BHP Billiton Petroleum

A leading operator of a world class resource

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President, Petroleum
9 September 2015

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Forward-looking statements

This presentation contains forward-looking statements, which may include statements regarding, among other things: trends in commodity prices and currency exchange rates; demand for commodities; plans, strategies and objectives of management; closure or divestment of certain operations or facilities (including associated costs); anticipated production or construction commencement dates; capital costs and scheduling; operating costs and shortages of materials and skilled employees; anticipated productive lives of projects, mines and facilities; provisions and contingent liabilities; tax and regulatory developments.

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Petroleum resources

The estimates of petroleum reserves and contingent resources contained in this presentation are based on, and fairly represent, information and supporting documentation prepared under the supervision of Mr. A. G. Gadgil, who is employed by BHP Billiton. Mr. Gadgil is a member of the Society of Petroleum Engineers and has the required qualifications and experience to act as a qualified petroleum reserves and resources evaluator under the ASX Listing Rules. This presentation is issued with the prior written consent of Mr. Gadgil who agrees with the form and context in which the petroleum reserves and contingent resources are presented.

Aggregates of reserves and contingent resources estimates contained in this presentation have been calculated by arithmetic summation of field/project estimates by category. Due to portfolio effects, aggregates of proved reserves may be conservative. Reserves and contingent resources estimates have been estimated using deterministic methodology with the exception of the North West Shelf gas operation in Australia. For this project probabilistic methodology has been utilised to estimate and aggregate the proved reserves dedicated to the gas project only and represents an increment of 38 MMboe above the deterministic estimate. The barrel of oil equivalent conversion is based on 6,000 scf of natural gas equals 1 boe. The reserves and contingent resources contained in this presentation are inclusive of fuel required for operations. The respective amounts of fuel for each category are provided in footnotes proximate to each resource graphic. The custody transfer point(s)/point(s) of sale applicable for each field or project are the reference point for reserves and contingent resources. Reserves and contingent resources estimates have not been adjusted for risk. Unless noted otherwise, reserves and contingent resources are as at 30 June 2015. Where used in this presentation, the term resources represents the sum of 2P reserves and 2C contingent resources.

BHP Billiton estimates proved reserve volumes according to SEC disclosure regulations and files these in our annual 20F report with the SEC. All unproved volumes are estimated using SPE-PRMS guidelines which allow escalations to prices and costs, and as such, would be on a different basis than that prescribed by the SEC, and are therefore excluded from our SEC filings. We have provided a list of resource terms along with their definitions in this presentation. Non-proved estimates are inherently more uncertain than proved.

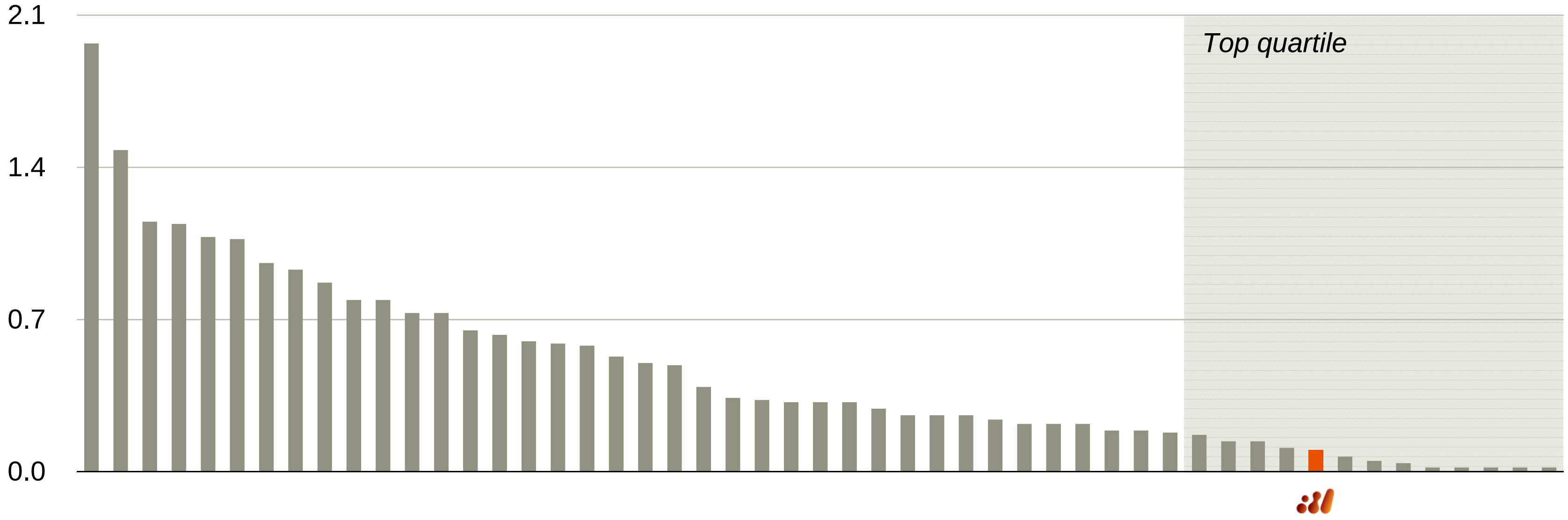
A leading operator of a world class resource

- **A focused portfolio of high-quality assets in stable geographies**
  - premier liquids position with high-return growth opportunities
  - large gas position with multi-decade resource potential
  - targeted oil exploration program with significant opportunities in our core basins
- **A relentless focus on sustainability and leading operational capability**
  - best-in-class operating costs in Conventional
  - leading drilling and completions cost efficiency in Onshore US
- **We have the flexibility to respond to market conditions while preserving value**
  - natural field decline and demand growth will support higher oil and gas prices

Operating safely and sustainably is our priority

- Top quartile safety performance versus peers
- Eliminating silica exposure in fracking operations at Onshore US
- Reduced greenhouse gas emissions by 12% in FY15

Lost-Time Injury Frequency (LTIF)
(number of recordable injuries per million hours worked, CY14)



Source: International Association of Oil and Gas Producers.

