Oil and Gas Reporting and Disclosure In Selected Countries

Focus On Cost / Field Detail Reporting

Summary

- **In the vast majority of regimes around the world companies are required to disclose detailed data**
  - Prospective (plans) and actual
  - Typically down to well / field level detail

- **Data is provided to both resource-management and fiscal/taxation authorities**
  - Intra-governmental sharing
  - Greater flow to, rather than from, fiscal authorities

- **Reporting and public disclosure are two separate issues**
  - Public reporting is common
  - Though typically in aggregated or summary form

Why Does Alaska Need To Receive Data ?

- **Required in order to properly manage the State's resources**
  - "The energy resources of this State belong to the people of Alaska[1]"
- **Full understanding of technical and commercial factors**
- **Ability to plan and control**
  - Exploitation policy
  - Budget
- **These are universal principles**
  - Not unique to Alaska

[1] Adapted from Accountability principle of Alberta Royalty Review Panel

Forms Of Reporting and Sharing

- **Production and well data**
  - Monthly or as completed
- **Annual or Semi-Annual field-level information**
  - Typically collected by Ministry / Regulatory Body
- **Tax returns**
  - Collected by fiscal authority
- **Intra-Governmental Sharing**
  - Degree of sharing varies by country
  - Typically greater sharing by Ministry / Regulatory Body than by fiscal authority

Public Reporting

- **Mostly in aggregated / summary form**
- **Some countries provide field-level summaries**
  - Reserves
  - Capex
    - More often as total, but sometimes as annual time series
- **Opex rarely disclosed at field-level, although subscription services do provide this**
  - Data quality dependent upon various sources, including “oil company guidance”
  - Sometimes occurs in stock market documentation released by (usually) smaller companies

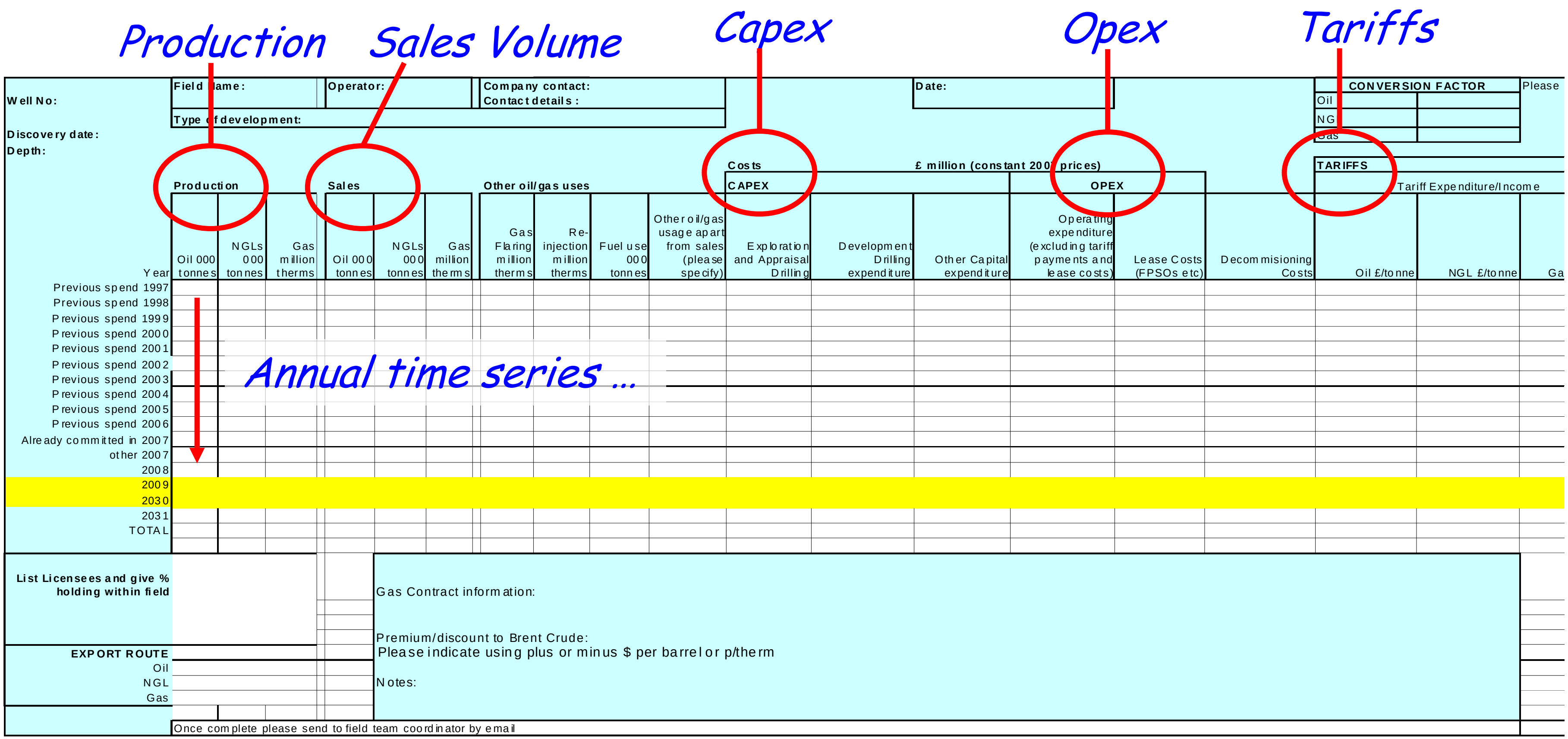
Examples Of Data Disclosure (Production and Cost Focus)

UK Summary

- **UK requires data disclosure at field level**
  - ➢ Field development plans
  - ➢ Annual (and semi-annual) data / statistical analysis
  - ➢ PRT returns
- **Disclosure to**
  - ➢ DTI (Oil & Gas Directorate)
  - ➢ Fiscal authorities
- **Publication of aggregated information**

United Kingdom

Detailed field-level production and cost projections (in standardized electronic format) are required as part of the Field Development plan submission / approval



United Kingdom

Annual UKCS Income and Expenditure summarized on an annual basis

Income from and Expenditure on UK Continental Shelf Exploration, Development and Operating Activities
(£ million)

