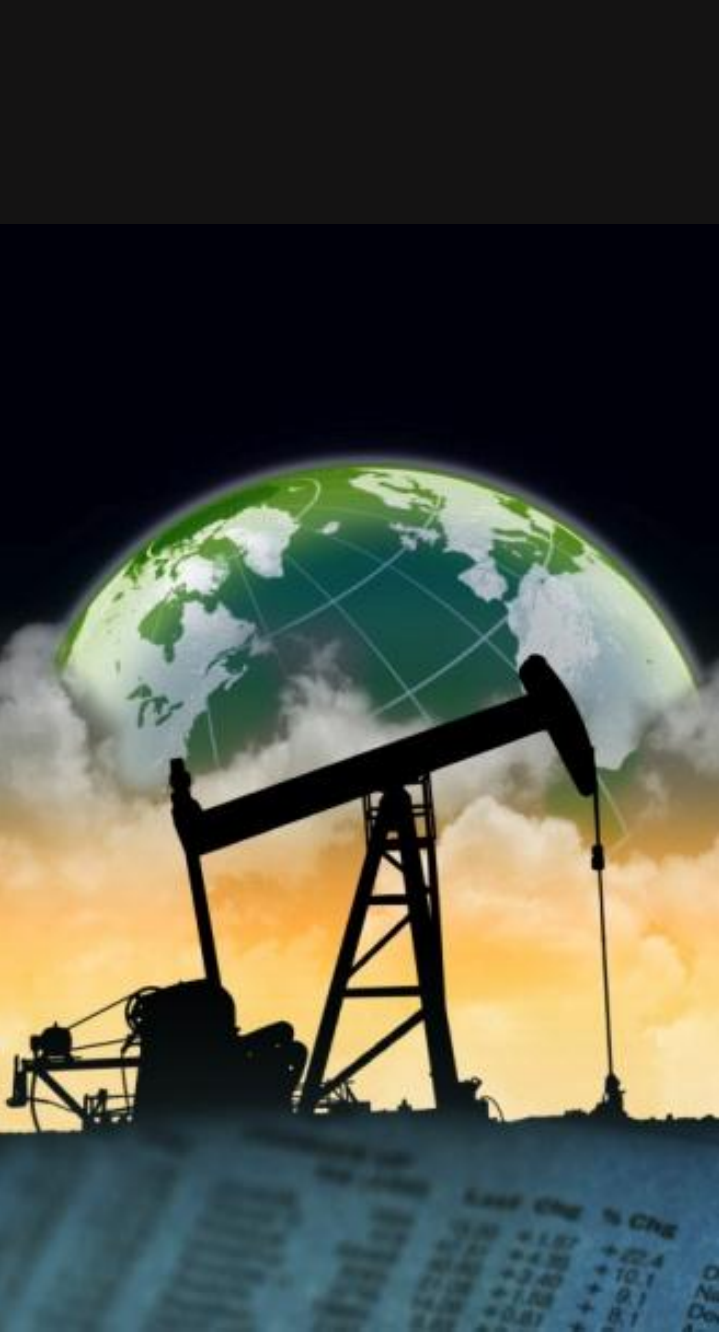

Capital Allocation and Global Portfolio Review:

Discussion Slides for the Alaska House Resources Committee

April 21, 2012

Tony Reinsch
Senior Director, Upstream & Gas
PFC Energy

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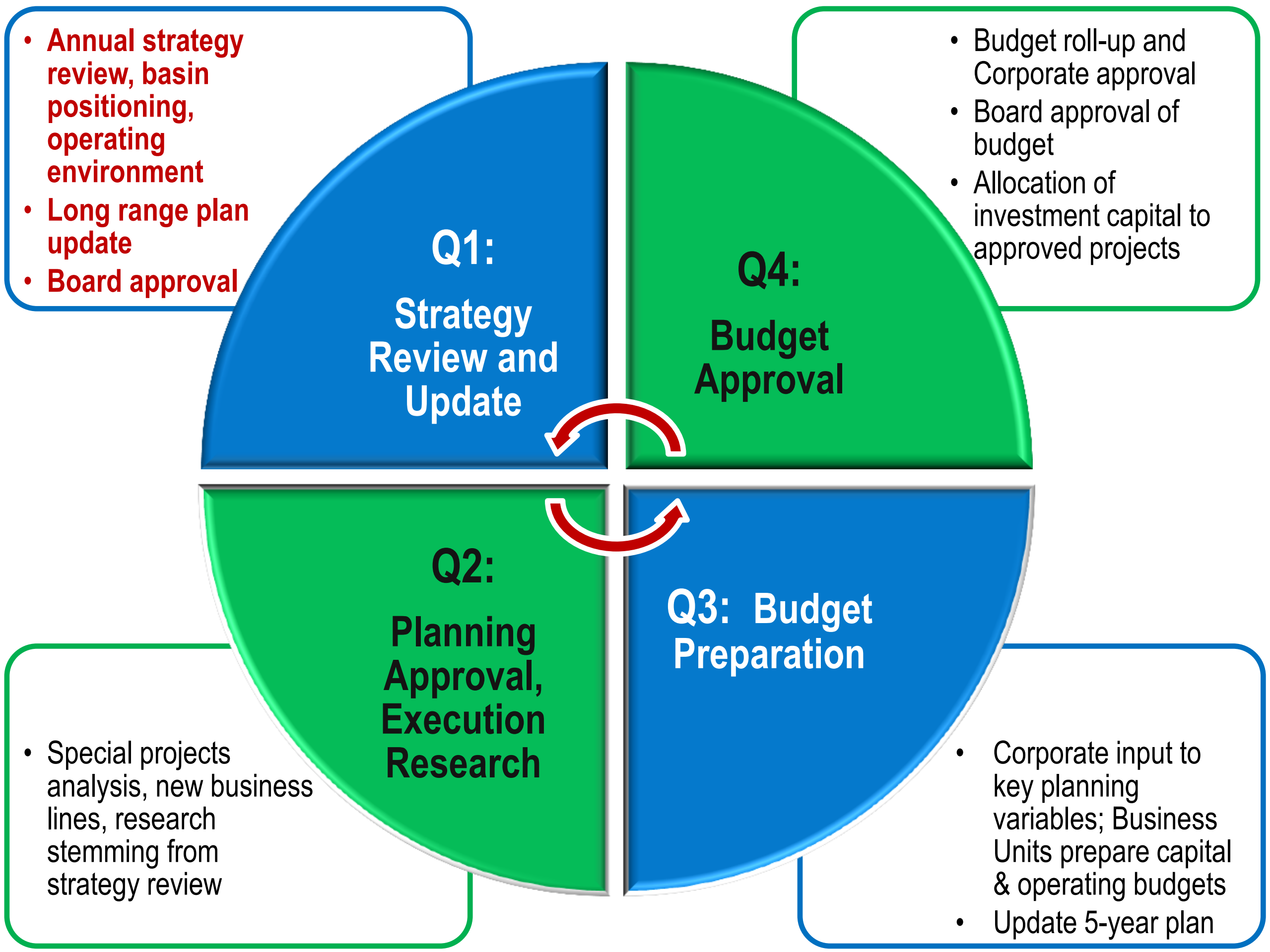
Oil & Gas Company Decision Making: Capital Allocation, Budget and Long-Range Planning

Points to Address: Discussion of Company Behaviors and Decision Making

- Key considerations for companies in making investment decisions, including decisions on whether to develop particular resources in the near term or postpone development
- Key metrics including ROCE, NPV, IRR, consideration of asset metrics versus portfolio metrics, and differences between integrated vs non-integrated companies

Annual Planning Cycle

Oil and gas companies follow a standardized process linking the annual Budget cycle to the Long Range Plan and corporate Strategy



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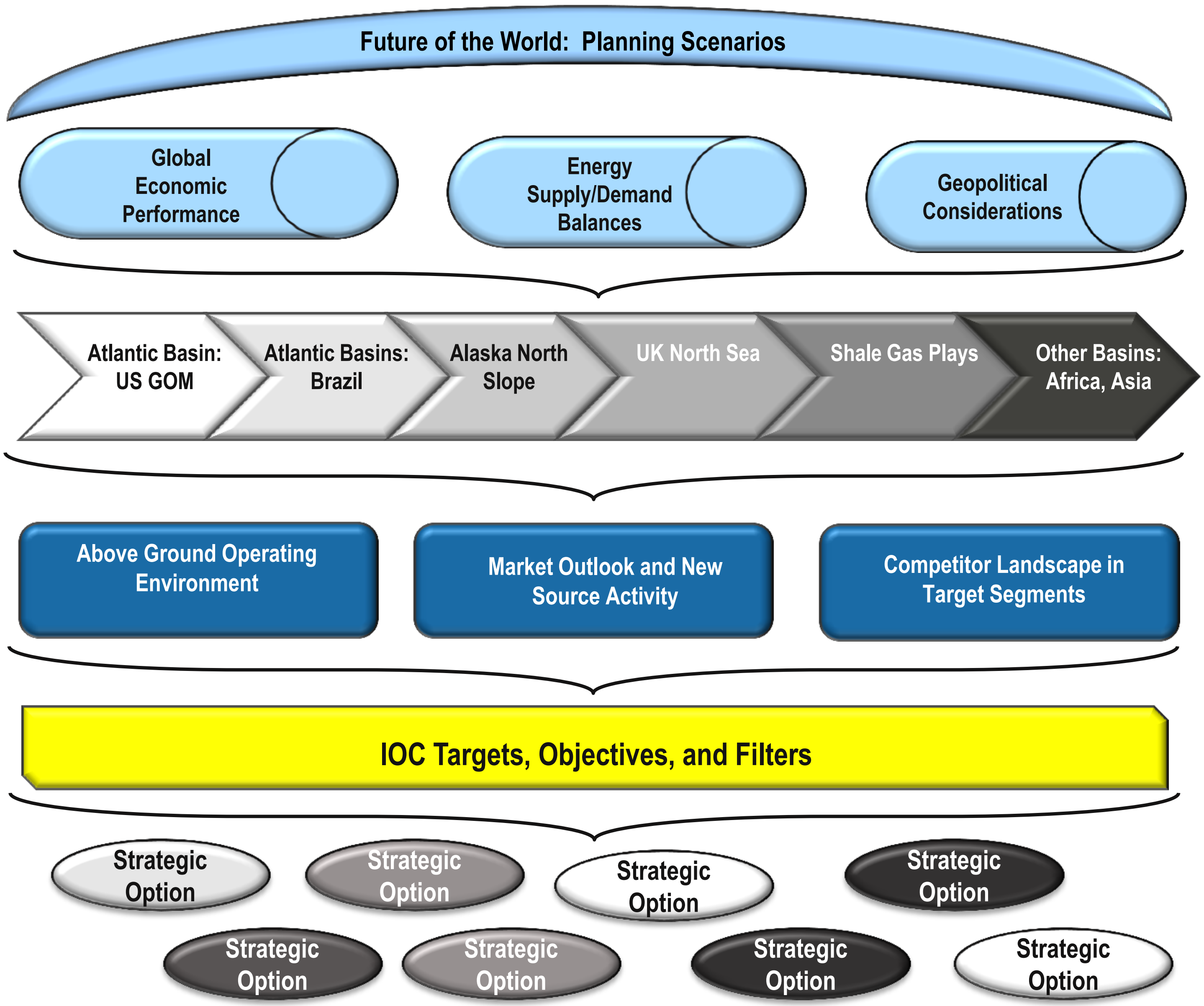
Strategy, Planning and Positioning



External Planning Environment: Identifying key uncertainties and forcing factors that will impact company Strategy and Long Run Planning

Preferred Operating Regions and Basins

Above ground risk, Potential "No Go" Geography

Blockers, Enablers, Gaps, Logjams; Determine materiality "Size of the Prize"

Identify Filters for Option Selection

Strategic Options: Robust across scenarios, Consistent with Objectives and Filters

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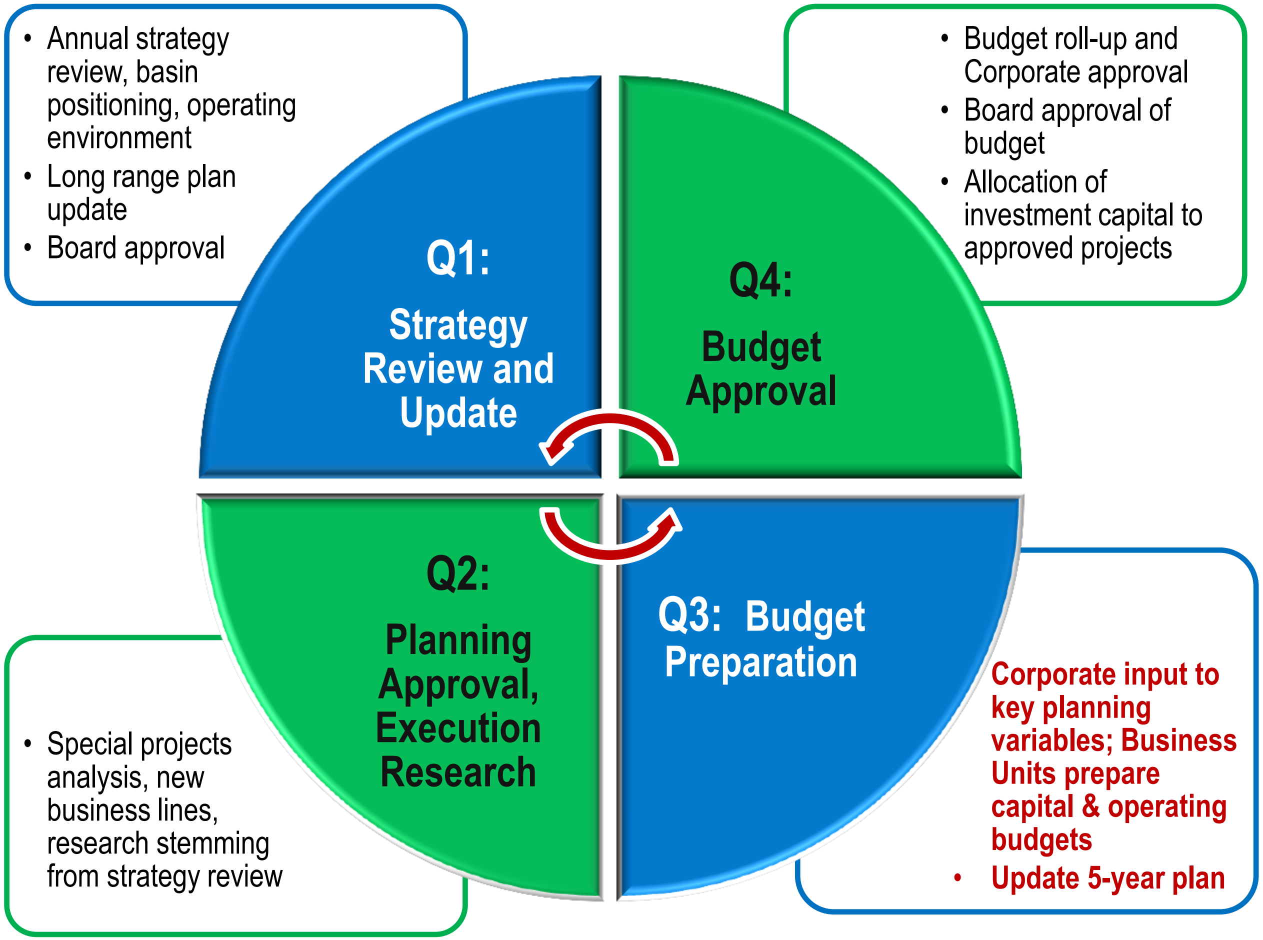
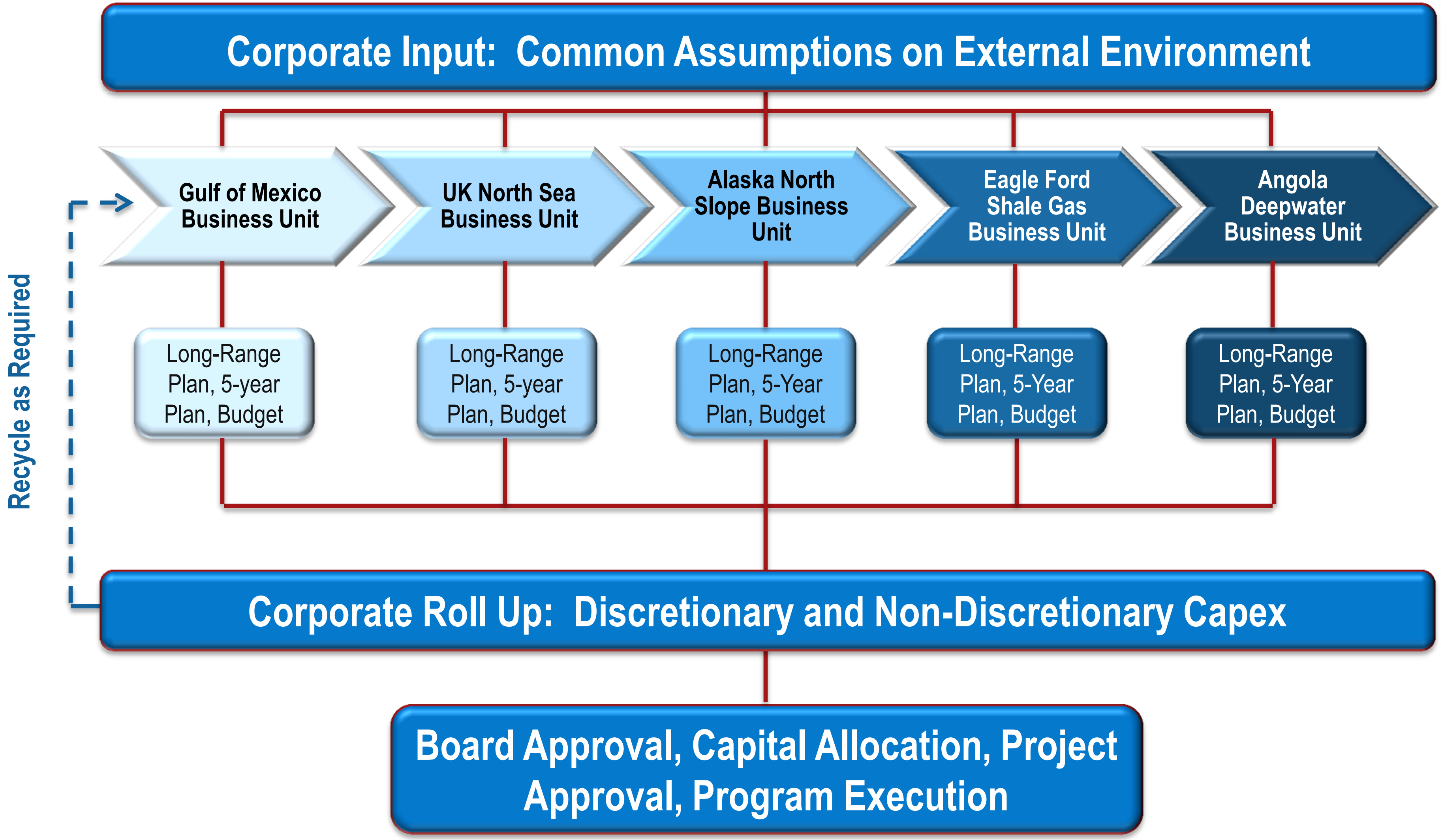
Annual Planning Cycle



