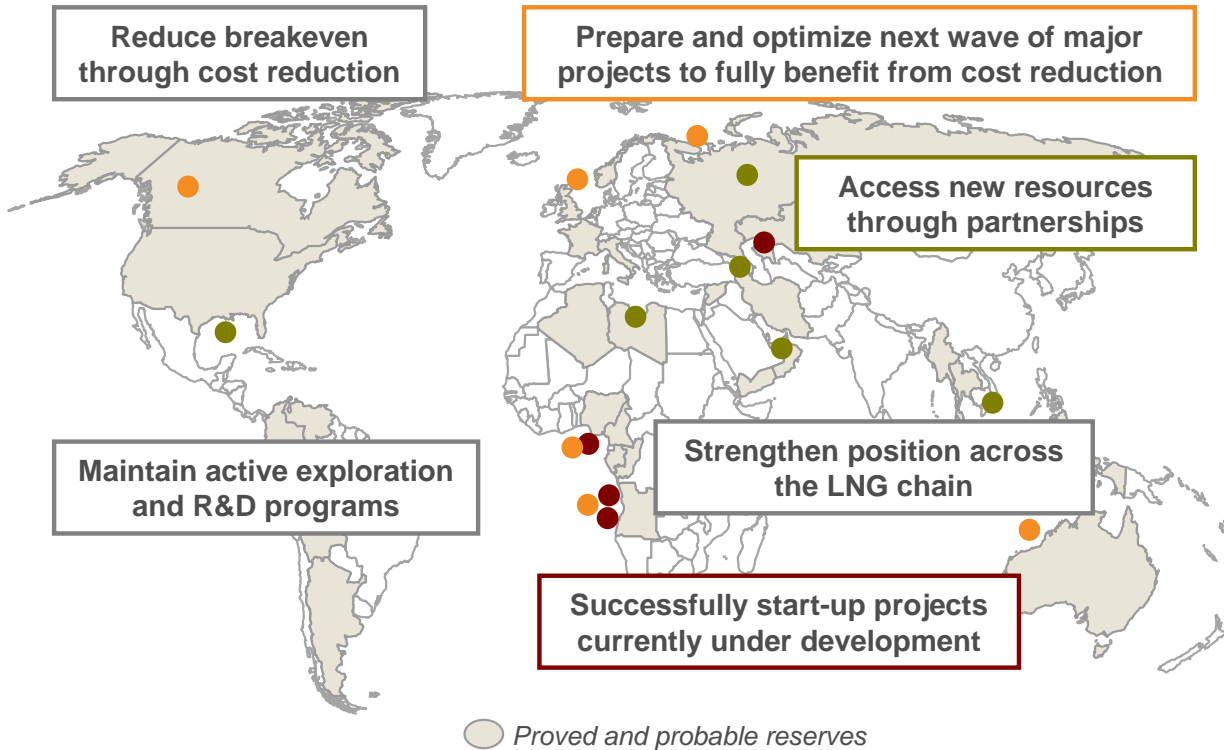


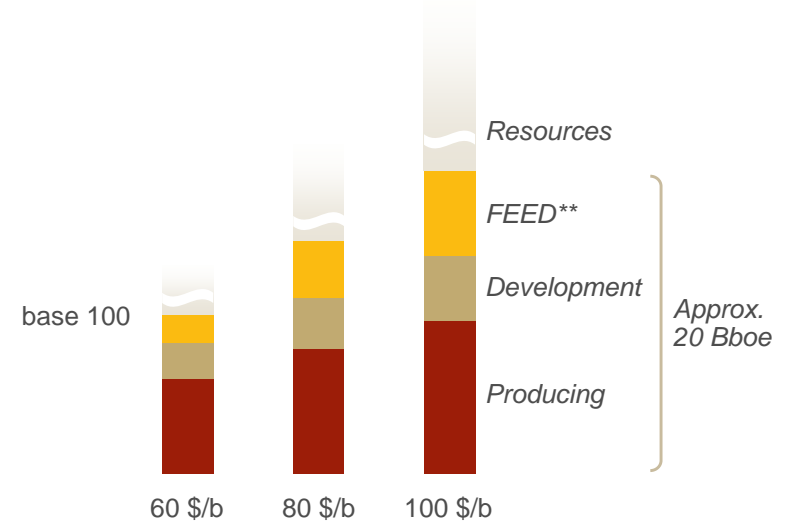
Upstream

Creating value through investments and partnerships

Strategic objectives



Net present value* of proved and probable reserves



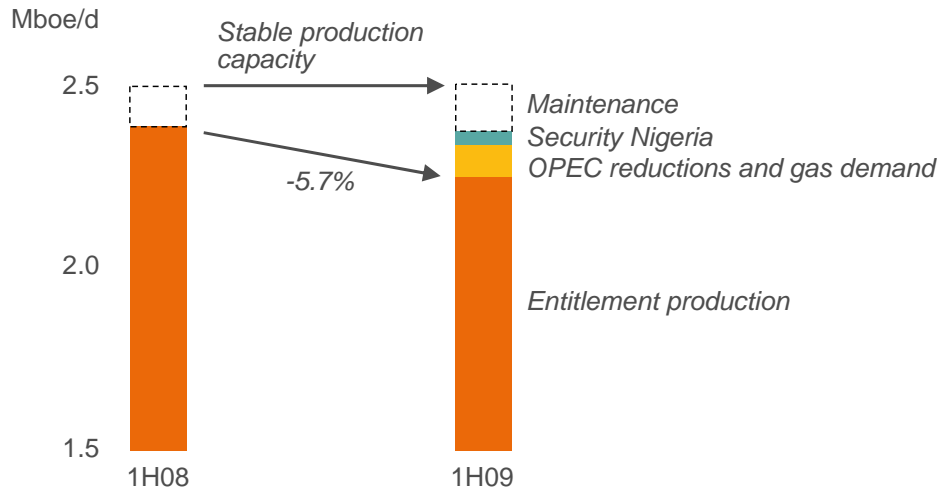
Increase leverage of portfolio to oil price

