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Merger and Acquisitions:

The case of ExxonMobil and Anadarko

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Abstract

The rationale under Merger and Acquisitions (M&A) has a huge spectrum, but it is always assumed to be a way of increasing shareholders value. The recent downturn in the oil and gas (O&G) market has been creating some speculations where M&A arises as a way to join companies that together can be more efficient in handling periods of low prices. In fact, this is a great opportunity for those with solid financial positions to invest in undervalued companies, and thus, strengthen their competitiveness in the future.

This dissertation focuses in assessing the potential value added from a deal between ExxonMobil and Anadarko. The former with an integrated business model and a strong balance sheet, and the latter, solely dependent on the upstream segment which means being more exposed to fluctuations in oil prices.

Thereafter, an in-depth company and industry analysis is conducted in order to establish which assumptions to apply to the valuation methods. The individual and combined analysis is supported by a literature review on valuation and M&A. Based on a theoretical framework, the merged entity valuation is developed, followed by a proposed price, method of payment and acquisition strategy.

Anadarko's standalone valuation suggests that its average share price during 2015 is undervalued with 13% upside potential. Due to synergies of $33,96Bn, the proposed deal has a premium of 49% and the final suggestion being an all-cash offer.

Resumo

Várias são as razões apontadas para justificar fusões e aquisições, mas todas têm subjacente o pressuposto da criação de valor para os acionistas. Num período de queda histórica do preço do petróleo, estas surgem como uma alternativa para a criação de estruturas mais eficientes. A fragilidade financeira experienciada pelo setor emerge também como uma oportunidade. Empresas menos vulneráveis às oscilações dos preços podem aumentar a sua competitividade futura investindo em empresas que viram o seu valor de mercado desvalorizar significativamente.

Assim, esta dissertação foca-se na análise da criação de valor que pode resultar da aquisição da Anadarko, uma empresa unicamente dependente da exploração e produção de petróleo, pela ExxonMobil, com um modelo de negócios integrado que vai desde a exploração até à comercialização.

Uma análise detalhada à indústria e a ambas as empresas permite estabelecer os pressupostos necessários para o desenvolvimento dos modelos de avaliação e da estratégia de aquisição. Adicionalmente, uma análise da literatura académica sobre modelos de avaliação e fusões e aquisições sustenta os modelos desenvolvidos, bem como as recomendações relativas ao preço, modo de pagamento e estratégia de aquisição.

A avaliação da Anadarko sugere que o preço médio por ação verificado ao longo do ano de 2015 está subavaliado em 13%. Assim, com sinergias avaliadas em $33,96 biliões, a aquisição proposta tem um *premium* de 49% e deverá ser paga unicamente em dinheiro.

Acknowledgments

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List of Abbreviations

APV – Adjusted Present Value

BC – Bankruptcy Costs

BOE – Barrel of oil equivalent

BS – Balance Sheet

BV – Book Value

CAPEX – Capital Expenditures

CAPM – Capital Assets Pricing Model

CARG – Compound Annual Rate Growth

CCF - Capital Cash Flow

CF – Cash Flow

CFE - Cash Flow to Equity

CTR – Corporate Tax Rate

D&A – Depreciation and Amortization

D.G.C.L. - Delaware General Corporation Law

DCF – Discounted Cash Flow

DD – Due Diligence

DDM – Dividend Discount Model

EBIT – Earning Before Interest and Taxes

EBITDA – Earnings Before Interest, Depreciation and Amortization

EIA - Energy Information Administration

EV - Enterprise Value

EVA - Economic Value Added

E&P – Exploration and Production

FCF – Free Cash-Flow

FCFF – Free Cash Flow to the Firm

FS – Financial Statement

G&A – General and Administrative

GDP - Gross Domestic Product

IEA - International Energy Agency

IS – Income Statement

LNG – Liquefied Natural Gas

LP – Limited Partnership

LT – Long-Term

LTD – Long-term Debt

M&A – Merger and Acquisitions

MIT - Massachusetts Institute of Technology

MRP – Market Risk Premium

MTP – Meet the Premium

NG – Natural Gas

NGL – Natural Gas Liquids

O&G – Oil and Gas

OECD - Organisation for Economic Co-operation and Development

OPEC - Organization of the Petroleum Exporting Countries

PP&E – Property, Plant and Equipment

ROCE – Return on Capital Employed

ROE – Return on Equity

ROIC – Return on Invested Capital

ST – Short-Term

STD – Shot-term Debt

TB – Treasury Bond

TV – Terminal Value

U.S. – United States

WACC – Weighted Average Cost of Capital

WES - Western Gas Partners

Introduction

The recent downturn in the oil and gas (O&G) market has been creating some speculations about Merger and Acquisitions (M&A) deals between companies with strong balance sheets and others which are struggling with financial pressure. Those with solid financial positions invest in undervalued companies and thus strengthen their competitive position in the future, which is the case with ExxonMobil and Anadarko.

Both are O&G companies based in the United States with operations worldwide. However, ExxonMobil has an integrated business model which has so far proven to be strong enough to deal with the fluctuations of oil prices. In contrast, Anadarko is entirely dependent on its upstream segment, and consequently, it has been struggling with the current historically low commodity prices.

A consolidation process between the two companies requires an extensive look at the strategic and financial reasoning behind it. In order to proceed with the evaluation of this deal a literature review has been developed, and covers the existing academic literature about valuation methods and an analysis of the most common issues related to M&A deals. These foundations will be crucial to develop the forecast models and to propose the best acquisition strategy and payment methods.

Thereafter, an in-depth industry and company analysis will be conducted in order to establish the right assumptions to develop the forecast for the standalone valuations. Once the individual analysis is done, an integrated perspective will be developed in order to evaluate the consolidation benefits.

Finally, the last section focuses on the details of the acquisition process, providing the final recommendations in terms of premium, method of payment and acquisition strategy.

Literature Review

1. Valuation Overview

While conceptually there is one correct value for a firm, in practice there are multiple ways of calculating it. As a result, the important question is which valuation technique offers the easiest and most accurate way which is comparable against other models.

1.1. Cash-Flow Methodology

The DCF method emerged in the 1970s as the best way to value corporate assets. The logic behind this method is the relationship between present and future value, where timing and risk need to take place following the uncertainty of the future business CF. This uncertainty is translated in an opportunity cost represented by the time value and the risk premium. The following topics will analyse some of the different variations of DCF methods.

Four different DCF approaches are based on the nature of the used CF and the discount rate: APV, CCF, FCFF and CFE (Oded & Michel, 2007). The first three are based on EV and the latter on equity values. The DDM is another CF method that follows an equity based approach.

1.1.1. Equity Value Perspective: DDM

Foerster and Saap (2005) considered the DDM a useful approach to value the equity of firms with mature dividend-payment polices by discounting all future expected dividend payments, supported by the intrinsic assumption that changes in dividends explain changes in asset prices.

The generalized DDM approach was later replaced by the Gordon Growth Model that relies on the assumption of constant dividend growth:

Generalized DDM

$$\sum_{n=1}^{N} = \frac{D_n}{(1+k_r)^n}$$

Gordon growth DDM

$$\sum_{n=1}^{N} = \frac{D_0(1+g)^n}{(k_r-g)^n}$$

However, a constant growth is not always applicable due to different life cycles and consequently, this model is only suitable for companies with stable growth rates (Damodaran, 2005).

Despite some studies continuing to present DDM as a reliable method, studies with longer time series, which are considered to be more reliable, tend to question these results. Since the payout ratio is dependent on many factors, forecasting future dividends requires a significant amount of speculation.

1.1.2. EV Perspective: APV and WACC

The more common version of the DCF is based on the WACC, a discount rate that applies the debt and equity costs to the capital structure ratios with the respective adjustment for the tax shield. The simplicity of WACC has the drawback of considering the interest tax shield straight away and not taking into account the potential changes in the company's capital structure over time.

In order to avoid misevaluation, complex capital structures requiring a WACC should be adjusted per project and period. Cash, timing and risk have distinctive structural features that WACC does not recognize in a very accurate way and consequently, other complementary tools should be considered (Luehrman, 1907). However, Oded & Michel (2007) argued that *when the debt rebalancing policy is applied consistently, all valuation methods produce equivalent results.*

However, the APV, as suggested by Stewart Myers from MIT, is one of the proposed models that according to Luehrman (1997) outperforms WACC by considering separated CF from business operations and financing strategies. For Luehrman (1997) *"APV always works when WACC does, and sometimes when WACC does not"*.

When executing the APV method, the first step is to determine the forecasted CF, which is then discounted as if the company was fully financed by equity. The value associated with the financing programme is evaluated separately.

However, there is no consensus amongst academics for the discount rate used to value the financing programme. The risk associated with the tax shields is seen by some academics as the same as debt obligations and therefore, the tax shields should be discounted using the cost of debt. Whereas others agree that the use of leverage will be dependent on the operational performance, and therefore, should be discounted at the same discount rate as operational CFs. Grinblatt and Titman (2002) argued that the tax shield should be discounted with different discount rates based on the rebalancing assumption.

Putting both pieces together, business operations CFs and the value of the financing side effects, valuation through APV is obtained.

1.1.3. Critical issues related with DCF methods

1.1.3.1. CAPM

The CAPM establishes the relation between risk and expected return, calculated through the sum of risk-free (r_f), which represents the time value of money, with the product between the systematic risk (β) and the risk premium required by investors (r_m-r_f). In fact, under this approach investors are solely concerned with the systematic risk, mathematically translated by the covariance between the stock and the market returns.

Despite contradictory academic evidence and some more modern approaches (e.g. arbitrage pricing theory) CAMP is still one of the most accepted methods to calculate the cost of equity.

Gene Fama and Ken French (1992) argued that the stock returns were related with the size and book-to-market ratios of the firm, which contradict the systematic risk measure denoted by CAPM. However, later Kaplan and Ruback (1996) developed a study based on CAPM which proves that the implied risk premium is positively related to firm and industry betas, as opposed to firm size or pre-transaction book-to-market ratios.

1.1.3.2. Risk-Free Rate

Due to the more frequently errors associated with risk-free determination (Fernández, 2004) it is desirable to use a risk free rate with the same duration of the analysed cash-flows.

1.1.3.3. Risk-Premium

There is some disagreement between which is the best approach: LT arithmetic average (1) or a geometric average (2) of the historical return spread between a stock market index and risk-free bonds.

Kaplan & Ruback (1996) developed a study based on the LT arithmetic average approach (1), the most common in finance texts, which proved that APV works best with arithmetic average. For DCF methods, there was no evidence that the arithmetic approach would have improved its performance. However, Fernández (2004) argued that "*the required MRP is an expectation and*

has little to do with history", but since he did not present any alternative, this analysis will use the arithmetic average.

1.1.3.4. Beta

There are two main issues that should be pointed out for beta: the time period and the source of the market index.

Beta estimation is based upon historical betas but Fernández (2004) and Damodaran (2001) supported that calculated betas change dramatically and depend on the period used to estimate them. They ignore potential recent variations on the business operation, leverage and other important variables that impacts the firm's systematic risk. Thus, Damodaran (2002) recommended the use of bottom-up betas, which includes recent updates in operating and leverage levels.

Measuring the systematic risk (β) could follow three different approaches in terms of source that were applied by Kaplan & Ruback (1996): firm (1), industry (2) and market (3). This study proved that the firm-based method is the less accurate, with industry and market outperforming it. The statistical noise of individual beta made industry betas more stable and consistent.

Copeland, T. et al. (1991) suggested using the public estimation of beta for listed companies, while still taking into account the existing industry betas and other reliable sources to validate this assumption. The reasoning behind validation also aligns with the conclusion of Kaplan & Ruback, (1996) that individual beta estimates vary widely and industry average beta are usually more reliable.

Nevertheless, the challenge here is to find reliable comparable companies able to guarantee consistency and a representative sample.

1.1.3.5. Terminal Value

The TV is calculated though a terminal CF that is assumed to grow in perpetuity at a constant nominal growth rate (Kaplan & Ruback, 1996). It carries a significant weight on the present value of any valuation. Consequently, its underlying assumptions are very important and a sensitivity analysis is greatly recommended.

Normally, the TV proceeds a forecasting time frame that is defined individually, based on the specifications of each project or business stage in terms of CAPEX. Considering the perpetuity

growth rate, CAPEX should be aligned with D&A (Kaplan & Ruback, 1996) and should also reflect the nominal GDP growth (Steiger, 2008).

1.1.4. Return-based Approach

The return-based logic has two main approaches: ROE and EVA. Dynamic ROE, the equity approach, is calculated based on the current BV plus the discounted future excess returns. On the other hand, the EVA uses the EV approach. EVA is achieved by the sum of the current capital stock plus the discounted value of future EVA. Some academics argue that the inconsistency of the usage of BV and the imperfections between EVA and stock returns make these approaches less used as a firm valuation tool.

1.2. Option Theory

The high uncertainties and risks at every stage of petroleum projects, along with limited maturities, make O&G companies considerably hard to value. Real options are especially valuable for this industry since it provides different methods to value such uncertainties (Copeland & Keenan, 1998), Black-Scholes and the Binomial model being the most important.

Luehrman (1997) considered Black-Scholes, a model developed by Fischer Black and Myron Scholes and modified by Robert Merton (Black & Scholes, 1973), his favourite because of its versatility and simplicity. However, in this analysis, the option theory will not be considered since it would not be suitable to apply it to an integrated company like ExxonMobil.

1.3. Multiples

Whereas the previous valuation methods are based on assumptions related with the firm being valued, relative valuation estimates the company's value based on historical markets and transaction values of comparable companies. However, both types of valuation demand important assumptions: that comparable companies are aligned in terms of growth and risk. The market-based approach assumes that the value of comparable companies will fluctuate in direct proportion to the varying performance measurements used (Kaplan & Ruback, 1996). Foushee et al (2012) adds that truly comparable companies also have to compete in the same markets. According to Kaplan and Ruback (1996) having these conditions fulfilled, the relative valuation approach can be valuable since it already includes updated market expectations.

The market multiples can also be separated based on their fundamental determination. Investors tend to use enterprise-value multiples since they are not manipulated by differences in the capital structure (Foushee, et al., 2012). Goedhart et al (2005) highlight that EV-to-EBITDA is also preferred because it does not take into account non-operating expenses.

Despite multiples providing the advantage of including market expectations, they also have their weaknesses. Kaplan and Ruback proved that DCF methods were more accurate, but the most reliable estimates were the ones that used both.

2. M&A Issues

2.1.Synergies

The rationale behind M&A is essentially explained by the synergies that arise from combining two firms.

Damodaran (2005) grouped synergies into operating and financial synergies. Operating Synergies includes economies of scale, higher bargaining power, growth opportunities and a combination of different operating strengths, all with the potential outcome of an increased operating income. Financial Synergies could arise from a combination of firms with excess cash and limited project opportunities, higher debt capacity and diversification, which could result in higher cash-flows or lower cost of capital. A study conducted by Bhide (1993) concluded that for one third of takeovers, operating synergy was the primary driver.

However, several challenges are posed when it comes to their effective implementation. In terms of financial synergies, the ones that arise from diversification tend to fail in creating value and consequently, markets usually react negatively to the announcement of diversifying acquisitions (Doukas, et al., 2001).

In fact, there are some academics that propose synergy analyses based on the difficultness of achieving them. Cullian, et al. (2004) proposed an interesting framework that mapped synergies according to their easiness in terms of implementation. Eccles, et al. (1999) pointed out that due to the difficulty in estimating revenue synergies, some analysts neither include nor discount them heavily.

Damodaran (2005) proposed a way to value synergies based on three steps: value the firms independently (1); value of combined firm with no synergy (2) and revalued the combined firm with synergies (3), where the difference between (2) and (3) is the value of synergies. However, the forecasting CF of the combining firms should be discounted at an appropriate rate that is imposed on the new firm.

Cullian, et al. (2004) also highlights the importance of a rigorous DD process that identifies the most common financial tricks, such as overoptimistic projections. In the end, it is the acquisition price that will determine whether an acquisition result is value increasing or value destroying.

2.2. The Announcement reactions and Post-merger results

Mckinsey and Co. developed a study which intended to analyse if the return on the amount invested in an acquisition exceeded the cost of capital, and if the acquisition helped the parent companies outperform. The study proved that around 48% failed both tests and 10% failed at least one test. Eccles, et al. (1999) also concluded that the total market-adjusted return of the acquirer went down at the time of the announcement for 59% of the deals.

Such negative reactions of the markets are a result of investor scepticism regarding the acquirer's ability to sustain the original value of each company and achieve the synergies needed to justify the premium of that acquisition (Sirower & Sahni, 2006).

In order to avoid mistakes of excess premium, Sirower and Sahni (2006) created an important guideline, the MTP line, which defines the up-limit of the acquirer, and any deal below the MTP line is considered worthless.

Sirower and Sahni (2006) also proposed a three-three matrix which results in three types of deals: joining companies with the same capabilities (cost synergies); or companies with different capabilities (revenue synergies); and deals that bring completely new capabilities (both).

In contrast with the scepticism exposed above, Bruner (2014) argues against them with evidence that M&A does pay-off: there is a tendency to "exaggerate the extent of failure" without a location-based approach which goes beyond the simple goals-outcome analysis. For Bruce (2014) *all M&A is local.*

In conclusion, despite several studies supporting the failure of M&A, the analysts should evaluate case by case without creating straightforward assumptions from a particular sample. It is crucial to adopt the best DD and post-merger approach while bearing in mind the main reasons for the failure of historical cases.

2.3. Method of Payment

Regarding payment methods, stock tends to be associated with negative returns due to the market signal of managers believing that shares are overpriced.

Therefore, when payments are due in cash, the returns of target shareholders are significantly high in comparison with stock. In terms of materiality, the payments in stock are lower, despite the significantly positive returns (Bruner, 2014). Bruner (2014) also highlighted that normally larger deals are likely to step up the positive and negative returns, for cash and stock payment methods respectively.

The main issue associated with the payment method is that with cash, the risk is solely on the buyer side. While in stock transactions, the targets share the risk (Rappaport & Sirower, 1999).

2.4. Premium

The most unsuccessful cases of M&A resulted from the inflated premiums paid by companies. The high premiums can be justified in part by some failure in the DD process or post-merger issues.

Damodaran (2005) presented three possible explanations why bidders overpay: a biased evaluation process, managerial hubris and failure to have a plan to effectively implement synergies. Normally, this overpayment is even larger in hostile acquisitions and tender offers (Huang & Walkling, 1987).

However, the premiums paid are in part a reflection of the market conditions. An analysis conducted by Jarrell, Brickley and Netter (1998) concluded that premiums ranged between 19% and 35% between 1980 and 1985, suggesting that premiums are not only dependent on the value of synergies.