Sales

Opex

Capex

	Income					Expenses					Capital Expenditure				Prices		
	Oil Sales	NGL Sales	Gas Sales	Other Income[1]	Total Income	Operating Costs	*of which decommissioning costs*	Other expenses[2]	Total Expenses	Gross Operating Surplus[3]	E&A[4]	*of which seismic*	Investment other than E&A	Total	Average Oil Price (£/tonne)	Average Gas Price (p/therm)	GDP Deflator (2003=100)
1970	0	0	0	4	5	6	*n/a*	0	6	-2	20	*n/a*	53	73	n/a	n/a	9.9
1971	0	0	80	8	88	11	*n/a*	0	11	78	57	*n/a*	72	129	n/a	n/a	10.8
1972	0	1	114	9	124	15	*n/a*	0	15	110	43	*n/a*	112	155	n/a	n/a	11.7
1973	0	2	133	11	146	18	*n/a*	0	18	129	69	*n/a*	215	284	n/a	n/a	12.6
1974	0	3	166	21	190	20	*n/a*	0	20	170	153	*n/a*	584	737	n/a	n/a	14.4
1975	43	15	190	29	277	46	*n/a*	0	46	231	242	*n/a*	1,374	1,616	n/a	n/a	18.3
1976	624	21	258	21	924	130	*n/a*	0	130	794	301	*n/a*	2,070	2,372	n/a	1.8	21.1
1977	2,197	29	317	20	2,562	207	*n/a*	0	207	2,356	375	*n/a*	2,107	2,482	n/a	2.1	24.0
1978	2,771	35	432	12	3,250	346	*n/a*	0	346	2,904	261	*n/a*	2,170	2,431	n/a	3.1	26.8
1979	5,641	53	538	44	6,276	502	*n/a*	18	519	5,757	241	*n/a*	2,064	2,305	n/a	3.8	30.7
1980	8,719	132	647	82	9,580	692	*n/a*	34	726	8,854	379	*n/a*	2,388	2,767	n/a	4.9	36.7
1981	12,206	135	843	114	13,298	1,017	*n/a*	45	1,063	12,235	550	*n/a*	2,847	3,397	n/a	6.5	40.8
1982	14,129	312	956	160	15,557	1,309	*n/a*	73	1,382	14,174	875	*n/a*	3,059	3,934	142.0	7.4	43.9
1983	16,496	528	1,117	188	18,328	1,495	*n/a*	67	1,562	16,767	993	*n/a*	2,853	3,846	148.3	8.4	46.3
1984	19,927	659	1,290	256	22,133	1,733	*n/a*	62	1,795	20,338	1,395	*n/a*	3,189	4,584	164.9	10.0	48.4
1985	19,204	692	1,709	384	21,988	2,248	*n/a*	76	2,324	19,664	1,445	*n/a*	2,794	4,239	158.3	11.9	51.1
1986	8,909	386	1,927	455	11,678	2,144	*n/a*	57	2,201	9,476	1,039	*n/a*	2,419	3,457	73.3	12.6	52.9
1987	9,513	358	1,990	533	12,394	2,107	*n/a*	55	2,162	10,232	809	*n/a*	2,044	2,853	81.7	12.4	55.7
1988	7,084	249	2,046	859	10,238	2,060	*n/a*	58	2,118	8,120	1,129	*n/a*	2,126	3,256	63.4	13.1	59.2
1989	7,214	272	2,187	547	10,220	2,330	*n/a*	57	2,386	7,833	1,182	*n/a*	2,635	3,817	81.1	14.2	63.6
1990	8,432	277	2,377	405	11,491	2,892	*n/a*	46	2,938	8,552	1,637	*n/a*	3,478	5,115	94.6	14.3	68.5
1991	7,578	385	2,988	476	11,428	3,296	*n/a*	58	3,354	8,073	1,955	*n/a*	5,101	7,056	86.0	15.9	73.0
1992	7,430	380	3,016	626	11,453	3,312	*n/a*	53	3,365	8,088	1,508	*n/a*	5,428	6,936	81.9	15.8	76.0
1993	8,110	523	3,568	699	12,899	3,661	*n/a*	47	3,708	9,191	1,213	*n/a*	4,661	5,874	85.8	15.0	78.0
1994	8,964	528	3,836	974	14,302	3,860	*n/a*	40	3,900	10,401	939	*160*	3,671	4,609	77.0	16.3	79.2
1995	9,881	614	4,141	1,166	15,802	3,913	*n/a*	37	3,950	11,852	1,085	*204*	4,355	5,440	81.1	16.3	81.4
1996	11,850	749	5,295	1,243	19,136	3,978	*n/a*	31	4,009	15,127	1,097	*190*	4,364	5,461	97.3	16.6	84.2
1997	10,327	700	5,254	1,279	17,561	4,150	*n/a*	34	4,184	13,377	1,194	*151*	4,263	5,457	87.4	16.7	86.6
1998	7,487	551	5,313	1,453	14,804	4,190	*n/a*	111	4,301	10,503	762	*125*	4,996	5,758	59.8	16.2	88.9
1999	10,257	727	5,031	1,436	17,451	4,249	*n/a*	282	4,531	12,920	457	*56*	3,063	3,520	80.0	13.7	90.9
2000	16,275	1,117	6,606	1,488	25,486	4,360	*n/a*	106	4,466	21,020	348	*40*	2,750	3,098	138.1	15.8	92.1
2001	13,646	963	8,140	1,435	24,185	4,347	*n/a*	49	4,396	19,789	420	*34*	3,570	3,990	125.7	19.0	94.1
2002	13,629	894	8,199	1,397	24,118	4,596	*n/a*	48	4,643	19,475	389	*45*	3,598	3,988	123.8	16.4	97.0
2003	13,365	1,105	7,554	1,538	23,562	4,496	*n/a*	8	4,504	19,058	334	*42*	3,412	3,746	130.0	17.4	100.0
2004	13,477	1,266	7,443	1,178	23,364	4,664	*145*	87	4,751	18,613	396	*57*	3,302	3,698	154.0	21.0	102.6
2005	16,656	1,684	8,902	1,451	28,693	5,113	*412*	128	5,241	23,452	460	*34*	4,371	4,831	215.8	27.6	104.9

