Deepwater (400 - 1,500 m) and ultra-deep (>1,500 m) are important contributors to recent oil and gas growth, accounting for 65% of new global resources over the last five years. Deepwater Africa projects now produce approximately 3 mmboepd with potential to add 5 mmboepd more from known discoveries.

However, the attraction of deepwater is challenged by:

- Decline in exploration success rates and discovered resources
- Rising costs
- Shift in focus to lower risk North American unconventionals.

The oil price crash adds another pressure. An estimated $47 billion has been removed from Deepwater Africa projects by recent oil price movements. This forces companies to reconsider deepwater investments.

So it is worth asking: **is Deepwater Africa over?**

BMO A&D reviewed key issues and opportunities for companies considering Deepwater Africa. We predict the sector is far from over.

A number of factors affect the sector today:

- **Commerciality** – analysis indicates a 200 mmboe reserve cut-off for commercial deepwater projects
- **Lead times** – typically 7 – 8 years; setting aggressive schedules can make or brake projects
- **Costs** – falling with oil prices, potential to lock in deflated costs and improve project economics
- **Fiscal drift** – a key factor historically, and emphasised by the oil price fall. Companies must change if they are to continue attracting investment.

Predicting the Deepwater Africa of tomorrow highlights this potential:

- **Up to $92 billion upside** on oil price and cost
- Projects show robust break even prices, but profitability is challenged; patience and close attention can deliver material value
- **Asset Quality varies significantly** from country to country and within countries. The reaction of host governments to increased pressure on the deepwater sector also varies
- Multiple quality, values, project types and business environment of host countries offer companies wide options for asset management.

**Deepwater Africa is far from over.** There remains significant potential for capable participants. BMO Capital Markets can rapidly apply proprietary tools, extensive industry experience and corporate access to advise clients with divestments and acquisitions in Deepwater Africa.
Deepwater Africa

Exploration Trends

REGIONAL OVERVIEW

- Africa’s long history of deepwater exploration began with PGO-1 in Guinea Bissau drilled by Texaco in 1968. The first discovery was Tano South-1 in Ghana by ConocoPhillips in 1978.
- Over 70 Bboe have been discovered in Deepwater Africa. The USGS estimates yet-to-find of 80 Bbbl oil, 187 Tcf gas, and 11 Bbbl condensates.
- Over the last decade deepwater accounted for 43% of globally discovered resources. A third of that was found in Africa.
- Although success rate of deepwater exploration improved to rival onshore and shallow water, recent rates and discovered resources are falling.
- Even including East Africa’s vast gas resources, African deepwater exploration is in a five year trend of diminished success and discovered resource, especially oil.
- The steady move into ultra-deepwater and increasing percentage of gas in discoveries add new obstacles to the challenges faced by deepwater programs.

DEEPWATER EXPLORATION WELL SUCCESS RATES

GLOBAL DISCOVERIES BY WATER DEPTH

DEEPWATER AFRICA IN NUMBERS

42 Bboe
- Discovered in last decade in Deepwater Africa

$247 bn
- Value created from last 20 years of Deepwater Africa

$1.79 bn
- Transaction value of PTTEP - Cove Energy acquisition

Source: Wood Mackenzie

1. Includes reserves and resources
2. Based on discoveries since 1995, including past and forecast value

Source: Wood Mackenzie

Onshore Shelf Deepwater Ultra-deepwater Well Count

Source: Wood Mackenzie
Deepwater Africa  Challenge from Costs

PRE-CRASH COSTS

- Deepwater is among the most expensive E&P sectors due to technological and environmental challenges, and increasing demand for services.
- In Africa the average capex of deepwater projects is $3.7 billion or $17/boe but total costs can exceed $40 billion (e.g. Bonga Field, Nigeria).
- Costs are increasing across Africa. Although more than 35 projects are now onstream, economies of scale are not yet realised. For example, in Angola unit cost since 2000 rose from $10 to $24/boe.
- By contrast, costs in Brazil deepwater remained relatively stable averaging between $10 and $20/boe. A potential reason is the smaller geographic spread of assets in Brazil (i.e. 950 km stretch of coastline) compared to Africa (~5,500 km stretch of coastline from Angola to Mauritania).
- Exploration remains expensive. The 2014 pre-salt well, Kamoxi-1 in Block 36 Angola cost a reported $340 million. Kamoxi-1 is not an isolated case.

COST DEFLATION

- The recent oil price crash follows 5 years of relatively stable prices.
- Operators now face decreasing revenues, financial instability, and declining returns but the price collapse has a silver lining: cost deflation.
- Discretionary spending is slashed; reduced demand is driving down rig rates (e.g. Seadrill reports a 33% drop in floater rates over the last year).
- Explorers will exploit declining costs and lock in low-price contracts. Finding costs should improve but reduced drilling yields fewer discoveries.
- Developments with intensive drilling can sign better long-term contracts; newly sanctioned projects should benefit from lower costs for construction, materials, and possibly labour, if crude oil prices remain low.
- These trends suggest the economics of deepwater projects may improve too from a brief period of lower crude oil prices.
A VOLATILE WORLD

- Commodity prices drive oil and gas developments. Large deepwater resources with good subsurface quality like Kudu in Namibia remain undeveloped for years if prices do not balance development risks.
- Brent oil price has fallen from >$100/bbl to ~$53/bbl at the time of writing.
- The crash has many sources – growing North American production, languishing global demand and a fight for market share by producers. The impacts on deepwater in Africa are equally varied and dramatic:
  - **Value** – Comparing price forecasts\(^1\) from late 2014 (WM Q4 2014) to now, (WM Q2 Base), African deepwater fields have reduced in value by some $50 billion NPV\(_{10}\)
  - **Costs** – Operators’ spending cuts and project deferrals have reduced demand for services. This gradually creates a lower cost environment benefiting explorers and operators. Before then, developments face delays or permanent scraping
  - **The Train Wreck** – Delays are bad but the “perfect storm” hit projects with lengthy, deep investment at high costs and first production when oil prices bottom out, for example Akpo (Nigeria) in 2010, Kizomba satellites (Angola) and maybe TEN (Ghana) if low prices persist.
- With Brent hovering between $45-55/bbl price uncertainty forces companies to re-value their portfolios, implement cost cutting, and assess the new match between assets and long-term strategy.
- Portfolio reviews under various price scenarios are required across the industry. These will lead to project deferrals, asset realignment and corporate M&A.
- As an “Imposed” factor in asset quality, commodity prices are uncontrollable. Many companies can do little more than react to fluctuations.
- However, assets with sufficient optionality make it easier to ride out periodic downturns. They increase portfolio resilience. This review identifies such deepwater projects.