Furthermore, Dennis & McConnell (1986) developed a study based on the 10 days before and after the announcement of an acquisition, showing that in fact nearly half the premium is already reflected in the acquisition price (Figure-1).

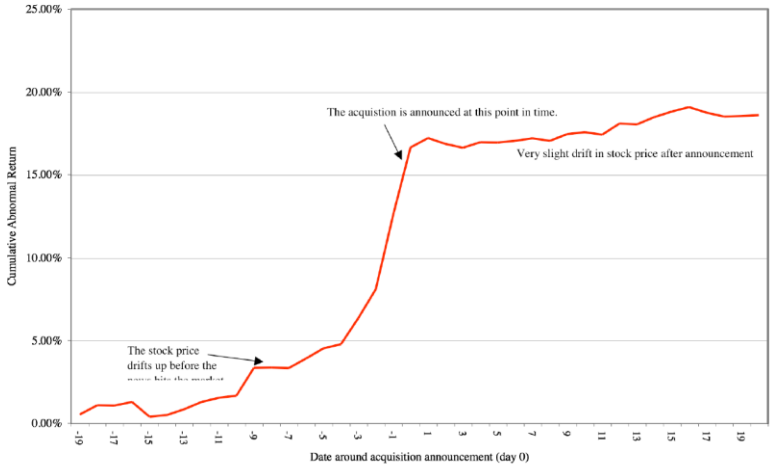


Figure 1 - Cumulative Excess Return to Target Company Stock (Source: Damodaran 2005)

Industry Overview

1. Market Conditions and Business Environment

The proposed acquisition is analyzed under a context of substantial uncertainty for O&G companies. Until 2014, normal price levels ranged between $90-100/barrel, currently, prices are below $40/barrel: upstream O&G companies have been facing huge challenges with revenues dropping by more than 50%.

The upstream, oilfield services and midstream sectors are the ones which have suffered intense CF pressure as opposed to downstream sectors which have profited from higher refining margins.

Changes in supply and demand help justify the plummeting oil prices (Appendix 1). First, there is the overproduction of oil in the U.S., and the collapse of China's economy; second, the global decrease in consumption results in rising storage levels, which means global crude oil supply exceeds demand growth.

EIA predicts that a continuing fall in U.S. oil production throughout 2016, and an economic retrenchment in countries economically dependent on oil, might significantly reduce their ability to invest in this sector (IEA, 2015).

These factors imply that supply will gradually adjust to the current demand levels, though a rapid recovery is not anticipated because of the high stock levels. As a result, upstream companies started to react with several cost saving measures in 2015.

1.1.Supply and Demand

Besides the ST drivers for supply and demand, others factors such as government policies, technological developments and global climate changes, should also be considered on a medium and LT perspective (Appendix 2).

Population and economic growth are considered the two biggest drivers for energy demand (Figure-2): by 2040, global population is expected to grow from 7.2Bn to 9Bn and global GDP will be doubled (ExxonMobil, 2016)

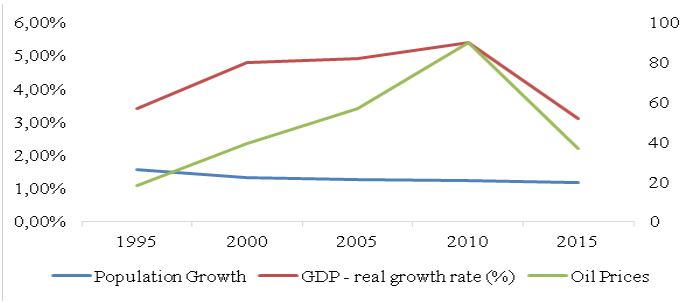


Figure 2 - Historical Data for Population Growth (World Population, 2016), GDP (GDP, 2016) and Oil Prices (Crude Oil , 2016)

The Outlook for Energy (ExxonMobil, 2016) predicts that by 2040, oil and NG will continue to represent around 60% of global demand. Globally, the demand for energy is expected to rise 25% by 2040, 45% of which will be from non-OECD countries (Figure-3).

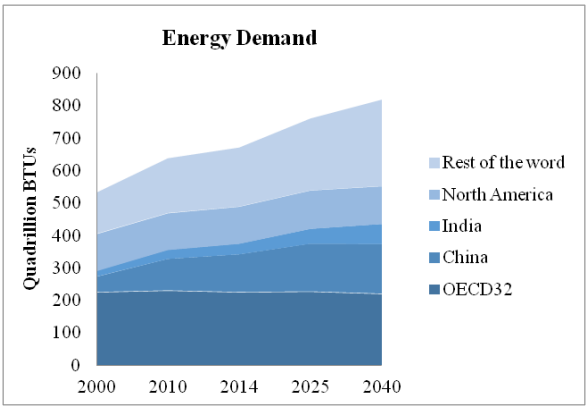


Figure 3 - Energy Demand per region (ExxonMobil, 2016)

In terms of oil, OECD has projected an annual average growth of 1.2% on global demand until 2021 (Table-1). The supply levels have risen throughout 2015, however, due to a significant number of projects deferred and cancelled, the annual average growth rate until 2021 is expected to be just 0.7% (OECD; IEA, 2016). Following this forecast, supply and demand of oil will only be aligned in 2017.

Table 1 - World Demand and Supply (OECD; IEA, 2016)

	2015	2016	2017	2018	2019	2020	2021
World Demand	94,4	95,6	96,9	98,2	99,3	100,5	101,6
Non-OPEC Supply	57,7	57,1	57	57,6	58,3	58,9	59,7
OPEC Crude*	32	32,8	33	33	33,2	33,5	33,6
OPEC NGLS etc	6,7	6,9	7	7,1	7,1	7,1	7,2
Total World Supply*	96,4	96,7	97	97,8	98,7	99,5	100,5
Implied Stock Change	2	1,1	0,1	-0,4	-0,7	-1	-1,1

As for gas, global demand is expected to rise by 50% from 2014 to 2040 (ExxonMobil, 2016)

1.2. Prices

The golden days where oil companies got over $100/bbl are not likely to reoccur, not even in the long term (Appendix 3). NG prices have also declined significantly since 2013.

Table 2 - Commodity Prices (Source: (World Bank, 2016)

Commodity	Unit	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Coal, Australia	$/mt	84,6	70,1	57,5	50	51,9	53,9	55,9	58,1	60,3	62,6	65	67,4	70
Crude oil, avg spot	$/bbl	104,1	96,2	50,8	37	48	51,4	54,9	58,8	62,9	67,3	72	77,1	82,6
Natural gas, Europe	$/mmbtu	11,8	10,1	7,3	6	6,2	6,4	6,6	6,8	7	7,3	7,5	7,7	8
Natural gas, US	$/mmbtu	3,7	4,4	2,6	2,5	3	3,5	3,7	3,9	4,1	4,3	4,5	4,8	5
Natural gas LNG, Japan	$/mmbtu	16	16	10,4	8,5	8,7	9	9,3	9,5	9,8	10,1	10,4	10,7	11

The recovery of oil prices observed from 2016 (Table-2) onwards is essentially a result of the significant production cuts on the supply side coupled with a slight growth in demand, enabling a rebalance in demand and supply levels.

1.3.Overall Industry Expectations

The energy sector is facing new dynamics with a different competitive environment where a free market is established. Technology enhancement is the main driver (Figure-4): shale gas, NGL, tight oil and oil from deep water are the unconventional energy sources that explain the increased supply levels, accounting for 40% of the energy sources in 2040 (Appendix 4).

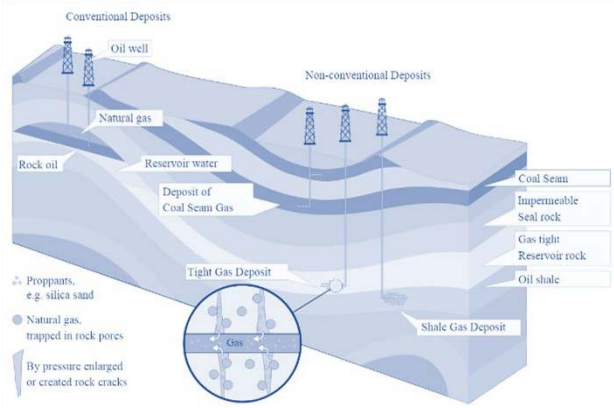


Figure 4 - Unconventional energy source (Wikipedia, 2014)

The fact that North America has become a new expert in unconventional gas production has completely changed its position as a supplier in the worldwide market. North America is expected to see liquids production grow by 40%.

2. Legal, Regulatory and Financial Environment

Ending the U.S. crude export ban, more restricted financing policies, environmental taxes and compliance policies are some of the issues which are expected to particularly affect O&G companies, in particular the U.S. ones (Appendix 5).

Company Analysis

1. ExxonMobil

1.1.Overview

ExxonMobil is the largest of the vertically integrated oil majors, with divisions and affiliated companies worldwide. This American multinational corporation headquartered in Texas from a regional U.S. company to the largest publicly traded petroleum and petrochemical enterprise in the world.

With a well-diversified and integrated portfolio, ExxonMobil achieved their lead market position with high-quality operations. Having upstream, downstream, chemical and NG and power marketing as its business segments, and reaching the worldwide market through three well-known brands - Exxon, Esso and Mobil - ExxonMobil has been able to reduce their exposure through operational and geographical diversification.

A. Upstream

The upstream segment includes a diverse portfolio of exploration opportunities and production of conventional, heavy oil, tight gas, shale gas, deepwater NG, arctic and sour gas projects. ExxonMobil currently has active upstream E&P in 36 countries with a leading resources and assets industry base. The Americas (35%) and Asia (34%) being the leading locations.

ExxonMobil was able to continue to increase its portfolio by adding 1.4Bn OEB (liquids grew by 3.2%, but NG decreased by 6%) and maintain their industry-leading resource base at approximately 91Bn oil equivalent barrels (OEB) with 16 years shelf life at current production rates (Appendix 6).

Going forward, ExxonMobil is planning to complete 10 projects in 2016 and 2017 as its near-term activity and its continued work of developing their large unconventional liquids-rich resource base in the U.S.

B. Downstream

ExxonMobil downstream operations are market leaders in terms of petroleum products and finished lubricants, leveraged by its worldwide distribution network with refining facilities in 14

countries and with over 5.000 owned/leased retail stations (Appendix 7). ExxonMobil has built a strong worldwide distribution network and its results in 2015 proved the value of its integrated business model.

ExxonMobil is the leader in the industry, with 80% of its refining capacity integrated with chemical and lube base-stock production facilities, which are translated in important synergies and significant cost optimization. Innovation, world-class brands and an integrated supply chain leaves ExxonMobil in a good position for long-term growth.

C. Chemical

Finally, the chemical segment operates in 16 countries, with a major presence in North America (45%) and Asia Pacific (40%). The company manufactures and sells petrochemicals including olefins, polyolefin, aromatics, and a wide variety of specialty products.

Globally, ExxonMobil is the largest manufacturer of aromatics and one of the largest of olefins, some of the highest-growth petrochemical commodities. ExxonMobil has been investing to meet growing demand, especially through integration with nearly 90% of its chemical capacity being integrated with large refineries and NG processing plants. The demand for chemical products is expected to grow nearly 45% over the next decade and ExxonMobil is projected to double its exports by 2025.

1.2. Financials

Taking into consideration the industry's challenging environment, the results of 2015 demonstrated that ExxonMobil has a strong financial performance in relation to its peers, partly justified by its integrated businesses model and performance efficiency.

Lower commodity prices and higher cost production of non-conventional oil justify the lower earnings of $16.2Bn, 50.3% less compared with 2014 (Figure-5). As expected, the earnings were down mainly as a consequence of upstream activities, which decreased $20Bn from 2014. This decrease was offset smoothly with an increase of $3.5Bn in the downstream and $103M in the chemical segments.

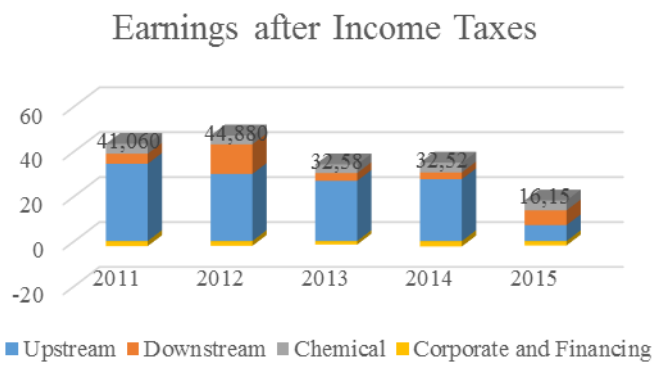


Figure 5 - Earnings after Income Taxes (Company Annual Reports)

Even with lower level of earnings, its performance still reveals that ExxonMobil is a strong company, with assets reaching $336,758Bn and its equity representing 52,5% of assets. Total liabilities in 2015 were 5% less compared with 2014, however the LTD increased to $19,2Bn which reflects the issuance of $8Bn of LTD. Moreover, its unused committed ST and LT credit, $6Bn and $0,4Bn respectively, reinforces ExxonMobil's financial strength. ExxonMobil's creditworthiness is also translated by its fixed-charge coverage and consolidated debt-to-capital ratios of 17,6 and 18,0, respectively.

In terms of liquidity, ExxonMobil also reached a total cash and cash equivalents of $3,7Bn, $1Bn less than last year. In 2015, cash and cash equivalents were used partly to purchase shares of ExxonMobil stock ($4Bn) and dividends ($12,1Bn). Concerning dilution, the earnings per share were $0,67 in 2015, a decrease of 57%.

The cash provided by operations and asset sales totalled $33Bn, outperforming its peers (ExxonMobil, 2016). The company also reached an industry-leading return on average capital employed of 7,9% in 2015. However, due to low commodity prices and worldwide oversupply, ExxonMobil reacted immediately by adjusting its investment and lowering its CAPEX to $31,1Bn in 2015, 19,4% lower than in 2014 (Figure-6).

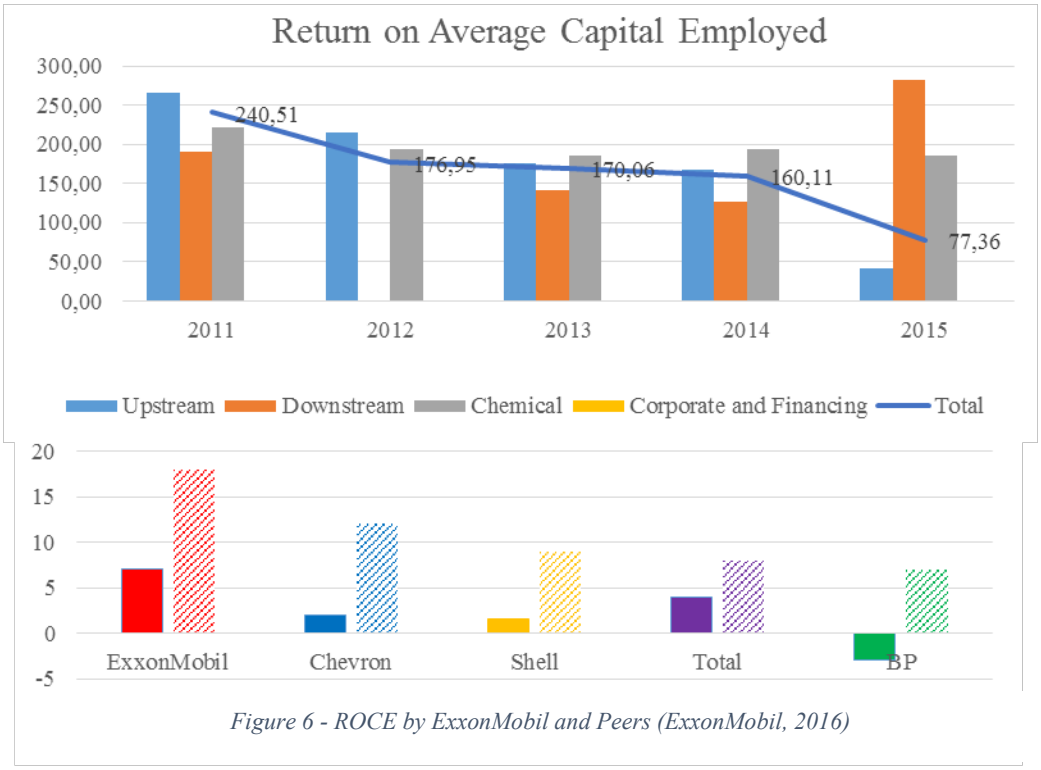


Figure 6 - ROCE by ExxonMobil and Peers (ExxonMobil, 2016)

Nevertheless, even with a more conservative investment approach, ExxonMobil seems to be committed to project execution and effective cost management. ExxonMobil has been investing through the cycle, creating long-term shareholders' value - its 5-years cumulative total returns always being higher than the industry levels prove this (Figure-7).

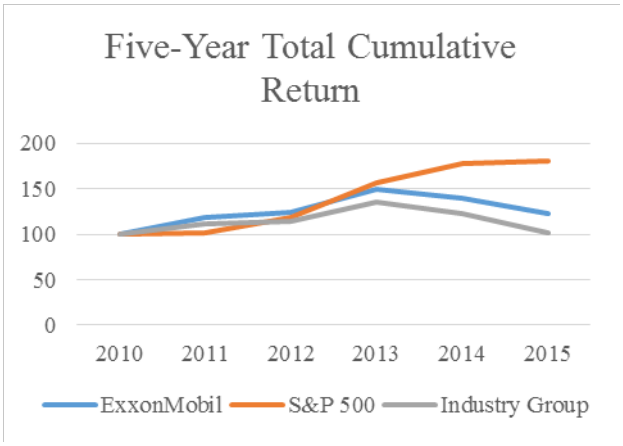


Figure 7 - ExxonMobil's Five-Year Total Cumulative Return (Morningstar, 2016)

In general, despite the industry's downturn, it is possible to acknowledge the superior results of ExxonMobil in relation to the overall industry.

2. Anadarko

2.1.Overview

Anadarko, founded in 1959, has its headquarters in Texas and is one of the world's largest independent E&P companies in the O&G industry. With approximately 2,1Bn BOE of proved reserves, Anadarko develops, acquires and explores oil and NG resources onshore in the U.S. and in high-potential offshore worldwide.

