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J.P.Morgan

Anadarko Petroleum

Day 5 of Anadarko Week; Deep Dive on GoM and International; Significant FCF Complements High Growth Shale Assets

Overweight

APC, APC US

Price: $66.08

Price Target: $72.00

JPM View: On the fifth and final day of Anadarko Week, we perform a deep dive of APC’s offshore and international assets, which are key anchors of the company's FCF profile. We also review the company's balance sheet strength. In the go-go days of shale, the principal valuation tool was net asset value (NAV). Under a pure NAV approach conventional assets received limited airplay as they generally provided only limited valuation upside outside of changes in commodity prices. The market generally valued these assets at PDP value that declined over time. While we think NAV remains a useful valuation tool for evaluating the space, one of the consistent themes that we have articulated throughout Anadarko Week is the growing importance of FCF generation. In an environment where cash return to shareholders is a critical driver of E&P stock performance, conventional assets with attractive FCF characteristics have more strategic importance, we think. Our modeling confirms that APC’s conventional assets (GoM, Ghana, and Algeria) that are levered to attractive Brent/LLS pricing are key drivers of the company’s FCF generation potential, which should enable meaningful cash return to shareholders. Based on our updated modeling at the strip, we see more than $6.5 billion in cash return to shareholders between 4Q17 and the end of 2020 inclusive of the dividend. Importantly, we anticipate a relatively flat production profile from the company's key conventional assets with growth from the TEN field in Ghana offsetting natural field declines in Algeria, while GoM volumes should be relatively flat given the company's tieback inventory and participation in the Hadrian North discovery. We reiterate our OW rating and $72 per share price target.

- **Attractive portfolio of conventional assets should support strong FCF.** We believe APC’s reshaped asset base through active portfolio management has an optimal mix of stable conventional production (low sustaining capex and high margins) to deliver attractive debt adjusted growth and significant free cash flow. In the GoM, we are modeling more than $1.0 billion in FCF per annum through 2020 and an average of $650 MM per annum in FCF from Algeria and Ghana. Importantly, APC's overall oil production from the GoM, Ghana and Algeria should be relatively flat over this time period at ~210 MBo/d.

Large Cap Oil & Gas Exploration & Production

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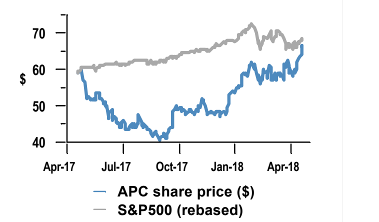
Price Performance



	YTD	1m	3m	12m
Abs	20.6%	15.9%	13.5%	11.8%
Rel	20.7%	16.6%	17.7%	-3.4%

Anadarko Petroleum Corporation (APC;APC US)

FYE Dec	2015A	2016A	2017A	2018E	2019E
Adjusted EPS ($)					
Q1 (Mar)	(0.72)	(1.12)	(0.60)	0.32	0.67
Q2 (Jun)	0.01	(0.60)	(0.77)	0.46	0.49
Q3 (Sep)	(0.70)	(0.89)	(0.77)	0.53	0.44
Q4 (Dec)	(2.46)	(0.49)	0.20	0.63	0.55
FY	(3.88)	(3.07)	(1.96)	1.93	2.14
Bloomberg EPS FY ($)	-2.49	-3.05	-2.04	1.67	1.80

Source: Company data, Bloomberg, J.P. Morgan estimates.

Company Data	
Price ($)	66.08
Date Of Price	19 Apr 18
52-week Range ($)	67.24-39.96
Market Cap ($ mn)	34,052.87
Fiscal Year End	Dec
Shares O/S (mn)	515
Price Target ($)	72.00
Price Target End Date	31-Dec-18

See page 42 for analyst certification and important disclosures.

- **Upside potential from the TEN field in Ghana.** A potential near-term catalyst for APC is the restart of drilling activity at the TEN field in Ghana following the resolution of a border dispute by a favorable ITLOS ruling in 2017. At the time of the suspension of drilling activities, the TEN consortium led by Tullow had completed 11 of the 24 wells planned at the field. In 2017, gross production at the TEN field averaged 56 MBo/d vs. nameplate capacity of 80 MBo/d. Tullow has guided to 2018 gross production of 64 MBo/d, which is 7% higher than JPMe at 60 MBo/d. There appears to be potential upside to volume forecasts as production has consistently eclipsed 70 MBo/d over the past few months and Tullow recently spudded a key development well at the Ntomme field, which could support upside to Ghana volumes. As a reminder, APC owns a 19% interest in the TEN complex.

- **Option value at Mozambique LNG.** APC appears to be making tangible progress on the Mozambique project with the completion of the legal and contractual framework, onsite preparation work, and agreements on 5.1 MMTPA of volumes (APC needs ~8.5 MMTPA to move forward with project financing). Given improving supply-demand conditions in the global LNG market and current negotiations with multiple buyers underway, APC could fill its remaining volumes necessary for project financing by year-end 2018. Including project financing and its 26.5% working interest, APC estimates $2.0 billion in equity cash outflows during the four-year estimated construction period. APC views Mozambique as an attractive longer dated project that provides long-term visibility to the story, while not detracting from the company's unique cash return story given the measured level of investment during the construction phase of the project. In Figure 26, we highlight our gross cash flow estimates from the projects. We estimate APC could generate more than $600 MM in annualized FCF from the initial two trains following start-up.

FCF Analysis from Conventional Assets

On the final day of Anadarko Week, we perform a deep dive of APC's offshore and international assets, which are key anchors of the company's FCF profile. We also review the company's balance sheet strength. While we think NAV remains a useful valuation tool for evaluating the space, one of the consistent themes that we have articulated throughout Anadarko Week is the growing importance of FCF generation. In an environment where cash return to shareholders is a critical driver of E&P stock performance, conventional assets with attractive FCF characteristics have more strategic importance.

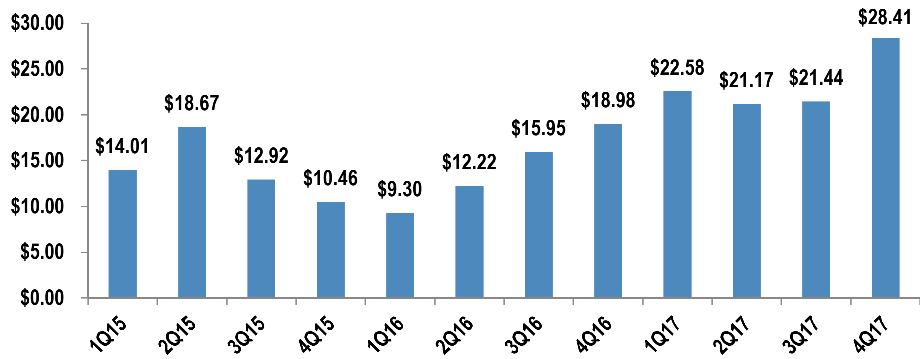
Our modeling confirms that APC's conventional assets (GoM, Ghana, and Algeria) that are levered to attractive Brent/LLS pricing are key drivers of the company's FCF generation potential, which should enable meaningful cash return to shareholders. Based on our updated modeling at the strip, we see more than $6.5 billion in cash return to shareholders between 4Q17 and the end of 2020 inclusive of the dividend.

Gulf of Mexico

Anadarko acquisition of Freeport McMoRan

In September 2016, APC announced a contrarian $2.0 billion acquisition of deepwater assets from Freeport McMoRan. The acquired assets included ~80 MBoe/d of production (80% oil), 3 operating facilities, and several exploration and tieback prospects. Through the transaction, APC nearly doubled its GoM production to ~155 MBoe/d (85% oil). The key asset acquired was a 25% working interest in Lucius, which increased APC's working interest to 49%. APC acquired the deepwater oil and gas assets for only ~1.5x 2017 EBITDA and 21K per flowing Boe, significant discounts to its pre-transaction multiples of 9.0x and 64K per flowing Boe, respectively. It appears that APC essentially was able to purchase the assets for the value of the proven reserves and low risk tieback opportunities only. Under the 2016 strip at the time, management estimated ~$3.0 billion of free cash flow from the assets over the next five years. The transaction closed in 4Q16 and along with improving oil prices is supporting a significant improvement in EBITDAX margins per Boe (see Figure 1). The deepwater acquisition along with its Algeria and Ghana assets have positioned the company to be a significant FCF generator at oil prices above $50 per bbl, while still supporting double digit oil growth.

Figure 1: Historical EBITDAX Margins

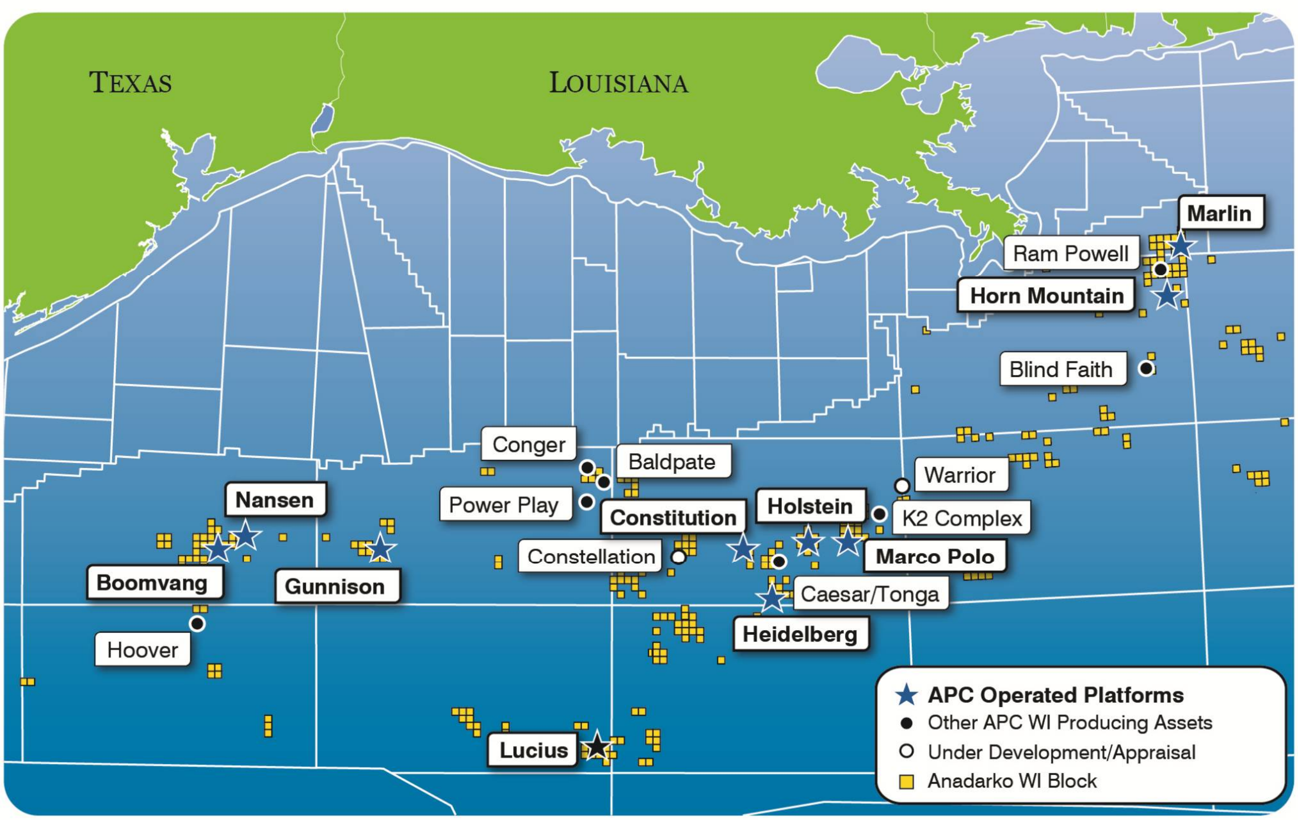


Source: J.P. Morgan estimates, Company data.

Gulf of Mexico Update

APC owns interests in 319 GoM blocks, 10 active floating platforms, and 37 producing fields (see Figure 2**Error! Reference source not found.**). Given the depth of its infrastructure in the GoM, APC's strategy has pivoted from drilling rank, high-impact exploration wells to lower risk and high RoR tieback opportunities (i.e., smaller satellite fields around infrastructure).

Figure 2: Anadarko's Gulf of Mexico Position



Source: Company reports.

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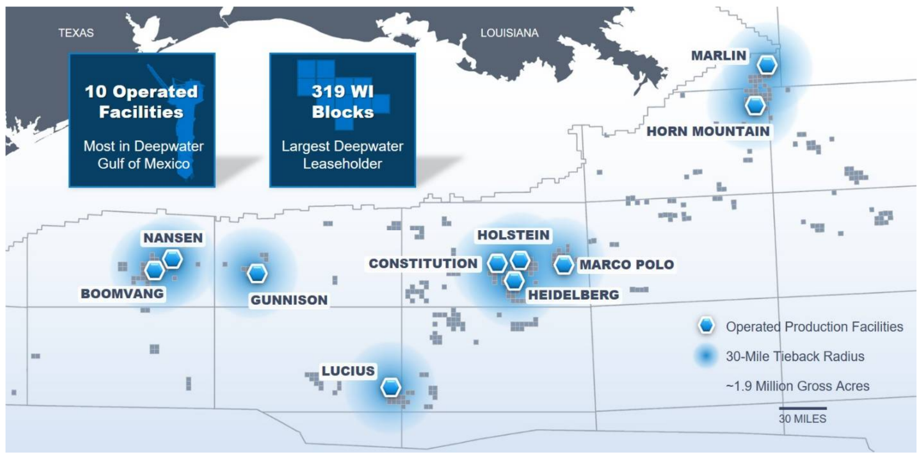
APC is currently executing its tieback strategy at the Horn Mountain (100% WI) field and estimates a greater than 100% IRR on this project with less than a one-year payback on its investment. In 2017, APC brought online two Horn Mountain tiebacks with drill to first production times of 110 days and 80 days, respectively. In 4Q17, APC drilled its third tieback, which encountered 42 feet of high quality oil play and good connectivity to existing wells. First production is expected in the first half of 2018, which should help offset natural field declines. As a reminder, the first Horn Mountain tieback well came online at a strong sustained rate in excess of 16 MBo/d.

Figure 3: Tieback Opportunities Near Infrastructure



Source: Company reports.

We believe APC should have good operating momentum in 2018 from the GoM on the back of Horn Mountain and development drilling at several other projects offshore. 1Q18 GoM production should benefit from the tie-back at Marlin, while 2Q18 should be positively impacted by the tieback at Caesar/Tonga (33.75% WI). At the Constellation field (33.33% WI), APC completed its initial development well in 2Q17, which encountered more than 120 ft. of net oil pay. First production is expected in late 2018 when the field is tied into the Constitution spar facility. At Holstein (100%), APC had installed a platform drilling rig and initiated a 4 well program in 4Q17. At Holstein, APC should have four wells coming online in 2018. In 2019, APC should benefit from further development drilling at Lucius (48.9% WI). APC entered into agreements to expand the Lucius unit to encompass the adjacent Hadrian North discovery in late 2017. Development of this tie-back opportunity commenced in 2018, with first production expected in 2019.

Anadarko's Gulf of Mexico Free Cash Flow Potential

Assuming \$50 to \$60 per bbl WTI, APC's 2018 to 2020 outlook assumes FCF ranging from \$900 MM to \$1.4 billion per annum. At the current strip, we model \$1.26 billion of FCF in 2018, \$1.2 billion in 2019, and \$1.1 billion in 2020. Despite the backwardation in the strip, we model a relatively flat free cash flow profile given the fact that GoM that capex should roll modestly lower in 2019 and 2020 given the roll-off of two deepwater rigs.

Figure 4: Anadarko's Gulf of Mexico Operating Summary

Gulf of Mexico Summary (Anadarko Petroleum) JP Morgan Research Estimates	2018E Year	2019E Year	2020E Year	2021E Year
Operating Summary				
Benchmark Prices				
WTI	$62.93	$59.21	$55.62	$55.62
Gas	$2.87	$2.79	$2.78	$2.78
Realized Prices				
Oil realization ($/Bbl)	$61.67	$58.03	$54.50	$54.50
NGL realization ($/Bbl)	$27.69	$26.05	$24.47	$24.47
Gas realization ($/Mcf)	$2.67	$2.60	$2.58	$2.58
Daily Production				
Oil production (Mbbl/d)	120	121	121	121
NGL production (Mbbl/d)	10	10	11	11
Gas Production (Mcf/d)	91	85	82	79
Total Production (MBoe/d)	145	145	145	145
% Growth (YoY)		-0.2%	0.0%	0.0%
% Oil Growth (YoY)		0.5%	0.0%	0.5%
Production Summary				
Oil production (MMBo)	44	44	44	44
NGL production (MMBo)	4	4	4	4
Gas production (MMcf)	33	31	30	29
Total production (MMBoe)	53	53	53	53
% Oil	83%	83%	83%	84%
% NGL	7%	7%	7%	7%
% Gas	10%	10%	9%	9%

Source: J.P. Morgan estimates, Company data.

