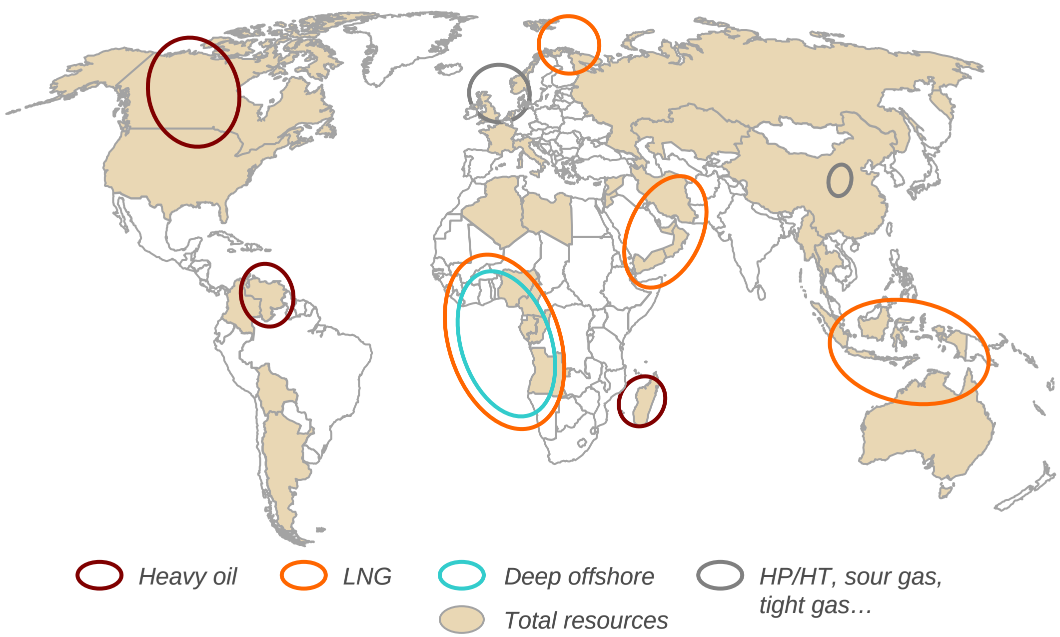
Upstream

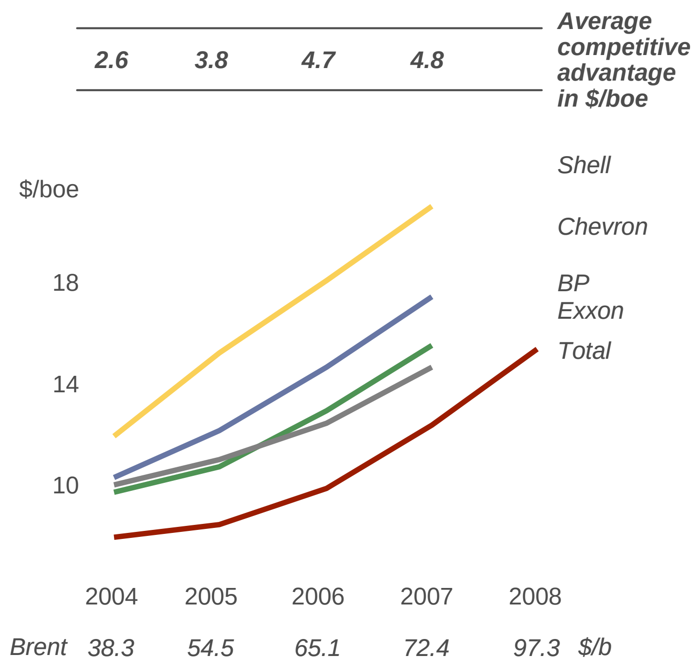
Competitive Upstream position

Geographically and technologically diversified

(more than 40 years of resources at year-end 2008)*



Lowest technical costs**



Centralized management and strict discipline

Large portfolio of projects under development or pending FID

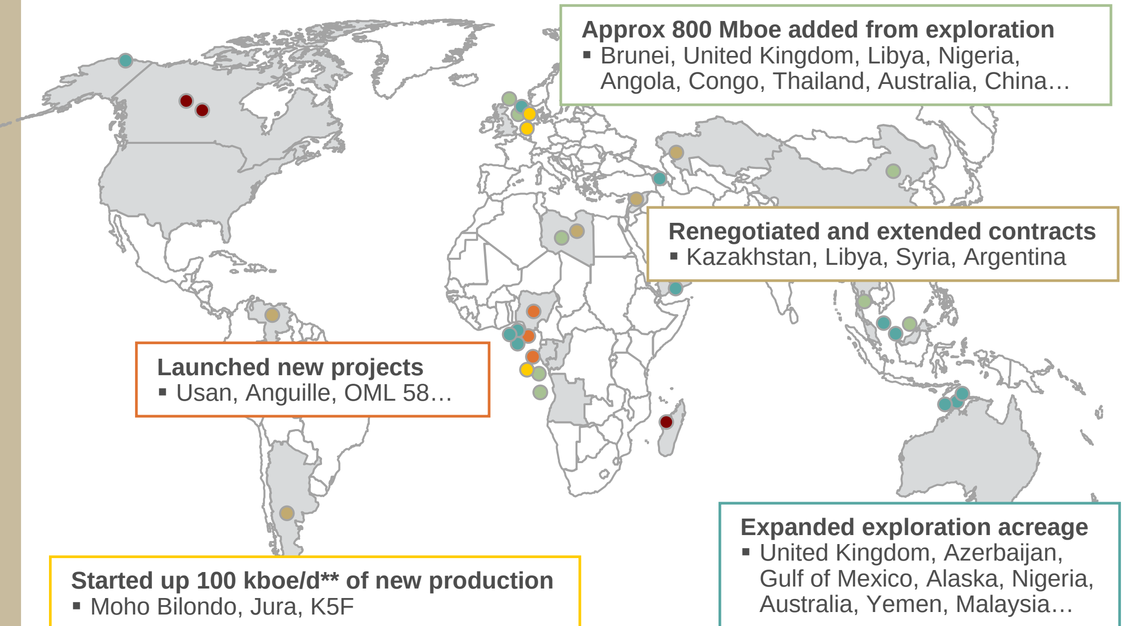
* proved and probable reserves plus potential median recoverable reserves from known accumulations (SPE - 03/07)