* net present value discounted at weighted-average cost of capital of the future net cash flow expressed in dollars generated by proved and probable reserves at year-end 2008

** projects under FEED or advanced development studies

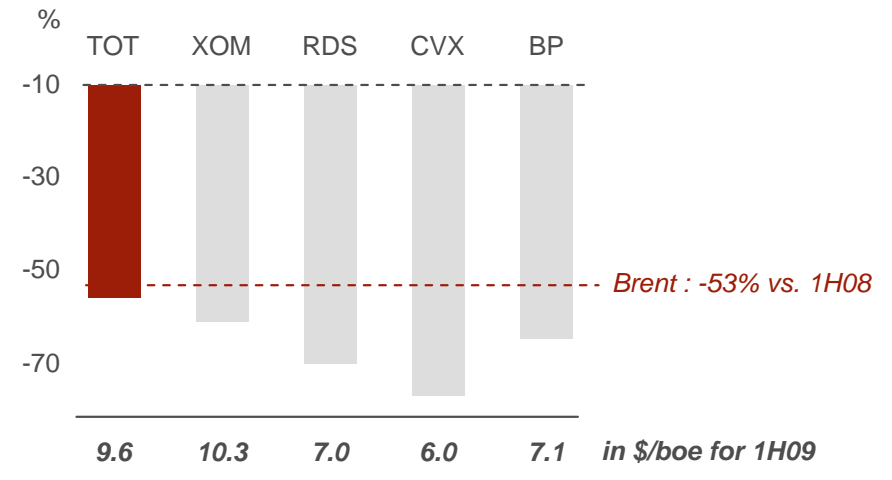
Best resilience despite disappointing production

Production capacity



Upstream adjusted net operating income

(1H09 vs. 1H08)



> 1H09 entitlement production impacted by

- Security issues in Nigeria : -40 kboe/d
- OPEC reductions and weak gas demand : -90 kboe/d

> Low exposure to US natural gas

> Lowest technical costs among the majors in 2008

> Limited impact of OPEC reductions on net operating income in 1H09

**Benefit by year-end from ramp-up of new projects
and favorable gas pricing structure**

2009 : successful year for production start-ups

Akpo (24%)



- > Plateau : 225 kboe/d
- > 0.8 Bboe*
- > Start-up : March 2009

Tahiti (17%)



- > Plateau : 135 kb/d
- > 0.5 Bb*
- > Start-up : May 2009

Tombua Landana (20%)



- > Plateau : 100 kboe/d
- > >0.2 Bboe*
- > Start-up : August 2009

Qatargas II TB (16.7%)



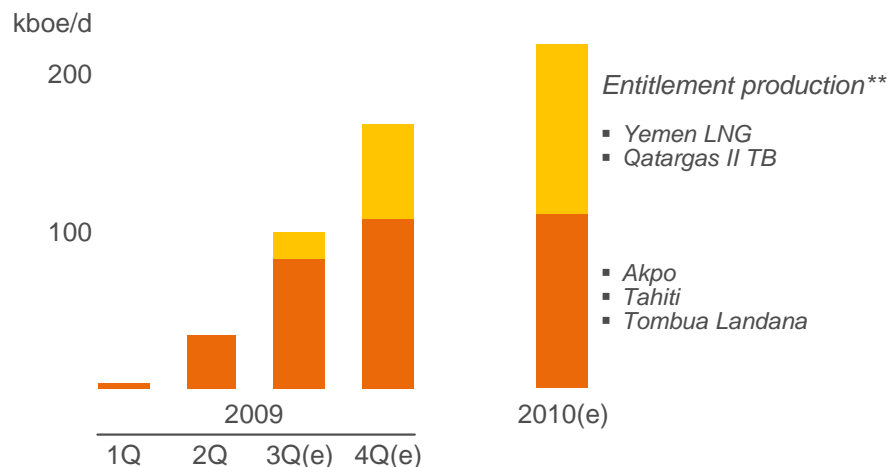
- > Plateau : 290 kboe/d
- > 2.6 Bboe*
- > Start-up : September 2009

Yemen LNG (39.6%)

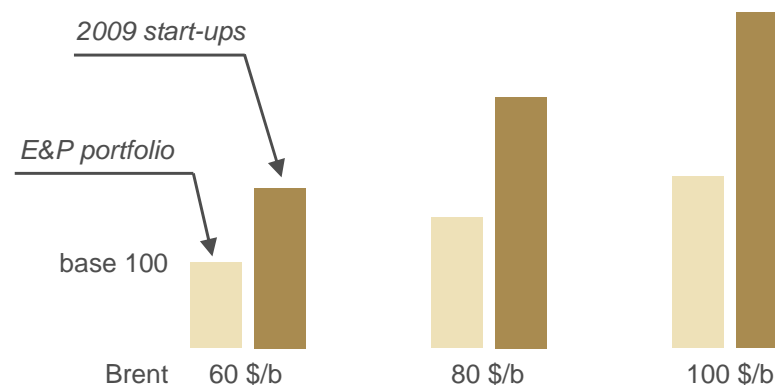


- > Plateau : 190 kboe/d
- > 1.7 Bboe*
- > Start-up : September 2009(e)