Planning Cycle and Capital Allocation



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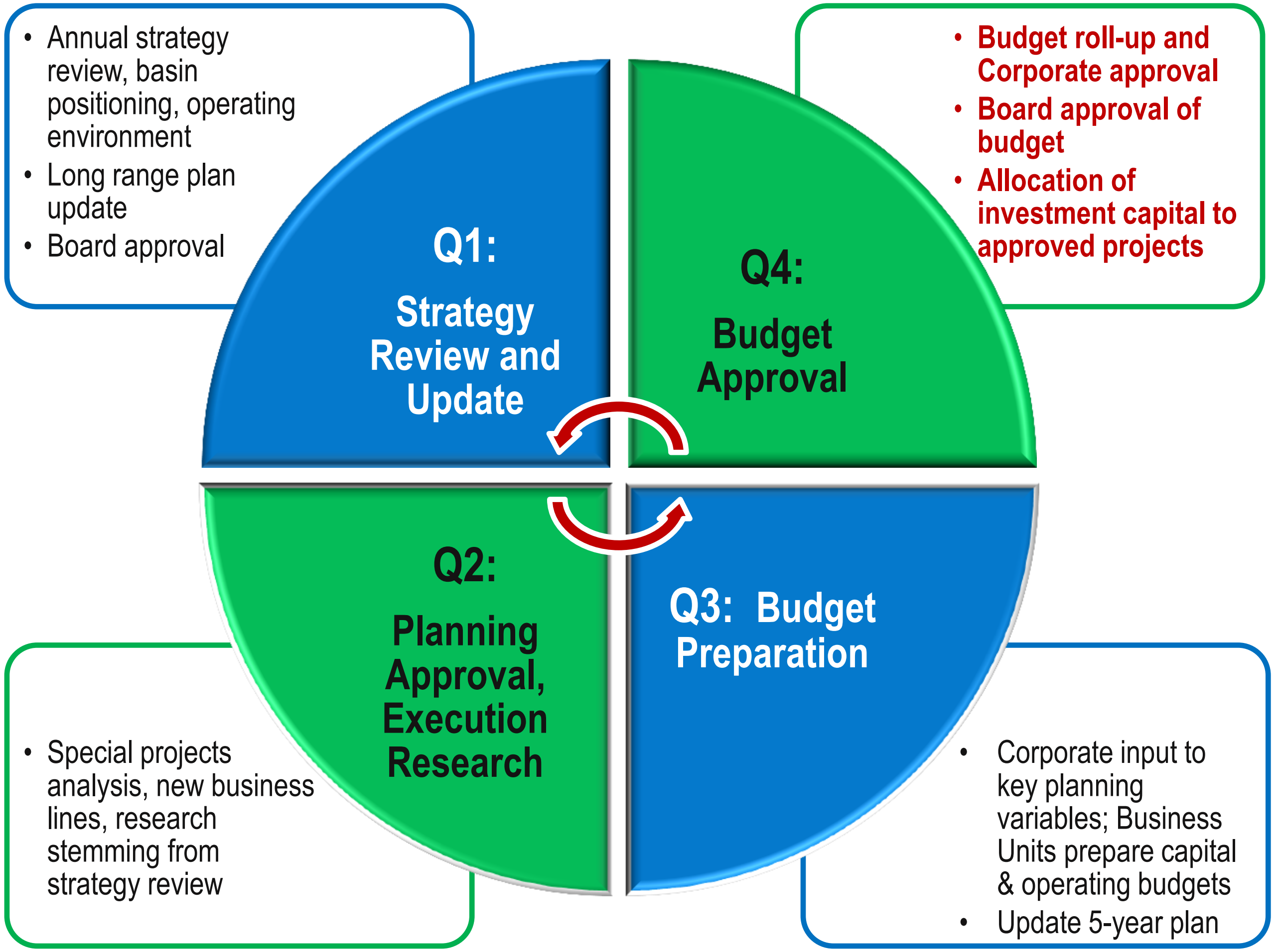
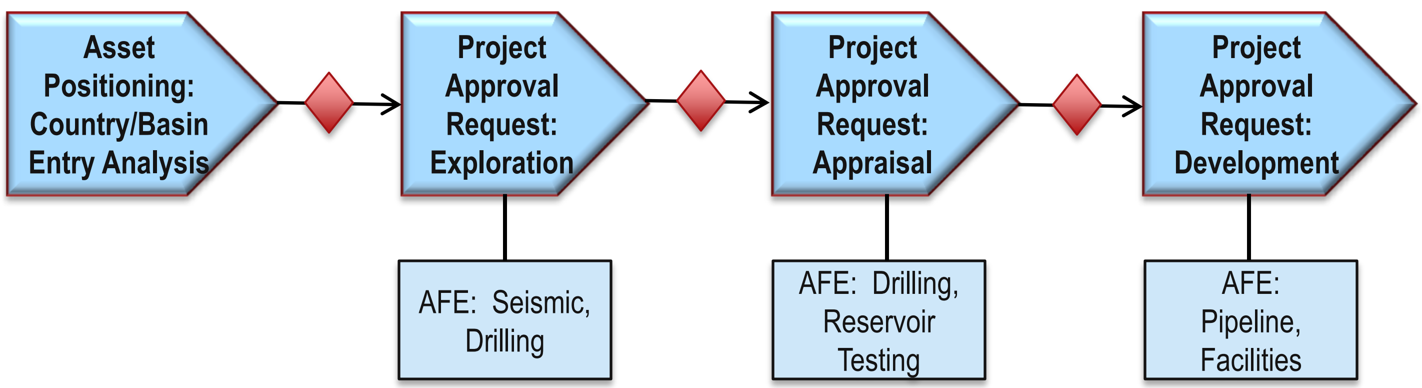
Annual Planning Cycle



Attracting Capital: The Project Approval Process

- Materiality, total capex exposure, full-cycle economics/metrics, are all considerations in determining whether an IOC will position, or continue to invest, in a particular asset, basin, country.
- Each project is disaggregated into “discrete investment decisions”, in the form of Project Approval Requests (PARs), creating a natural *stage-gate* for capital approval and allocation.
    - A PAR can extend beyond a single fiscal year budget, depending on scope of the work program. Represents ***non-discretionary*** capex at the start of the budget year
    - Each PAR has one or a series of associated Approval for Expenditure (AFE) documents for a specific activity or capex element
    - Sum of AFEs for a calendar year = ***capital Budget***
- Each stage-gate creates an opportunity for the Company to continue, amend, suspend, or exit/divest

Asset Modelling and Decision Process: Materiality and Total Capex Exposure



Request for capital budget allocation; decision to continue, amend, suspend, or divest

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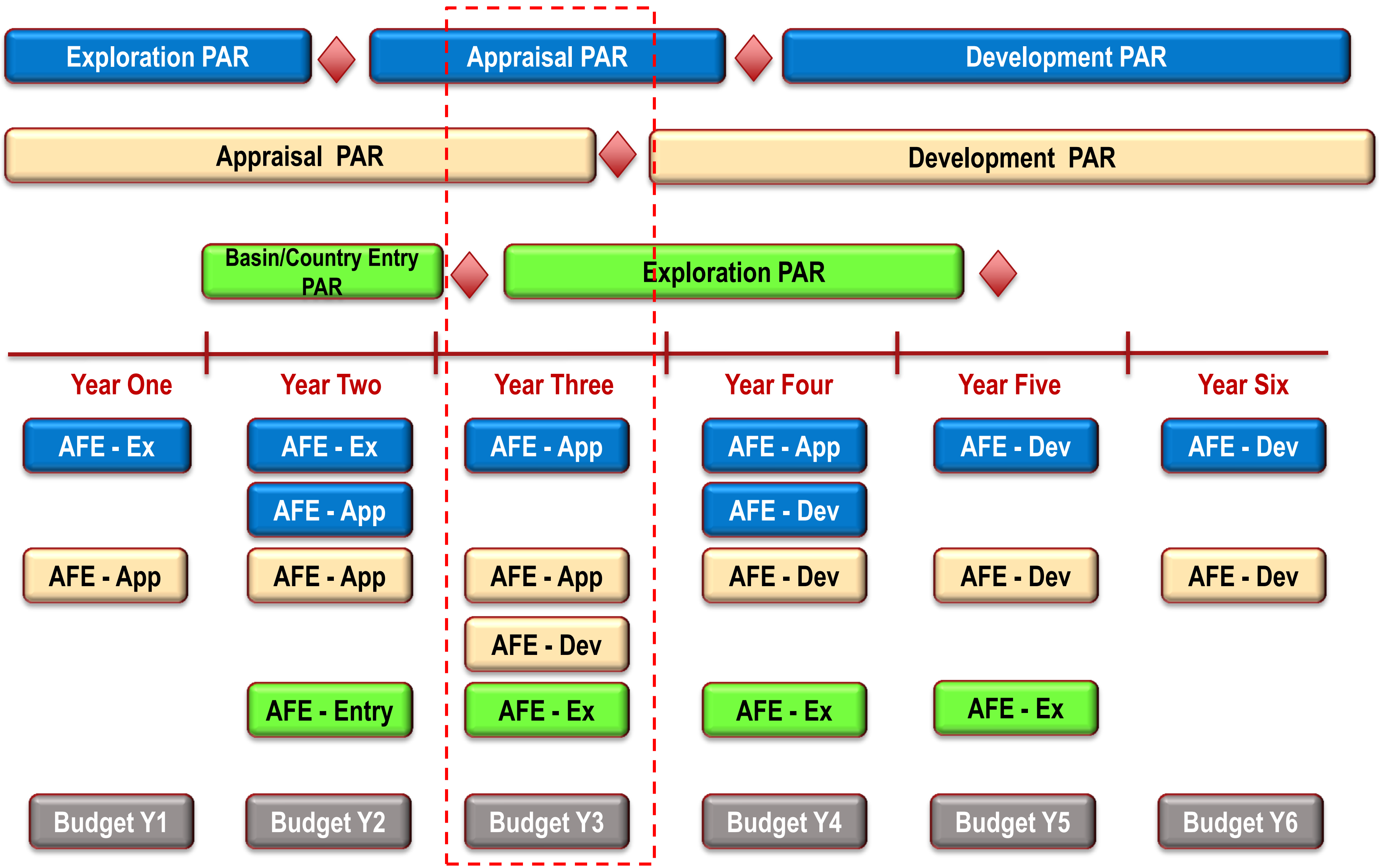
Business Control Architecture:
PAR => AFE => Budget



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Upstream Financial Metrics: Measuring Performance

- **Growth** .. Ability to manage the "top line."
  - CAGR in Production and Reserves relative to target
  - Quality of growth .. Where, how, consistent or not
  - Plowback Rate. .. To show relative growth intentions between different regions

- **Profitability** .. Ability to manage the "bottom line."
  - Upstream Cash flows
  - Upstream Net Income
  - Upstream Production Costs

  Absolute and "per boe" basis

- **Efficiency** .. Ability to manage capital.
  - Upstream ROCE
  - Finding costs, F&D costs, Replacement Costs

- **Cash Flow** .. Ability to manage investment/re-investment in the portfolio.
  - Financial Strategy (debt targets, debt/capital ratio, dividend requirements)
  - Self-financing nature of portfolio (free cash flow versus capex: regional and global)

- **Risk** .. Ability to manage a diversified portfolio.
  - Financial Risk: Debt-to-Capital ratio, financial flexibility
  - New Source Risk: Thinner margin barrels dominating new source volumes

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Project Selection and Decision Metrics

Energy companies employ a variety of Benchmarks or Metrics to rank investment opportunities and to allocate financial capital. Some of the more common include:

- Pay-out period; length of time required to recoup financial capital being placed at risk. Simplest selection metric, important to firms with scarce capital resources. No reference to project value after pay-out
- Internal Rate of Return; discount rate at which PV of costs = PV of revenues
- Net Present Value; PV of costs less PV of revenue flows (using discount rate reflecting cost of capital, cost of borrowing, or other);
  - NPV/boe; incorporates concept of investment efficiency
  - NPV/Investment; incorporates assessment of return to the investment dollar. Also referred to as **PVPI**
- Recycle Ratio: Netback or profit per boe divided by F&D cost per boe. A measure of project or corporate profitability (target >1)
- Discounted and Undiscounted Net Cash Flow Profiles; measure of availability of free cash flow for follow on or alternative investments
- Maximum Negative Cash Flow Exposure; useful in situations where access to financial capital is an issue. What is the maximum exposure being undertaken by the firm
- Net Booked Reserves; contribution of the projects to corporate value (based on bookable reserves, amongst other measures)
- Capex/boe; cost per barrel of production capacity. Burdens the projects by the cost of infrastructure, facilities, etc. Tends to favor less complex, more mature capex alternatives

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Project Metrics: Net Present Value

- **Net Present Value (NPV)**: The estimated value of a project when all future net cash flows are discounted to the present at an appropriate rate (the "discount factor"). If NPV > 0, then the project is expected to deliver a return greater than the cost of development, including a return on capital invested (accounted for in the discount rate).
- Advantages:
  - **Time value at corporate rate included**
  - **Can be calculated exactly**
  - **Can accommodate risk**
    - **NOTE: Above ground risk incorporated through discounting of costs and/or revenue flows, *NOT* through use of alternative discount rates**
  - **Useful for valuing projects**
  - **Discount rate reflects corporate preference for opportunity cost of investment capital (e.g., market interest rate, cost of equity capital, weighted average cost of capital (debt and equity))**
- Disadvantages:
  - **Difficult to rank projects. Significantly different capital and expenditure profiles can deliver the same NPV, due to the effect of discounting.**
    - **E.g., very large cash flows in a future time period can have the same "present value" as small cash flows in forward years. This may not, however, have the same impact and value for the company treasury**

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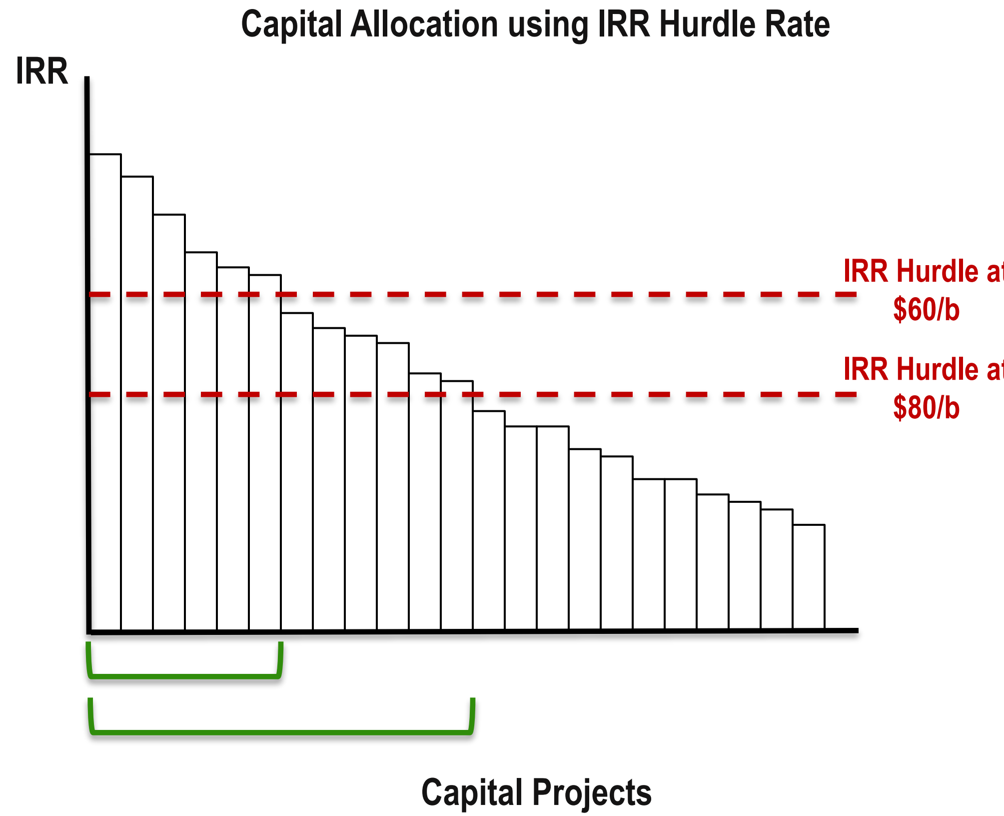
Project Decision Variables: Internal Rate of Return

- **Internal Rate of Return (IRR)**: The discount rate that equates all future cash inflows to outflows at a point in time (usually the present)
- Advantages:
  - **Easy to understand.**
  - **Incorporates time value**
  - **Can be compared to a required minimum (or hurdle rate)**
  - **Independent of magnitude of cash flows.**
- Disadvantages:
  - **Multiple rates of return are possible in cases of material cash flow volatility (e.g., large positive and negative swings over project life); uncomfortable for decision makers looking for unique decision criteria**
  - **Doesn’t measure absolute worth of the project**
  - **Not useful for single project analysis**
  - **Implicit assumption that interim cash flow is invested at calculated IRR (issue for high return projects) => overstates the true project value**

Capital Allocation: IRR Hurdle Rate

- Eligible projects ranked by IRR:
  - **Eligibility based on series of discrete project metrics within each PAR**
  - **Metrics change at each stage of the project cycle, as risks are addressed and estimates become more certain**
  - **Examples:**
    - **NPV10 > 0**
    - **PVPI > 1.3**
    - **Payback < 3 years**
- Corporate establishes a "hurdle" IRR number. Projects with IRR's in excess of the hurdle rate attract budget capital, while those below the hurdle rate are not funded



- Issues with IRR Hurdle Rate:
  - **Increase in free cash flow (due to, say, rise in energy prices) => increased capital budget => lower Hurdle rate in order to undertake additional projects => reduce overall portfolio quality and lower efficiency of capital employed. Evidenced in *cycles of value destruction* within the industry**
  - ***Gaming the system*: Project managers have an incentive to overstate the "size of the prize" or understate costs, in order to attract investment capital to proposed projects**
  - **IRR ranking does not speak to *materiality* => equivalent IRR's can have substantially different capex and revenue profiles**

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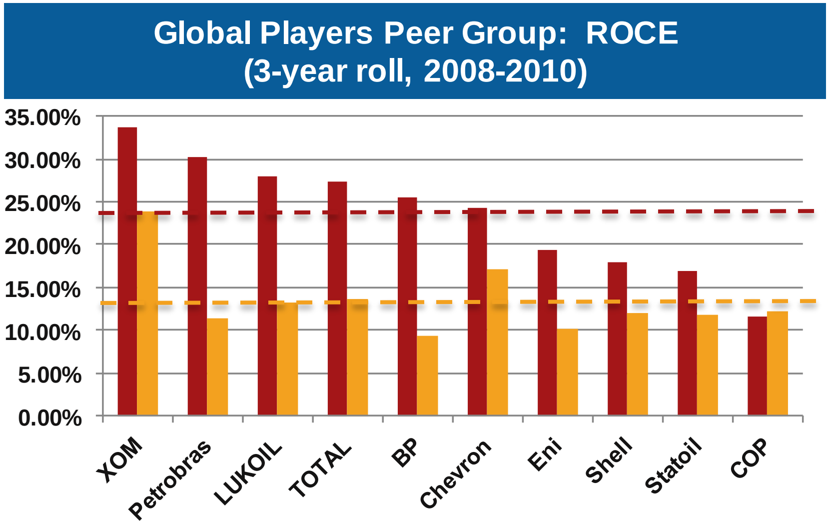
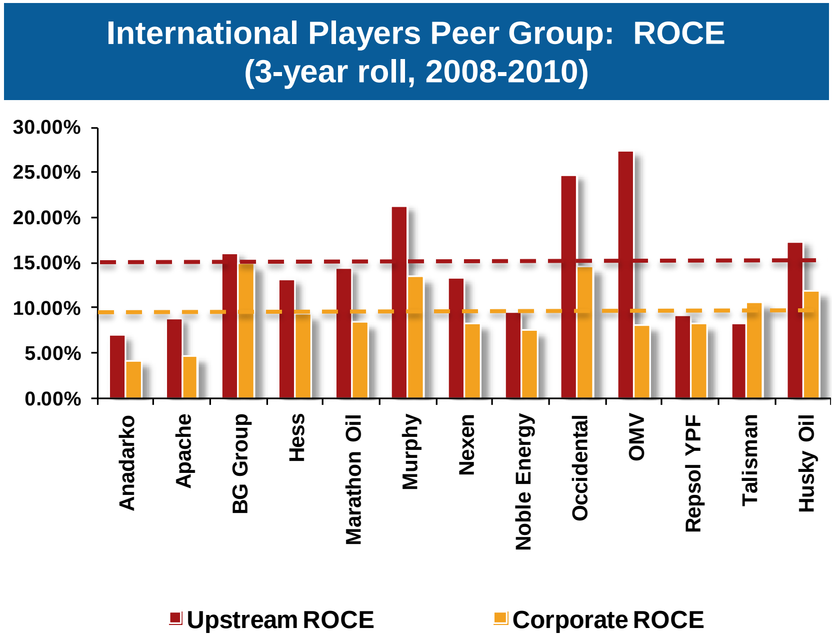
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **Return on Capital Employed**:
  - ROCE = [(Net profit before interest and taxes) / (Gross Capital employed)] x 100
  - Where:
    - Gross capital employed = Fixed assets + Investments + Current assets OR
    - Gross capital employed = Share Capital + General & Capital Reserves + Long term loans
    - (+) Correlation with production, commodity prices
    - (-) Correlation with upstream spending
  - Indicates how well management has used the investment made by owners and creditors into the business.
  - The higher the return on capital employed, the more efficient the firm is in using its funds. Over time, ROCE reveals whether the profitability of the company is improving or eroding





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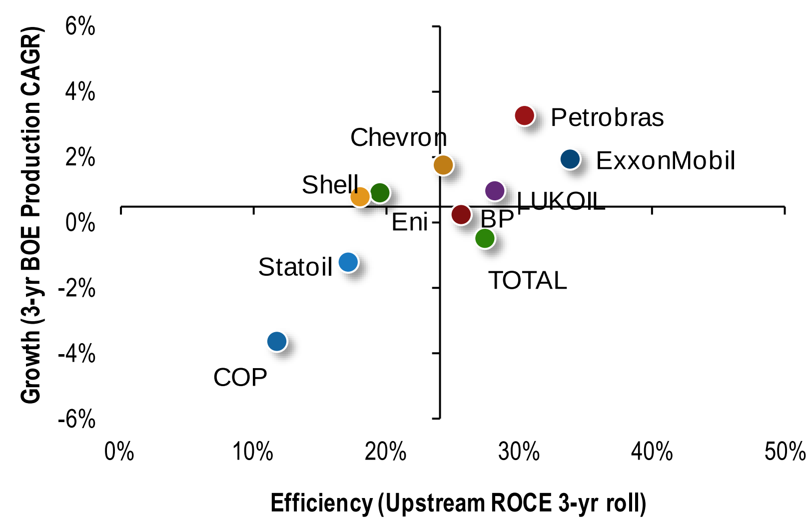
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **Issues with ROCE**:
  - Major capital project investments increase the denominator in advance of revenue (profit) impacts in the numerator => *penalizes the IOC for major capital investment undertakings*
    - Explains in part why it is unusual to find companies with high ROCE and high growth metrics
  - Once in place, the scale of major capital project investments tend to deliver superior ROCE performance => *bias toward large asset portfolios*
    - Exception is deepwater developments, where high, short plateaus and steep production declines can result in highly volatile ROCE outcomes
  - Depreciation creates *bias in favor of mature portfolio*: More mature the asset base, the lower the denominator (capital exposed) and the higher the ROCE (all else being equal)

Global Players Peer Group: Growth v Efficiency



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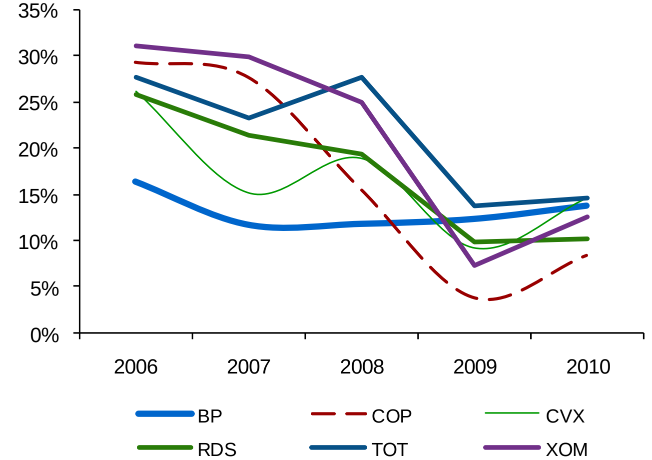
Special Issue: Integration vs. De-Integration

Arguments For Integration

- Superior market/financial management over commodity cycle
  - Counter: Collapse in Downstream profitability has seen a rise in successful "pure play" refining companies
- Integration is important for molecule management; ensures sophisticated refining capacity is in place for particular crudes
  - Counter: Independent energy producers are not hitting roadblocks in this regard; independent refiners are responsive to requirements.