### SOURCE

2. See other BMO Capital Markets publications on Asset Quality
Deepwater Africa  Challenge from North American Unconventionals

OVERVIEW

- US oil production compounded annual growth rate (CAGR) since 2010 is over 10%. This was driven largely from unconventional tight oil.
- Unconventionals, with long horizontals and multi-stage hydraulic fracturing, began as high cost, capital intensive projects for moderate initial rates that decline rapidly and then decline gradually over a long time.
- Analysts suggested the high break-even cost and declining oil prices would curtail unconventionals and eliminate many niche companies.
- However, oil price decline continues to drive operating efficiency. Improved margins add pressure to traditionally high cost sectors like heavy oil and deepwater.
- Although large areas of many plays are uneconomic below $70/bbl, improving efficiency and falling costs lowered breakeven prices. Unconventionals now seem more robust than initially portrayed.
- BMO Capital Markets expects these pressures to persist, even if oil prices rebound. Deepwater Africa needs similar improvements to remain competitive.

US UNCONVENTIONAL INCREASES IN PRODUCTION & EFFICIENCY

First Mover - Conoco Phillips Reduces Deepwater

Source: EIA, Company filings (Hess, EOG Resources, ConocoPhillips)
Deepwater Africa Today  Summary

- Deepwater Africa is a global success story with significant potential remaining, however:
  - The sector now faces major headwinds including oil price, costs and capital migration
  - Challenges are compounded by geopolitics, fiscal and regulatory regimes and other risks.
- Deepwater Africa has almost 200 assets with a wide range of risks and rewards.
- BMO Asset Quality incorporates all of these factors to compare assets with reduced bias.
- This Drill Bits outlines where and if Deepwater Africa potential can be realised:
  - at the country scale
  - at the asset scale
  - for prospective companies in the region.
- This section considers the sector's key Inherent, Execution and Imposed risks.
Deepwater Africa Today

Inherent Asset Quality: Risks to Realising Potential

REGIONAL OVERVIEW

- Over 70 Bboe has been discovered in Deepwater Africa.
- Petroleum Systems across Africa generated and captured vast amounts of petroleum which have been successfully targeted by E&P companies.
- The majority of discoveries were found in Miocene reservoirs of Angola and Nigeria. More recent exploration has targeted Cretaceous turbidites (e.g. Jubilee, FAN) and Oligocene reservoirs in East Africa.
- While prolific, the deepwater oil and gas fields face many Inherent risks that affect asset quality and can make or break developments, for example:

**Size**

Bigger fields tend to grow, small fields tend to shrink. Size is a key inherent quality, especially in deepwater where costs and location require scale to be commercial.

**Deliverability**

Accurately predicting reservoir deliverability can make the difference between underperforming fields like Chinguetti (Mauritania) and Azurite (Congo) and strong performers like Zafiro (Equatorial Guinea) and PSVM (Angola).

**Phase**

Many prospects were prognosed as oil but discovered with high gas content, raising development and commercial challenges, especially for deepwater.

**Delineation**

Proper understanding of the extent and connectivity of the reservoir before FID is vital. There are numerous examples of surprises (e.g. Chinguetti, Mauritania).

Deepwater Africa Today

Execution Asset Quality: Development Hurdles

CHALLENGING DEVELOPMENTS

- **Execution** issues are critical to asset quality – poor execution destroys value even in large accumulations. A third of discovered deepwater resources in Africa remain undeveloped. Reasons include: poor terms, markets, commodity prices, small resources and misaligned partnerships.

- On average, lead time between discovery and production is falling but outside the deepwater heartlands (Angola, Egypt, Nigeria) insufficient infrastructure is a continuing obstacle.

- Economic cut-off varies by fiscal regime but 200 mmboe is a demonstrable threshold. That threshold is higher for gas.

- Continued deepwater activity in Africa requires economy of scale. More developments should reduce costs and facilitate sanction of smaller accumulations.

- A new hurdle comes from a shift to value from volume by super-majors. When crude prices were stable from 2008-2014, return on capital employed declined as costs rose. New shareholder pressure focuses operators on capital efficiency and improved unit costs.

- Part of the reason is **discovery of large volumes no longer assures high return**. Exploration moved into deeper waters and more remote frontiers, straining development capability and returns.

- Examples are in East Africa (Mamba Complex) and Falkland Islands (Sea Lion). Such discoveries present greater challenges to achieve production, despite large discovered resources.

- Oil price decline exacerbates those problems and lengthens time between initial discovery and first production.

- Low oil prices curtail exploration and resource growth. Basin maturation and infrastructure growth may slow. Full-cycle economics will decline as higher-return incremental production is delayed. The longer prices are low, the greater the impact on deepwater.

HURDLES TO COMMERCIALITY

- Reservoir deliverability
  - e.g. Odum, Ghana

- Licence dispute/access issues
  - e.g. Kuyere, Nigeria

- Infrastructure constraints
  - e.g. Saphir, Cote d’Ivoire

- Partner constraints
  - e.g. Lira, Angola

- Sub-economic volumes
  - <200 mmboe
  - e.g. Bobo, Nigeria, Azul, Angola

- Market/price constraint
  - e.g. Cormoran, Mauritania, Doro, Nigeria

- Resources (mmboe)
  - 4,102
  - 3,310
  - 532
  - 635
  - 415
  - 201

- Licensed mmboe
  - 4,102

ECONOMIC VOLUMES

- ~200 mmboe economic cut-off

- Count of Fields
  - 0 - 10
  - 10 - 100
  - 100 - 200
  - 200 - 500
  - 500 - 1,000
  - 1,000 - 5,000
  - 5,000 - 10,000

Large volume resource examples
- Area 1, Mozambique
- Lontra, Angola
- Bolia-Chota, Nigeria

Source: Wood Mackenzie

Source: Wood Mackenzie
DEVELOPMENTS OVERTIME

- Required time, cost, staff, local content and regulation to develop in deepwater create budget and schedule overruns, e.g., PSVM, Angola.
- Operators improved workflow, incorporated uncertainty and risk management, better integrated subsurface characterisation, and broadened depletion options analysis prior to FID, e.g., Pazflor field, Angola.
- Average lead time (discovery to production) in Deepwater Africa is 7 - 8 years. Reducing lead time further requires ever-earlier planning as developments become more complex due to remoteness, deeper water and drilling depth, more complex fluids, and regulations against gas flaring.
- Challenges are increased by aggressive schedules. Studies of poor performing E&P mega projects\(^1\) show the average schedule slipped 30% versus successful projects, but actual required execution time was only a few percent different (see below). The cause - overly aggressive schedules.
- Balance is required to avoid early value erosion or project failure.