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

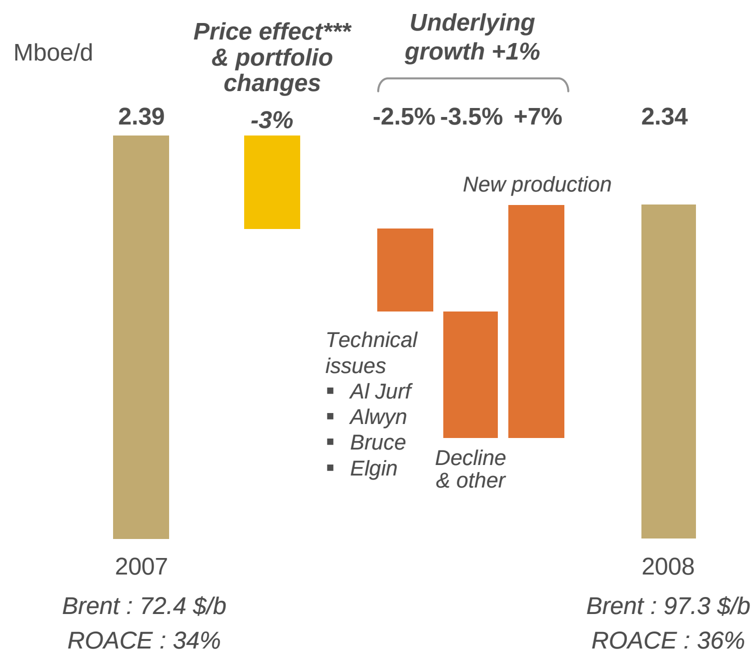
Robust Upstream performance

Numerous advances since the start of 2008

Accessed more than 2 Bboe of new long-term resources
- Madagascar, Synenco, UTS Energy*…



Production



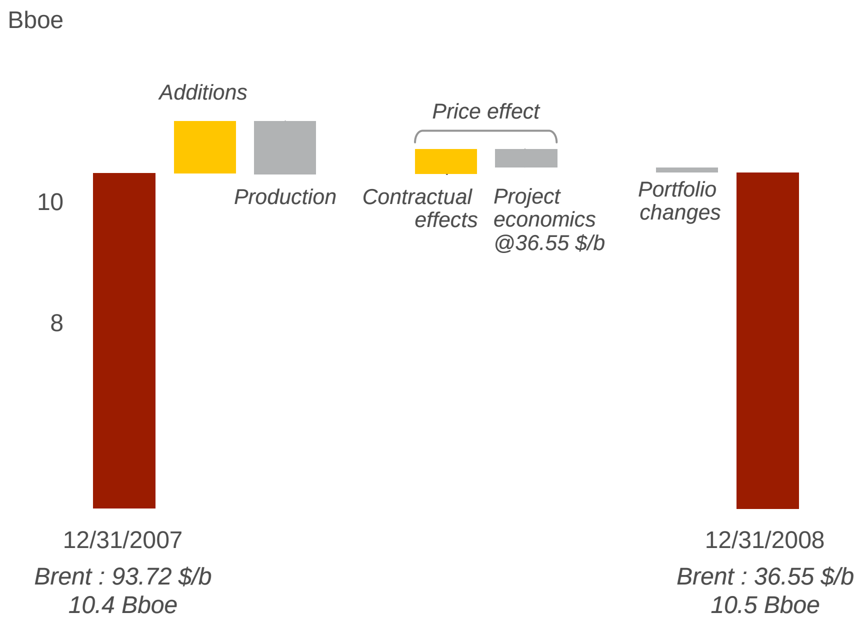
Upstream adjusted net operating result of 15.8 B$ in 2008, an increase of 30%

Average cost to access new resources of less than 2 $/boe

* subject to the success of the open public offer for UTS Energy
** entitlement production, Total share, at projected plateau
*** impact of changes in hydrocarbon prices on entitlement production

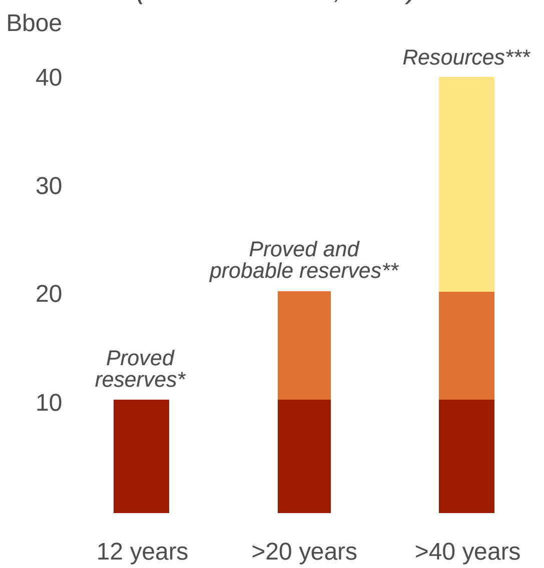
2008 reserve replacement

Proved reserves*



Reserves and resources

(at December 31, 2008)



112% reserve replacement rate excluding acquisitions and divestments*

Proved reserve life maintained at 12 years

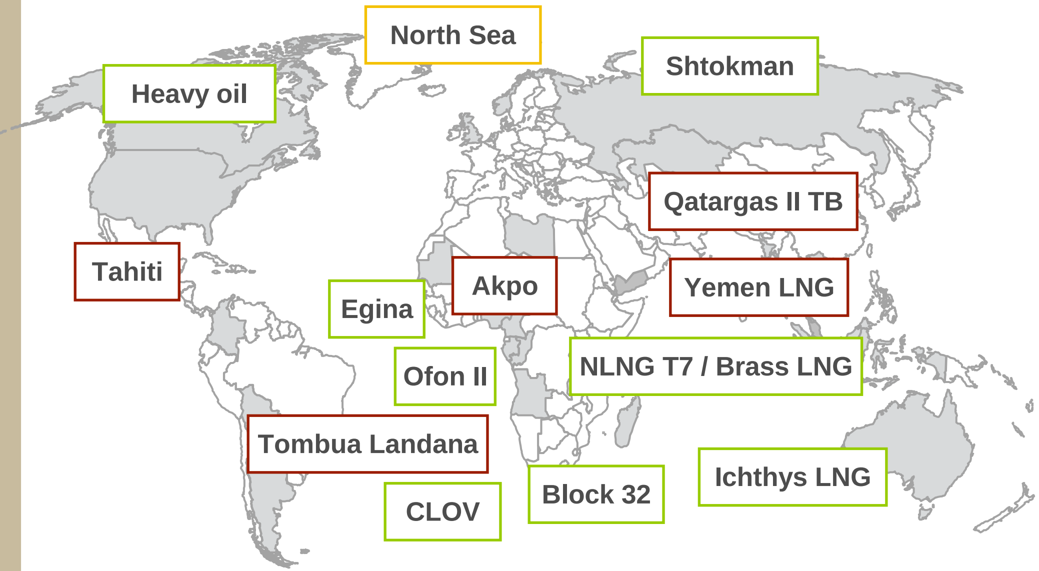
* reserves of consolidated subsidiaries (FAS 69) and share of equity affiliates and non-consolidated companies ; additions at 93.72 $/b ; 101% reserve replacement rate including acquisitions and divestments ; 99% in a constant 93.72 $/b Brent environment excluding acquisitions and divestments