Downstream ROCE – Selected Integrated IOCs (3-year roll)



- Integration is relevant for specific oil developments (e.g., Canadian oil sands, Venezuela heavy, high wax or acid content)
- Integration is a technical differentiator amongst energy companies => enhance ability to secure projects
  - Counter: The ability to build a refinery—which few integrated energy players have actually done recently—has little in common with the ability to execute on complicated upstream projects
- Integration allows participation in the Downstream Non-OECD growth story
  - Counter: The rapid petroleum product demand growth regions (China, Middle East, India) are dominated by National Oil Companies (NOCs) or quasi-NOCs, that choose partners based on what they bring to the table

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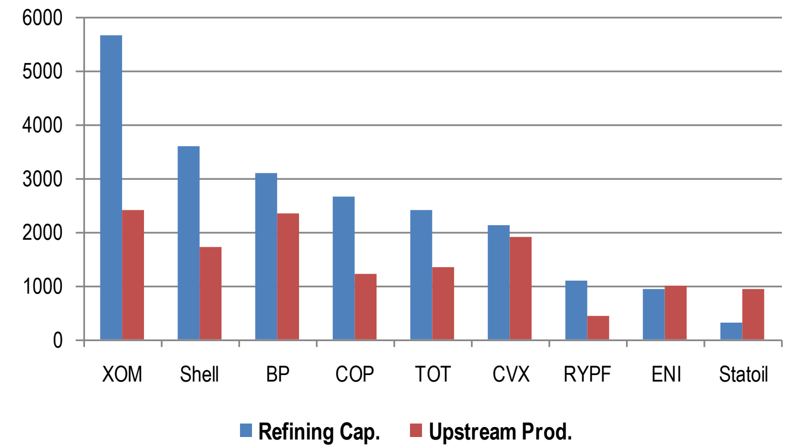
Special Issue: Integration vs. De-Integration

Arguments Against Integration

- Capital markets value integrated IOCs below the sum of their parts
  - Counter: Expensive to split a company => if there is any identifiable value, should remain integrated (e.g., refining-petchems)
- Strategic focus: In many integrated companies, the Downstream sector is neglected strategically at the expense of Upstream positioning and growth—particularly in the current climate of narrow refining margins and sustained, high oil prices.
  - Counter: Unless the integrated IOC is certain that refining margins and economics will never recover, there is merit to retaining this mechanism for optimal capital allocation between sectors
- Materiality: There are few materially, physically integrated IOCs remaining
  - ExxonMobil and TOTAL have pursued integration between refining and petrochemicals, and there are strong arguments to continue this form of integration
  - Statoil, Eni, and Repsol are integrated on the basis of past roles as quasi-NOCs, and would likely face considerable government opposition to de-integration
- The world has evolved: more flexible and liquid trading markets and improved market & industry regulation have eroded whatever market management or cross subsidization benefits integrated IOCs derived from Downstream presence/dominance over the first 70+ years of their existence.

Refining Capacity versus Upstream Oil Production Selected Integrated IOCs, 2010 (mboe/d)



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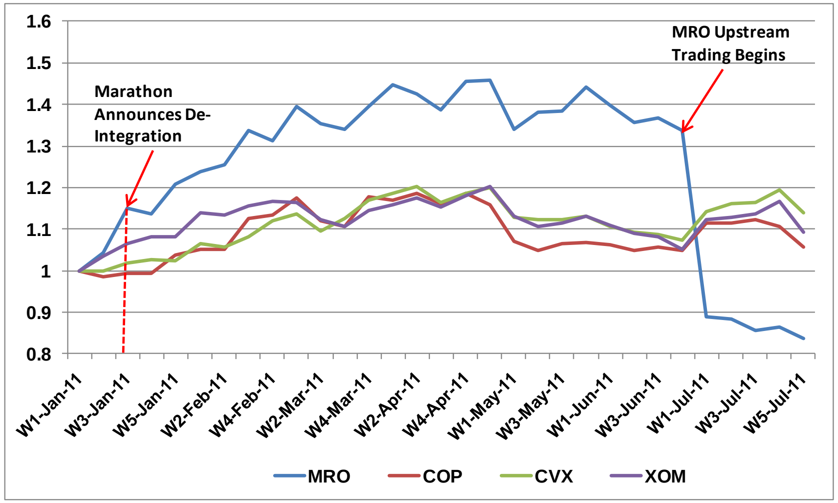
Special Issue: Integration vs. De-Integration

- *Share appreciation* appears the Number One driver for de-integration. Marathon and ConocoPhillips have both concluded that integration hides value that can otherwise be secured through greater management focus, transparency, and more appropriate strategy and execution within the de-integrated entities
- *Market development arguments* for a Downstream presence have largely ended
  - BP, TOTAL, Shell all divesting from Africa in favor of "pure play" refiners and marketers
  - No remaining examples where downstream presence is key to upstream success.

Weekly Share Price Performance, Selected IOCs (Week 1, January 2011 = 1.0)



- Improvements in internal decision processes and external regulation have eroded any value that could be secured through *cross-subsidization or barriers to competitor entry*
  - Rate of return regulation in midstream operations, open-access provisions, increased sophistication in both project and portfolio analysis => few opportunities remaining for active market manipulation
- There are *technical drivers* for integration, related to specific crude types and processing challenges (e.g., Canadian oil sands, Brazil waxy heavy crude, Venezuela ultra-heavy, Chad acidic crudes). However, these benefits can be secured through contracts and JV or partnering agreements with third party refiners

Conclusion: Pressure for further de-integration moves will come from "share appreciation" arguments, most likely directed to Chevron and Shell (and BP once its portfolio has re-stabilized)

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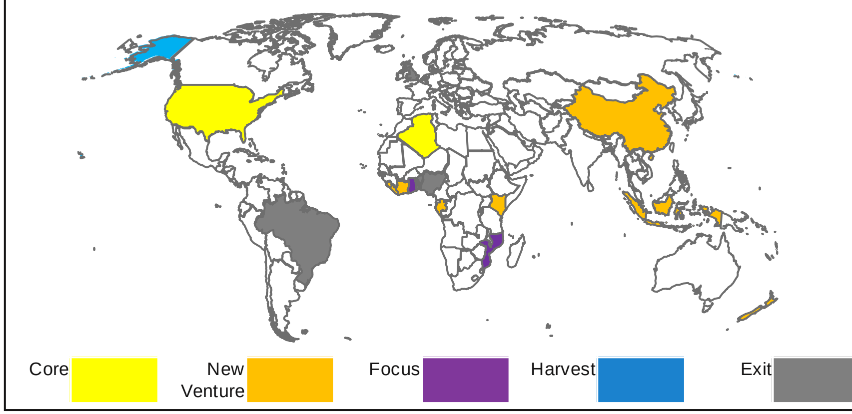
Special Issue: Basin Designation and Allocation of Free Cash Flow

- **"Core Area": Stable stream of net cash flows, and is material to the company. Can contribute to investment activity in other regions, but requires more than replacement level investment in order to maintain core area status. Tends to corresponds to a company's legacy assets.**
- **"Focus Area": Significant contributor to projected new source production and reserves growth in the medium- to long-term. Typically a net consumer of free cash flow until significant production levels are achieved.**
- **"New Venture": Areas new to the company—may be unexplored to fairly mature. Company has few, if any, assets and investment inflows can be modest (positions are usually characterized by exploration activity).**
- **"Harvest Area": Produces positive net cash flow, with Investment activity typically at/below replacement level. Limits to growth from lack of geological potential, competitor landscape, limited "room to run", etc.**
- **"Sit & Hold": Substantial resource base but investment delayed due to unattractive fiscal terms or significant above ground risks. Company may hold large projects in this area but is holding back the pace of investment (more common for National Oil Companies).**
- **"Exit/Potential Exit": For reasons including lack of materiality, limits to future growth, change in strategy, the company has/is expected to make a decision to exit (asset sales, asset swaps, relinquishment of acreage).**

Global Areas of Upstream Operations

		US	Algeria	China	Cote d'Ivoire	Gabon	Indonesia	Kenya	Liberia	New Zealand	Sierra Leone
Liquids	(mboe/d)	30	23	0	0	0	0	0	0	0	0
Gas	(mboe/d)	38	0	0	0	0	0	0	0	0	0
		Ghana	Mozambique	Benin	Brazil	Faroe Islands	Malta	Nigeria	Qatar	T&T	United Kingdom
Liquids	(mboe/d)	0	0	0	0	0	0	0	0	0	0
Gas	(mboe/d)	0	0	0	0	0	0	0	0	0	0



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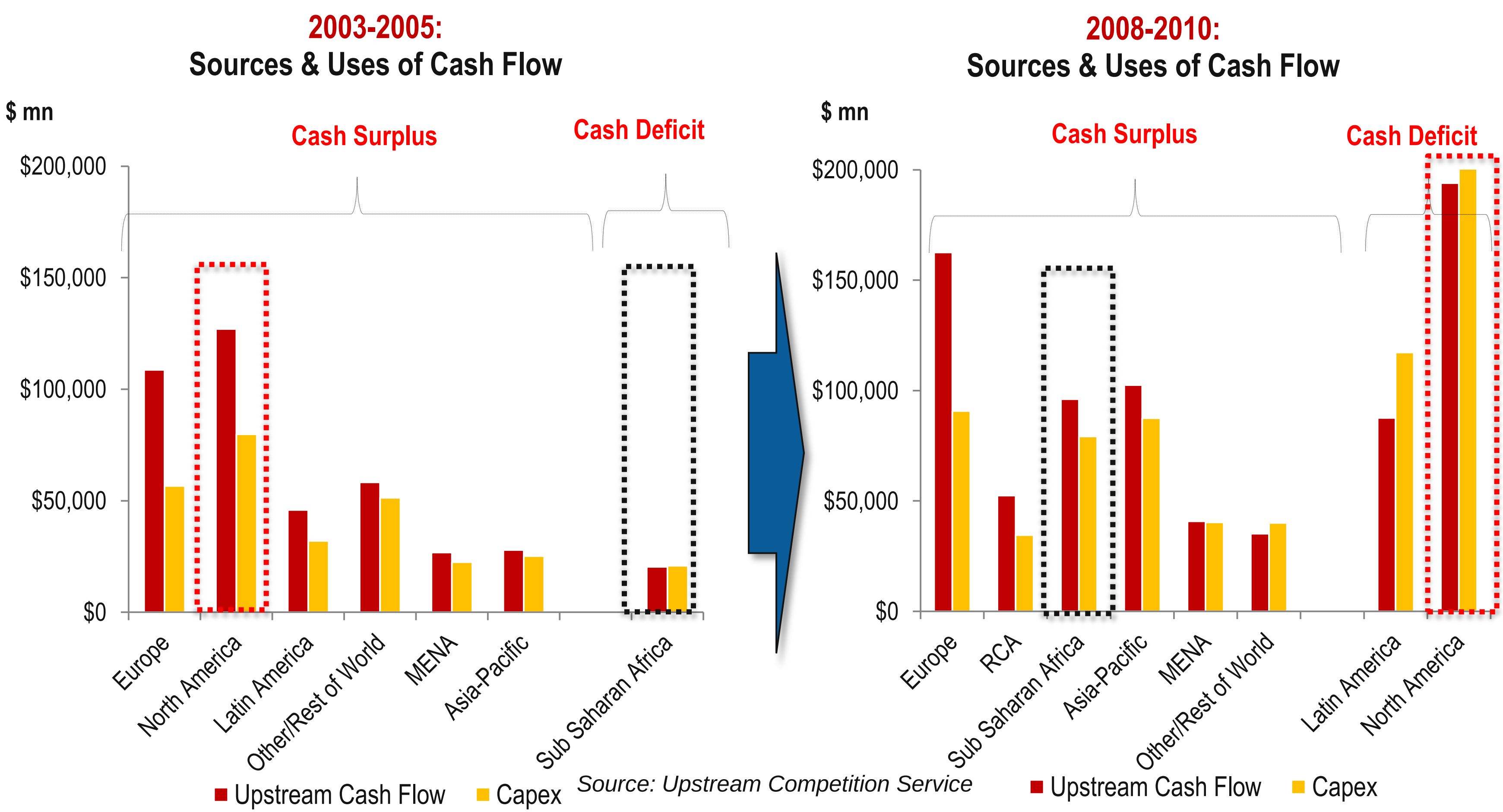
Special Issue: Basin Designation and Allocation of Free Cash Flow



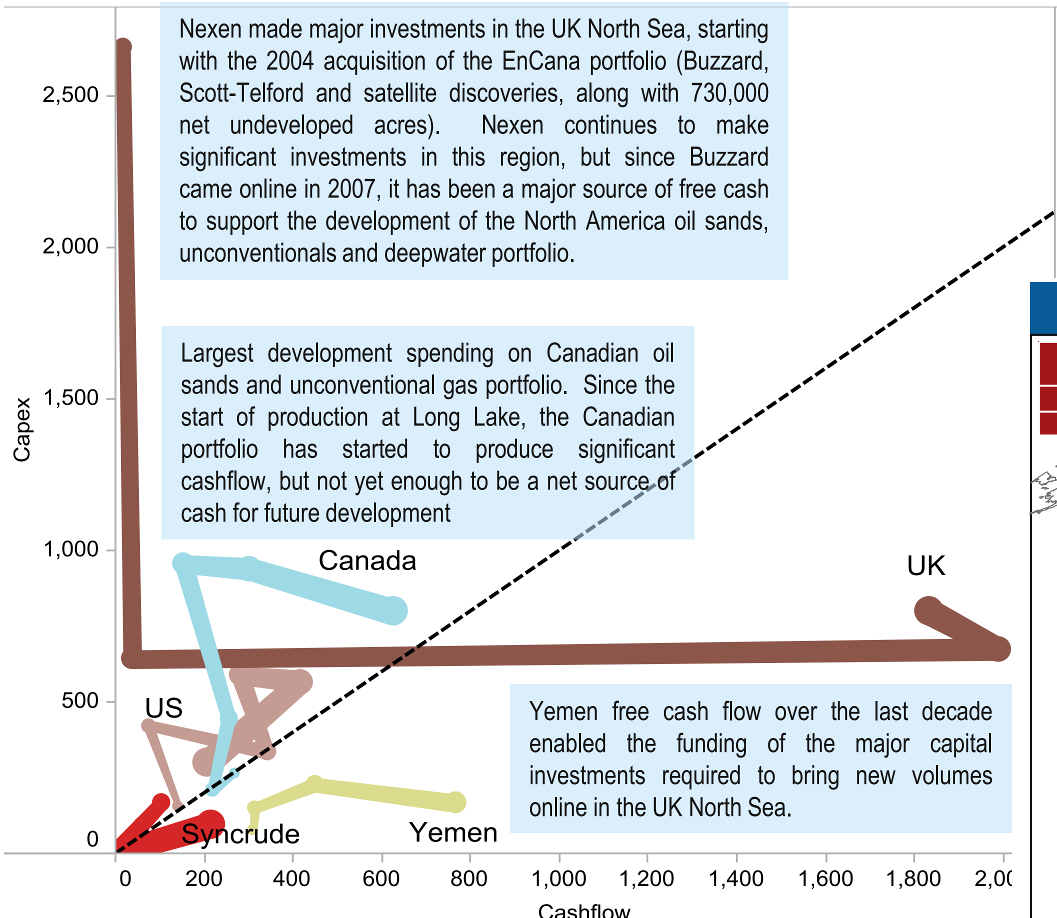
Source: Upstream Competition Service

Along with Europe, Sub-Saharan Africa is now a key cash generating region for the large Upstream companies—with surplus cash flow now supporting growth in North America

** Includes data from the following companies: Anadarko, Apache, BG, BHP, BP, CNRL, Chevron, ConocoPhillips, Devon, EnCana, Eni, ExxonMobil, Hess, Husky Oil, Marathon, Murphy, Nexen, Noble Energy, Oxy, Petrobras, Repsol YPF, Santos, Shell, Statoil, Suncor, Talisman, TOTAL, Woodside*

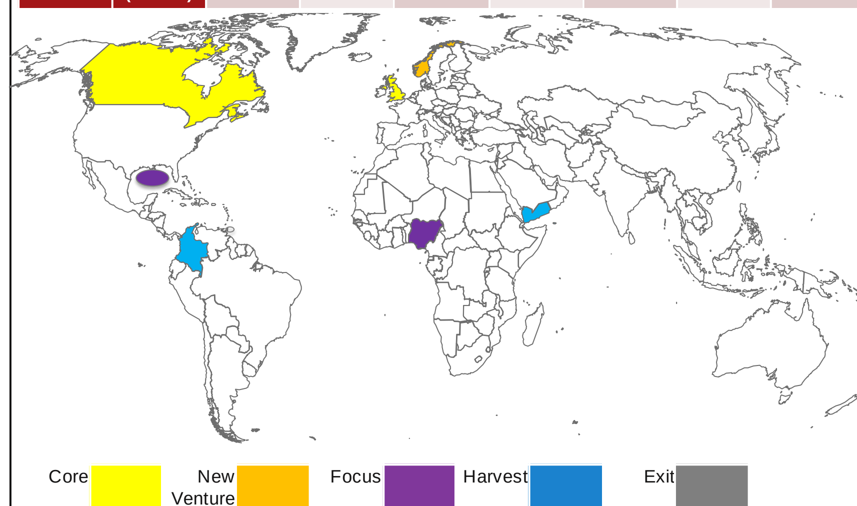
Example: Nexen Inc.

- Free cash flow from Yemen/Masila block directed to North Sea (Buzzard) assets; then from North Sea to Canadian oil sands and shale gas assets.
- Currently in Exit process in Yemen and shifting to Harvest in the UK



Global Areas of Upstream Operations

		Canada	United Kingdom	USA	Nigeria	Yemen	Colombia	Norway
Liquids	(mboe/d)	41	104	8	0	23	2	0
Gas	(mboe/d)	19	6	16	0	0	0	0



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Questions & Discussion

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Global Strategy & Portfolio Overview of Major Alaska Producers

- BP
- ConocoPhillips
- ExxonMobil

BP: Company Overview

Strategic Signature

- BP is a global integrated company, with production in 16 countries and upstream operations in an additional 10 countries.
- In 2011, total global production averaged ~3,400 mboe/d, making it the second largest company in the peer group (superseded by ExxonMobil (~4,513 mboe/d). The Russia & Central Asia (RCA) and North America regions accounted for ~55% of 2011 production.
- Much of the post-Macondo portfolio rationalization program (targeting $30 bn in asset sales including mid/downstream assets) has been completed. The result is a pared down and more focused geographic portfolio.
- BP expects growth of 1%-2% per annum through 2015 from a 3-pronged growth strategy:
  - **Deepwater Basins**: US GOM, Angola, Egypt, Brazil
  - **Global Gas**: US, Trinidad & Tobago, North Sea
  - **Giant Oil Fields**: Russia, Alaska, Iraq, others.
- Committed ~$20 bn net investment to 16 projects sanctioned over 2010-2011. Will curb ROCE performance for the coming 2-3 years.
- With the burden of the Macondo oil spill and reparations continuing through the mid-term, BP will be hard pressed to outperform its peers on any key metrics, leaving the company open to calls for more radical restructuring.

Company Overview

- **HQ:** London
- **Employees:** 79,700
- **2011 Reserves:** 17,330 mmboe
- **2011 Production:** 3,400 mboe/d
- **3 Yr Production Growth:** -3.53% CAGR (2008-2011)
- **April 2012 Market Cap:** $133 bn
- **April 2012 P/E Ratio:** 6.15
- **2011 Corp Revenue:** $375 bn
- **2011 Upstream Capex (Est.):** $17 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	LNG
✓	✓	✓	✓	✓	✓

Partnership History

Date	Partner	Region (or Country)	Type
2007	Husky	Canada	Sunrise Oil Sands
2008	Chesapeake	US	Unconventional
2009	CNPC	Iraq	Rumaila TSA
2011	Reliance	India	Offshore Gas

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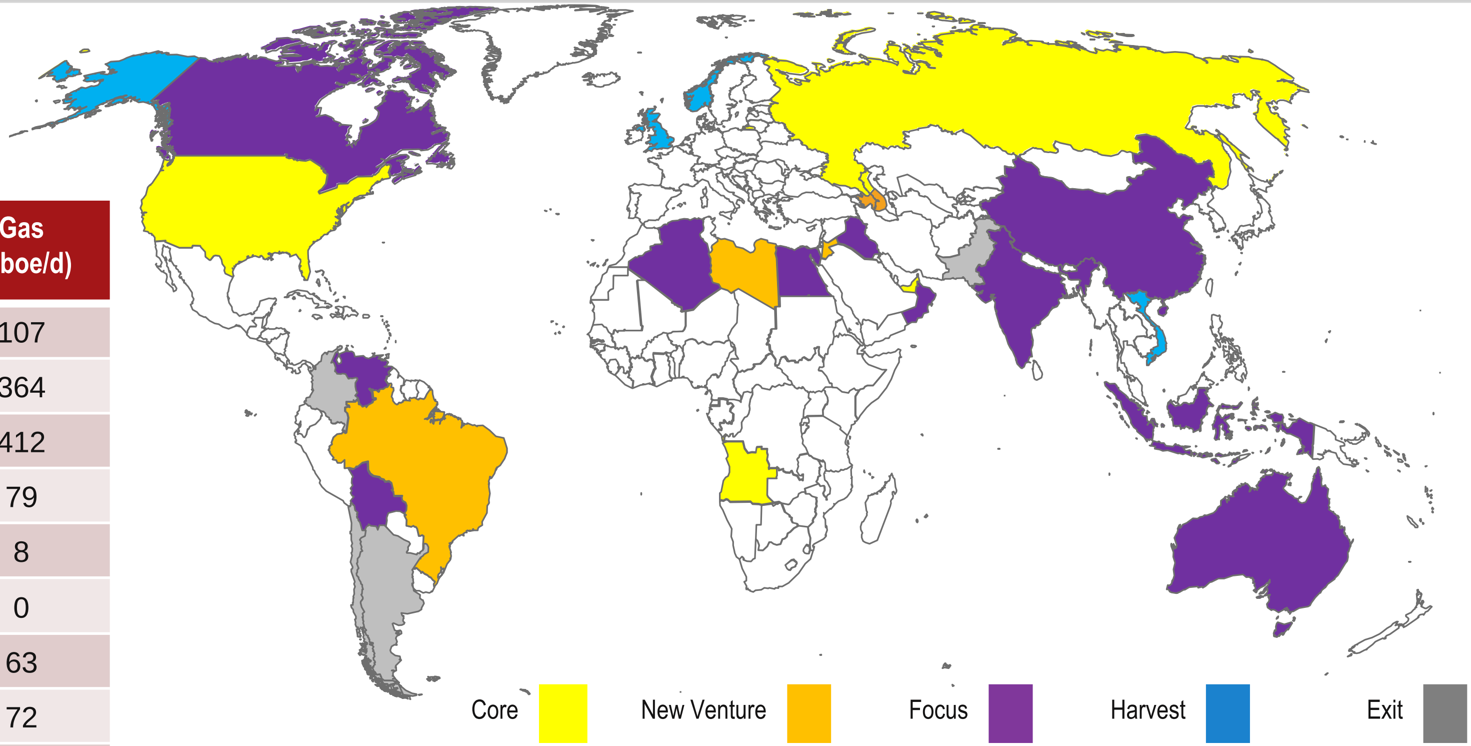
BP: Global Areas of Upstream Operations



	Liquids (mboe/d)	Gas (mboe/d)
Russia	856	107
US	594	364
T&T	36	412
UK	137	79
UAE	190	8
Angola	170	0
Argentina	75	63
Egypt	59	72
Azerbaijan	103	22
Australia	30	77
Indonesia	2	71
Norway	40	3
Canada	7	34
Algeria	17	21
Pakistan	10	25
Venezuela	23	2

	Liquids (mboe/d)	Gas (mboe/d)
China	0	16
Vietnam	0	13
Bolivia	0	2
Brazil	0	0
Chile	0	0

	Liquids (mboe/d)	Gas (mboe/d)
Iraq	0	0
Oman	0	0
Jordan	0	0
Libya	0	0
India	0	0

BP Global Production Portfolio - 2010

Canada: modest conventional production, with future potential tied to oil sands

Russia: BP's largest producing country (963 mboe/d), representing ~26% of 2010 output. Substantial long term growth potential. Continued interest in Russia (and Arctic) expansion, despite limitations arising from the TNK-BP joint venture.