Production from 2009 start-ups



Net operating income per barrel*** from 2009 start-ups



Important contribution to value creation
Well balanced between short and long plateau

* proved and probable reserves at 100%, Total estimates

** entitlement production defined as FAS 69 production plus mining, including equity affiliates

*** calculated at plateau ; Henry Hub @ 3.5 \$/Mbtu

Four major developments to support medium-term growth



- > Plateau : 200 kb/d
- > 0.5 Bb*
- > Start-up : 2011(e)



- > Plateau : 180 kboe/d
- > 0.4 Bboe*
- > Start-up : 2012(e)



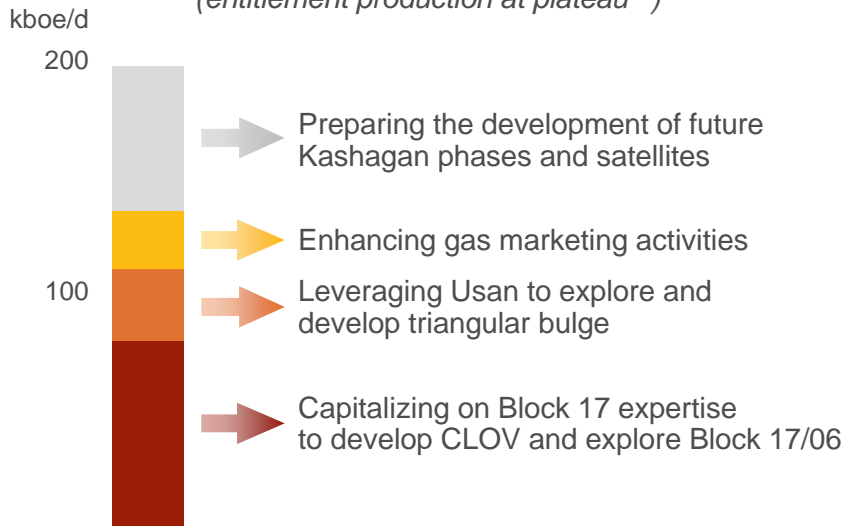
- > Plateau : 175 kboe/d
- > 1.9 Bboe*
- > Start-up : 2012(e)



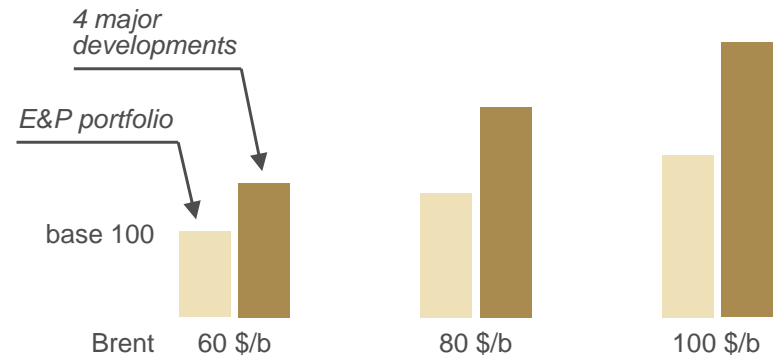
- > Plateau : 300 kb/d
- > >3.0 Bb*
- > Start-up : 2012(e)

Production from major developments

(entitlement production at plateau**)