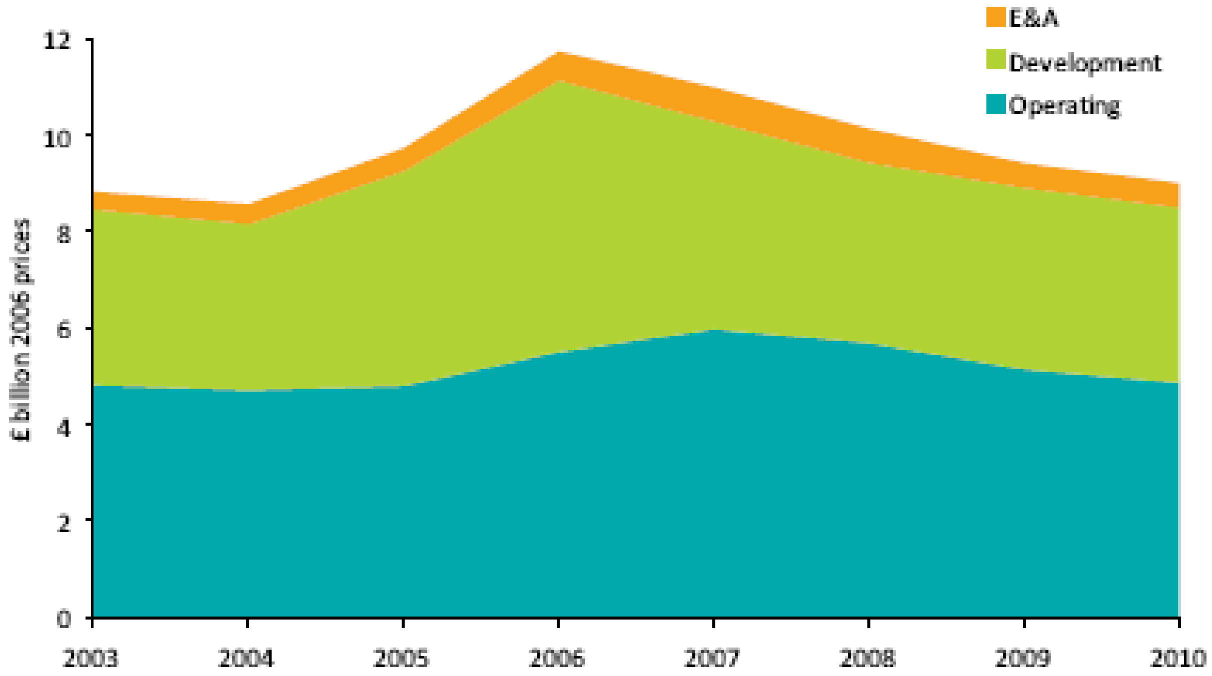
Notes

(1) Revenues from pipelines and terminals, and other revenues of operators and production licensees.
(2) Other costs of operators and production licensees not attributable to oil or gas fields.
(3) Gross Operating Surplus = Total Income less Total Expenses.
(4) E&A costs include Exploration and the cost of Appraisal wells drilled prior to development approval.
The figures exclude change in stocks and book value of stocks.

United Kingdom

Medium-term forecasts derived from annual returns

Figure 30: UKCS Expenditure Forecast 2003-2010

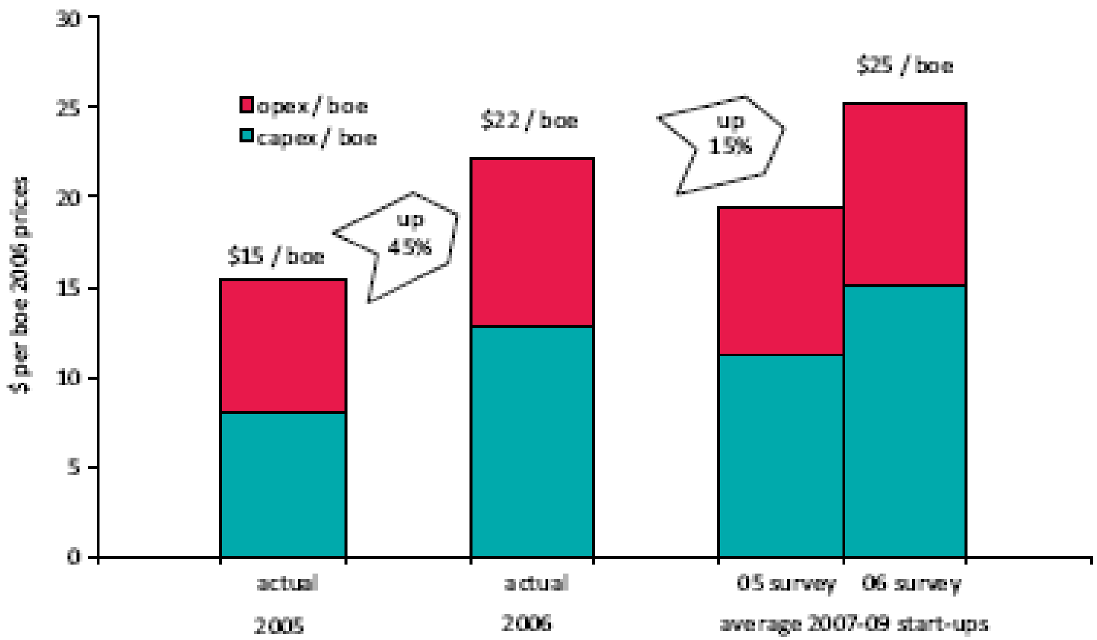


Source: Oil & Gas UK

United Kingdom

Cost trends

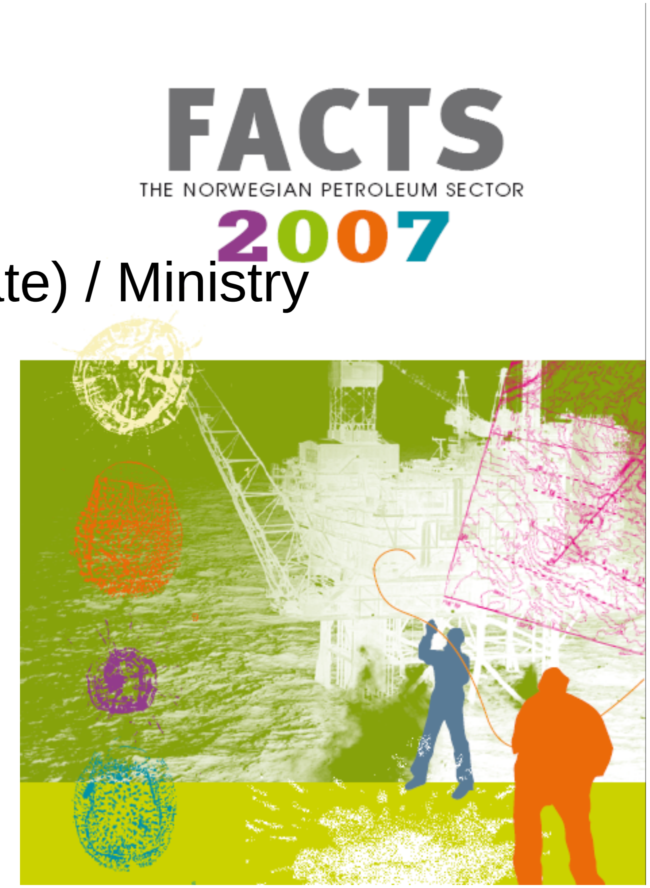
Figure 33: UKCS New Developments' Unit Technical Cost 2005-2009



Source: Oil & Gas UK

Norway Summary

- **Norway requires data disclosure at field level**
  - Field development plans
  - Annual data / statistical analysis
  - Tax returns
- **Disclosure to**
  - NPD (Norwegian Petroleum Directorate) / Ministry
  - Fiscal authorities
- **Publication of aggregated information**



Norway

Field / discovery listing of resource volumes

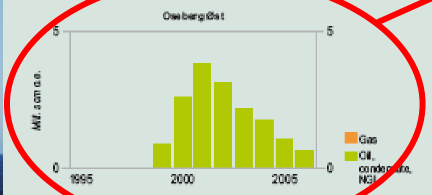
Tilstedeværende ressursar i felt
In-place resources in fields