US: 2nd largest producing country, with core **deepwater** area. Activity slowed post-Macondo, yet expect strong future growth. **Onshore L48** is key gas area (~22% of 2010 global output), with focus on unconventionals. **Alaska** potential tied to commercialization of Prudhoe Bay resources.

UK: Declining position from mature offshore assets. High-value operating area, generating large cash flows.

Trinidad & Tobago: Core gas producing area tied to Atlantic LNG.

mboe/d

- 0
- 500
- 1,000
- 1,345

Asset Type

- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Azerbaijan: Participation in 2 large-scale projects: Azeri-Chirag-Guneshli & Shah Deniz.

UAE: Core position through equity affiliates, though concession are being re-negotiated

India: 2011 Partnership with Reliance for exploration in shallow and deepwater.

Australia and **Indonesia** are key gas producing areas tied to investments in LNG.

Argentina: onshore & shallow water assets (held by PAE) were to be sold to Bridas, but transaction failed in 4Q:11.

Angola: Sole presence in SSA is Angola deepwater. High growth from 2002-2009, now challenged with start-up of several unsanctioned projects

Iraq: Development of Rumailia oil field

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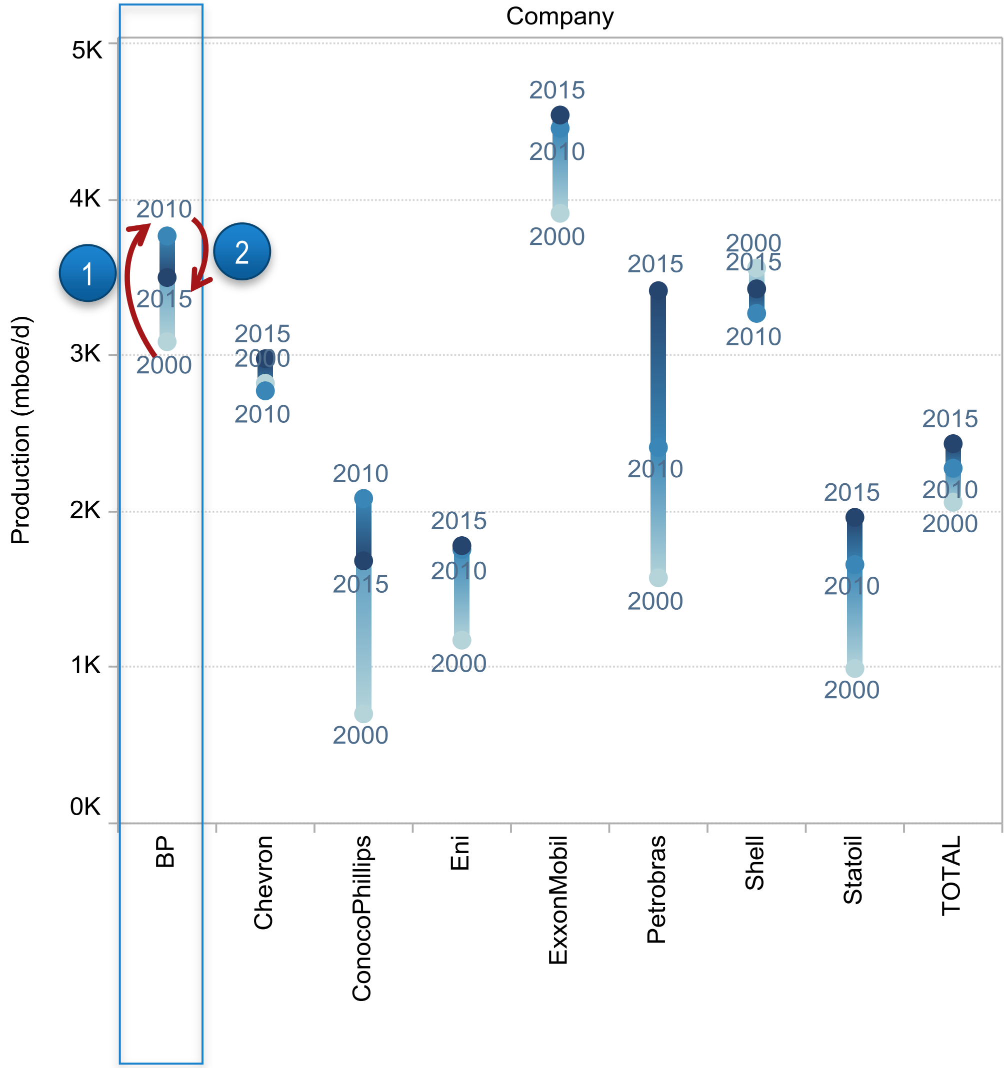
Total Portfolio Evolution:
BP vis-à-vis the Competition

Production (mboe/d) in 2000, 2010 and 2015 (PFC Forecast): BP and Peers



In 2010, BP was the second largest producer of the peer group. BP and COP are the only two companies forecast to deliver production declines over the 2010-2015 period.

1 **2000-2010:** Production increases from ~3,080 mboe/d to ~3,780 mboe/d due to addition of Russia (~960 mboe/d), Trinidad & Tobago (~250 mboe/d) and Angola (~170 mboe/d). This expansion offsets declines from Europe (-660 mboe/d and North America -350 mboe/d) .

2 **2011-2015:** BP's production is expected to decline from 2000-2015, due mostly to the post-Macondo asset divestiture program, combined with curbed activity in the GOM deepwater.

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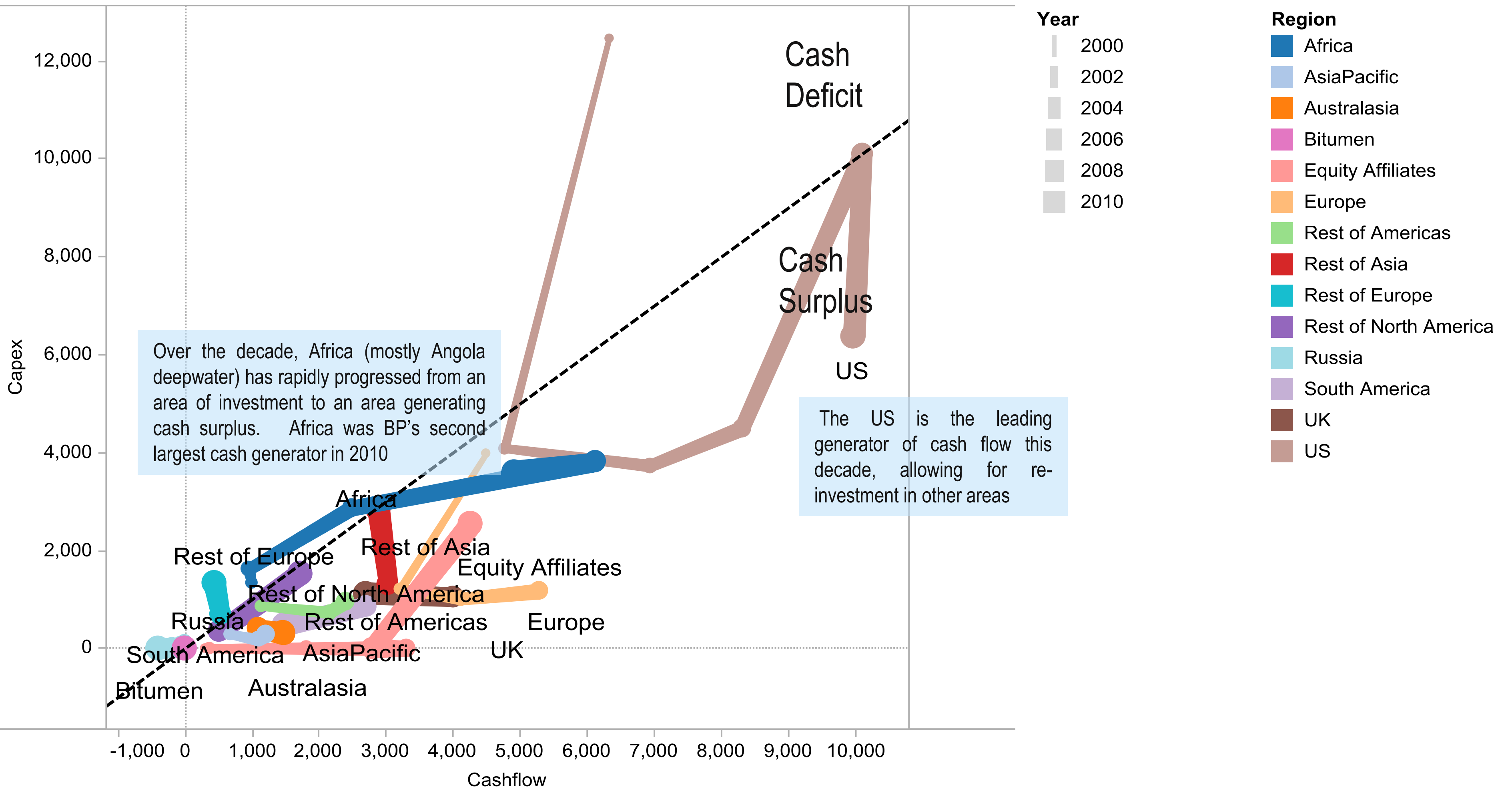
How the Portfolio is Financed: Sources and Uses of Cash



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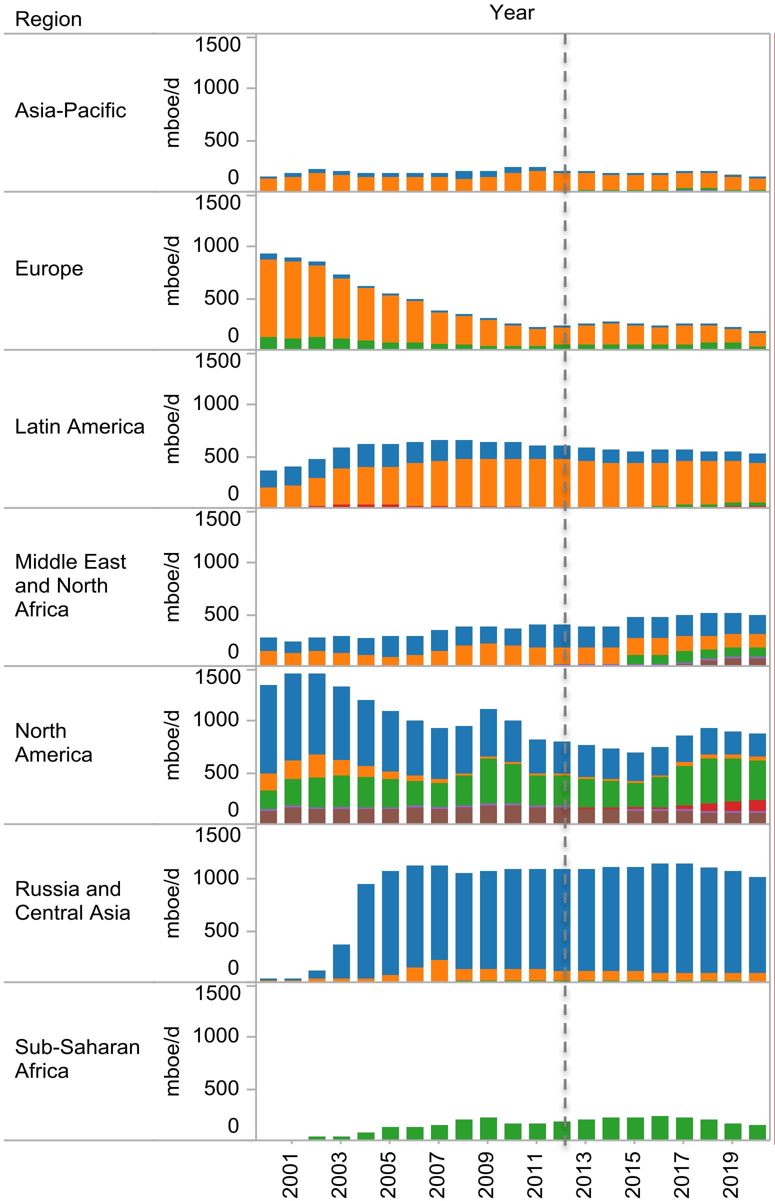
Global Production: Evolution of the Portfolio



Asia Pacific: Relatively small producing area (~6% of 2010 output). Production largely from offshore Australia and Indonesia with lesser volumes from China. Partnership with Reliance (India) creates exploration opportunities. Focus on deepwater and CBM. Divested assets in Pakistan and farmed down in Vietnam.

Europe: Mature and generally declining production position in the UK and Norway, mostly in shallow waters. Exploration and development projects are ongoing, often leveraging BP's existing infrastructure and assets in the region.

Latin America: Growth driven by shallow water gas developments in Trinidad & Tobago. Focus on onshore gas commercialization in Bolivia. Failed to sell Argentine assets (held through PAE) to Bridas in 2011. Brazil deepwater offers mid- to long-term potential from newly acquired deepwater acreage.

Middle East & North Africa: Position built from collaboration with NOCs (Adma-Opco, GUPCO, Sonatrach, LNOC, etc.). Substantial new source growth expected from Iraq, Egypt deepwater, offshore Oman. Exploration opportunities in Jordan.

North America: Second largest production region & largest cash flow generator. Deepwater GOM holds significant growth potential after years of investment. US L48 portfolio is material, yet declining, source of gas, with a growing emphasis on shale gas. Additional future growth from Canadian oil sands.

Russia & Central Asia: Principally comprised of TNK-BP venture created in 2003, now BP's largest source of production, characterized as long-life, slow decline output. In Azerbaijan, production is from large-scale ACG and Shah-Deniz. The Region is the largest source of new source volumes through 2015.

Sub-Saharan Africa: Operates only in the Angola deepwater play, which quickly emerged as a key oil-producing country. BP has collaborated with operators TOTAL (Block 17) and Chevron (Block 15). In the future, development of BP-operated blocks 31 and 18 is expected to reverse the recent decline in production.

Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

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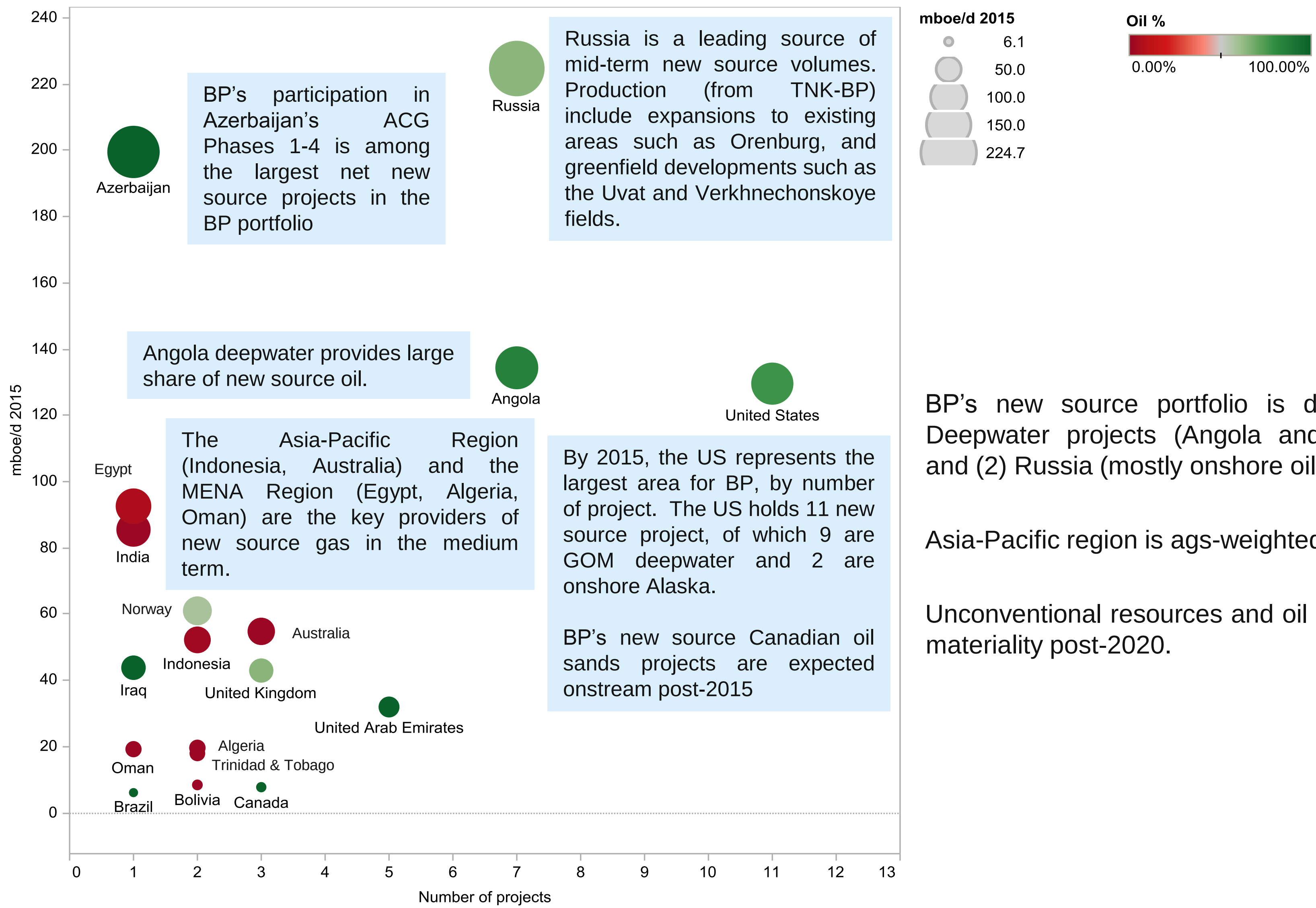
Global Production:
Country Growth Project Analysis

BP: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split



BP's new source portfolio is driven by (1) Deepwater projects (Angola and US GOM); and (2) Russia (mostly onshore oil).

Asia-Pacific region is ags-weighted.

Unconventional resources and oil sands deliver materiality post-2020.