Net operating income per barrel***



Additional upside to benefit from oil price recovery

* proved and probable reserves at 100%, Total estimates

** entitlement production defined as FAS 69 production plus mining, including equity affiliates

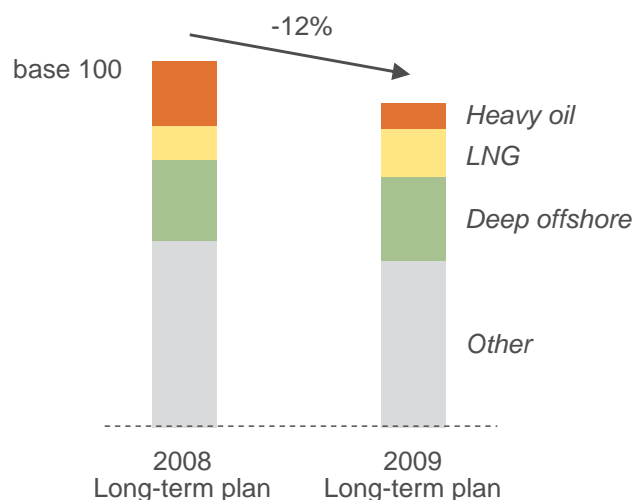
*** calculated at plateau



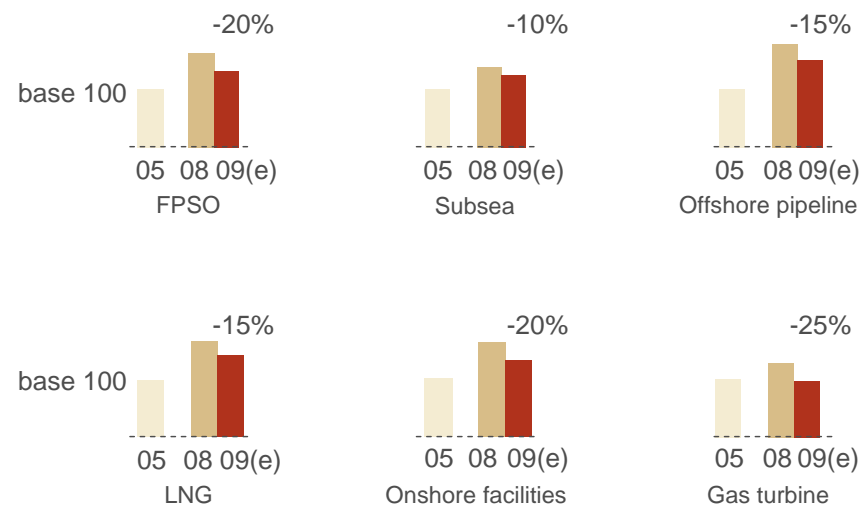
Optimizing the next wave of projects

Pending FIDs* :		2010(e)				2011(e)	
	Surmont Ph. 2	CLOV	Laggan/Tormore	Ofon II	Shtokman	Ichthys	Egina

Cumulative Upstream development Capex 2010-14(e)



Cost estimates for major components of Capex



> **Maintain investment discipline**

- 80 \$/b base case scenario for long-term oil price
- Test resilience at 60 \$/b and upside at 100 \$/b

> **FIDs for major new projects not expected before 2010(e)**

> **Relaunch of some calls for tender on Ofon II**

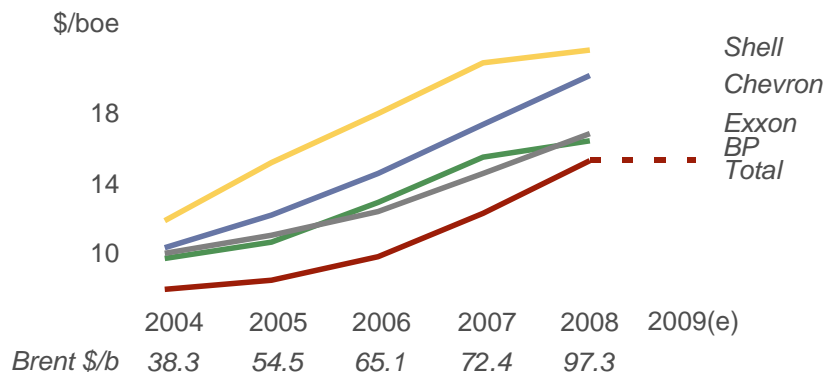
Cost reduction and delay of some projects if needed

* Final Investment Decision to launch project

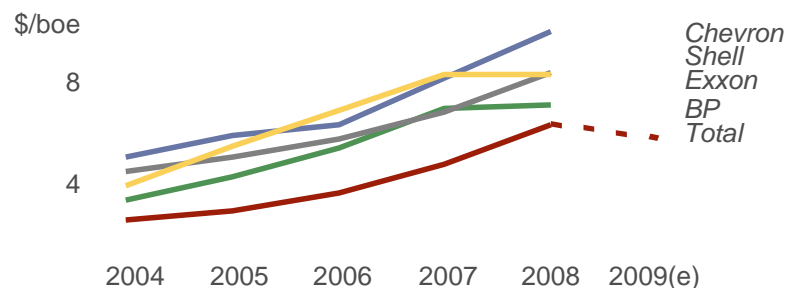


Active cost reduction program

Lowest technical costs*



Opex*



- > 2009(e) DD&A increase offset by Opex reduction
- > Benefit from market effects : FX, idle capacities

Opex reduction

> Contract renegotiation

- Well servicing contract (up to -30%)
- Maintenance contract (up to -20%)
- Tender offer for jack-up rigs in Qatar and Vietnam (up to -40%)
- Group purchase agreement on steel and chrome tubulars (up to -25%)
- Logging contract price reduction in exchange for extension (up to -30%)

> Optimization

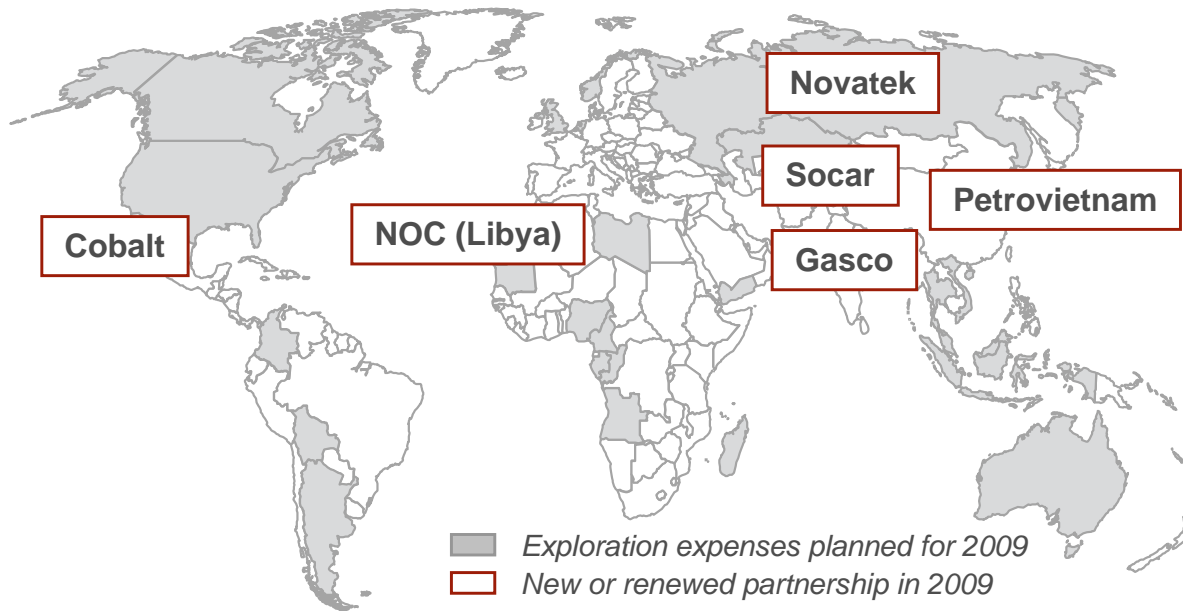
- Logistics : transportation sharing (supply boats, helicopters)...
- Efficiency : reduce speed of vessels...
- Simplification : exploration well architecture...
- G&A cost reduction