** limited to proved and probable reserves at year-end 2008 covered by E&P contracts on fields that have been drilled and for which technical studies have demonstrated economic development in a 60 $/b Brent environment, also includes projects to be developed by mining

*** proved and probable reserves plus potential median recoverable reserves from known accumulations (SPE - 03/07)

TOTAL

2009 Upstream main operational objectives



Start up five 2009 major projects
- *About 200 kboe/d at plateau, Total share*

Optimize development of giant in-progress projects
- *Focus on costs and timing*
- *Represents more than 6 Bboe and 40-50 B$*, Total share*

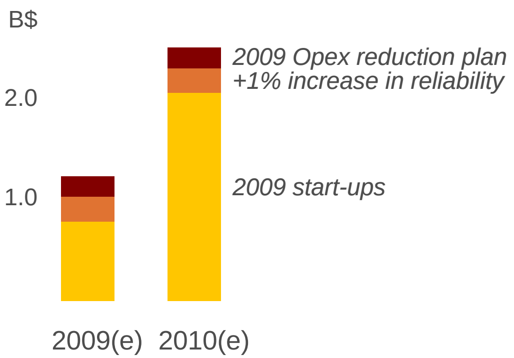
Increase reliability to reduce unscheduled downtime
- *Main technical issues : 2.5% impact on 2008 production*

Maintain active exploration program
- *Discovery cost target around 2-3 $/boe*

Reduce breakeven point for producing fields
- *Target to reduce company-operated Opex by 0.8 B$ by end-2009****
- *Significant potential for lower non-operated Opex*

Impact of 2009 main objectives**

(excluding potential Capex reductions)



Maintain Upstream Capex and technical costs at levels comparable to 2008

Continue to create significant value

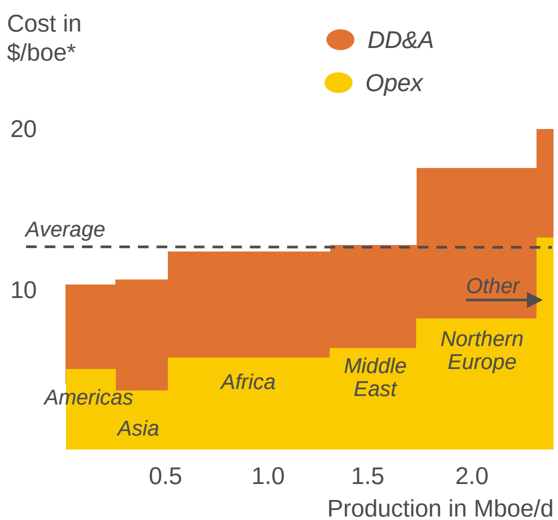
* proved and probable reserves and Capex over the life of projects
** impact on Upstream cash flow ; in a 60 $/b Brent environment
*** 100% on a full-year basis, excluding personnel costs ; variation from initial estimates

TOTAL

Managing Upstream production costs

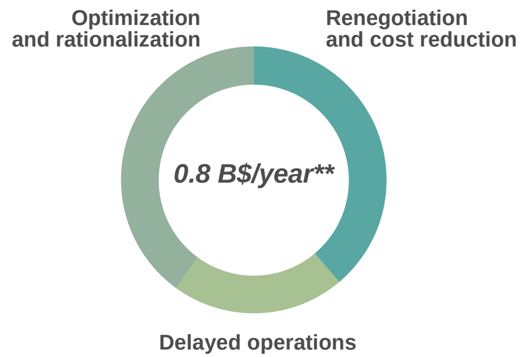
Upstream cost structure*

(2008 average by region, excluding exploration)



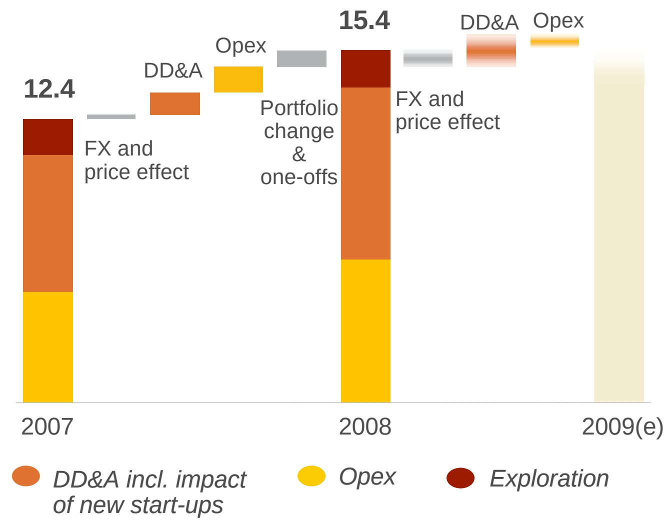
2009 Opex reduction plan

(operated activities)



Technical costs***

(in $/boe)



Implementing plans to reduce breakeven point
and capture lower costs resulting from current economic contraction

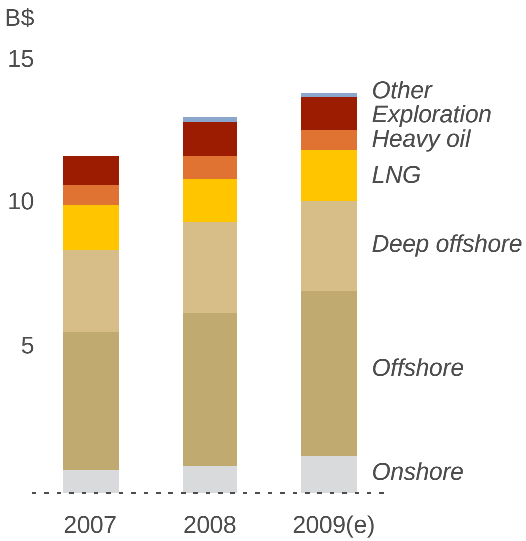
* Upstream Opex and DD&A, based on FAS 69 for consolidated subsidiaries, including Opex and DD&A of main equity affiliates, excluding buy-back contracts

** 100% on a full-year basis, excluding personnel costs ; variation from initial estimates

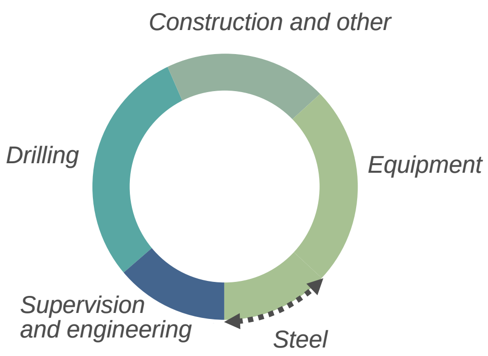
*** FAS 69, consolidated subsidiaries ; portfolio changes including PetroCedeño and impairment of Joslyn ; for 2009 in an environment of 60 $/b Brent and 1 € = $1.30