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Figure 5: Anadarko's Gulf of Mexico Summary Statement

Gulf of Mexico Summary (Anadarko Petroleum) JP Morgan Research Estimates	2018E Year	2019E Year	2020E Year	2021E Year
Summary Income Statement				
Oil revenues ($MM)	**$2,703**	**$2,556**	**$2,400**	**$2,412**
NGL revenues ($MM)	**$102**	**$97**	**$96**	**$96**
Gas revenues ($MM)	**$88**	**$80**	**$77**	**$74**
Total Gulf of Mexico revenues ($MM)	**$2,893**	**$2,733**	**$2,573**	**$2,581**
Operating Expenses				
Cash costs	**$636**	**$635**	**$635**	**$635**
Depreciation, Depletion, and Amortization	**$968**	**$966**	**$966**	**$966**
Total	**$1,604**	**$1,601**	**$1,601**	**$1,601**
Pre-Tax Income	**$1,289**	**$1,132**	**$972**	**$980**
Less: Income taxes	**$271**	**$238**	**$204**	**$206**
Net Income	**$1,018**	**$894**	**$768**	**$774**
Summary Cash Flow Statement				
Discretionary Cash Flow				
Adjusted Net Income	**$1,018**	**$894**	**$768**	**$774**
Deferred Income Taxes	**$271**	$238	$204	$206
DD&A	**$968**	**$966**	**$966**	**$966**
Discretionary Cash Flow from Operations	**$2,256**	**$2,098**	**$1,938**	**$1,946**
CAPEX	**$1,000**	**$900**	**$800**	**$1,000**
Free Cash Flow	**$1,256**	**$1,198**	**$1,138**	**$946**

Source: J.P. Morgan estimates, Company data.

In Figure 6, we illustrate our oil production forecast for APC's GoM segment. APC has 30+ tieback opportunities, which should help to support relatively flat GoM oil production at 120 MBo/d over the next three year period. Over this period, we have APC's GoM assets generating cumulative free cash flow north of $3.4 billion. In 2018, tiebacks at Horn Mountain, Marlin, Caesar/Tonga and Constellation should help Gulf of Mexico oil production be flat yoy.

Figure 6: Anadarko's Gulf of Mexico Oil Production Model

Oil Production (Mboe/d) Summary	1Q18	2Q18	3Q18	4Q18	FY18	1Q19	2Q19	3Q19	4Q19	FY19	1Q20	2Q20	3Q20	4Q20	FY20	1Q21	2Q21	3Q21	4Q21	FY21
Gulf of Mexico	120	121	116	124	**120**	123	123	113	123	**121**	123	123	113	123	**121**	123	124	114	124	**121**

Source: J.P. Morgan estimates, Company data.

In Figure 7, we highlight the attractive returns for tiebacks near infrastructure. Using the recent Horn Mountain tieback as a guide, we assume that a well comes online at an initial rate of 14 MBo/d. We estimate a gross EUR of 22 MMBoe at capex of $145 MM. Given the high oil mix and cyclically low offshore service costs, we estimate that a typical tieback in the GoM near infrastructure could generate 80%+ IRRs.

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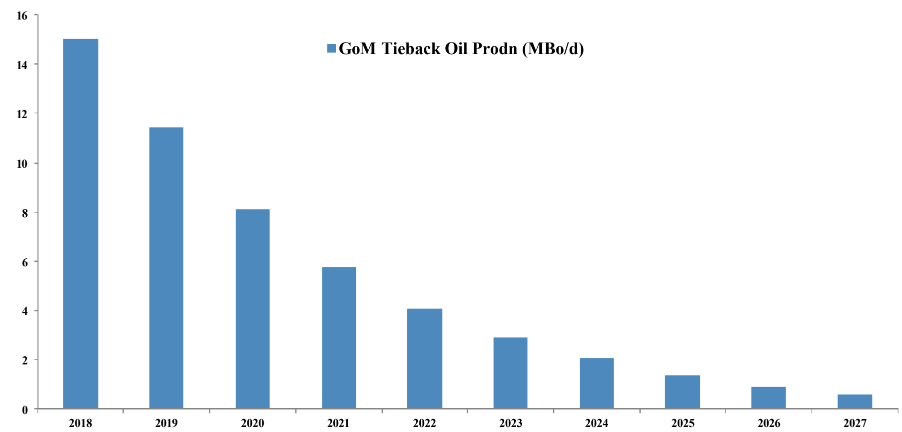
Figure 7: Anadarko Gulf of Mexico Tie Back Example

Gulf of Mexico Tie Back



Type Curve Parameters		Cost Assumptions		Well Economics	
30 day oil rate (MBo/d)	14	Tieback Capex ($ MM)	$145.2	F&D cost ($/Boe)	$6.66
Gross EUR (MMBoe)	22	LOE & Gathering ($/Boe)	$11.00	IRR (pre-tax)	84%
% oil	76%	Royalty	12.5%		
% gas	17%	Discount rate	10.0%		
% NGL	7%				

Source: J.P. Morgan estimates, Company data.

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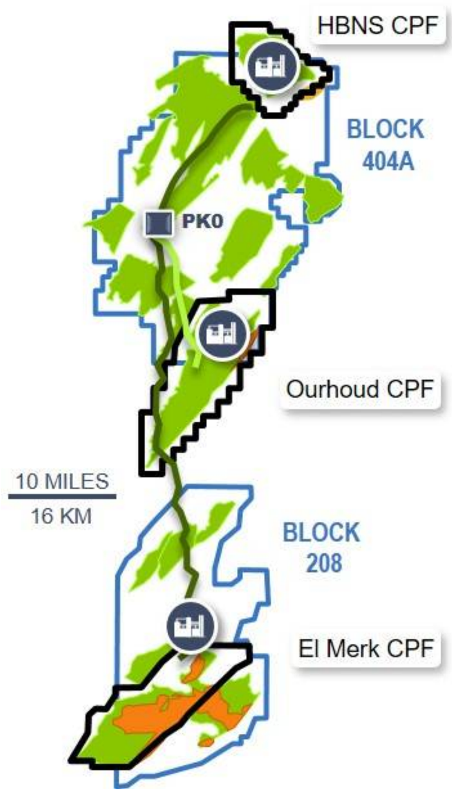
Algeria

We anticipate significant FCF generation from the company's conventional international assets in Algeria and Ghana. On a combined basis, we are forecasting an average of more than $650 MM per annum in FCF generation on an after tax basis over the next four years, or $2.7 billion in total. Importantly, APC's overall production from Ghana and Algeria should be relatively flat over this time period (modest growth in Ghana offsetting natural field declines in Algeria).

In Algeria, Anadarko's operations are located primarily in the Sahara Desert in Blocks 404 and 208. These blocks are governed by a Production Sharing Agreement (PSA) between Anadarko, Sonatrach, Eni and Maersk Oil which includes 24.5%, 51%, 12.5% and 12.5% working interests, respectively. APC produces oil through the Hassi Berkine South and Ourhoud central processing facilities (CPFs) in Block 404 and oil and NGLs through the El Merk CPF in Block 208. In 2017, APC drilled 7 development wells in Algeria and total gross production from these fields averaged at 337 MBbls/d. As an outcome of OPEC meeting in late 2017, Algeria and other members agreed to extend the reduction in production output through the end of 2018. APC stated that it had minimal production impact from this reduction during 2017 and also expects minimal impact in 2018.

Figure 8: APC's Algeria Offshore Producing Assets



Source: Anadarko Petroleum

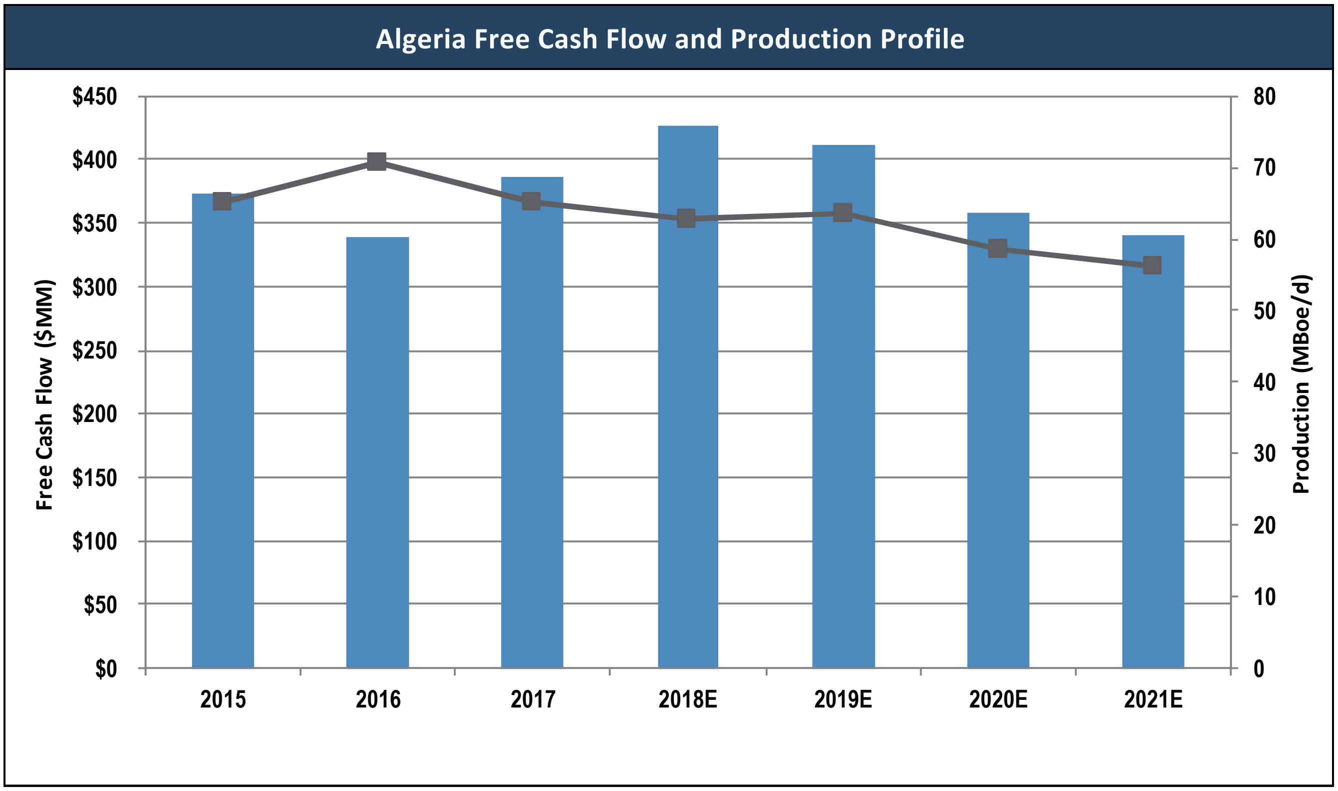
Figure 9 illustrates our segment model for Algeria, including our revenue, cost, production, and price realization expectations. We expect APC's Algeria production to average 63 MBoe/d in 2018, generating after-tax FCF of $427 MM at the strip assuming capex of $30 MM, which is in-line with company guidance. Over a four—year period from 2018 to 2021, we see cumulative FCF of $1.5 billion. In Figure 10, we summarize our production and FCF estimates from Algeria.

Figure 9: APC- Algeria Segment Model

Algeria Summary (Anadarko Petroleum) JP Morgan Research Estimates	2015 Year	2016 Year	2017 Year	2018E Year	2019E Year	2020E Year	2021E Year
Summary Income Statement							
Oil revenues ($MM)	$1,122	$1,036	$1,191	$1,413	$1,366	$1,192	$1,141
NGL revenues ($MM)	$66	$61	$59	$92	$84	$72	$69
Total Algeria revenues ($MM)	$1,188	$1,097	$1,250	$1,505	$1,450	$1,264	$1,210
Operating Expenses							
Cash costs	$136	$147	$150	$160	$163	$150	$143
Depreciation, Depletion, and Amortization	$174	$223	$201	$171	$173	$160	$153
Algeria TPE	$297	$252	$300	$357	$348	$303	$290
Total	$606	$623	$650	$688	$684	$613	$587
Pre-Tax Income	$582	$474	$600	$817	$766	$651	$623
Less: Income taxes	$334	$323	$392	$531	$498	$423	$405
Net Income	$247	$152	$207	$286	$268	$228	$218
Summary Cash Flow Statement							
Discretionary Cash Flow							
Adjusted Net Income	$247	$152	$207	$286	$268	$228	$218
DD&A	$174	$223	$201	$171	$173	$160	$153
Discretionary Cash Flow from Operations	$421	$375	$408	$457	$442	$388	$371
CAPEX	$47	$36	$22	$30	$30	$30	$30
Free Cash Flow	$374	$339	$386	$427	$412	$358	$341
Operating Summary							
Realized Prices							
Oil realization ($/Bbl)	$51.93	$44.16	$53.74	$67.10	$63.94	$60.55	$60.53
NGL realization ($/Bbl)	$29.85	$25.56	$35.87	$48.60	$45.44	$42.05	$42.03
Daily Production							
Oil production (Mbbl/d)	59	64	61	58	59	54	52
NGL production (Mbbl/d)	6	7	4	5	5	5	4
Total Production (MBoe/d)	65	71	65	63	64	59	56
% Growth (YoY)	-5.5%	8.5%	-7.9%	-3.6%	1.2%	-7.8%	-4.3%
% Oil Growth (YoY)	-10.3%	8.5%	-5.5%	-5.0%	1.5%	-7.8%	-4.3%
Production Summary							
Oil production (MMBo)	22	23	22	21	21	20	19
NGL production (MMBo)	2	2	2	2	2	2	2
Total production (MMBoe)	24	26	24	23	23	21	20
% Oil	91%	91%	93%	92%	92%	92%	92%
% NGL	9%	9%	7%	8%	8%	8%	8%

Source: J.P. Morgan estimates, Company data.

Figure 10: APC - Algeria Production and Free Cash Flow Profile (after-tax)



Source: J.P. Morgan estimates, Company data.

Hassi Berkine/Ourhoud (Block 404)

Overview

Hassi Berkine is the largest operated oilfield in Algeria that has been developed with IOCs and includes three major discoveries on Block 404: Hassi Berkine (HBN), Hassi Berkine South (HBNS), and Ourhoud. Production is achieved from two development areas. The Hassi Berkine development includes nine fields that fall within block 404 plus a unitized portion in block 403a. Production from these fields is processed through the HBNS facility. The Ourhoud field extends across blocks 404, 405a and 406a and is subject to a joint development project between partners in the three blocks. The field has its own central processing facilities. Production commenced at the HBNS field in May 1998, with the HBN and Ourhoud fields beginning production in Dec 2001 and Nov 2002, respectively.

Participation

In October 1989, Anadarko signed the exploration and production sharing contract for Block 404 with Sonatrach. Currently, Anadarko operates with a 24.5% working interest in the block, with its other partners Sonatrach, Eni and Maersk Oil owning 51%, 12.5%, and 12.5% working interests, respectively. The Exploitation License Agreements (ELA) for HBNS, Ourhoud and HBN were awarded in May 1998, February 1999 and October 1999, respectively, and expire between 2023 and 2033. However, the development license for Ourhoud expires in 2022.

Exploration

Anadarko started exploration program on Block 404 in November 1993 with the HBN-1 discovery well and concluded the program in December 2007. Anadarko now only participates in development activity.

HBN: Anadarko drilled its first discovery well, HBN-1, in the north of Block 404a in November 1993 and completed the well in February 1994. The discovery well encountered more than 75 net feet of oil pay in the Triassic TAG-I sand at a test rate of 5.4 MBoe/d (80% oil). APC drilled its next exploration well HBE-1on the block southeast of HBN-1.

Ourhoud: Anadarko discovered the Ourhoud field in 1994, with the drilling and completing of the BKE-1 well. The well delivered a flush test rate of 15.8 MBoe/d (96% oil). Another appraisal well BKE-2, located 2 miles to the southwest of the discovery well, delivered a strong test rate of 18 MBoe/d (96% oil). APC partnered with Cepsa and drilled successful appraisal well towards the south of the field in the second half of 1996. APC also completed the acquisition of 150 sq. miles of 3D seismic data, which helped in the further development of the field.

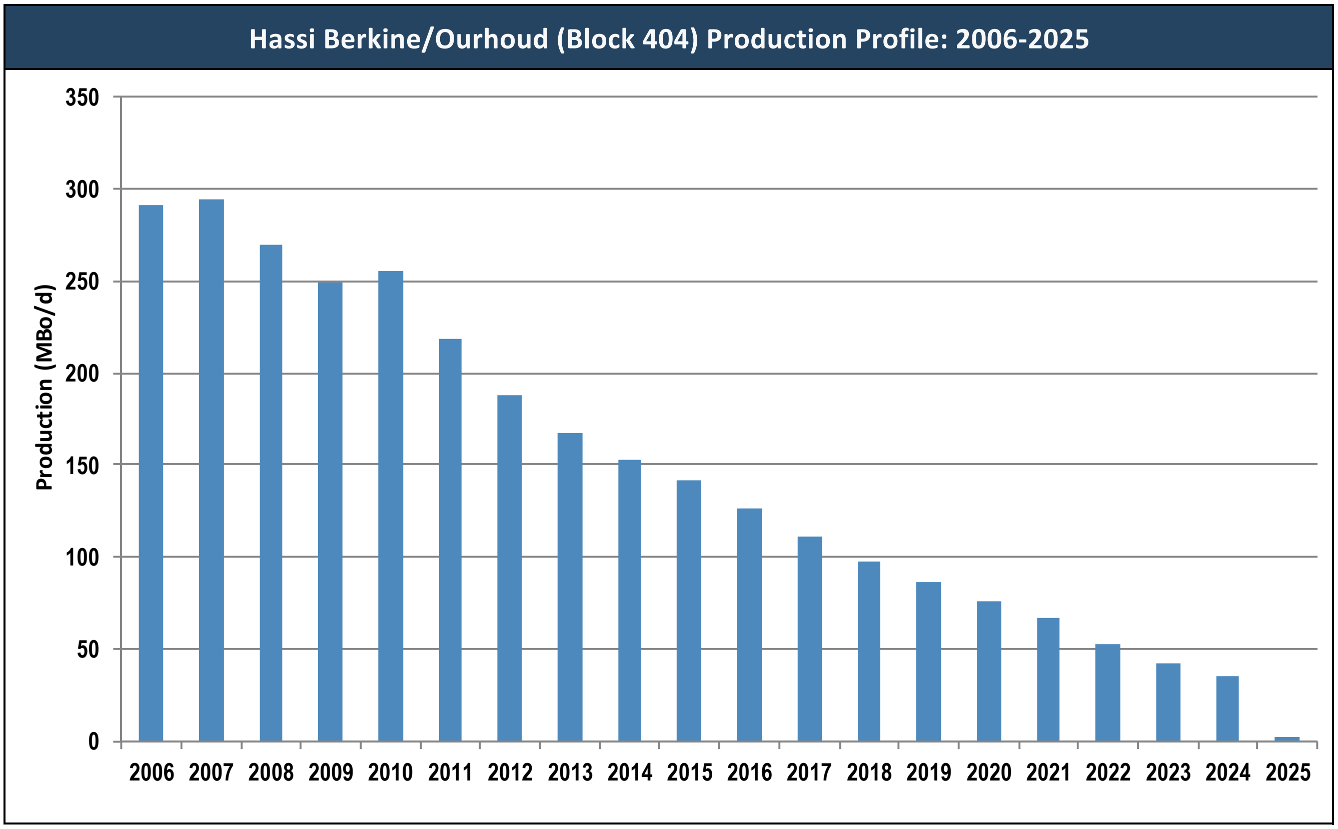
HBNS: Anadarko discovered the HBNS field in Feb 1995, with the drilling and completing of the HBNS-1 discovery well. The well encountered 85 net feet of oil pay in the Triassic TAG-I sand with a strong test rate of 19 MBoe/d (84% oil).