Felt	Olje mill Sm3 *Oil million Sm3*	Assosiert væske NGL/Kondensat mill Sm3 *Associated liquids million Sm3*	Assosiert gass mrd Sm3 *Associated gas (billion Sm3)*	Fri gass mrd Sm3 *Free gas billion Sm3*
ALBUSKJELL	36	0	56	0
ALVHEIM	81	0	8	9
BALDER	137	0	7	0
BLANE	3	0	0	0
BRAGE	137	7	11	3
COD	5	0	11	0
DRAUGEN	212	0	12	0
EDDA	16	0	5	0
EKOFISK	1,071	0	286	0
ELDFISK	470	0	124	0
EMBLA	43	0	15	0
ENOCH	2	0	0	0
FRAM	58	0	8	8
FRIGG	0	1	0	150
FRØY	35	0	8	0
GIMLE	8	0	0	0
GLITNE	24	0	1	0
GRANE	209	0	3	0
GULLFAKS	583	0	69	0
GULLFAKS SØR	154	43	36	118

Norway

Detail on field-by-field basis

Production forecast by year



Oseberg Øst

Block and production licence	Block 30/6 - production licence 053, awarded 1979	
Discovered	1981	
Development approval	11.10.1996 by the King in Council	
On stream	08.05.1999	
Operator	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4,70 %
	Norsk Hydro Produksjon AS	34,00 %
	Norske ConocoPhillips AS	2,40 %
	Petoro AS	33,60 %
	Statoil ASA	15,30 %
	Total E&P Norge AS	10,00 %
Recoverable reserves	Original:	Remaining as of 31.12.2006
	27,8 million scm oil	11,7 million scm oil
	0,4 billion scm gas	[illegible] billion scm gas
Production	Estimated production in 2007:	
	Oil: 10 000 [illegible] Gas: 0,02 billion scm	
Investment	Total investment is expected to be NOK 10,2 billion (2007 values)	
	NOK 8,3 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is 160 metres.

Reservoir:
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil-bearing layers of varying reservoir characteristics within the Middle Jurassic Brent group.

Recovery strategy:
The field is produced with pressure maintenance using both water injection and WAG (water alternating gas) injection.

Transport:
The oil is sent by pipeline to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) to the Sture terminal. The gas is mainly used for injection, gas lift and fuel.

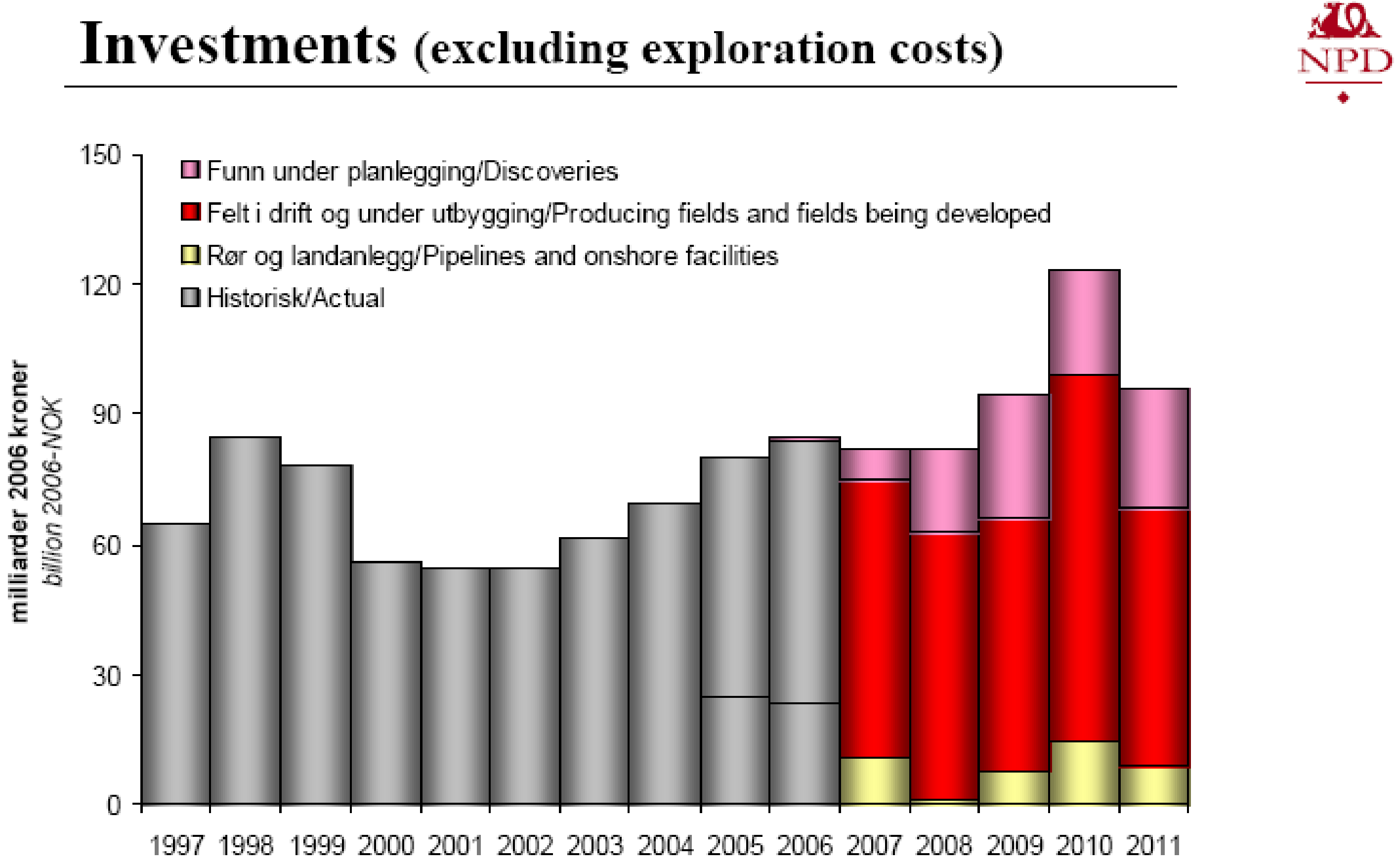
Status:
Various measures for increased oil recovery are being evaluated in an ongoing process. A new drilling campaign is expected to yield increased production. The first well in the new drilling campaign is planned to be set on stream in February 2008.