2009 Upstream Capex budget of 14 B$*

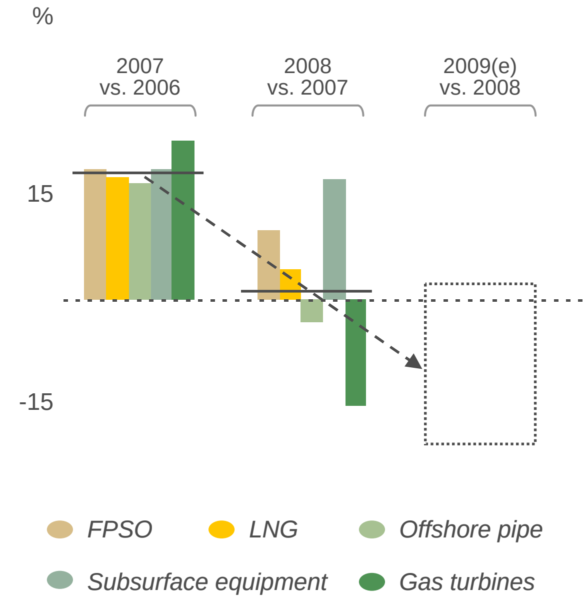
Upstream Capex*



Total-operated Capex**



Cost trends for major components of Capex**



Active approach to reducing cost of projects in all segments

Lower development costs as soon as 2009

* includes net investments in equity affiliates and non-consolidated companies ; for 2009 : 1 € = $1.30, excluding acquisitions and divestments

** Total estimates

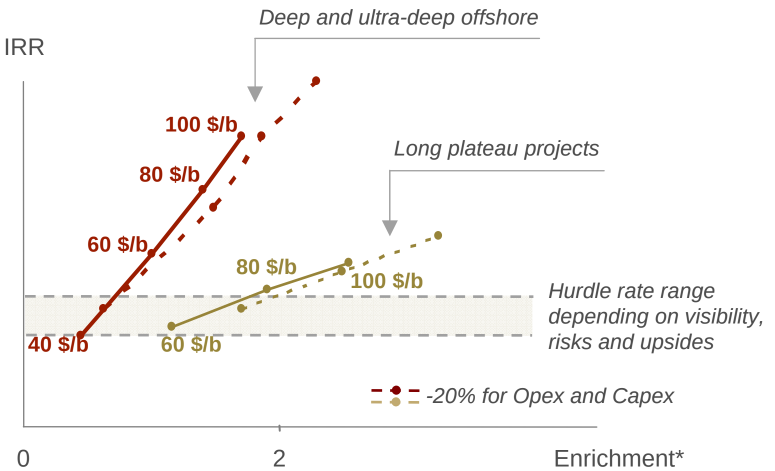
TOTAL

Preparing the next wave of major projects

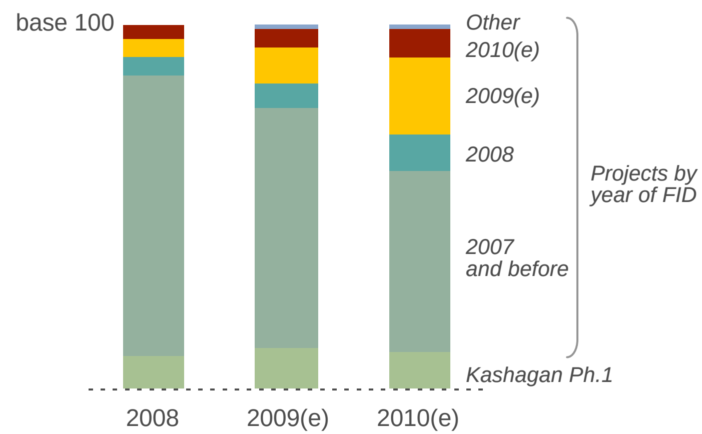
2008 — 2010(e)

ALNG Pazflor Usan Anguille OML58 Laggan/Tormore Egina CLOV Shtokman Block 32 Ichthys Canada LNG in Nigeria

Profitability of major pending projects



Capex for Upstream projects



- **Maintain investment discipline**
- **FIDs of main projects not until end-2009 and 2010(e)**

Creation of value from projects generated by exploration, even in a weak environment

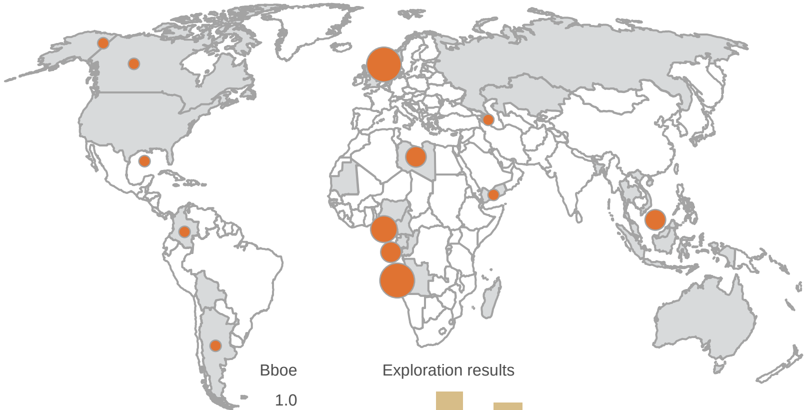
Ample time to prepare for upcoming FIDs

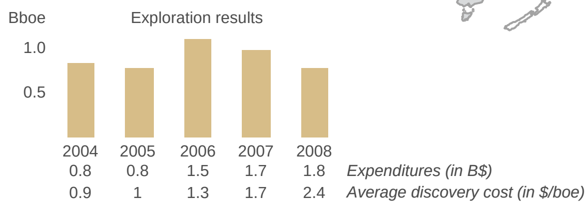
* cumulative net cash flow over life of project, divided by development Capex