BKNE: Post completing an appraisal program on the HBN, Ourhoud and HBNS fields, Anadarko drilled a discovery well in May 1996, located 12 miles northwest of the BKE-1 well. However, this well was not tested and instead an appraisal well was drilled in July 1988, which tested at 7.5 MBoe/d (62% oil). APC further drilled 3 appraisal wells BKNE-B-1, BKNE-B-2 and BKNE-B-3, of which only BKNE-B-2 was completed as an oil producer.

HBNSE, RBK and QBN: Anadarko drilled 4 discovery wells in 1997. The 1st well, HBNSE-1, encountered 46 net feet of oil pay in the TAG-I sandstone and was tested at 23.3 MBoe/d (73% oil). The 2nd discovery well, HBNC-1, in the Triassic zone, delivered a test rate of 19.6 MBoe/d (85% oil). The other two wells, RBK-1 and QBN-1, were minor discoveries towards the north of Ourhoud field.

Figure 11 and Figure 12 illustrate Wood Mackenzie's forecasts for the Hassi Berkine and Ourhoud fields that are primarily in Block 404.

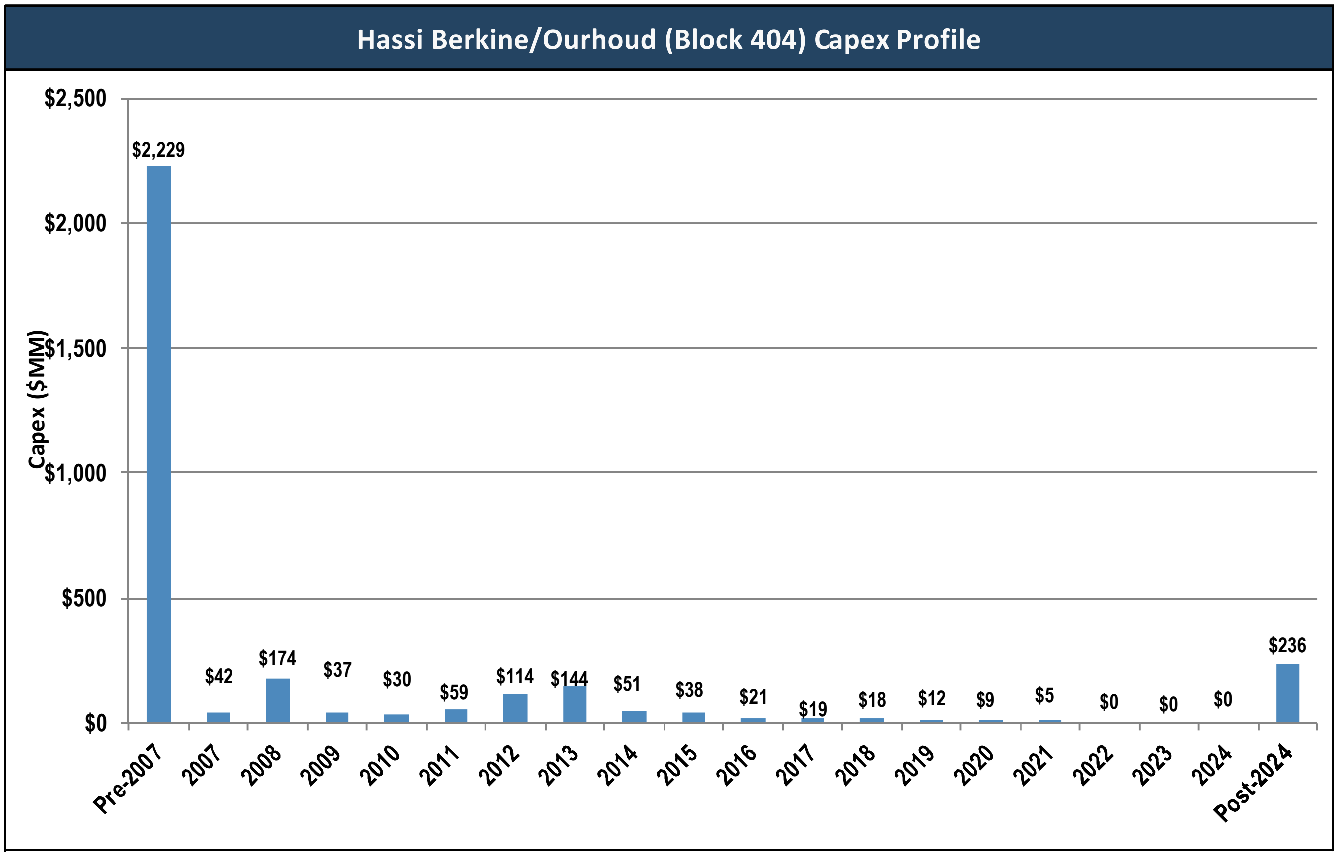
Figure 11: Block 404 Oil Production Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

Capital Expenditure

Figure 12: Block 404 Capex Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

El Merk (Block 208)

Overview

Anadarko discovered the El Merk field during the 1990s, which includes four major discoveries on Block 208: El Merk (EMK), EME, EMT and EMN. The fields contain light oil, condensate, and gas. EMK is the largest field on Block 208 which extends into Block 405a and is subject to a unitization agreement. Algerian authorities approved the development of Block 208 in May 2003. The field was developed with the help of 119 wells linked to a Central Production Facility (CPF) located at the EMN field. CPF has a capacity to process 150 MBbl/d of liquids and 600 MMcfe/d of gas. Production commenced at the El Merk field in March 2013 with a single processing train and ramped in 3Q13 and early 2014 with the commissioning of the second and third trains.

Participation

In October 1989, Anadarko signed the exploration and production sharing contract for Block 208 with Sonatrach. Currently, Anadarko operates with a 24.5% working interest in the block, with other partners Sonatrach, Eni and Maersk Oil owning 51%, 12.5%, 12.5% working interests, respectively. The Exploitation License Agreements (ELA) for the El Merk fields on Block 208 were awarded in May 2003, which was extended to 25 years in 2012 and is now expected to expire in 2032.

Exploration

EMK: Anadarko drilled its first discovery well in Algeria, EMK-1 (El Merk-1), in November 1992 and completed the well in February 1993. The well was tested at 2.6 MBoe/d (76% oil) from the Triassic TAG-I sand formation and 4 MBoe/d (44% oil) from the TAG-S formation. APC drilled its next exploration well EMK-2, but the exploration probe was unsuccessful. APC drilled its third exploration well EMK-3, which tested three different zones. The test rates were 2.6 MBoe/d (76% oil), 2.8 MBoe/d (80% oil), 3.0 MBoe/d (39% oil), respectively.

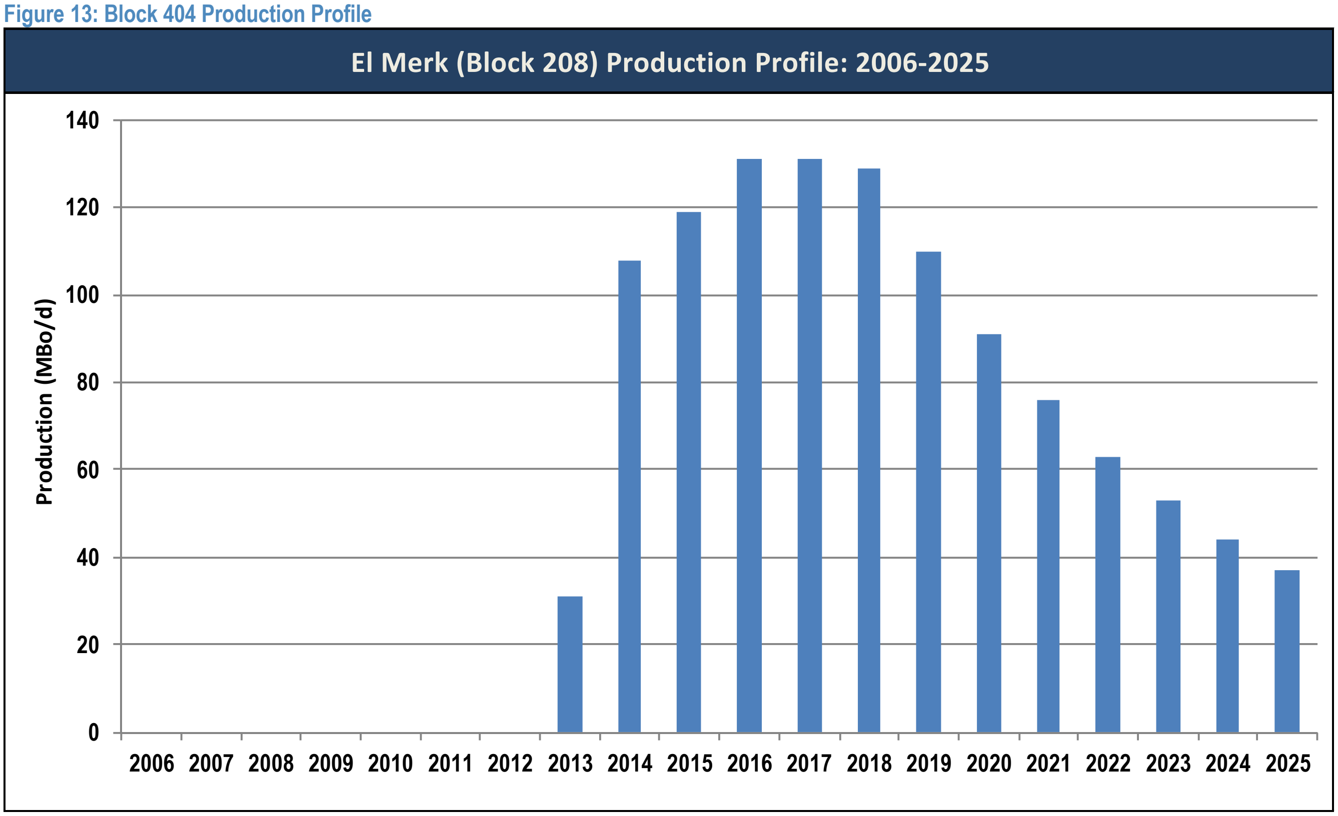
EME: Anadarko discovered the EME field in February 1994, with the drilling and completion of the EME-1 well, which tested three different formations: Triassic, Devonian and Carboniferous. The Triassic TAG-I sands delivered a test rate of 2.2 MBoe/d (81% oil). The two zones in the Early Carboniferous delivered combined test IP's of 13.3 MBoe/d (47% oil). The Middle Devonian zone was tested at 38 MMcf/d of gas. Another minor gas discovery well, EMC-1, was drilled in January 1997 and delivered a test IP of 3.0 MBoe/d (43% oil). However, further EMC appraisal wells have not been drilled yet but are expected to form part of the EME field.

EKT: Anadarko discovered the Et Kheit Et Tessekha (EKT) field in late 1996, with the drilling and completing of the EKT-1 well. It encountered 144 net feet of oil pay in the Triassic interval, delivering test IP's of 15 MBoe/d (90% oil). EKT-2 was drilled in 1997 and found oil shows. EKT-3 delivered a test rate of 6.3 MBoe/d (93% oil).

EMN: EMN field marks the most significant discovery on Block 208. Anadarko drilled EMN-1 in March 1998 and tested the well at a robust 23.9 MBoe/d (89% oil) from its 118 net feet of oil pay in the Triassic TAG-I sandstone formation. APC drilled its next exploration well EMN-2 in mid-1998 and encountered 49 net feet of oil pay. APC tested three different Triassic TAG-I sandstone intervals, with test IP's of 0.8 MBoe/d (94% oil), 2.5 MBoe/d (91% oil), 2.2 MBoe/d (10% oil), respectively. Anadarko and its partners submitted a declaration of commerciality report to Sonatrach for the El Merk North field post successful completion of EMN-3.

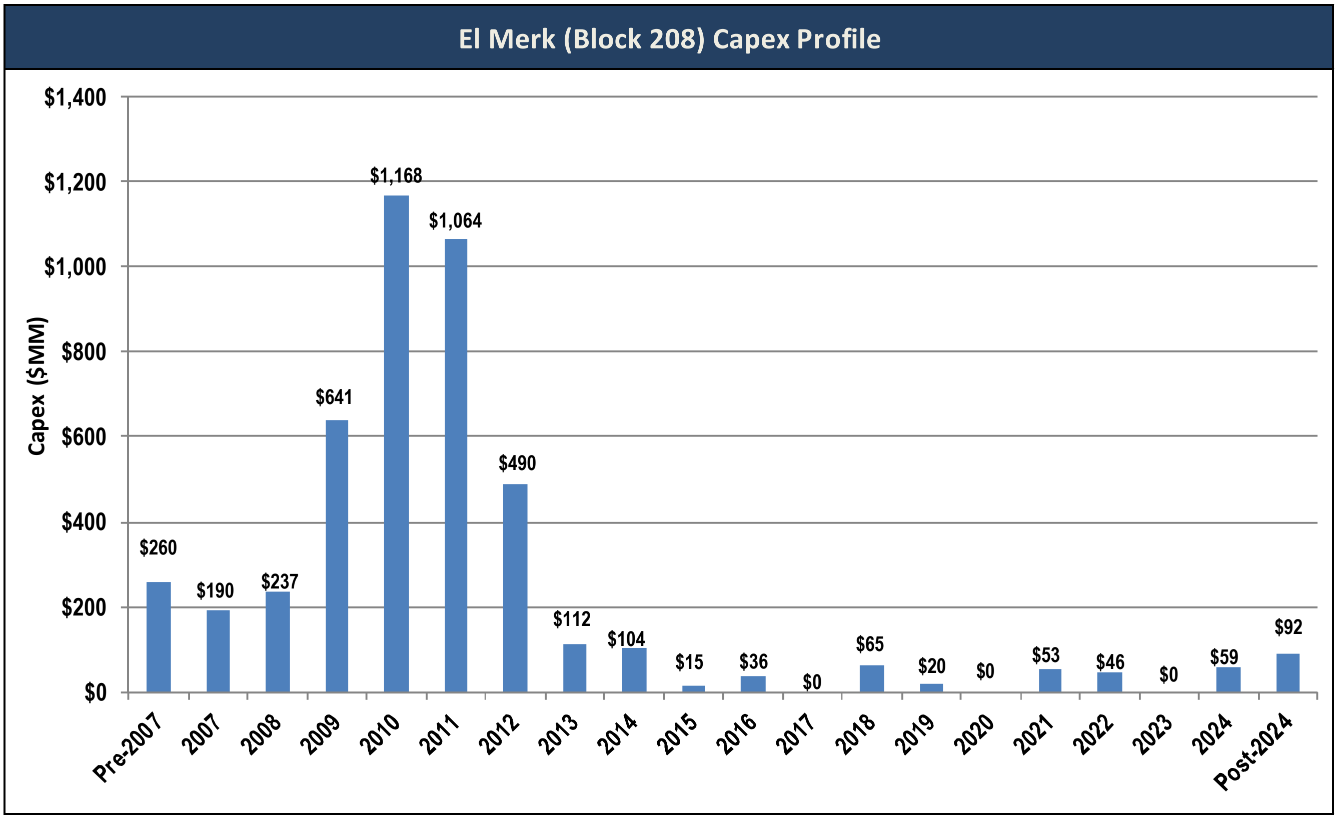
Figure 13 and Figure 14 illustrate Wood Mackenzie's forecasts for the El Merk field in Block 208.

