.2	1.0	125%	6.5	4.3	1.4	301%	58	56	59	95%	1.5	1.9	[illegible]	92%
Thailand	3.0	3.0	1.5	205%	1.8	2.2	0.8	278%	7.8	5.5	2.3	237%	16	15	14	101%	0.1	0.1	[illegible]	108%
Philippines		12.9	11.3	114%		2.5	2.2	111%		5.1	(12.2)	-42%		9	2	461%		0.1	[illegible]	65%
China	2.6	3.0	0.4	822%	1.5	2.4	0.3	738%	12.0	7.0	3.5	202%	27	26	22	118%				
Pakistan			5.5						5.0		(5.5)						0.1			
Bangladesh	2.9	3.2	3.0	108%	7.3	6.7	6.5	102%	6.5	6.2	2.4	256%					0.1	0.1	[illegible]	[illegible]
Rest of EPA																				
EPA	1.3	1.7	1.0	174%	1.8	2.2	1.0	214%	6.2	3.8	1.4	273%	313	328	301	109%	4.3	5.7	[illegible]	[illegible]
Corporate/Other																				
EP Adjustment															(28)					
EP World (incl Oil Sands)	2.2	2.1	1.0	202%	2.7	2.6	1.6	168%	8.0	4.0	1.8	223%	2,248	2,199	2,266	97%	25.3	26.8	27.1	98%
WOUSA	1.8	1.8	0.9	197%	2.4	2.2	1.4	157%	6.6	3.7	1.7	215%	1,842	1,782	1,789	100%	21.2	22.8	22.4	101%
USA	3.9	3.2	1.4	231%	4.3	4.9	2.3	210%	14.9	5.8	2.3	258%	405	417	477	87%	4.0	4.0	4.7	84%

EP sector results Q1/02

EPF-2 1632 page 32

FOIA Confidential
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V00300658

DB 29407

EP information by country (B2) against YTD target

*Operational Account basis

	Operating cost (mln $)				Depreciation (mln $)				Production capex * (mln $)			Exploration expenditure * (mln $)		
	YTD'01	YTD'02	Target	%Tgt	YTD'01	YTD'02	Target	%Tgt	YTD'02	Target	%Tgt	YTD'02	Target	%Tgt
Netherlands	34	36	42	86%	43	36	47	75%	37	41	90%	5	4	146%
UK	155	131	162	81%	229	232	209	111%	211	163	130%	1	5	19%
Norway	40	46	48	96%	33	37	39	96%	122	28	439%	11	14	73%
Denmark	21	27	30	92%	43	30	43	70%	49	68	72%	1	3	41%
Germany	20	18	17	106%					3	6	45%			35%
Austria										1		.		[illegible]
Nigeria - SPDC	57	69	54	87%	46	45	60	81%	141	100	168%	13	10	[illegible]
Nigeria - SNEPCO		2	2	89%					75	168	28%	44	18	-3%
Gabon	17	15	18	85%	14	10	13	78%	11	11	105%	6	3	216%
Cameroun	9	7	9	82%	6	5	5	105%	2	1	110%	0		[illegible]
Angola									7	10	73%	5	3	[illegible]
Rest of EPG	4	3				1			1	4	13%	21	9	[illegible]
EPG	357	355	380	93%	413	396	417	95%	657	600	110%	108	71	[illegible]
USA (SO/SPI)	128	132	156	85%	238	274	345	80%	369	195	189%	85	112	[illegible]
Canada	45	46	53	87%	30	34	37	93%	245	155	158%	44	31	[illegible]
Venezuela	11	12	12	99%	12	11	14	75%	9	15	57%			
Argentina	5	1	2	52%	1	2	4	46%	2	6	34%	2		[illegible]
Brazil		2	1	244%	3	4	3	112%	1	1	67%	18	18	[illegible]
Rest of EPW												1	1	[illegible]
EPW	190	193	224	87%	284	325	403	81%	625	372	168%	150	161	[illegible]
Oman PDO	96	83	109	77%					41	70	59%	13	13	103%
Oman Glsco	2	3	6	54%	35	105	122	86%	20	36	55%			
Oman Offshore														6%
Abu Dhabi									11	13	86%			134%
Egypt	17	14	15	97%	24	38	33	114%	28	3	882%	8	13	56%
Syria	38	34	38	90%	19	23	25	91%	9	21	42%			
Russia		16	17	92%			10	-3%	39	46	85%			
Kazakhstan												19	21	[illegible]
Iran		14	12	111%		7	10	69%	49	45	109%	2		
Rest of EPM												3	5	[illegible]
EPM	153	164	196	84%	78	172	200	86%	198	234	84%	46	53	[illegible]
Australia	4	9	8	118%	24	11	12	93%	17	23	73%	16	18	[illegible]
Brunei		1	2	74%		4	3	118%	22	45	49%	1	2	[illegible]
New Zealand	3	13	13	100%	3	55	27	203%	3	3	85%	2	1	[illegible]
Malaysia	23	28	49	58%	42	41	62	66%	37	78	47%	4	3	110%
Thailand	7	6	7	86%	4	4	4	120%	7	9	79%			
Philippines		17	22	76%		3	4	75%	3	1	266%			114%
China	7	7	6	123%	7	6	5	111%	5	5	101%	1	3	[illegible]
Pakistan			1	41%					11	9	118%		2	[illegible]
Bangladesh	2	2	2	96%	5	4	5	91%				1	1	[illegible]
Rest of EPA														[illegible]
EPA	48	84	109	77%	85	128	122	105%	104	173	60%	24	30	[illegible]
Corporate/Other	(25)	(70)	(78)		1	(145)	(19)		22	78		(3)	118	
EP Adjustment														
EP World (incl Oil Sands)	721	727	831	87.5%	861	877	1123	78%	1604	1456	110%	324	433	75%
Associates	169	117	118	99%	79	71	70	102%						
PSC Costs	(52)	(57)	(76)	75%	(56)	(59)	(61)	97%						
Oman/Germ	(69)	(45)	(77)	58%	82	59	93	64%						
OA number	768	742	798	93.0%	966	943	1222	77%						

EP sector results Q1/02

EPF-211s33 page 33

Specials

	NIBIAT (press release) (mln $)				NIAT including minority interest (mln $)			
	Q1/01	Q1/02	2001	2002	Q1/01	Q1/02	2001	2002
World reported net income (including specials)	2,847	1,570	2,847	1,570	2,851	1,566	2,851	1,566
Redundancy / restructuring Group Companies								
Subtotal redundancy / restructuring	0	0	0	0	0	0	0	0
Divestment / asset sales		115		115		115		115
Taxation								
Litigation provision								
Impairment write-downs								
Total specials	0	115	0	115	0	115	0	115
World adjusted net income	2,847	1,455	2,847	1,455	2,851	1,452	2,851	1,452

List of 2002 special items

			NIAT
Q4/02			
Q3/02			
Q2/02			
Q1/02	Sale of license for Expandable tubular products and services to Weatherford (USA)	101	
	Sale of CNOOC Shares (China)	14	
			115
2002 specials total			115

List of 2001 special items

		NIAT
Q4/01	No specials	0
Q3/01	Litigation Provisions (USA)	-10
Q2/01	Litigation Provisions (USA)	-14
Q1/01	No specials	0
2001 specials total		-24

From:	Powell, Ceri CM SIEP-EPB
To:	Van De Vijver, Walter SI-MGDWV
CC:	
BCC:	
Sent Date:	2002-07-26 13:54:26.000
Received Date:	2002-07-26 13:54:28.000
Subject:	FW: Summary Notes from MGDWV visit to SDS - July 2002
Attachments:	Highlights from SDS - July 19th.doc

-----Original Message-----
From: Powell, Ceri CM SIEP-EPB
Sent: 26 July 2002 13:00
To: Leonard, Mark MS SIEP-EPT-D
Subject: Summary Notes from MGDWV visit to SDS - July 2002

Mark,
Please find attached Walter's summary notes and action points from the visit to SDS last week - the first page is an Executive Summary and then some more detailed points.

John Darley has been sent an identical document.

If you need any clarification, please let me know or send Walter an Email directly.

Kind Regards,
Ceri

Ceri M. Powell
Business Advisor to EP CEO
SIEP The Hague, C16/504
*P.O. Box 663, 2501 CR, The Hague, The Netherlands
*Work: +31 (0) 70 377 3641
*E-mail: ceri.powell@shell.com

EXHIBIT
Darley 9
11/16/06
GAIL F SCHOHR, C.S.R., C.R.R

Executive Summary and Key Forward Actions

SDS (Shell Deepwater Services)

The overall impression is of an outfit in touch with the external pressures from the competitive environment, with detailed planning and modelling available to understand the contribution of deepwater to Shell's future production profile. Shell share production could still grow way beyond 1,000,000 boe/d in the coming 10 years. The current workload for SDS is Nigeria 30% and SEPCo 50%. From an external visitor perspective the organization appears very large.

Difficult areas appear to be Brazil with no hub class discoveries and poor quality crude with refining issues, and the lack of experience in NOV operations that will become more critical through the next decade as NOV production rises to 30% of Shell's global production by 2012.