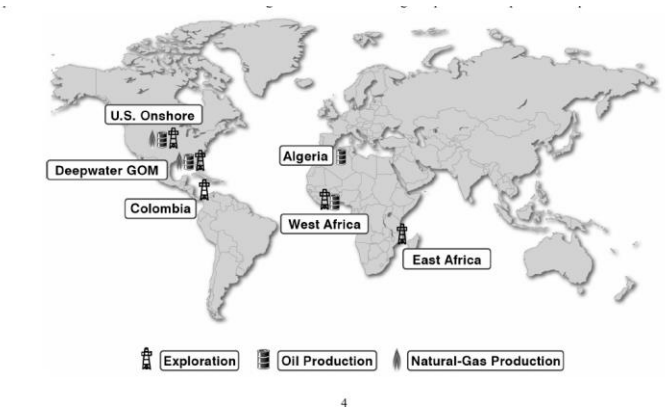


Figure 8 - Anadarko's Worldwide Activity (Anadarko Petroleum Corp, 2016)

Anadarko's asset portfolio includes U.S. onshore and Gulf of Mexico. Worldwide, Anadarko has activities in Algeria, Ghana, Mozambique, Colombia, the Ivory Coast, New Zealand and Kenya (Figure-8).

Anadarko is organized in three main segments: O&G E&P, midstream and marketing. According to the ExxonMobil's segmentation, these three segments fall under ExxonMobil's upstream segment.

A. Upstream

The E&P segment has activities worldwide involving oil, condensate, NG and LNG, but the midstream segment is based in the U.S. and is involved in gathering, processing, treating, and transporting its own as well as third-party production.

The upstream segment has its main activity in the U.S. (89% of sales), where Anadarko's operations are resumed to 48 states, deepwater Gulf of Mexico and onshore Alaska (Appendix 8). Internationally, activities are mainly based in Algeria and Ghana, and also include LNG development activities in Mozambique. (Appendix 9).

In terms of sales-volumes, the company's product mix increased to 53% liquids in 2015 compared with 49% in 2014, due to the lower production levels of NG since 2013.

The gathering, processing, treating and transportation activities are crucial in order to complement the company's production activities with further advantages in terms of cost management, timing control and value enhancement (Appendix 10).

The midstream activities are destined both to internal and third-party customers. This segment includes the subsidiary WES LP which operates midstream assets (Appendix 11).

Finally, the marketing segment is responsible for selling Anadarko's production as well as third-party purchased volumes. The company's activities include oil, NG and NGLs in the U.S., but internationally, only oil and NGLs. (Appendix 12).

2.2. Financials

The company's performance during 2015 was highly affected by the lower commodity prices with significant impact on its revenues, operational CF, CAPEX and future growth rates. As opposed to ExxonMobil, Anadarko is entirely dependent on its sales of oil, NG and NGL production, without an integrated business model to offset its upstream downward slope.

Since 2014, Anadarko has had a net loss, however, the -$1,75Bn in 2014 contrasts with the loss of $6,7Bn in 2015 (Appendix 13). The net loss is mainly explained by the 42% decrease in sales revenues, following the YOY growth since 2012. In fact, even with the operating income reaching $8,81Bb ($5,4Bn in 2014), Anadarko was able to reduce its operating expenses by 13% while sustaining its production levels.

The company's assets have also decreased by almost 24% since 2014 and its capital structure has felt the imbalances, with equity representing 33% (37% in 2014) of its assets.

As of December 2015, Anadarko had $15,72Bn of LTD. In terms of liquidity, Anadarko had $4,75Bn of borrowing capacity and $939M of cash available at the end of 2015. Furthermore, during 2015 it was also able to monetize $2,0Bn and achieved a decrease of 36% in CAPEX.

Through these adjustments, Anadarko has been dealing with a more challenging environment which was also reflected in its $1,9Bn cash ($8,5Bn in 2014) from operating activities.

Despite the compromise with enhancing operational efficiencies and reducing CAPEX, its ROCE decreased to -21% (6% in 2013).

As for dividends, Anadarko paid $553M to its common stockholders in 2015 ($505M in 2014). The cumulative 5-year total return of Anadarko's common stock compared with the S&P500 index and a peer group of 11 companies[1] was lower than the industry levels, as well as the S&P 500, especially since 2012 (Figure-9).

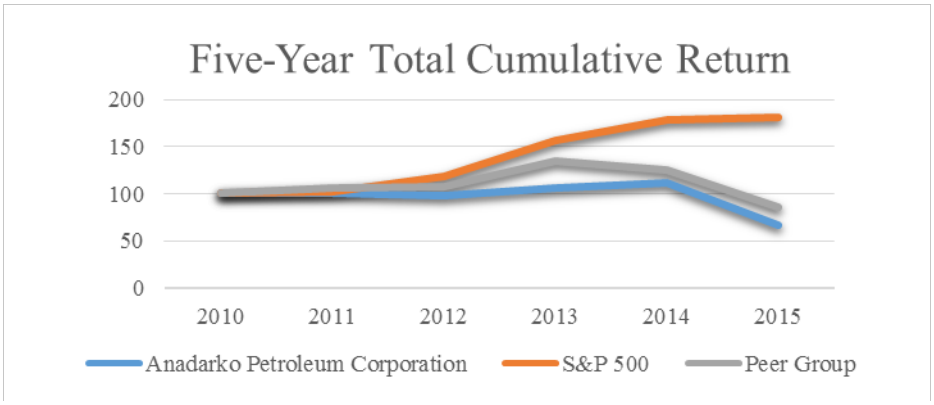


Figure 9 - Anadarko's Five-Year Total Cumulative Return (Anadarko Petroleum Corp, 2016)

Standalone Firm's Valuation

In this section, ExxonMobil and Anadarko's valuation will be developed separately through the APV, WACC and Relative Valuation.

The APV and WACC valuation models are established through analyses of the company's performance over the last five years and forecast for the next ten years. The last five years' performance enables us to disregard not only some financial crisis effects, but more importantly, the lower oil commodity prices of late. Due to the lowest of oil prices in 2015, and the steady growth expected for the coming years, it is reasonable to forecast the CF for 10 years, when the main growth driver of both companies will achieve stable and sustainable price levels again.

The relative valuation approach will be developed based on a peer group analysis and an overall industry perspective.

Finally, considering the dependency of the overall industry performance on oil commodity price, it is important to consider the main macroeconomic drivers applied to the forecast models.

[1] Peer group: Apache Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Murphy Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; and Pioneer Natural Resources Company.

1. Macro Inputs

The forecast model is mainly determined along with the expected evolution of oil prices, both for the explicit period and TV. The assumption used for the TV was based on the expected worldwide average of the annual percentage change of GDP (2012-2040) *(U.S.EIA, 2016)* (Table-3).

Table 3- Crude Oil Average Price (World Bank, 2016)

Commodity	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Crude oil	$/bbl	96,2	50,8	37	48	51,4	54,9	58,8	62,9	67,3	72	77,1	82,6
Growth	-	-7,59%	-47,19%	-27,17%	29,73%	7,08%	6,81%	7,10%	6,97%	7,00%	6,98%	7,08%	7,13%

The different GDP growth scenarios based on the potentially higher or lower oil prices (U.S.EIA, 2016), will be under the assumption of different bull and bear scenarios (Table-4).

Table 4 - GDP growth scenarios (U.S.EIA, 2016)

	Bull Scenario (High Oil Prices)			Bear Scenario (Low Oil Prices)			Base Case Scenario		
	Average annual % change, 2012-40			Average annual % change, 2012-40			Average annual % change, 2012-40		
	Liquids consumption	**Gross Domestic Product (GDP)**	**Primary Energy Consumption**	**Liquids consumption**	**Gross Domestic Product (GDP)**	**Primary Energy Consumption**	**Liquids consumption**	**Gross Domestic Product (GDP)**	**Primary Energy Consumption**
Total OECD	-0,12	2,01	0,66	0,22	1,99	0,63	0,05	2,00	0,64
Total Non-OECD	1,83	4,50	2,13	1,83	3,90	1,76	1,83	4,20	1,94
Total World	0,98	3,52	1,56	1,10	3,11	1,31	1,04	3,31	1,43

Other macro inputs are used but they will be considered in the following section for each company separately.

2. ExxonMobil Standalone Valuation

2.1. Revenues

2.1.1. Upstream

The upstream revenues represent on average 9% of the total operating revenues over the last five years, but in absolute terms, they have been decreasing significantly, (-15% CARG). The decrease of upstream revenues has followed the same pattern as oil prices, but in operational terms, it has had different performances among liquids and NG (Figure-10). NG production and revenue has decreased since 2011.

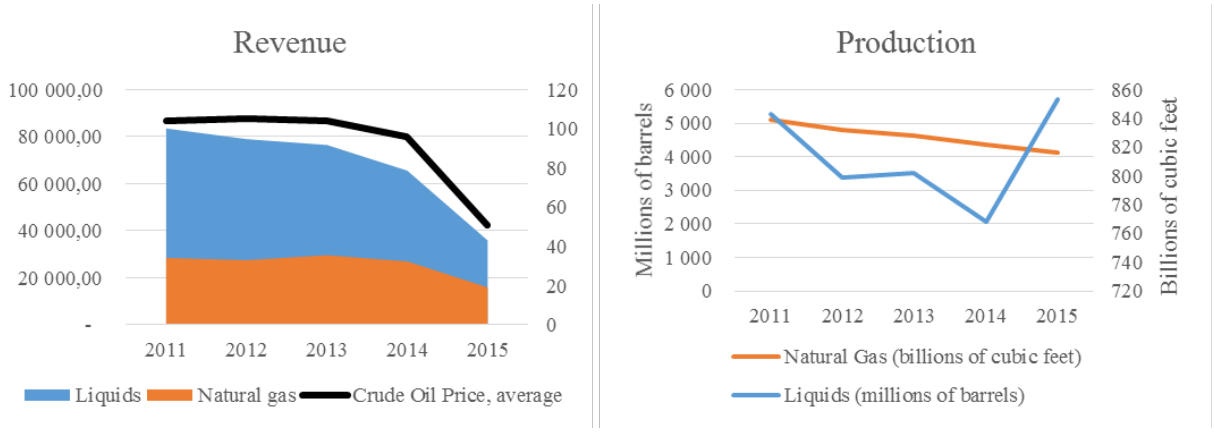


Figure 10- ExxonMobil's Revenues and Production Levels (2011-2015) (Company Annual Reports)

Going forward, the company's production of liquids is expected to increase (4.3M BOE by 2017) with ten new projects expected to be completed by 2017. However, the geographic mix and type of resource are expected to be different - North America is assuming an increasingly powerful position.

Even with considerable growth perspectives, the company's revenues are limited to the growth of oil prices. The driver used to estimate the upstream revenues is aligned with the forecasted growth for crude oil prices. However, the new projects that are coming online, an outstanding performance in terms of operational efficiency and a strong financial flexibility, are enough to establish a growth of upstream revenues that outpace the commodity price growth.

Following this rationale, after prices hit rock bottom, revenues are expected to increase around 6,67% until 2025 (Figure-11). Due to the delay in recovering oil prices, revenues in 2016 are expected to have the same downward pattern as in 2015 (-27%).

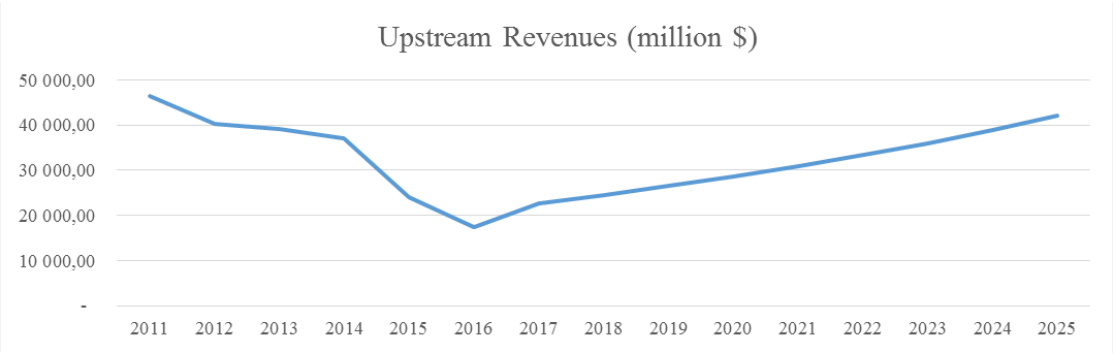


Figure 11 - Forecast of ExxonMobil's Upstream Revenues

2.1.2. Downstream

Downstream revenues have represented, on average, around 81% of total revenues since 2011, but have decreased as ExxonMobil has looked to diminish its footprint in this segment (81,07% in 2011 to 79,89% in 2015).

The production forecast is based on the forecasted demand for petroleum and other liquids (excluding petrochemicals) which is expected to decrease slightly over the next ten years (Annual Energy Outlook 2015 (U.S EIA)).

The correlation between the evolution of unit revenues for downstream products and crude oil prices is clear. Therefore, the unit revenue will follow the same pattern as crude oil prices, except in 2016, when downstream revenues are not expected to be in direct correlation with oil prices.

Overall, ExxonMobil's average revenue per barrel of refined products is expected to move in close correlation with global crude oil prices. Product sales are expected to decline modestly throughout the forecast period (Appendix 14).

2.1.3. Chemical

Chemical revenues represented around 10,8% of the total sales in 2015 (8,9% in 2011). Chemical revenues historically have also been closely linked to oil prices and therefore the forecast will follow the same driver. In terms of production, chemical product sales remained stable since 2011.

Looking ahead, due to ExxonMobil's investments and increased capacity, their production is expected to increase. The forecast is based on the demand for petrochemical products (between 3%

and 3,6% until 2025) (U.S.EIA, 2016). Overall, chemical revenues are expected to grow around 6% from 2015 until 2025.

2.2. EBITDA Margin

The EBITDA margin analysis highlights the value of ExxonMobil's integrated business model, with EBITDA being less volatile to weak periods of lower oil prices. Over the last four years, the EBITDA margin on average was 17% (Figure-12).

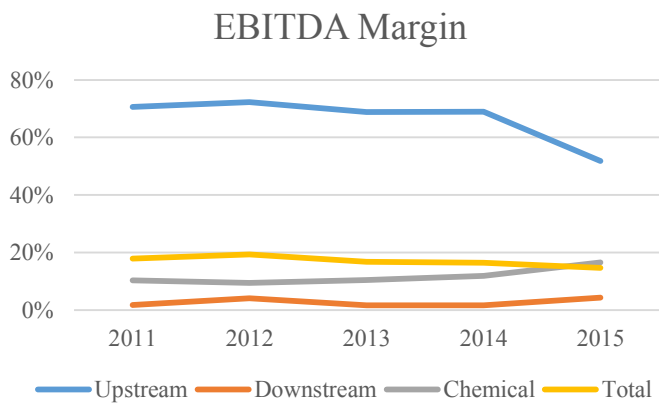


Figure 12 - ExxonMobil's EBITDA Margin (2011-2015)

The upstream EBITDA margin is specially affected by oil prices, but hydrocarbon production costs and labour costs also play an important role. Since 2012, the EBITDA margin of upstream activities has decreased by 7,5% (CARG) (Appendix 15).

Going forward, it is expected that the recovery of oil prices will positively affect the EBITDA margin, along with growth in liquids production against NG. Conversely, the transition to unconventional energy sources are factors which will increase the company's upstream expenses.

The other two segments, downstream and chemical, are positively affected by lower crude oil prices (increased EBITDA YOY of 2,6% and 4,6% in 2015, respectively). Still, there are other important issues that should be considered (Appendix 16).

Looking ahead, margins in the downstream segment are expected to sustain higher levels in 2016. Thereafter, they should return to the average level of the last four years (2,7%).

In terms of chemical products, margins have been increasing consistently since 2012 (10% to 17%). Going forward, they are expected to reach even higher margins in 2016, but afterwards, they should decrease as crude oil price recovers.

Overall, total EBITDA margins should not change significantly over time, as seen over the last years.

2.3. CAPEX, D&A and Working Capital

ExxonMobil announced its plans to cut on CAPEX in reaction to lower oil prices ($23,2Bn in 2016, $8Bn less).

Historically, the upstream segment has accounted, on average, for more than 85% of the total CAPEX. In absolute terms, net upstream CAPEX has increased significantly as the company focuses on new upstream growth projects. In line with what happened in 2015, the next two years are expected to have smaller absolute levels of CAPEX and going forward, it should increase gradually, along with oil price recovery (6% CARG 2015-2025).

Following the strategy of ExxonMobil to reduce its focus on the downstream sector in favour of upstream exploration, the downstream CAPEX has fallen since 2009. However, due to its recent investments, ExxonMobil reached more than 25% growth YOY in 2015. Going forward, downstream's CAPEX should average at the same levels as the last four years.

The Chemical segment's CAPEX clearly highlights the large projects that ExxonMobil has been investing in. After a growth of 20% since 2011, these projects are expected to still demand CAPEX until 2017. Going forward, it is expected that chemical's CAPEX will decline gradually.

Overall, in the next two years CAPEX is expected to decrease, but afterwards it should grow along with oil prices recovery (Table-5). New assets will depreciate at the rate of the existing assets (7% - average depreciation rate since 2011).

Table 5 - ExxonMobil's CAPEX and Depreciation

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Property, plant and equipment n-1	**251.605**	**233.993**	**216.380**	**198.768**	**181.156**	**163.543**	**145.931**	**128.319**	**110.706**	**93.094**
(-) Depreciation and depletion expenses	17.612	17.612	17.612	17.612	17.612	17.612	17.612	17.612	17.612	17.612
(+) Net Property, plant and equipment	233.993	216.380	198.768	181.156	163.543	145.931	128.319	110.706	93.094	75.481
(+) Annual CAPEX	23.200	23.200	24.843	26.535	28.420	30.402	32.528	34.800	36.569	38.446
(+) Depreciation new Assets	1.624	3.248	4.987	6.844	8.834	10.962	13.239	15.675	18.235	20.926
(-) Net New Assets	21.576	41.528	61.384	81.075	100.661	120.101	139.390	158.515	176.849	194.369
Property, plant and equipment n	255.569	257.908	260.152	262.230	264.204	266.032	267.709	269.221	269.943	269.851
Total annual depreciation	**19.236**	**20.860**	**22.599**	**24.457**	**26.446**	**28.574**	**30.851**	**33.287**	**35.847**	**38.538**

The working capital for the forecast period is the net of free cash and STD (Table-6). The forecast BS separates operational cash and free-cash: operational cash is based on the average weight of total revenues, and the free-cash results from the earnings that will be generated over the forecast period, net of dividends, investments in CAPEX and debt obligations. The additional notes and forecasted FS are detailed in the appendix 17.

Table 6- ExxonMobil's Working Capital

Working Capital	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total current assets (A), excluding free-cash	30.911	40.196	43.189	46.303	49.797	53.465	57.420	61.667	66.295	71.311
Total Current Liabilities, net short-term debt (B)	28.234	36.736	39.491	42.348	45.544	48.891	52.500	56.375	60.598	65.175
Total Current Liabilities	44.096	53.783	53.439	52.674	49.281	48.891	52.500	56.375	60.598	65.175
Short-term debt	15.862	17.047	13.949	10.325	3.737	-	-	-	-	-
Working capital (A-B)	2.678	3.460	3.698	3.955	4.253	4.574	4.920	5.292	5.697	6.136
Change in working capital	(4.731)	782	238	256	298	321	346	372	405	439

2.4. Valuation

2.4.1. APV

APV, according to Luehrman (1997), outperforms WACC by separately considering CF from business operations and financing strategies. Different assumptions were made, especially to determine the discount rate, the TV and the BC.