Figure 13: Block 404 Production Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

Figure 14: Block 208 Capex Profile

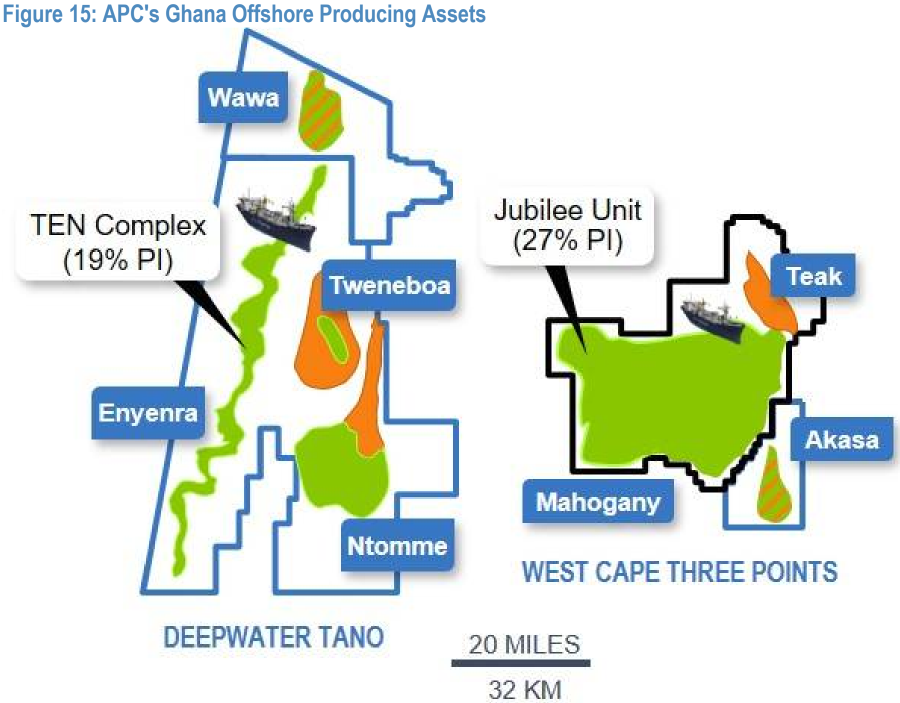


Source: J.P. Morgan estimates, Wood Mackenzie.

Ghana

Anadarko's exploration and development activities in Ghana are located in the West Cape Three Points block and the Deepwater Tano Block. The Jubilee field which spans both these blocks delivered average gross oil production of 89 MBbls/d in 2017. In October 2017, the partnership received Ghanaian government approval for the Jubilee full-field plan of development, with drilling operations expected to commence in 2018. The TEN project, located in the Deepwater Tano Block, achieved first oil in 3Q16 and delivered average gross oil production of 56 MBbls/d in 2017.

Figure 15: APC's Ghana Offshore Producing Assets



Source: Anadarko Petroleum

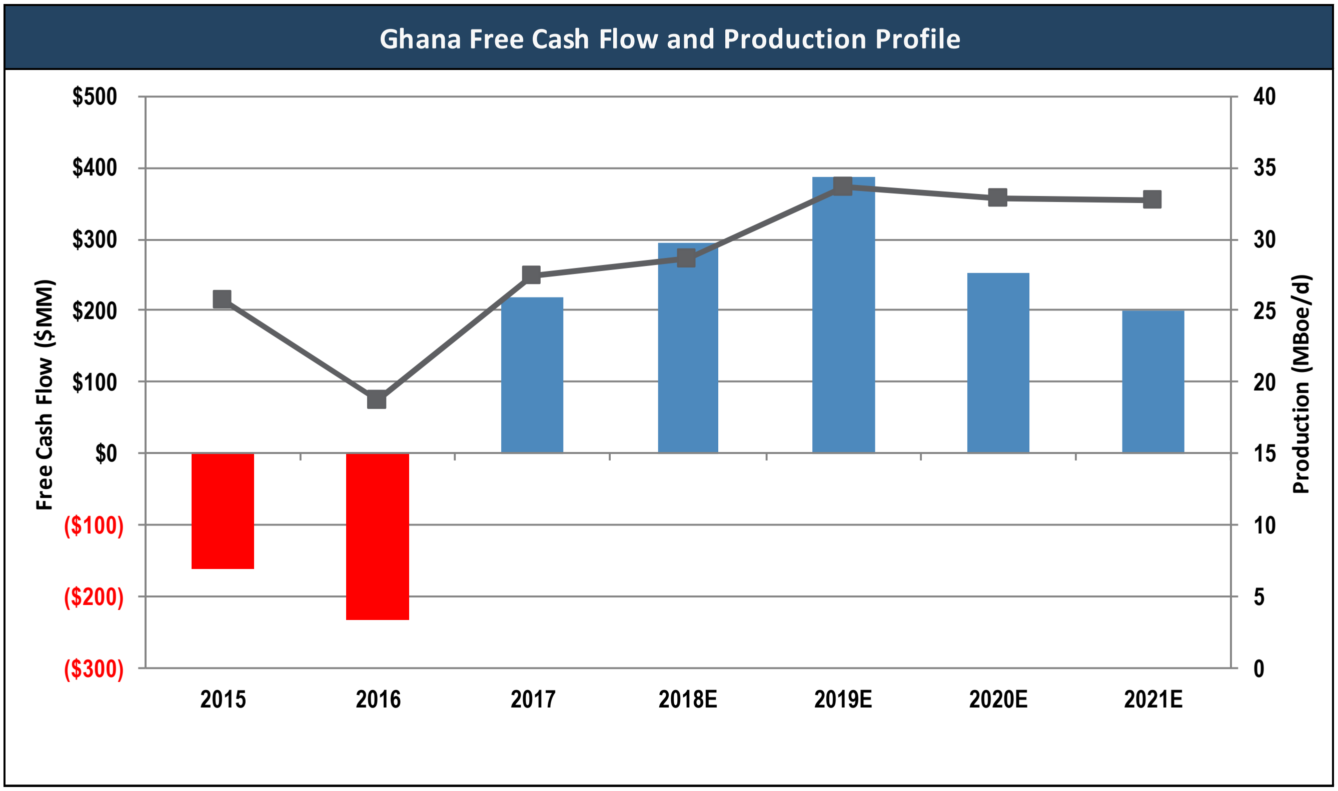
Figure 16 illustrates our Ghana segment model, including our revenue, cost, production, and price realization expectations. We expect APC's Ghana production to average 29 MBoe/d in 2018, generating after-tax FCF of $295 MM at the strip. We note that APC guided pre-tax FCF generation of $185 MM to $285 MM assuming $50 to $60 per bbl Brent from it Ghana assets. We expect capex in 2018 to dial-in at $120 MM, in-line with company guidance. We see more than $1.1 billion of cumulative FCF from APC's Ghana assets through 2021 assuming strip pricing.

Figure 16: APC - Ghana Segment Model

Ghana Summary (Anadarko Petroleum) JP Morgan Research Estimates	2015 Year	2016 Year	2017 Year	2018E Year	2019E Year	2020E Year	2021E Year
Summary Income Statement							
Oil revenues ($MM)	$479	$297	$540	$703	$786	$724	$721
Total Ghana revenues ($MM)	$479	$297	$540	$703	$786	$724	$721
Operating Expenses							
Cash costs	$127	$123	$166	$212	$223	$249	$265
Depreciation, Depletion, and Amortization	$236	$267	$268	$217	$199	$203	$154
Total	$363	$391	$434	$429	$423	$452	$419
Pre-Tax Income	$116	-$94	$107	$275	$363	$273	$302
Less: Income taxes	$74	$19	$77	$78	$96	$142	$177
Net Income	$43	-$113	$29	$197	$267	$131	$125
Summary Cash Flow Statement							
Discretionary Cash Flow							
Adjusted Net Income	$43	-$113	$29	$197	$267	$131	$125
DD&A	$236	$267	$268	$217	$199	$203	$154
Discretionary Cash Flow from Operations	$279	$154	$297	$414	$467	$334	$279
CAPEX	$440	$386	$78	$120	$80	$80	$80
Free Cash Flow	($161)	($232)	$219	$295	$387	$254	$199
Operating Summary							
Realized Prices							
Oil realization ($/Bbl)	$51.03	$43.25	$53.84	$67.24	$63.93	$60.53	$60.52
Daily Production							
Oil production (Mbbl/d)	26	19	27	29	34	33	33
Total Production (MBoe/d)	26	19	27	29	34	33	33
% Growth (YoY)		-27.0%	46.4%	4.2%	17.5%	-2.6%	-0.4%
% Oil Growth (YoY)		-27.0%	46.4%	4.2%	17.5%	-2.6%	-0.4%
Production Summary							
Oil production (MMBo)	9	7	10	10	12	12	12
Total production (MMBoe)	9	7	10	10	12	12	12
% Oil	100%	100%	100%	100%	100%	100%	100%

Source: J.P. Morgan estimates, Company data.

Figure 17: APC - Ghana Production and Free Cash Flow Profile (after-tax)



Source: J.P. Morgan estimates, Company data.

Jubilee

Overview

Jubilee field is located in Deepwater Ghana and was discovered in 2007. The Jubilee field consist of two blocks: Kosmos Energy operated West Cape Three Points (WCTP) Block and the Tullow Oil operated Deepwater Tano Block and was unitized between these two blocks with the percentage split of 54.37% and 45.63%, respectively. Tullow was appointed as field unit operator and Kosmos the technical operator for the development phase. The field is being developed in three phases; 1, 1a and the Greater Jubilee Full Field Development. Phase 1 and Phase 1a production began in 2010 and 2012 respectively In December 2015, the partners submitted a development plan for the Greater Jubilee area which was approved in Nov 2017 and drilling will begin in 2018.

Key Near-Term Events

The key near term issue in 2018 for APC is the production shutdown planned due to the FPSO turret bearing issue. In 2016, Tullow Oil announced that damage to the FPSO turret bearing had occurred as a result of which new production and offtake procedures were implemented. However, the partners agreed to a long-term solution to convert the FPSO to a permanently spread-moored facility. In 4Q16, an interim spread mooring of the FPSO commenced and was completed during 1Q17. In early 2018, the operator will start the first of three shutdown periods that are expected to

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occur in 2018 to effectively stabilize the turret and rotate the FPSO to its permanent heading. However, a key near term catalyst is the commencement of drilling in 2018 for the full-field development in the Greater Jubilee area, which was approved in November 2017. Tullow expects average gross production from the Jubilee field to be more than 75 MBo/d in 2018, including the impact shut-ins.

Participation

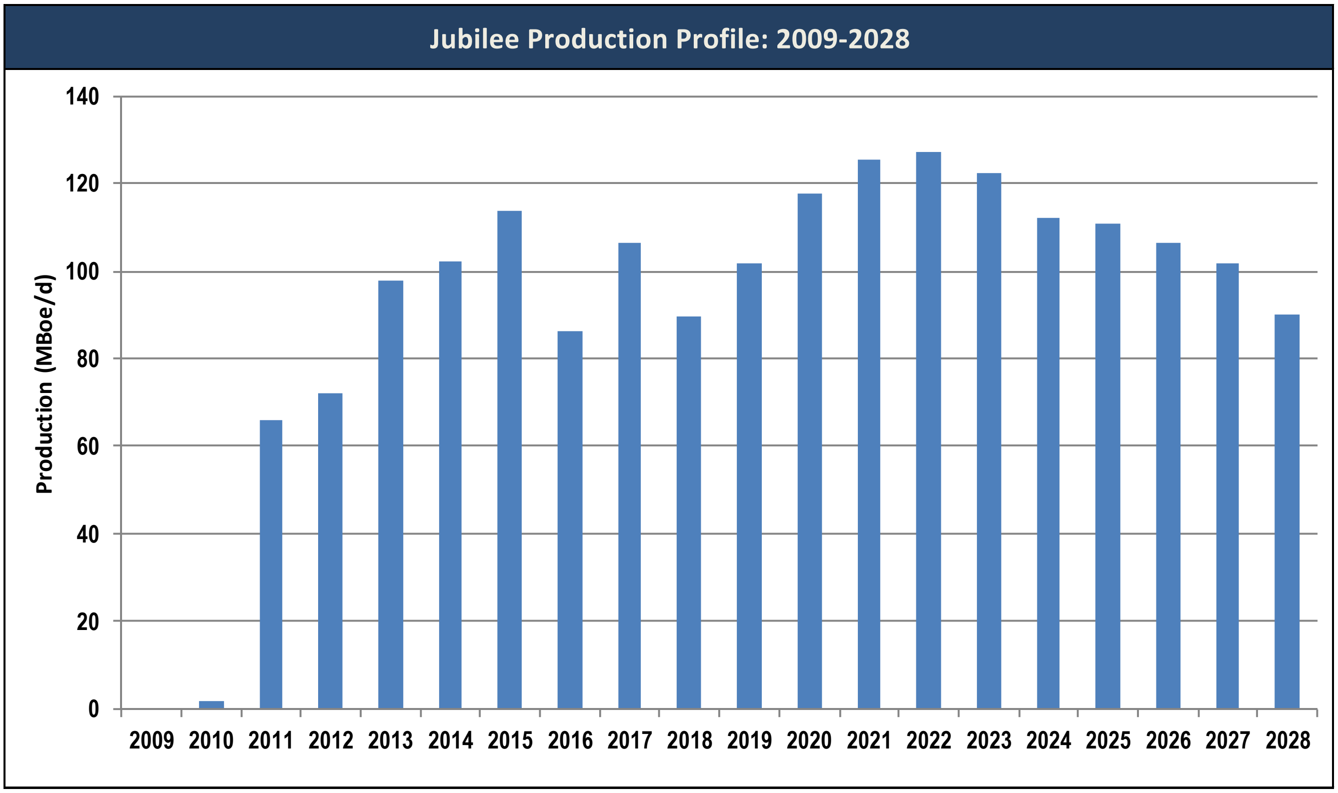
The Deepwater Tano and West Cape Three Point Blocks are taxed under different petroleum agreements; however, the petroleum law dictates that Jubilee is produced as one unit in order to decrease costs and maximize recovery. The field is unitized 54.37% to WCTP, and 45.63% to Deepwater Tano. Currently, Anadarko owns 24.08% non-operating working interest in the field, with other partners Tullow Oil, Kosmos Energy, Ghana National Petroleum Co (GNPC) and PetroSA owning 35.48%, 24.08%, 13.64% and 2.72% working interest, respectively.

Exploration

Kosmos Energy started its exploration program on the WCTP Block in May 2007 with the discovery of Mahogany-1, a 312 net feet of oil pay discovery in the Upper Cretaceous sandstone reservoir. The exploration studies extended westwards into the neighboring Deepwater Tano Block with Tullow drilling Hyedua-1 in July 2007. This confirmed the existence of a continuous reservoir across the two blocks and the field was renamed Jubilee. The next exploration well called Mahogany-3 was drilled in 2009. The well discovered a deeper reservoir beneath Jubilee, which was deemed not an extension to Jubilee as originally thought. The field was renamed Mahogany East. In 2010, an exploratory well was drilled to target both the Dahoma prospect, but turned out to be a dry hole. The exploration license for the WCTP and Deepwater Tano Blocks expired in May 2011 and January 2013, respectively. In February 2011, another discovery named Teak was made and further appraisal wells Teak-2 and Teak-3A tested the Campanian and Turonian sandstone reservoirs. The Akasa-1well drilled in Aug 2011 discovered light oil in Turonian-age sand packages. However, results from the Teak-4 drilled in 2012 were disappointing. The exploration and appraisal drilling activities on WCTP Block are expected to resume in 2018, however, it is assumed that the best prospects have been targeted and the potential of the relinquished area is limited.

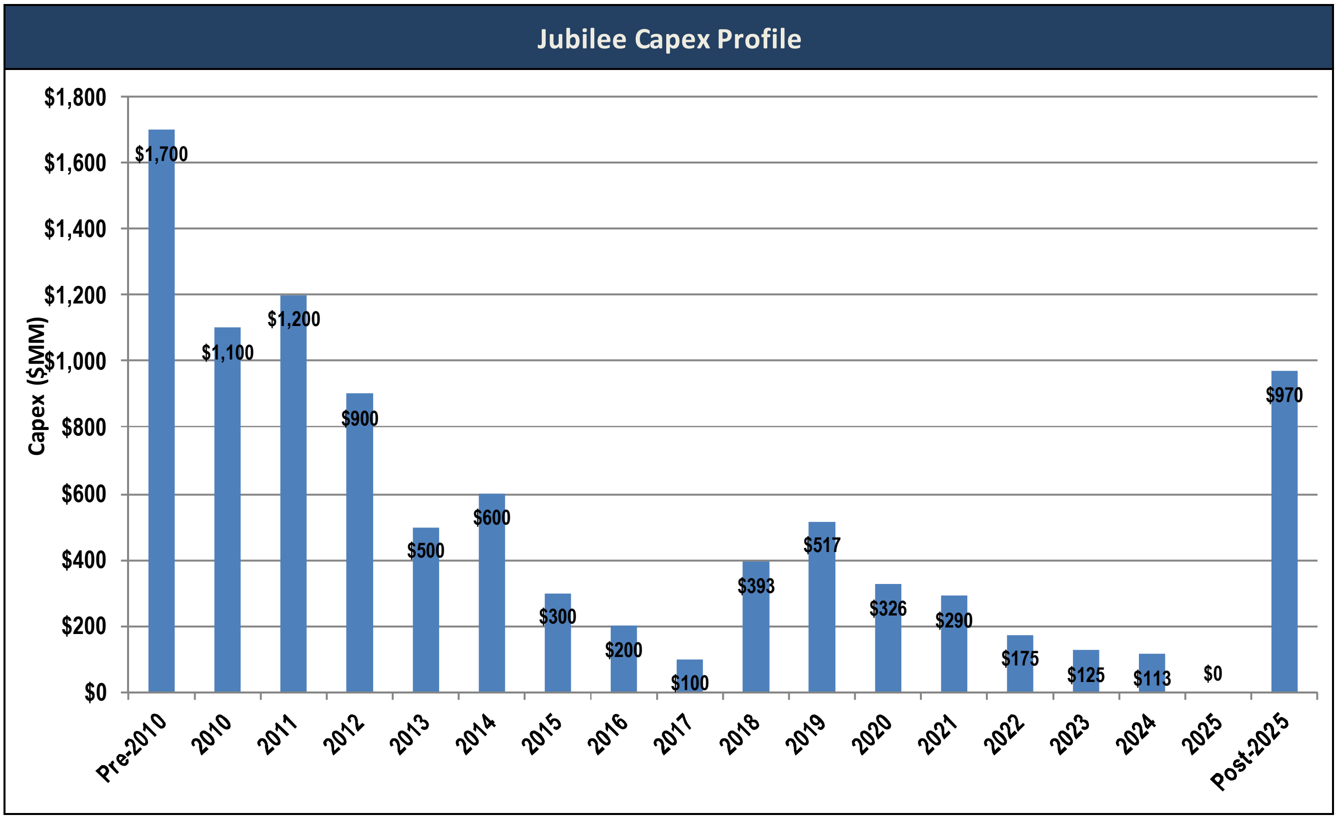
Figure 18 illustrates our gross production forecast for Jubilee through the life of the field. Figure 19 and Figure 20 illustrate the capex and free cash flow profiles of the field.