E&P MEGA PROJECT SUCCESSES & FAILURES\(^1\)

**Source:** Independent Project Analysis, Inc.

1. Criteria for successful projects defined in Merrow (2011) – generally the NPV of the project was much lower (generally less than half) than it would have been if the project had delivered on its FID promises.
Deepwater Africa Today  Execution Asset Quality: Operating Environments

OVERVIEW

- West Africa, the U.S. Gulf of Mexico (GoM) and Brazil form the deepwater “Golden Triangle”.
- The GoM is mature, 50% of discoveries are onstream and 15% are depleted.
- Technology and subsurface understanding allowed GoM operators to pursue ever deeper water and targets. Sustained growth is illustrated by Chevron’s 2014 Anchor discovery of 280 mmboe at 34,000 ft in 5,280 ft of water.
- Brazil is immature with the lowest field count, highest estimated average resource and remaining value per discovery, e.g., Libra and Lula fields.
- West Africa is mid-mature with older fields like Kuito and large undeveloped discoveries like Cameia and the East African gas discoveries.
- Lead times to development fell uniformly as technology improved, infrastructure was exploited, and lessons were reapplied.
- Among the most notable fast-tracked discoveries was Jubilee, developed in only three years following discovery. However, subsequent production problems cast doubt on the fast-tracked development.
- New developments may further reduce lead time where partners can rapidly select development concepts. Equally important are partner-government alignment, financial strength, and ability to move safely with cost controls.
- Increased shareholder focus on value, means lead times must continue to fall without loss of production efficiency.

<table>
<thead>
<tr>
<th>Year of Discovery</th>
<th>Average Years Discovery to Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>1995</td>
<td>10</td>
</tr>
<tr>
<td>2000</td>
<td>8</td>
</tr>
<tr>
<td>2005</td>
<td>6</td>
</tr>
<tr>
<td>2010</td>
<td>4</td>
</tr>
<tr>
<td>2015</td>
<td>2</td>
</tr>
</tbody>
</table>

Source: Wood Mackenzie

Deepwater Africa Today  Execution Asset Quality: Costs

OVERVIEW

- Signs of cost deflation are appearing already (as seen opposite).
- Rapid decrease in demand for rigs, seismic vessels and other services have resulted in significantly lower contract prices.
- Most companies are still readjusting to lower oil prices and service companies are desperate for work.
- Operators can lock-in considerably reduced multi-year contracts before their rates stabilize and operators start to renegotiate contracts in earnest.
- Ongoing or forthcoming projects benefit due to high, near-term capex including drilling, subsea work and consumables.
- Deepwater Africa projects like Lucapa and Block 32 Kaombo in Angola, and West Nile Delta Project in Egypt could realise billions of dollars in savings.
- Deepwater costs must come down to attract investment and offset the migration of capital to North American unconventionals.

EXAMPLE PROJECTS WITH COST DEFLATION BENEFIT POTENTIAL

<table>
<thead>
<tr>
<th>Project</th>
<th>NPV10 (US$ bn)</th>
<th>20 wells, FPSO, subsea tie backs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lucapa (Angola)</td>
<td>$2</td>
<td></td>
</tr>
<tr>
<td>Aje (Nigeria)</td>
<td>$4</td>
<td></td>
</tr>
<tr>
<td>West Nile Delta Project (Egypt)</td>
<td>$6</td>
<td></td>
</tr>
<tr>
<td>Block 32 Kaombo (Angola)</td>
<td>$8</td>
<td></td>
</tr>
</tbody>
</table>

DEEPWATER STILL ALIVE

- “Already achieving savings of up to 30%” - [Total Investor Day, 23-Sep-15]
- “ Cameia….have identified over $2 billion of estimated cost savings… estimated development costs <$20/bbl” - [Cobalt Investor Presentation, August-15]
- “Bonga SW: >$500 million drilling cost reduction” - [Shell Q2 ’15 results presentation, 30-Jul-15]
- “Selection of FLNG has drastically reduced gross development capex to first gas from c.$3 billion for conventional LNG plant to $800 million for FLNG…and accelerated first gas by 2-3 years” - [Nick Cooper, Ophir Energy CEO, 9-Jul-15]
- “There are more sophisticated projects where the different approach, standardisation, different way of working and innovative engineering can generate more than 30% savings” - [Jean Cahuzac, Subsea 7 CEO, 29-Jul-15]
- “SNE field….10% return breakeven oil price: <$40/bbl, assuming sustained industry costs 20% below 2014 levels” - [Cairn Energy Preliminary 2014 Results Presentation, 10-Mar-15]

Source: Wood Mackenzie, Company filings
Deepwater Africa Today

Imposed Asset Quality: Fiscal Regimes

FISCAL DRIFT

- Fiscal terms balance government take against investment incentives. When reviewing terms to assess asset quality BMO considers:
  - Stability to plan long term investments
  - Flexibility for governments to manage maturing projects, varying cost and prices
  - Strength of profit like government carry and profit share.
- License rounds and early awards in new deepwater areas encourage investment with attractive terms. Terms often tighten as companies flock to early success and governments seek a greater share.
- This can be ineffective as large resources are often found early and benefit from better terms. Tougher terms accompany smaller, later discoveries so less value flows to the host country. Late entrants are penalised, investment is discouraged, impeding E&P maturation and associated synergies.
- For example the UK steadily increased taxes in a mature theatre. Operators sought better investments elsewhere. Eventually the UK reduced taxes but instability discouraged investment and did not help grow government revenues.
- Success in Deepwater Africa and high oil prices led governments to steadily tighten terms that originally were attractive to balance perceived risk (see figure opposite). Now average government take for Deepwater Africa is 68% and can exceed 90%. Fiscal uncertainty affects several theatres, such as Nigeria.
- For deepwater, with intensive up-front investment, typical fiscal terms developed for shallow water and onshore are inefficient for investors and governments.
- Corporate and asset buyers and sellers now face tax on transfer of interest. Notable examples come from Gabon, Kenya, Tanzania and Uganda. Disputes even arise in countries that lack capital gains legislation and discoveries.
- The oil price fall reduces both government revenues and investment by contractors. Governments must adjust to continue attracting deepwater investment. For example Egypt already is relaxing terms, offering more upside to prospective buyers of deepwater assets. Others like Nigeria are considering tougher terms.