FORWARD KEY ACTIONS:

- More clarity for top EP management on where FONG will be used is needed – a lot of confusion currently.
- More work on developing the No 1 in deepwater metrics as positive, simple, clear messages to the external world needs to be done.
- Ensure that there is a dedicated team on Block 18, to ensure that the critical control points for Shell are being appropriately dealt with by the operator.
- More transparency and accurate numbers on staff creep from Houston to New Orleans is needed from SDS as well as SEPCo.
- Is the overall management structure sufficiently lean (including "soft issues" management)?

Highlights, Key Positives (✓) and Negatives (✖) of visit, and points of Action/Steer.

SDS - Houston

SDS, based dominantly in Houston but with 150 staff in New Orleans, provides Deepwater Services – Exploration, Development and Production – to the deepwater business within the OUs worldwide. The extended leadership team was present at a 2-hour presentation/engagement session at Wood Creek.

The overall impression is of an outfit in touch with the external pressures from the competitive environment, with detailed planning an modelling available to understand the contribution of deepwater to Shell's future production profile. SDS should be careful not to create tension by taking credit for success when significant amount of technical work on successful projects has been undertaken by the OUs.

Global Overview

✓ The future production from deepwater in 2012 has been increased from 1 MBOE/day to 1.4MBOE/day, partly due to the Enterprise acquisition but also from Nigeria – Bolia, Bosi and Bonga.

✓ The Enterprise production brings the deepwater production to a 10% growth rate through 2002-2006 (but without the Enterprise deal, deepwater could not sustain the historical growth rates through 2003 and 2004)

✓ SDS and Shell EP have achieved a No 1 or No 2 position in many facets within the global deepwater competitive landscape – a first pass overview of these provided an impressive array of metrics which can be used at specific external engagements.

✖ SDS and Shell EP need to increase the skill base for dealing with Non Operated Ventures, which will account for 30% production by 2012.

✖ Concern as highlighted by SDS management over the lean portion of the deepwater funnel between VAR 2 and VAR 3 – no new big projects and no new hubs.

ACTION/STEER:

- A closer link between thee Deepwater funnel, obviously the fundamental tool of the business, and the Global Exploration and NBD funnels in EPB, would be advantageous.
- More work on developing the No 1 in deepwater metrics as positive messages to the external world needs to be done – ensuring the messages are validated, sustainable, extremely simple and clear. Distill the facts from today not the anticipation of tomorrow.

Specific Deepwater Basins

In terms of staff time, 50% of SDS time is spent on the GoM and 33% on Nigeria.

✓ Regional studies offshore Sabah kept the oil play in the shallow-deepwater transition alive, and now KBB-3 has proved an oil play (However, Murphy can now claim the first deepwater oil in East Malaysia which is a blow to Shell)

- The Brazil portfolio is very robust with 15 blocks in 3 plays – the concern remains oil quality. BS-4 has just passed VAR2 and is now working with OP for refining solutions, and BC-10 will achieve VAR2 in 2003 (late Q2, early Q3).

✖ Some major GoM fields are declining at 10-20% PER YEAR!, so significant expenditure on new projects is needed just to keep the GoM production flat.

✖ For Nigeria the OPEC quota and gas solutions remain the blockers to truly unleashing the province. An even bigger prize potentially awaits in the Ultra Deep Water.

✖ The timetable in Brazil is closely tied to ANP that may force the pace of development faster than is comfortable for Shell's internal decision-making processes.

✖ A great deal of concern around the small field delivery in the GoM – the subsea concept is not delivering the future production as quickly or effectively as was anticipated.

ACTION/STEER:

- Don't "run ahead of the headlights" on Perdido – large hype followed by failure is not appreciated (remember Baha).
- On Nigeria increased communication between the technical team management and the business is necessary (no surprises, clear accountabilities).
- Don't oversell Brazil yet – no hubs have emerged which is disappointing and we need to think further about the ANP strategy.

- Don't waste time on places like India – work within the confines of the Aspired Portfolio in conjunction with EPB.
- Ensure that there is a dedicated team on Block 18, to ensure that the critical control points for Shell are being appropriately dealt with by the operator.

Deepwater Technology

✓ Punch and Go drilling technology could revolutionise exploration – with the option of drilling 10 wells for the same price as 2. Currently the technology is limited to 2000ft drilling depth so significant work is needed until positive impact on the exploration decision-making process will be seen.
✓ Expandable tubulars and now the mondiameter wells are a real competitive edge for Shell EP.

ACTION/STEER:
- More clarity for top EP management on where FONG will be used is needed – a lot of confusion currently.

Reserves Booking/E&A Strategies and Organisation

ACTION/STEER:
- Worried by premature bookings globally – NO BOOKINGS PRE VAR 3
- Lots of money is being spent on projects before FID, with no reserves left ot book at FID – this has a serious impact on the global F&D costs, and is a trend which must be reversed.
- Booking more aggressively to SFR is acceptable but moving from SFR to Proved needs great care.
- With the significant deepwater leadership team proposed in the new STEP matrix model, is the Deepwater Steering Council really necessary?
- Very concerned that, contrary to previous steer, new deepwater developments are being worked from New Orleans AND Houston. More transparency and accurate numbers on staff creep from Houston to New Orleans is needed from SDS as well as SEPCo.

File PDO

Darley, John J SIEP-EPT

From: Willis, Rob R SIEP-EPT-AGI
To: j.darley@siep.shell.com
Cc: LYLE.L.E.HENDERSON/O=SHELLUS/PRMD=SHELLUSA/ADMD=ATTMAIL/C=US/DD.ID=126773@kseu500; Iain.I.D.R.Percival/O=epea/PRMD=shell/ADMD=400net/C=nl@kseu500; Ruijtenberg, Piet PA SIEP-EPT-AGI
Subject: SepTAR PDO Studies: Briefing Note

John,

As requested a briefing note for your meeting with Din Megat. Please call if you have any questions.

Regards
Rob
ph: 3112178

Closed-out studies
=================
Three SepTAR studies have been closed-out. Study recommendations have been accepted by PDO.
Al Burj field: implement WI, plus reserves booking (2.3MMm3).
Karim West field: implement 2X5 spot WI pilot, oil gains expected in 2003.
Harweel cluster Harweel Cluster (carbonate stringer) project. The results indicated that primary recoveries were high enough to justify primary development and that there was very significant potential for gas injection if the early production can show adequate reservoir connectivity.

Status of current studies
==========================
The ongoing SepTAR (AGI/H) PDO studies are on track (i.e. Mukhaizna, Rahab, Lekhwair, Al Huwaisah, Amin, Nimr G, Zauliyah). There is an ongoing effort to role interim results back into PDO's program e.g. QA/QC of 2002 drilling locations (Nimr G prioritised drilling of a number of wells), Quick wins identified (Amin 500m3/d risked gains).

A PDO field "Portfolio" review is expected to complete end June 2002 (3 SepTAR staff were assigned to this 2 month project). The objective of the review is to further develop the current studies ranking method (Undeveloped Reserves vs Oil Gains). The Portfolio review will look into grouping fields/areas into themes e.g. reservoir type, fluid type, process type. The portfolio review will also aim to create a funnel "schematic" i.e. time relationship to development, and when they should study what.

iii) The internal PDO studies need attention (50% of in-house studies have either stopped or are behind schedule). The quarterly PDO/SepTAR Studies Steering Group (SSG) meeting scheduled for the 3rd of June has been postponed to a later date in the month. PDO will have an internal meeting to solely address the slippage of in-house studies

EXHIBIT
Darley 10
11/16/06
GAIL F. SCHORR, C.S.R., C.R.R.

Start-up of new studies
=======================
The Marmul Al Khalata field project framing exercise was completed at the end of May 2002. There are no PDO staff available to work with us in SepTAR on this study! An issue in terms of later embedment of results in PDO at project close-out. A compromise maybe that SepTAR staff could handover in PDO at end of the project (1 or 3 months?), or PDO to some how find someone to participate.

Natih framing exercise beginning July - issue data transfer is very slow!, not critical path yet.

Natih B thermal conduction project - PDO agreed to cut core, additional service work to be agreed by PDO.

As SepTAR staff close-out ongoing studies, the plan is to role them onto the next studies. We are therefore available to pick up the next tranche of studies in July (AGH) and October (AGI). We are currently waiting on the portfolio review results to see what fields we are likely to study next.

A Reservoir Management FRD, expected to last some 90 days, is scheduled to start at the beginning of June. The idea is for an experienced group of staff to review a number of selected fields: demonstrate sound RM practices, implement surveillance plans, identify oil gains. Paul Mann (RBA) is currently attempting to identify SepTAR staff who could possibly work on this initiative, The issue here is availability, and current work priority, of high quality SepTAR staff! Resourcing for this initiative is in an embryonic stage.

Planning/Process
==================
PDO (Lamki) has requested a SepTAR studies effort of some 38 persons till mid 2003, then ramping down to around 10. We have a process in place to capture ad hoc service request, and ensure they are ranked, then either proceed, put on hold or are rejected. Controlling "Ad hoc" requests requires a lot of attention given the size of both the SepTAR and PDO organisations e.g. PDO asset teams directly requesting SepTAR support and visa versa. To further address this, PDO requested a focused (controlled) effort in terms of SepTAR Technology thrusts into PDO. The seamless team concept was again discussed, Stuart Evans to progress with Keith Eastwood.