Figure 18: Jubilee Production Profile



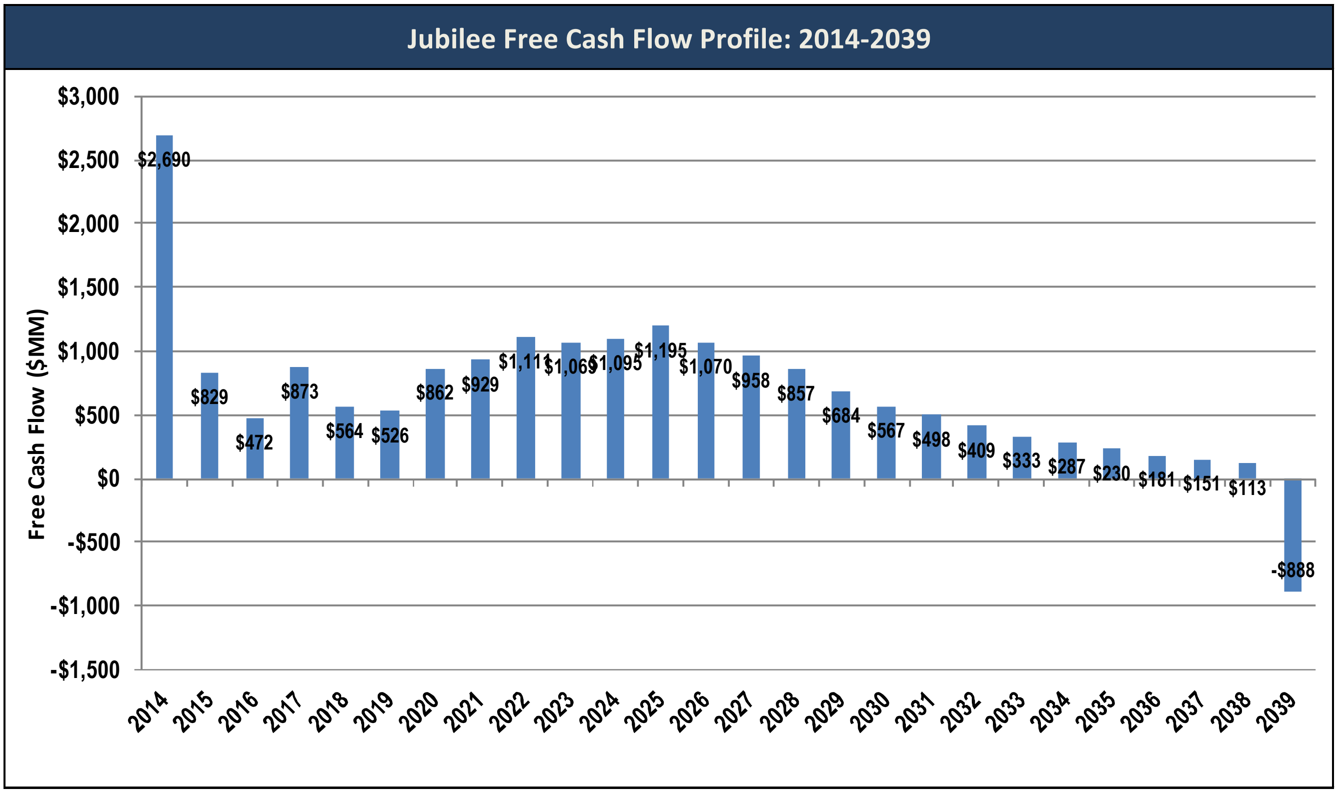
Source: J.P. Morgan estimates, Wood Mackenzie.

Figure 19: Jubilee Capex Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

Figure 20: Jubilee Free Cash Flow Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

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TEN

Overview

The TEN project represents a cluster of three fields: Tweneboa, Enyenra and Ntomme located in the Deepwater Tano Block. Tweneboa field was discovered in 2009 with Tullow Oil drilling the first exploratory well Tweneboa-1 in a Turonian reservoir. Enyenra and Ntomme were discovered in 2010 and 2012, respectively. The block also contains the Wawa discovery. Tullow Oil made the final investment decision (FID) in May 2013 for development of TEN and achieved its first oil in August 2016.

Near Term Catalyst

The key near term catalyst for APC is the drilling restart at the TEN (Ntomme) field in mid-2018. Earlier in 2015, as a result of the border dispute between Ghana and Cote d'Ivoire, the Special Chamber of the International Tribunal of the Law of the Sea (ITLOS) intervened and there was a suspension in drilling activity at the field until it completed its ruling on the maritime border dispute. In September 2017, ITLOS made a ruling indicating that the new maritime boundary would not affect the TEN fields. As a result, Tullow received approval to restart drilling activities at TEN. Drilling is expected to restart from mid-2018. In 2017, gross production at TEN averaged 56 MBo/d vs. nameplate capacity of 80 MBo/d and Tullow has guided to 2018 gross production of 64 MBo/d, which is 7% above JPMe at 60 MBo/d. There appears to be potential upside potential as production has consistently eclipsed 70 MBo/d over the past few months. Tullow contracted the Maersk Venturer drilling rig for a four-year period and began drilling a development well at the Ntomme field. Results from the Ntomme field are anticipated later this summer. Another key catalyst from TEN is the beginning of Gas sales in 2H18 as the partner companies have signed a gas sales agreement with the Ghanian government in 2017. Gas production is dependent on local demand and the ability of GNPC to build the necessary infrastructure for transportation. Earlier in February 2017, Tullow completed the gas interconnection line between TEN and Jubilee. In 2018, Tullow also expects the initial start of gas sales, anticipating gross gas production of 4.2 MBoe/d.

Participation

In 2006, Tullow Oil, Anadarko, Kosmos Energy and Sabre Oil & Gas received the license to develop Deepwater Tano Block. However, Sabre Oil & Gas divested its interest in the block to PetroSA in 2012. The Ghanaian National Petroleum Company (GNPC) has a 10% carried equity and has exercised its right to an additional 5% non-carried. Currently, Anadarko owns a 17% non-operating working interest in the project, with other partners Tullow Oil, Kosmos Energy, Ghana National Petroleum Co (GNPC) and PetroSA owning 47.18%, 17%, 15% and 3.83% working interests, respectively.

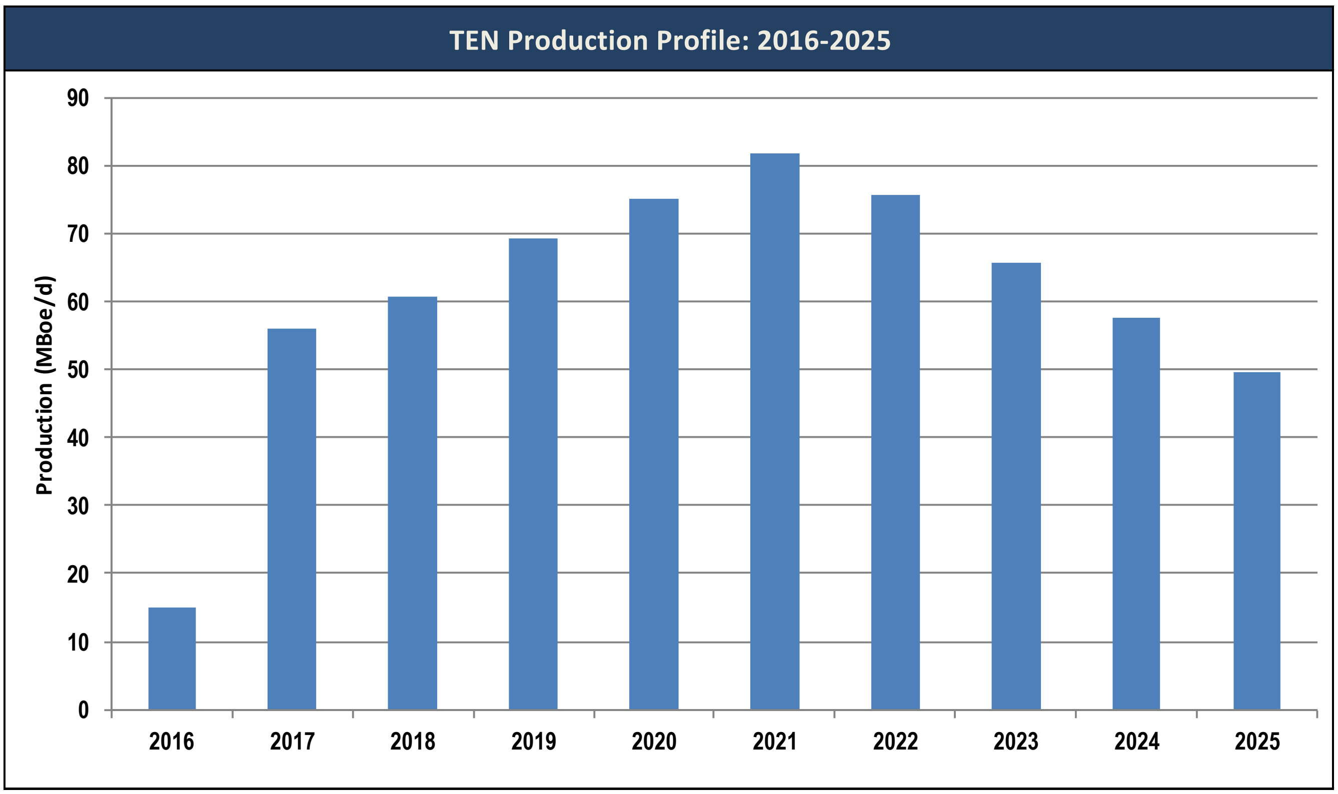
Exploration

Tullow Oil started its exploration program in January 2009 with the drilling of the first exploratory well Tweneboa-1 in a Turonian reservoir. The first appraisal well Tweneboa-2 was completed in January 2010. The next appraisal well Tweneboa-3, completed in January 2011, was sidetracked and discovered the Ntomme field.

Another appraisal well Ntomme-2A was completed in Jan 2012 tested 410 net feet of oil pay beneath the gas-condensate cap. In March 2012, the Owo-1 well discovered the Enyenra light oil field. Further appraisal wells Enyenra-2A, 3A, and 4A all encountered oil and are expected to be converted to development wells. The Wawa-1 exploration well, located 3.7 miles north of Enyenra, discovered commercial volumes of oil and was delineated from the exploration license pending further appraisal. The Okure and Sapele prospects were drilled in 2012 and 2013 but were unsuccessful.

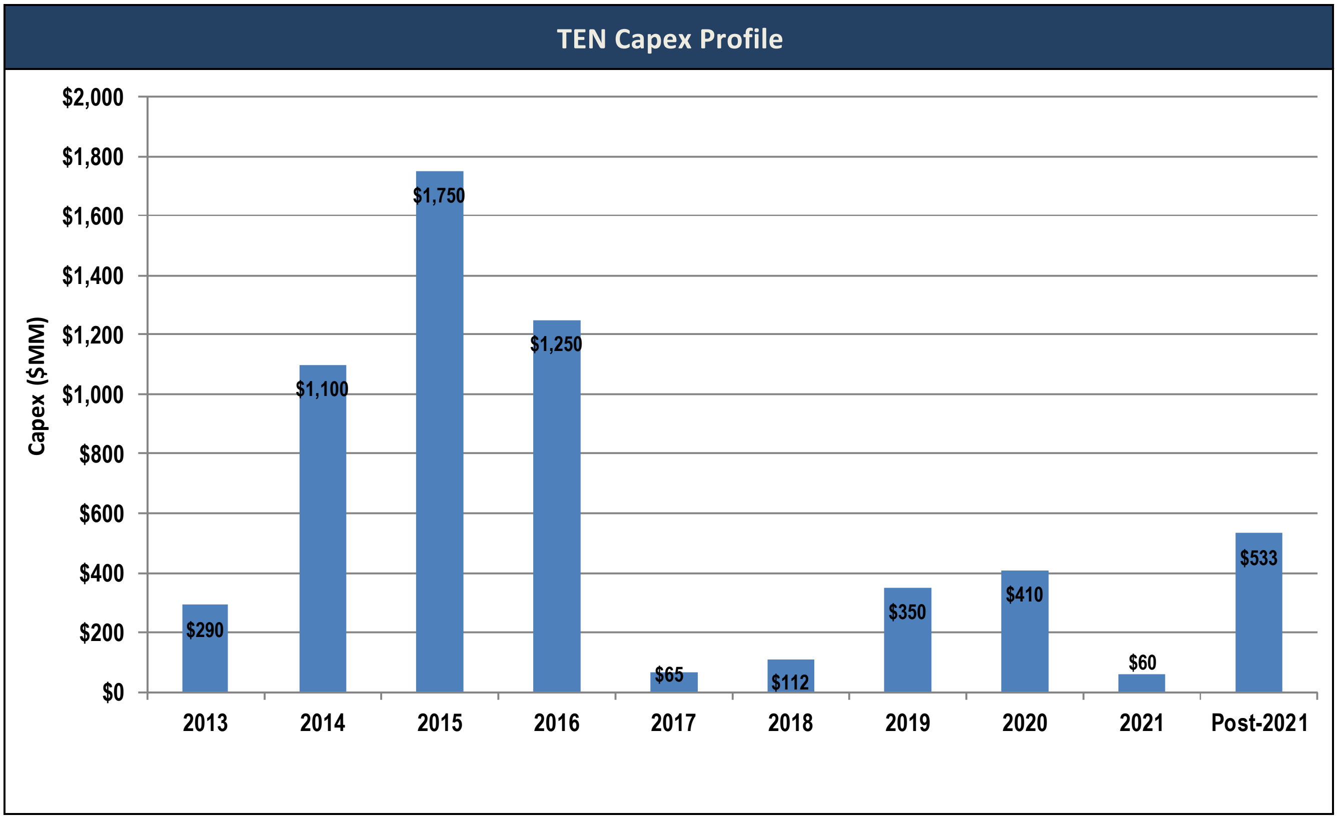
Figure 21 illustrates our gross production forecast for the TEN field through the life of the field. Figure 22 and Figure 23 illustrate the capex and free cash flow profiles of the field.

Figure 21: TEN Production Profile



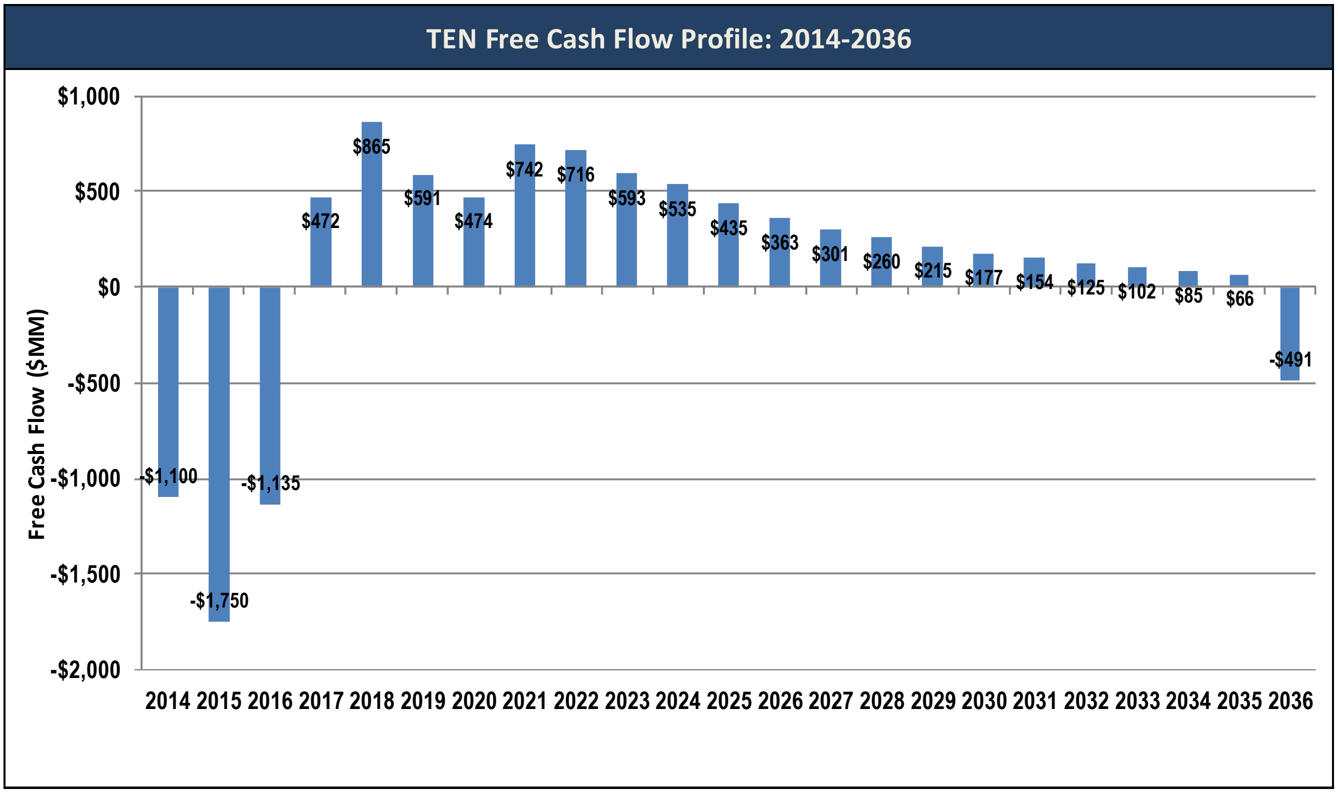
Source: J.P. Morgan estimates, Wood Mackenzie.