Reserves and EUR

Total capital investment
- *historical*
- *expected ultimate*

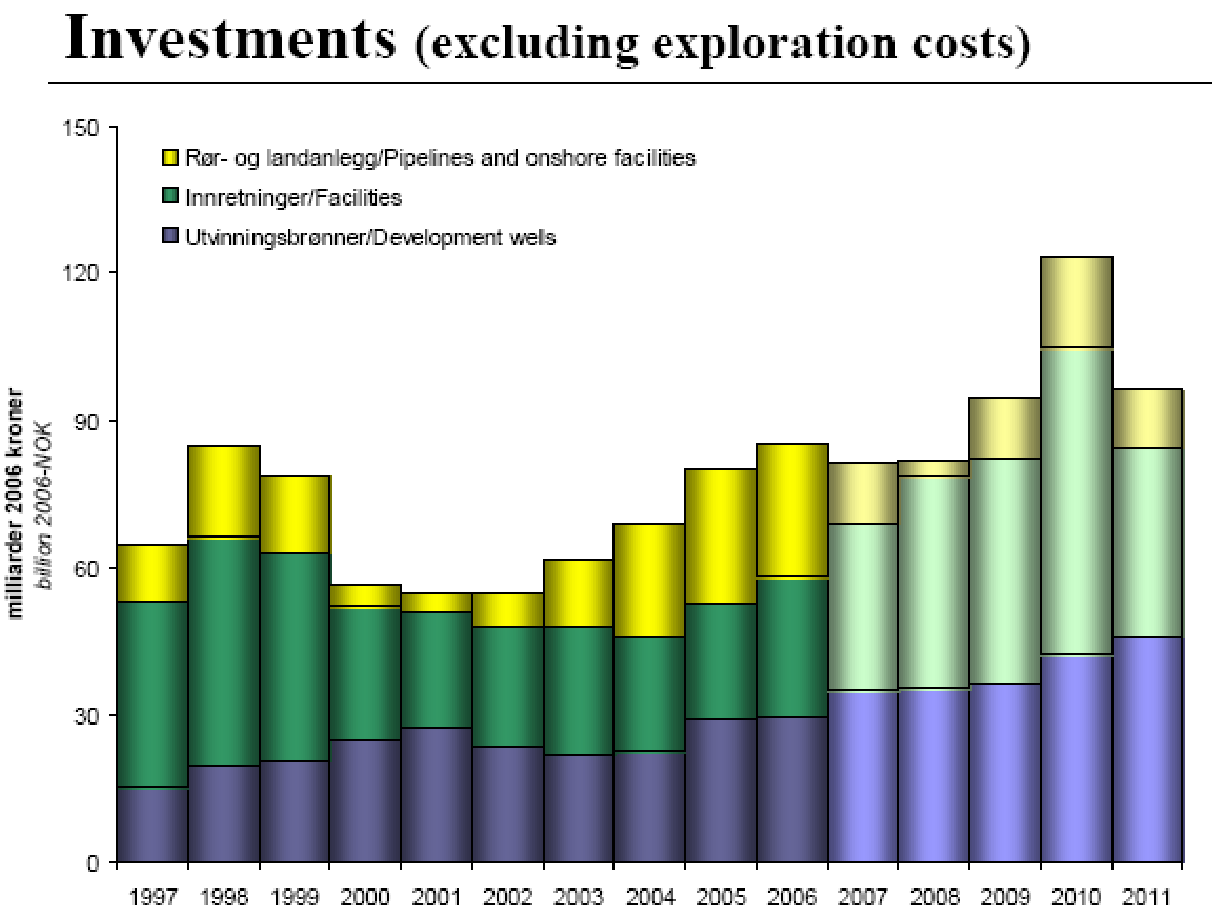
Norway

Medium-term forecasts derived from annual returns



Norway

Medium-term forecasts derived from annual returns



Norway

Source of Investment

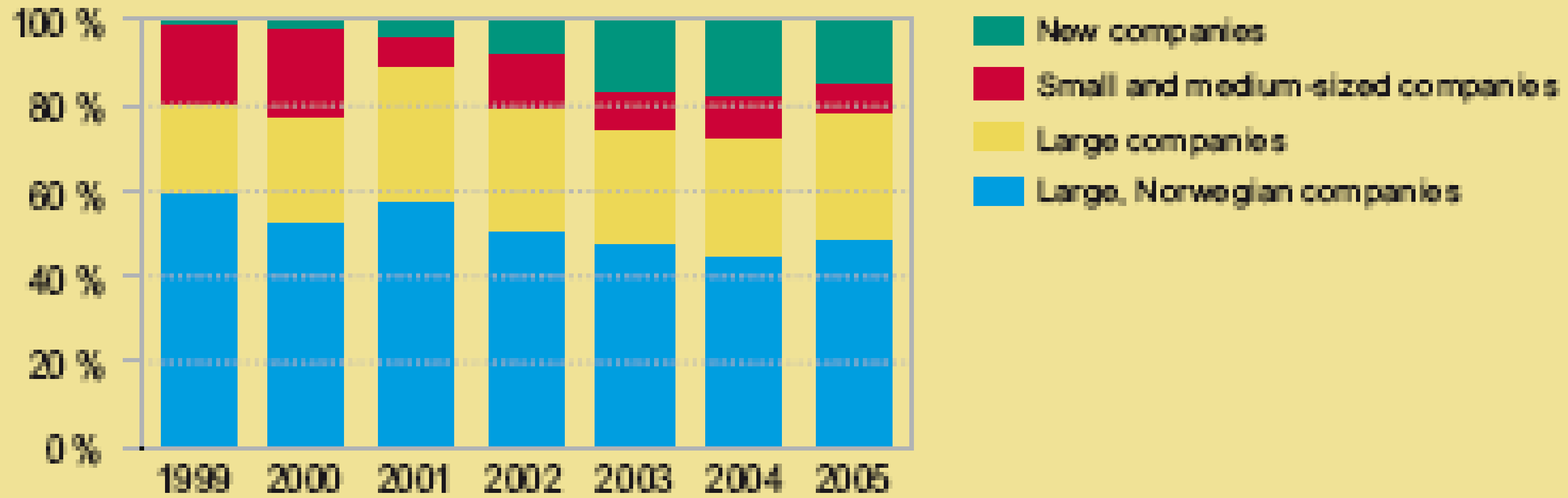
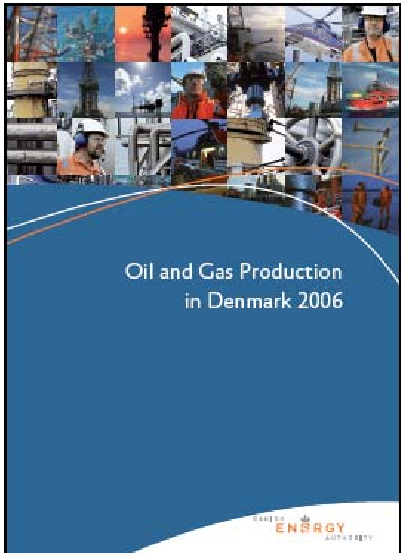


Figure 3.8 Exploration costs in production licences on the Norwegian continental shelf, distributed according to the size of the companies

(Source: Norwegian Petroleum Directorate)

Denmark Summary

- **Denmark requires data disclosure at field level**
  - Field development plans
  - Annual data / statistical analysis
  - Tax returns
- **Disclosure to**
  - Danish Energy Authority
  - Fiscal authorities
- **Publication of some detailed plus aggregated information**



Denmark

Field listing of annual capital investments .. both historical ..