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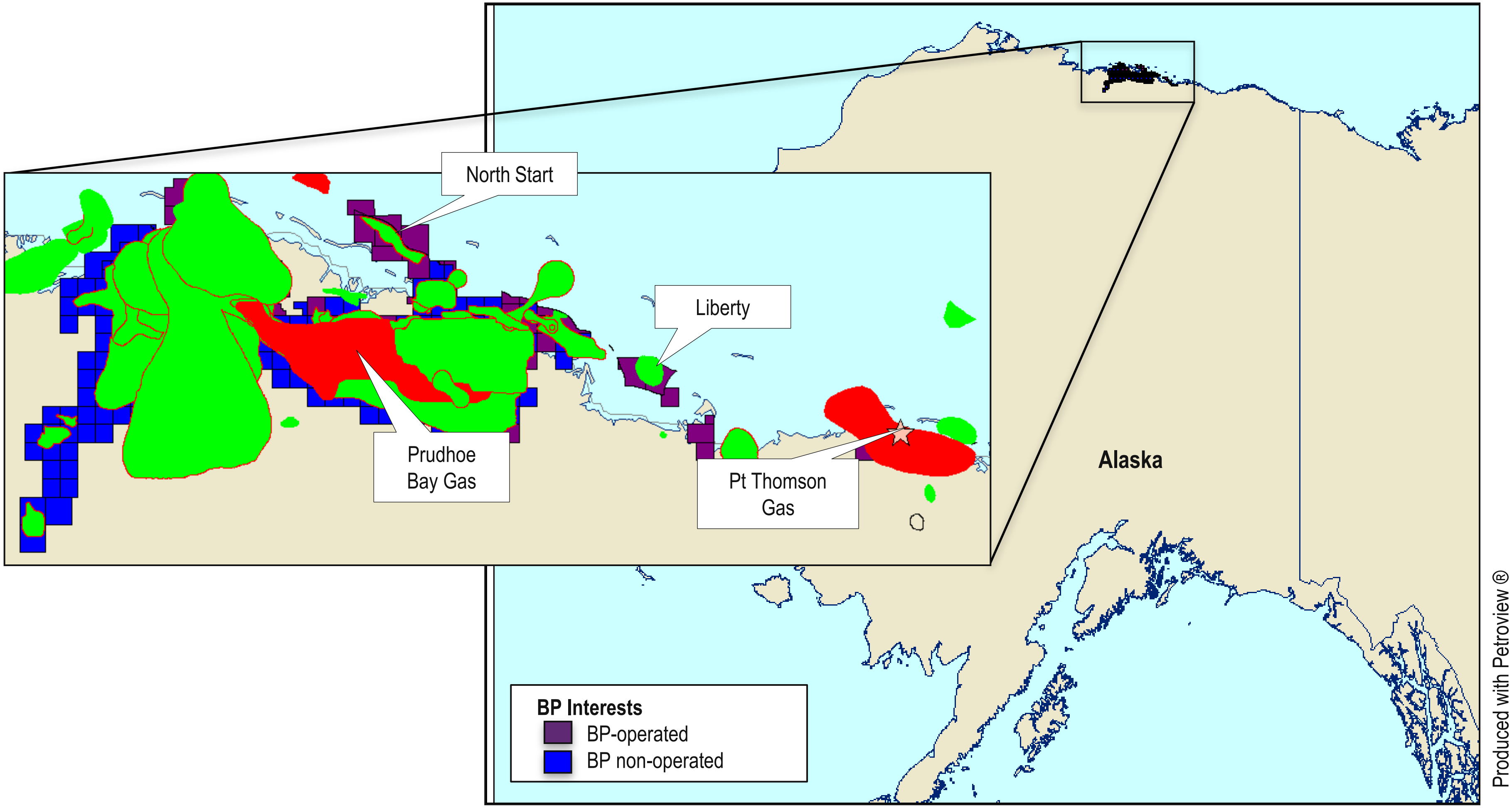
BP in Alaska



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BP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• Most of BP's assets are located on the **North Slope**, where production volumes have generally declined because of the maturity of the asset base and/or gas infrastructure constraints. Liquid production has declined from ~224 mboe/d in 2006 to ~166 mboe/d in 2010, while gas production has fallen from ~67 mmcf/d to ~46 mmcf/d over the same period. • BP's largest source of production is the **Greater Prudhoe Area** (26% w.i., operated), covering ~150,000 acres with more than 1,000 active wells. Gas resources are currently stranded because of the lack of pipeline capacity to southern markets. BP and ConocoPhillips had teamed up to propose a new natural gas pipeline (**Denali**) to run from Prudhoe Bay through western Canada to US markets. However, in May 2011, the partners announced that plans for the pipeline had been terminated, citing the lack of long-term purchase contracts. The proposed pipeline would have accommodated 4 bcf/d of natural gas. • BP and partners are moving forward with the development of gas liquids on the ~8 tcf **Point Thomson** field (32% w.i., non-operator). The gas cycling project is expected to produce ~10 mb/d of liquids; first production is targeted for 2014. Full field development awaits gas transport infrastructure. • In the **Beaufort Sea**, BP has suspended work on the extended-reach drilling program on the **Liberty** oil field (100% w.i.), pending revision of project design and schedule. • BP is also seeking to develop viscous (**Kuparuk**) and heavy (**Milne**) oil resources on the North Slope.	**Current production volumes are modest and declining, yet significant potential lies in the long-term commercialization of Prudhoe Bay and Point Thomson gas resources. Cancellation of the Denali gas pipeline proposal leaves BP as a potential supplier to an alternative pipeline/LNG export option, should one be approved and developed.**

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PFC-Identified Challenges

- **Re-establish its operator profile in the global deepwater:** While its competitors extend their commitments to global LNG, unconventional shale gas exploitation, and oil sands development in order to drive future portfolio growth, BP has deepened its commitment to the global deepwater play, despite the ongoing fallout from the Macondo oil spill. Expansion of its US GOM lease holdings (through the Devon portfolio acquisition), entry into the Brazil deepwater, and a material commitment to the K-G Basin deepwater play in India, together with phased field development offshore Angola and West Nile Delta in Egypt, positions BP as arguably the premier deepwater player in the Global Player peer group. BP will be under the spotlight regarding its future conduct and performance throughout the global deepwater basins.
- **Resolve shareholder relationship issues within the TNK-BP JV:** Accounting for ~29% of total worldwide production in 2011 (and ~40% of total worldwide oil production), the TNK-BP position is absolutely core to the BP portfolio from a volumetric perspective. However, the unsuccessful attempt to partner with Rosneft in the Russia Arctic raises concern over how much value TNK-BP can continue to create for BP. With TNK-BP now focused on international expansion, must BP settle for lower returns from what has until now been a highly lucrative position?
- **Complete the portfolio rationalization process:** The strength of the global asset transactions market prompted BP to expand its divestiture program from an initial $20 bn to $30 bn, divesting large swaths of its portfolio deemed non-Core and/or non-aligned with the company's growth focus. While the company did not plan on the depth of portfolio rationalization undertaken to date, this is a rare opportunity to high-grade asset holdings with the blessing of shareholders and analysts alike. BP is expecting to complete the divestiture process by end-2012.
- **Determine a path forward in the Brazil deepwater:** Having secured Brazil government approval to acquire the Devon asset portfolio, BP has established a foothold in the Brazil deepwater, with potentially the largest operated pre-salt portfolio outside Petrobras. The next step is to determine the appropriate approach to growth in the pre-salt play. With legislation now in place granting NOC Petrobras a minimum 30% w.i. and operatorship in all unlicensed pre-salt acreage, this may be another case of executing a strategic alliance (similar to that secured with Reliance in India and proposed with Rosneft in the Russia Arctic).
- **Accelerate development of US Onshore unconventional gas resource:** BP received a very competitive price for the Permian Basin and Western Canada conventional gas assets sold to Apache (totaling ~75 mboe/d of production and ~340 mmboe of reserves, equivalent to ~$24.60/boe of reserves in the ground or ~$109,000/flowing boe of production). This is particularly so given what is shaping up to be an extended period of gas price weakness in the North America market. To make up for lost volumes, BP may look to accelerate production from its ~10 tcf of reserves in the Woodford, Fayetteville, Haynesville, and Eagle Ford shale gas plays.
- **Accelerate development of BP's oil sands leases:** BP has built up a material oil sands lease portfolio in Western Canada, including 50% w.i. in the Sunrise in situ development project (sanctioned in November 2010), a 75% w.i. in the Terre de Grace in situ project (secured in March 2010 from Value Creation for ~$900 mn), and 50% w.i. in the Kirby in situ oil sands leases (with the other 50% divested to Devon in March 2010). Full development of these projects could represent 500-600 mbo/d of stable, long-life oil production, complementing the "Giant Oil Fields" growth platform and providing a portfolio buffer against the steep decline production profiles associated with deepwater developments.

ConocoPhillips: Company Overview

Strategic Signature

- March 2010, ConocoPhillips announces a new strategic pathway: Direct proceeds from a ~$15 bn asset and joint venture divestment program to:
  - reduce its debt-to-capital position;
  - increase near-term shareholder returns;
  - shift further out of the downstream, and
  - position the company for future growth from a smaller but higher-value portfolio position.
- Since the 2010-2012 Restructuring Plan, ConocoPhillips has:
  - executed on ~$7 bn in asset sales
  - divested its entire 20% equity interest in LUKOIL, and
  - directed proceeds from these sales to debt reduction and share repurchase.
- July 2011, ConocoPhillips announces a restructuring, to create ***two separate corporate entities***, Downstream (Phillips 66) and a pure play, E&P company (ConocoPhillips).
- Production expected to decline to ~1.5 mmboe/d in 2012, recovering to 1.64-1.69 mmboe/d by 2015. The company will rely on a large, diversified upstream portfolio positioned heavily in OECD countries (US, Canada, Australia, UK, and Norway, which accounted for ~72% of worldwide production in 2010).
- Growth of 0.5% per annum from 2012 through 2015 is forecast to come from Global Gas/LNG, SAGD Oil Sands, and Unconventional developments. However, as ConocoPhillips now stands to compete with the Independent, non-integrated oil & gas companies, the company's future strategy remains uncertain.

Company Overview

- **HQ:** Houston, TX
- **Employees:** 29,600
- **2011 Reserves:** 8,387 mmboe
- **2010 Production:** 1,610 mboe/d
- **3 Yr Production Growth:** -30.68% CAGR (2008-2011)
- **Apr 2012 Market Cap:** $3.3 bn
- **Apr 2012 P/E Ratio:** 8.12
- **2011 Corp Revenue:** $235 bn
- **2011 Upstream Capex:** $13.5 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✔	✔		✔	✔	

Partnership History

Date	Partner	Region (or Country)	Type
2003	LUKOIL	Russia	Various
2006	Cenovus	Canada	Oil Sands
2008	Origin Energy	Australia	LNG

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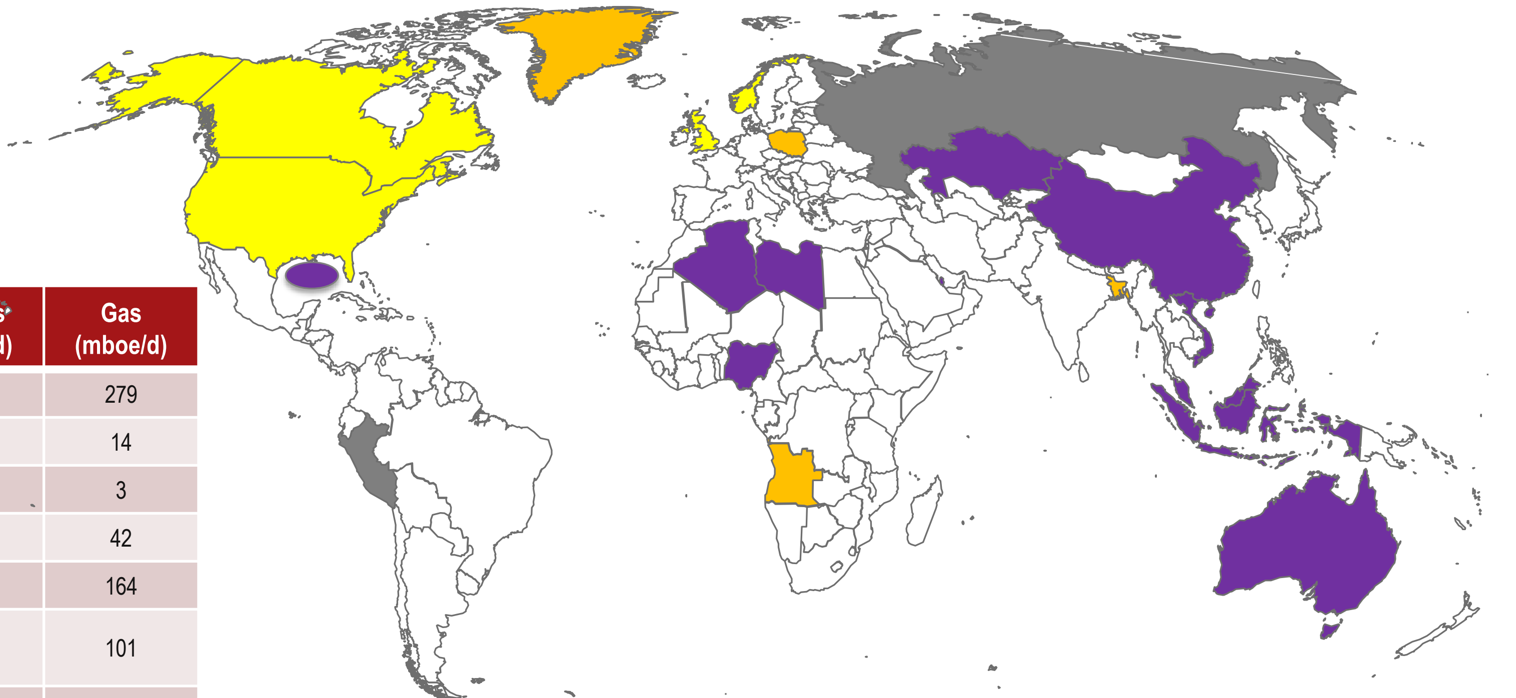
ConocoPhillips: Global Areas of Upstream Operations

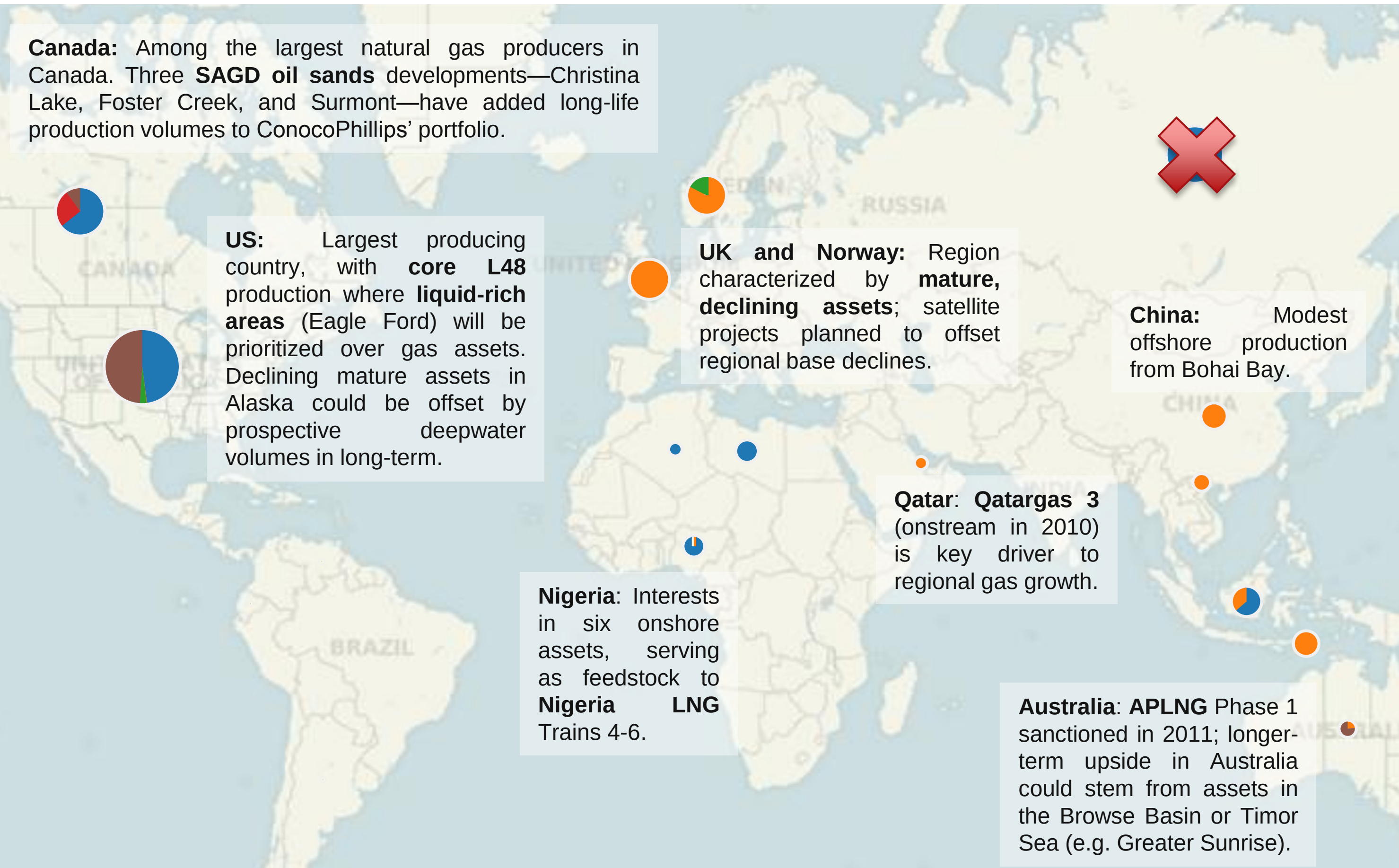


Country	Liquids (mboe/d)	Gas (mboe/d)
USA L48	142	279
USA Alaska	230	14
USA GOM	18	3
Russia	336	42
Canada	109	164
United Kingdom	74	101
Norway	137	35
Indonesia	17	232
Australia/ Timor Sea	31	58
China	68	0
Libya	46	1
Nigeria	20	24
Vietnam	24	2
Algeria	13	0
Qatar	3	9

Country	Liquids (mboe/d)	Gas (mboe/d)
Angola	0	0
Bangladesh	0	0
Brunei	0	0
Greenland	0	0
Kazakhstan	0	0
Malaysia	0	0
Poland	0	0
Peru	0	0

ConocoPhillips Global Production Portfolio - 2010

Russia: LUKOIL sale leaves ConocoPhillips with modest production from its two joint ventures in Russia (Polar Lights Company and Naryanmarneftegaz). Regional production declines from **21% of worldwide production in 2009 to 3% in 2011**.



mboe/d

- 0
- 500
- 1,000
- 1,345

Asset Type

- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Canada: Among the largest natural gas producers in Canada. Three **SAGD oil sands** developments—Christina Lake, Foster Creek, and Surmont—have added long-life production volumes to ConocoPhillips' portfolio.

US: Largest producing country, with **core L48** production where **liquid-rich areas** (Eagle Ford) will be prioritized over gas assets. Declining mature assets in Alaska could be offset by prospective deepwater volumes in long-term.

UK and Norway: Region characterized by **mature, declining assets**; satellite projects planned to offset regional base declines.

China: Modest offshore production from Bohai Bay.

Qatar: **Qatargas 3** (onstream in 2010) is key driver to regional gas growth.

Nigeria: Interests in six onshore assets, serving as feedstock to **Nigeria LNG** Trains 4-6.

Australia: **APLNG** Phase 1 sanctioned in 2011; longer-term upside in Australia could stem from assets in the Browse Basin or Timor Sea (e.g. Greater Sunrise).

Vietnam: Continued development of mature Cuu Long Basin; **potential divestment target**.

Malaysia: Development of **deepwater** fields (Gumusut-Kakap and Kebabangan) will bring Malaysia into ConocoPhillips' producing country portfolio.

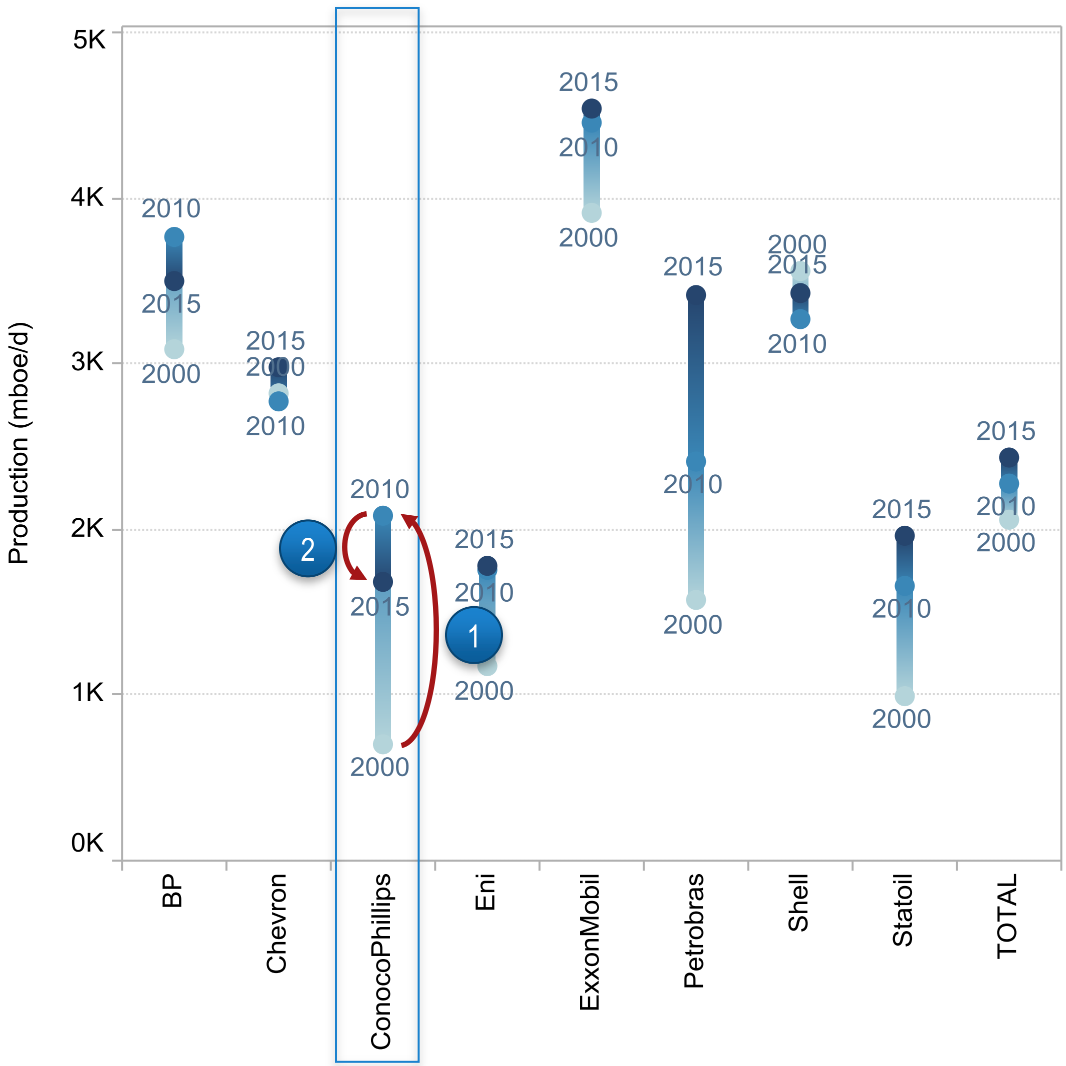
Indonesia: Largest contributor to Asia-Pacific production; ongoing development of **Corridor PSC** and **South Natuna Block B**.