GLOBAL FISCAL DRIFT

FISCAL TERMS OF KEY COUNTRIES

<table>
<thead>
<tr>
<th>COUNTRY</th>
<th>AVG. GOVT. TAKE</th>
<th>COMMENTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Angola (PSC)</td>
<td>79%</td>
<td>- PSC terms biddable therefore wide range of terms across the country - Early PSCs have uplift of costs by at least 40%, $3 billion costs can recover $4.2 billion - Historically high signature bonuses (up to $1.4 billion)</td>
</tr>
<tr>
<td>Egypt (PSC)</td>
<td>6%</td>
<td>- Gas pricing linked to Brent since 2001 and adjusted in successive licensing rounds - West Nile Delta project (BP / DEA) awarded improved terms in 2010; floor of $3.09/mcf at $75/bbl and ceiling of $4.22/mcf at $100/bbl - Includes mechanism to increase gas price in line with rising project cost</td>
</tr>
<tr>
<td>Nigeria (PSC)</td>
<td>61%</td>
<td>- No royalty at &gt;1000 m water depth - 1993 PSCs have no limit on cost oil and costs ring fenced at PSC level - 2010 local content law - 70% of project sourced locally, increasing costs</td>
</tr>
<tr>
<td>Ghana (Concession)</td>
<td>59%</td>
<td>- 10-15% NOC participation, since 2014 additional 20% for commercial oil discovery - Additional Oil Entitlement (AOE) in effect if IRR above 19% (pre-2014), AOE if IRR above 12% (post-2014)</td>
</tr>
<tr>
<td>Mozambique (PSC)</td>
<td>57%</td>
<td>- Profit share based on R-factor, 40-85% contractor share, 32% CGT - Cost oil limit at 65%, development costs recovered over four years - Income tax is 24% for Area 1 for first 8 years after first gas</td>
</tr>
<tr>
<td>Tanzania (PSC)</td>
<td>67%</td>
<td>- Petroleum Act passed in July 2015, designed to encourage exploration - Offers higher profit shares to contractors; but only oil projects will benefit - Government share still relatively high, 70% onshore/shelf, 70%-85% for DW - The Act stated all gas processing facilities must be onshore, limiting future FLNG</td>
</tr>
</tbody>
</table>

1. Includes royalties, income tax, profit oil, and bonuses
2. Average government takes between 1985 and 1990 compared with average between 2008 and 2012 (as % of oil and gas revenues)
3. In the last decade some changes to US fiscal policies for the energy sector have given generous tax relief to oil and gas companies (e.g. American Job Creation Act/2004 and 2055 Energy Bill)
Deepwater Africa Tomorrow

Summary

OVERVIEW

- Previously we showed key challenges facing Deepwater Africa, e.g.:
  - Declining exploration success
  - High finding and development costs
  - Falling oil prices and capital migration to North America
  - Increasing lead times and over aggressive project schedules
  - Remoteness and little existing infrastructure
  - Tough terms and fiscal drift.
- Despite headwinds, considerable potential remains for motivated operators with a long-term interest to grow.
- This section addresses a number of factors like those below for prospective new entrants and entrenched companies looking for growth.

DEEPWATER STILL ALIVE

- “The growth priorities, deep-water and integrated gas…”
  - [Ben Van Beurden, Shell CEO, 5-Sep-14]

- “Cairn is pleased to announce a discovery of high quality oil in the second well in the Senegal exploration programme…”
  - [Cairn Energy, 10-Nov-14]

- “The magnitude of deepwater reserves and production potential is simply too large for the industry to ignore…”
  - [Paal Kibsgaard, Schlumberger, 23-Mar-15]

- “We’re [BHP Billiton] not going to rely on the US Shale. We’re going to have to expand back into the conventional business…where we could do it faster, we could do it cheaper…”
  - [Tim Cutt, BHP Billiton, 18-May-15]

- “ENI has made a world class supergiant gas discovery at its Zohr Prospect, in the deep waters of Egypt…will be able to transform the energy sector of Egypt…”
  - [ENI, 30-Aug-15]

Source: Company filings
Deepwater Africa Tomorrow

Oil Price Upside

OVERVIEW

- Oil price decline reduced value by almost $50 billion across Deepwater Africa.
- This creates a significant buying opportunity for new entrants and existing operators who wish to grow.
- BMO analysed oil price effects on asset value for 90 deepwater assets:

Cumulative drop in value of $11 billion for 20% decline in long term oil price assumption

Average asset oil price upside\(^{(1)}\) of $1 billion

Highest sensitivity to price: Lucapa (Angola)

Material upside with limited downside; top 3 assets

- Jubilee (Ghana)
- Block R (Equatorial Guinea)
- Haute Mer Zone D (Congo)

Potential Upside

For acquisition cost of $0-200 million there are sixteen assets in six countries with $18-1,400 million upside from oil price rebound. These projects include both producing and pre-FID assets.

Source: Wood Mackenzie

1. Upside based on increase of oil price forecast by $20/bbl

OIL PRICE SENSITIVITY OF KEY ASSETS

<table>
<thead>
<tr>
<th>Asset</th>
<th>Percentage Change in NPV with oil price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lucapa (Angola)</td>
<td>(360.5%) 353.9%</td>
</tr>
<tr>
<td>Cassiopee (Congo)</td>
<td>(104.6%) 87.9%</td>
</tr>
<tr>
<td>Block 21 (Angola)</td>
<td>(68.2%) 65.6%</td>
</tr>
<tr>
<td>SNE (Senegal)</td>
<td>(47.6%) 40.7%</td>
</tr>
<tr>
<td>TEN (Ghana)</td>
<td>(41.5%) 39.7%</td>
</tr>
<tr>
<td>Uge (Nigeria)</td>
<td>$20/bbl decrease in oil price(^{(2)})</td>
</tr>
</tbody>
</table>

OIL PRICE ASSUMPTIONS\(^{(2)}\)

<table>
<thead>
<tr>
<th>Year</th>
<th>Low</th>
<th>Base</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>20</td>
<td>40</td>
<td>120</td>
</tr>
<tr>
<td>2016</td>
<td>40</td>
<td>60</td>
<td>120</td>
</tr>
<tr>
<td>2017</td>
<td>60</td>
<td>80</td>
<td>120</td>
</tr>
<tr>
<td>2018</td>
<td>80</td>
<td>100</td>
<td>120</td>
</tr>
<tr>
<td>2019</td>
<td>100</td>
<td>120</td>
<td>120</td>
</tr>
</tbody>
</table>
OVERVIEW

- Oil price movements change project thresholds.
- High cost sectors like oil-sands, unconventionals and ultra-deepwater are early casualties of an oil price downturn.
- Preliminary analysis suggests Deepwater Africa is robust with over 1.7 mmboepd of current production profitable below $40/bbl and 0.94 mmboepd of future developments profitable below $60/bbl.
- $120 billion remaining value (NPV$_{10}$) is in current production profitable below $45/bbl.
- The best acquisition targets are robust to low oil price and strategically misaligned for owners; all high quality assets (in green below) are profitable below $45/bbl (chart below).
- This breakeven analysis is a strong indication that deepwater is not over.