TOTAL

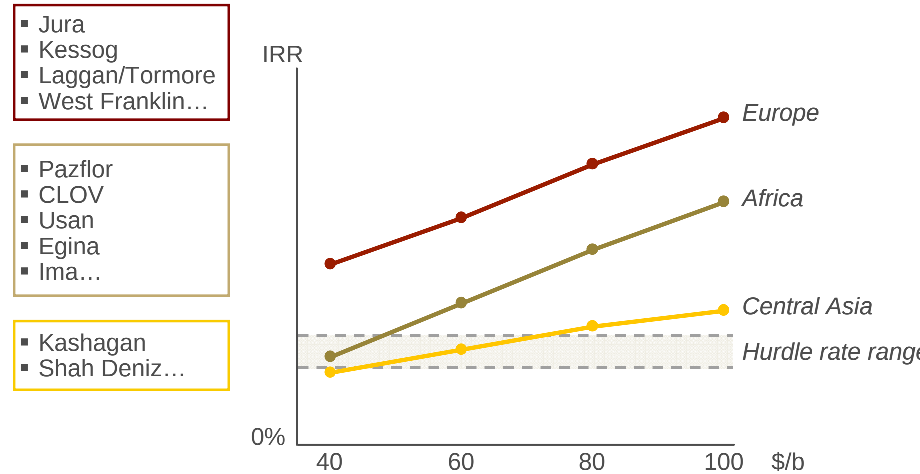
2009 exploration budget of 1.7 B$

Exploration wells planned for 2009





Average profitability of new projects generated from exploration



- **Maintain exploration budget comparable to 2008**
- **Selective prospect screening**
  - Quarterly review of exploration program
  - Priority to large-scale prospects and to prospects with potential to prove new themes
- **Seismic costs lower and drilling costs expected to fall**
- **Simplification of the exploration program**
  - Well trajectories
  - Data acquisition programs

Priority to explore major prolific basins
Maintain discovery cost around 2-3 $/boe

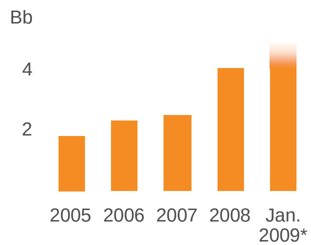
TOTAL

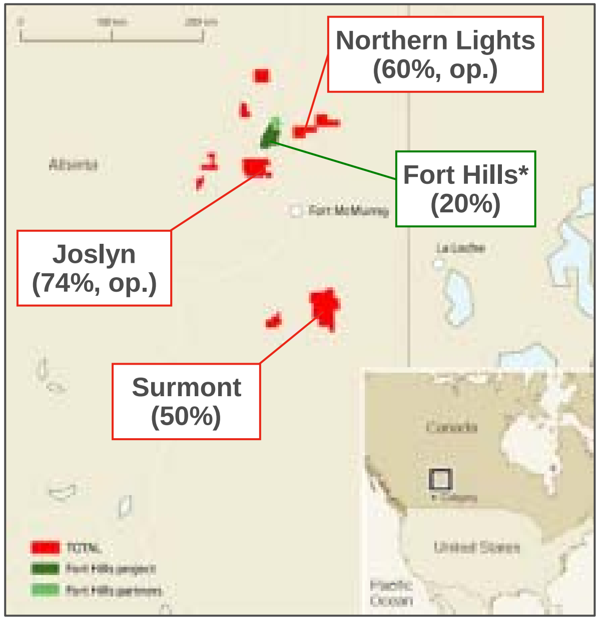
Consolidation of heavy oil portfolio

- **Canada : acquisition of Synenco in 2008 and public offer for UTS* in January 2009**
  - 1.5 Bb of resources Total share*

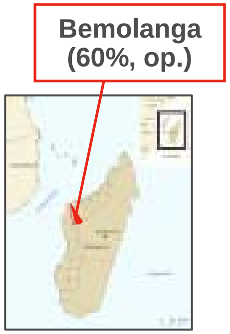
Heavy oil resources

(end of period)





- **Reevaluation of costs, technologies, structure and timing of Canadian projects**
  - Joslyn, Fort Hills*, Northern Lights
  - First phase of Fort Hills projected in 2013(e) with plateau production of 160 kb/d
  - Plans for upgrader unchanged



- **Position taken in world-class Madagascar basin**
  - Acquisition of 60% of Bemolanga in 2008
  - 1 Bb of resources, Total share

Giant long-plateau projects needed to supply global oil demand by 2020(e)

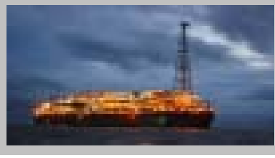
Need to reduce breakeven point

R&D important to increase recovery rates and limit environmental footprint

* subject to the success of the open public offer for UTS Energy ; 0.8 Bb of resources out of the 1.5 Bb

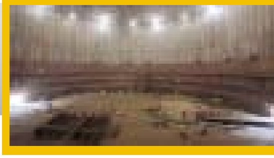
Five major projects to start-up in 2009(e)

Akpo (24%)



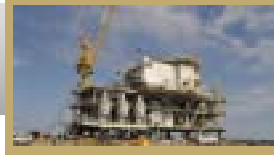
- Plateau : 225 kboe/d
- 0.8 Bboe*
- Start-up : 2Q(e)

Yemen LNG (39.6%)



- Plateau : 190 kboe/d
- 1.7 Bboe*
- Start-up : 2Q(e)

Tahiti (17%)



- Plateau : 125 kb/d
- 0.5 Bb*
- Start-up : 2Q(e)

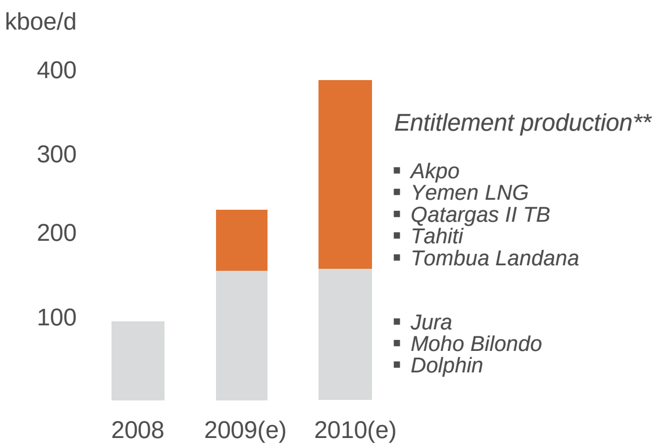
Tombua Landana (20%)

- Plateau : 130 kboe/d
- >0.2 Bboe*
- Start-up : 2H(e)

Qatargas II TB (16.7%)

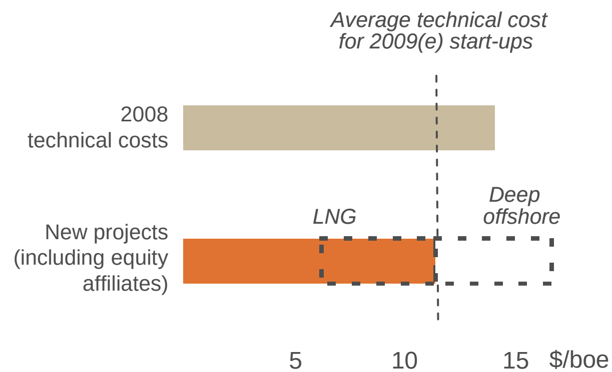
- Plateau : 290 kboe/d
- 2.6 Bboe*
- Start-up : 2H(e)