Firstly, the CAPM is used to determine the discount rate, consequently, risk-free, MRP and beta are needed. The risk-free is assumed as the yield on the U.S.'s 10-year TB (Copeland, Koller, & Murrin, 1991), based on the geometric mean of the last 10 years (2,53%). Since the TB yield in the U.S. ranged between 4,7% and 1,76% over the last decade, it seems more accurate to use this average in order to avoid the volatility of special one-time events. Furthermore, it is important that the risk-free has the same duration as the analysed cash-flows, consequently, the U.S.'s 10-year TB are also more adequate than bonds with a lower maturity.

Regarding MRP, the same approach was used since it was considered the arithmetic average of the implied premium verified during the last decade, which results in a premium of 5,32%. Considering the beta of ExxonMobil's peer group (1,145), and after adjusting this beta to the capital structure of ExxonMobil, the unlevered beta used is 0,89. Applying the CAPM, the unlevered cost of capital is 7,27% (Appendix 18).

In order to calculate the tax shield, the CTR applied was 35%, the U.S. federal statutory income tax rate. Despite an ongoing debate regarding the discount rate used to value the tax shields, the

perspective (as supported by most academics) of using cost of debt to discount tax shields, was used.

The third step is to evaluate the expected BC. In theory, this requires the estimation of the probability of default and the BC - the more challenging part since they cannot be deducted directly. Therefore, one way is to estimate a bond rating and use the respective empirical estimates of default probability. For a company with the same credit rating as ExxonMobil, the cumulative probability of default over ten years is 0,03% (Damodaran A. , The Cost of Distress: Survival, Truncation Risk and Valuation, 2006). Throughout the following formula, it is possible to convert the cumulative probability of default on an annual basis:

$$1 - (1 - \pi_{Distress})^t$$, where $\pi_{Distress}$ is the annual probability of distress

Thus, the annual probability of default is 0,003%. In terms of BC, there are different studies that have looked at this issue, but the one considered here was the method proposed by Korteweg (2007), where the BC are found to be around 2,6% of the firm's unlevered value (Appendix 19).

Table 7 - ExxonMobil's BC

Bankruptcy Costs (million$)	
Value Unlevered	400.186
% of costs	2,60%
CFD	10.405
Probability	0,003%
Expected CFD	31,22%
Discount Factor	39,53
Present Value	12,34

The total amount of BC discounted at the risk-free is $12,34M (Table-7). The financial distress CFs should not be discounted at a discount rate above the risk-free (Almeida & Philippon, 2004)

Finally, for the TV, the growth rate was based on the expected annual average per cent change of GDP worldwide. After considering the weight of future demand for O&G energy for OECD and non-OECD countries, the growth rate used was 3,32%.

In conclusion, according to APV, the Entreprise Value of ExxonMobil is $403,98Bn and the Equity Value is $362,79Bn (Table-8) (Appendix 20).

Table 8 - ExxonMobil's Valuation with APV

APV (million$)	
Enterprise Value	403.981
(-) Net Debt	35.195
(-) Minority Interest	5.999
Equity Value	362.787
Common Shares	4.196
Per Share	86,46

2.4.2. WACC

Besides the steps already developed, the cost of debt is needed to value ExxonMobil through the WACC. Capital structure and the adjusted cost of equity based on a levered beta is detailed above.

The cost of debt was computed through the risk-free plus the default-risk spread according to the company's probability of default. Thus, following the estimation presented by Korteweg (2007), the company's cost of debt is 3,28%. This was the method that seemed to be the most appropriate since the cost of debt calculated through the ratio of interest expenses (excluding non-debt related expenses) over net debt, fluctuated significantly.

Lastly, the element needed to reach the cost of capital is the company's capital structure. Over the last few years, the company's debt-to-value ratio has ranged widely between 3% and 10,7%, averaging 6%. Using the average leverage level of the last four years seems to be the more reasonable assumption.

Considering this capital structure, the levered beta used to calculate the cost of equity was also adjusted through the following formula:

$$\beta_E = \left[1 + (1 - t)\,\frac{D}{E}\right]\beta_A$$

Finally, with all assumptions described, the WACC is 7,13% (Appendix 21), the company's EV is $413,65Bn and the Equity Value is $372,48Bn (Table-9) (Appendix 22).

Table 9- ExxonMobil's Valuation with WACC

WACC (million$)	
Enterprise Value	413.673
(-) Net Debt	35.195
(-) Minority Interest	5.999
Equity Value	372.479
Common Shares	4.196
Per Share	88,77

2.4.3. Relative valuation

Relative valuation is an important complement to the WACC and APV method, since it brings the advantage of including market expectations and confronts them with company specific assumptions. The peer group selection was determined based on two main drivers: risk levels and business models (Appendix 23).

Table 10 - ExxonMobil's Peer group selection

Multiples: Peer group selection								
(million $)	EV/EBITDA	EV/EBIT	P/E (TTM)*	P/B	P/FCF	Market Cap	Debt to Equity R	ROC
Chevron	8	41	37	1	-	169.378	0	3
Shell	6	44	79	1	41	147.271	0	2
BP	15	(17)	-	1	253	104.767	1	(4)
Total	5	19	21	1	-	109.681	1	1
Average	8	22	34	1	73	132.774	0	1
ExxonMobil	9	16	20	2	85	323.960	0	8
Source: Thomson Reuters	*trailing twelve months							

ExxonMobil has been historically traded at a premium compared to its peers (Table-10). It has the highest market capitalization, the lowest leverage level and the highest return on capital.

In terms of price to EV-to-EBITDA and Price-to-FCF, ExxonMobil stands out, reflecting the market's confidence in the company's future stocks (Appendix 24). However, its price-to-earnings ratio is below its peers' average, probably due to the maturity level of ExxonMobil.

The price-to-market ratio of ExxonMobil is higher than its peers, which could mean overvaluation. However, it does not necessarily mean that the company is overvalued, instead it translates the market premium due to the company's resilience to deal with peaks of low and high prices.

Nevertheless, as a consequence of different capital structures, the EV ratios are usually the best to accurately develop a relative valuation. Between EV/EBITDA and EV/EBIT, since this industry

has high levels of capital invested, the ratio in relation to EBITDA also has the advantage of being insensitive to depreciations.

Table-11 summarizes the relative valuation of ExxonMobil based on peers and on general industry multiples (Damodaran A. , Damodaran, 2016)

Table 11 - ExxonMobil's Relative Valuation

ExxonMobil	EV/EBITDA	EV/EBIT	P/E
Peer Group	341.654	474.894	550.957
Industry Average	363.732	968.195	722.067

Indeed, after applying these multiples, the results based on EV/EBITDA are the most aligned with the other valuation methods already developed and the market consensus.

2.5. Sensitivity Analysis

Considering the volatility and complexity of the oil industry, developing a sensitivity analysis is essential. The bull and bear scenario are defined upon two different growth rates applied to the TV: the bull scenario applies a growth rate for the TV of 3,5%, contrasting with 3,14% applied to the bear scenario. These different growth rates reflect the higher or lower potential prices for oil in the future.

Furthermore, in order to reflect these scenarios over the explicit forecast period, the growth rate for crude oil prices also changed by plus and minus 2% for the bear and bull scenario, respectively.

Table 12 - ExxonMobil's Sensitivity Analysis

EXOONMOBIL			Terminal Value		
			3,32%	3,50%	3,14%
% Oil Prices Growth	APV	Forecast	86,46	90,06	83,18
		Forecast + 2%	98,61	102,71	94,88
		Forecast - 2%	76,62	79,83	73,69
	WACC	Forecast	88,77	92,65	85,25
		Forecast + 2%	101,36	105,77	97,35
		Forecast - 2%	78,57	82,03	75,44

Following this analysis, the share price of ExxonMobil changes between $73,69 and $102,71 considering the APV model, and $75,44 and $105,77 considering the WACC model (Table-12).

2.6. Valuation Output

Comparing the valuation results from the different methods, two main conclusions can be highlighted: there is a reasonable consensus within the lowest value provided by each method ($70,22 and $78,5), however the highest value changes significantly, which can be justified by some of the limitations of particular methods (Figure-13).

The WACC and APV results are similar and are relatively aligned with the market consensus (Appendix 25), both for the lowest and highest valuations. However, the multiples approach, especially the one based on the overall industry, provided unreasonable values for ExxonMobil.

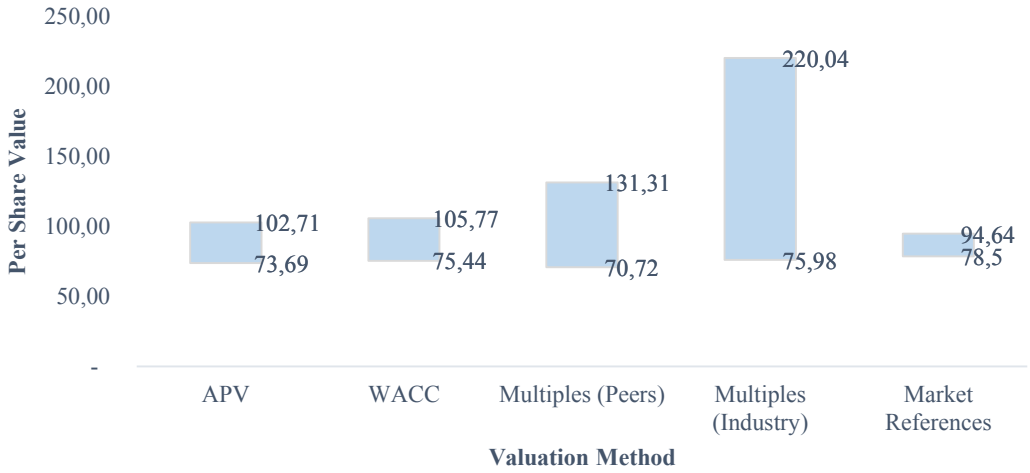


Figure 13 ExxonMobil's Valuation Output

3. Anadarko Standalone Valuation

3.1. Revenues

The analysis of sales volume and price evolution of oil, NG and NGL over the last four years provide some important inputs to develop the forecast and understand the company's strategic decisions.

The following graph highlights the consistent growth of oil and NGL volume sales since 2011 as opposed to NG. Anadarko derives all of its NG production from the U.S. where the over-supply has resulted in depressed domestic NG prices, with liquids becoming far more profitable.

The forecast applied to the sales volume followed the same pattern as worldwide oil and NGL production, as well as that of NG consumption.

The oil volume sales had such a significant growth over the last four years (10,1% CARG 2011-2015) that it is not expected to be as significant for the forecast period (2,7% CARG 2015-2020 and 1,5 % CARG 2020-2025). The recent decline in oil prices has obligated Anadarko to claw black on CAPEX, however, after 2020 it should start to recover with the predicted higher oil prices (Appendix 26).

The correlation between NGL and crude oil prices result in these two commodities tending to follow the same pattern, both in terms of price and production. NGL production will reach 3% CARG 2015-2025 (4,9% CARG 2011-2015)

After a decrease from 7,2% (2011) to -9,8% (2014), NG production will follow the same decreasing pattern over the forecast period, reaching -3,8% in 2020. Afterwards, it is expected to recover again, slowly reaching a 1,7% CARG in 2025. The growth rate assumption used to forecast the volumes of NG production follows the expected growth for the worldwide NG consumption, but after 2020, it is expected to outpace it by 1% due to predicted recovery prices and the increased pace of development of Anadarko's onshore assets.

Following on from this, liquids are expected to represent, on average, 57% of the sales volume-mix, contrasting with the 46% verified over the historical period. The unit prices closely follow the estimated prices provided by the U.S. EIA.

3.2. EBITDA Margin

Anadarko's EBITDA margin reached 57% in 2012, at its peak of high commodity prices. But since 2014, this figure has decreased significantly to negative values. In 2015, the company EBITDA margin was less than -48%.

It is expected that Anadarko's EBITDA margin will increase gradually over time with commodity prices recovering to around 46% by the end of the forecast period (Figure-14).

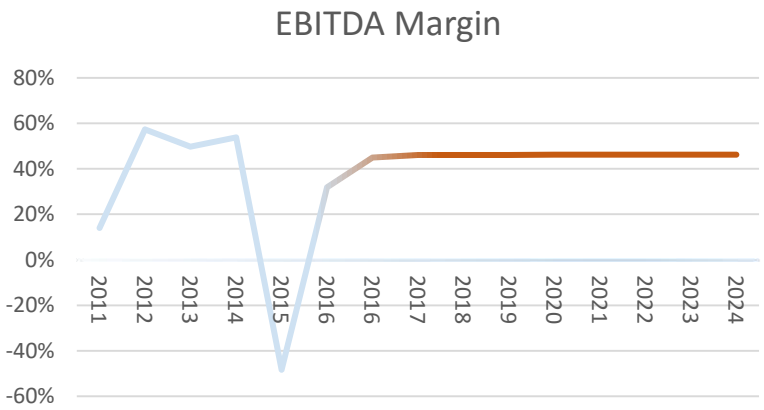


Figure 14- Anadarko's EBITDA Margin

The focus now will be on the drivers and assumptions related to operation costs. O&G operating and transportation expenses, along with gathering, processing and marketing costs were driven from sales since they are directly correlated.

However, exploration expenses have risen consistently over the last few years (8,38% of total sales in 2011 compared with 32% in 2015) and consequently, its forecast was driven as the average percentage of sales of the last four years with a slight growth averaging 1,5% (Appendix 27).

G&A expenses were also driven as a percentage of sales, however, since labour costs represent a big part of these, and due to their increase, this forecast was determined as a percentage of sales plus the expected growth for labour costs in this industry (EIA, 2015).

Following these assumptions, the EBITDA margin will grow significantly until 2020 with an effort to recover from the negative margins. After 2020, it is expected to stabilise around 46%.

3.3. CAPEX, D&A and Working Capital

The CAPEX forecast of Anadarko combines both Anadarko and WES CAPEX (Table-13). For WES, the CAPEX forecast was determined as a percentage of sales. The remaining CAPEX expenditures were based on the forecasted growth of crude oil prices, but considering the volatility of a non-integrated business model, a more modest growth rate of less than 2% was applied. However, this was applied only to 2018 and beyond. In 2016, it was based on the company projections (Anadarko Petroleum Corporation, 2016) and in 2017, a modest growth of 15% was applied (29% projected for the growth of oil).

Table 13 - Anadarko's CAPEX and Depreciations

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Property, plant and equipment net of depreciations n-1	**33.751**	**31.692**	**29.633**	**27.575**	**25.516**	**23.457**	**21.398**	**19.339**	**17.281**	**15.222**
(-) Depreciation and depletion expenses	2.059	2.059	2.059	2.059	2.059	2.059	2.059	2.059	2.059	2.059
(+) Net Property, plant and equipment	31.692	29.633	27.575	25.516	23.457	21.398	19.339	17.281	15.222	13.163
(+) Annual CAPEX	3.044	3.546	3.749	3.950	4.166	4.394	4.638	4.895	5.180	5.052
(+) Depreciation new Assets	213	461	724	1.000	1.292	1.599	1.924	2.267	2.629	2.983
(-) Net New Assets	2.831	5.915	8.941	11.891	14.765	17.560	20.274	22.902	25.453	27.757
Property, plant and equipment n	**34.523**	**35.549**	**36.515**	**37.407**	**38.222**	**38.958**	**39.613**	**40.183**	**40.674**	**40.920**
Total annual depreciation	**2.272**	**2.520**	**2.783**	**3.059**	**3.351**	**3.658**	**3.983**	**4.326**	**4.688**	**5.042**

The depreciation rate used was 6,1% for the existing assets, which is the average depreciation rate since 2011. For the new assets, the depreciation rate applied was 7%.

The WC for the forecast period is the net of STD, and the other components of current assets and current liabilities are calculated through the average weight of the last four years in relation to revenues (Table-14).The additional notes and forecasted FS are detailed in the appendix 28.

Table 14 - Anadarko's Working Capital

Working Capital	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total current assets (A)	2.811	3.494	3.714	3.934	4.145	4.467	4.903	5.406	6.026	6.623
Total Current Liabilities, net short-term debt (B)	3.255	3.846	4.154	4.431	4.689	4.755	5.062	5.393	5.802	6.195
Total Current Liabilities	6.776	8.514	8.770	8.815	8.081	7.080	5.803	5.393	5.802	6.195
Short-term debt	3.521	4.668	4.616	4.384	3.392	2.325	741	-	-	-
Working capital (A-B)	(445)	(352)	(440)	(498)	(543)	(288)	(159)	13	224	428
Change in working capital	(279)	93	(88)	(57)	(46)	255	129	171	212	204

3.4. Valuation

3.4.1. APV

The steps developed to calculate Anadarko's valuation throughout APV were the same already explained for ExxonMobil. Due to both companies operating in the same industry and being based in the same country with worldwide operations, most of the assumptions applied followed the same reasoning.

The discount rate based on the unlevered beta calculated throughout the CAPM for Anadarko is 7,45%, and the risk-free (2,53%) and MRP (5,32%) used was exactly the same as ExxonMobil (Appendix 29). However, the unlevered beta was calculated based on Anadarko's peer group, and adjusting it to its capital structure. Anadarko's peer group's unlevered beta is 1,58 for an average debt-to-equity ratio of 1,09, which after adjustments resulted in an unlevered beta of 0,92.

The CTR used was 35%, the U.S. federal statutory income tax rate and the tax shield were discounted using the cost of debt.

The BC were determined throughout the same pattern as ExxonMobil, but considering that Anadarko has a bond rating of BBB, its cumulative probability of default on an annual basis is 0,435%. Anadarko had a negative EBIT in 2015, thus its negative ICR would mean a spread equivalent to a D2/D rating. Thus, the applied rating was based on its rating of LTD established by S&P and Fitch as of December 31, 2015. The BC applied were also based on a percentage suggested by Korteweg (2007) (2,6%) (Table-15).

Table 15 - Anardako's BC

BC	
Value Unlevered	36.454,22
% of costs	2,6%
CFD	947,81
Probability	0,435%
Expected CFD	4,13
Discount Factor	39,53
Present Value	163,13

Finally, the assumption under the growth rate applied to the TV was also 3,2%. In conclusion, using the APV method, the EV of Anadarko is $40,9Bn and the equity value is $23,5 Bn (Table-16) (Appendix 30).