Algeria: Onshore oil field production; additional volumes from El Merk (EMK) expected for 2012 start-up.

Libya: Legacy onshore Waha concession; above ground conflict will delay new source oil projects.

Total Portfolio Evolution: ConocoPhillips vis-à-vis the Competition

Production (mboe/d) in 2000, 2010 and 2015 (PFC Forecast): ConocoPhillips and Peers



ConocoPhillips' 2010-2012 Restructuring Plan will see the company become the largest of the Independent, non-integrated international oil & gas companies, compared to its former position as the third-smallest of PFC Energy's expanded Global Player peer group.

1. **2000-2010:** Production increases largely driven by the merger of Conoco and Phillips in the beginning of the decade (growing volumes from 698 mboe/d in 2000 to 1,082 mboe/d in 2002) and the Burlington Resources purchase in 2006 (growing volumes from 1,824 mboe/d in 2005 to 2,358 mboe/d in 2006). The gradual acquisition of a 20% stake in LUKOIL was a key driver to mid-decade growth.

2. **2011-2015:** ConocoPhillips's production is expected to decline from 2010-2015, due to the company's intensive asset divestiture program (the initial ~$15 bn asset and joint venture divestment program was expanded in 2011 when ConocoPhillips announced it would shed an additional $5-$10 bn in non-Core assets by end-2012). Volumes are forecast to decline from ~2,078 mboe/d in 2010 to ~1,674 mboe/d in 2015.

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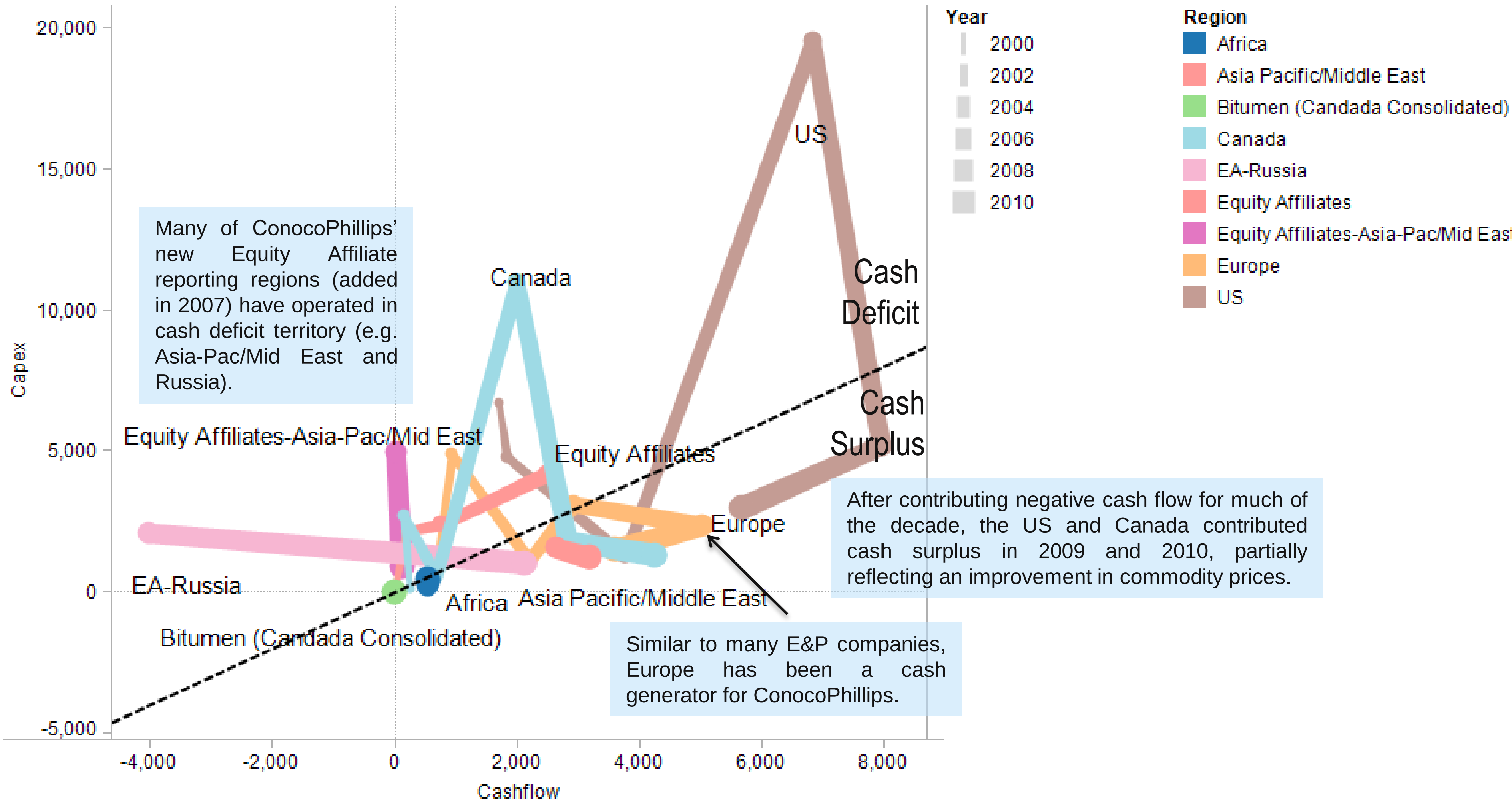
How the Portfolio is Financed: Sources and Uses of Cash



Many of ConocoPhillips' new Equity Affiliate reporting regions (added in 2007) have operated in cash deficit territory (e.g. Asia-Pac/Mid East and Russia).

After contributing negative cash flow for much of the decade, the US and Canada contributed cash surplus in 2009 and 2010, partially reflecting an improvement in commodity prices.

Similar to many E&P companies, Europe has been a cash generator for ConocoPhillips.

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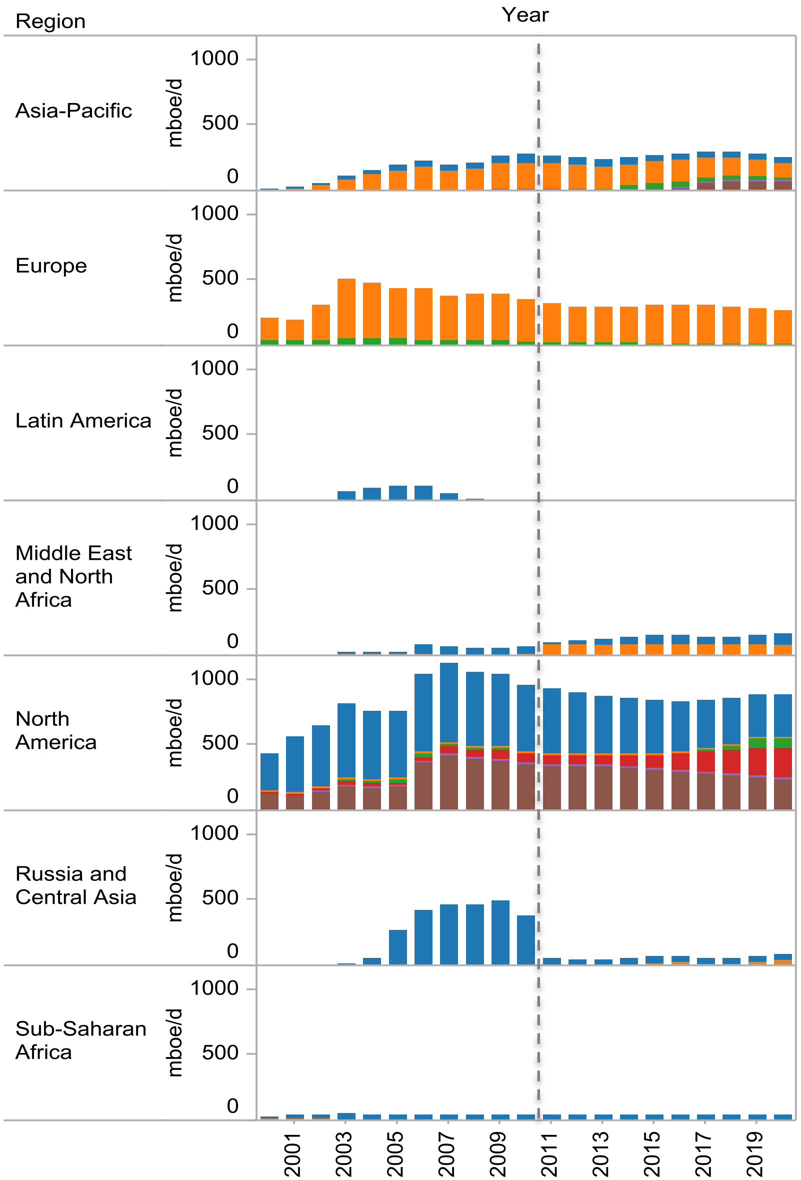
Global Production: Evolution of the Portfolio



Asia Pacific: Project queue 14 projects deep makes Asia-Pacific the largest development pipeline in all of ConocoPhillips' portfolio. Region estimated to occupy 20% of 2011 upstream capex. New projects in both legacy countries (Indonesia, Vietnam) are being complimented by start ups in Malaysia (Gumusut-Kekap, Kebabangan) and Australia (APLNG).

Europe: Mature and generally declining production position in the UK and Norway, mostly in shallow waters. Satellite projects poised to somewhat offset base declines.

Latin America: After reaching historic peak production in 2005, volumes fell to zero in 2009. The Latin America portfolio, largely acquired through the Burlington transaction, has never been a material part of ConocoPhillips' global operations. With no new volumes anticipated in the portfolio, a complete exit from the region could be likely.

Middle East & North Africa: Future growth is largely tied to the Qatargas 3 LNG project and El Merk (EMK) in Algeria. Longer-term growth is poised to stem from Libya (as yet unsanctioned joint NC 98 and North Gialo developments) assuming a timely re-commencement of upstream activities.

North America: Largest production region & cash flow generator. New growth initiatives focus on exploitation of Eagle Ford shale liquids and Canadian oil sands (Christina Lake, Foster Creek, and Surmont), which are projected to reverse the decline in Canadian production by 2014 and deliver medium- and long-term volume growth.

Russia & Central Asia: LUKOIL sale leaves ConocoPhillips with only modest production from its two joint ventures in Russia and few growth opportunities within the remaining portfolio. The sole growth asset is an 8.4% stake in the Kashagan field, which continues to face major challenges.

Sub-Saharan Africa: Onshore assets serve as feedstock to Nigeria LNG Trains 4-6. Longer-term upside tied to feedstock for the yet-to-be-sanctioned Brass LNG plant, while 2011 re-positioning in Angola could provide exploration opportunities critical to securing new source ventures for long-term growth.

Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

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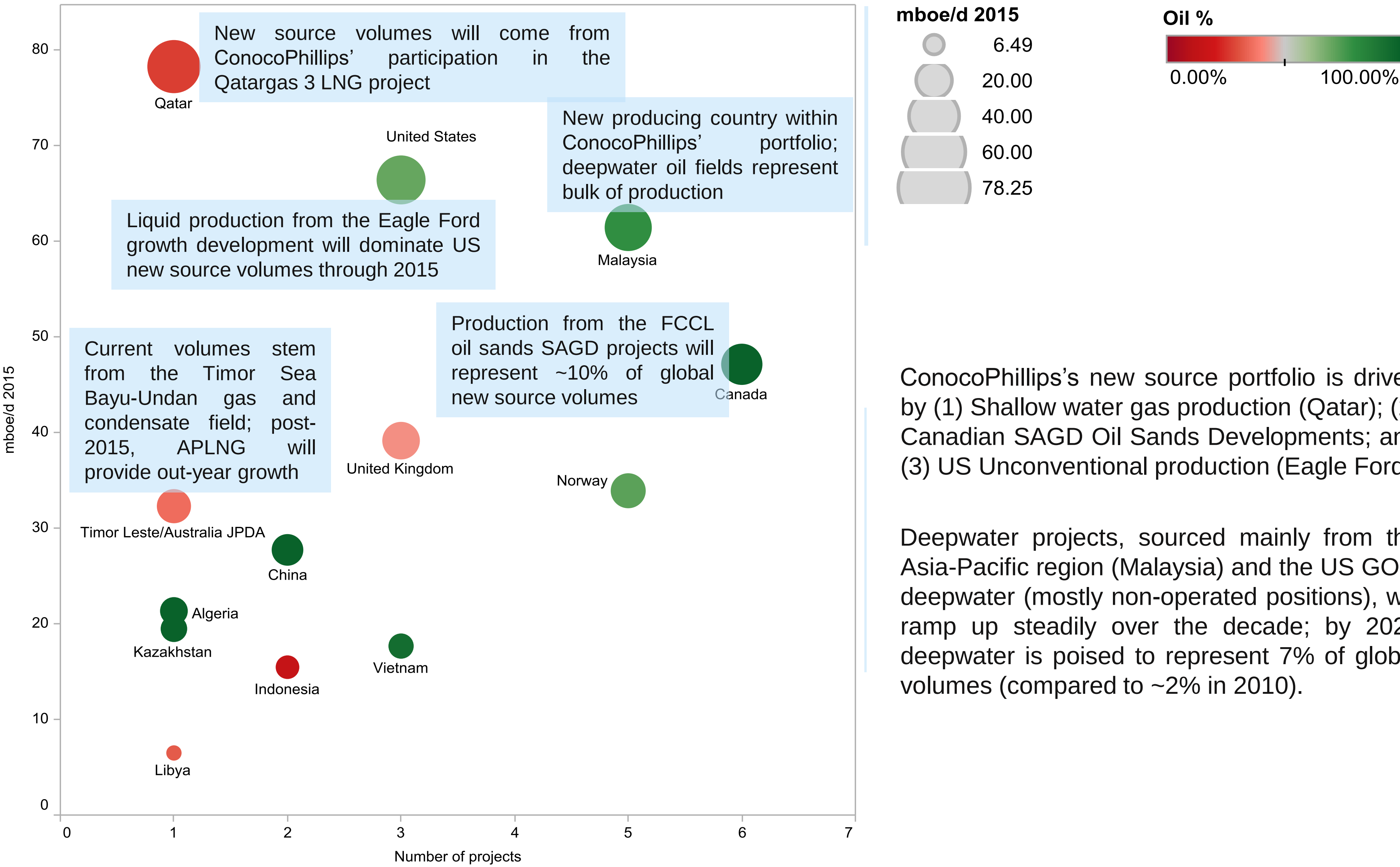
Global Production:
Country Growth Project Analysis

ConocoPhillips: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split



ConocoPhillips's new source portfolio is driven by (1) Shallow water gas production (Qatar); (2) Canadian SAGD Oil Sands Developments; and (3) US Unconventional production (Eagle Ford).

Deepwater projects, sourced mainly from the Asia-Pacific region (Malaysia) and the US GOM deepwater (mostly non-operated positions), will ramp up steadily over the decade; by 2020 deepwater is poised to represent 7% of global volumes (compared to ~2% in 2010).

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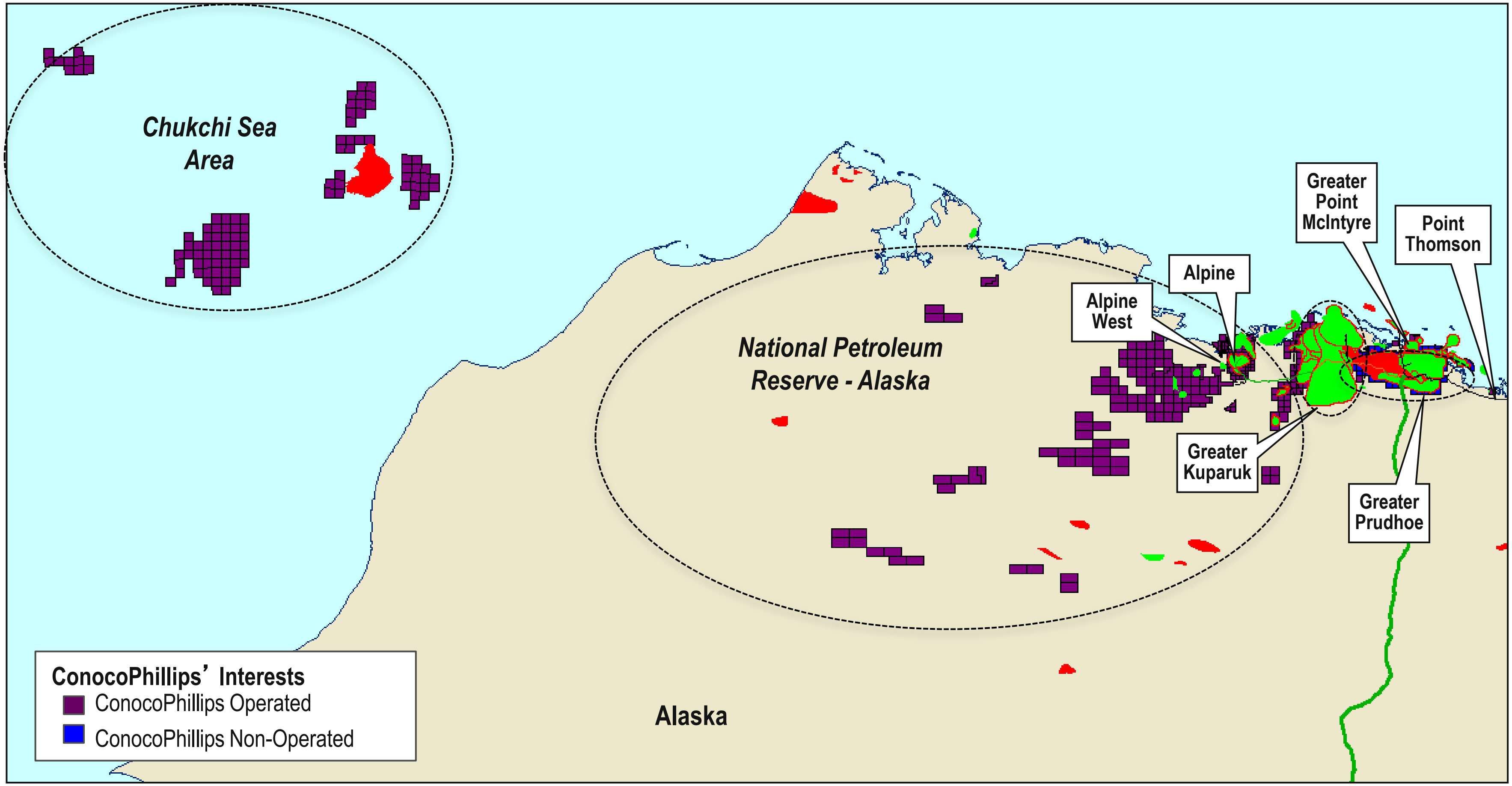
ConocoPhillips in Alaska – North Slope



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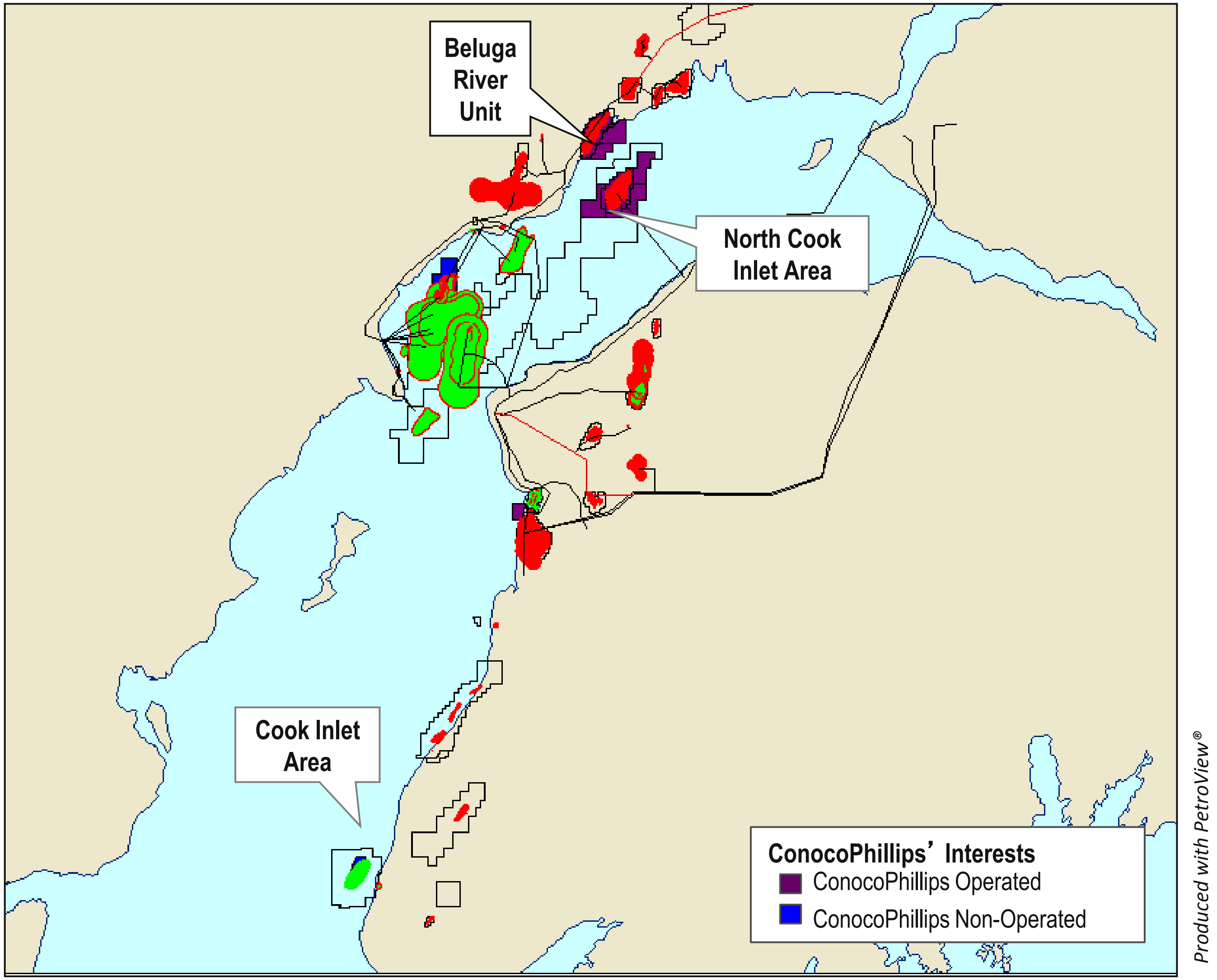
ConocoPhillips in Alaska – Cook Inlet

ConocoPhillips' Interests in the Cook Inlet (Alaska)



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ConocoPhillips **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• ConocoPhillips' assets in Alaska are legacy assets acquired from Arco Alaska in 2000 and include the Greater Prudhoe Area, Greater Prudhoe Bay Area, Greater Kuparuk Area, Western North Slope, and Cook Inlet Area. The company's largest producing area in Alaska is the Greater Prudhoe Area, a collection of mature, long-life fields. Production from the mature Alaska portfolio has been in slow decline since 2004. In 2010, net production from Alaska averaged 230 mb/d of oil and 82 mmcf/d of gas, accounting for ~21% of US production. • ConocoPhillips and BP have been joint proponents of the **Alaska Gas Pipeline** (or **Denali Pipeline**), intended to accelerate commercialization of Prudhoe Bay gas through Western Canada and into US markets. In 2010, the partners officially withdrew their support for the proposed project, in response to continued US gas price weakness and absence of buyer commitments. This places substantial uncertainty around further commercialization of ConocoPhillips' Alaska gas resources. • Activity in the ConocoPhillips-operated Greater Kuparuk Area (GKA), has recently focused on development of viscous oil resources. The GKA, located 40 miles west of Prudhoe Bay on the North Slope, includes the Kuparuk field and its satellites: West Sak, Tarn, Tabasco, Meltwater, and Palm. Heavy oil resources **West Sak** and **Ugnu** (52.2% w.i., operated) are potential projects currently in the appraisal phase. Expected gross peak production is ~23 mboe/d.	As Alaska's largest oil and gas producer, ConocoPhillips holds a leading position in the region. Although the company continues to target smaller projects within the GKA (West Sak and Ugnu) and NPR-A (Alpine West, Greater Moose's Tooth unit and Fiord West), ConocoPhillips will ultimately need expanded access to Asia gas markets in order to reverse the downward production trend in Alaska.