Production from new projects

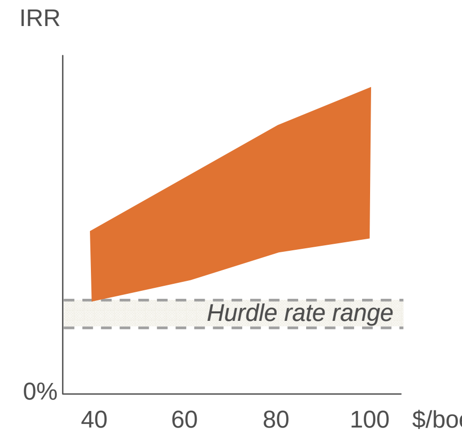


Technical costs***

(excluding exploration cost)



Profitability of 2009(e) start-ups



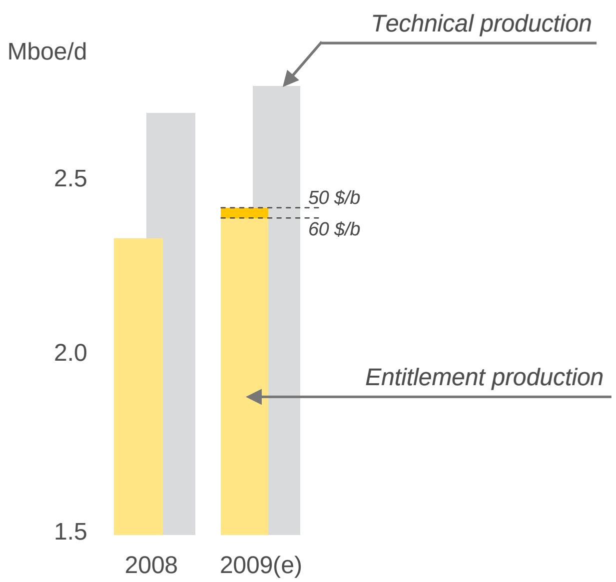
New start-ups to make important contribution to value creation as soon as 2009

* initial proved and probable reserves at 100%, Total estimates
** entitlement production defined as FAS 69 production plus mining, including equity affiliates
*** development Capex and Opex over the life of the project divided by proved and probable reserves

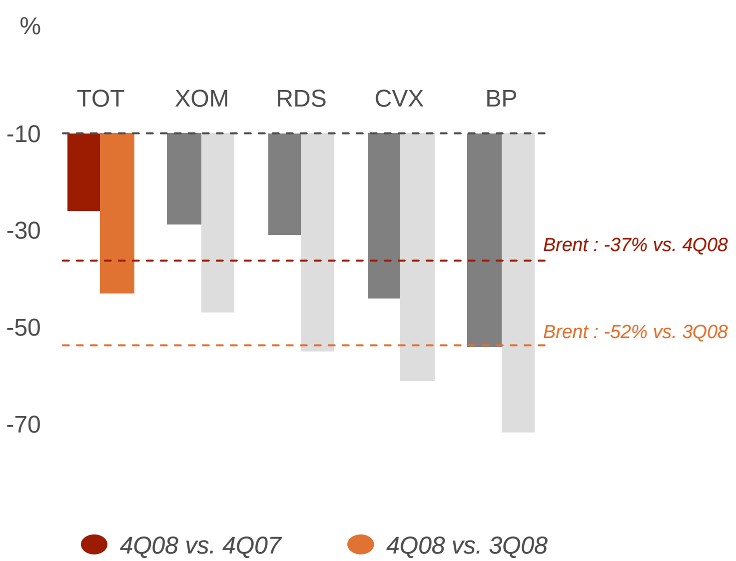
Impact of hydrocarbon prices on Upstream portfolio

Production*

(excluding impact of OPEC reductions in 2009)



Upstream adjusted net operating income per boe



One-third of Total's OPEC oil production is fixed margin

Production sensitivity of approx 2-3 kboe/d per $/b in 2009 based on Brent environment around 60 $/b

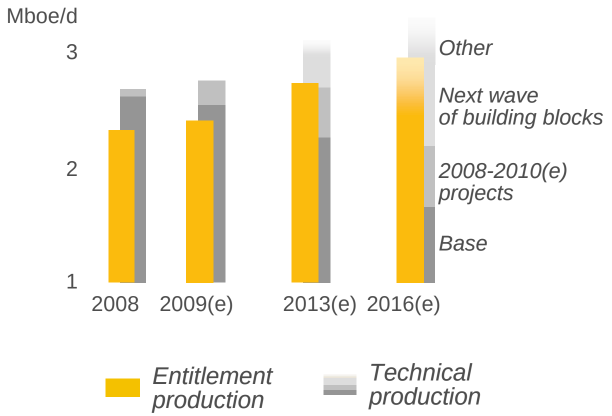
* technical production defined as equity share of wellhead production ; entitlement production defined as FAS 69 production plus mining, including equity affiliates

** adjusted income expressed in dollars ; estimates for other majors based on public data

Large portfolio of projects sustains long-term production growth

Production

(entitlement production and technical production)*



- **Base decline rate estimated at about 4% per year on average**
- **No significant impact from changing the composition and timing of Canadian assets through 2016(e)**