MOG
===
Technical advisors from the Ministry of Oil and Gas have been involved in a number of study milestone visits, both in PDO and SepTAR. I believe they have buy in of our work program, and are comfortable with the SepTAR effort to date.

DUDA fI- RKQ- 6,(31(37

From: Willis, Rob R SIEP-EPT-AGI
To: j.darley@siep.shell.com
Cc: LYLE.L.E.HENDERSON/O=SHELLUS/PRMD=SHELLUSA/ADMD=ATTMAIL/C=US/DD.ID=126773@kseu500; Iain.I.D.R.Percival/O=epea/PRMD=shell/ADMD=400net/C=nl@kseu500; Ruijtenberg, Piet PA SIEP-EPT-AGI
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FOIA Confidential Treatment Requested

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MOG
===

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July 3rd

PDO Board Mtg :

Base Case: established
Threat Case: not enough people
Opportunity Case: rig count / staff?

> 2002 prodn lagged
> Plan build 2003.
> Not moving in right direction / what answers do Shell give

1. How situation arose? Why so bad
2. What Shell commitment needed?

↳ Partnership back on track.

> Need to actually have things in place / running

Paul: Prodn: slide continues, "ramp-up" disappeared?, stimulation not delivery.
769,000 (2002),
: Septar study program ok : PDO study progress very poor.
plan 80 man years, actually 60 man years.

Prog 2003: earlier plan? 720,000 b/d : now: 700,000 b/d.
- related to staffing / establishment / lack of opportunities?
- no stretch, not looking for opportunities.

Portfolio: 1 month in, for 3 months (J. Evans) : strategic thinking.
21 fields: 80% reserves, ← reserves supported.
segment by themes. need W.I. and ETR, + short term New Field.

Manpower: Amran responsibility. - Resource requirements 2003/04

200,000 b/d: short term drive to identify
drive
↳ Steve O.

- exploration re-focus.
- appraisal, plan for success
- EOR / IOR. waterflood FRD
- res mgt FRD W.I. FRD.

From: Darley, John J SIEP-EPT
To: Leonard, Mark MS SIEP-EPT-D; Knight, Barry BP SIEP-EPT-DE
CC: Sullivan, Paul PR SI-PSSL-BI; Antheunis, Dan D SIEP-EPT-A; Henderson, Grahaeme G SIEP-EPT-IO; Greer, David DJ SIEP-EPT-P; Polder, Laurien LJ SIEP-EPT-H; Rambousek, Jim JC SIEP-EPT-C
BCC:
Sent Date: 2002-09-22 13:49:04.000
Received Date: 2002-09-22 13:49:04.000
Subject: FW: AG Edwards analyst meeting
Attachments:

Mark, Barry,

Good to see your work was well received by the investor community

John

> -----Original Message-----
> From: Sexton, David A SHLOIL
> Sent: 20 September 2002 20:01
> To: Darley, John J SIEP-EPT
> Cc: Cunnane, Bernadette B SIEP-EPT-ER; Henry, Simon S SI-FI
> Subject: AG Edwards analyst meeting
>
> John:
>
> Again, my thanks for agreeing to speak at the AG Edwards
> conference in Boston. Based on the feedback I received, your
> presentation was well received and a big hit! I am sorry I
> missed you and Loren at the lunch but by the time I finished
> calling people back, the lunch was almost over and I had to
> leave for the airport.
>
> Finally, attached is the report from the conference that
> resulted from your presentation and as you can see, the
> analyst firm has us at a buy, which is always very positive
> for our company.
>
> On to Houston..
>
> David
>
>

EXHIBIT
Darley 11
11/17/06

A.G. Edwards

Royal Dutch Petroleum

September 19, 2002

Buy/Conservative

L. Bruce Lanni, *Senior Analyst* (212) 557-5023
Ron Oster, *Associate Analyst* (314) 955-7914
Marlise Randle, *Associate Analyst* (212) 557-0496

ENERGY

Symbol: **RD**
Exchange: **NYSE**
Recent Price: **$40.55**

Fiscal Year Ends December 31

	2002E	2003E	2004E
EPS	$2.60	$3.15	$3.35
P/E	15.6	12.9	12.1
DCF	$5.10	$5.90	$6.15
P/DCF	8.0	6.9	6.6

	2002E	2003E	2004E
EV	$50.15	$50.10	$49.65
EBITDA	$7.00	$8.20	$8.60
EV/EBITDA	7.2	6.1	5.8
ROCE	10%	12%	12%

Fundamental

52-Week High	$57.30
52-Week Low	$39.65
Dividend	$1.57
Yield	3.9%
Est. EPS CAGR (2002-04)	14%
Est. LT Div. CAGR (2002-04)	5%
Net Debt	31%
Interest Coverage	15.7
Market Value (bil.)	$85
Price Objective	$52

Trading

Shares Outstanding (bil.)	2.1
Estimated Float (bil.)	2.1
Insider Holdings	1%
Institutional Holdings	26%
Avg. Daily Volume (mil.)	2.8

Operating

Business Segment Mix (% earnings)	
Oil & Gas	65%
Refining & Marketing	24%
Chemical	6%
Est. Production CAGR (2002-04)	3%
R/P Ratio (years)	14.1
Resv Replacement (3-Yr Avg)	86%
F&D Costs (3-Yr Avg)	$4.40
Oil Sensitivity ($1/bbl change)	$0.21
Gas Senv ($0.10/mcf change)	$0.08
Refining Senv ($1/bbl change)	$0.32

Disclosure Information: Please refer to pages 11-12 of this report for important disclosure information.

Concept List: DSIP

The Original Pioneer of the Deepwater

- Following management's presentation at our Deepwater Energy Conference in Boston (9/19), the company reiterated their continued emphasis on the deepwater, where they are currently the second largest producer with an estimated 800,000 BOE/d. Key areas of focus remain the Gulf of Mexico and West Africa (particularly Nigeria), along with Malampaya (Philippines).
- From 2000-2005, capital investment in the deepwater is expected to make up 33% (or $2.5 billion per year) of total E&P spending, demonstrating management's continued confidence in this region, following a record year in terms of deepwater reserves discovered in 2001. Moreover, *the deepwater is expected to comprise approximately 15% of worldwide production in 2005.*
- Royal Dutch/Shell has set numerous deepwater records for platforms as well as aggressively pursuing the utilization of subsea production facilities, and continues to make research and technology an area of focus. *Management estimates that their most recent advancement, monodiamter wells, could decrease deepwater drilling costs by 50% and could be implemented in 2003.*
- Despite being the top producer in the Gulf of Mexico, estimated at 450,000 barrels per day, further growth will be augmented by about 40 deepwater discoveries to date and the full ramp up of its Princess discovery in late 2002 (working interest 45%), along with the Na Kika complex (working interest 50%) in mid-2003.
- In addition, Royal Dutch/Shell is estimated to have the largest deepwater reserve base in Nigeria, bolstered by a strong leasehold position and the Bonga/Bonga Southwest discoveries, which could contain gross combined reserves over 1.5 billion BOE, or about 800 million BOE each. Accordingly, we reiterate our Buy rating on RD and price objective of $52.

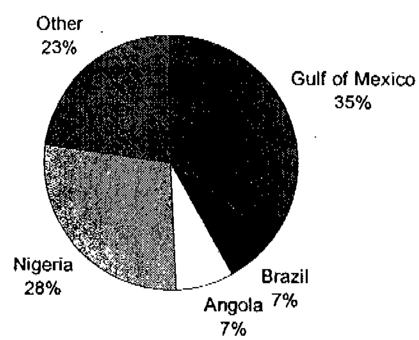
Company Description: *Royal Dutch is an integrated oil and gas company with global operations in both the upstream and downstream business segments.*

Overview

Management has successfully altered the complexion of the company by implementing a number of strategic initiatives, including aggressive cost reductions and asset sales, in a successful effort to maintain strong returns and win back investor confidence after missing out on the massive consolidation trend that swept across the industry. Its portfolio has been strengthened in all business segments through smaller strategic acquisitions and the divestments of non-core assets. In addition, capital discipline remains embedded in the company, as demonstrated by its high returns (ROCE), disciplined CAPEX spending (based on conservative oil and U.S. gas price forecast of $16 per barrel (Brent) and $3.00 per Mcf (Henry Hub) and above average upstream performance.

Oil and gas production is expected to grow at an annual rate of 2-3% over the next several years, with new volumes augmented by the company's extensive inventory of worldwide deepwater prospects (an area in which the company has been highly successful) and to some extent the acquisition of Enterprise. *The company is the second largest producer in the deepwater (next to Petrobras), with current production estimated in the area of 800,000 BOE/d (barrels of oil equivalent per day).* Key areas of focus include: the Gulf of Mexico, West Africa (Nigeria and Angola) and Brazil, along with Canada, the Philippines, Malaysia, Australia, Russia and the North Sea. Approximately 35% of Royal Dutch/Shell's total estimated deepwater reserves (includes producing, under development and discoveries) has been in the Gulf of Mexico followed by Nigeria at 28%.