Figure 22: TEN Capex Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

Figure 23: TEN Free Cash Flow Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

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Mozambique

Anadarko's Mozambique operations are located in the Offshore Area 1, which encompass 1.2 million gross acres. APC operates with a 26.5% working interest on the Area 1 block. Anadarko recently received regulatory approval for the development of LNG in Mozambique, and now continues to advance the initial two-train Golfinho/Atum project toward FID. Anadarko also made significant progress on the marketing front. APC needs ~8.5 MMTPA to move forward with project financing. In 3Q17, Anadarko and its partners signed a long-term sales and purchase agreement for 2.6 MMTPA of LNG with PTT. In 4Q17, APC's total sales agreement reached to 5.1 MMTPA along with the signing of a HOA Tohoku Electric Power Company. Recently, in February 2018, APC entered into a long-term LNG SPA with Électricité de France, S.A., (EDF), which includes the supply agreement of 1.2 MMTPA for a term of 15 years. On the exploration front, APC continues to interpret the 3D seismic data covering the Orca, Tubarão, and Tubarão-Tigre discovery in Area 1.

Area 1 (LNG)

Overview

Area 1 is located in the northern part of Mozambique in the Rovuma Basin. In 2005, APC received operatorship for the block and has drilled 17 exploration wells and discovered 10 gas fields and one small oil field since then. Approximately 62 Tcf of estimated recoverable gas volumes have been discovered in Area 1. Eni also discovered gas on Area 4, located across the Area 1 boundary. The exploration results from the Area 1 Prosperidade Complex (Windjammer, Barquentine, Lagosta and Camarão) suggest that Oligocene reservoirs are in communication with some of the Area 4 Mamba complex discoveries. Prosperidade contains around 26 Tcf of the discovered gas volumes. In December 2015, APC and Eni signed a unitization agreement stating that the first 16 Tcf from Area 1 and the first 14 Tcf from Area 4 will be produced in a separate but coordinated development. The remaining volumes will be jointly developed by a new jointly owned JV operator by APC and Eni.

The partnership for the Area 1 are planning and developing Golfinho/Atum reserves to evaluate a LNG development to monetize the 16 Tcf of gas which would support a two-train, 12.88 MMtpa LNG plant running for 25 years. In December 2014, the Mozambican parliament enacted the LNG Decree Law for developing the Area 1 and Area 4 onshore LNG projects. In May 2015, Anadarko made progress on the development of the LNG project, by selecting the CB&I, Chiyoda Saipem JV as the preferred consortium for the onshore engineering procurement and construction (EPC) contract. In 2017, Anadarko and its partners reached agreement on a long-term sales and purchase agreement (SPA) for 2.6 MMTPA of LNG with PTT Public Company Limited (PTT), Thailand's national oil and gas company. In Feb 2018, APC entered into a long-term LNG SPA with Électricité de France, S.A., (EDF), which includes the supply agreement of 1.2 MMTPA for a term of 15 years. Anadarko recently received, in March 2018, approval from the Government of Mozambique for the Golfinho/Atum Field Development Plan.

Anadarko continues advancement toward a FID as it builds upon other recent achievements, including the marketing of LNG volumes, commencement of resettlement, and ongoing work to secure project financing.

Participation

In 2006, Anadarko received the license to explore Area 1 from Mozambican government. Currently, Anadarko operates with a 26.5% working interest in the project, with other partners Mitsui & Co, ENH, Beas Rovuma Energy Mozambique, Bharat Petroleum, ONGC, and PTTEP owning 20%, 15%, 10%, 10%, 10% and 8.5% working interests, respectively.

Development

Engineering Contracts - Upstream

In 2011, Technip and KBR were awarded the contract for pre-FEED studies for Area 1. In December 2012, three offshore FEED contracts were awarded to Technip, a Subsea 7/Saipem JV and a McDermott/Allseas JV. The contract covered engineering, procurement, construction (EPC) design for a subsea development, which included the subsea infrastructure and gas-to-shore pipeline system. The offshore FEED studies are completed.

Upstream

Golfinho and Atum fields are expected to provide the gas volumes for two trains, while the other Area 1 fields could be developed as part of future phases. The development would involve a subsea-to-shore scenario for the initial phase, with subsea compression equipment installed later in field life to provide compression facilities. The gas should require minimal processing, as it is rich in methane content (96.5%) with minimal condensate volumes. Two 22 inch diameter and 22 miles long offshore pipelines are proposed to transport gas to an onshore processing facility before supplying the LNG terminal. The condensate will get separated onshore and would be sold directly to Petromoc and transported via roads.

Key Development Metrics

The two-train LNG project would be supplied with the help of 45 development wells, including 21 on Golfinho and 14 on Atum with one drilled in 2021, three in 2022 and five in 2023. The remaining wells will be drilled through the project's life.

Engineering Contracts - LNG

In December 2012, three onshore FEED contracts were awarded to Bechtel, a JGC/Fluor JV and a CB&I/Chiyoda JV for an initial four train development of a common LNG facility with the Area 4 partners. In 2014, the onshore FEED studies were completed. In May 2015, Anadarko selected CB&I, Chiyoda Saipem JV as the preferred consortium for the onshore engineering procurement and construction (EPC) contract.

LNG plant

The typical construction phase for a LNG plant is 3.5 to 5 years from project sanction to first LNG. In 2012, site selection for the Afungi LNG plant was finalized, which will be located near the town of Palma, in Cabo Delgado, northern Mozambique.

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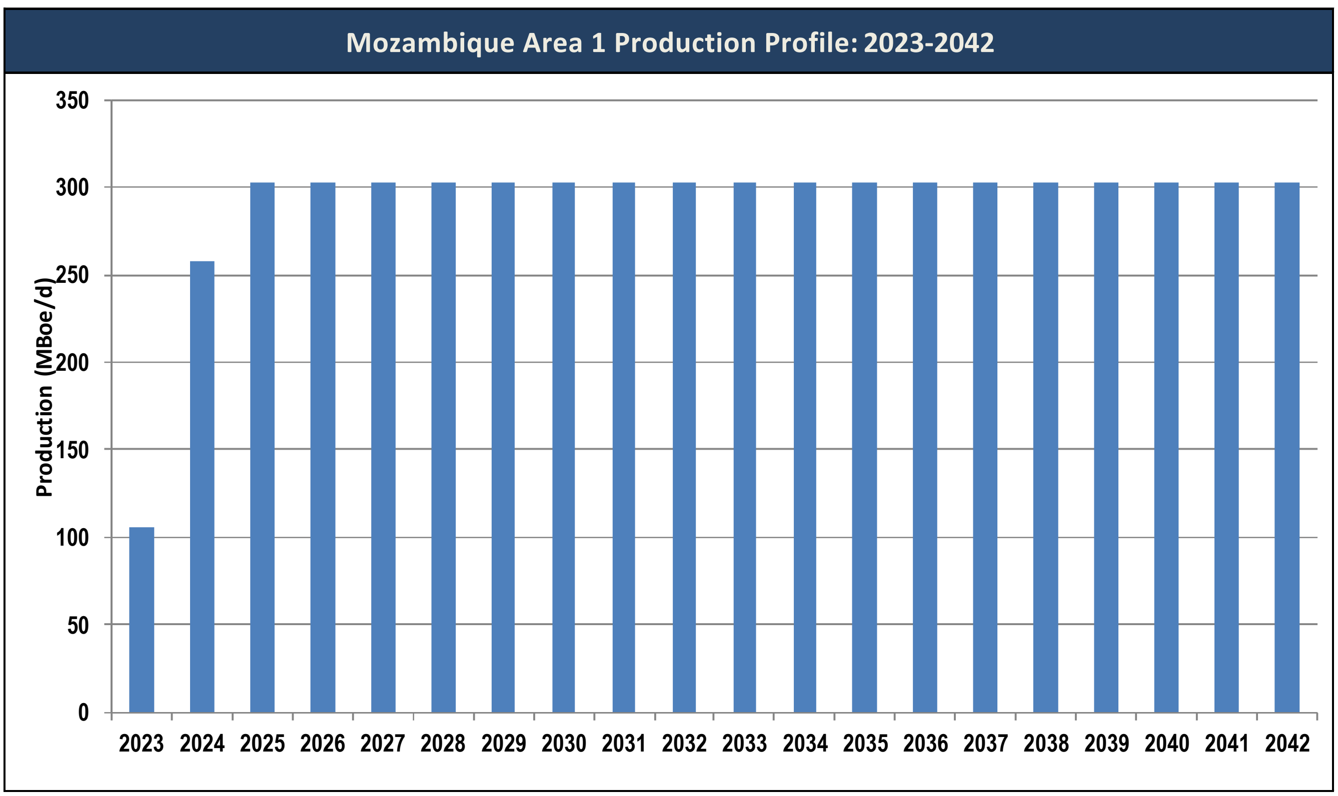
Sales Contract

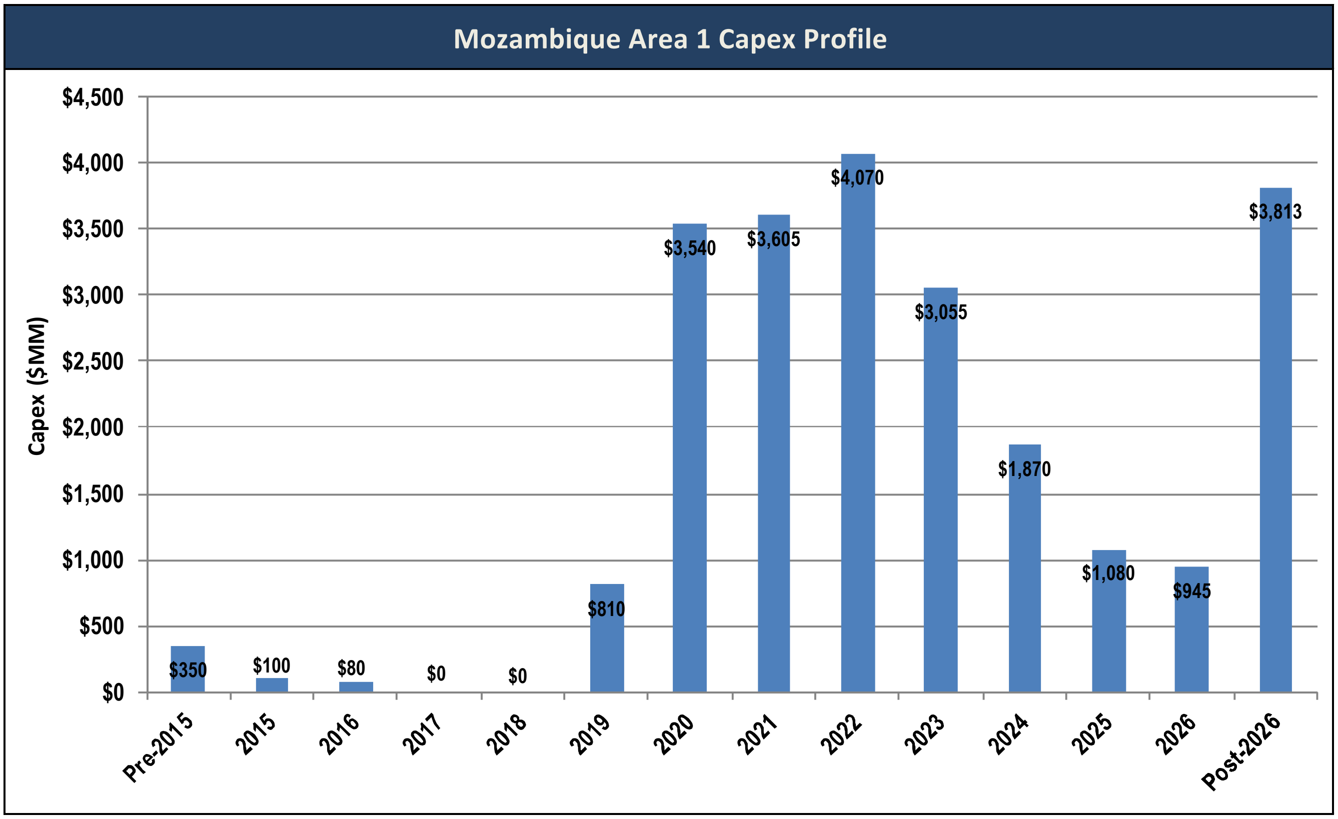
LNG projects in Mozambique have a favorable geographic position to supply both the Pacific and Atlantic basin markets. The primary target is expected to be the premium markets in Asia, however, in order to secure agreements in a timely manner LNG is expected to be marketed to many key markets. Corporates like Mitsui (Japan), ONGC/Oil India/Bharat Petroleum (India) and PTT (Thailand) are expected to aid in the marketing efforts. APC appears to be making tangible progress on the Mozambique project with the completion of the legal and contractual framework, onsite preparation work, and agreements on 5.1 MMTPA of volumes. APC needs a total of ~8.5 MMTPA to move forward with project financing. The preliminary discussions started with a number of Japanese buyers in 2012. In 3Q17, Anadarko and its partners in Area 1 reached agreement on the project's first long-term SPA for 2.6 MMTPA with PTT. In 4Q17, APC continued to make progress on long-term LNG offtake agreements, with the total agreement reaching to 5.1 MMTPA. In 4Q17, a HOA was reached with one of Japan's most important LNG buyers, Tohoku Electric Power Company, Inc., to bring them to the Anadarko-operated Mozambique LNG project. In February 2018, APC entered into a long-term LNG SPA with EDF, which includes the supply agreement of 1.2 MMTPA for a term of 15 years.

Figure 24: Area 1 Gross Production Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

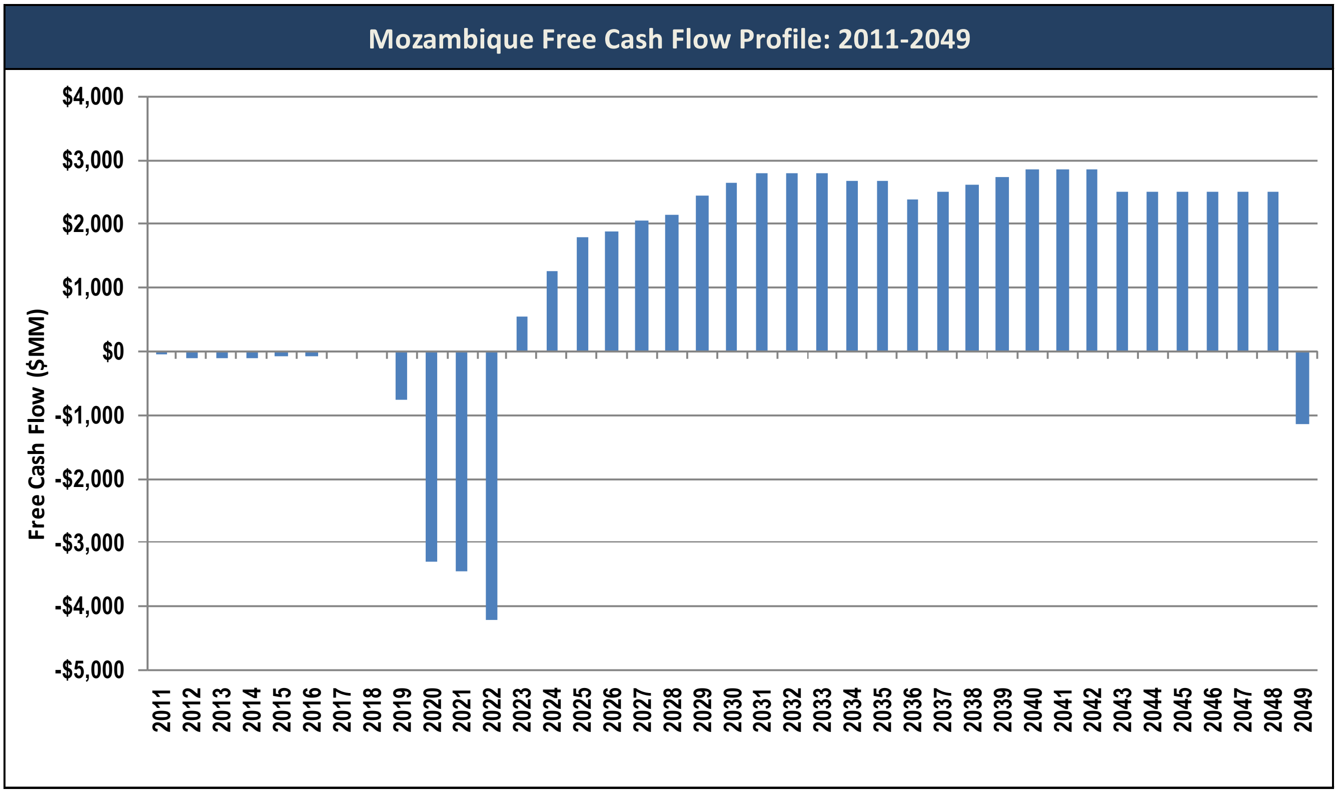
Figure 25: Area 1 Gross Capex Profile



Source: J.P. Morgan estimates, WoodMackenzie.