**Implementing plans
to reduce cash breakeven
1H09 Opex per barrel
reduced by 14% vs. 2008**

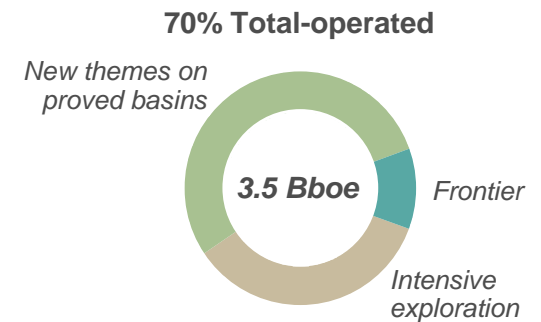
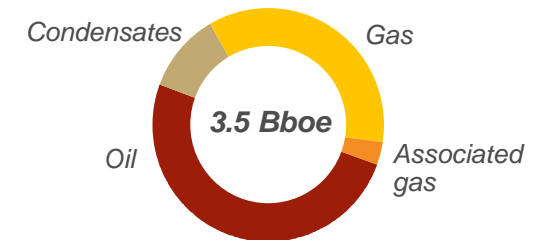
* FAS 69 (Opex, DD&A and Expl.), consolidated subsidiaries, estimates for other majors based on public data

Preparing for the long term through exploration and partnerships

Access to potential resources



Current exploration potential*



- > **Strengthen position in prolific or new basins since beginning of 2009**
 - GOM, Egypt, Russia, Azerbaijan, Vietnam
- > **Discovery cost around 2-3 \$/boe****
- > **Capitalize on technology**
 - HP/HT, complex reservoir, seismic data collection and interpretation

- > **Continue exploration in core areas**
 - West Africa, North Sea
- > **Develop new partnerships to access high potential areas**
 - Iraq, Venezuela, Libya

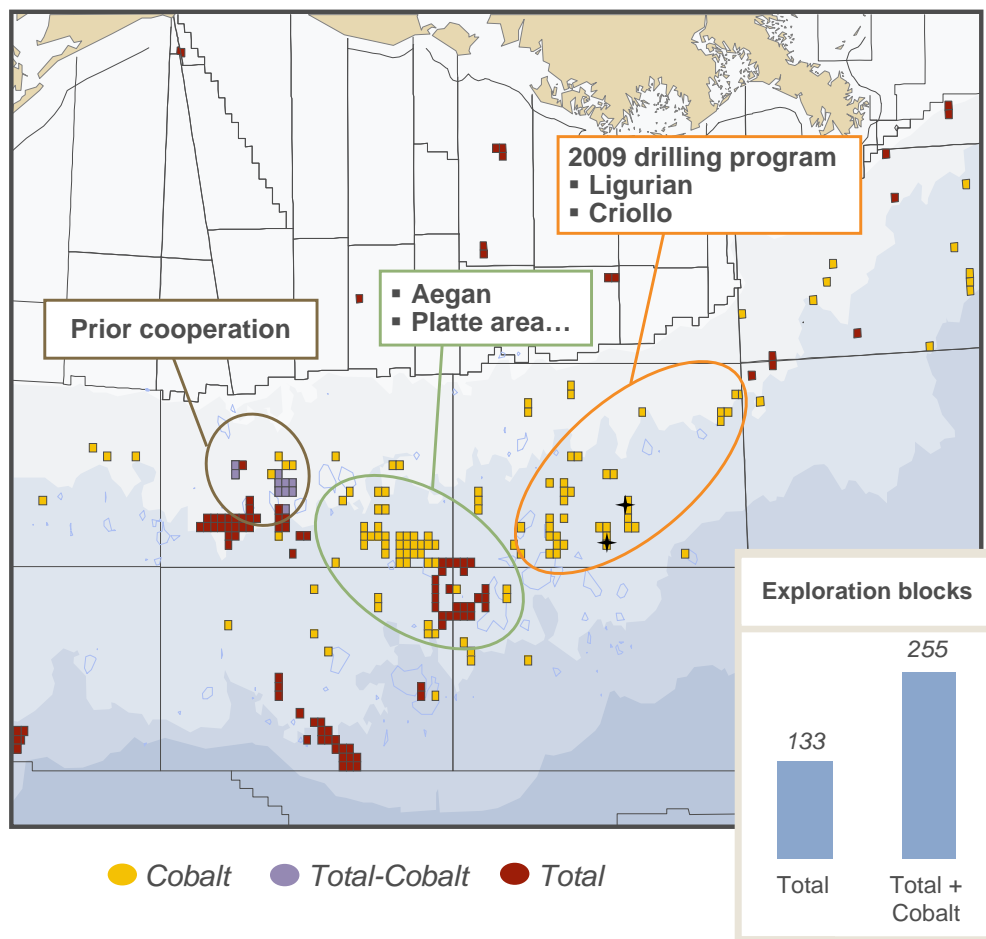
Around 500 Mboe accessed since beginning 2009
Maintain a competitive advantage vs. other majors on discovery cost