BREAKEVEN$^{(1)}$, VALUE$^{(2)}$ & ASSET QUALITY

Source: Wood Mackenzie
1. Break even where remaining present value of asset equals zero at 10% discount rate, valued in 2015
3. Cumulative production based on 2015 average production for producing assets and peak production for non-producing assets
### OVERVIEW

- Over 100 companies are active in Deepwater Africa and fall into five categories.
- Each group and company offer different partnership qualities which BMO incorporates into the Asset Quality comparison tool.
- Large potential remains for asset acquisitions, divestures and corporate transactions in the sector.

<table>
<thead>
<tr>
<th>GROUP</th>
<th>KEY COMPANIES</th>
<th>MAIN POINTS</th>
<th>OUTLOOK</th>
<th>AQ DISTRIBUTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Majors</td>
<td>ExxonMobil, eni, TOTAL, bp, ConocoPhillips, BG GROUP</td>
<td>Dominate deepwater due to high costs (capex, signature bonuses) and patient time frame</td>
<td>Oil price fall to accelerate shareholder driven (&quot;value over volume&quot;) portfolio rationalisation</td>
<td>Excellent: 33, Good: 88, Mod: 56, Low: 10</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Large positions in Angola, Nigeria and Egypt</td>
<td>Look for further asset or country position divestments (e.g. Conoco Nigeria in 2014)</td>
<td>Potential divestment targets?</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Accessible high quality assets</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>NOCs burdened with poor assets</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Predominantly poor quality with notable exceptions</td>
</tr>
<tr>
<td>Independents</td>
<td>Anadarko, MarathonOil, Noble, Kosmos, Ophir, Hess, DEA</td>
<td>Mostly exploration focussed single-asset companies not yet able to divest (e.g. Tullow, Kosmos, Ophir)</td>
<td>Small players continue to look for farm outs for value realisation; Cobalt successfully achieved $1.75B sale of Blocks 20 &amp; 21 to Sonangol in difficult low oil price environment</td>
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<tr>
<td></td>
<td></td>
<td>Large independents focussed on high quality assets (e.g. Noble, Marathon, Hess)</td>
<td>Larger independents may offload West Africa outposts (e.g. Marathon/Noble)</td>
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</tr>
<tr>
<td>NOCs</td>
<td>Sonangol, CNPC, CNPC, Statoil, Petrobras, EOG</td>
<td>National Oil Companies (NOC) hold the largest share of reserves and production after the Majors (e.g. Sonangol, ENH)</td>
<td>Reduced appetite by foreign NOCs who are managing acquisitions made under premises of high commodity price</td>
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<td></td>
<td></td>
<td>Foreign NOC have made considerable strategic investments (e.g. PTTEP in East Africa, Statoil in Angola)</td>
<td>Sonangol was the buyer in 9 of last 11 deepwater Angola; most domestic NOCs budgets will now be constrained</td>
<td></td>
</tr>
<tr>
<td>Indigenous</td>
<td>Dangote, Oando, Jacka, FAMPA</td>
<td>Predominantly in Nigeria, locals are increasing entering deepwater assets to complement onshore positions (e.g. Oando’s acquisition of ConocoPhillips Nigerian portfolio in 2014)</td>
<td>Well placed to acquire any further deepwater divestments &amp; leverage local contacts</td>
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<td></td>
<td></td>
<td></td>
<td>Will indigenous companies spread outside of Nigeria?</td>
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</tr>
<tr>
<td>Other</td>
<td>Mitsubishi, Odebrecht, Edison, Glencore, Pavilion Energy</td>
<td>Utilities (e.g. GDF Suez), conglomerates (e.g. Mitsui) and others have minor positions regionally</td>
<td>Conglomerates, diversified companies and private equity with non-petroleum capital sources may seek distressed asset sales</td>
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</table>
In the sections, Africa Today and Tomorrow we focused on deepwater issues that reflect global trends. For example:

- Deepwater’s 43 Bboe of discovered reserves in ten years are most of Africa’s new additions; this mirrors deepwater’s total rich global contribution of +/-45%
- Increased gas content seen in Africa also characterizes deepwater discoveries in India, the Mediterranean, N.W. Europe and S.E. Asia
- Capital migration to unconventionals slowed deepwater activity everywhere
- Cost inflation was widespread too, e.g., deepwater Australian developments.

The following section demonstrates issues within Africa are also widespread. Some typical challenges for African countries and globally are:

- Fiscal terms changed and “drifted” to a richer oil price environment
- Improving/reducing conflict, corruption, crime, environment, transparency
- Inefficiencies from mediocre governance or highly involved state companies
- Domestic content requirements misaligned with available resources
- Dictates for hydrocarbon management that stall or preclude development
- Remoteness of operations/from markets, budget strain and supply chains.

How each country handles both typical and unique issues for their jurisdiction will:

- Influence the relative attractiveness of countries for further investment, and
- Provide yet another way to compare operating theatres and assets within them for investment quality.

The countries across Deepwater Africa can be split into three categories based on maturity, as seen opposite. This section presents analysis of a few key countries from these categories to demonstrate key issues in the framework of Asset Quality:

- Egypt – Deepwater region ‘trending up’
- Angola – Deepwater heartland
- Mozambique / Tanzania – The deepwater growth region of the last 5 years.
- Further analysis on other countries is available from BMO Capital Markets upon request.

Source: Wood Mackenzie
INTRODUCTION

- Preceding sections summarized Deepwater Africa including broad application of BMO’s Asset Quality (AQ) system (inset box, right).
- Here over 190 deepwater assets organized by country are summarized.
- The strength of the BMO AQ system is to facilitate comparison. This is possible despite the unique characteristics of each asset.
- Comparing projects through a standardized system reduces bias. It enables comparison of asset groups between countries or corporate portfolios.
- The AQ system also dovetails with risks/uncertainty to enhance comparison of regions or steps in project management following acquisition.