PFC Energy

COP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• In the Western North Slope, ConocoPhillips faces regulatory challenges surrounding project development in the NPR-A region. In order to offset declines at the **Alpine** field (78% w.i., operated) and its three satellites, Nanuq, Fiord, and Qannik, ConocoPhillips is exploring development of additional satellite fields in the adjacent NPR-A, an area that requires distinct permit approval. **Alpine West** (or **CD-5**), a proposed Alpine satellite project, has been significantly delayed due to local opposition and regulatory barriers. Most recently, in early 2010, the U.S. Army Corps of Engineers denied a permit for a bridge that would provide access to the CD-5 site, a move that will further delay the project (originally planned for 2012) and several additional developments that would depend on the infrastructure. Other possible projects on the NPR-A include the **Greater Moose's Tooth** unit and **Fiord West**, which are both in appraisal phases. • While ConocoPhillips has three primary gas fields in the Alaska region–the North Cook Inlet, Beluga River, and Point Thomson–**Point Thomson** (5% w.i., non-operated) remains the only potential new source development. In 2010, development activities continued with the drilling of two appraisal wells. First production of gas liquids is anticipated in 2014. Longer-term growth potential lies in commercialization of the gas reserves, which is in turn dependent on construction of a long-distance gas trunk line. • In 2010, ConocoPhillips and Statoil engaged in an asset swap wherein ConocoPhillips sold a 25% w.i. in 50 of its **Chukchi Sea** leases to Statoil in exchange for financial payment and a 50% w.i. interest in 16 Statoil-operated Gulf of Mexico leases, as well as Statoil's 25% w.i. in five additional GOM leases already operated by ConocoPhillips. All of the involved GOM blocks are in the emerging Lower Tertiary play. ConocoPhillips plans to begin exploratory drilling on its Chukchi acreage in 2013.	

PFC Energy

PFC-Identified Challenges

- **Competing as a "Pure Play" E&P Company**: The separation of ConocoPhillips into two, stand-alone Upstream and Downstream entities is scheduled to be finalized in 1H:2012. The ~85% of total portfolio value residing in E&P assets will thereby become the largest "pure play" E&P Independent, a competitor landscape position the company held uncomfortably prior to the Burlington Resources acquisition in 2006. Can ConocoPhillips Upstream compete successfully in the Independent's space by delivering either leading shareholder returns or leading production growth? Or has it simply re-established its original dilemma—too large to compete with the faster moving International Independents, and too small to compete with the Global Players? And if so, does it survive?
- **Re-Establishing a Value Proposition**: ConocoPhillips' new strategic focus on Sustained Value Generation is intended to re-establish the company's competitive advantage in the E&P space. In the near-term, the 2010-2013 Restructuring Plan will deliver a smaller company with limited medium-term production growth and improved, but unlikely to be leading, ROCE and financial performance. Clearly, the cannibalization of the company's assets and recycling of proceeds to shareholders in order to shore up share valuation and total shareholder returns is a stop-gap strategy at best. Given continuing financial and operational challenges (ROCE, production cost, upstream net income, etc.), ConocoPhillips may struggle to deliver a value proposition that will compete successfully in either the Global Player or International Independents peer group.
- **Improving Operational Performance**: While showing improvement in finding and development costs, ConocoPhillips ranks at or near the bottom of the expanded Global Players peer group in net income/boe, production costs/boe, and Upstream ROCE. The current portfolio high-grading has already delivered Upstream ROCE improvement (from 7% in 2009 to 10% in 2010) and should deliver improvement in operational metrics; both Syncrude and the LUKOIL holdings were arguably underperforming positions. With long lead time, large scale, capital intensive developments like Qatargas 3, Jasmine, Kashagan Phase 1, and Surmont poised to deliver material production and cash flow, ConocoPhillips should see the flow-through benefits in terms of more competitive ROCE and operational metrics.
- **Delivering Production Growth**: The share repurchase program accompanying portfolio rationalization under the Restructuring Plan is projected to deliver ~3% growth in per share production in 2010 and 2011. However, physical volumes will decline in absolute terms over the 2010-2011 period—by ~208 mboe/d in 2010 from 2009 levels, and a further ~360 mboe/d in 2011 from 2010. The only region poised to deliver higher production volumes in 2020 versus 2010 is the relatively minor MENA region, projected to reach ~177 mboe/d in 2020 versus 72 mboe/d in 2010. New source volumes in Canada and the North Sea will struggle to offset mature asset declines, delivering flat production in the core North America and Europe regions, while the LUKOIL sell-down will dampen what was once considered a core driver of future growth for the company. While boasting a 10 bn boe resource base, it is not clear how ConocoPhillips will deliver the promised surge in organic growth over the 2015-2020 period from its captured portfolio—although the enhanced capex spend in the Eagle Ford play is a good starting point. Barring a material acquisition (certainly not out of the question), the company will be looking to its exploration portfolio to deliver a medium term "engine of growth".

PFC Energy

ExxonMobil: Company Overview

Strategic Signature

- ExxonMobil: largest global integrated oil and gas company
  - ~4,513 mboe/d in 2011; production in 21 countries, with upstream operations in an additional 20 countries.
- Growth strategy based on scale, basin dominance, and execution excellence => continuously seek access to investment opportunities of adequate size and materiality.
- Faced with (i) commissioning of the final elements of the company's Qatar project portfolio, (ii) declining production from its Europe and Asia-Pacific portfolios, (iii) roadblocks to materiality in Brazil deepwater, Venezuela extra-heavy, and Equatorial Margin, and (iv) already holding a considerable stake in the Canadian oil sands, ExxonMobil took an aggressive move into unconventional shale gas exploitation.
- The 2009 acquisition of XTO Energy brings materiality to ExxonMobil's technical expertise in tight gas, CBM, and shale oil and gas exploitation, with ~2.3 bcf/d and 87 mboe/d of production, proved reserves of ~2.3 bn boe, and a resource base of 7.5 bn boe.
- Will seek to leverage XTO into a global unconventional portfolio.
- Acquisition drove a 13% increase in production in 2010, returning ExxonMobil to first place amongst its peers

Company Overview

- **HQ:** Irving, Texas
- **Employees:** 83,600
- **2011 Reserves:** 24,922 mmboe
- **2011 Production:** 4,513 mboe/d
- **3 Yr Production Growth:** 4.53% CAGR (2008-2011)
- **Apr 2012 Market Cap:** $402 bn
- **Apr 2012 P/E Ratio:** 10.1
- **2011 Corp Revenue:** $3433bn
- **2011 Upstream Capex:** ~$28 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✓	✓		✓	✓	✓

Partnership History

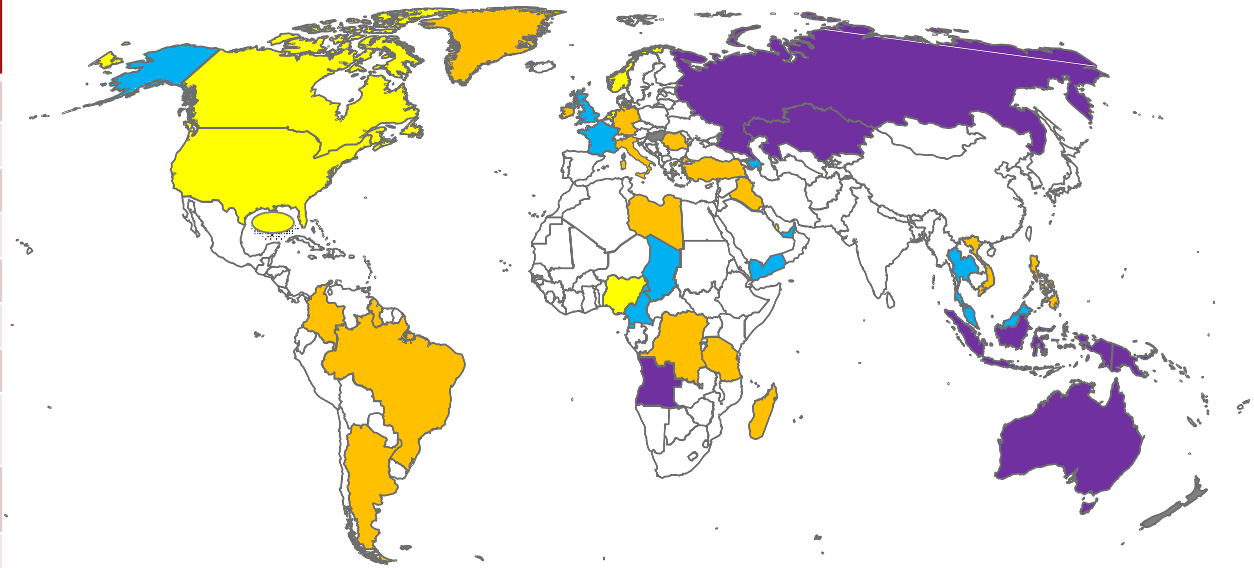
Date	Partner	Region (or Country)	Type
2011	Sinopec	China	Unconventional
2011	Rosneft	Russia	Offshore Oil & Gas

ExxonMobil has a limited history of partnership, preferring instead to purchase and operate material positions independently

PFC Energy

ExxonMobil: Global Areas of Upstream Operations

Country	Liquids (mboe/d)	Gas (mboe/d)
Qatar	232	644
USA	408	433
Nigeria	391	2
Norway	246	117
Netherlands	0	340
Canada	242	86
UAE	246	0
United Kingdom	80	92
Kazakhstan	127	24
Angola	141	0
Malaysia	48	86
Australia	51	55
Germany	0	91
Equatorial Guinea	53	0
Russia	43	8
Indonesia	13	36
Chad	43	0
Azerbaijan	21	0
Argentina	0	9
Papua New Guinea	7	0
Thailand	0	4



Country	Liquids (mboe/d)	Gas (mboe/d)
Brazil	0	0
Cameroon	0	0
Colombia	0	0
Congo	0	0
Greenland	0	0
Guyana	0	0
Hungary	0	0
Iraq	0	0
Ireland	0	0
Italy	0	0
Libya	0	0

Country	Liquids (mboe/d)	Gas (mboe/d)
Madagascar	0	0
New Zealand	0	0
Philippines	0	0
Poland	0	0
Romania	0	0
Tanzania	0	0
Turkey	0	0
Vietnam	0	0
Yemen	0	0

Core
New Venture
Focus
Harvest
Exit

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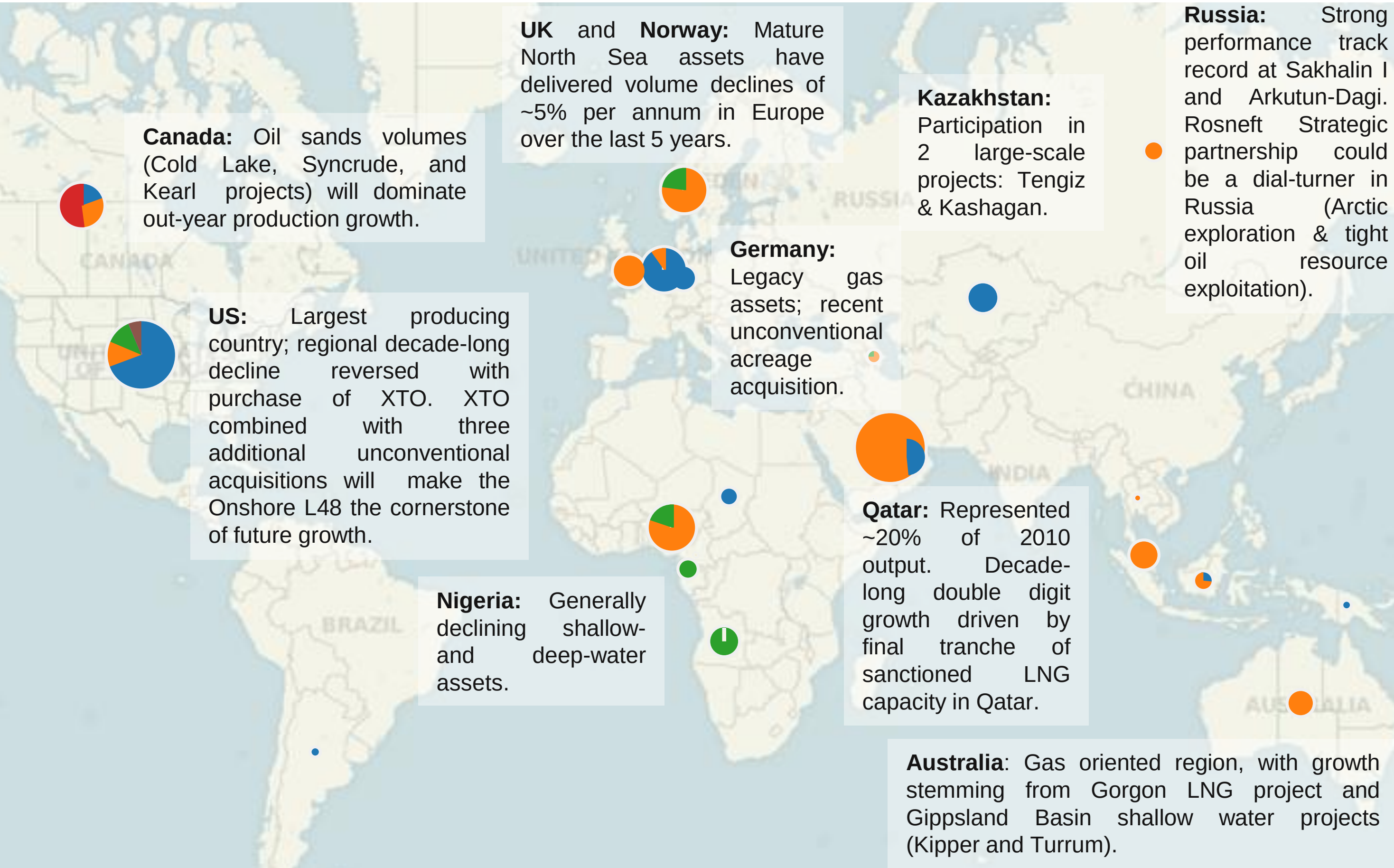
ExxonMobil Global Production Portfolio - 2010



mboe/d

- 0
- 500
- 1,000
- 1,345

Asset Type

- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Indonesia: Near-term gas volumes will hold production steady as ExxonMobil positions for new ventures in the unconventional space (coal bed methane).

Malaysia: Key gas producing area; focus on enhanced oil recovery (EOR) and field life extension schemes.

Argentina: legacy, declining gas assets; recent acreage positioning in prospective shale Neuquen Basin.

Angola: Multi-field new source developments (Kizomba Satellites Phase 1, Pazflor, and CLOV) drive regional growth.

Papua New Guinea: Formerly small contributor to the ExxonMobil portfolio, PNG will rise in prominence within the portfolio through the monetization of gas reserves at PLNG.

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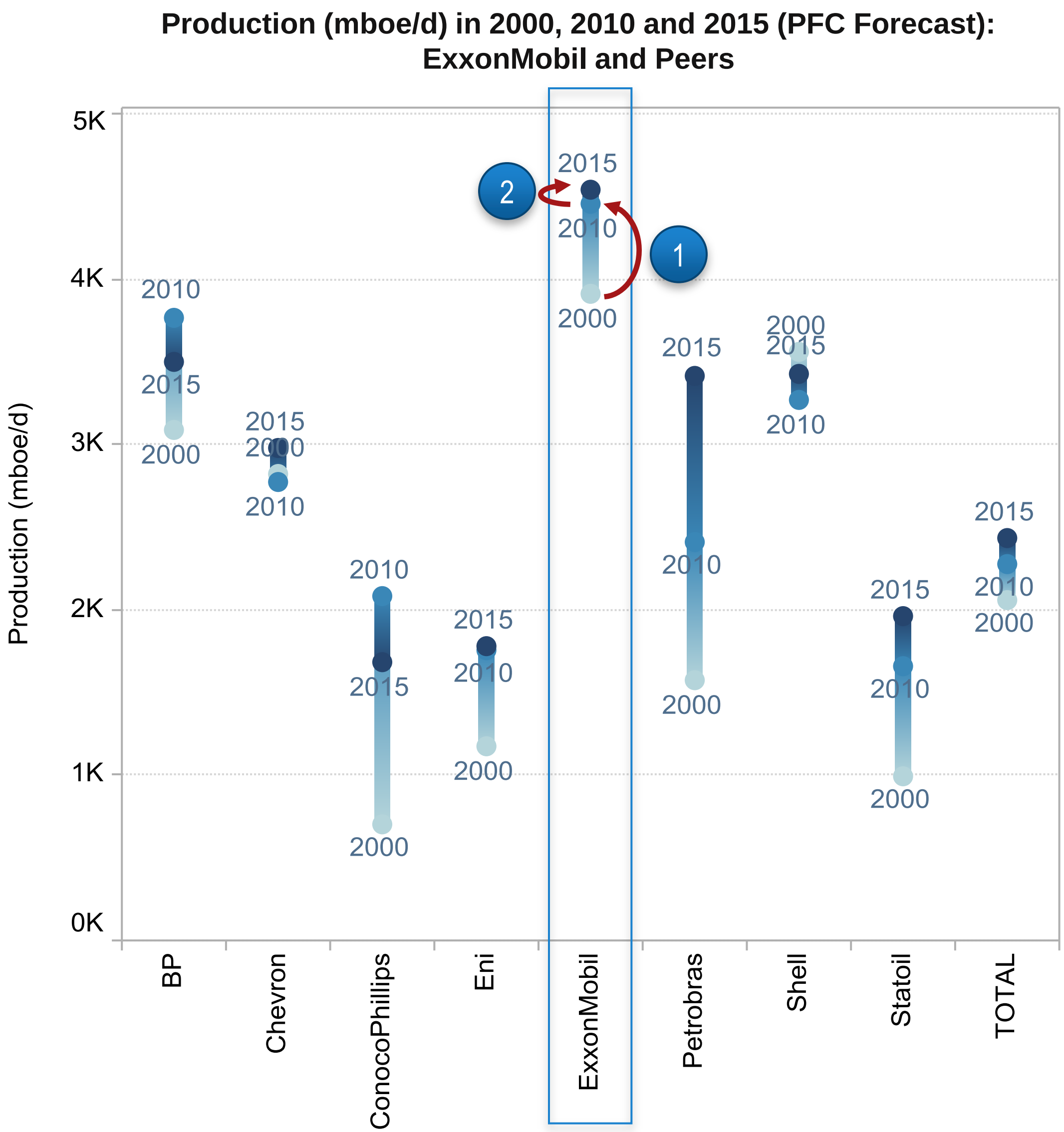
Total Portfolio Evolution: ExxonMobil vis-à-vis the Competition



Averaging ~4.45 mmboe/d in 2010, ExxonMobil continues to lead its peer group in terms of production.

1 **2000-2010:** Production oscillated through the decade, landing in 2009 at roughly the same level as 2000 (roughly ~3.9 mmboe/d), before rising 13% in 2010 (~6% excluding the XTO acquisition), reaching ~4.45 mmboe/d. For a company that has prided itself on organic reserves and production growth, the XTO acquisition marks a considerable departure in growth strategy for ExxonMobil.

2 **2011-2015:** Modest volume growth, reaching ~4.54 mmboe/d in 2015. While PFC Energy estimates are lower than ExxonMobil targets, the absence of guidance regarding growth projects associated with the XTO portfolio makes the pace of future growth uncertain.