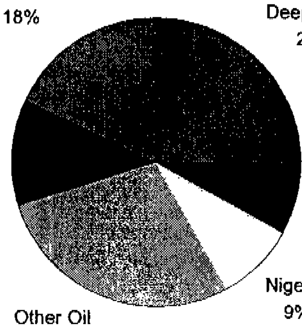
FIGURE 1 Estimated Deepwater Reserves



Source: Douglas-Westwood Limited, Infield Systems Limited, MMS, Company Data, Various Industry Data and A.G. Edwards & Sons, Inc. Estimates.

In addition, Royal Dutch/Shell estimates that its total deepwater capital investments during 2000-2005 should be in the area of $2.5 billion, or 33% of its $7.5 billion annual upstream budget.

FIGURE 2 Estimated Upstream Capital Investment 2000-2005



Source: Royal Dutch/Shell

Deepwater Exploration, Development and Production Regions

Gulf of Mexico

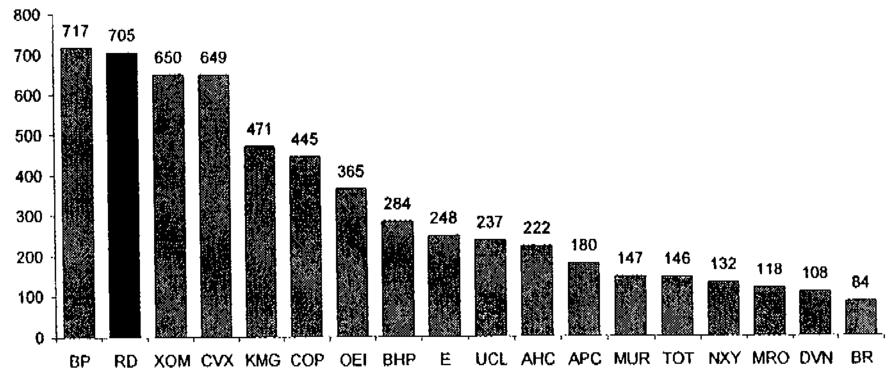
Royal Dutch/Shell was the first company to commence production from the deepwater Gulf of Mexico (GOM), driven by its explosive deepwater activities in the early 1990's. *The company has been a pioneer in this area, setting numerous deepwater records for platforms as well as aggressively pursuing the utilization of subsea production facilities.* Production first occurred at Royal Dutch/Shell's Cognac field in 1979 in 1,000 feet of water, some five years ahead of the next GOM deepwater discovery (Exxon's Lena in 1984) that was brought on-line. Since then the company has been one of the leaders in moving into the deep water, setting numerous deepwater records and milestones.

- 1988 - Bullwinkle - world's tallest conventional fixed platform
- 1993 - Auger TLP established a GOM water depth record
- 1996 - Mars TLP again setting a water depth record
- 1997 - Ram/Powell TLP surpassed Mars in a water depth
- 1998 – Ursa TLP was installed in 3,800 feet of water
- 2001 - Brutus TLP was installed in GC 158 in 2,985 feet of water
- 2003 – Na Kika floating development and production system ultimately will service 6 subsea production systems

Not surprisingly, BP and Royal Dutch/Shell (post the Enterprise acquisition) have amassed interests in the most deepwater blocks, followed by ExxonMobil and ChevronTexaco. In addition, *the company has made approximately 40 deepwater discoveries in the GOM and is currently the top producer, estimated at 450,000 barrels per day*, augmented by bringing on-line its Brutus field in late 2001. Production volumes are projected to increased after full ramp up of its Princess discovery in late 2002 (working interest 45%) and the Na Kika complex (working interest 50%) in mid-2003.

FIGURE 3 U.S. Deepwater Lease Ownership

(Leases updated for WGOM sale 184)



Source: Company data and A.G. Edwards & Sons, Inc. estimates

Clearly a dominant player in this area, Royal Dutch/Shell still holds eight of the top 20 discoveries in the region. Major producing fields include (based on gross reserves): Cognac (305 million), Bullwinkle (180 million), Auger (215 million), Mars (700 million), Mensa (120 million), Ram/Powell (260 million), Ursa (390 million) and Brutus (245 million). Future developments that should continue to make this an area of growth include: Princess (200 million), Na Kika (290 million), Glider (130 million), Holstein (250 million) and Baha (180 million BOE).

FIGURE 4 Gulf of Mexico: Major Oil and Gas Fields

			Reserves (Net)			Production (Net)		
Field	Operator	First Production	Total (MMBOE)	Oil (MMBbls)	Gas (Bcf)	Total (MBOE)	Oil (Mb/d)	Gas (MMcf/d)
Cognac (MC 194)	SC	1979	106	65	251	14	3	66
Bullwinkle (GC 65, 109)	SC	1989	183	144	231	73	57	100
Auger (GB 426)	SC	1994	217	154	375	170	101	415
Mars (MC 809)	SC	1996	501	429	429	184	157	157
Mensa (MC 687)	SC	1997	120	-	720	50	-	300
Ram/Powell	SC	1997	100	54	273	46	27	116
Ursa (MC 809)	SC	1999	165	105	357	91	63	168
Brutus (GC 158)	SC	2001	246	175	425	125	100	150
Princess (MC 765)	SC	2002	90	68	135	18	14	27
Glider (GC 248)	SC	2003	133	100	200	32	25	40
Na Kika (MC 474)	SC/BP	2003	146	83	383	77	50	163
Holstein (GC 644-5)	BP	2004	125	100	150	35	30	30
Baha (AC 600)	SC	2008	69	56	75	19	15	23

Source: Douglas-Westwood Limited, Infield Systems Limited, MMS, Company Data, Various Industry Data and A.G. Edwards & Sons, Inc. Estimates.

West Africa
Led by the discovery of multiple giant oil fields offshore Angola and Nigeria, *West Africa is emerging as the world's fastest growing deepwater regions.* Average annual deepwater production growth for West Africa is estimated at 28% through 2006 versus a global deepwater growth rate of 11%. Moreover, the proportion of worldwide deepwater production from West Africa is projected to be 22% in 2010 versus 7% in 2001. Accordingly, *Royal Dutch/Shell's leading position in this region (particularly in Nigeria) places the company favorably for future growth and additional upside from its exploration potential.*

Nigeria
Royal Dutch/Shell is estimated to have the largest deepwater reserve base in Nigeria, bolstered by a strong leasehold position and the Bonga/Bonga Southwest discoveries, which could contain gross combined reserves over 1.5 billion BOE, or about 800 million BOE each. *To put these discoveries in perspective, the average field size in the deepwater West Africa is estimated at 485 million BOE.*

The Bonga field (operator, 55% working interest) was Nigeria's initial deepwater discovery. First production is now scheduled for 2004 (Bonga Southwest scheduled for 2006) and will be developed using 29 subsea wellheads, tied back to an FPSO (Floating, Production, Storage and Offloading system) with 225,000 barrels per day of processing capacity and 2 million barrels of storage. Total project costs are estimated at $2.7 billion. Gross peak production rates for Bonga should be in the 250,000 barrels per day area and approximately 230,000 barrels per day for Bonga Southwest. Additional satellite prospects in the area could extend production and make this an area of growth for many years to come. Moreover, Bonga represents Nigeria's first deepwater gas development, with 500 Bcf of gross reserves and expected peak daily production of 170 MMcf per day. This gas will supply the third train of the Bonny LNG facility, which should be completed by late 2003.

In addition to the Bonga developments, Shell has announced several other major discoveries on block OPL-219 where they are the operator with a 55% working interest, including: Doro (1.1 billion gross reserves), Ngolo (400 million gross reserves) and Bolia (250 million gross reserves).

Moreover, the company also has a 44% working interest in the ExxonMobil operated block OPL-209 which includes including: Erha (1 billion gross reserves) and Bosi (1 billion gross reserves). Government approvals have been requested and contractor bids have been solicited for the Erha project with expected start-up in 2005. The Erha FPSO is designed to produce volumes of 150 Mb/d (gross).

FIGURE 5 **Nigeria: Major Oil and Gas Fields**

			Reserves (Net)			Production (Net)		
Field	Operator	First Production	Total (MMBOE)	Oil (MMBbls)	Gas (Bcf)	Total (MBOE)	Oil (Mb/d)	Gas (MMcf/d)
Bonga Main (OML 118)	SC	2004	104	94	63	29	25	23
Ehra (OPL 209)	XOM	2005	560	504	336	162	118	269
Bonga SW (OML-118)	SC	2006	458	413	275	127	110	99
Doro (OPL-219)	SC	2008	605	55	3300	61	6	330
Bolia (OPL-219)	SC	2009	142	124	110	33	33	-
Ngolo (OPL-219)	SC	2010	220	165	330	55	44	66
Bosi (OPL 209)	XOM	2011	579	112	2800	97	22	448

Source: Douglas-Westwood Limited, Infield Systems Limited, MMS, Company Data, Various Industry Data and A.G. Edwards & Sons, Inc. Estimates.

Angola

Royal Dutch/Shell's deepwater focus in Angola revolves around the company's 50% interest in the BP operated Block 18. Six wells were drilled in the period 1999/2000, resulting in six discoveries: Plutunio (300 million gross reserves), Platina (300 million gross reserves), Paladio (165 million gross reserves), Galio (165 million gross reserves), Cobalto (135 million gross reserves), and Cromio (105 million gross reserves).