Table 16 - Anadarko's valuation with APV

APV (million$)	
Enterprise Value	**40.941,20**
(-) Net Debt	14.761,00
(-) Minority Interes	2.638,00
Equity Value	**23.542,20**
Common Shares	508,00
Per Share	46,34

3.4.2. WACC

The valuation of Anadarko through the WACC demands for further assumptions. The cost of debt combines the risk-free of 2,53% plus the default-risk spread of 2,25%. As explained before, the default-risk spread was determined based on a rating of BBB, which corresponds to 2,25% of the spread. Thus, the cost of debt of Anadarko is 4,78%.

The capital structure of Anadarko has changed quite significantly over the last year, with its debt-to-equity ratio changing from around 40% to more than 60%. However, considering the forecast for oil prices, it is not expected that Anadarko will be able to go back to the usual debt-to-equity

ratios in the ST. Although, the assumed target debt-to-asset ratio was 44%, since Damodaran proposes this for upstream O&G companies. Moreover, by assuming this capital structure, the debt-to-equity ratio of 79% is in line with the average of the forecasted leverage (78% in BV).

Assuming this capital structure, the levered beta of Anadarko is 1,40, after the respective adjustment based on its peer group's beta. Finally, the cost of capital under the WACC is 6,94% (Appendix 31), the company's EV is $ 42,59Bn and the equity value is $25,19Bn (Table-17) (Appendix 32).

Table 17 - Anardako's Valuation with WACC

WACC (million$)	
Enterprise Value	**42.589,72**
(-) Net Debt	14.761,00
(-) Minority Interest	2.638,00
Equity Value	**25.190,72**
Common Shares	508,00
Per Share	**49,59**

3.4.3. Relative Valuation

Applying the relative valuation has some particularities that limit the usage of this approach with Anadarko. Multiples as EV-to-EBITDA and EV-to-EBIT are not material if EBITDA and EBIT are negative, which is the case of Anadarko as of December 2015.

Due to the different capital structures of Anadarko's peer group (Table-18), with debt-to-equity ratio ranging from 0,34 to 3,42, EV ratios are the more accurate. Thus, EV-to-EBITDA and EV-to-EBIT should be applied. Nevertheless, since both figures, EBITDA and EBIT, are negative, the way to apply them is through normalized or forward values. Applying the forward average of EBITDA for the next five years seems to be an accurate alternative.

Table 18 - Anadarko's Peer Group

Multiples (million $)							
(million $)	/EBIT	EV/EBIT	P/E (TTM)	P/B	Market Cap	Debt to Equity Ratio	ROC
Devon Energy Corp	5	11	-	1	13	2	(60)
EOG Resources Inc	9	31	-	3	39	1	(22)
Apache Corp	3	-	-	2	17	3	(98)
Pioneer Natural Resources Co	23	-	24	2	19	0	7
Marathon Oil Corp	9	-	-	0	9	0	(8)
ConocoPhillips	12	-	-	1	58	1	(4)
Average	11	57	24	2	29	1	(30)
Anadarko	14	-	-	2	25	1	(22)

Source: Thomson Reuters (Data from 31/12/2015)

The relative valuation of Anadarko was based on a peer group composed by seven companies, all based in the U.S with only upstream activities. (Appendix 33).

Following this peer group and after applying the Forward EV-to-EBITDA and Forward EV-to-EBIT to Anadarko, the final results are significantly different from the ones reached with APV and WACC. The Forward EV-to-EBITDA (5y) is the only one which provides a valuation that can be considered, since it is not so different from the market consensus (Table-19) (Appendix 34).

Table 19 - Anadarko's Relative Valuation

Anadarko	Forward EV/EBITDA (5y)	Forward EV/EBITDA (10y)	Forward EV/EBIT (5y)	Forward EV/EBIT (10y)
Peer Group	50.314	66.825	20.464	28.743
Industry Average	26.353	26.353	-	-

3.5. Sensitivity Analysis

The sensitivity analysis was developed based on the same assumptions as ExxonMobil (Table-20).

Table 20 - Anadarko's Sensitivity Analysis

ANADARKO			Terminal Value		
			3,32%	3,50%	3,14%
% Oil Prices Growth	APV	**Forecast**	46,34	49,27	43,67
		Forecast + 2%	70,32	74,36	66,63
		Forecast - 2%	25,90	27,89	24,09
	WACC	**Forecast**	49,59	53,57	45,99
		Forecast + 2%	78,14	83,63	73,18
		Forecast - 2%	59,50	27,95	22,81

Following this analysis, the share price of Anadarko ranges between $24,09 and $74,36 for APV and $22,81 and $83,63 considering WACC.

3.6. Valuation Output

The valuation output for Anadarko reached very different results (Figure-15). In terms of multiples, the only one which is rather aligned is the Forward EV-to-EBITDA (5y). The optimistic scenario based on the WACC presents the highest valuation, but considering the base case scenario, both WACC and APV are aligned with the market consensus.

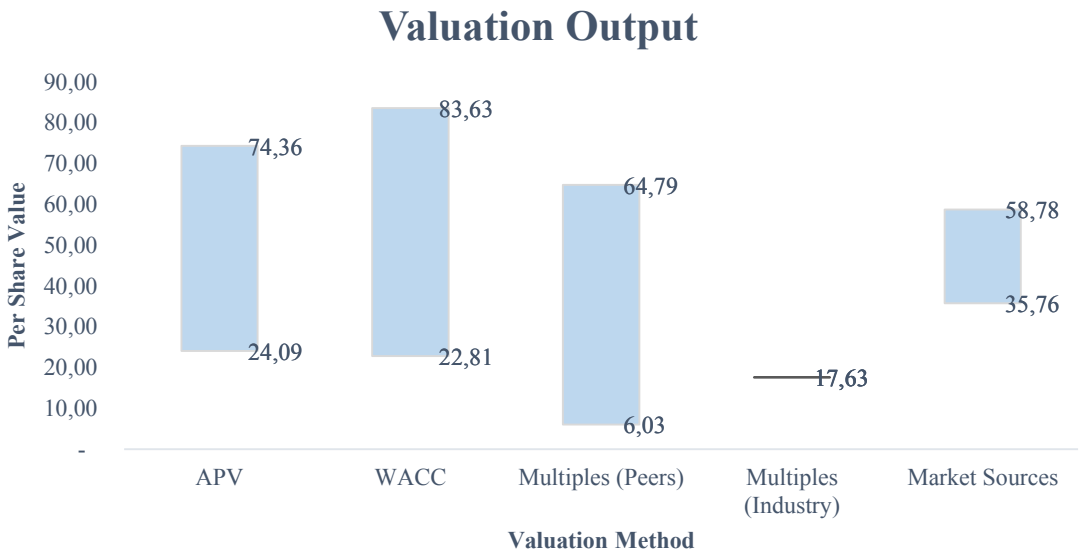


Figure 15 - Anadarko's Output Valuation

Merged Entity

1. Rationale for this transaction

Although the decrease in oil prices recently suffered presents a challenging period for most companies in the industry, at the same time it is an opportunity for companies with strong BS who can use their cash reserves and their lower leverage ratios to engage in deals that benefit them with undervalued assets and that can reaffirm their competitive position in the future.

ExxonMobil is one of the few companies that can easily benefit from the underpriced targets available in the market, due to its strong BS and cash availability.

Looking for the potential targets of ExxonMobil, different companies could be interesting targets in terms of underpricing. However, a financial driver alone cannot explain the rationale behind a buyout, operational synergies are also demanded to justify such a decision during this challenging period.

Besides being one of many that has become a lot cheaper, Anadarko emerged as an interesting target due to its high-quality asset base in the Gulf of Mexico and US shale.

Major international O&G companies have faced competition from mini-majors such as Anadarko, which have been assuming an important position in North American shale production. ExxonMobil is one of the majors which has invested more determinedly in order to face this threat, and the XTO Energy acquisition in 2009 was part to this strategic move.

Acquiring Anadarko would make ExxonMobil one of the largest onshore U.S. operators which is in-line with the company's strategy. Furthermore, significant cost savings can arise from common areas where both companies are operating.

Obviously, when considering a company such as ExxonMobil which already produces 2.3% of the world's oil and is recognized for its safety practices and leadership in delivering projects on time, there are few mini-majors that can significantly influence the production and efficiency levels of ExxonMobil. However, in a period of low oil prices, ExxonMobil has the financial conditions to capture high-quality assets and low-risk development opportunities through the acquisition of undervalued companies such as Anadarko.

2. Valuation of the Merged Entity

Following the model proposed by Damodaran (2005), the valuation of the merged entity will be split into three steps: value of combined firm without synergies (1); revalued the combined firm including synergies (2) and calculate the synergies through the difference between the first and second step (3).

Thus, ExxonMobil and Anadarko will be valuated first, based on the same assumption used over the standalone valuation, and consequently, the value of the merged entity with no synergies must be exactly the same as the sum of the values of each independent firm. Secondly, the valuation of the combined firm should include all the synergies that arise from their combination. Lastly, the value of synergies can be isolated by subtracting the valuation with and without synergies.

2.1 Valuation without synergies

The valuation with no synergies must guarantee that the combined entity is based on the same structural assumption. From the valuation methods used for standalone valuation, only the WACC

will be considered in this section, since APV and WACC resulted in a similar conclusion in the standalone analysis.

The new combined IS and BS stand up from the simple and direct sum of all rubrics existing in each company's standalone FS (Appendix 35). Still, some elements should be explained in more detail.

Starting with the revenues, it is important to clarify that the combined revenues impacted only the upstream segment.

The other important issue which deserves clarification is the discount rate. Regardless of all scale differences, both companies are equally exposed to the same industry challenges and the same governmental regulations, since they both have their headquarters in the U.S.. Accordingly, both ExxonMobil and Anadarko will have the same Risk-free, MRP and CTR.

However, the companies' debt leverage is significantly different, and consequently, the independent capital structure and cost of debt are dissimilar. These differences impact the beta and the spread used to calculate the discount rate. Following that, the best approach to value the combined entities without changing the original assumptions was to consider a weighted average approach based on each individual EV. Finally, the growth rate applied for the TV was the same for both companies and, therefore, the one used for the merged company.

In conclusion, considering this approach, the final EV value of the combined firm was $456,04Bn, which differs slightly from the $456,26Bn obtained through the simple sum of both companies' EV. A potential explanation for this difference is the impact that different discount rates can have across the different assets since this impact is not always in the same proportion. However, since this difference is not significant, it will be ignored and the EV value to be used in the last step to calculate synergies will be the one based on the sum of both companies.

This approach ignores the potential fact that existing shareholders still do not want their part in the new entity and therefore it is assumed that there is no need for increasing debt and making changes on the capital structure.

2.2 Synergies

After developing the first step, it is important to do a careful analysis over why one plus one could be bigger than two, i.e. synergies which make this deal valuable.

Damodaran (2005) grouped synergies into operating and financial. Both will be discussed in this section.

2.2.1 Operating

2.2.1.1 Revenues

The literature review already mentioned that revenue synergies are the most difficult to implement. However, if they are normally problematic, for natural resources companies they are even more so. In O&G companies, the challenge arises from the fact that they do not have control over market prices (Appendix 36).

Another way to increase revenues could be through increasing production, however for O&G companies, it takes time to have projects up and running (Appendix 37).

In conclusion, for both sources of revenue synergies, either an increase in unit price or an increase in production volumes are difficult to achieve, and that is why revenue synergies are not going to be considered in this case.

2.2.1.2 Operating Costs

As opposed to revenue synergies, costs are the most reliable sources of synergies. Reducing costs is normally easier because they are more dependent on internal issues. Asides from this, the fact that they are fast to implement and have perpetual results, makes them more attractive.

However, looking in particular at the O&G industry, it is interesting to realize that the M&A's role has different drivers according to changes in commodity prices. During periods of increasing oil prices, the dominant driver is growth, whereas in flat or depressed periods, improvements on ROIC through cost reduction and capital efficiency are the most common drivers.

The latter being the one behind the rationale of this deal, thus cost synergies are crucial to determine the value of this acquisition. There are a couple of cost synergies which could be highlighted in this deal, especially due to the adjacency of ExxonMobil and Anadarko's operations in the U.S..

The cost synergies will be based on Anadarko's U.S. operations since it accounts for 89% of the sales volumes. Anadarko's international assets will be ignored as they would not have a significant impact for a company such as ExxonMobil, neither for cost synergies.

Due to the large scale and spread of ExxonMobil throughout the U.S., it was easier to look at Anadarko's exploration areas and based on those, compare it to ExxonMobil. In the U.S., Anadarko has E&P onshore activities in the Lower 48 and Alaska, and deepwater Gulf of Mexico. The common exploration areas of Anadarko and ExxonMobil are mapped below (Figure-16).

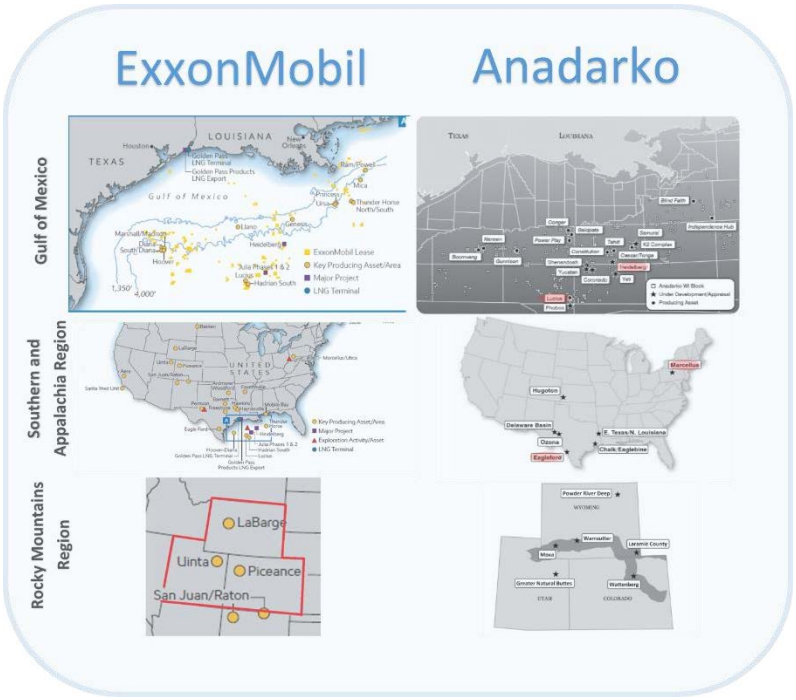


Figure 16 - Common Exploration Areas of Anadarko and ExxonMobil

The detailed analysis of both companies in these common areas are developed in Appendix 29. Their assets and projects in these fields provide enough reasons to justify synergies by cutting overhead costs and optimizing overlapping operations.

The combined firm could benefit from the possibility of operating with the same network of pipelines, support ships and other costly fixed operating assets. Other savings are expected from job cuts and a stricter strategy to centralize controls on CAPEX. However, there is not enough information to go into detail and identify specifically which costs and CAPEX are associated with these projects. As a result, a broader approach will be required to value these synergies.

Looking at the combined IS, the synergies can arise from cutting costs in O&G operating activities; transportation; production and manufacturing; exploration and G&A expenses.

Reducing headcount and G&A function is highly probable when considering a parent company such as ExxonMobil, with hundreds of thousands employees. Probably both companies have headquarters in common cities and no longer need two separate buildings. Potential synergies can also arise from exploration costs. Being as both use the Successful Effort method of accounting, these will simply be considered as other operating costs.

Lastly, the remaining operating costs related with sales-based taxes cost synergies should not be considered, as these are controlled by government and industry-wide regulations.

Therefore, most benefits from this deal are likely to arise during the post-merger integration process through its substantial divestments - which are crucial when looking for opportunities to significantly reduce costs in today's environment.

However, with not enough information to be able to go into detail and create reasonable assumptions for each cost category, the synergy model was developed based on the following statistics: on average, M&A deals in the O&G industry result in 2,4% of combined target sales (BCG; TUM, 2013) ; 67% of cost synergies are successfully captured (PwC's Deals M&A, 2014) and in the former deal between Exxon and Mobil, from the total synergies, Exxon realised two-thirds of cost savings (Appendix 39) (Christopher, Harris, & Chavan, 2012)

Based on the above sources and considering that Anadarko's U.S. revenues account for 31% of the combined upstream revenues, the cost synergies stemmed in approximately 0,02% of the total combined entity's operating costs. This percentage seems to portray quite a conservative scenario, but in fact, it should be remembered that this deal is affecting just one segment of the combined company and it is bringing together two companies from completely different scales.

Finally, in order to calculate the total cost synergies, CAPEX potential synergies should be considered. Since ExxonMobil and Anadarko are operating in common areas, some overlap in terms of projected investments is expected. Due to the lack of information in terms of CAPEX projections for these regions, the assumptions used were also conservative: 5% reduction for Anadarko and 10% for ExxonMobil. For ExxonMobil, this percentage was applied to the proportion of upstream CAPEX in the U.S. (average of 26% since 2011). For Anadarko, it was

applied to the total amount of CAPEX since the existing information does not distinguish between U.S. and non-U.S. CAPEX.

Nonetheless, since CAPEX synergies are assumed to be PP&E, the depreciation expenses were deducted proportionally to the reduction in CAPEX (Table-21).

It should be noted that CAPEX synergies will not have a direct positive impact in the earnings. However, the main objective with a basin- and regional-density deal driven by cost reduction and improved ROIC is to optimize the combined portfolio in order to have the most capital-efficient projects. Indirectly, reaching a better ROIC means to create higher shareholder returns.

Table 21 - CAPEX Synergies

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total combined CAPEX	26.244	26.746	28.593	30.485	32.586	34.796	37.166	39.695	41.749	43.499
CAPEX Synergies	802	800	959	1.022	1.093	1.167	1.246	1.331	1.400	1.459
NET CAPEX Synergies	25.442	25.946	27.634	29.463	31.494	33.629	35.920	38.364	40.349	42.040
Depreciation Adjustment	(56)	(112)	(179)	(251)	(327)	(409)	(496)	(589)	(687)	(789)

2.2.2 Financial

In terms of financial synergies, three different drivers stand out in M&A deals:

- Combining the excess cash and few investment opportunities of one company to one with high-return projects and yet, little available cash to invest;
- Tax benefits from accumulated net operating losses or higher depreciations
- Higher debt capacity

ExxonMobil is a company with excess cash, however in terms of investment opportunities and attractiveness there is no significant differences between both companies.

As for the second driver, Anadarko's EBIT was only negative at the 2015 year-end and there is no significant net operating losses accumulated to consider this as a source of financial synergies. In terms of depreciations, neither ExxonMobil nor Anadarko are expected to be able to increase their depreciation.