* mean risked resources ; Group share

** 3-year average



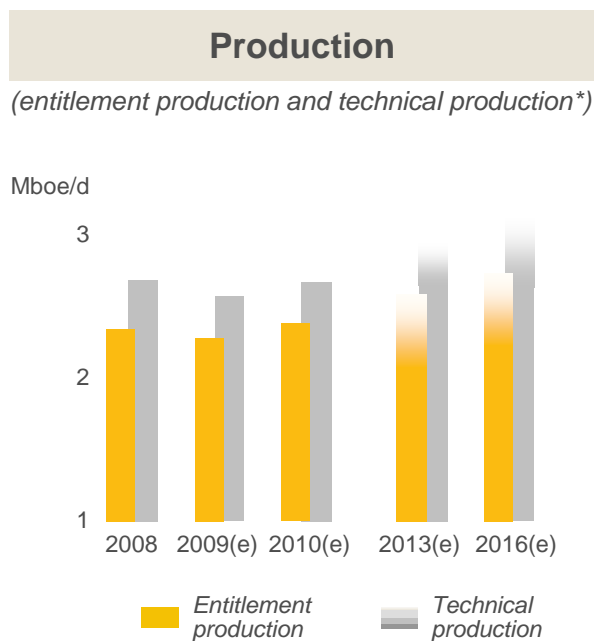
Alliance for exploration in the Gulf of Mexico



- **Total 40% - Cobalt 60% merger of GOM exploration portfolios (255 blocks)**
- **Subsalt prospects analogous to major GOM discoveries (Miocene and Paleocene)**
 - Drilling program
 - 2009 : Ligurian (3Q) and Criollo (4Q)
 - 2010(e) : 3 additional wells
- **Capitalize on Cobalt's GOM exploration expertise**

Large and promising exploration program over the coming years

Large portfolio of projects sustains long-term production growth



➤ **Projected base decline rate at about 5% per year on average**

	Projects	Country		Capacity (kboe/d)	Share	Op**	Status
2018(e)	Kashagan Ph. 2	Kazakhstan	Liquids	850	16.8%		Study
	Pars LNG	Iran	LNG	295	30%	✓	Study
	NLNG T7	Nigeria	LNG	250	15%		FEED
	Joslyn North Mine	Canada	Heavy oil	100	75%	✓	Pre-FEED
	Ichthys LNG	Australia	LNG	335	24%		FEED
	Brass LNG	Nigeria	LNG	300	17%	✓	FEED
	Shah Deniz FF	Azerbaijan	Gas	475	10%		Study
	Shtokman Ph. 1	Russia	LNG/pipeline	410	25%		FEED
	Block 32-CSE	Angola	Deep offshore	Study	30%	✓	Study
	Eldfisk 2	Norway	Liquids	70	39.9%		FEED
	Moho North	Congo	Deep offshore	Study	53.5%	✓	Study
	Egina	Nigeria	Deep offshore	200	24%	✓	FEED
	Hild	Norway	Liq/Gas	70	49%	✓	Appr.
	Ekofisk South	Norway	Liquids	60	39.9%		FEED
	Tempa Rossa	Italy	Heavy oil	50	50%	✓	Dev.
	Surmont Ph. 2	Canada	Heavy oil	90	50%		FEED
	Laggan/Tormore	UK	Liq/Gas	90	50%	✓	FEED
	CLOV	Angola	Deep offshore	160	40%	✓	FEED
	Anguille redev.	Gabon	Liquids	40	100%	✓	Dev.
	2013(e)	Ofon II	Nigeria	Liquids	100	40%	✓
OML 58 upgrade Ph. 1		Nigeria	Gas/Cond.	50	40%	✓	Dev.
Sulige		China	Gas	70	100%	✓	Study
Kashagan Ph. 1		Kazakhstan	Liquids	300	16.8%		Dev.
Angola LNG		Angola	LNG	175	13.6%		Dev.
Bongkot South		Thailand	Gas	70	33.3%		EPC
South Mahakam Ph. 1/2		Indonesia	LNG	55	50%	✓	FEED
Usan		Nigeria	Deep offshore	180	20%	✓	Dev.
Pazflor		Angola	Deep offshore	200	40%	✓	Dev.
2009(e)		Yemen LNG	Yemen	LNG	190	39.6%	✓
	Qatargas II (TB)	Qatar	LNG	290	16.7%		Prod.
	Tombua Landana	Angola	Liquids	100	20%		Prod.
	Tyrihans	Norway	Liq/Gas	96	23.2%		Prod.
	Tahiti	US	Deep offshore	135	17%		Prod.
	Akpo	Nigeria	Deep offshore	225	24%	✓	Prod.