	Projects	Country		Capacity (kboe/d)	Share	Op**	Status
	Victoria	Norway	Liq/Gas	Study	40%	✓	Appr.
2013-2016(e)	Joslyn	Canada	Heavy oil	100	74%	✓	Pre-FEED
	Pars LNG	Iran	LNG	300	30%	✓	Study
	Shah Deniz FF	Azerbaijan	Gas	475	10%		Study
	Kashagan Ph. 2	Kazakhstan	Liquids	850	16.8%		Study
	Brass LNG	Nigeria	LNG	300	17%	✓	FEED
	Ichthys LNG	Australia	LNG	335	24%		FEED
	NLNG T7	Nigeria	LNG	250	15%		FEED
	Surmont Ph. 2	Canada	Heavy oil	90	50%		FEED
	Shtokman Ph. 1	Russia	LNG/pipeline	410	25%		FEED
	Moho North	Congo	Deep offshore	Study	53.5%	✓	Study
	Block 32-CSE	Angola	Deep offshore	Study	30%	✓	Study
	Hild	Norway	Liq/Gas	70	49%	✓	Appr.
	Eldfisk 2	Norway	Liquids	70	39.9%		FEED
	Ekofisk South	Norway	Liquids	60	39.9%		FEED
2010-2013(e)	Egina	Nigeria	Deep offshore	200	24%	✓	FEED
	CLOV	Angola	Deep offshore	160	40%	✓	FEED
	Laggan/Tormore	UK	Liq/Gas	90	50% ***	✓	FEED
	Kashagan Ph. 1	Kazakhstan	Liquids	300	16.8%		Dev.
	Sulige	China	Gas	Study	100%	✓	Study
	Bongkot South	Thailand	Gas	70	33.3%		EPC
	Angola LNG	Angola	LNG	175	13.6%		Dev.
	Tempa Rossa	Italy	Heavy oil	50	50%	✓	Dev.
	Usan	Nigeria	Deep offshore	180	20%	✓	Dev.
	South Mahakam Ph. 1	Indonesia	LNG	55	50%	✓	FEED
	Pazflor	Angola	Deep offshore	200	40%	✓	Dev.
	Anguille redev.	Gabon	Liquids	40	100%	✓	Dev.
	Ofon II	Nigeria	Liquids	100	40%	✓	Dev.
	OML 58 upgrade Ph. 1	Nigeria	Gas/Cond.	50	40%	✓	Dev.
2009(e)	Tyrihans	Norway	Liq/Gas	70	23.2%		Dev.
	Qatargas II (TB)	Qatar	LNG	290	16.7%		Dev.
	Tombua Landana	Angola	Liquids	130	20%		Dev.
	Tahiti	US	Deep offshore	125	17%		Dev.
	Yemen LNG	Yemen	LNG	190	39.6%	✓	Dev.
	Akpo	Nigeria	Deep offshore	225	24%	✓	Dev.
2008	West Franklin	UK	Gas	45	46.2%	✓	Prod.
	Jura	UK	Liquids	50	100%	✓	Prod.
	Moho Bilondo	Congo	Deep offshore	90	53.5%	✓	Prod.

* technical production defined as equity share of wellhead production ; entitlement production defined as FAS 69 production plus mining, including equity affiliates ; based on Brent oil price environment of 50 $/b in 2009 and 80 $/b thereafter

** operated by Total or through an operating company

*** 47.5% interest in Tormore

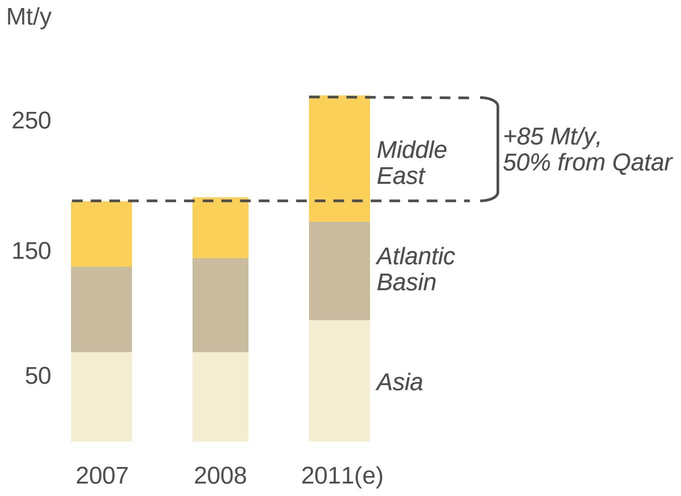
TOTAL

Upstream - LNG

TOTAL

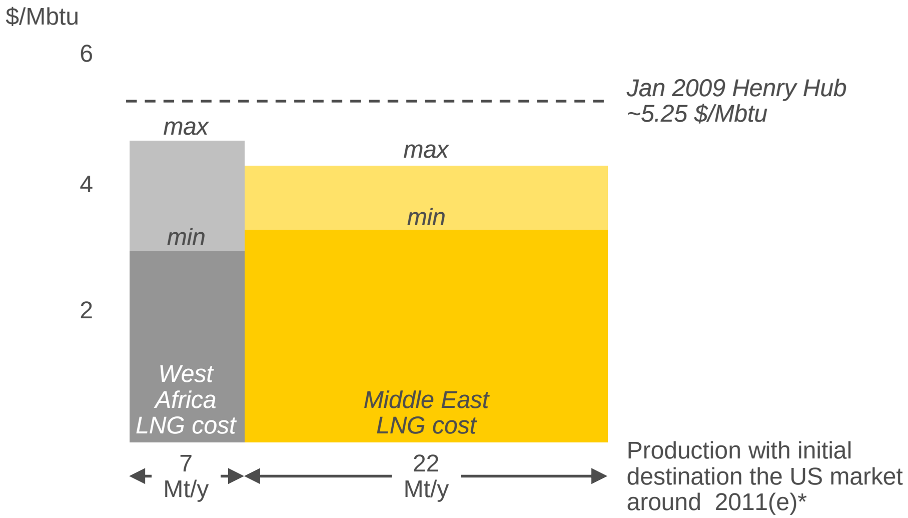
Short-term LNG market fully supplied

Global LNG production capacity



Breakeven for LNG projects

(LNG delivered cost to US market)



US market is probable outlet for excess LNG supply

Return to tighter markets anticipated in the medium term

5-15 years required to prepare and start up new projects

Significant geopolitical, environmental and economic constraints

Long-term growth potential concentrated in Nigeria, Australia and Iran

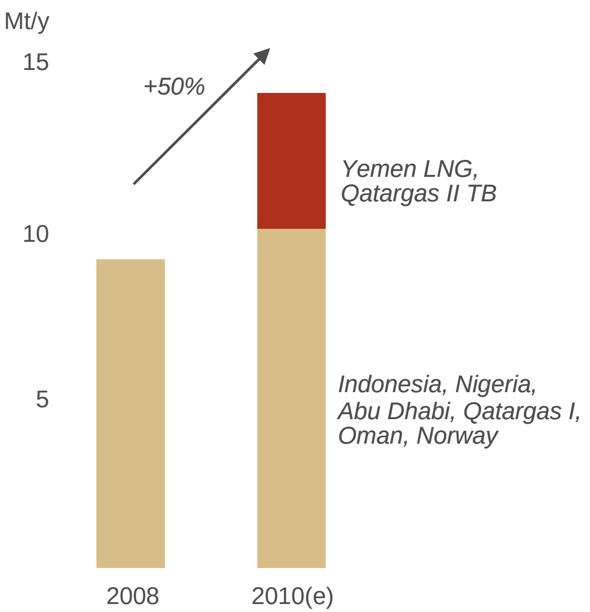
Total estimates

* + 21 Mt/y supplied from rest of Atlantic and Mediterranean basins

TOTAL

Changing the scale of Total's LNG portfolio by 2010

LNG sales by Total*



Yemen LNG (39.6%)

- Start-up 2Q09(e)
- Capacity : 6.7 Mt/y
- Purchases by Total : 2 Mt/y

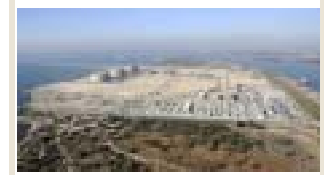
Qatargas II TB (16.7%)