Lastly, considering standalone figures and looking at the new capital structure, Anadarko will definitely benefit in terms of debt capacity. Consequently, even considering the higher leverage of Anadarko, due to ExxonMobil's cash availability and lower debt leverage, the combined firms should be considered safer.

In theory, this safeness should be translated in higher debt capacity and in lower cost of debt. After combining both companies without synergies, the new debt-to-equity ratio considering market values is 16%. In contrast, ExxonMobil had a ratio of 10,7% in 2015 and an average of 6% over the last five years.

Including synergies, the average debt-to-asset ratio of the explicit forecast period is 7% and therefore this was the basis for the target capital structure. Following this capital structure, it is not expected that the interest rates used to value ExxonMobil will change. Which means higher savings in terms of interest expenses which are partly offset as a consequence of the interest-tax shield.

Finally, the cost of debt was also determined in the standalone valuation, considering the same risk-free and the ICR of 9,42 translated in a spread of 0,75%. This last element was based on forecasted figures for 2016. The beta used was based on the ExxonMobil's peer group beta. This peer group is still the most appropriate for the new merged entity. Then, the new discount rate applied to WACC is 7,11% (Appendix 40).

2.3 Integration Costs

For the synergies analysis, high consideration was given to cost reduction, but these types of synergies involve a great effort in terms of integration. Consequently, it is important to take into account integration costs and discount them from the total value of synergies.

However, this is a demanding process which involves detailed knowledge about the specific synergies and inside information to clearly evaluate them. Thus, a generic assumption will be made.

Summarizing, the integration costs can be separated into two phases: transaction process and the steps needed to exploit synergies. During the first phase, the typical costs are related to law firms, existing taxes and consulting assistance. Going forward, in order to proceed with workforce adjustments, build a new entity, integrate all operational adjustments and internally recreate the new entity's culture and structure, significant investments will be required.

The assumption used was based on the survey developed by EY in 2013 which argues that, on average, companies spend 14% of the total deal value on integration costs (Ernst and Young, 2014).

2.4 Valuation with Synergies

The last step to value the merged entity with synergies is finally possible. Through the WACC method, the merged entity including synergies is $490,22Bn, which means that they account for $33,96Bn (Appendix 41). Considering integration costs of $ $4,75Bn, the EV is $485,47Bn (Table-22).

Table 22 - Valuation of Merged Entity with Synergies

WACC	
EV without Synergies (A)	**456.262,22**
EV with Synergies (B)	**490.219,54**
Synergies (B-A)	**33.957,32**
Integration Costs (14%)	**4.754,02**
Net EV	**485.465,52**
(-) Net Debt	49.956,00
(-) Minority Interest	8.637,00
Equity Value	**426.872,52**

Comparing the value of the net synergies of integration costs with the value reached for Anadarko, highlights the relative magnitude of this amount. The net synergies account for $29,20Bn, more than Anadarko's equity value ($25,19Bn).

Following the same assumptions applied before in the sensitivity analysis, the value of the merged entity ranges between $353,7Bn and $518,87Bn (Table-23).

Table 23 - Sensitivity Analysis of Merged Entity with Synergies

Merged Entity (Including Synergies)		**Terminal Value**		
		3,32%	**3,50%**	**3,14%**
% Oil Prices Growth	**Forecast**	**426.873**	**446.332**	**409.215**
	Forecast + 2%	**496.369**	**518.866**	**475.952**
	Forecast - 2%	**369.059**	**385.988**	**353.698**

The Acquisition

There are advantages and disadvantages associated with the different ways of proceeding, however the spectrum is not completely free.

This deal is obviously only possible in one way: the first acquires the second. However, Anadarko has some provisions which could make the negotiation process more challenging. Minimizing the size of the control premium and the transaction costs will be part of the strategic objectives of ExxonMobil and, therefore, will be addressed in this analysis.

1. Mode of Acquisition

The negotiation process can be carried out as a friendly takeover, which means that settlements are made in an informal dialogue that allows for an agreement to be reached early in the process. However, it can also be subject to a hostile acquisition.

The reasons behind hostile takeovers are many and different theories try to explain them. The history of hostile takeovers shows that they are more common during periods when the stock market is not soaring (DePamphilis, 2010), since shareholders are more willing to accept offers when their shares are overvalued.

In fact, considering the current low valuation of the majority of O&G companies due to low commodity prices, the perception for shareholders is probably that the shares are undervalued. Therefore, using a hostile takeover approach would be apparently the right way for ExxonMobil. However, Anadarko has certain provisions on its restated certificate of incorporation and by-laws which limit the suitable approaches available to ExxonMobil.

Anadarko has some common takeover defences (Appendix 42), but besides that, it is also subject to Section 203 of the Delaware General Corporation Law (D.G.C.L.) (Appendix 43) which imposes restrictions on business combination with interested stockholders – i.e. owning at least 15% of the outstanding voting stock. Obviously, all these provisions do not make the deal impossible, but will demand for a higher premium.

Therefore, and since these provisions do not apply if Anadarko's board approves the transaction before ExxonMobil becomes an interested stockholder, ExxonMobil should begin negotiations by approaching the board in a friendly manner.

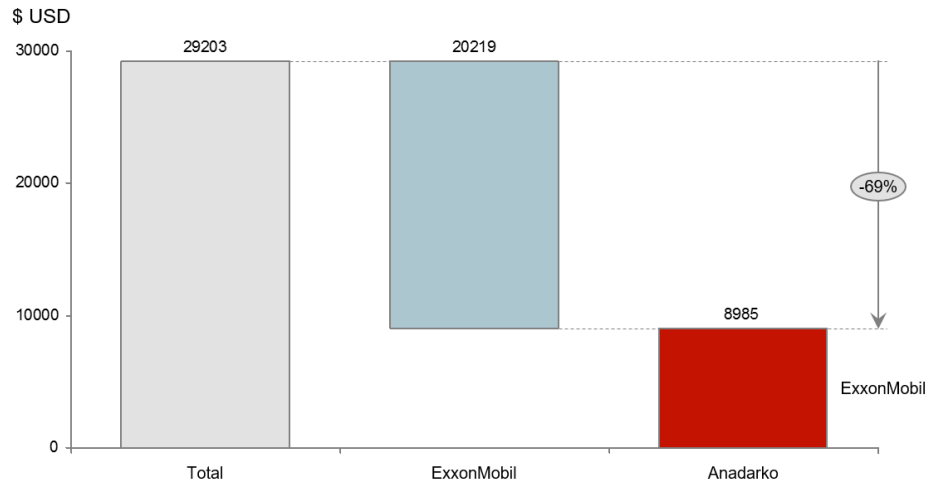
Thus, ExxonMobil should initiate an informal dialogue with Anadarko's top management and try to reach an agreement on the key issues, namely, long-term business strategy of the new merged entity, key management positions and short-term operations. Until it has the standstill agreement, ExxonMobil will not make any investment in Anadarko before the corporate board approves this transaction.

This acquisition is based on the assumption that ExxonMobil views Anadarko as an undervalued company, but the existing anti-takeover provisions will demand for a significant premium. However, due to the implications of the lowest commodity prices in history on the company's valuation, this is the best time to go forward with this acquisition.

2. Distribution of Synergy Benefits

Looking at the degree of relatedness, this deal is clearly a horizontal acquisition, where both companies will essentially benefit from their adjacency.

A great percentage of synergies arise from cost synergies, and neither company has an operating competitive advantage or a special market position over the other. However, a proportional division of synergies based on EV would not be reasonable since ExxonMobil has an EV almost 10 times bigger than Anadarko. The rationale behind this deal is a result of ExxonMobil's strategy to increase its share in the upstream segment in North America, and consequently, using the percentage of upstream sales seems a more reasonable approach to split synergies. Thus, ExxonMobil and Anadarko will receive 69% and 31% of the total amount of synergies, respectively (Figure-17).



	Absolute	% Total EV	% US Upstream Sales (2016)	Synergies (Probab 67%)
EV ExxonMobil	413.673	91%	69%	20.219
EV Anadarko	42.590	9%	31%	8.985

Figure 17 - Synergies Distribution

3. *Premium Offered*

Anadarko's standalone valuation suggests an equity value of $27,83Bn, 13% upside potential compared with $24,69Bn - its average market capitalization during 2015. Consequently, the new equity value with synergies is $36,81Bn, 32% upside potential compared to the standalone valuation. Thus, the value of synergies, along with Anadarko's undervaluation, results in a premium of 49% (Table-24).

Table 24 - Premium Offered

Anadarko			
Annual Market Cap	24.693	Real Downside Potential	13%
Equity Value Standalone Valuation	27.829	Real Preimum Offered	32%
Equity Including Synergies	36.813	Total Premium Offered	49%

4. *Method of Payment*

The existing fundamentals to choose between cash or stock tends to support deals financed with cash rather than stock. The lack of confidence assumed with stock offers, due to the opportunity to share risk, is one of the reasons that justify the worst market reactions. In this case, since synergies were calculated under a conservative scenario (67% probability of realization), there is no reason to use stocks to share the risk with Anadarko's stockholders.

This argument further supports the initial position of proceeding with a deal based on a cash payment. However, the company's ability to effectively pay with cash without harming its capital

structure or negatively impacting its current capital structure is an important factor that must be considered.

As suggested by Damodaran (2006), the ICR can be used as a proxy to estimate the maximum amount of debt that the company can take and still have the same investment grade. Since this deal involves the acquisition of a company which is 10 times smaller than the acquirer, it would be unreasonable to assume that Anadarko would be able to really affect ExxonMobil's credit rating. In fact, the merged entity's synergies has an ICR in line with a rating of Aaa/AAA.

The merged entity without synergies has an ICR of 9,01 (Table-25) and in order to maintain a minimum of 8,5 ICR, it can have a maximum amount of debt of $97,48Bn, which means being able to issue another $47,46Bn. This new amount of debt already represents 129% of the total price offered for this acquisition ($36,81Bn).

Table 25- ICR of Merged Entity

2016E	ExxonMobil	Anadarko	Merged (no syn)	Aaa/AAA Requirement	After Extra Leverage
Cash	3.557	749	4.306		4.306
Debt	33.312	16.703	50.015		97.477
EBITDA	34.098	2.479	36.577		36.577
Interest Cost	683	914	1.597		1.692
EBIT	14.178	207	14.386		14.386
Interest coverage	**21**	**0**	**9**	**> 8.5**	**9**

However, considering that ExxonMobil also has $ 3,56Bn available in cash and unused committed ST and LT lines of credit with a total amount of $6,4Bn, it has in total $57,42Bn available, which is more than the total price offered. Thus, it is possible to assume that ExxonMobil can acquire Anadarko with cash and still maintain its financial flexibility (Table-26).

Table 26 - Debt Capacity of the Merged Entity

Total Debt (2016)	97.477
Total Debt (2015)	50.015
New Debt Issues	**47.462**
Cash	3.557
Unused ST and LT Credit	6.400
Total Available	**57.419**
Price offered	**36.813**
% Cash Available/Price offered	**1,56**

5. The Takeover Bid

Overall, an offer with a 49% premium and the ability to proceed with a cash offer, are reasons to believe that ExxonMobil's offer will be perceived as friendly, which is truly important due to the Anadarko's takeover restrictions, in particular the D.G.C.L.. Still, having a detailed DD that is able to clarify the value added with this deal is crucial for the friendly takeover to be successful.

Conclusion

All companies in the O&G industry experienced a drop in valuation due to the current prices. This has resulted in increasing financial pressure and significant market uncertainty. Despite being a challenging period for most companies in the industry, it is also an opportune time to invest in undervalued assets.

The rationale of this proposed deal emerged as a consequence of ExxonMobil's strong BS, together with its desire to build on its upstream activity in North America and pursue its goal of remaining at the forefront of the industry worldwide. Through cash reserves and lower leverage ratios, ExxonMobil can look for a target with valuable resources such as Anadarko.

Anadarko is deemed an attractive target due to its valuable resources in North America, but specially due to the potential for cutting overhead costs and optimizing on overlapping operations. Being operationally efficient and able to cut costs without losing competitiveness is the desired scenario of every company in the industry at the moment.

Thus, due to the strategic reasons behind this deal, costs account for the majority of the estimated synergies. The uncontrolled market prices of a standalone company explain why revenue synergies were not considered in this case. Besides cost synergies, financial synergies were also accounted to a lesser extent. In total, net synergies accounted for $29,2Bn, which represent 69% of Anadarko's EV.

Concerning the acquisition, ExxonMobil should acquire Anadarko through a friendly approach supported by a cash offer with a premium of 49%.

Appendixes

Appendix 1: How to justify the collapse of oil and gas prices?

During 2015, supply continued to feed the storage levels, especially in Saudi Arabia, with OPEC giving priority to protect their market share. Furthermore, the cut of U.S.'s production levels has been lower than what was predicted by industry analysts. In addition, there is uncertainty regarding the potential increase in production that is expected to arise from Iran, a country which was freed from nuclear sanctions and wants to recover market share.

Despite the efforts to decrease total U.S. production since the middle of 2015 and the agreement established between some OPEC members and Russia in mid-February to freeze production to the levels of January 2016, there is still doubt about the effectiveness of such measures regarding the oil price.

Upstream companies started to react to this low price environment in 2015 with cash conservation measures, plans for cost reductions through manpower layoffs, renegotiation or cancellation of supply contracts and postponement of capital projects.

Appendix 2: Global demand and supply of oil and gas

Technical innovations have been assuming a critical influence concerning cost reduction and access to new exploration areas which was impossible to explore in the past. This fact along with improvements in energy efficiency and changes in major economies of developing countries explain the world peak of oil supply.

Concerning oil, OPEC and U.S. are the leaders with production levels of more than 1 million and 0.8 million barrels per day, respectively (OECD; IEA, 2016).

In relation to gas, the rising of renewables along with very cheap coal have shown sluggish growth in the gas demand in the OECD countries, particularly in Japan where demand is expected to fall. The price-demand sensitivity of non-OECD Asian countries is an uncertainty (IEA, 2015) and in the medium-long term, it is questionable if gas will be competitive enough to be more than a shortage option. The environmental restriction will be indisputably a strong incentive, but not enough to have a radical impact on demand.

According to International Energy Agency (2015), the global LNG export capacity will represent more than 40% of the current capacity. However, due to the capital intensive investment associated with LNG and considering the current low prices, it is expected that part of the new LNG plants will struggle to be effectively concretized.

Appendix 3: Oil Prices

The World Bank (2016) is changing its forecast for lower oil prices, both for short and long-term perspective. In the short-term perspective the forecasted average price is $37/bbl in 2016, contrasting with $51/bbd expected in January of 2015 and in the long-term, the forecast changed from $100/bbd to $82,6/bbd.

Appendix 4: Unconventional energy sources

Technology-driven supplies explain the difference between the 1 trillion barrels of recoverable crude and condensate resources estimated to exist in 1981 by U.S. geological survey and the 4,5 trillion barrels currently estimated. These energy sources along with renewal energy are expected to be enough to face the global demand growth beyond 21 century (IEA, 2015).

Following The Outlook for Energy (ExxonMobil, 2016)all energy sources will grow until 2040 with massive increase in cleaner fuels, in particular, natural gas which will grow 70% comparing with levels of 2014. From the natural gas growth, one-third is due to unconventional gas and arises mostly from North America (60%).

Still, this new era of unconventional energy sources and renewable energy is full of uncertainties and the consequences for oil and gas companies are not entirely understood. However, lower prices are already demanding for efficient structures able to reduce cost production and increase unit margins.

Investing strongly in technology is critical not just to be able to reach unconventional sources of energy but also to deal with these price forces.

Appendix 5: Legal, Regulatory and Financial Environment

The end of the U.S. crude export ban: Established in December 2015 as a consequence of the existing price parity between West Texas Intermediate (WTI) and Brent Crude, which eliminate opportunities for price arbitrage. On a more local perspective, this regulatory change is expected

to increase light sweet oil demand from Europe and Asia and for the overall oil market. Having U.S. as an exporter means that WTI will be a truly International benchmark adding more efficiency to the global trading market.

More restricted financing policies: Senior secured debt, bonds and junior subordinated debt were the sources used to fund the push of domestic production in U.S. However, due the collapse of prices in more than 65%, some oil and gas companies are experiencing unsustainable levels of debt. Along with this financial pressure, the lenders of these companies are experiencing double pressure from the Office of the Controller of the Currency and FDIC to develop more demanding stress tests. Consequently, a significant reduction of financing options will be available (Heroux, 2016).

Environmental taxes: Regulatory policies have also increased pressure on the oil and gas industry worldwide, but the U.S. has been particularly held down with higher environmental taxes in 2016 and additional bans and restrictions implemented by local voters. For example, banning the use of hydraulic fracturing, initiatives include increasing mandatory operations setbacks and empowering local governments to regulate oil and gas operations.

Compliance Rules: Compliance rules have being implemented with the final goal of obligating oil and gas companies to detail more and more their emissions during their operations. The challenge for these companies will be to show that their production is respecting the low-carbon environment.

Appendix 6: ExxonMobil's Upstream Segment

Looking at recent data published in the Financial & Operational Review of ExxonMobil (ExxonMobil, 2016), in terms of upstream is important to highlight six major projects completed in 2015, specifically the two capital-efficient deepwater projects in offshore West Africa which started ahead of schedule and below budget.

From the 91 billion oil-equivalent barrels, 73% are proved reserves with installed production facilities. The components of ExxonMobil's resources base is made up of around 60% liquids and in terms of development type, 73% comprised conventional oil and gas, unconventional oil and gas, and heavy oil/oil sands resources.

Operating Highlights	
Liquids production (net, thousands of barrels per day)	2.345
Natural gas production available for sale (net, millions of cubic feet per day)	10.515
Oil-equivalent production (net, thousands of oil-equivalent barrels per day)	4.097
Refinery throughput (thousands of barrels per day)	4.432
Petroleum product sales (thousands of barrels per day)	5.754
Chemical prime product sales (thousands of tonners)	24.713

Operating Highlights (ExxonMobil, 2016)

Appendix 7: ExxonMobil's Downstream Segment

From crude oil conversion into fuels for transportation, lubricants and chemical plant feedstocks for plastics and many other consumer and industrial products, ExxonMobil reaches a worldwide market through 8.000 miles of active pipelines globally, 24 lubricant plants and about 225 fuel terminals around the world.

In North America, ExxonMobil has nine refineries distributed through the United States and Canada and has the capacity to process about 2,3 million barrels of crude oil per day which is equivalent to 45% of its global refining capacity. Europe represents 30% and Asia represents 20% of ExxonMobil's global refining capacity.

Bases basestock, the major component of lubricating oils, and finished lubricants represent part of the committed investment that has been made and in 2015 was completed one lubricant plant expansions in Texas, China and Finland to serve strong lubricant demand growth in many focus markets.