Although substantial resources have been discovered, they are widely spaced geographically, which leads to infrastructure related costs and operational issues that need to be contained in order to achieve a viable development project. The selected concept will likely be a large-scale development scheme where production is bought to a central processing hub in the Greater Plutonio area with first production scheduled for 2005.

In addition to Block 18, Shell holds a 10% interest in Block 21 and a 15% interest in Block 34.

FIGURE 6 **Angola: Major Oil and Gas Fields**

			Reserves (Net)			Production (Net)		
Field	Operator	First Production	Total (MMBOE)	Oil (MMBbls)	Gas (Bcf)	Total (MBOE)	Oil (Mb/d)	Gas (MMcf/d)
Plutonio (Block 18)	BP	2005	150	138	75	35	30	30
Cobalto (Block 18)	BP	2007	69	65	25	18	15	15
Platina (Block 18)	BP	2008	150	138	75	35	30	30
Galio (Block 18)	BP	2008	82	75	43	23	20	20
Campos (BC-10)	SC	2009	196	196	-	35	35	-
Cromio (Block 18)	BP	2009	54	50	25	18	15	15

Source: Douglas-Westwood Limited, Infield Systems Limited, MMS, Company Data, Various Industry Data and A.G. Edwards & Sons, Inc. Estimates.

Brazil

Royal Dutch/Shell has interests in seven deepwater exploration blocks three operated (BC-10, BS-4 and BM-C-10) and four non-operated (BCe-2, BM-C-14, BM-S-8 and BM-FZA-1). The company has discovered hydrocarbons in five out of nine initial exploration wells, and announced a successful appraisal well and production test on an oil discovery in block BS-4.

With first production expected from Bijupira in 2003, the company is set to become only the second international company with oil production in Brazil and the only non-Petrobras operator in the Campos Basin. The only other foreign company with Brazilian production is Repsol, which owns 10% of the Albacora complex.

Peak production from Bijupira is expected to be in the 50,000 barrel per day range. Shell picked up the field following its acquisition of Enterprise, which farmed into the acreage in 2000 and owned 80%. Total development costs have been cited in the $700 million area for the field and recoverable reserves currently estimated at 130 million barrels. In addition, Shell made a significant discovery on its BS-4 block in the Santos Basin late last year.

FIGURE 7 Brazil: Major Oil and Gas Fields

Field	Operator	First Production	Reserves (Net) Total (MMBOE)	Reserves (Net) Oil (MMBbls)	Reserves (Net) Gas (Bcf)	Production (Net) Total (MBOE)	Production (Net) Oil (Mb/d)	Production (Net) Gas (MMcf/d)
Bijupira	SC	2003	103	96	40	45	40	28
Campos (BC-10)	SC	2009	196	196	-	35	35	-

Source: Douglas-Westwood Limited, Infield Systems Limited, MMS, Company Data, Various Industry Data and A.G. Edwards & Sons, Inc. Estimates.

Investment Summary

We continue to view Royal Dutch favorably and rate shares **Buy/Conservative** based on:

- Management's ability to successfully alter the company by implementing a number of strategic changes,
- Consistently generating one of the highest returns (ROCE),
- Highly successful upstream operations, particularly in the deepwater,
- Strengthening its downstream operations through recent acquisitions/divestitures, and
- Increasing cash returns to shareholders' through dividend increases and share buybacks.

Additionally, trading at 14x our 2003 mid-cycle earnings estimate, Royal Dutch appears to be under valued based on discrepancies versus its peers, trading at approximately a 20% discount to ExxonMobil and 5% below BP. Moreover, given the company's current fundamentals, exploration prowess, returns, portfolio of long-term growth projects and our opinion that the stock is still feeling the after affect of being removed from the S&P 500, we feel this represents a buying opportunity and continue to rate shares **Buy/Conservative**.

Our **$52 price objective** is based on 18x (within 10% of the historic S&P 500 multiple of 18x-20x) our 2003 estimate for mid-cycle earnings of $2.85; defined as $22.00 oil prices (WTI), $3.50 U.S. natural gas prices (Henry Hub) and a $4.50 U.S. composite refining margin. These estimates reflect what we believe is a normalized trading range for commodities and downstream margins.

Finally, we recently revised our 3Q02 earnings estimate to $0.63 from $0.69 and full year 2002 estimate to $2.60 from $2.70, reflecting lower than expected refining margins (both U.S. and foreign). This compares to consensus estimates of $0.69 and $2.70, respectively.

FIGURE 8 **Valuations and Investment Premise and Concerns**

Valuations

Royal Dutch

Ticker; NYSE	RD
Rating; Buy/Conservative	B/C
Price Objective (12-month) *	$52
2003 Mid-cycle EPS *	$2.85
2003 Projected EPS **	$3.15
Current P/E (based on 2003 Mid-cycle EPS) *	15x
Current P/E (based on 2003 Projected EPS) **	12x
Target P/E (based on 2003 Mid-cycle EPS) ***	18x
Premium (discount) to international group (based on 2003 Mid-cycle EPS)	-8%

* Our price objective is based on our 2003 estimate for mid-cycle earnings; defined as $22.00 oil prices (WTI), $3.50 U.S. natural gas prices (Henry Hub) and a $4.50 U.S. composite refining margin. These estimates reflect what we believe is a normalized trading range for commodities and downstream margins.

** Our projected 2003 EPS is based on $25.00 oil prices (WTI), $3.50 U.S. natural gas prices (Henry Hub) and a $4.00 U.S. composite refining margin.

*** The target P/E, which is based on mid-cycle earnings, assumes RD trades at a 5%-10% discount to a normalized S&P 500 multiple of 18x-20x.

Investment Premise

- Currently trading at 14x 2003 mid-cycle earnings, Royal Dutch appears to be under valued relative to its peers, at approximately a 20% discount to ExxonMobil (20x), and 5% below BP (15x). Moreover, based on the company's current fundamentals and future growth projections (which are essentially in line with its peers), we believe a price-to-earnings multiple within 10% of the S&P 500 is justified.

- Management has successfully altered the company by implementing a number of strategic changes, including divestitures and acquisitions to strengthen its portfolio and maintain strong operational and financial performance. Royal Dutch consistently has generated one of the highest returns (ROCE), above average upstream performance and is in the process of strengthening its downstream operations through recent acquisitions/divestitures.

Investment Concerns

- Ability to meet stated growth objectives, cost reductions, and financial targets.
- Exploration success, as it relates to future production growth and capital reinvestment rates.
- Earnings are subject to the cyclical nature and volatility associated with commodity prices.
- The increasing difficulty of growing production and reserves given the company's massive size and reserve base.
- Negative sentiment about the structure of the company and potential issues regarding accounting methods associated with global trading.

FIGURE 9 **Earnings Model**

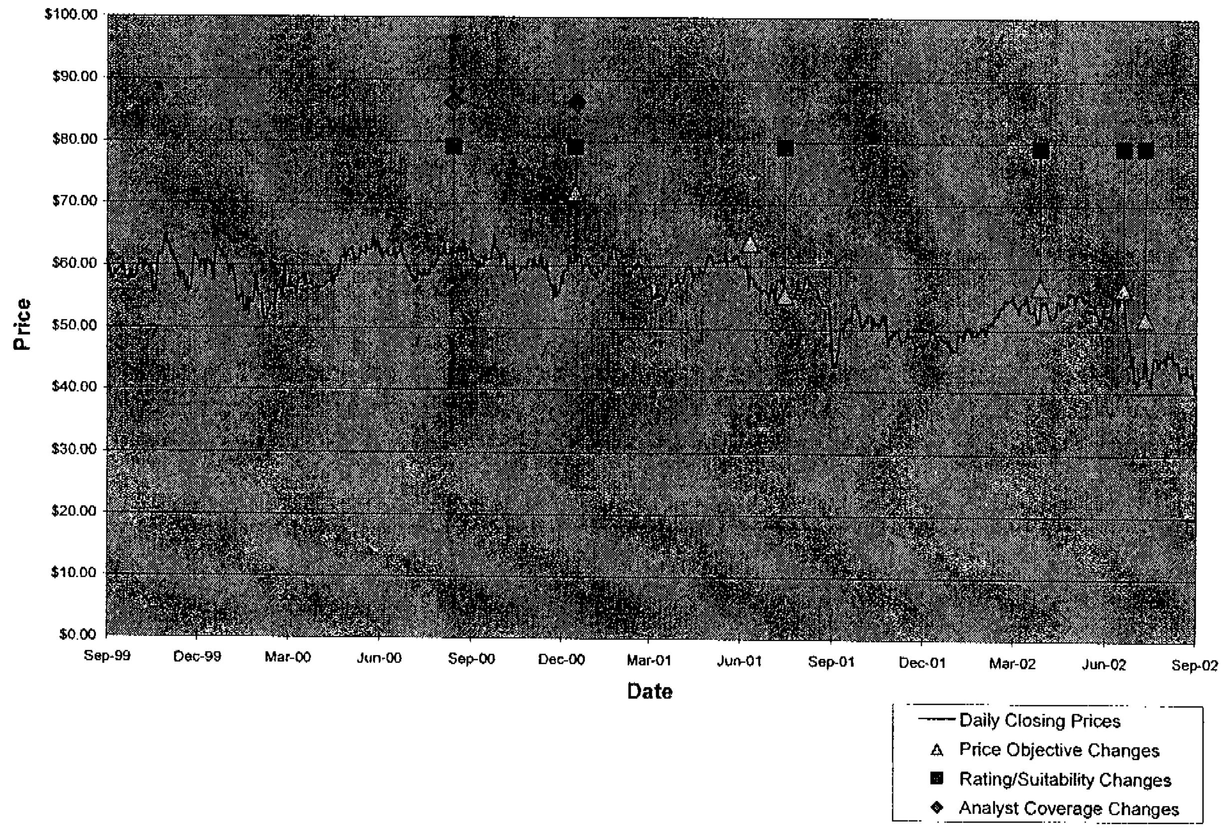
(Dollars in million, except per share data, excludes special items)