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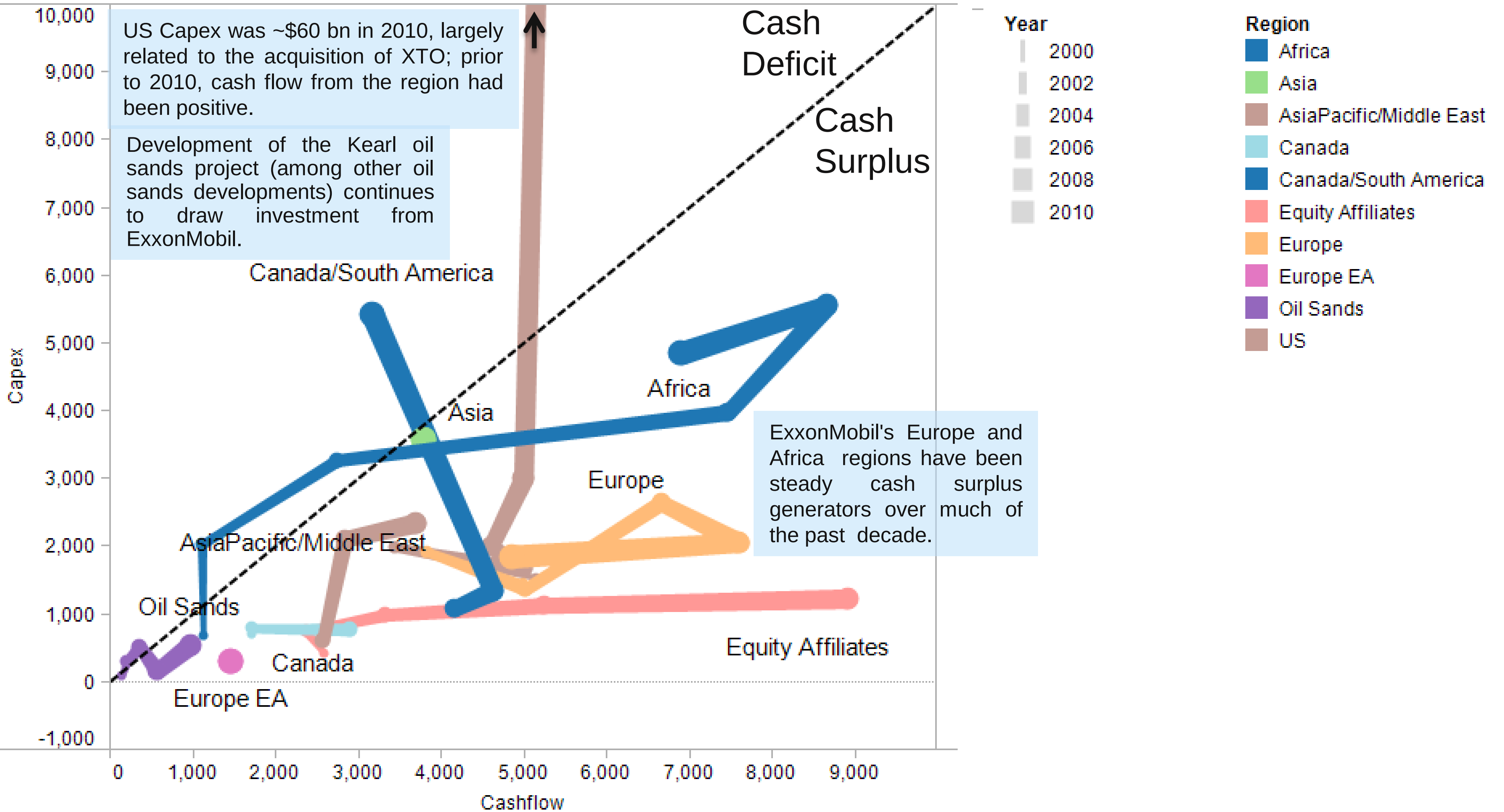
How the Portfolio is Financed: Sources and Uses of Cash



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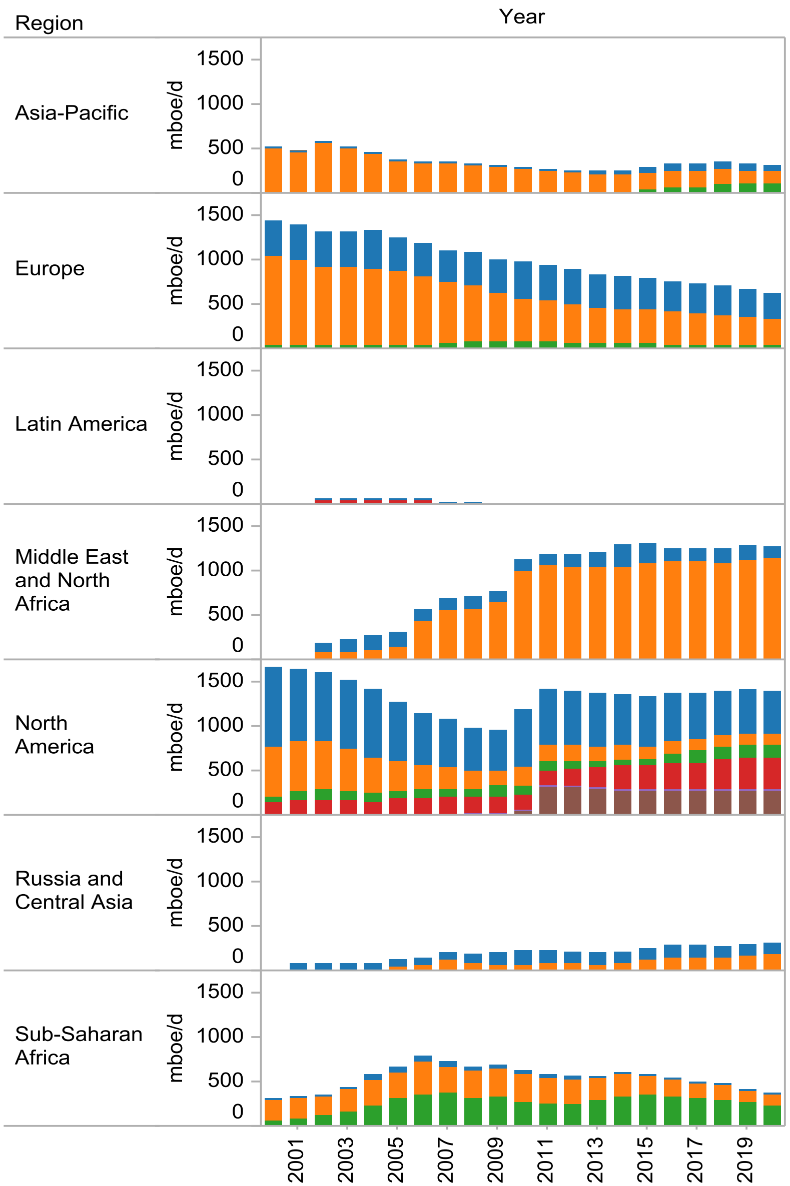
Global Production: Evolution of the Portfolio



Asia Pacific: Declines in ExxonMobil's relatively mature Asia-Pacific portfolio have been consistent for most of the past decade. A revival in regional production (though medium to long term in nature) is based primarily on two large gas export projects: Papua New Guinea LNG and Gorgon LNG (Australia).

Europe: Mature and generally declining production position. Positive net cash flow enables, in part, financing of frontier exploration in both unconventionals and the deepwater: ExxonMobil will seek to leverage the capabilities of XTO in Germany and Poland, while also assessing the prospectivity of the Turkish Black Sea.

Latin America: At 9 mboe/d, the region has no material impact on the ExxonMobil portfolio. Production is sourced solely from mature, declining gas assets in Argentina. The recent acquisition of 130,000 net acres of prospective shale gas resource in the Neuquen basin is part of a global strategy to leverage XTO capabilities in unconventional resource plays.

Middle East & North Africa: The rapid growth in MENA production that ExxonMobil experienced between 2002 and 2010 is on the cusp of reaching plateau, as the final Qatargas, RasGas, and Al-Khaleej phases have come onstream. While ExxonMobil will record growth from the West Qurna I project, upside in Iraq remains unclear.

North America: The acquisition of XTO Energy will drive a resurgence in regional production. A focus on Fayetteville, Haynesville/Bossier, Barnet, and Woodford shale gas plays, and transitioning portfolio to a more balanced oil:gas ratio in the out-years. A suite of Canadian oil sands developments and potential offshore projects will also contribute growth.

Russia & Central Asia: Major growth 2005-2010 was driven by a handful of mega-projects (Tengiz and Kashagan, Sakhalin I, and Azeri-Chirag-Guneshli); future performance relies heavily on subsequent development phases of these projects, most of which face challenges. The Rosneft partnership could provide additional long-term opportunity.

Sub-Saharan Africa: Growth in SSA has leveled off as new developments struggle to keep pace with steep deepwater decline rates. The primary bright spot in portfolio is Angola, where three new projects (Pazflor, Kizomba Satellites, and PSVM) are scheduled to come onstream over the next two years.

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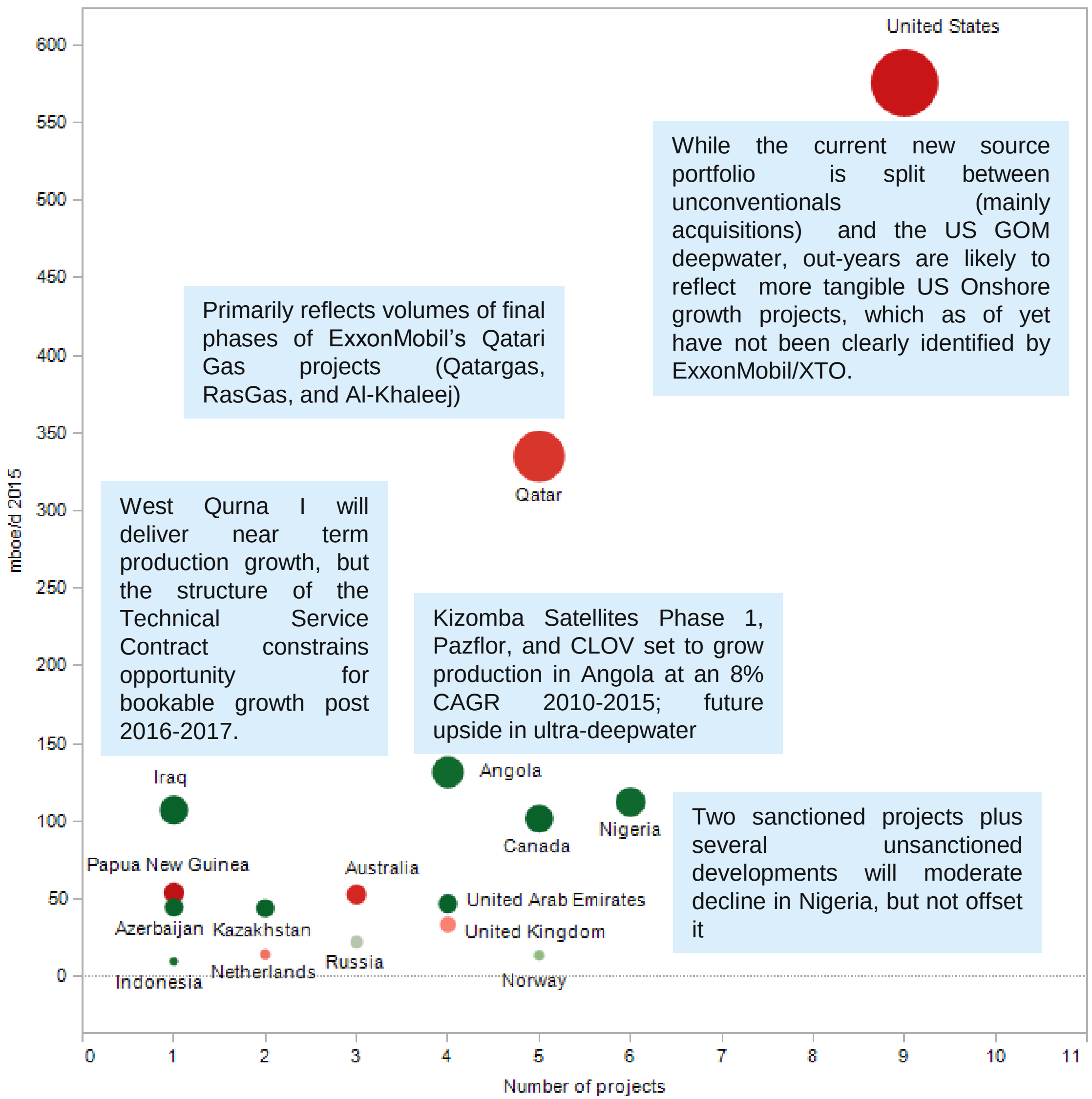
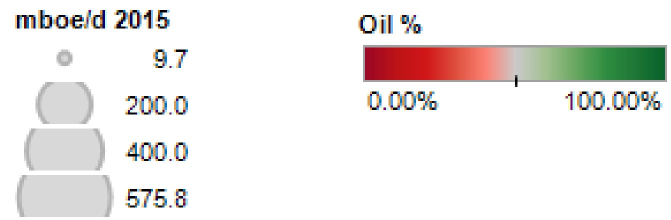
Global Production:
Country Growth Project Analysis

ExxonMobil: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split

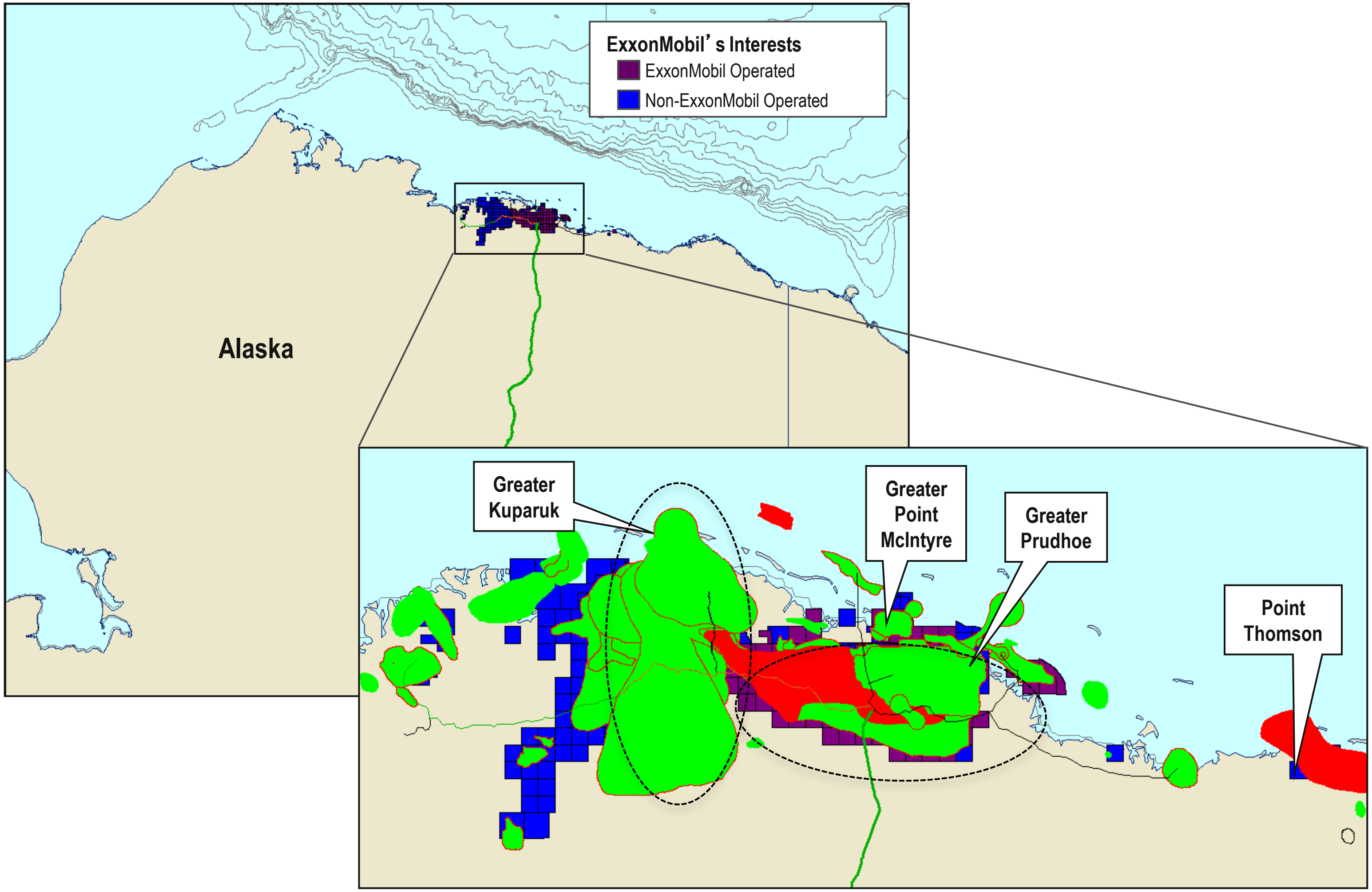




ExxonMobil's US new source portfolio will dwarf new source production from all other countries. Through 2015, the US will contribute nearly 40% of global new source incremental volumes, 99% of which will stem from the company's unconventional activities (acquisitions plus the Piceance tight gas development).

International unconventional developments to remain largely immaterial until 2020 or thereafter.

ExxonMobil in Alaska – North Slope



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ExxonMobil **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• In Alaska, ExxonMobil holds interests in the **Greater Prudhoe**, **Greater Point McIntyre**, and **Greater Kuparuk** areas. The company is one of the largest North Slope producers, although production from the region is declining; 2010 net production averaged 117 mb/d of liquids. • Development activities continued at **Point Thomson** in 2010 (35% w.i., operated), and first production of gas liquids is anticipated in 2014. The longer-term potential lies in commercialization of the gas reserves, which is dependent on building a gas pipeline.	**Material harvest position.** As the largest holder of discovered gas resources on the North Slope and a co-operator of the Prudhoe Bay Western Region development, ExxonMobil holds a leading position in Alaska.

PFC-Identified Challenges

- **Deliver on unconventional resource positioning**: The XTO Energy acquisition and subsequent shale gas acreage transactions have made ExxonMobil a force in the North America unconventional resource play. That said, the company has provided limited guidance on pace of forward development despite continued acreage accumulation. Furthermore, given the weak US gas price environment, it is unclear how rapidly ExxonMobil's management will grow sales volumes. ExxonMobil is counting on additional long-term value arising from the XTO transaction through development of its expanding portfolio of International unconventional resource holdings.
- **Execute on Asia-Pacific LNG Projects**: ExxonMobil has a queue of LNG developments in Asia-Pacific, including Gorgon LNG (operated by Chevron), PNG LNG, and the potential Scarborough gas field development, all of which are poised to generate longer-term volume growth. Each of these projects comes with significant technical challenges—CO_2 capture and disposal at Gorgon LNG, remote gas field development and long distance pipeline transport in the case of PNG LNG, and the remote offshore location of the Scarborough field in the Carnarvon Basin (which may result in the field being dedicated as feedstock supply to the Pluto or Wheatstone LNG projects, rather than a greenfield LNG development). Performance will be critical to ensuring long-term regional portfolio growth.
- **Maintain leadership in share buy-back and dividend performance**: ExxonMobil has been a clear peer group leader in returns to shareholders, distributing ~$19.7 bn through dividends and share buy-backs in 2010 and spending ~$114 bn on share repurchase over the 2006-2010 period. With the increased emphasis being placed on unconventional gas resources to deliver future volume growth, shareholders will be looking for ExxonMobil to continue its leading dividend and share buy-back performance, as the core differentiator from its faster growing (in volumetric terms) peer group companies.
- **Replace volume growth from Qatar North Field commercialization**: With full ramp-up of the final four liquefaction trains at the RasGas and Qatargas LNG complexes, and continued imposition of a development moratorium for the North Field resource by the Qatar government, ExxonMobil will be challenged to deliver material global growth.
  - It is not clear how aggressively ExxonMobil will look to develop its US Onshore unconventional gas resources, given current and projected gas pricing in the North America market;
  - Monetization of captured frontier gas resources in North America (Alaska North Slope, Mackenzie Delta) continues to face delays in the form of regulatory hurdles (recently removed for the Mackenzie Valley gas pipeline project) and gas market supply-demand balances => renewed interest in Alaska LNG expansion;
  - Development of captured oil reserves in the Caspian region have experienced significant delays and cost over-runs, and are coming under increased political risk through accelerating resource nationalism;
  - ExxonMobil was successful in securing a growth position in Iraq through the West Qurna-1 redevelopment project, but positioning in Kurdistan exploration appears to have cost them a spot in Iraq's 4th Licensing Round. It is not clear that Iraq can become a Core growth area for the company.

Questions & Discussion

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Notice

PFC Energy has prepared the materials utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice, based on information available at the time such materials were created. To the extent these materials contain forecasts or forward looking statements, such statements are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen, including the actions of governments, individuals, third parties and market competitors. **ACCORDINGLY, THESE MATERIALS AND THE INFORMATION CONTAINED THEREIN ARE PROVIDED “AS IS” WITHOUT WARRANTY OF ANY KIND, EITHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO THE IMPLIED WARRANTIES OF MERCHANTABILITY, ACCURACY, OR FITNESS FOR A PARTICULAR PURPOSE.** Conclusions presented herein are intended for information purposes only and are not intended to represent recommendations on financial transactions such as the purchase or sale of shares in the companies profiled in this report.

PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

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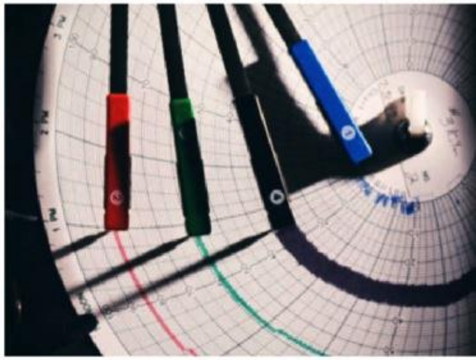

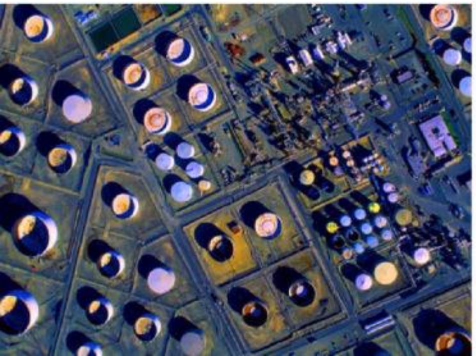

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