* technical production defined as equity share of wellhead production ; entitlement production defined as FAS 69 production plus mining, including equity affiliates and non-consolidated subsidiaries ; based on Brent oil price environment of 60 \$/b in 2010 and 80 \$/b thereafter ; 2010 estimates include OPEC reduction of 80 kb/d

** operated by Total or through an operating company

Upstream - LNG

Adding two very competitive and long-lasting major LNG projects

Qatargas II TB (16.7%)



- > Start-up : September 2009
- > Capacity : 7.8 Mt/y
- > 55 kb/d of condensates
- > Capex : 4.1 B\$
- > Purchases by Total : 5.2 Mt/y

Very low breakeven price thanks to liquids contribution

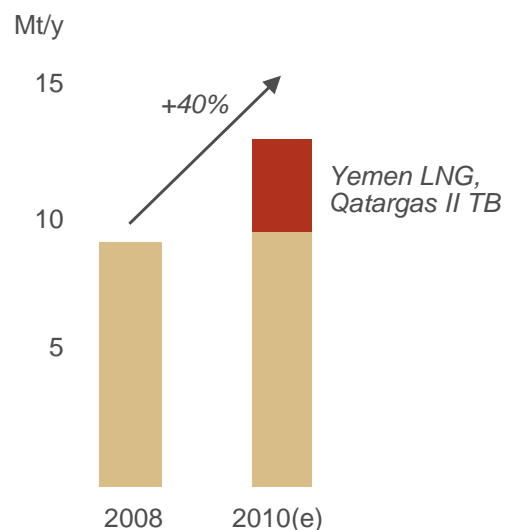
Yemen LNG (39.6%)



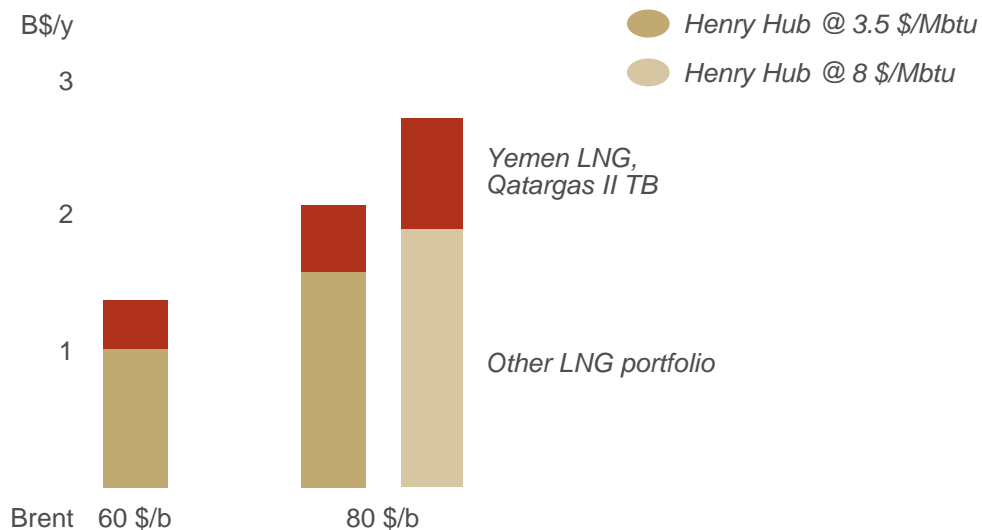
- > Start-up : September 2009(e)
- > Capacity : 6.7 Mt/y
- > Capex : 4.5 B\$
- > Purchases by Total : 2 Mt/y