Appendix 8: Anadarko's upstream activity in the United States

The Rocky Mountains Region Anadarko is expected to be a focus area for Anadarko in 2016. During 2015, Anadarko was focused on production and adding reserves through horizontal drilling and infill drilling, resulting in an increase in liquids sales volumes of 11% in relation to 2014. The Southern and Appalachia Region is where Anadarko has been focused on finding and developing

natural gas and liquids from shales, tight sands and fractured-reservoir plays. In 2016, it expects to proceed with its horizontal drilling program with a special focus on the Delaware basin. In the Gulf of Mexico has 60% of working interest in 279 blocks, operates in eight active floating platforms and holds interest in 34 fields. In Alaska its main activity is concentrated on the North Slope and in the last quarter of 2015 it has four out of seven producing wells coming online from the Alpine West infrastructure.

Appendix 9: Anadarko's upstream activity internationally

Anadarko possessed 40 gathering systems and 54 processing and treating plants.

In Algeria the product is sold by tankers Saharan Blend and in Ghana through Jubilee Oil, both high-quality crude that supplies refiners with significant quantities of premium gasoline, diesel and jet fuel, within others. Colombia, Côte d'Ivoire, Mozambique, New Zealand and Kenya are the other countries where Anadarko has operations. In 2016 Anadarko will have a particular focus in its explorations in Colombia and Côte d'Ivoire.

The international proved reserves are composed of a mix of 35% oil and condensate, 48% of natural gas and 17% of NGLs.

Appendix 10: Anadarko's midstream activities

These plants are based mainly on its onshore producing facilities located in Wyoming, Colorado, Utah, New Mexico, Kansas, Oklahoma, Pennsylvania, and Texas. In 2015, liquids-rich resources were the main focus of Anadarko in terms of growth, including Wattenberg, the Delaware basin, the Eagleford shale and the Marcellus shale dry-gas play. In 2016, the company is planning to focus on the Delaware basin.

Appendix 11: Western Gas Partners, LP (WES)

In the limited partnership, Western Gas Equity Partners, LP (WGP), a publicly traded consolidated subsidiary, owns interest in WES and at the end of 2015 Anadarko's ownership interest in WGP was 87,3% as limited partner interest and the entire non-economic general partner interest. WGP's ownership interest in WES was 34,6% limited partner interest, the entire 1,8% general partner interest and all of the WES incentive distribution rights. Through other subsidiaries, Anadarko also has 8,5% limited partner interest in WES.

Appendix 12: Anadarko's marketing activities

Minimizing market-related shut-ins, maximizing prices and managing credit-risk exposure are the main goals of the marketing segment. Anadarko's worldwide oil, condensate, natural-gas and NGLs product sales are normally marketed at the currently market prices at the time of the sale.

As the midstream segment, Anadarko also sells products from third parties, especially the ones which come from neighbour producers. Throughout this strategy, Anadarko can aggregate volumes that together guarantee the maximization of its transportation, storage and fractionation capacity. Therefore, Anadarko is able to reach more competitive prices and a more efficient performance.

The products are marketed at fixed-price and cost escalation-based agreements within a variety of contract structures. However, to hedge its risk exposure to changes in market prices, Anadarko engages in limited trading activities, since it normally has a net short position as an oil's seller, natural gas and NGLs agreements which is offset by the Company's natural long position as a producer.

Appendix 13: Anadarko's Net Loss

From this net loss, $5,1 billion are related to impairments primarily due some U.S. onshore and Gulf of Mexico properties, but also impairments of exploration assets, as some unproved properties, write-off of suspended exploratory well costs in Brazil and losses on divestitures.

Appendix 14: ExxonMobil's Downstream Revenues

The rational under the forecast demand for refined products is based on the long-term outlook of intense competition in terms of supply, where new capacity is expected to outpace the growth of global demand.

Furthermore, the proposed carbon policy, specific climate-related regulations worldwide and the growth of biofuels supply are potential factors to impact the downstream segment negatively. In terms of unit revenue, even with a scenario of lower crude prices, the future profitability will be small due the worldwide supply and demand imbalance.

Appendix 15: ExxonMobil's Upstream EBITDA

The decrease in EBITDA margins in the upstream segment was in part a consequence of lower oil prices but also a reflection of its shift to unconventional energy sources. Unconventional energy

source explorations are typically more costly, both for exploration and refinery treatment. Furthermore, the production mix of liquids and natural gas also affect the expenses regarding the upstream segment since normally liquids are more profitable to produce than natural gas.

Appendix 16: ExxonMobil's downstream EBITDA

Downstream EBITDA margins did not have the same trajectory over the last few years, ranging between 1,5% and 4%. The main reasons to explain the lowest EBITDA margins in 2013 and 2014 are the industry overcapacity and lower WTI and Brent crude oil spreads.

Spreads in benchmarked oil prices are not likely to significantly affect downstream EBITDA margins hereafter, especially since the U.S. crude oil export ban was lifted which is expected to narrow the spread between North Sea Brent and U.S. WTI. However, refining margins should still feel the pressure of new capacity additions which will probably be enough to beat growth in global demand. Furthermore, the potential increase of heavy crude oil supply from the upstream segment also could impact refinery margins since it requires more advanced techniques and has negative environmental impacts.

Appendix 17: ExxonMobil's Forecasted FS and Notes

Income Statement (million $)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Sales and other operating revenue(1)	467.029	453.123	420.836	394.105	259.488	210.328	273.668	294.188	315.478	339.286	364.219	391.104	419.970	451.431	485.526
Upstream	46.442	40.326	39.061	37.162	24.053	17.519	22.727	24.564	26.483	28.629	30.911	33.383	36.048	38.962	42.131
Downstream	378.623	374.047	342.706	318.747	207.293	171.564	222.379	237.927	253.911	271.716	290.412	310.460	331.856	355.057	380.058
Chemical	41.942	38.726	39.048	38.178	28.134	21.236	28.550	31.683	35.070	38.926	42.879	47.244	52.047	57.392	63.316
Corporate and Financing	22	24	21	18	8	10	12	13	14	15	16	18	19	20	22
Income from equity affiliates	15.289	15.010	13.927	13.323	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644
Other income	4.111	14.162	3.492	4.511	1.750	-	-	-	-	-	-	-	-	-	-
Total revenues and other income	**486.429**	**480.681**	**438.255**	**411.939**	**268.882**	**217.972**	**281.312**	**301.832**	**323.122**	**346.930**	**371.863**	**398.748**	**427.614**	**459.075**	**493.170**
Crude oil and product purchases	266.534	263.535	244.156	225.972	130.003	118.072	153.629	165.148	177.099	190.464	204.461	219.554	235.758	253.419	272.559
Production and manufacturing expenses	40.268	38.521	40.525	40.859	35.587	28.845	37.532	29.910	32.075	34.495	37.030	39.763	42.698	45.897	49.363
Selling, general and administrative expenses	14.983	13.877	12.877	12.598	11.501	7.134	9.282	9.978	10.701	11.508	12.354	13.266	14.245	15.312	16.468
Depreciation and depletion	15.583	15.888	17.182	17.297	18.048	19.236	20.860	22.599	24.457	26.446	28.574	30.851	33.287	35.847	38.538
Exploration expenses, including dry holes	2.081	1.840	1.976	1.669	1.523	1.234	1.606	1.372	1.471	1.582	1.698	1.824	1.958	2.105	2.264
Interest expense	247	327	9	286	311	683	610	508	401	355	329	329	329	329	329
Sales-based taxes(1)	33.503	32.409	30.589	29.342	22.678	1.324	20.678	22.228	23.837	25.636	27.520	29.551	31.732	34.110	36.686
Other taxes and duties	39.973	35.558	33.230	32.286	27.265	27.265	23.537	25.301	27.132	29.180	31.324	33.636	36.119	38.825	41.757
Total costs and other deductions	**413.172**	**401.955**	**380.544**	**360.309**	**246.916**	**203.793**	**267.735**	**277.045**	**297.173**	**319.667**	**343.291**	**368.775**	**396.127**	**425.844**	**457.965**
Growth		(0)	(0)	(0)	(0)	(0)	0	0	0	0	0	0	0	0	0
Income before income taxes	73.257	78.726	57.711	51.630	21.966	14.178	13.578	24.787	25.949	27.263	28.572	29.973	31.487	33.231	35.205
Income taxes	31.051	31.045	24.263	18.015	5.415	4.962	4.752	8.675	9.082	9.542	10.000	10.491	11.020	11.631	12.322
Net income including noncontrolling interests	42.206	47.681	33.448	33.615	16.551	9.216	8.825	16.111	16.867	17.721	18.572	19.483	20.466	21.600	22.883
Net income attributable to noncontrolling interests	1.146	2.801	868	1.095	401	223	214	390	409	429	450	472	496	523	554
Net income attributable to ExxonMobil	**41.060**	**44.880**	**32.580**	**32.520**	**16.150**	**8.993**	**8.612**	**15.721**	**16.458**	**17.291**	**18.122**	**19.011**	**19.970**	**21.077**	**22.329**
Dividends	**9.020**	**10.092**	**10.875**	**11.568**	**12.090**	**4.608**	**4.413**	**8.056**	**8.433**	**8.860**	**9.286**	**9.741**	**10.233**	**10.800**	**11.442**
Earnings Reinvested	**32.040**	**34.788**	**21.705**	**20.952**	**4.060**	**4.608**	**4.413**	**8.056**	**8.433**	**8.860**	**9.286**	**9.741**	**10.233**	**10.800**	**11.442**
Earnings attributable to ExxonMobil						4.496	4.306	7.861	8.229	8.646	9.061	9.505	9.985	10.539	11.164
Earnings attributable to noncontrolling interests						112	107	195	204	215	225	236	248	262	277
Payout Ratio	21%	21%	33%	34%	73%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%

Balance Sheet (million $)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Assets															
Current assets															
Cash and cash equivalents	12.664	9.582	4.644	4.616	3.705	3.557	4.605	4.928	5.274	5.671	9.497	17.674	26.515	36.725	48.401
Operating Cash						*3.557*	*4.605*	*4.928*	*5.274*	*5.671*	*6.097*	*6.555*	*7.048*	*7.584*	*8.166*
Free Cash						-	-	-	-	-	*3.401*	*11.119*	*19.468*	*29.141*	*40.236*
Cash and cash equivalents - restricted	404	341	269	42	-	-	-	-	-	-	-	-	-	-	-
Notes and accounts receivable, less estimated doubtful am	38.642	34.987	33.152	28.009	19.875	16.254	21.149	22.734	24.380	26.219	28.146	30.224	32.455	34.886	37.521
Inventories															
Crude oil, products and merchandise	11.665	10.836	12.117	12.384	12.037	6.541	8.511	9.149	9.811	10.551	11.327	12.163	13.061	14.039	15.099
Materials and supplies	3.359	3.706	4.018	4.294	4.208	2.189	2.848	3.061	3.283	3.531	3.790	4.070	4.370	4.698	5.052
Other current assets	6.229	5.008	5.108	3.565	2.798	2.371	3.085	3.316	3.556	3.824	4.105	4.408	4.734	5.088	5.472
Total current assets	72.963	64.460	59.308	52.910	42.623	30.911	40.196	43.189	46.303	49.797	56.866	68.539	81.134	95.436	111.546
Investments, advances and long-term receivables	34.333	34.718	36.328	35.239	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245
Property, plant and equipment, at cost, less accumulated de	214.664	226.949	243.650	252.668	251.605	255.569	257.908	260.152	262.230	264.204	266.032	267.709	269.221	269.943	269.851
Other assets, including intangibles, net	9.092	7.668	7.522	8.676	8.285	8.285	8.285	8.285	8.285	8.285	8.285	8.285	8.285	8.285	8.285
Total assets	331.052	333.795	346.808	349.493	336.758	329.010	340.635	345.871	351.064	356.531	365.427	378.778	392.886	407.909	423.927
Liabilities															
Current liabilities															
Notes and loans payable	7.711	3.653	15.808	17.468	18.762	15.862	17.047	13.949	10.325	3.737	-	-	-	-	-
Accounts payable and accrued liabilities	57.067	50.728	48.085	42.227	32.412	24.417	31.771	34.153	36.624	39.388	42.283	45.404	48.755	52.407	56.366
Income taxes payable	12.727	9.758	7.831	4.938	2.802	3.816	4.966	5.338	5.724	6.156	6.609	7.096	7.620	8.191	8.810
Total current liabilities	77.505	64.139	71.724	64.633	53.976	44.096	53.783	53.439	52.674	49.281	48.891	52.500	56.375	60.598	65.175
Long-term debt	9.322	7.928	6.891	11.653	19.925	17.450	14.974	12.499	10.023	10.023	10.023	10.023	10.023	10.023	10.023
Postretirement benefits reserves	24.994	25.267	20.646	25.802	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647
Deferred income tax liabilities	36.618	37.570	40.530	39.230	36.818	36.818	36.818	36.818	36.818	36.818	36.818	36.818	36.818	36.818	36.818
Long-term obligations to equity companies	1.808	3.555	4.742	5.325	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417
Other long-term obligations	20.061	23.676	21.780	21.786	21.165	21.165	21.165	21.165	21.165	21.165	21.165	21.165	21.165	21.165	21.165
Total liabilities	170.308	162.135	166.313	168.429	159.948	147.592	154.804	151.985	148.744	145.351	144.961	148.570	152.445	156.668	161.245
Equity															
Common stock without par value	9.512	9.653	10.077	10.792	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612
Earnings reinvested	330.939	365.727	387.432	408.384	412.444	416.940	421.246	429.107	437.336	445.981	455.042	464.548	474.533	485.071	496.236
Accumulated other comprehensive income	(9.123)	(12.184)	(10.725)	(18.957)	(23.511)	(23.511)	(23.511)	(23.511)	(23.511)	(23.511)	(23.511)	(23.511)	(23.511)	(23.511)	(23.511)
Common stock held in treasury	(176.932)	(197.333)	(212.781)	(225.820)	(229.734)	(229.734)	(229.734)	(229.734)	(229.734)	(229.734)	(229.734)	(229.734)	(229.734)	(229.734)	(229.734)
ExxonMobil share of equity	154.396	165.863	174.003	174.399	170.811	175.307	179.613	187.474	195.703	204.348	213.409	222.915	232.900	243.438	254.603
Noncontrolling interests	6.348	5.797	6.492	6.665	5.999	6.111	6.218	6.413	6.617	6.832	7.057	7.293	7.541	7.802	8.080
Total equity	160.744	171.660	180.495	181.064	176.810	181.418	185.831	193.886	202.320	211.180	220.466	230.207	240.441	251.241	262.682
Total liabilities and equity	331.052	333.795	346.808	349.493	336.758	329.010	340.635	345.871	351.064	356.531	365.427	378.778	392.886	407.909	423.927

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Short-term debt	15.862	17.047	13.949	10.325	3.737	-	-	-	-	-
Long-term Debt	17.450	14.974	12.499	10.023	10.023	10.023	10.023	10.023	10.023	10.023
Long-term Debt Obligations	-	2.476	2.476	2.476	2.476					
Total Debt	33.312	32.021	26.447	20.348	13.760	10.023	10.023	10.023	10.023	10.023
Equity	181.418	185.831	193.886	202.320	211.180	220.466	230.207	240.441	251.241	262.682
Assets	329.010	340.635	345.871	351.064	356.531	365.427	378.778	392.886	407.909	423.927
D/E Ratio	18%	17%	14%	10%	7%	5%	4%	4%	4%	4%
D/Assets	10%	9%	8%	6%	4%	3%	3%	3%	2%	2%

Long-term Debt Commitments *(millions of dollars)*		
2016	**2017-2020**	**2021 and Beyond**
-	9.902	10.023

Notes: Concerning leverage, ExxonMobil had a historical debt to equity ratio (BV) of 11,3% (2007-2015). However, it has increased over the last years. In 2015, ExxonMobil had a debt to equity ratio of 22% after issued $8 billion of long-term debt in the first quarter of 2015. Going forward, the long-term debt obligations until 2020 are $9.902M and $10.023M in 2021 and beyond. Due this schedule, the $9.902M amount was equally split between 2017 and 2020 and after 2021 ExxonMobil is assumed to have the same long-term debt amount of $10.023M. Following this reasoning, the debt to equity ratio will decrease over the forecast period and with an average of 9% which is in line with the historical data.

The interest expenses were calculated separately for short and long-term debt: the interest-rate for short-term debt were based on the weighted-average interest rate on short-term borrowings of the

last four years (0,7%) and interest rate of long-term debt was based on the cost of debt used to calculate the discount rate (3,28%).