Higher-cost oil and gas supply will be required

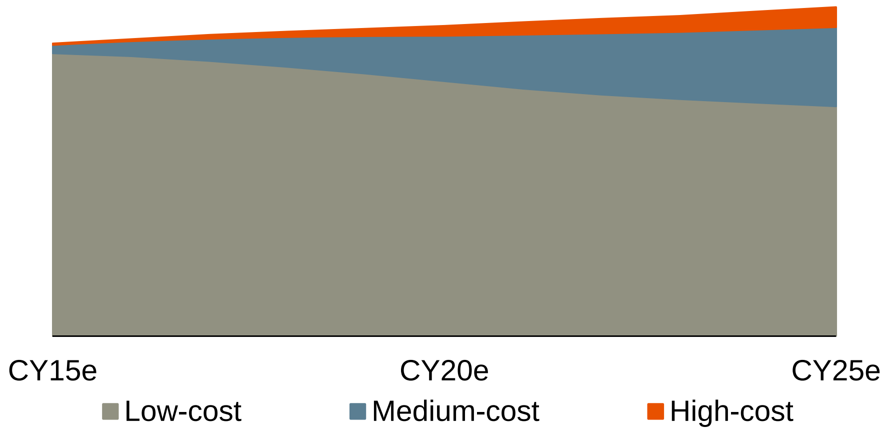
Liquids

- Development of emerging economies will continue to drive demand for crude oil
  - ~1 MMbbl/d annual demand growth
- New higher-cost liquids supply will need to be induced as low-cost fields decline
  - 3 to 4 MMbbl/d annual base decline

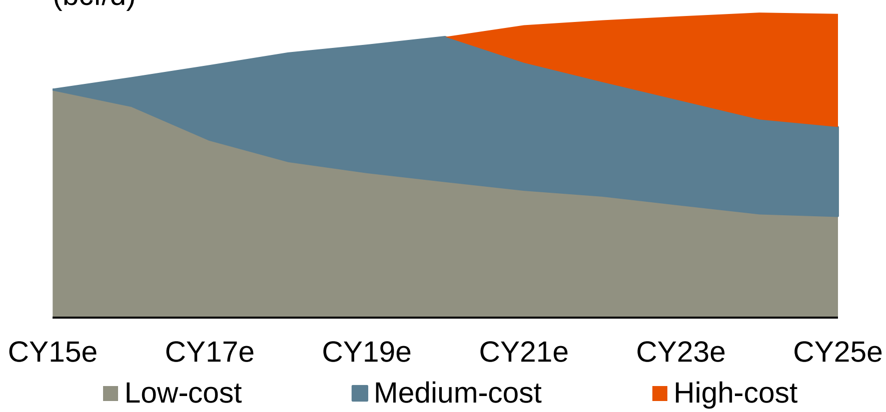
Gas

- Continued investment in new supply will be required to satisfy longer-term US gas demand
  - demand expected to grow ~20 to 25 bcf/d in the next decade
  - natural field decline of 40 bcf/d expected in the next decade

High-cost oil supply required to meet demand
(MMbbl/d)



High-cost supply will also be needed in US gas
(bcf/d)



Source: BHP Billiton analysis.

A high-quality, focused portfolio

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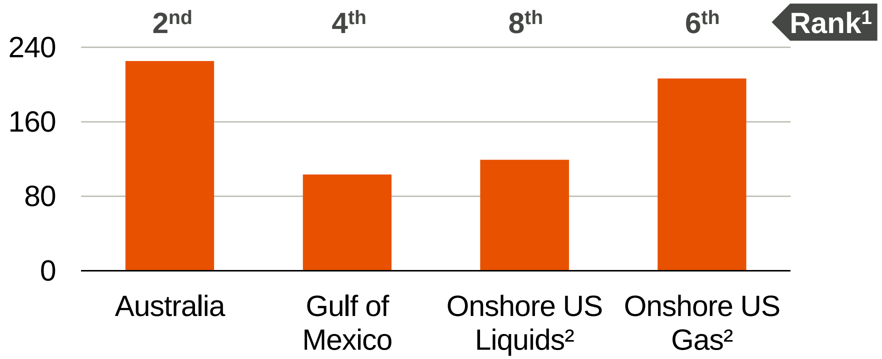
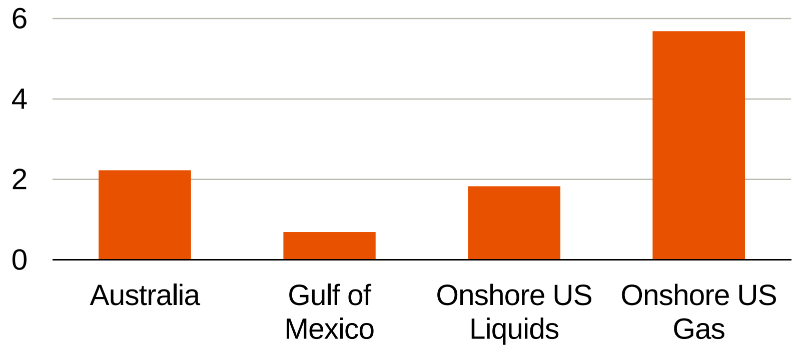
- We have a focused portfolio of high-quality assets
  - a major producer in our heartland regions in Australia and North America
- We are well positioned to realise significant value from our high-quality resource base
  - Onshore US development will be timed to benefit from an expected price recovery
- A targeted exploration program focused on Tier 1 oil potential