- Start-up 2009(e)
- Capacity : 7.8 Mt/y
- Purchases by Total : 5.2 Mt/y

South Hook (8.35%)

- Start-up 1Q09(e)
- Capacity : 15.6 Mt/y

Fos Cavaou (30.3%)



- Start-up summer 09(e)
- Capacity : 6.1 Mt/y

Increasing LNG sales by 50% and tripling long-term purchases

Two major projects in the Middle East well positioned to sell to all markets

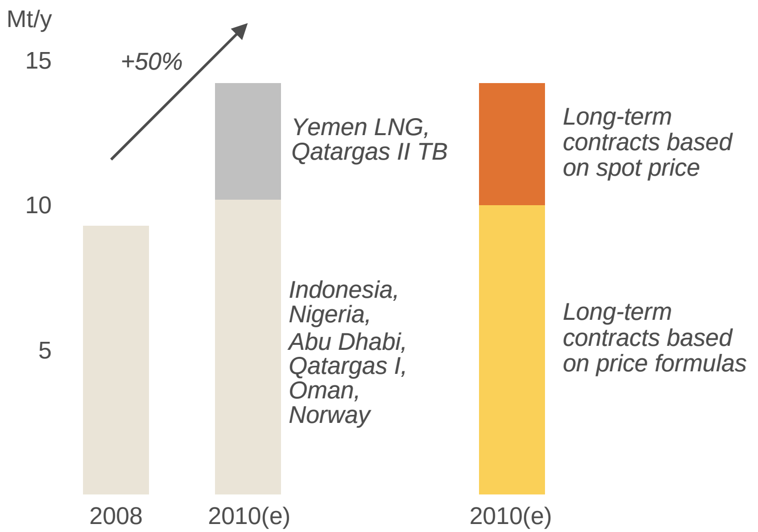
Benefiting from long-term LNG purchase contracts and trading

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

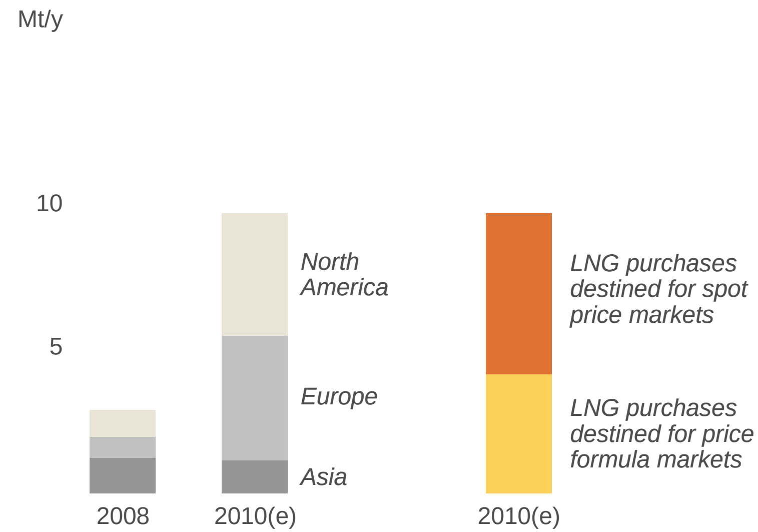
TOTAL

Balanced exposure along entire LNG value chain

LNG sales*



LNG purchases by destination



- **Approx 16% of Total's 2010(e) production**
- **Angola LNG start-up (13.6%) scheduled for 2012(e)**

- **~60% of portfolio of purchase contracts for markets with formulas correlated to spot price**
- **LNG supply contract with CNOOC starting in 2010 (1 Mt/y)**

Robust portfolio of long-term projects

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

TOTAL

Preparing the next wave of LNG projects

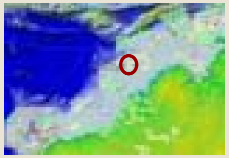
Shtokman (25%)

- Grassroots project
- Capacity : 7.5 Mt/y
- FEED

NLNG T7 (15%)

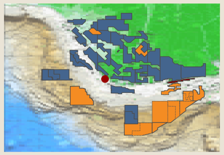
- Expansion
- Capacity : 8.5 Mt/y
- FEED

Ichthys LNG (24%)



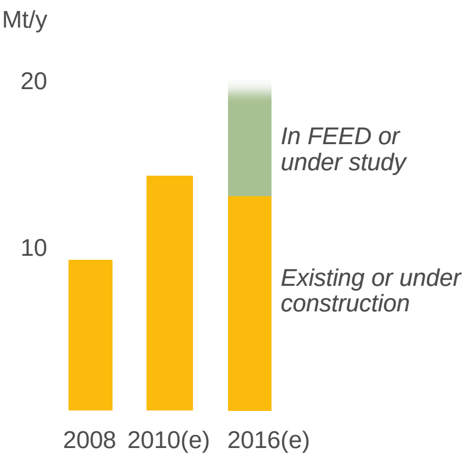
- Grassroots project
- Capacity : 8.4 Mt/y
- Onshore FEED launched

Brass LNG (17%)

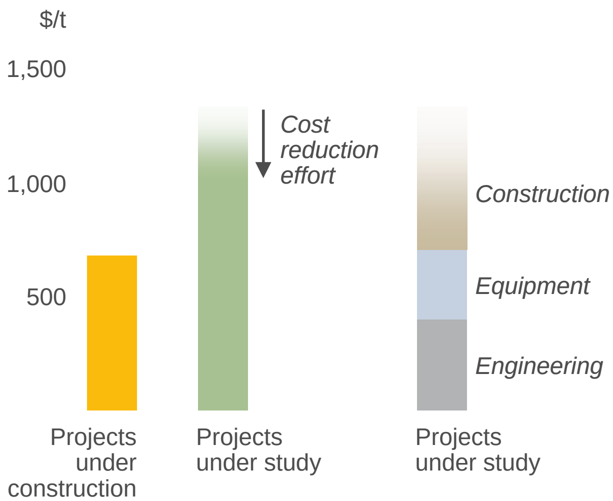


- Grassroots project
- Capacity : 10 Mt/y
- FEED

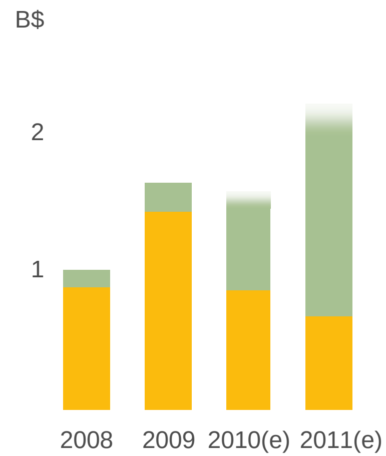
LNG sales*



LNG project costs



LNG Capex (Group share)



Taking advantage of the deflationary environment to optimize costs and timing for LNG projects

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