Table 7.4 Investments, DKK million, nominal prices

	2002	2003	2004	2005	2006*
Cecilie	223	660	309	(18)	4
Dagmar	-	-	-	-	148
Dan	437	943	750	750	684
Gorm	242	107	108	291	304
Halfdan	2,412	1,779	1,124	683	1,293
Harald	0	4	22	53	1
Kraka	3	-	2	-	-
Nini	285	1,288	319	163	19
Roar	-	-	-	-	-
Rolf	-	37	4	-	1
Siri	111	406	425	73	140
Skjold	5	77	8	11	4
South Arne	849	764	762	310	451
Svend	223	-	-	-	-
Tyra	85	305	459	1,020	1,520
Tyra Southeast	569	82	96	45	-
Valdemar	(1)	200	52	553	992
NOGAT pipeline	-	766	664	12	-
Not allocated	31	(31)	2	5	97
Total	**5,475**	**7,386**	**5,105**	**3,951**	**5,658**

**Estimate*

Denmark

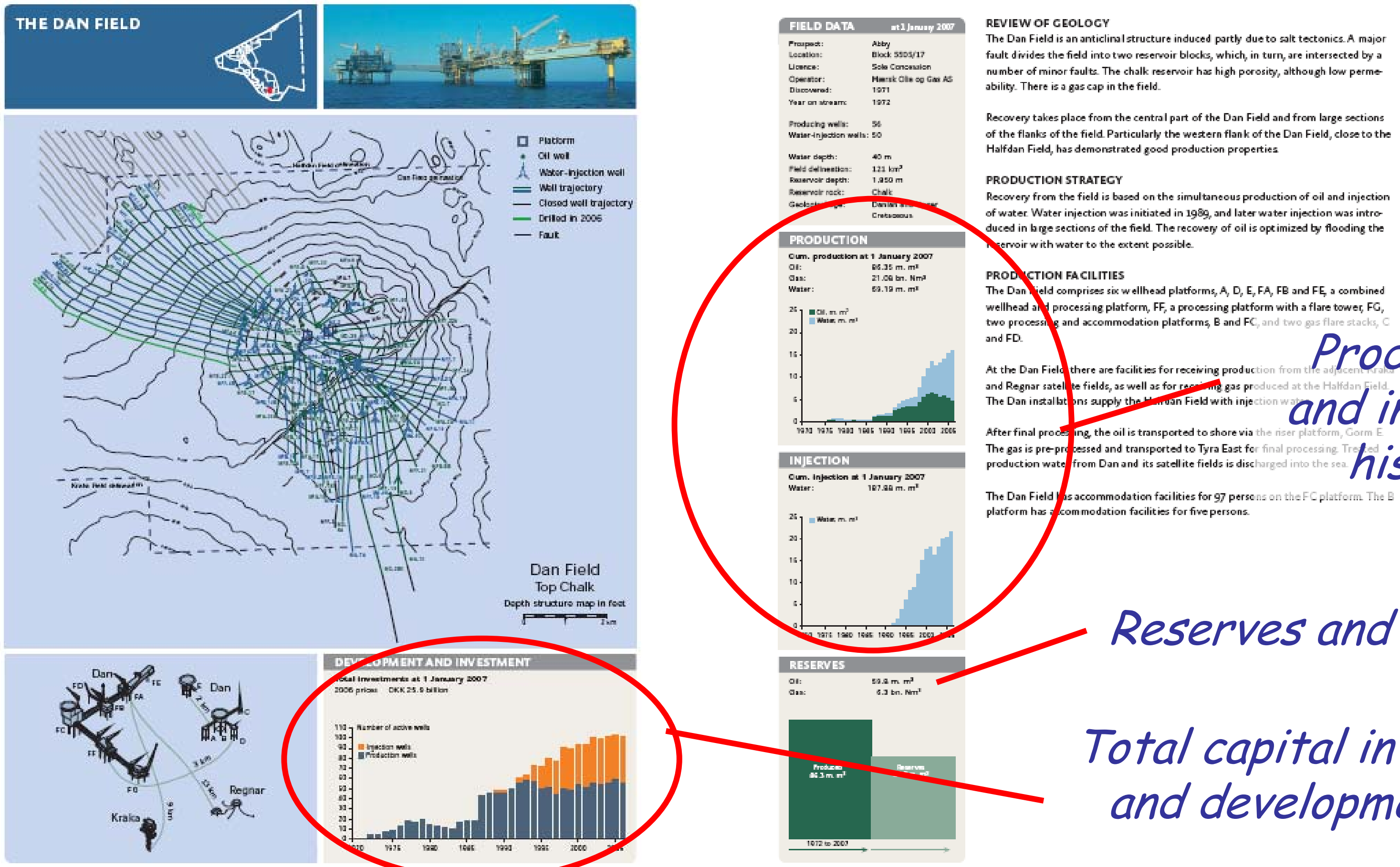
.. and projected

Table 7.5 Estimated investments in development projects, 2007-2011, DKK billion, 2006 prices

	2007	2008	2009	2010	2011
Ongoing and approved					
Adda	-	0.1	0.6	-	-
Alma	-	0.6	0.5	-	-
Boje	-	-	-	0.8	-
Cecilie	-	-	-	-	-
Dagmar	-	-	-	-	-
Dan	0.9	0.6	-	-	-
Elly	0.3	1.6	-	-	-
Gorm	0.1	0.0	-	-	-
Halfdan	2.0	0.9	0.1	-	-
Harald	0.0	0.1	-	-	-
Kraka	0.3	-	-	-	-
Lulita	-	-	-	-	-
Nini	0.1	-	-	-	-
Regnar	-	-	-	-	-
Roar	-	-	-	-	-
Rolf	-	-	-	-	-
Siri	0.3	-	-	-	-
Skjold	-	-	-	-	-
South Arne	0.8	-	-	-	-
Svend	-	-	-	-	-
Tyra	0.4	0.4	0.4	0.0	1.3
Tyra Southeast	0.5	-	-	-	-
Valdemar	1.6	0.7	-	-	-
Total	**7.3**	**5.1**	**1.5**	**0.8**	**1.3**
Planned	-	-	-	-	0.8
Possible	-	0.7	4.7	6.6	4.0
Expected	**7.3**	**5.8**	**6.2**	**7.4**	**6.2**

Denmark

Detail on field-by-field basis



FIELD DATA at 1 January 2007

Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	56
Water-injection wells:	50
Water depth:	40 m
Field delineation:	121 km²
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2007

Oil:	86.35 m. m³
Gas:	21.08 bn. Nm³
Water:	69.19 m. m³

INJECTION

Cum. injection at 1 January 2007

Water:	187.88 m. m³

RESERVES

Oil:	59.8 m. m³
Gas:	6.3 bn. Nm³

REVIEW OF GEOLOGY

The Dan Field is an anticlinal structure induced partly due to salt tectonics. A major fault divides the field into two reservoir blocks, which, in turn, are intersected by a number of minor faults. The chalk reservoir has high porosity, although low permeability. There is a gas cap in the field.

Recovery takes place from the central part of the Dan Field and from large sections of the flanks of the field. Particularly the western flank of the Dan Field, close to the Halfdan Field, has demonstrated good production properties.

PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water. Water injection was initiated in 1989, and later water injection was introduced in large sections of the field. The recovery of oil is optimized by flooding the reservoir with water to the extent possible.