ASSET QUALITY RANKING

- The following section discusses country reviews:
  - Summarise key issues and what to watch for
  - Rank assets by overall quality
  - Assess overall quality for the three major categories of AQ: Inherent (IN), Imposed (IM) and Execution (EX).
- AQ scores are shown in a “heat map” like the table below. Higher estimated quality is in green, lower quality in red.
- A few examples are provided to demonstrate methods and highlight issues in the country that widely affect assets.
- A geographic map shows AQ by license.

ASSET QUALITY (AQ)

- High quality assets offer the best value and options for a given spectrum of risks.
- Attributes affecting value fall in three broad categories:
  - **Inherent** – fixed, natural attributes of assets like subsurface conditions
  - **Imposed** – man-made influences such as fiscal terms
  - **Execution** – aspects of accessing and selling petroleum like drilling, facilities and operator experience.

<table>
<thead>
<tr>
<th>Inherent</th>
<th>Imposed</th>
<th>Execution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accumulation size</td>
<td>Entry issues &amp; cost</td>
<td>Services access &amp; suitability</td>
</tr>
<tr>
<td>Fluid phase &amp; composition</td>
<td>Fiscal &amp; regulatory structure</td>
<td>Drilling &amp; Completions</td>
</tr>
<tr>
<td>Reservoir architecture, deliverability &amp; energy</td>
<td>Commercial rights, obligations, &amp; counterparties</td>
<td>Facilities requirements</td>
</tr>
<tr>
<td>Trap detection &amp; delineation</td>
<td>Partnership</td>
<td>Export facilities &amp; access</td>
</tr>
<tr>
<td>Upside accessibility &amp; scale</td>
<td>Alignment - Government</td>
<td>Operator-asset match</td>
</tr>
<tr>
<td>Terrain or sea conditions</td>
<td>Communities</td>
<td>Resource draw</td>
</tr>
<tr>
<td>Environmental sensitivities</td>
<td>Geopolitical landscape</td>
<td>Cost controls</td>
</tr>
</tbody>
</table>

**Materiality versus Complexity**

- Every attribute is balanced between materiality-complexity, obstacles-costs.
- Attributes overlap and are linked. For example, light sweet crude commands premium prices and is easier to handle. Low viscosity enhances flow. So attributes like fluid character have a compounding influence on Asset Quality.
- Risks and uncertainty extend beyond the subsurface and pervade E&P.
- Projects have individual risk spectrums that impact estimated value.
- Prioritising investments means considering influences beyond estimated return, resources, production and costs.
PAST AND PRESENT

- Egypt's long production history has diverse sources. From first oil in 1910, Gulf of Suez (GoS) production grew to 800 kboepd. The Western Desert contributed consistently since the 1980s, but not enough to replace GoS decline. Onshore and shallow water Nile delta increased significantly during the late 1980s and 1990s.
- Since 1996 many large gas fields were discovered in deepwater. These eventually fed the world’s first deepwater-sourced LNG plants.
- The sector now contributes 23% of reserves and 10% of production, which is declining just when Egypt needs it most. Large players dominate deepwater (BP, BG, ENI, Petronas) but smaller companies are active too.
- Egypt’s lengthy production history also is a story of obstacles overcome, e.g.:
  - Domestic energy use rose under subsidies and capped netback to producers
  - PSC terms are among the toughest globally (>85% state take)
  - Government companies hold high equity in many projects and leases
  - Egypt has a dismal record of paying operators
  - Political turmoil after 2011 suppressed foreign investment and deepened the arrears of payments owed to operators.
- Can Egypt again overcome obstacles? Can deepwater compete for investments?
- Domestic politics stabilized but remains uneasy. The large population is a potentially lucrative market. Diverse production regions offer platforms for new technologies and to exploit cost deflation. Infrastructure is under utilized. Services are readily available.

THE FUTURE

- Egypt is moving aggressively to attract investment. Changes include:
  - Improved terms and netback to gas producers (doubled to nearly $6/MMBTu)
  - Reduced government subsidies for domestic energy supplies
  - New, selected allowance for direct export (e.g. DanaGas and TransGlobe)
  - Stepped up repayment to operators (arrears halved from a high of $6.5 billion).
- More can be done but improvements are among the best globally. These were done to rebuild after domestic turmoil; fortuitously they coincide now with falling oil prices.
- New contracts show it is working, especially BP’s sanction of West Nile Delta. At $12 billion projected investment, this is one of the few large sanction projects of 2015.
- New entrants could flock to Egypt because:
  - The diverse theatres suit many operators and types of operation
  - PSCs are tough but structured to repay investment efficiently
  - Deepwater participants are few, equity stakes high, resource potential is big
- Watch for continued government moves to raise investor confidence. Key for deepwater are cost controls and the success/spread of deeper plays.
DEEPWATER ZOHRE DISCOVERY

- ENI announced the discovery of a supergiant gas field in Egypt deepwater on August 30, 2015.
- The discovery could hold a potential 30 trillion cubic feet of dry gas.
- ENI will immediately appraise the field with the aim to fast track the development.
- The discovery is the largest discovery in Egypt and one of the biggest discoveries in the world over the last decade.
- ENI’s leading position in Egypt and 100% equity will allow a fast lead time.
- For Egypt, Zohr may negate the need for LNG imports and allow Egypt to become energy self-sufficient again.
- The Zohr discovery follows a raft of recent discoveries such as BP’s Salamat and Atoll fields, and the FID of projects like West Nile Delta.
- Deepwater Egypt is alive and kicking.

WELL SUMMARY

Discovery Well: Zohr 1X NFW
Block: Shorouk Block
Area: 100 km
Total depth (TD): 4,131 m
Water depth: 1,450 m
Net pay thickness: >400 m
Reservoir: Miocene carbonate
Upside: deeper Cretaceous

Source: Company filings, Wood Mackenzie
Since 2011 over 130 Tcf and 35 Tcf of gas was discovered in Mozambique and Tanzania, placing East Africa among the best exploration hotspots. Large scale multi-train LNG projects are now planned in both countries.

Early entrants benefited from high value creation. For example, emergence of a future LNG hub attracted over $12 billion of strategic M&A from National Oil Companies.