Free Cash Flow Profile

Figure 26: Mozambique Area 1 Gross Free Cash Flow Profile



Source: J.P. Morgan estimates, Wood Mackenzie.

APC Liquidity Overview

APC maintains solid credit metrics relative to its E&P peers, bolstered by the company's ample liquidity, we see the company as one of the better positioned E&P's to manage through the cycle and eventually work its way back to fully IG at all rating agencies. APC has ~$15.5bn of total debt, $1.0bn of which is due in the next 18 months. APC has $9.6bn of total liquidity, which includes $4.6bn of cash and $5.0bn of revolver availability. The company maintains two revolving credit facilities: a $2.0bn 364-day senior unsecured revolver due in 2019 and a $3.0bn senior unsecured revolver due 2022. In January 2018, the Company amended the APC RCF to extend the maturity date to January 2022 and amended the 364-Day Facility to extend the maturity date to January 2019. As of YE2017 both revolvers had $0 outstanding, though the revolver due 2022 has $384,000 in letters of credit. APC owns 81.6% of interest in WGP, which has liquidity supported by a $250mm revolver ($28mm letters of credit outstanding as of February 2018) due 2019 and WES's $1.5bn senior unsecured revolver due in 2023. In February 2018, WES amended their revolver to extend the maturity date to February 2023 and increased capacity from $1.2bn to $1.5bn. As of YE2017 the WES revolver had $370mm outstanding and $4.6mm of letters of credit.

APC believes that its current cash balance and operating cash flows will be sufficient to fund operations and capex as well as to fund the increase in quarterly dividends to $0.25 per share, repurchase the remaining shares under the $3.0bn repurchase program by the end of 2018, and retire Anadarko's debt maturing in 2018 and 2019, with a target of $1.0bn of total debt reduction in 2018. Management increased their repurchase program from $2.5bn to $3.0bn in 2018 after the company repurchased $1.1bn of shares in 2017 and $500mm in February 2018.

APC's liquidity was bolstered by $4.0bn of asset sale proceeds in 2017, including the sale of the Eagle Ford, Marcellus, Eaglebine, Utah CBM and Moxa assets, and $383mm of proceeds from their sale of non-operated interest in Alaska.

APC versus Peers

Relative to similarly rated E&P peers APC has one of the most aggressive repurchase programs as it has $1.3bn of repurchases remaining for 2018. DVN recently announced a $1.0bn repurchase program while increasing dividend by 33% after tendering for $1.0bn of debt in 2018. MRO currently has $1.5bn of share repurchase authorizations available on their $6.2bn program announced in 2006 after the company did not repurchase shares in 2017. APC's decision to increase shareholder value was a result of their improved balance sheet and improved economic outlook, as opposed to peers like HES who recently announced a $1.0bn repurchase program after activists demanded for CEO John Hess to step down if the company did not repurchase shares.

Moody's views APC's buyback program as a credit negative for the company because they will return a significant amount of its asset sales proceeds to shareholders instead of focusing on debt reduction. We disagree with Moody's sentiment and view APC's share repurchase as only a modest credit negative as we remain concerned about activists getting involved in high cash balance companies.

Also worth noting, the relationship with Moody's and APC is one of the more contentious relative to its E&P peers. We do not believe APC's share repurchase program should be viewed as material by ratings agencies as APC's management team has a history of being prudent and the company has a total liquidity position of $9.6bn which is ahead of similarly rated peers DVN ($5.7bn), HES ($9.0bn) and MRO ($4.0bn). We believe the repurchase program represents a modest shift by the company towards a more shareholder-friendly financial policy but in a balanced manner that does not materially impact the balance sheet or credit metrics. APC remains committed to further debt reduction in 2018 as they target $1.0bn of total debt reduction. Relative to peers with similar ratings APC has lagged a bit on this front, DVN tendered for $1.0bn of debt so far in 2018 as management targets debt reduction of up to $1.5bn, MRO reduced debt by $1.75bn in 2017 and HES has completed $350mm of debt reduction in 2018 with the call redemption of the company's 8.125% notes due in 2019 and targets $500mm of total debt reduction in 2018. APC and peers MRO and DVN target to maintain self-funded capital program in 2018 at $50 WTI, with the exception of HES who will not be break-even until 2020.

In all, we expect APC's balance sheet to continue to improve through the year relative to its peers.

Figure 27: APC Debt Profile

Debt	APC
7.050% Anadarko Holding Co Notes due 2018	114
TEUs - senior amortizing notes due 2018	17
6.950% Senior Notes due 2019	300
8.700% Senior Notes due 2019	600
4.850% Senior Notes due 2021	800
3.450% Senior Notes due 2024	625
6.950% Senior Notes due 2024	650
5.550% Senior Notes due 2026	1,100
7.500% Debentures due 2026	112
7.000% Debentures due 2027	48
7.125% Debentures due 2027	150
6.625% Debentures due 2028	14
7.150% Debentures due 2028	235
7.200% Debentures due 2029	135
7.950% Debentures due 2029	116
7.500% Senior Notes due 2031	900
7.875% Senior Notes due 2031	500
Zero Coupon Senior Notes due 2036	2,360
6.450% Senior Notes due 2036	1,750
7.950% Senior Notes due 2039	325
6.200% Senior Notes due 2040	750
4.500% Senior Notes due 2044	625
6.600% Senior Notes due 2046	1,100
7.730% Debentures due 2096	61
7.500% Debentures due 2096	78
7.250% Debentures due 2096	49
Total borrowings at face value	13,514
Net unamortized discounts, premiums, and debt issuance costs	(1,549)
Total borrowings (4)	11,965
Capital lease obligations	231
Less short-term debt	142
Total long-term debt	12,054

Source: J.P. Morgan estimates, Company Reports.

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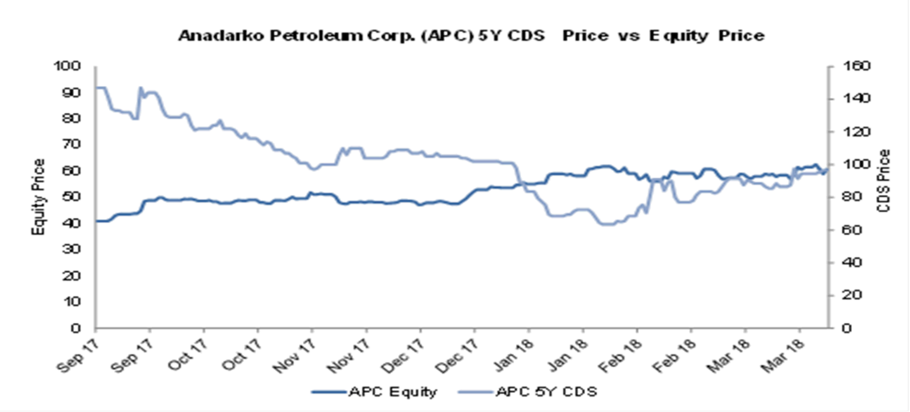
Figure 28: WES Debt Profile

Debt	WES
WES 2.600% Senior Notes due 2018	350
WES 5.375% Senior Notes due 2021	500
WES 4.000% Senior Notes due 2022	670
WES 3.950% Senior Notes due 2025	500
WES 4.650% Senior Notes due 2026	500
WES 5.450% Senior Notes due 2044	600
WES RCF	370
Total borrowings at face value	3,490
Net unamortized discounts, premiums, and debt issuance costs	(25)
Total borrowings	3,465
Total long-term debt	3,465

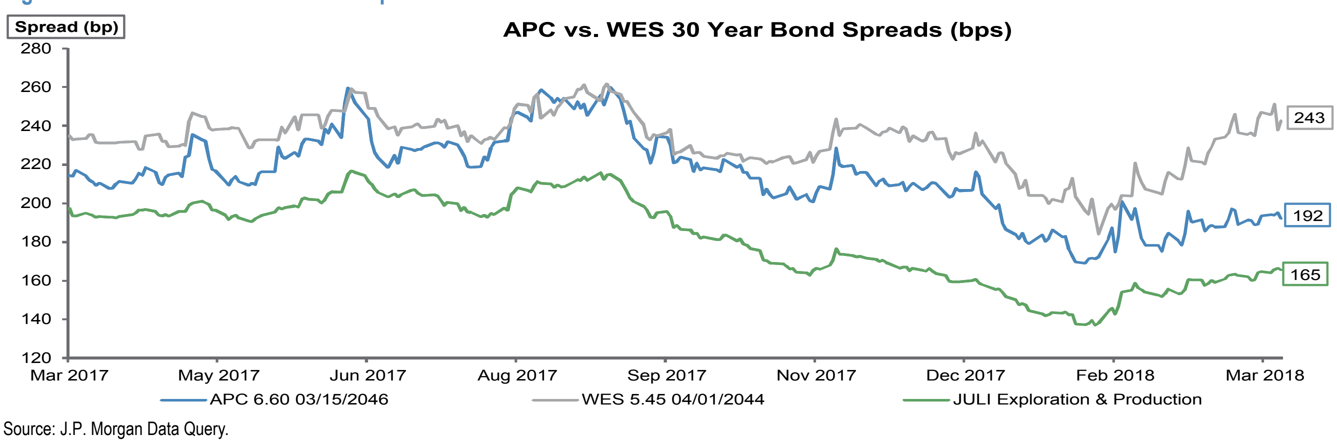
Source: J.P. Morgan estimates, Company Reports.

Figure 29: APC 5Y CDS Price vs. Stock Price



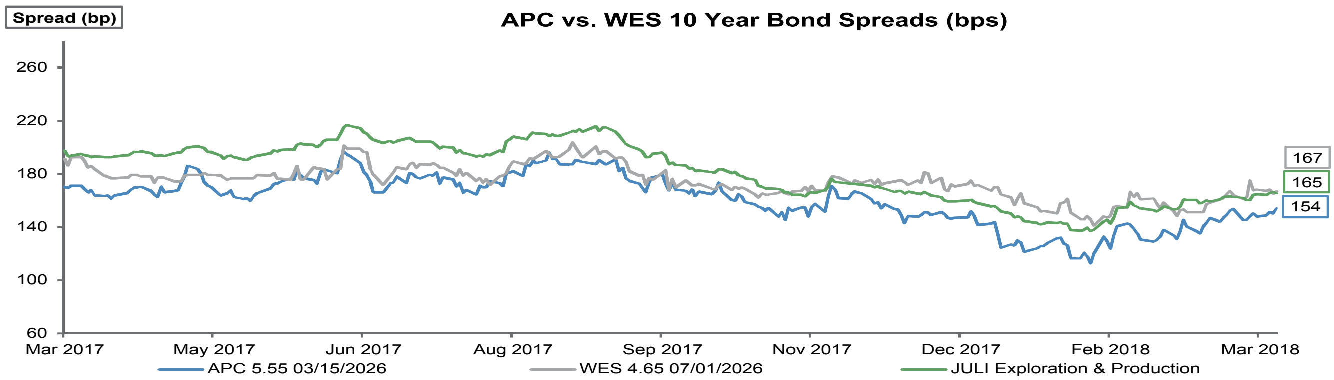
Source: Bloomberg.

Figure 30: APC vs. WES 30 Year Bond Spread



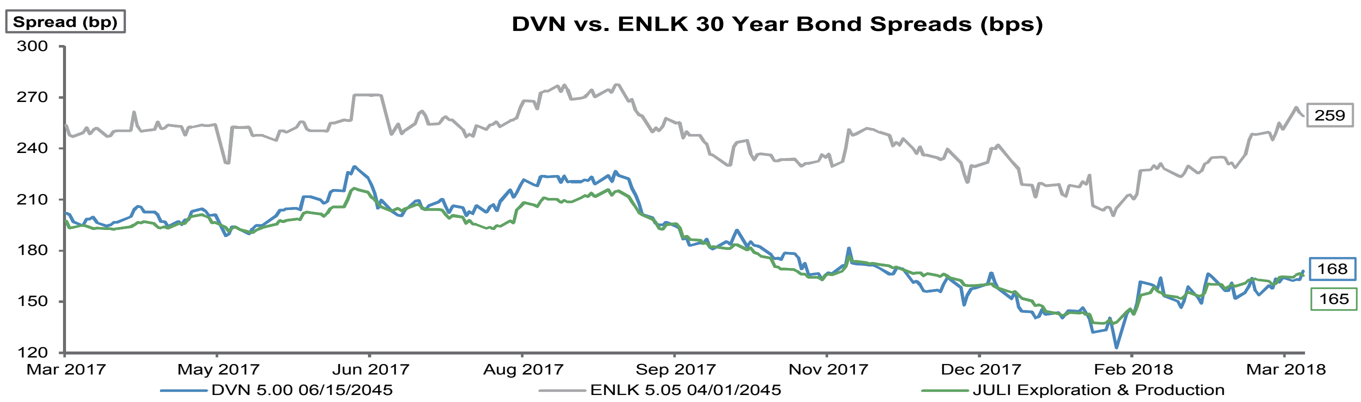
Source: J.P. Morgan Data Query.

Figure 31: APC vs. WES 10 Year Bond Spread



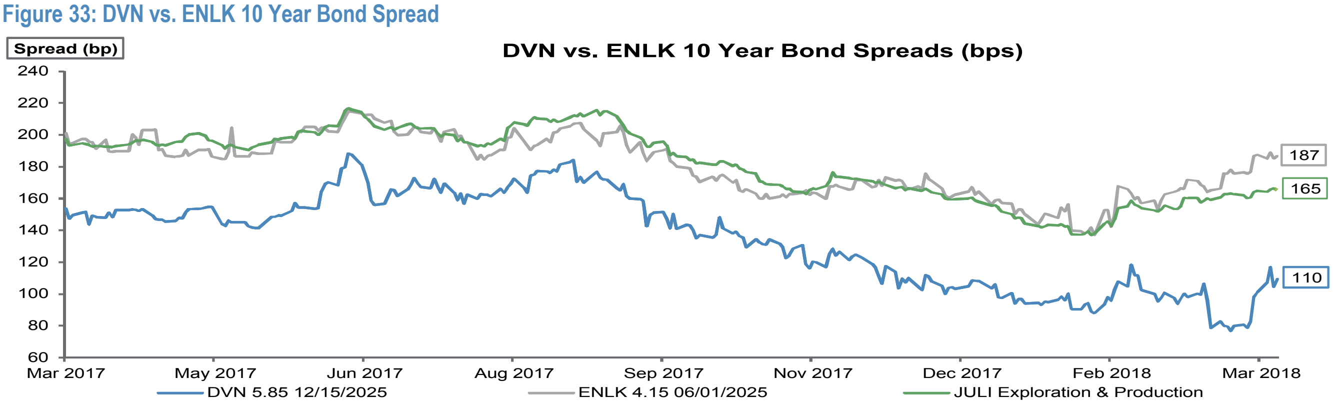
Source: J.P. Morgan Data Query.

Figure 32: DVN vs. ENLK 30 Year Bond Spread



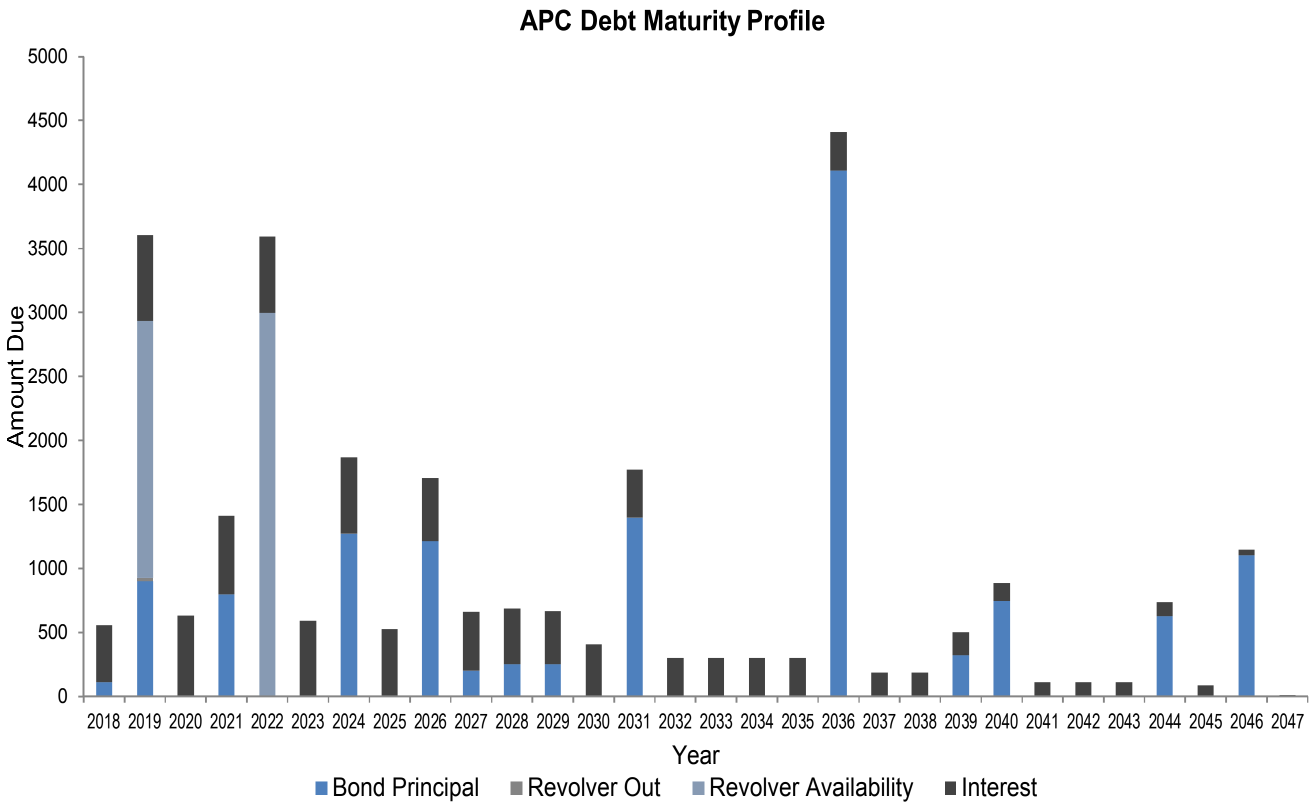
Source: J.P. Morgan Data Query.