PRODUCTION FACILITIES

The Dan Field comprises six wellhead platforms, A, D, E, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD.

At the Dan Field there are facilities for receiving production from the adjacent Kraka and Regnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

After final processing, the oil is transported to shore via the riser platform, Gorm E. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

The Dan Field has accommodation facilities for 97 persons on the FC platform. The B platform has accommodation facilities for five persons.

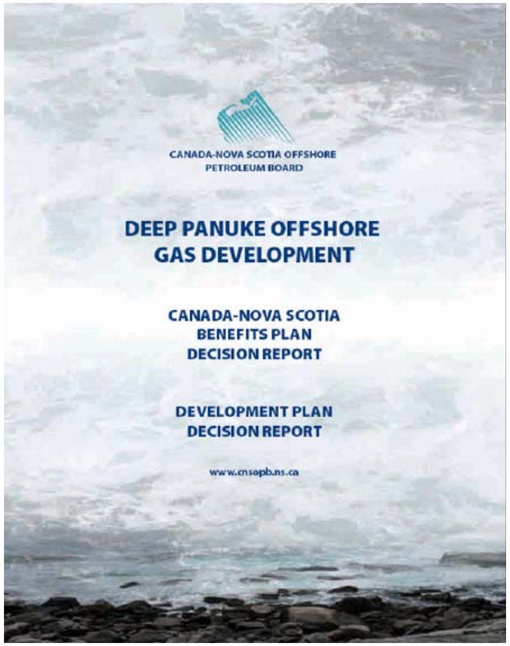
Production and injection history

Reserves and EUR

Total capital investment and development drilling

Nova Scotia Summary

- **Requirement for public Review of field developments**
- **Deep Panuke development recently submitted**
  - ➢ Approved Oct 3, 2007



Nova Scotia Deep Panuke

Includes sales gas forecast …

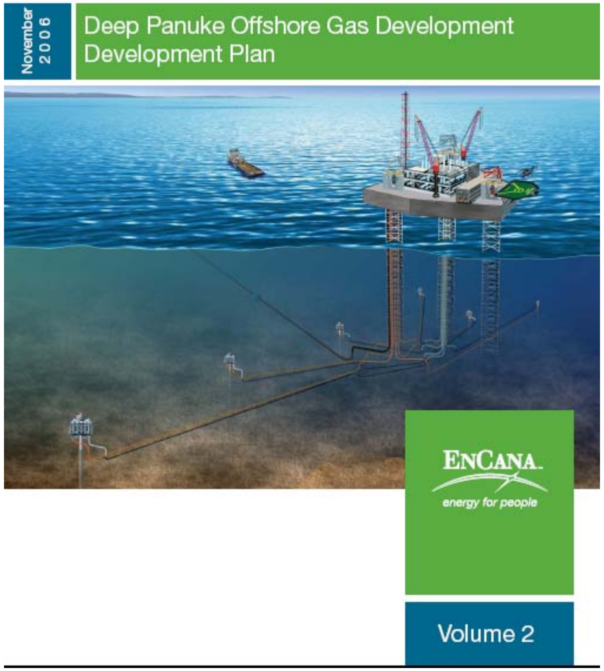
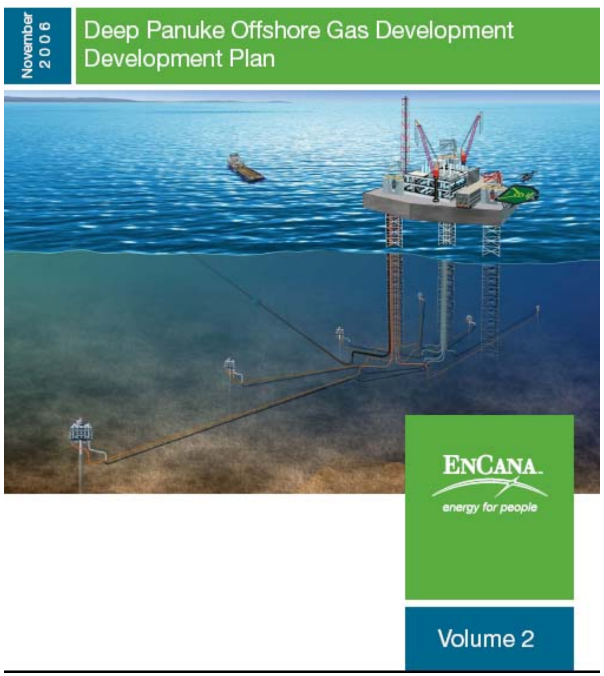


Table 6.1 Sales Gas Forecast

Year	P90		P50		P10		Mean	
	(10^6 sm3/d)	(MMscfd)	(10^6 sm3/d)	(MMscfd)	(10^6 sm3/d)	(MMscfd)	(10^6 sm3/d)	(MMscfd)
2010	5.7	202	5.7	201	5.7	202	5.7	201
2011	8.5	300	8.4	300	8.5	300	8.5	300
2012	7.0	249	8.5	300	8.4	300	8.2	291
2013	4.5	159	6.4	228	8.4	300	6.2	219
2014	3.1	110	4.8	171	7.7	275	5.0	177
2015	2.2	79	3.8	136	6.0	213	4.0	143
2016	1.6	58	3.1	110	4.7	168	3.4	119
2017	1.3	45	2.5	90	4.1	145	2.7	97
2018	1.1	40	2.1	76	3.3	118	2.3	81
2019	0.0	0	1.6	58	2.9	103	1.9	67
2020	0.0	0	1.5	52	2.4	86	1.6	55
2021	0.0	0	1.5	52	2.1	73	1.3	47
2022	0.0	0	1.3	45	1.7	62	1.3	45
2023	0.0	0	1.1	40	1.6	55	1.1	41
2024	0.0	0	0.0	0	1.4	50	0.0	0
2025	0.0	0	0.0	0	1.4	51	0.0	0
2026	0.0	0	0.0	0	1.3	47	0.0	0
2027	0.0	0	0.0	0	1.2	41	0.0	0
2028	0.0	0	0.0	0	1.1	38	0.0	0

Nova Scotia Deep Panuke

… and cost forecast by expenditure type



6.3.1 Development Phase Expenditures

Estimates for the development phase include costs incurred by EnCana, as operator of the Project, from the fourth quarter 2006 to first gas production, scheduled to occur in the fourth quarter of 2010.

The costs shown in Table 6.2 are for the M&NP option, and exclude any costs associated with the MOPU, which will be included as operating costs payable during the production life of the Project.

The SOEP Subsea Option would see a reduction in the cost of the export pipeline during the Development Phase. However, there would be an increase in operating costs for tariffs charged as a result of using the SOEP pipeline. At this time, these costs are not defined.

Table 6.2 Development Phase Expenditures	**C$ Millions 2006**
EnCana Project Management & Engineering	115
Subsea	135
Export Pipeline	200
Drilling and Completions	160
Subtotal:	610
Contingency	90
Total Cost to First Gas	**700**

Annual operating costs, including the field centre (MOPU) lease, are estimated at $150 million per year, +/-25%.