A major producer in our core regions
(BHP Billiton production, Mboe/d, CY14, net)



A high-quality resource base
(BHP Billiton resource[3], FY15, billion boe)



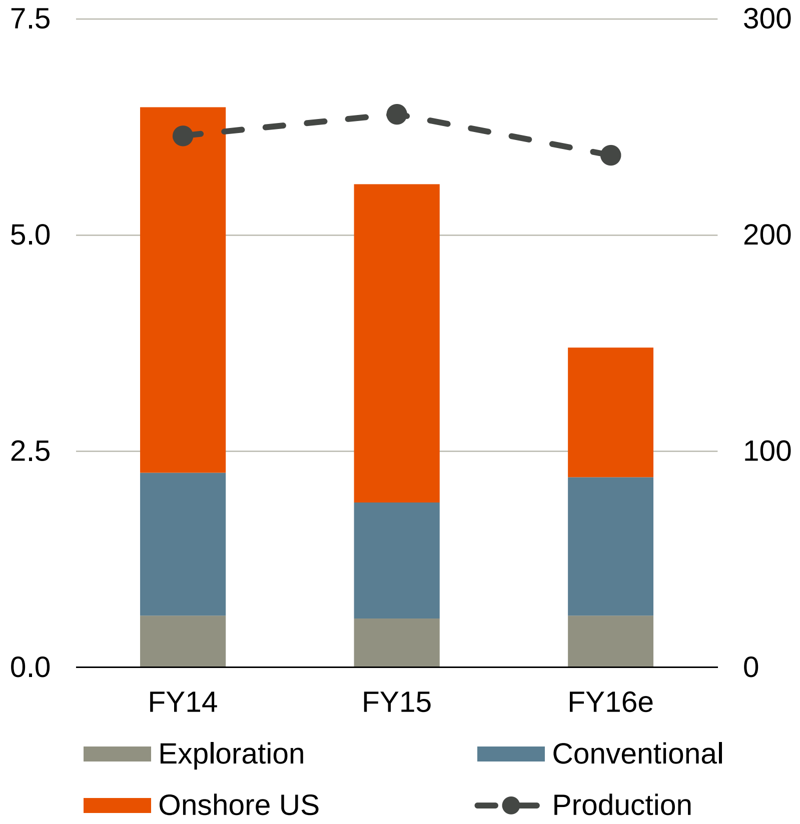
Source: BHP Billiton analysis; Wood Mackenzie.
1. Peers include Woodside, Shell, ExxonMobil, Chevron, BP, Santos, Apache, Origin, BG, Chesapeake, Southwestern, Anadarko, Devon, Encana, ConocoPhillips, EOG, Marathon, Continental, Hess, ENI, Freeport-MMR, Petrobras.
2. Includes US tight oil, US shale gas and US tight gas.
3. Australia: Proved 781 MMboe, 2P 943 MMboe, 2C 1,285 MMboe, Fuel 208 MMboe; Gulf of Mexico Proved 244 MMboe, 2P 366 MMboe, 2C 325 MMboe, Fuel 16 MMboe; Onshore US Liquids Proved 262 MMboe 2P 932 MMboe 2C 899 MMboe, Fuel 22 MMboe; Onshore US Gas Proved 535 MMboe 2P 3,189 MMboe 2C 2,497 MMboe, Fuel 141 MMboe; ROW excluded.

Actively responding to changing conditions

- We focus on value and returns
  - we are a large petroleum business within a diversified resources company where all options must compete for capital
- We have responded quickly to market conditions
  - current plans see capital and exploration expenditure reduced by 34% in FY16 with flexibility to go even lower
- Sustainable improvements in capital efficiency support flexibility in Onshore US
  - prioritising development of highest returning liquids-rich acreage
  - high-quality dry gas options deferred for longer-term value with low cost of carry
- Committed to a focused exploration program testing major opportunities through the cycle

A rapid response to a changing environment

(capital and exploration expenditure, US$ billion) (MMboe)



Leading operational capability in Conventional

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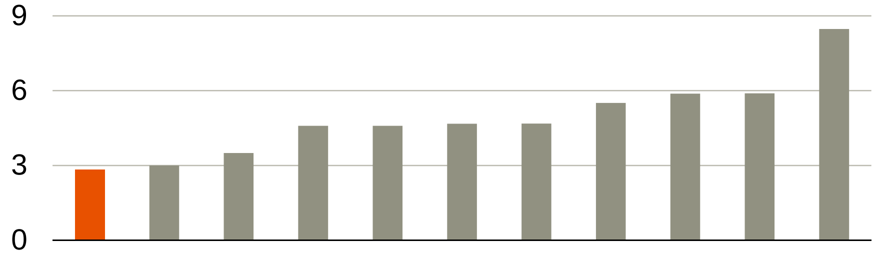
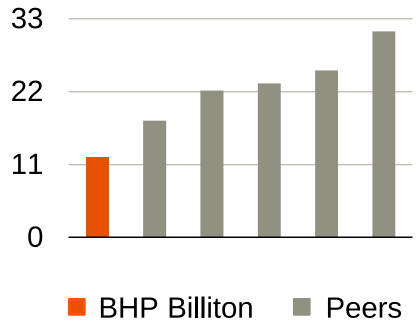
- Our operational experience and capability are a competitive advantage
  - unit cash costs of US$10.92/boe in FY15[1]
  - average operational uptime of 95% in FY15[2]
- Our Conventional assets will continue to deliver strong, stable free cash flow
  - EBITDA margin of >70% in FY15
- Expect to produce 125 MMboe in our Conventional business in FY16