Quarterly Earnings	1Q01	2Q01	3Q01	4Q01	2001	1Q02	2Q02	3Q02E	4Q02E	2002E
Oil and Gas										
United States	902	647	435	244	2,229	263	502	479	460	1,704
International	1,945	1,538	1,343	993	5,818	1,167	1,307	1,418	1,477	5,369
Total Oil and Gas	2,847	2,186	1,778	1,237	8,047	1,430	1,809	1,896	1,937	7,073
Refining and Marketing										
United States	12	271	95	24	402	2	25	-	95	122
International	946	764	704	561	2,975	439	322	295	445	1,501
Total Refining and Marketing	958	1,035	799	585	3,377	441	347	295	540	1,623
Chemical										
United States	(72)	28	(49)	(70)	(163)	(20)	(13)	(10)	15	(28)
International	125	99	77	103	404	95	145	155	175	570
Total Chemical	53	127	28	33	241	75	132	145	190	542
Gas and Power/Other	301	330	229	166	1,026	175	60	45	125	405
Interest Expense	(36)	(61)	(82)	(63)	(242)	(115)	(120)	(120)	(120)	(475)
Corporate and Other	(261)	(96)	(47)	(66)	(490)	(31)	(58)	(60)	(30)	(179)
Net Income	3,842	3,521	2,705	1,892	11,959	1,975	2,170	2,201	2,642	8,989
Net Income per Share										
Royal Dutch Petroleum	1.08	0.99	0.77	0.54	3.38	0.56	0.62	0.63	0.77	2.60
Shell Transport	0.93	0.85	0.65	0.46	2.89	0.48	0.52	0.53	0.64	2.15

Annual Earnings	1995	1996	1997	1998	1999	2000	2001	2002E	2003E	2004E
Oil and Gas										
United States	445	953	1,276	89	1,111	2,853	2,229	1,704	1,918	1,914
International	2,536	3,789	3,293	1,885	3,235	6,582	5,818	5,369	5,802	6,096
Total Oil and Gas	2,981	4,741	4,569	1,974	4,346	9,435	8,047	7,073	7,720	8,009
Refining and Marketing										
United States	330	347	427	265	98	395	402	122	390	515
International	2,467	1,729	1,786	1,970	1,432	2,643	2,975	1,501	1,965	2,075
Total Refining and Marketing	2,797	2,076	2,213	2,235	1,530	3,038	3,377	1,623	2,355	2,590
Chemical										
United States	576	348	405	136	257	263	(163)	(28)	55	95
International	1,303	417	498	316	556	662	404	570	600	645
Total Chemical	1,879	765	903	452	813	925	241	542	655	740
Gas and Power/Other	125	263	185	258	143	658	1,026	405	625	645
Interest Expense	-	723	786	653	442	(550)	(242)	(475)	(470)	(470)
Corporate and Other	(783)	(368)	(486)	(416)	(208)	(325)	(490)	(179)	(175)	(200)
Net Income	6,999	8,200	8,170	5,156	7,066	13,180	11,959	8,989	10,710	11,314
Net Income per Share										
Royal Dutch Petroleum	1.96	2.29	2.29	1.44	1.98	3.69	3.38	2.60	3.15	3.35
Shell Transport	1.69	1.98	1.97	1.24	1.71	3.18	2.89	2.15	2.60	2.75
Production Growth (YOY)										
Worldwide	3%	4%	-1%	0%	-1%	2%	2%	6%	3%	3%
United States	9%	-4%	3%	7%	-1%	-14%	-2%	4%	0%	0%
Foreign	2%	6%	-2%	-1%	-1%	6%	3%	7%	4%	4%
Liquids	3%	2%	1%	1%	-4%	0%	-2%	8%	4%	3%
Natural Gas	4%	7%	-5%	-1%	3%	4%	10%	4%	2%	3%

Source: A.G. Edwards & Sons, Inc. estimates; company data.

Royal Dutch Petroleum



Price Objective (PO) Changes *								
Date	Closing Price	PO	Date	Closing Price	PO	Date	Closing Price	PO
01/02/2001	62.50	72.00	08/03/2001	55.49	NA	07/08/2002	56.75	NA
06/29/2001	58.27	64.00	04/15/2002	52.49	57.00	07/30/2002	44.69	52.00

* NA: Positive rating removed; no price objective supplied.

Rating/Suitability Changes					
Date	Closing Price	Rating/Suitability	Date	Closing Price	Rating/Suitability
09/01/2000	62.13	Maintain/Conservative	04/15/2002	52.49	Buy/Conservative
01/02/2001	62.50	Buy/Conservative	07/08/2002	56.75	Hold/Conservative
08/03/2001	55.49	Maintain/Conservative	07/30/2002	44.69	Buy/Conservative

Analyst Coverage Changes					
Analyst	From	To	Analyst	From	To
Edward E. Maran	09/01/2000	01/03/2001	Bruce Lanni	01/03/2001	

			Past 12 months	
Rating	**Master List Companies**	**Current Rating Distribution**	**Investment Banking Clients**	**% of Investment Banking Clients ***
Buy	292	42%	56	19%
Hold/Neutral	387	55%	30	8%
Sell	20	3%	2	10%

* Percentage of Investment Banking Clients on Master List by rating.

OUR 3-TIER RATING SYSTEM (12-18 month time horizon)
Buy: A total return is anticipated in excess of the market's long-term historic rate (approximately 10%). Total return expectations should be higher for stocks which possess greater risk.
Hold: Hold the shares, with neither a materially positive total return nor a materially negative total return is anticipated.
Sell: Stock should be sold, as a materially negative total return is anticipated.

RISK SUITABILITY (Relates to fundamental risk, including earnings predictability, balance sheet strength and price volatility)
Conservative: Fundamental risk approximates or is less than the market.
Aggressive: Fundamental risk is higher than the market.
Speculative: Fundamental risk is significantly higher than the market.

On 9/28/01 AGE changed its rating system from 5 tiers to 4 tiers. "Strong Buy" replaced the previous "Buy" rating, "Buy" replaced the previous "Accumulate" rating, and "Hold" replaced the previous "Maintain" rating. We compressed the previous ratings of "Reduce" and "Sell" into one rating, "Sell".

On 9/13/02 AGE changed its rating system from 4 tiers to 3 tiers. We eliminated the "Strong Buy" rating, and we changed the rating on all stocks with that rating to "Buy". All other ratings and their definitions remained in place.

COMPANY SPECIFIC DISCLOSURES:
Not applicable.

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Price objectives and recommendations contained in this report are based on a time horizon of 12-18 months, but there is no guarantee the objective will be achieved within the specified time horizon. Price objectives are determined by a subjective review of fundamental and/or quantitative characteristics of the issuer and the security that is the subject of this report. Specific information is provided in the text of the research report.

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Presentation by John Darley, Director, Shell Technology E&P

Analysts Field Day, Houston 8th October

[slide 1: title slide] Good morning, ladies and gentlemen. It's a pleasure to be with you today. As director of Shell Technology EP, I am delighted to have this opportunity to explain the role played by technology in support of our EP business goals.

[slide 2: disclaimer slide] Before I proceed, I am obliged to state that my presentation contains forward-looking information. I call your attention to our standard disclaimer and will give you a few moments to read it.

[slide 3:Technology for profitability and growth] The Shell Technology EP organisations support EP business activities in our operating units around the world. From our prime locations in Houston and The Netherlands, we provide both specialist expertise in key technologies as well as integrated solutions covering the full value chain of the EP business. . This morning, I would like to illustrate how our technology programmes support the business in terms of generating profitability and growth, very much complementing the activities explained by Raoul, in relation to SEPCo., and also supporting our global EP businesses.

I will start by illustrating the value of EP technologies and link with Raoul's presentation to show how technology moves around the globe. Early implementation remains a key challenge to capture maximum value from technology, and I will show how we have made great strides in this area over the past couple of years. Pursuing improvements in all areas of the EP business under our "Limit" programmes continues to generate excellent returns and the integration of technologies is key to the optimised management of both mature assets and new fields.

[slide 4 : North Sea Oil Production] As an Exploration and Production organisation, we remain totally committed to the application of appropriate technologies to enable continuous improvement in the value of our EP business. The slide gives a very graphic representation of

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the impact of technology development in the North Sea. Early views of the North Sea potential are reflected in the yellow profile. Subsequent waves of production are generated by the application of new technologies. The red band between 1986 and 1995 reflects the advent of 3D seismic imaging leading to a better understanding of the subsurface, coupled with advances in well design and well engineering capability, especially horizontal wells. The green slice that takes us into the current decade, very much looks at further extrapolation of subsurface imaging particularly time lapse seismic, or 4D seismic as it is sometimes called, helps us to understand where remaining hydrocarbons are to be produced from mature accumulations, coupled with yet further advances in well technologies particularly in downhole steering and multilateral, or branched well completions. I believe that there are further waves ahead as we look out into the next decade and we'll talk about some of the these in the course of this presentation.