Mozambique is progressing faster with FEED completed/ongoing for Anadarko’s onshore LNG and ENI’s Coral FLNG. Tanzania progress is slower; BG JV and Statoil JV signed an agreement to pursue onshore LNG jointly. FEED has not started.

Both countries altered fiscal terms following large discoveries:

- Mozambique passed laws in 2014, including a supplementary law for Area 1 and Area 4 LNG projects. Changes include greater state participation, onerous capital gains taxes, local content and 25% of production allocated to local markets
- Tanzania’s fiscal terms are PSC based. The Petroleum Act of 2015 followed previous acts in 2008 and 2013. The Act is designed to encourage further exploration but government share remains high at 70% onshore / shelf and 70-85% for deepwater. The Act also states all gas processing facilities must be onshore limiting development of gas through floating liquefied natural gas (FLNG).

MOZAMBIQUE RESERVES (TCF)  TANZANIA RESERVES (TCF)

Source: Wood Mackenzie
There are 50 discoveries in deepwater including one liquids discovery (Ironclad) in southern Area 1 and the Njika gas field, in southern Mozambique (inset map).

Grouped in 16 assets, these fields are assessed with BMO’s AQ tool. Analysis identifies key risks / uncertainties in each asset, under an assumption that high quality assets provide the best value and business options for a given spectrum of risks.

The main gas assets (Area 1, Area 4, Blocks 1, 2 and 4) are largely high quality, with differentiators that influence likelihood of development. For example:

- Agulha in Area 4 has similar recoverable volumes as Saffron in Block 2. Distance from other fields and wet gas suggests it may be developed slower. This raises uncertainty for near-term cash flow generation. So AQ under Execution is reduced.
- Saffron by comparison should contribute to LNG Train 1. Uncertainty for near-term cash flow generation is lower. Execution rating in AQ is higher.

Significant resources, advancing LNG plans and high estimated NPV (total >$43 billion) place these assets high among Deepwater Africa.

Andadarko and ENI are marketing stakes in their assets. This as a significant opportunity to access a long-term, high quality resource. New entrants are likely to be large buyers with long-term needs and major oil companies with big resources to replace.

The poorest quality asset in East Africa is Njika which was the first deepwater discovery in Mozambique, made by Sasol in 2008, far to the south of the Area 1 and 4.

Due to challenging reservoir conditions, water depth, distance from infrastructure and lack of gas market the field is unlikely to be developed for some time, resulting in a low asset quality score across the board.
Nigeria Overview

PAST AND PRESENT

- Africa’s largest oil and gas producer has 9 producing deepwater fields with combined output of 770 kboepd, or 27% of Nigeria’s production.
- Despite its leading position, investment in Nigeria is shrinking due to:
  - Maturing industry with remaining potential skewed toward costlier deep water
  - Widespread piracy, environmental damage and bunkering/theft of oil onshore
  - Increasing piracy offshore, especially near pipeline landing points
  - Some shallow water/onshore access hindered by terrain and community issues
  - NNPC high equity in many projects that strains finances, delays projects and hampers execution
  - Uncertain fiscal terms from prolonged revision of the Petroleum Industry Bill (PIB). One proposed changes is for even greater NNPC share of deepwater projects
  - Pressure to increase local content before domestic facilities and capacity exist
  - More recently, instability and concerns arising from actions of Boko Haram.
- These issues contribute to recent divestments decisions, especially from supermajors like ConocoPhillips, Chevron, ENI and Shell.
- Indigenous companies like Farmfa, Oando, SEPLAT, and Seven Energy grew by acquisition and operate an ever increasing share of production.
- Deepwater is less exposed to some issues but faces uncertainty from PIB revisions. Competing opportunities (e.g. Angola) and poor exploration success recently slowed activity. Just one deepwater wildcat was drilled in 2014 versus 43 in 2004.

THE FUTURE

- Nigeria and Sao-Tome’s 50 deepwater assets lost $22 billion PV in the oil price decline. Low oil price also will curtail exploration and delay developments but it brings some upside.
- Costs deflation improves economics of near-term developments because Nigerian terms are sensitivity to capex. Nigeria’s large services sector promotes deflation versus smaller, more remote theatres. Local content laws may slow deflationary gains.
- Sellers will redeploy capital to core areas, away from risks and uncertainty. Indigenous companies comprise a competitive buyer group but costs may slow their move into deepwater.
- Watch for adjustments by the new government that signal longer term changes in the investment climate. The next few months are crucial for Nigeria.

Source: Wood Mackenzie
**ASSET QUALITY RANKING**

<table>
<thead>
<tr>
<th>Asset</th>
<th>IN.</th>
<th>EX.</th>
<th>IM.</th>
<th>Total</th>
<th>Africa</th>
</tr>
</thead>
<tbody>
<tr>
<td>OML 118 (Bonga Fields)</td>
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<tr>
<td>OML 133 (Egba and Bisu)</td>
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<tr>
<td>Agbami-Ekoi (OML 577)</td>
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<td>Abo Central (OML 525)</td>
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<tr>
<td>Agbami-Ekoi (OML 528)</td>
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<td>Akoperi (OML 122)</td>
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<td>OML 120 (PSA)</td>
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<td>Ugo (OML 145)</td>
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<tr>
<td>Elam and Zababada (OPL 245)</td>
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<tr>
<td>OML 116 (PSIC)</td>
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<td>Sisaili (OML 29)</td>
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<td>Bobil-Chota (OML 155/OML 131)</td>
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<td>Ngolo (OML 150)</td>
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<td>OML 111 (Gas)</td>
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<td>Doro (OML 118)</td>
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<td>Nnwea (OML 129)</td>
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<td>Efere (OML 138)</td>
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<td>Usani and Usani West (OML 138)</td>
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<td>Bilah (OML 129)</td>
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<td>Egina South (PSA)</td>
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<td>MinkidiogBOro (OML 134)</td>
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<td>Ebomu (OML 134)</td>
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<td>Okodo (OML 125)</td>
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<td>Aja Deep (OML 110)</td>
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<td>Oko (OML 135)</td>
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<td>Opaya (OPL 285)</td>
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<td>Emirin (Unlicensed Area)</td>
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<tr>
<td>Kuro (OPL 297)</td>
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</tbody>
</table>

**Example factors affecting assets**

- High AQ from large producing fields and future developments with good partnerships. Gas, while low value in Nigeria, is treated as upside. However, in some assets gas hinders execution.
- Good inherent and execution values offset by low imposed quality due to lack of partner alignment across licenses.
- Strong execution values due to likelihood of development (FID taken in Q4 2014) but lower inherent quality (reservoir performance uncertainty) and imposed (large number of partners and PIB uncertainty).