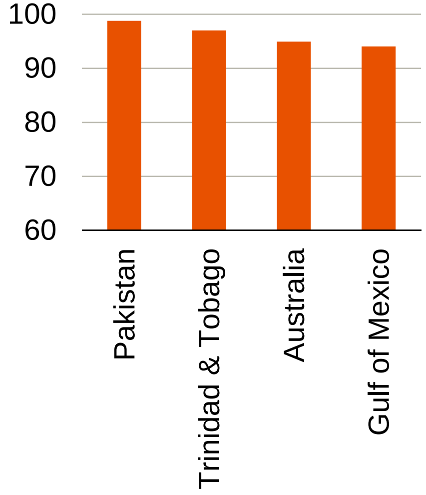
Industry leader in offshore drilling[3]
(average drill time, days per 1,000 feet)



Best-in-class unit costs[4]
(cash costs, US$ per boe)



Strong operational uptime[2]
(BHP Billiton operations, %)

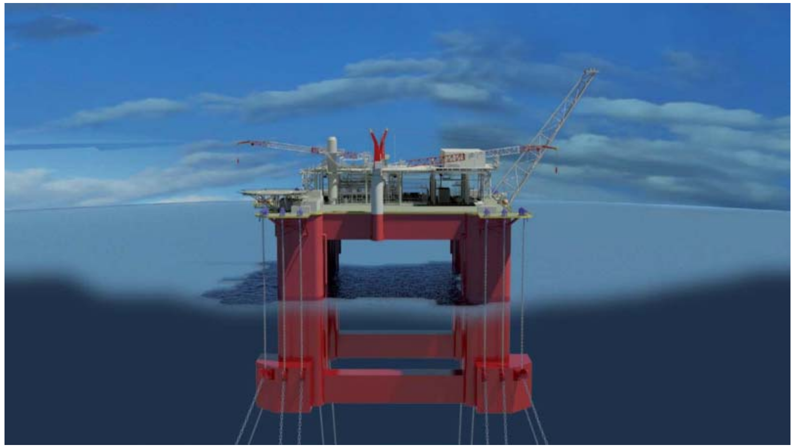


Source: BHP Billiton analysis; Rushmore; Offshore Oil Scouts Association; Wood Mackenzie; company annual reports.
1. Includes production cash cost, ad valorem, severance taxes, transportation, and excise & royalties.
2. Uptime, in terms of volumes, is the ratio of reported production to the Ideal Day Rate, expressed as a percentage. BHP Billiton Operated Assets.
3. Deepwater Gulf of Mexico, sub-salt, post-moratorium. Peers include Anadarko, Apache, BP, Chevron, ConocoPhillips, ExxonMobil, Hess, Noble, Shell and Statoil.
4. Conventional production, FY14. Peers include BP, Chevron, ConocoPhillips, ExxonMobil and Shell.

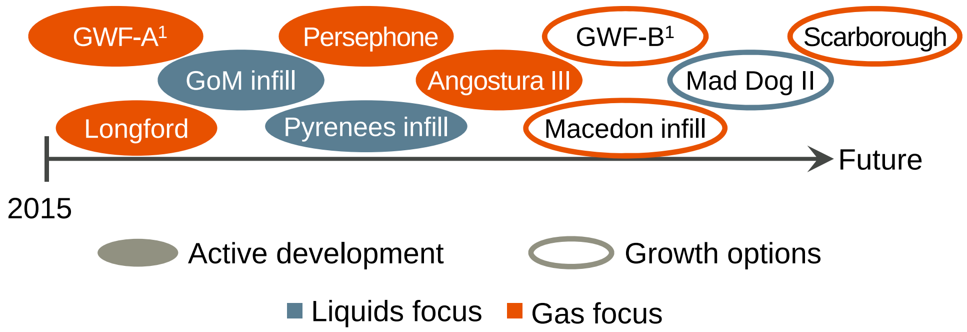
Competitive growth opportunities in Conventional

- Capital expenditure of ~US$1.6 billion expected in FY16
- Our high-quality Conventional portfolio will continue to create value
  - we are prioritising brownfield projects and infill drilling programs in our heartlands in the short term
  - Mad Dog II is a significant opportunity in the medium term
  - exploration has the potential to further broaden our opportunity set

Mad Dog II – Semi-submersible FPU concept



Pipeline of projects
(indicative project timeline)