[slide 5 : Bonga Field Reservoirs] One of the key developments of the past decade, partly enabled by the revolution in IT capability, is the rapid transfer of technologies around the globe. Raoul talked about the deepwater development in the Gulf of Mexico, and indeed the home of deepwater is the Gulf of Mexico but we are now taking the experience we have had in the Gulf of Mexico and extrapolating that to other parts of the world. Here you see our Bonga field, the first deepwater field in Nigeria, which will come on-stream in 2004. One significant benefit from the Gulf of Mexico experience lies in the understanding and interpretation of deepwater reservoirs (turbidite accumulations to use the technical term). The Bonga Field was discovered in 1994 Improved seismic interpretation capabilities, partly developed in the Gulf of Mexico turbidite accumulations are now applied to Bonga to reveal many "in-field" opportunities (shown as coloured bodies) in addition to the main reservoir, with the potential for significant increases in hydrocarbon reserves.

[slide 6 : Technologies identify more reserves], As you can appreciate from the production profile shown here, we are already pursuing additional de-bottlenecking opportunities even before the field comes on-stream. Clearly, experiences from the Gulf of Mexico play a role not only in subsurface interpretation, but also in well drilling and completion, facilities design and production operations for deepwater accumulations around the world.

[slide 7 : Oman improved oil recovery] The globalisation of technology does not only play in the deepwater. Our approach to improved recovery from the complex reservoirs in Oman is another example of this arena. In Petroleum Development Oman, a programme called aspirationally "T50" is aiming to implement technologies to improve recovery factors from the current projected levels of around 25% on average for the oil reservoirs, to somewhere in the region of 50%. Projects include water injection, steam injection and several other improved oil recovery projects, including miscible flooding. A number of the fields subject to initial studies are shown on the slide.

PDO is leveraging Shell's global knowledge and research and development expertise, as well as using existing third party technologies in these long-term programmes.

A specific element here will be to deploy Enhanced Oil Recovery techniques, applied in the United States during the past 20 years, to the Oman reservoirs. Our technical specialists based in the Houston technology centre, together with their colleagues in The Netherlands, are employing their experience and skills to raise the recovery performance of the oil fields in Oman.

[slide 8 : Global implementation] One of the key challenges of technology deployment is speed of implementation.

[slide 9 : key technologies – global implementation in Shell] We have identified four key technologies that will really add value to the business. They are summarised on this slide. Two years ago we created global implementation teams with a mandate to ensure these key technologies are put into place as quickly as possible in Shell operating units around the world.

The centrally deployed teams provide support and assistance to asset units throughout Shell's EP business in the areas of 4D reservoir imaging, under-balanced drilling, expandable tubulars and smart wells.

[slide 10 : Global implementation world map] This slide shows the very active coverage of these technologies around the world, together with the values generated.in 2001. A key feature of the central deployment or central implementation team is that experiences garnered in one location can quickly be transferred to the next potential application , and deployed there even more effectively. So experience with expandable tubulars in Oman can be transferred to Nigeria and on to the north sea.

[slide 11 : Expandable and monodiameter wells]Recently, as Raoul mentioned, we announced the capability to deploy a MonoDiameter well. This truly is one of the most important technology breakthroughs in well engineering of recent years. The monodiameter well concept, which was proved earlier this year in south Texas, has huge application potential in deepwater.

With MonoDiameter technology, tubulars are expanded during well construction to create one continuous internal diameter from surface to total depth. Thus each well drilled can potentially reach its reservoir with a well bore size that will enable reservoirs to produce at their full potential, with the additional benefit of also saving significant amounts of time and money while potentially reducing the environmental footprint, in some cases by as much as 75%. We are extremely excited about the MonoDiameter concept because of its cost saving potential – of up to 50% - in the high cost world of deepwater drilling.

The speed of deployment of expandable tubular technologies over the pat two years, supported by the global implementation approach, has been a key factor in accelerating our capability to deploy the mono-diameter well by some four to five years, over our original aspiration.

[slide 12 : Smart Well technology] The concept of smart well technology is emerging rapidly in the E&P industry, and reflects a capability in a well or in an array of well-bores to be able to

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measure data (including subsurface data), utilise the data in real time to assess performance and subsequently, and again in real time, to optimise well and field performance, often by the remote manipulation of downhole valves and control devices. The schematic depicts a multilateral well in a subsurface formation, with an array of such capabilities.. I have included here an example of down-hole processing, and we've already tested down-hole oil and water separation in Oman for example, with re-injection of unwanted water. This well also has the capability for permanent reservoir imaging, whereby well-bore sensors, are able to remotely to detect fluid movements, or the encroachment of water, for example, deep in the reservoir.

[slide 13 : Smart Well technology] We have our first example of a smart field in South-Furious in Malaysia, The small oil field SF30 was commercially discovered in January 2000 offshore in the South China Sea in some 70 ft of water depth.

First oil was achieved in September 2001, some 20 months after the discovery. Some 22 MMbbls will be recovered from the first 5 wells. Smart capabilities were installed in three wells, based on the following business drivers: :

- cost reduction of reduced wire-line interventions and problems
- the capability for more sophisticated and flexible reservoir management (controlled commingling and testing of individual zones)
- more frequent well surveillance with a lower level of deferments
- accelerated oil from gas lift optimisation and thus improved oil recovery
- acquiring the technology before applying it in less forgiving environments
- shut-off of unwanted water / gas production

[slide 14 : Na Kika] Another example of Smart Well deployment is the Na Kika field in the Gulf of Mexico, which Raoul mentioned earlier. This emerging technology has proven key to realising value from these deepwater assets.

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[slide 15 : Smart Well value loop] A central concept in smart fields is the *'value loop'* consisting of data gathering, modeling and decision making, in support of field development, management and optimization activities. Novel technologies increasingly allow us to *'acquire the data we need to support our decisions, rather than use the data we have'*. We can gather, process and use both static and dynamic asset performance data more cost-effectively than ever. Periodic optimization can thus be replaced with continuous 'real time' optimization yielding significant production gains. Ideally a Smart Field *learns* from and *adapts* to changing conditions and new data. With smart wells we now also have the means to effect control over reservoir and production system performance. A well with multi-zone inflow controls and metering can replace multiple wells/drainage points, improving the cost-efficiency of draining complex reservoirs, yielding higher production rates and increased ultimate recovery. And it is this latter point, increased ultimate r ecovery that the greatest value of smart fields will be realised.

[slide 16 : Time lapse reservoir imaging (4D seimic) Draugen] The next of our key technologies is 4D reservoir imaging, which allows us to visualise the displacement processes in the reservoir. This example from the Draugen field in Norway shows how the technology and integrated teamwork made a real difference. The 4D reservoir data identified un-swept areas in this water-flood reservoir. An infill was proposed to improve sweep efficiency. It proved to be one of the record producers of the North Sea, calculated to have added $85 million value to the field and one of the largest produces in the north sea at 70 thou bpd. Continued application of 4D seismic is allowing further optimisation of the Draugen field, and extending plateau production well beyond original expectations.

[slide 17 : under-balanced drilling Here's another technology helping us to get more production and reserves for our money - underbalanced drilling, which speeds drilling performance and improves well pductivity. Underbalanced drilling can both cut the cost of new field development, and is also a key lever in re-development of mature accumulations, a good example being the depleted Leman field in the North Sea. Results achieved to date with underbalanced drilling include experience in Malaysia and in Oman where there has been

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significant improvements. Our global implementation team are positioned around the world, supporting a current underbalanced drilling programs of eight projects, expanding to twice that level in 2003 – an international industry leadership position.

[slide 18 Information technology] In addition to the more traditional oil field technologies, the continued acceleration of capabilities in information technology, and information management offers tremendous opportunities for improved data sharing, communications, and knowledge transfer around the world. Within our EP business we have the aspiration to increase bandwidth by a factor 100 over the coming two to three years, and already by a factor 20 in 2002. The benefits are clear: For example, teams in Nigeria are able to use servers, applications and software from Houston, Rijswijk and around the world. The technology also enables our technical professionals around the world to advise and work with each other on problem solving and technical solutions. . We are currently running a programme which we call EP down the wire, which will allow all our technical professionals all around the world to access the latest EP applications on their desktop.

[Slide 19 Realising the Limit] We have spoken about our Realising The Limit programmes over the past couple of years. These programmes we kicked off in 1999 and are still delivering very good value

[slide 20 Realising the limit – 2001 value identified]. The limit programmes focus on four key areas of our business, and provide a structured approach to generate significant business improvement: for example, improved investment efficiency in the capital to value programme; hydrocarbon reserves identification and enhancement opportunities; production optimisation in producing the limit; and ways to improve efficiency in the well drilling and completion .

The values achieved in 2001 are summarised on the slide here and all elements of the programme continue to generate significant value across the globe. We are currently building on

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these experiences to promote further improvements under the theme of Technical and Operational Excellence.