Nova Scotia

Deep Panuke approval explicitly requires continual update to cost information submitted with Annual Production Report

Condition 30: Submission of Economic Data

The Proponent shall inform the Board of any material changes to the cost information and production profiles that were submitted with the Development Plan. This information shall be included with the Annual Production Report. This should include details of the operating and capital expenditures for the previous two years, the current year and projections for the next two years as well as reserve revisions

Publicly Available Sources

Example detailed field cashflow available from Deloitte's subscription service

MAGNUS

BP operated UKCS field

	ANNUAL NOMINAL CASH FLOW												
	PRODUCTION								TAXATION		Annual cashflow		Remaining NPV @ 10% On Jan 1
Year	Liquids mbbl/d	Gas mmcf/d	Gross Revenue GBPmm	Royalty GBPmm	Opex / Tariff GBPmm	Operating Profit GBPmm	Capex / Abandonment GBPmm	Gross Profit GBPmm	PRT/APRT GBPmm	CT GBPmm	Total GBPmm	Cumulative GBPmm	GBPmm
2006	34.4	38.6	498.7	-	81.0	417.7	32.0	385.7	170.2	86.6	128.9	2,521.0	302.2
2007	36.7	38.0	484.7	-	80.2	404.5	32.7	371.8	198.6	90.6	82.6	2,603.5	197.2
2008	30.6	28.0	362.2	-	73.8	288.3	33.4	255.0	135.8	71.1	48.0	2,651.5	130.3
2009	25.4	16.0	267.6	-	65.5	202.1	-	202.1	101.9	53.3	46.9	2,698.4	93.0
2010	21.1	9.2	180.8	-	60.3	120.5	-	120.5	64.7	35.8	20.0	2,718.4	53.2
2011	17.6	5.3	140.4	-	55.6	84.8	-	84.8	41.9	23.4	19.5	2,737.9	37.5
2012	14.6	3.0	113.1	-	51.6	61.5	-	61.5	31.5	16.9	13.1	2,751.0	20.9
2013	12.2	1.7	97.9	-	48.1	49.8	-	49.8	24.7	13.2	11.9	2,762.9	9.2
2014	10.1	1.0	99.0	-	45.1	53.8	-	53.8	25.0	13.1	15.8	2,778.7	(2.4)
2015	8.4	0.6	86.1	-	43.4	42.6	-	42.6	21.5	11.7	9.5	2,788.2	(19.2)
2016	7.0	0.3	73.7	-	40.7	33.0	-	33.0	16.3	9.2	7.5	2,795.7	(31.1)
2017	5.8	0.2	60.9	-	37.8	23.1	-	23.1	11.4	6.8	4.8	2,800.5	(42.0)
2018	4.8	0.1	52.1	-	34.9	17.2	-	17.2	8.2	5.1	4.0	2,804.5	(51.3)
2019	-	-	-	-	-	-	42.2	(42.2)	0.9	(12.8)	(30.3)	2,774.2	(60.7)
2020	-	-	-	-	-	-	36.3	(36.3)	-	(19.3)	(17.0)	2,757.2	(34.9)
2021	-	-	-	-	-	-	30.2	(30.2)	-	(16.1)	(14.1)	2,743.1	(20.5)
2022	-	-	-	-	-	-	25.7	(25.7)	-	(13.6)	(12.1)	2,731.0	(7.8)
2023	-	-	-	-	-	-	-	-	-	(4.3)	4.3	2,735.3	4.1
2024	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2025	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2026	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2027	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2028	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2029	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2030	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2031	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2032	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2033	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2034	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2035	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2036	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2037	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
2038	-	-	-	-	-	-	-	-	-	-	-	2,735.3	-
	mmb	bcf											
<2006	813.5	326.7	11,437.6	956.8	1,771.4	8,709.5	2,006.5	6,703.0	3,147.9	1,162.9	2,392.1		
2006+	83.5	51.8	2,517.2	-	718.1	1,799.1	232.6	1,566.5	852.6	370.7	343.2		
Total	897	379	13,955	957	2,490	10,509	2,239	8,269	4,001	1,534	2,735		

CURRENT YEAR PRODUCT DETAILS		
2006	Liquids USD/bbl	Gas
Price	65.4	3.7
Tariff	-	1.5

TAX SUMMARY			
	Govt. Take % Gross profit less Royalty		
	Past	Future	Total
Royalty	12.49%	0.00%	10.37%
PRT	41.10%	54.43%	43.36%
CT	15.18%	23.67%	16.62%
Total	68.77%	78.09%	70.35%

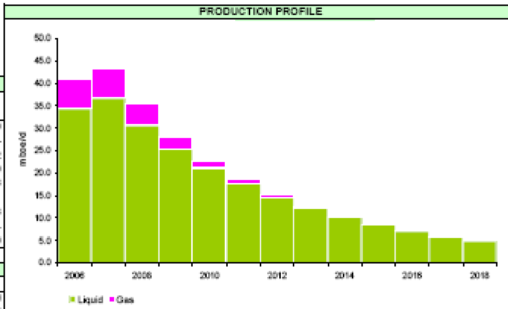
PER BARREL ANALYSIS	Real 2006 GBP/boe
Gross Revenue	21.59
Royalty & SPD	-
Opex & Tariff Expenditure	3.42
Operating Profit	16.59
Capex & Abandonment	5.28
Gross Profit	11.31
PRT	5.68
CT	1.84
Net Profit	3.79

CT LOSS OFFSET OPTION		
	GBP mm	Description
Setting	Offset	CT losses immediately offset
Effect	(10.94)	Standalone NPV difference

OIL ALLOWANCE	
Total available over field life	5,000,000
Remaining 1 Jan 2006	-
Unused at end of field life	-

RECOVERABLE RESERVES	Technical	Economic
Liquids mmb	897.0	897.0
Gas bcf	378.6	378.6

PRODUCTION PROFILE



NET PRESENT VALUE On 1 January 2006		
Discount Rate	Pre CT	Post tax
8.0%	1311.0	315.3
10.0%	1257.2	302.2
12.5%	1195.5	296.8
15.0%	1139.4	287.0
20.0%	1041.8	268.9

PROJECT ECONOMICS	
Discounting Method	Mid
Project payback year @ 10%	1984.5
IRR (from development start)	25%
PVI (from 2006)	3.6
Cover Ratio : 5 Years	N/A
Cover Ratio : 10 Years	N/A
Development start year	1975.0
Production start year	1983.5
Last PRT safeguard year	1987.5
Abandonment Year	2018.5
Technical production life (years)	35.5
Actual production life (years)	35.0

OIL PRICE (USD/bbl): 2006 - 65.59, 2007 - 59.00, 2008 - 54.00, 2009 - 49.00, 2010 - 43.00, Inflated thereafter @ 2.50% | EXCHANGE RATE (GBP→USD): 1.79 | INFLATION: 2.30%

Source: Deloitte Petroleum Services