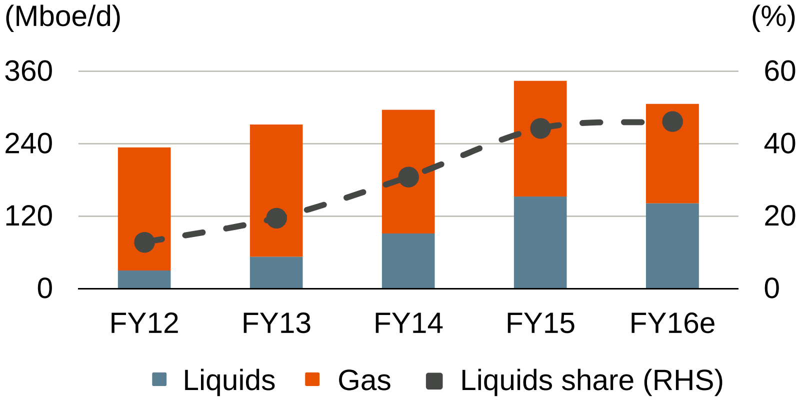


1. North West Shelf Greater Western Flank-A and Greater Western Flank-B.

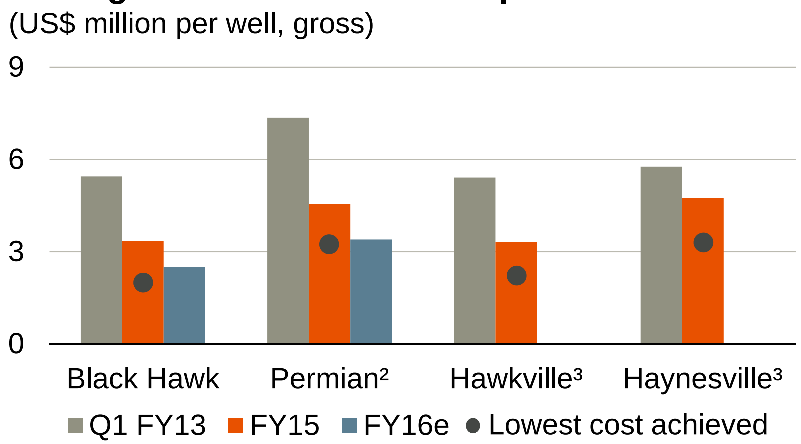
Driving continuous improvement in Onshore US

- We have prioritised high-return liquids production and deferred dry gas development for value
  - US$1.5 billion capital expenditure will support nine operated rig development program in FY16
  - activity will be further flexed if market conditions remain subdued
- Working to further improve competitiveness and cash margins
  - Black Hawk generates positive EBITDA at US$15/bbl WTI and US$3.00/mcf Henry Hub
  - drilling efficiencies of US$1.2 billion[1] achieved since Q1 FY13 with average well costs reduced by >US$2 million
- Expect to produce 112 MMboe in our Onshore US business in FY16 subject to activity levels

Significant growth in Onshore US liquids production



Drilling more wells for less capital

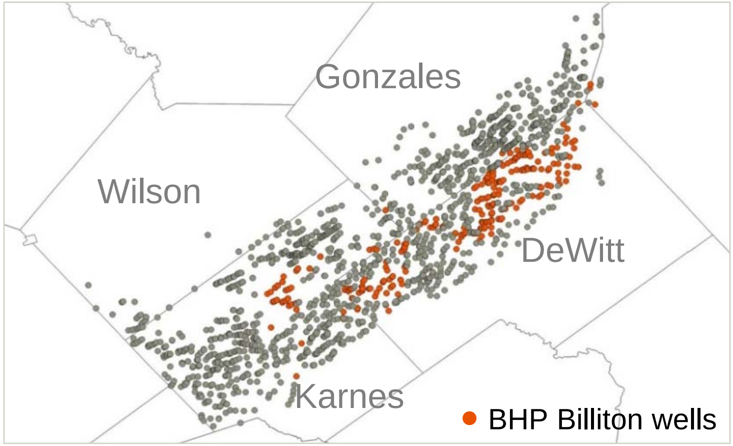


Source: BHP Billiton analysis.
1. Calculated difference between Q1 FY13 performance and realised performance on wells drilled from FY13 to FY15; net to BHP Billiton.
2. Represents Q2 FY13 due to lack of drilling data in Q1 FY13.
3. No drilling planned in FY16.

Black Hawk continues to exceed expectations

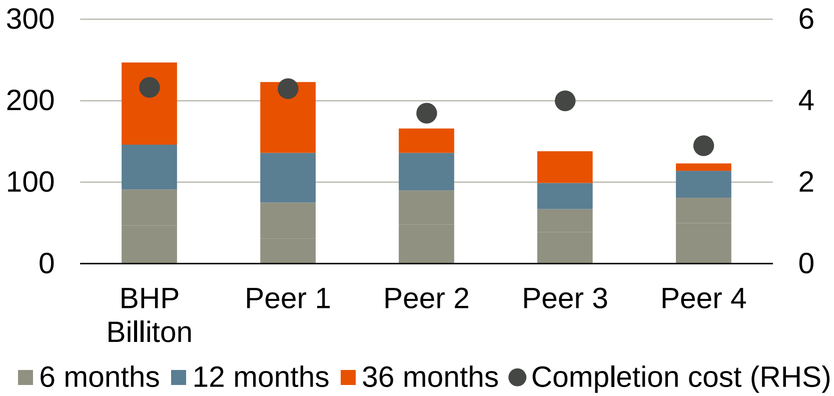
- We are the top performer in the Black Hawk
  - anticipate reducing drilling cost to US$2.5 million per well in FY16
  - >100 Mbbl ahead of peers on average three year cumulative production per well[1]
  - average returns ~35% at current prices
  - best-in-class completions cost efficiency
- Single largest producer in our Petroleum portfolio
  - average net production of >125 Mboe/d in FY15
  - ~550 additional gross[2] wells expected over life of field
  - potential to extend development program from 3 to 5 years through re-fracking