Figure 33: DVN vs. ENLK 10 Year Bond Spread



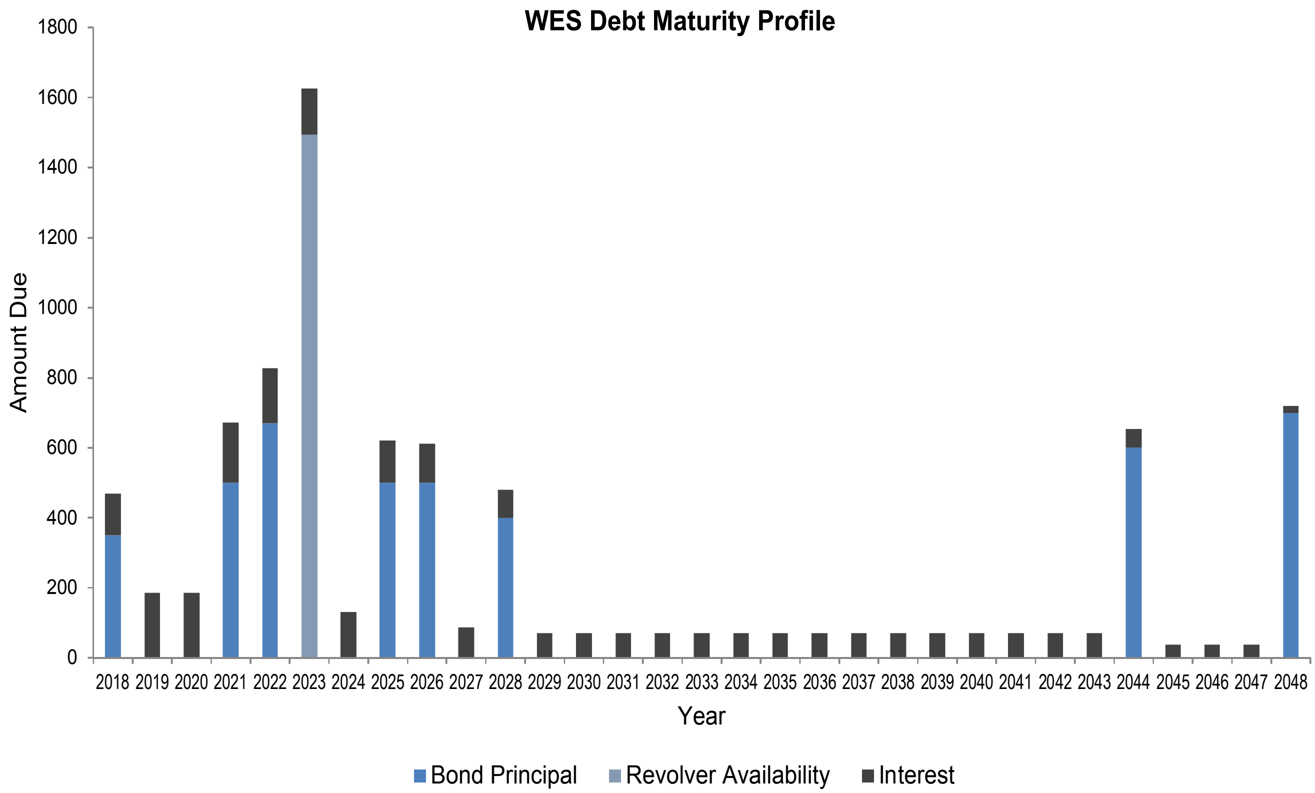
Source: J.P. Morgan Data Query.

Figure 34: APC Debt Maturity Profile



Source: Bloomberg.

Figure 35: WES Debt Maturity Profile



Source: Bloomberg.

Investment Thesis, Valuation and Risks

Anadarko Petroleum *(Overweight; Price Target: $72.00)*

Investment Thesis

We see several emerging positives that could support more upside in the stock (APC trades at a ~13.8% 2020E sustaining FCF yield vs. group average ~9.1%). We believe near-term and long-term oil growth outlooks are largely intact, with the near-term outlook buoyed by surprising strength in the GoM and long-term growth supported by visibility in the Delaware and DJ Basins. Meanwhile, APC's $4.5+ billion cash hoard provides optionality to support higher levels of cash return to shareholders. APC has one of the highest quality franchise assets at Wattenberg, and its U.S. onshore position is further enhanced by its Delaware Basin position. We believe a key catalyst for the stock is the potential shift into development mode in the Delaware Basin Wolfcamp play, where APC has significant running room in the core. In particular, we believe APC's Delaware Basin volumes could hit a meaningful growth inflection point by mid-year 2018 when it completes its midstream backbone project.

Valuation

Using our NAV methodology, we calculate a net asset value of $72 per share for APC at the strip. We believe an Overweight rating on APC is justified, as the stock is trading at a discount to our NAV. Our Dec-18 price target of $72 assumes that the stock trades at parity with our NAV estimate. In summary, we value proved developed NAV (net of liabilities) at ~$30.90 per share and undeveloped/unproven reserves at ~$40.70 per share to arrive at a total proved developed and undeveloped net asset value of $72 per share.

Risks to Rating and Price Target

- Post the Firestone incident, the regulatory and legal overhang could linger over APC's DJ Basin asset, which represents approximately 20% of our NAV estimate. The DJ Basin has historically had infrastructure issues including delays, high-line pressures, and a lack of natural gas processing capacity, which have all curtailed production at some point over the past several years.
- Post the Freeport-McMoran deepwater purchase, APC has increased its leverage to the U.S. GoM, which could lead to higher volatility in production levels and higher asset concentration risk, particularly at the Lucius development.
- There could be a delay in getting the midstream infrastructure ready, which is the key assumption that underpins our APC growth rates and rate of change in Delaware Basin well productivity.
- Continued oil price volatility could negatively impact play economics and ultimately corporate level cash flow, which could cause the stock to underperform our expectations.

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Anadarko Petroleum: Summary of Financials

Income Statement - Annual	FY16A	FY17A	FY18E	FY19E	FY20E
Revenue	**7,869**	**11,908**	**13,783**	**15,094**	**-**
SG&A	(1,440)	(1,075)	(990)	(1,000)	-
Adj. EBITDAX	**4,075**	**5,732**	**8,127**	**8,903**	**-**
Exploration expense	(946)	(2,541)	(395)	(557)	-
Adj. EBITDA	**3,129**	**3,191**	**7,733**	**8,345**	**-**
D&A	(4,301)	(4,279)	(4,583)	(5,155)	-
Adj. EBIT	**(1,172)**	**(1,088)**	**3,150**	**3,190**	**-**
Net Interest	(890)	(932)	(951)	(898)	-
PBT	**(3,829)**	**(1,688)**	**2,199**	**2,292**	**-**
Tax	1,021	1,477	(879)	(879)	-
Minority Interest	(263)	(245)	(330)	(340)	-
Adj. Net Income	**(1,604)**	**(1,074)**	**990**	**1,073**	**-**
Reported EPS	(5.89)	(0.83)	1.93	2.14	-
Adj. EPS	**(3.07)**	**(1.96)**	**1.93**	**2.14**	**-**
DPS	**-**	**-**	**-**	**-**	**-**
Payout ratio	-	-	-	-	-
Shares outstanding	522	548	513	502	-

Income Statement - Quarterly	1Q18E	2Q18E	3Q18E	4Q18E
Revenue	**3,207**	**3,364**	**3,536**	**3,677**
SG&A	(245)	(245)	(250)	(250)
Adj. EBITDAX	**1,852**	**1,982**	**2,098**	**2,196**
Exploration expense	(110)	(96)	(98)	(92)
Adj. EBITDA	**1,742**	**1,886**	**2,000**	**2,104**
D&A	(1,082)	(1,117)	(1,170)	(1,214)
Adj. EBIT	**660**	**770**	**830**	**890**
Net Interest	(239)	(237)	(237)	(237)
PBT	**421**	**532**	**593**	**653**
Tax	(185)	(216)	(232)	(246)
Minority Interest	(70)	(80)	(90)	(90)
Adj. Net Income	**166**	**237**	**270**	**317**
Reported EPS	0.32	0.46	0.53	0.63
Adj. EPS	**0.32**	**0.46**	**0.53**	**0.63**
DPS	**-**	**-**	**-**	**-**
Payout ratio	-	-	-	-
Shares outstanding	524	517	509	502

Balance Sheet & Cash Flow	FY16A	FY17A	FY18E	FY19E	FY20E
Cash and cash equivalents	3,184	4,553	3,349	3,540	-
Accounts receivable	1,728	1,829	1,829	1,829	-
Inventories	-	-	-	-	-
Other current assets	354	380	380	380	-
Current assets	**5,266**	**6,762**	**5,558**	**5,749**	**-**
PP&E	32,168	27,451	27,897	27,845	-
LT investments	-	-	-	-	-
Other non current assets	8,130	7,873	7,873	7,873	-
Total assets	**45,564**	**42,086**	**41,328**	**41,467**	**-**
Short term borrowings	-	-	-	-	-
Payables	2,288	1,995	1,995	1,995	-
Other short term liabilities	1,040	1,911	1,911	1,911	-
Current liabilities	**3,328**	**3,906**	**3,906**	**3,906**	**-**
Long-term debt	15,281	15,547	15,433	14,533	-
Other long term liabilities	11,458	8,843	9,221	9,690	-
Total liabilities	**30,067**	**28,296**	**28,560**	**28,129**	**-**
Shareholders' equity	12,212	10,696	9,673	10,244	-
Minority interests	3,285	3,094	3,094	3,094	-
Total liabilities & equity	**45,564**	**42,086**	**41,328**	**41,467**	**-**
BVPS	**23.41**	**19.52**	**18.86**	**20.42**	**-**
y/y Growth	*(7.3%)*	*(16.6%)*	*(3.4%)*	*8.3%*	-
Net debt/(cash)	12,097	10,994	12,084	10,993	-
Cash flow from operating activities	**3,000**	**4,009**	**6,281**	**7,036**	**-**
o/w Depreciation & amortization	4,301	4,279	4,583	5,155	-
o/w Changes in working capital	104	(306)	0	0	-
Cash flow from investing activities	**(2,762)**	**(482)**	**(3,799)**	**(4,306)**	**-**
o/w Capital expenditure	(3,505)	(4,344)	(4,399)	(4,606)	-
as % of sales	*44.5%*	*36.5%*	*31.9%*	*30.5%*	-
Cash flow from financing activities	**2,007**	**(1,613)**	**(2,457)**	**(1,742)**	**-**
o/w Dividends paid	(105)	(112)	(513)	(502)	-
o/w Net debt issued/(repaid)	(790)	208	(114)	(900)	-
Net change in cash	**2,245**	**1,914**	**26**	**989**	**-**
Adj. Free cash flow to firm	**(314)**	**(1,291)**	**653**	**1,633**	**-**
y/y Growth	*(96.0%)*	*311.1%*	*(150.6%)*	*150.0%*	-

Ratio Analysis	FY16A	FY17A	FY18E	FY19E	FY20E
ROE	(12.8%)	(9.4%)	9.7%	10.8%	-
ROA	(3.5%)	(2.4%)	2.4%	2.6%	-
ROCE	(5.3%)	(7.6%)	7.4%	7.9%	-
Net debt/equity	78.1%	79.7%	94.6%	82.4%	-
Interest cover (x)	3.5	3.4	8.1	9.3	-
P/E (x)	NM	NM	34.2	30.9	-
EV/EBITDA (x)	15.3	14.6	6.2	5.6	-
P/DCF (x)	11.2	8.4	5.4	4.7	-
EV/BOE (x)	-	-	-	-	-
EV/EBITDAX (x)	11.7	8.1	5.9	5.2	-
Dividend yield	-	-	-	-	-
Tax rate	(26.7%)	(87.5%)	40.0%	38.4%	-

Sector data	FY16A	FY17A	FY18E	FY19E	FY20E
Natural gas price - $/mcf	2.40	2.23	2.87	2.79	-
Crude oil (WTI) -$/bbl	43.34	50.89	62.93	59.21	-
Daily oil production (mbblpd)	316	355	388	444	-
NGLs Production (MMbbl)	46.85	36.22	37.21	41.68	-
Daily gas production (mmcfpd)	2,093	1,312	1,103	1,230	-
Daily production (mboed)	-	-	-	-	-
Total Production (mmboe)	290	245	246	279	-
Proved reserves (mmboe)	-	-	-	-	-
Unit costs per boe					
Lease operating expense	-2.79	-4.07	-4.69	-	-
Taxes other than income	-1.85	-2.37	-2.91	-	-
DD&A	-14.82	-17.44	-18.64	-	-
G&A	-4.96	-4.38	-4.03	-	-
Exploration expense	-3.26	-10.35	-1.60	-	-
Operating margin/boe	-6.90	-6.69	9.14	-	-
Cash margin/boe	7.93	10.74	27.78	-	-
EBITDAX margin	51.8%	48.1%	59.0%	59.0%	-
Discretionary cash flow	3,076	4,315	6,281	7,036	-
DCF/share	5.90	7.87	12.24	14.02	-

Source: Company reports and J.P. Morgan estimates.

Note: $ in millions (except per-share data).Fiscal year ends Dec. o/w - out of which

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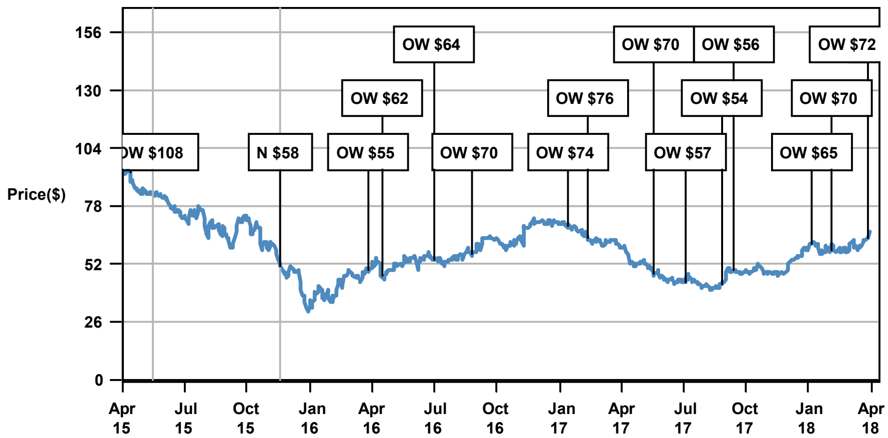
Anadarko Petroleum (APC, APC US) Price Chart



Source: Bloomberg and J.P. Morgan; price data adjusted for stock splits and dividends.
Initiated coverage May 06, 2002.
Break in coverage Jun 05, 2015 - Dec 09, 2015.

Date	Rating	Share Price ($)	Price Target ($)
04-May-15	OW	93.73	108.00
09-Dec-15	N	50.83	58.00
15-Apr-16	OW	49.46	55.00
04-May-16	OW	47.02	62.00
21-Jul-16	OW	54.17	64.00
15-Sep-16	OW	56.93	70.00
31-Jan-17	OW	69.53	74.00
02-Mar-17	OW	64.09	76.00
07-Jun-17	OW	47.17	70.00
24-Jul-17	OW	44.21	57.00
14-Sep-17	OW	43.53	54.00
02-Oct-17	OW	49.38	56.00
24-Jan-18	OW	60.94	65.00
22-Feb-18	OW	58.28	70.00
16-Apr-18	OW	63.46	72.00

The chart(s) show J.P. Morgan's continuing coverage of the stocks; the current analysts may or may not have covered it over the entire period.
J.P. Morgan ratings or designations: OW = Overweight, N= Neutral, UW = Underweight, NR = Not Rated

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Coverage Universe: Jayaram, Arun: Anadarko Petroleum (APC), Antero (AR), Apache Corp (APA), Chesapeake Energy (CHK), Cimarex (XEC), Concho Resources (CXO), Continental Resources (CLR), Devon Energy (DVN), EOG Resources (EOG), EP Energy (EPE), EQT Corp (EQT), Hess (HES), Marathon (MRO), Murphy (MUR), Noble Energy (NBL), Pioneer Natural Resources (PXD), Range Resources (RRC), Southwestern Energy (SWN)

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	Overweight (buy)	**Neutral** (hold)	**Underweight** (sell)
J.P. Morgan Global Equity Research Coverage	46%	41%	13%
IB clients*	52%	49%	39%
JPMS Equity Research Coverage	45%	43%	13%
IB clients*	72%	67%	57%

*Percentage of investment banking clients in each rating category.
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