**ASSET QUALITY OVERVIEW**

- 50 deepwater assets in Nigeria and Nigeria-Sao Tome JDZ are reviewed.
- Rankings and assets are summarized in the table (left) and map (below).
- Examples illustrate common issues and attributes as well as the basis of rankings.
- High numbers of assets bring diversity of quality. Nigeria and the JDZ contain some of the highest and the lowest quality deepwater assets in Africa.
- AQ is useful to compare assets within a country. That comparison improves when AQ is applied to different deepwater theatres across Africa and to corporate portfolios.
- The broader comparison of theatres and portfolios follow this section on countries.

**NIGERIA ASSET QUALITY MAP**

- Kina among the lowest quality in BMO’s database of 600+ assets due to small size, ultra-deepwater and presence in an unlicensed block.
ASSET QUALITY ACROSS DEEPWATER AFRICA

- BMO Asset Quality provides a multi-scale comparison of assets within any framework to identify assets offering the best value and options for a given spectrum of risks.
- Asset Quality comparison of nineteen Deepwater Africa countries and assets reveals four main groups and associated investment recommendations:
  - **The Elite** – Assets that would compliment any portfolio – *capture when possible*
  - **The Good** – High quality assets with good transaction achievability – *target as portfolio core*
  - **The OK** – Quality is depressed by various factors (e.g. fiscal terms, project execution) that may transform the asset if addressed – *niche players can target*
  - **The Ugly** – Poor quality assets with multiple low Inherent qualities, little chance of development and poor fiscal terms – *avoid*.
- At the country scale BMO believe **Egypt**, **Ghana** and **Senegal** are all ‘trending up’ and host quality discoveries for targeted upstream transactions.
Deepwater Africa  Adjusting to Oil and Gas Price Volatility

OVERVIEW

- High quality assets offer the best value and options for a given spectrum of risks. One type of realised risk is a sharp decline in oil and gas prices.
- Competitive countries and companies adapt to the new risk-value balance. Characteristics of assets and business environments may facilitate the adaptations.
- Ideal portfolios include assets profitable at low prices and others poised to exploit rebounding commodity prices but costly to achieve (see Asset examples, right).
- Different Fiscal Regimes match high and low price environments too (see table below).
- As value declines country risks are magnified. Controllable characteristics might be improved to sustain investment. For example, Egypt is paying contractors, providing market access and reducing fuel subsidies. Stability of improvements must be considered too (see table below).
- The impact of commodity prices is just one of 20 attributes in BMO’s Asset Quality (AQ) tool. Another key consideration is fit of the asset with its operators. Not all assets and environments suit every company.
- Combining BMO’s AQ tool with your corporate strategy provides a means to compare investments within or across themes like Deepwater Africa. The process helps optimize a portfolio to match risk-reward appetite.

COUNTRIES – PERCEIVED RISK, REACTIONS AND STABILITY

<table>
<thead>
<tr>
<th>COUNTRY</th>
<th>OVERALL RISK(1)</th>
<th>LOW OIL PRICE</th>
<th>HIGH OIL PRICE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ATTRACTIVENESS</td>
<td>FISCAL REACTION</td>
<td>ATTRACTIVENESS</td>
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<td>EGYPT</td>
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<td>NIGERIA</td>
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<tr>
<td>GHANA</td>
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<td>TANZANIA</td>
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<td>MOZAMBIQUE</td>
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ASSETS DURING LOW PRICES

- High margin established production (<$50/bbl break even examples)
- Developments may exploit typical cost deflation associated with low oil prices
- Capex targeting cost deflation and simple gains for low cost (debottlenecking, artificial lift)
- Fiscal benefit of tax royalty systems, ideally wide / no ring fence

ASSETS DURING HIGH PRICES

- High flow rate and peak production coincide with high prices or rebound
- Assets with optionality satellite accumulations that can be developed when ready
- Higher cost / higher volume upside (EOR, infill, new injection)
- PSCs that show limited increase in State take at higher oil prices and repay capital at >100%

FISCAL REGIMES AND OIL PRICE - EXAMPLES

GHANA

Concession based. Participants pay royalties, corporate taxes and Additional Oil Entitlement (AOE).

Historically attractive but 2014 exploration terms raised AOE and oil royalties to 12.5% from 5%.

Advantaged during low oil price for example, Jubilee has 6% decrease in State take with 30% decrease in forecasted oil price(1). Losses are carried forward. Ring fence is country wide (deepwater loss might be offset by shallow water profit). Must be tax paying to exploit advantages.

ANGOLA

Production Sharing Agreement (PSA) with widely varying terms, particularly as Sonangol share is biddable.

Profit oil is shared between State concessionaire (Sonangol) and partners based on accumulated production, and contractor rate of return.

PSC typically reduces price upside because state take increases with rising oil price. For example, Greater Plutonio shows a 3.6% increase in state take with 30% increase in forecasted oil price(1).

Source: Wood Mackenzie


2. Overall Risk is one attribute in BMO’s Asset Quality tool. This attribute averages 5 public and one proprietary risk measure to compare 178 countries.
Deepwater Africa

Conclusions

DEEPWATER TODAY

- Deepwater Africa has a long history of exploration and production.
- Almost 200 assets have been discovered in water up to 2,710 m deep. Exploration success continues in frontier areas like Senegal and Mauritania.
- Production is nearing 3 mmboepd and could rise to 5 mmboepd by 2023, but only 17% of assets are producing.
- The high cost of deepwater development remains a hurdle to growth; the oil price decline adds to pressure on this sector.
- Majors and large independents generally hold the higher quality assets and will cling to projects that offer good return from large investment.

DEEPWATER TOMORROW

- Despite concerns, deepwater is far from over.
- There is a wide range of asset quality but Africa offers some of the highest quality assets in the world.
- Recent large multi-million barrel, multi-Tcf discoveries in NW Africa confirm the material remaining potential of deepwater.
- Current production is robust to oil price decline, with large remaining value while future projects selectively offer high value for strong operators.
- Large investment is required but with cost deflation, many projects may yield better returns.
- Fiscal drift continues to reduce investment attractiveness and countries must change during these times of low oil price.
- The many majors, independents and indigenous companies create a dynamic investment environment and potential for high quality acquisitions and divestments.
- BMO Capital Markets can rapidly apply proprietary tools, extensive industry experience and corporate access to advise clients with transactions in Deepwater Africa.

Source: Wood Mackenzie
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