Black Hawk well locations[3]



Completions designed to optimise value[1,3]

(production, Mbbl per well, gross) (US$ million per well, gross)

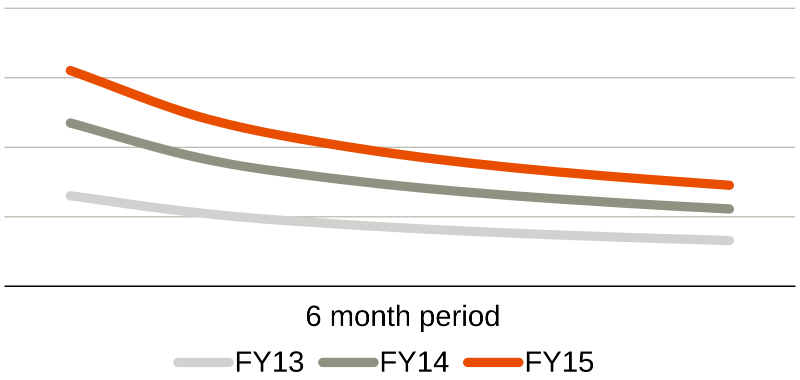


Source: IHS, Wood Mackenzie.
1. BHP Billiton includes Devon operated wells; excludes natural gas and NGLs.
2. BHP Billiton average working interest ~50%.
3. Peers include ConocoPhilips, EOG, Marathon, Pioneer.

Permian offers significant upside

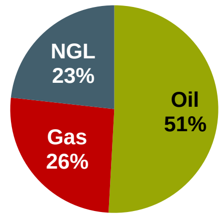
- Established position with ~78 thousand net acres in the core area
  - currently producing ~30 Mboe/d
  - two rig drilling program will maintain production and retain core acreage
- Potential to build a >150 Mboe/d business
  - ~850 additional gross wells expected over life of field
- Leveraging learnings from the Black Hawk to improve competitiveness at US$40-50/bbl WTI
  - highest-value zone identified with upside potential given multiple prospective horizons
  - drilling costs reduced by ~40% since FY13
  - increasing recovery per well over time
  - completions costs of ~US$4 million per well in Q4 FY15

Well performance is improving over time[1]
(Mboe/d, net)



Permian performance[2]	
Initial 30-day average production rate	1,550 boe/d
One year cumulative production	250 Mboe
Expected production over average well life	900 Mboe

Expected FY16 product mix

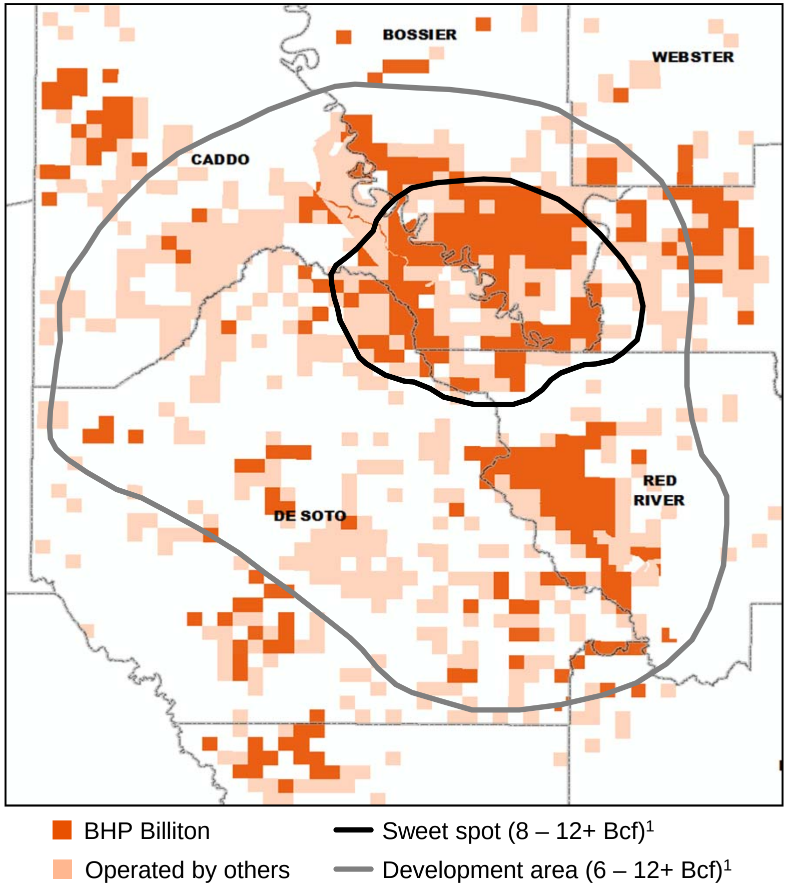


1. BHP Billiton data and analysis, Wolfcamp wells; normalised for 10% downtime.
2. Average for BHP Billiton wells in core development area put online up to 30 June 2015; gross.