[slide 21 Impact of DTL] The limit programmes are now well embedded in our major operating units and we are sharing the approach with a number of joint venture companies. Here is an example of drilling the limit in Abu Dhabi where, as a shareholder in ADCO, Shell is playing an important role in improving performance and enhancing our reputation in this important venture.

[slide 22 : technology integration] As I mentioned earlier, we firmly believe that our capabilities in specific leading edge technologies, such as the ones I have described, couple with an integrated approach to the full E&P life cycle, is essential to maximise the value of technology application across our asset base.

[slide 23 : Brunei Shell Petroleum- Long term oil production outlook] Here is a good example of the integration of key technologies in a mature producing area. In the late 1990's the mature fields in Brunei Darussalam were facing slow but steady decline. The combination of new technologies, including those we have discussed today – improved subsurface interpretation, well drilling and smart well applications, realising the limit have identified new oil and gas reserves, often within mature existing accumulations and provide the opportunities to increase and maintain oil production levels well into the next decade.

[slide 24 ; technology impact on production – Syria] Here is another example of the value of integrating a range of technologies, this time from our joint venture company in Syria. The potential to develop and apply various technologies to increase reserves and extend production life are summarised as discrete elements in the slide. Examples of this approach might include specific requirements for subsurface imaging (to assist seismic interpretation), produced water handling or well drilling technologies.

[slide 25 Malampaya – Deepwater gas to power project] The Malampaya gas project in the Philippines is another great example of technology integration. . This gas-to-power project, which involved significant investment both in the upstream and the downstream, produced its first hydrocarbons late last year, and has the capacity to supply 30 percent of the power required on the island of Luzon –where Manila is situated and the largest population in the Philippines. The Malampaya project is also considered to be a flagship project in terms of application of our key sustainable development principles To this end we implemented several environmental, social and local infrastructure projects during the construction of the Malampaya facility and just last month, at the World Summit, this project received an award for Sustainable Development.

[slide 26 : summary]

Shell's technology delivery to the E&P business covers the full spectrum of activity, from research and development through to project delivery, covering our global spectrum of operating environments, be it desert to deep water production. The capability to develop and deliver technology in one location, learn from this application and build on it for deployment elsewhere is, I believe, a source of competitive strength for Shell's E&P business.

The accelerated deployment of technology is essential both to maximise the value of the applications, as well as to move quickly up the learning curve. Our global implementation approach positions us as a leader in speed of world-wide application.

Finally, the ability to provide integrated solutions, combining a critical insight into leading edge technology values while delivering a total solution in field development execution and operation is critical to ensure continued profitability and growth in our E&P business.

[slide 27 : thank you]

From: Darley, John J SIEP-EPT
To: Ward, Brian BJ SEPI-EPG
CC:
BCC:
Sent Date: 2002-10-08 22:35:46.000
Received Date: 2002-10-08 22:35:00.000
Subject: FW: SDS Affiliate Services
Attachments: SDS Affiliate Services 10_10_2002 v1.ppt

Brian,

Nice overview of how SDS supports SNEPCO. Note tariff comparisons

John

> -----Original Message-----
> From: Leonard, Mark MS SIEP-EPT-D
> Sent: 07 October 2002 14:34
> To: Darley, John J SIEP-EPT; Lohr, Fran FA SIEP-EPB-I;
> Buckley, Bruce BR SIEP-EPT-DW; Deere, Cindy A SIEP-EPT-DC;
> Ray, Randal RG SIEP-EPT-HA; Malouta, Dean DN SIEP-EPT-DE;
> Enze, Chuck CR SIEP-EPT-PD
> Subject: FW: SDS Affiliate Services
>
> John, DWLT,
> Here is the latest version of the SDS "Value Proposition" to
> SNEPCo. I think we can use this in other contexts also.
> Mark
>
> -----Original Message-----
> From: Knight, Barry BP SIEP-EPT-DE
> Sent: Friday, October 04, 2002 5:56 PM
> To: Leonard, Mark MS SIEP-EPT-D; Sears, Richard RA
> SIEP-EPT-DE; Okpere, Kisito O SNEPCO-SND; Officer, Stewart WS
> SIEP-EPT-PB
> Subject: SDS Affiliate Services
>
> Gentlemen,
> Please find attached the current version of the SDS affiliate
> services presentation I am planning to give next Friday. I
> have still to make a few tweaks and make the final summary
> vugraph but it gives you the main content. Please let me know
> if you have any comments or issues.
>
>
>
>
> Barry

EXHIBIT
Darley 13
11/17/06

>
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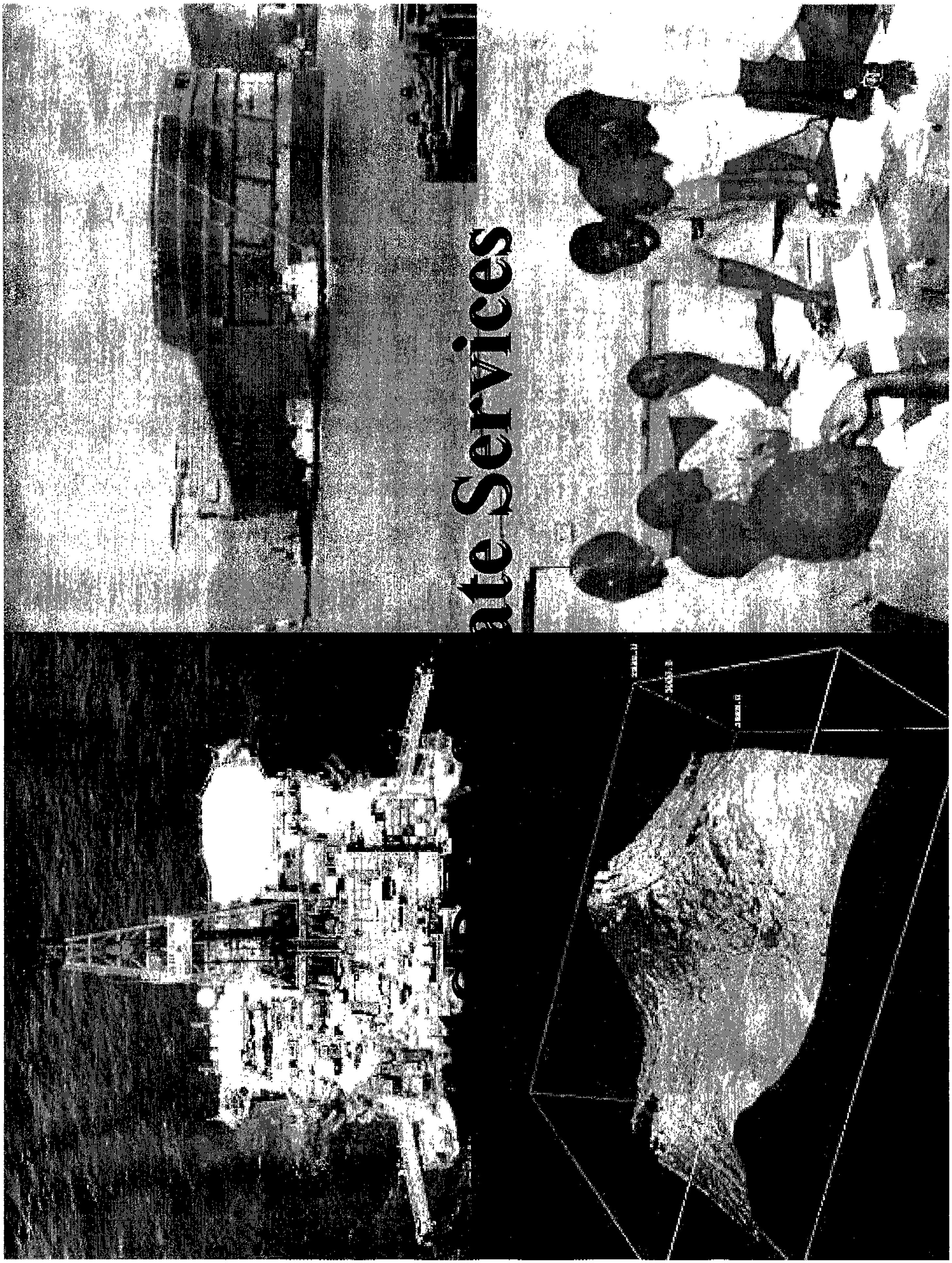
ate Services

SDS Affiliate Services

- SDS Value Proposition
- SDS Strengths, Value Creation & Technology Transfer
- SNEPCO Service $'s in SDS
- External Benchmarking of SDS Tariffs
- SDS Financial Control Procedures
- NAPIMS / DPR Value Proposition
- Summary

Shell Deepwater Services

Our Value Proposition For SNEPCO

- SDS brings the global deepwater capability & experience to Nigeria
- SDS delivers a continuous stream of evolutionary and revolutionary improvements (eg surface BOP's)
- SDS provides global opportunities for increasing the experience and skills of Nigerian staff
- SDS provides a up to 2 to 1 capability ratio by providing cost effective part time skills to teams
- SDS is fully integrated with SNEPCO (SNEPCO teams in SDS are an extension of SNEPCO)