Breakeven price after regas in the US around 2.5 \$/Mbtu

LNG sales by Total*



Contribution of LNG sales to net operating income**

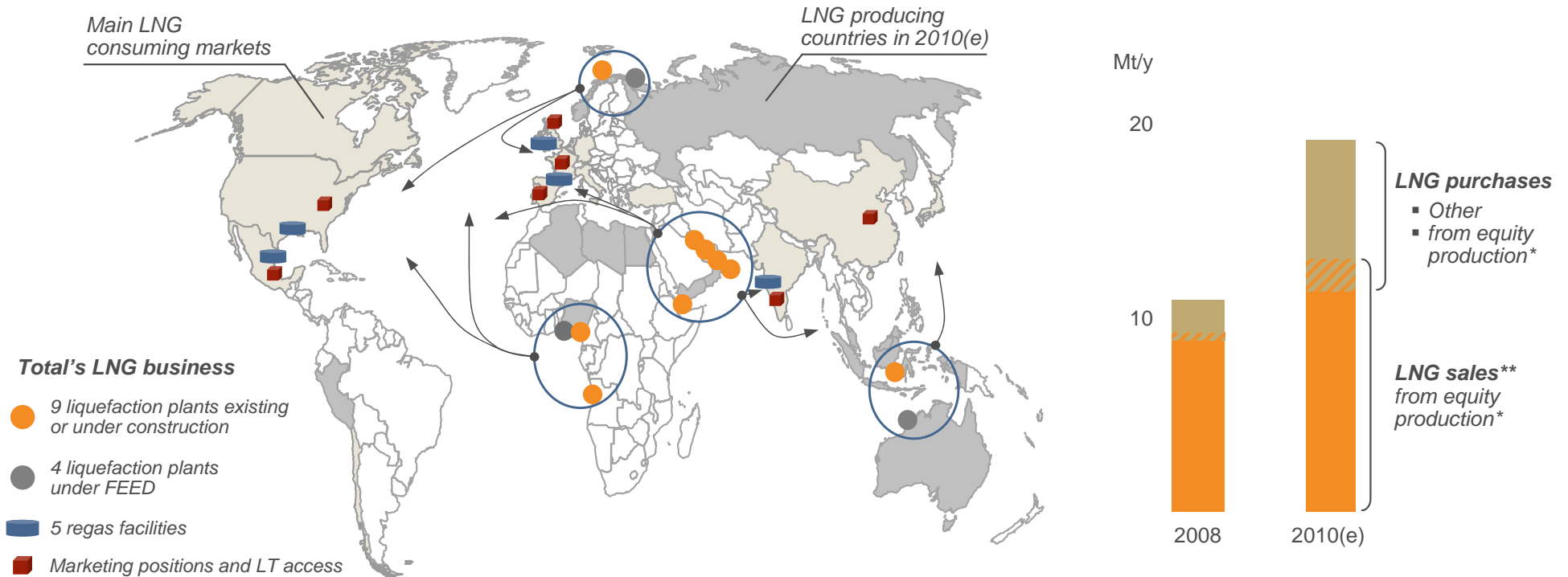


70% of Total's LNG sales based on oil-indexed formulas
Resilient portfolio offering strong leverage to oil and gas prices

* Group share of LNG sales by affiliates and participations, including FAS 69 production equivalent for Bontang sales and excluding trading
 ** 2011(e)

Capturing value along the entire LNG chain

Total's balanced exposure on LNG market



Strong geographical diversification of the liquefaction portfolio

Secured access to the main consuming markets through regas facilities or long-term contracts

Benefit of strong downstream gas positions to trade and market volumes

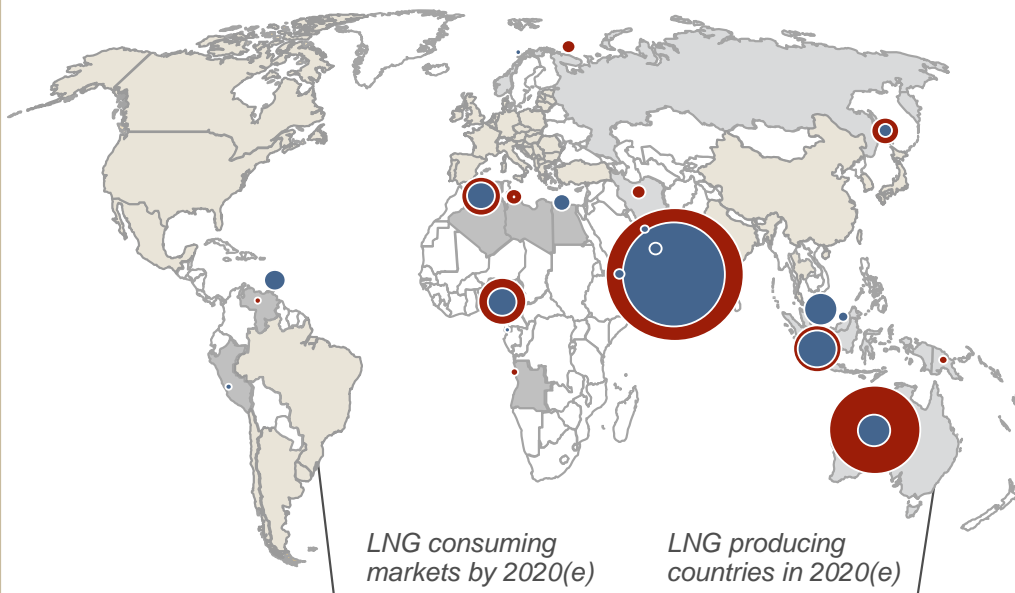
* in proportion to equity share in selling entity

** Group share of LNG sales by affiliates and participations, including FAS 69 production equivalent for Bontang sales and excluding trading

Securing access to future LNG capacity

Worldwide planned and potential LNG capacity

(Total estimates)



● Planned capacity by 2012(e) ● Potential capacity in 2020(e)

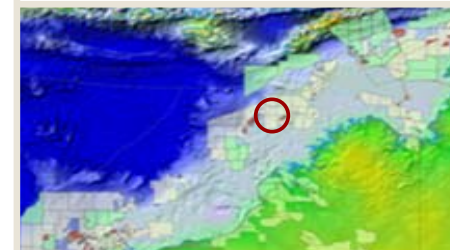
- LNG to grow by 7% per year on average through 2020(e)
- Few LNG substitutes for Asia
- Long-term growth potential concentrated in Nigeria, Iran, Australia and Russia

Shtokman Ph.1 (25%)



- Strategic partnership with Gazprom
- Gas field (134 Tcf) 600 km offshore, arctic conditions
- Reserves Ph.1 : 21 Tcf of gas
- Capacity Ph.1 : 2.3 Bcf/d, including 7.5 Mt/y of LNG
- Strong potential beyond Ph.1
- FEED completed in 4Q09(e)
- Offshore FPU gas producing and processing facilities
- LNG and pipeline gas treatment plants onshore near Murmansk
- FID : 2010(e)

Ichthys LNG (24%)



- Strategic partnership with Inpex
- Gas and condensate field 850 km west of Darwin
- Reserves : 530 Mb of condensates, 13 Tcf of gas
- Capacity : 8.4 Mt/y of LNG, 100 kb/d of condensates, 1.6 Mt/y of LPG
- Additional exploration potential
- FEED started in 2009
- Offshore processing facilities for gas, FPSO for condensates
- LNG plant onshore in Darwin
- FID : end-2010(e)

Taking advantage of the deflationary environment to optimize costs