Preserving the value of our dry-gas fields

- We have deferred our dry-gas development program for long-term value at low cost of carry
  - Onshore US dry-gas resource could support half a century of production at twice the current production rate
- Our Haynesville acreage is in the core of one of the industry's premier dry gas positions
  - working to achieve at least 20% returns at US$3.00/mcf Henry Hub
  - >1,800 additional gross wells expected
- The longer-term development of the Fayetteville remains an attractive option
  - extensively drilled with low geological risk
  - majority of our acreage held by production
  - >3,700 additional gross wells expected

Haynesville acreage by Recoverable Resource

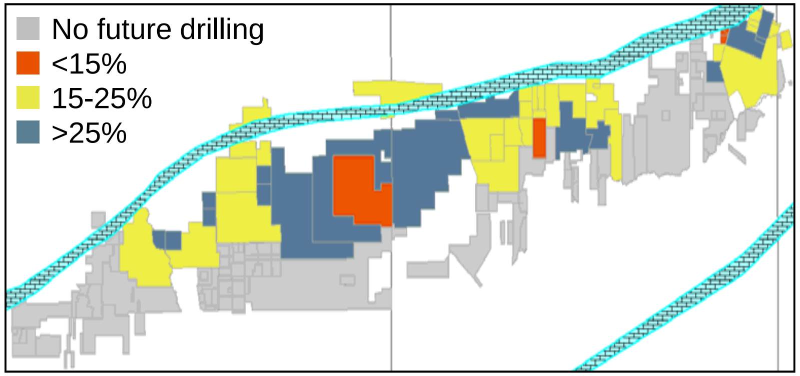


1. Typical gross resource yield per well.

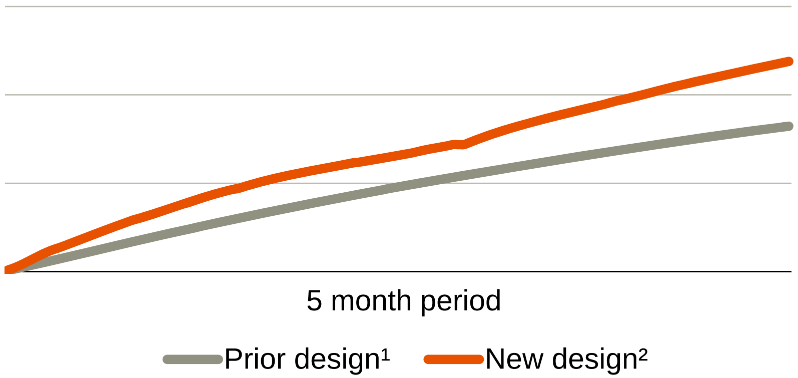
Focused on our highest-quality Hawkville acreage

- Large portions of the Hawkville remain competitive
  - within the sequence of our medium-term development plan, 40% of our acreage offers rates of return of >25%
  - ~750 additional gross wells expected over life of field
- Product mix, geological complexity and acreage retention requirements are key challenges
  - reduced development activity as a result of lower gas prices
  - optimised completions design will better suit geology and limit interference
  - focused on retention of our highest quality acreage

Competitive returns in liquids rich areas



Optimised completions to reduce interference
(Mboe/d, net, cumulative)

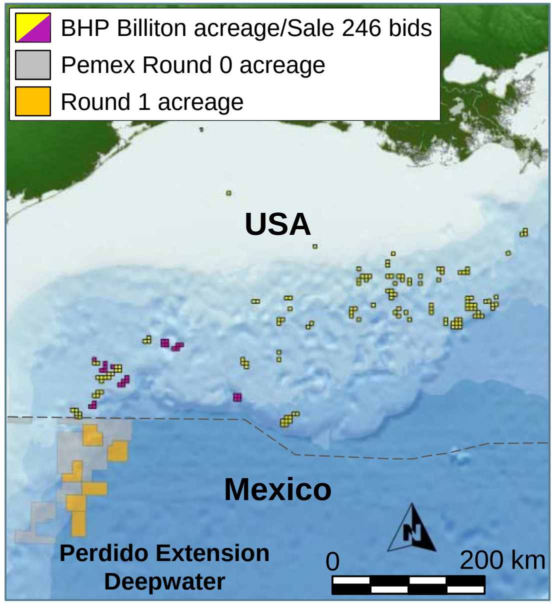


1. Prior design includes 13 wells put online March 2014.
2. Current design includes 3 wells put online March 2015.

Focused exploration program
3 basins in 3 years

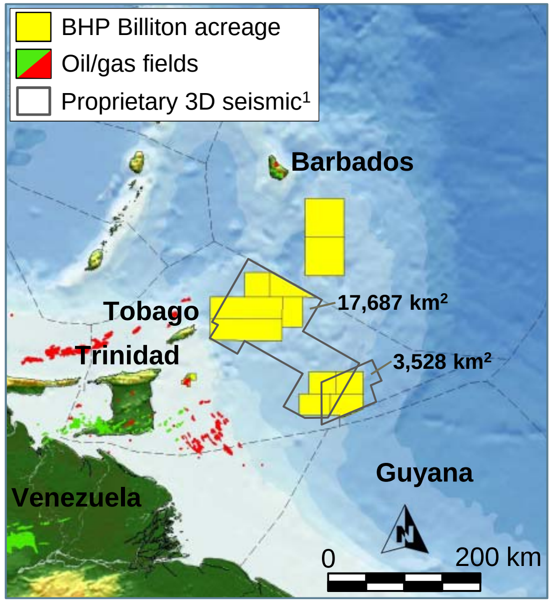
Gulf of Mexico

FY16 – Phase I | FY17 – Phase II



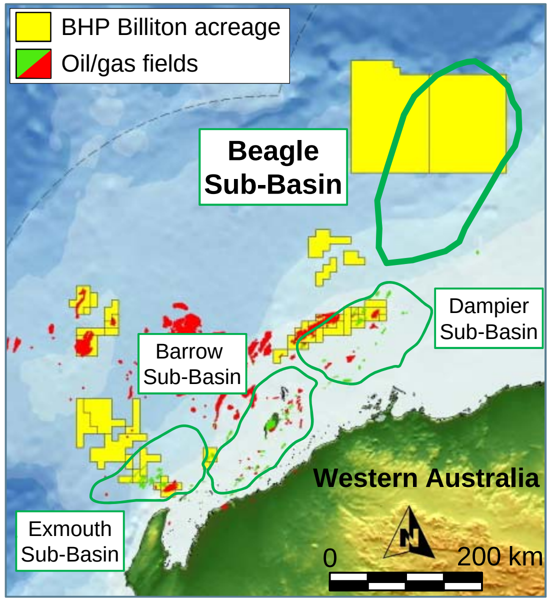
Trinidad and Tobago

FY17 – Phase I | FY18 – Phase II



Western Australia

FY18 – Phase I



1. 21,220 square kilometres 3D seismic acquisition completed over Trinidad and Tobago Blocks 3, 5, 6, 7, 14, 23a, 23b, 28 and 29.

Focused exploration program
Moving from access & evaluation to testing

Gulf of Mexico

- Leveraging our heartland expertise
- Targeting two immature Tier 1 plays (Paleogene and Cretaceous)
  - numerous Tier 1 opportunities; first well planned for FY17
- Evaluating deepwater Mexico

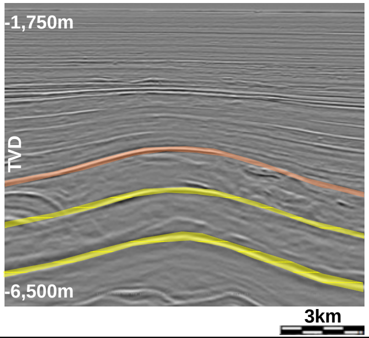
Trinidad and Tobago

- Leading ‘first-mover’ acreage position in two largely untested plays
  - proprietary 3D seismic on all blocks; on target for first well in CY16

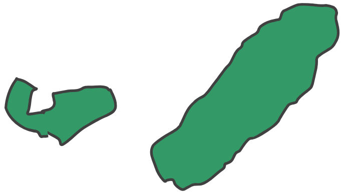
Western Australia

- Captured dominant position in largely untested liquids play in the Beagle sub-basin
  - licensing 10,032 km^2 of a multi-client 3D survey[1]; first well planned for FY18

Large structures

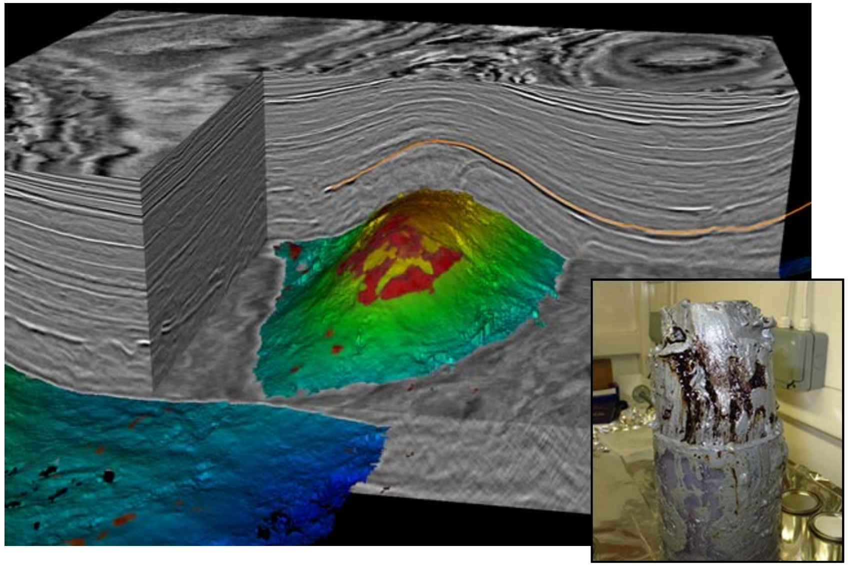


Large footprints*



*sizes to scale

3D seismic over T&T Lead I



1. AUS North West Shelf Capreolus 3D multi-client seismic survey totaling 22,130 km^2; acquisition in progress.

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  - large gas position with multi-decade resource potential
  - targeted oil exploration program with significant opportunities in our core basins

- **A relentless focus on sustainability and leading operational capability**
  - best-in-class operating costs in Conventional
  - leading drilling and completions cost efficiency in Onshore US

- **We have the flexibility to respond to market conditions while preserving value**
  - natural field decline and demand growth will support higher oil and gas prices

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Appendix

Performance	Black Hawk	Permian
Drilling cost[1]	$2.5 million	$3.4 million[3]
Completion cost[1]	$3.6 million[2]	$3.1 million[3]
Expected FY16 production mix (Oil/Gas/NGL)	62%/20%/18%	51%/26%/23%
Initial 30-day average production rate	1,659 boe/d	1,550 boe/d[4]
Median cumulative production	416 Mboe (3 year)	250 Mboe (12 month)[4]
Expected production over average well life	1,171 Mboe	900 Mboe[4]

1. Expected FY16 performance; gross average per well.
2. Normalised for 18 stage well.
3. Normalised for 5,000 ft/15 stage lateral wells.
4. BHP Billiton wells in core development area put online up to 30 June 2015; gross.