Appendix 18: ExxonMobil's unleveraged cost of capital

	Arithmetic Average		Geometric Average	
	Stocks - T. Bills	Stocks - T. Bonds	Stocks - T. Bills	Stocks - T. Bonds
1928-2015	7,92%	6,18%	6,05%	4,54%
Std Error	2,15%	2,29%		
1966-2015	6,05%	3,89%	4,69%	2,90%
Std Error	2,42%	2,74%		
2006-2015	7,87%	3,88%	6,11%	**2,53%**
Std Error	6,06%	8,66%		

Source: Aswath Damodaran

Peer Group	BL	Debt/Equity
Chevron	1,16	0,25
Shell	0,80	0,36
BP	1,30	0,55
Total	1,32	0,62
Average	1,15	0,45

Source: Thomson Reuters (June 16)

Year	MRP (S&P 500)
2006	4,16%
2007	4,37%
2008	6,43%
2009	4,36%
2010	5,20%
2011	6,01%
2012	5,78%
2013	4,96%
2014	5,78%
2015	6,12%
Average	5,32%

Source: Aswath Damodaran

EXXONMOBIL'S UNLEVERAGED COST OF CAPITAL	
Risk Free Rate	2,53%
Beta a	0,89
Market Risk Premium	5,32%
Ka (unleverage)	7,25%

Appendix 19: Bankruptcy Costs

Industry	2-digit SIC	L = 0.1	0.3	0.5	0.7	0.9	Observed L
Oil & Gas	13	0.003	0.026	0.073	0.144	0.238	0.020
Builders	15	0.004	0.036	0.100	0.196	0.325	0.094
Food	20	0.006	0.052	0.145	0.284	0.469	0.019
Paper	26	0.004	0.032	0.089	0.174	0.288	0.037
Publishing	27	0.021	0.188	0.523	1.024	1.693	0.080
Chemicals	28	0.003	0.025	0.068	0.134	0.221	0.003
Petroleum Products	29	0.011	0.096	0.265	0.520	0.860	0.024
Primary Metals	33	0.002	0.015	0.043	0.084	0.138	0.018
Machinery	35	0.001	0.009	0.024	0.047	0.077	0.003
Electric Equipment	36	0.003	0.028	0.078	0.152	0.252	0.004
Instruments	38	0.015	0.131	0.363	0.712	1.177	0.021
Transport (Air)	45	0.004	0.036	0.101	0.197	0.326	0.111
Telecom	48	0.002	0.016	0.046	0.090	0.148	0.013
Utilities	49	0.003	0.024	0.067	0.132	0.219	0.061
Wholesale (Non-durable)	51	0.003	0.027	0.074	0.145	0.239	0.015
Retail (Misc)	53	0.011	0.095	0.264	0.516	0.854	0.055
Banks	60	0.001	0.007	0.019	0.037	0.061	0.028
Insurance	63	0.009	0.079	0.218	0.427	0.707	0.100
Patent & Royalty	67	0.005	0.049	0.136	0.266	0.440	0.107
Hotels	70	0.001	0.012	0.033	0.064	0.106	0.015
Services - Equipment	73	0.004	0.039	0.108	0.212	0.350	0.004
Health	80	0.007	0.063	0.174	0.341	0.564	0.055
					).268	0.443	0.040

Source: Korteweg (2007)

$\pi_{Distress} = 1 - \sqrt[t]{(1 - \text{Cumulative Probability of Distress})}$

Rating	Cumulative probability of distress 5 years	10 years
AAA	0.03%	0.03%
AA	0.18%	0.25%
A+	0.19%	0.40%
A	0.20%	0.56%
A-	1.35%	2.42%
BBB 2.50%	4.27%	
BB	9.27%	16.89%
B+	16.15%	24.82%
B	24.04%	32.75%
B-	31.10%	42.12%
CCC 39.15%	51.38%	
CC	48.22%	60.40%
C+	59.36%	69.41%
C	69.65%	77.44%
C-	80.00%	87.16%

Source: Aswath Damodaran

Appendix 20: ExxonMobil's Valuation with APV

APV (million$)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EBIT	14.862	14.188	25.294	26.350	27.618	28.901	30.302	31.815	33.560	35.534
(+) Depreciation	19.236	20.860	22.599	24.457	26.446	28.574	30.851	33.287	35.847	38.538
(-) Tax on EBIT	(5.202)	(4.966)	(8.853)	(9.222)	(9.666)	(10.115)	(10.606)	(11.135)	(11.746)	(12.437)
(-) Δ working capital	4.731	(782)	(238)	(256)	(298)	(321)	(346)	(372)	(405)	(439)
(-) Capex	(23.200)	(23.200)	(24.843)	(26.535)	(28.420)	(30.402)	(32.528)	(34.800)	(36.569)	(38.446)
Free Cash Flow to the Firm (FCFF)	10.428	6.100	13.959	14.793	15.680	16.637	17.673	18.796	20.687	22.750
Discounted Cash Flow	9.723	5.303	11.315	11.180	11.049	10.931	10.826	10.735	11.017	11.296
Residual Value										296.812
Entreprise Value Unlevered	**400.186**									
Interest Expense	683	610	508	401	355	329	329	329	329	329
Interest Tax Shield	239	214	178	140	124	115	115	115	115	115
Terminal Value of Interest Tax Shield										2.540
Present Value of Tax Shield	232	200	161	123	106	95	92	89	86	83
Cumulative PV of Tax Shield	**3.808**									
Cumulative PV of Bankrupcy Costs	**12**									
Adjusted Present Value	**403.981**									

Appendix 21: ExxonMobil's WACC Calculation

Cost of Debt	
Interest Coverage Ratio	70,63
Rating	Aaa/AAA
Spread	0,75%
Risk Free Rate	2,53%
Kd	3,28%

Date of Analysis: Data used is as of January 2016

For large non-financial service companies with market cap > $ 5 billion

If interest coverage ratio is			
>	*≤ to*	*Rating is*	*Spread is*
8.50	100000	Aaa/AAA	0.75%
6.5	8.499999	Aa2/AA	1.00%
5.5	6.499999	A1/A+	1.10%
4.25	5.499999	A2/A	1.25%
3	4.249999	A3/A-	1.75%
2.5	2.999999	Baa2/BBB	2.25%
2.25	2.49999	Ba1/BB+	3.25%
2	2.2499999	Ba2/BB	4.25%
1.75	1.999999	B1/B+	5.50%
1.5	1.749999	B2/B	6.50%
1.25	1.499999	B3/B-	7.50%
0.8	1.249999	Caa/CCC	9.00%
0.65	0.799999	Ca2/CC	12.00%
0.2	0.649999	C2/C	16.00%
-100000	0.199999	D2/D	20.00%

Source: Aswath Damodaran

WACC	
Cost of Equity	7,45%
Cost of Debt	3,28%
Corporate Tax Rate	35,00%
E/V	94,01%
D/V	5,99%
D/E	6,46%
WACC	7,13%

Cost of Equity	
Risk Free Rate	2,53%
Market Risk Premium	5,32%
Beta Leverage	0,93
Ka (leverage)	7,5%

Appendix 22: ExxonMobil's Valuation with WACC

WACC (million$)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EBIT	14.862	14.188	25.294	26.350	27.618	28.901	30.302	31.815	33.560	35.534
(+) Depreciation	19.236	20.860	22.599	24.457	26.446	28.574	30.851	33.287	35.847	38.538
(-) Tax on EBIT	(5.202)	(4.966)	(8.853)	(9.222)	(9.666)	(10.115)	(10.606)	(11.135)	(11.746)	(12.437)
(-) Δ working capital	4.731	(782)	(238)	(256)	(298)	(321)	(346)	(372)	(405)	(439)
(-) Capex	(23.200)	(23.200)	(24.843)	(26.535)	(28.420)	(30.402)	(32.528)	(34.800)	(36.569)	(38.446)
Free Cash Flow to the Firm (FCFF)	10.428	6.100	13.959	14.793	15.680	16.637	17.673	18.796	20.687	22.750
Discounted Cash Flow	9.733	5.315	11.353	11.230	11.111	11.004	10.912	10.832	11.128	11.423
Residual Value										**309.631**
Entreprise Value	413.673									

Appendix 23: ExxonMobil's Peer Group

The two main drivers, the level of risk and business model, are correlated since being a company with an integrated business model influences its level of risk and the inherent vulnerability to changes in commodity prices. From this selection, only non-state-owned companies were considered. Furthermore, since Exxon Mobil is part of Big Oil, the peer group was easily defined based on the supermajors which are also part of this group. Still, there are differences among the supermajors that should be taken into account over the relative valuation.

Appendix 24: Price to Free Cash-Flow

Due the particularities of the oil industry and significant amounts of debt applied to future production, having future cash flows is crucial to maintain financial flexibility. Even with a consistent net income, focusing on cash flow metrics is important for this industry. Non-cash items such as depreciation, depletion, amortization and significant deferred taxes are some of the reasons why price-to-FCF is a ratio which should be consider among ExxonMobil peers.

Appendix 25: Market Consensus of ExxonMobil Valuation

	Yahoo Finance	Stock Analysis on Net	YCHARTS	4Traders
Enterprise Value	**431.980**	**434.702**	**438.290**	**370.567**
(-) Net Debt	35.195	35.195	35.195	35.195
(-) Minority Interest	5.999	5.999	5.999	5.999
Equity Value	**390.786**	**393.508**	**397.096**	**329.373**
Common Shares	4.196	4.196	4.196	4.196
Per Share	**93,13**	**93,78**	**94,64**	**78,50**

Date: July 2016

Appendix 26: Anadarko's Upstream revenues

Hydrocarbon production in onshore assets and working interest in the Gulf of Mexico are some of the important production basis which are expected to ramp up the company production volumes. This paired with higher commodity prices help predict that the oil sales volumes will outpace the worldwide supply growth in 2% in 2020.

The same reasoning is applied to the natural gas liquid since the increase in NGL production is expected to result in oversupply with low prices in the short-medium term.

Appendix 27: Anadarko's exploration expenses

It has been increasingly difficult to explore hydrocarbon reserves, especially in deepwater areas, as the Gulf of Mexico. In these areas, the time between discovery and production tends to be higher and the decommissioning activities are more costly than in shallower waters.

Appendix 28: Anadarko's Forecasted FS and Notes

Income Statement	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Oil and condensate sales	8.072	8.728	9.178	9.748	5.420	4.104	5.618	6.299	6.932	7.510	8.202	8.978	9.822	10.838	11.852
Natural-gas sales	3.300	2.444	3.388	3.849	2.007	1.969	2.306	2.694	2.866	3.030	3.210	3.414	3.636	3.953	4.195
Natural-gas liquids sales	1.462	1.224	1.262	1.572	833	653	925	1.021	1.126	1.235	1.377	1.533	1.692	1.871	2.071
Gathering, processing, and marketing sales	1.048	911	1.039	1.206	1.226	998	1.062	918	1.001	1.079	1.172	1.276	1.388	1.527	1.660
Gains (losses) on divestitures and other, net	85	104	(286)	2.095	(788)	61	78	87	94	102	110	120	131	144	157
Total Revenues	13.967	13.411	14.581	18.470	8.698	7.785	9.989	11.018	12.018	12.956	14.071	15.321	16.669	18.334	19.935
Oil and gas operating	993	976	1.092	1.171	1.014	826	770	871	950	1.024	1.113	1.212	1.318	1.450	1.576
Oil and gas transportation	891	955	981	1.116	1.117	909	754	854	931	1.004	1.090	1.187	1.291	1.420	1.544
Exploration	1.076	1.946	1.329	1.639	2.644	1.050	1.381	1.563	1.705	1.838	1.976	2.152	2.341	2.575	2.800
Gathering, processing, and marketing	791	763	869	1.030	1.054	827	880	760	829	894	971	1.057	1.150	1.265	1.376
General and administrative	1.060	1.246	1.090	1.316	1.176	1.067	910	1.001	1.091	1.172	1.273	1.387	1.508	1.658	1.802
Depreciation, depletion, and amortization	3.830	3.964	3.927	4.550	4.603	2.272	2.520	2.783	3.059	3.351	3.658	3.983	4.326	4.688	5.042
Other taxes	1.492	1.224	1.077	1.244	553	627	805	888	968	1.044	1.134	1.235	1.343	1.477	1.606
Impairments	1.774	389	794	836	5.075	-	-	-	-	-	-	-	-	-	-
Algeria exceptional profits tax settlement		(1.797)				-	-	-	-	-	-	-	-	-	-
Deepwater Horizon settlement and related	3.930	18				-	-	-	-	-	-	-	-	-	-
Other operating expense			89	165	271	-	-	-	-	-	-	-	-	-	-
Total Costs and Expenses	15.837	9.684	11.248	13.067	17.507	7.578	8.020	8.720	9.534	10.327	11.216	12.213	13.278	14.534	15.746
Operating Income (Loss)	(1.870)	3.727	3.333	5.403	(8.809)	207	1.969	2.298	2.484	2.629	2.855	3.109	3.391	3.800	4.189
Other (Income) Expense															
Interest expense	839	742	686	772	825	914	919	885	838	777	710	611	565	565	565
(Gains) losses on derivatives, net	461	(326)	(398)	197	(99)	-	-	-	-	-	-	-	-	-	-
Other (income) expense, net	4	(4)	89	20	149	-	-	-	-	-	-	-	-	-	-
Tronox-related contingent loss	259	(250)	850	4.360	5	-	-	-	-	-	-	-	-	-	-
Total	1.554	162	1.227	5.349	880	914	919	885	838	777	710	611	565	565	565
Income (Loss) Before Income Taxes	(3.424)	3.565	2.106	54	(9.689)	(707)	1.049	1.413	1.646	1.852	2.145	2.498	2.826	3.235	3.624
Income tax expense (benefit)	(856)	1.120	1.165	1.617	(2.877)	(247)	367	495	576	648	751	874	989	1.132	1.268
Net Income (Loss)	**(2.568)**	**2.445**	**941**	**(1.563)**	**(6.812)**	**(459)**	**682**	**919**	**1.070**	**1.204**	**1.395**	**1.624**	**1.837**	**2.103**	**2.356**
Net income (loss) attributable to noncontrolling interests	81	54	140	187	(120)	(3)	5	7	8	9	10	12	14	16	18
Net Income (Loss) Attributable to Common	(2.649)	2.391	801	(1.750)	(6.692)	(456)	677	912	1.062	1.195	1.384	1.611	1.823	2.087	2.338
Per Common Share					(4.261)										
Net income (loss) attributable to common stockholders basic	(5)	5	2	(3)	(13)	(1)	1	2	2	2	3	3	4	4	5
Net income (loss) attributable to common stockholders diluted	(5)	5	2	(3)	(13)	(1)	1	2	2	2	3	3	4	4	5
Average Number of Common Shares Outstanding Basic	498	500	502	506	508	508	508	508	508	508	508	508	508	508	508
Average Number of Common Shares Outstanding Diluted	498	502	505	506	508	508	508	508	508	508	508	508	508	508	508
Dividends (per Common Share)	0	0	1	1	1										
Dividends	179	180	271	501	549	-	-	-	-	-	-	-	-	-	-
Earnings Reinvested	(2.828)	2.211	530	(2.251)	(7.241)	(459)	682	919	1.070	1.204	1.395	1.624	1.837	2.103	2.356
Attributable to noncontrolling interests						(8)	12	16	19	21	25	29	32	37	41
Attributable to Anadarko						(451)	670	903	1.051	1.183	1.370	1.595	1.805	2.066	2.314

Balance Sheet (million $)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Assets															
Cash and cash equivalents	2.697	2.471	3.698	7.369	939	749	848	796	751	714	740	845	990	1.170	1.343
Accounts receivable							-	-	-	-	-	-	-	-	-
Customers	1.269	1.473	1.481	1.118	652	682	875	965	1.052	1.134	1.232	1.341	1.459	1.605	1.745
Others	1.990	1.274	1.241	1.409	1.817	946	1.214	1.339	1.461	1.575	1.710	1.862	2.026	2.229	2.423
Algeria exceptional profits tax settlement		730													
Other current assets	975	847	688	603	574	434	557	614	670	722	785	854	929	1.022	1.112
Total Current Assets	6.931	6.795	7.108	10.499	3.982	2.811	3.494	3.714	3.934	4.145	4.467	4.903	5.406	6.026	6.623
Properties and Equipment Cost	60.081	63.598	71.244	75.107	70.683										
Less accumulated depreciation, depletion, and amortization	22.580	25.200	30.315	33.518	36.932										
Net properties and equipment	37.501	38.398	40.929	41.589	33.751	34.523	35.549	36.515	37.407	38.222	38.958	39.613	40.183	40.674	40.920
Other Assets	1.516	1.716	2.082	2.310	2.350	2.350	2.350	2.350	2.350	2.350	2.350	2.350	3.508	5.898	8.758
Goodwill and Other Intangible Assets	5.831	5.680	5.662	6.569	6.331	6.331	6.331	6.331	6.331	6.331	6.331	6.331	6.331	6.331	6.331
Total assets	51.779	52.589	55.781	60.967	46.414	46.014	47.723	48.911	50.022	51.049	52.106	53.197	55.427	58.930	62.632
Liabilities						-	-	-	-	-	-	-	-	-	-
Accounts payable	3.299	2.989	3.530	3.683	2.850	1.957	2.548	2.856	3.133	3.391	3.457	3.764	4.095	4.504	4.897
Current asset retirement obligations	-	298	409	257	309	309	309	309	309	309	309	309	309	309	309
Interest payable	-	-	-	247	247	247	247	247	247	247	247	247	247	247	247
Other taxes payable	-	-	-	332	318	318	318	318	318	318	318	318	318	318	318
Accrued expenses	1.430	707	1.264	505	424	424	424	424	424	424	424	424	424	424	424
Short-term debt	170	-	500	-	33	3.521	4.668	4.616	4.384	3.392	2.325	741	-	-	-
Tronox-related contingent liability	-	-	-	5.210	-	-	-	-	-	-	-	-	-	-	-
Total Current Liabilities	4.899	3.994	5.703	10.234	4.181	6.776	8.514	8.770	8.815	8.081	7.080	5.803	5.393	5.802	6.195
Long-term Debt	15.060	13.269	13.065	15.092	15.718	13.183	11.925	11.325	10.725	10.725	10.725	10.725	10.725	10.725	10.725
Other Long-term Liabilities															
Deferred income taxes	8.479	8.759	9.245	8.527	5.400	5.400	5.947	6.559	7.155	7.713	8.377	9.122	9.924	10.915	11.868
Asset retirement obligations	1.737	1.587	1.613	1.796	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750
Tronox-related contingent liability	-	-	850	-	-	-	-	-	-	-	-	-	-	-	-
Other	2.621	3.098	1.655	3.000	3.908	3.908	3.908	3.908	3.908	3.908	3.908	3.908	3.908	3.908	3.908
Total liabilities	**32.796**	**30.707**	**32.131**	**38.649**	**30.957**	**31.017**	**32.044**	**32.312**	**32.353**	**32.177**	**31.840**	**31.307**	**31.700**	**33.100**	**34.446**
Equity						-	-	-	-	-	-	-	-	-	-
Stockholders equity															
Common stock, par value $0.10 per share (1.0 billion shares authoriz	51	51	52	52	52	52	52	52	52	52	52	52	52	52	52
Paid-in capital	7.851	8.230	8.629	9.005	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265
Retained earnings	11.619	13.829	14.356	12.125	4.880	4.429	5.099	6.001	7.052	8.235	9.605	11.200	13.005	15.070	17.385
Treasury stock (20.0 million and 19.3 million shares)	(804)	(841)	(895)	(940)	(995)	(995)	(995)	(995)	(995)	(995)	(995)	(995)	(995)	(995)	(995)
Accumulated other comprehensive income (loss)	(612)	(640)	(285)	(517)	(383)	(383)	(383)	(383)	(383)	(383)	(383)	(383)	(383)	(383)	(383)
Total Stockholders Equity	18.105	20.629	21.857	19.725	12.819	12.368	13.038	13.940	14.991	16.174	17.544	19.139	20.944	23.009	25.324
Noncontrolling interests	878	1.253	1.793	2.593	2.638	2.630	2.642	2.658	2.677	2.698	2.723	2.751	2.784	2.821	2.862
Total equity	18.983	21.882	23.650	22.318	15.457	14.998	15.680	16.598	17.668	18.872	20.267	21.890	23.727	25.830	28.186
Total liabilities and equity	51.779	52.589	55.781	60.967	46.414	46.014	47.723	48.911	50.022	51.049	52.106	53.197	55.427	58.930	62.632

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Short-Term Debt	3.521	4.668	4.616	4.384	3.392	2.325	741	-	-	-
Long-term Debt	13.183	11.925	11.325	10.725	10.725	10.725	10.725	10.725	10.725	10.725
Long-term Debt Obligations	2.033	1.258	1.258	600	600					
Total Debt	16.703	16.593	15.941	15.109	14.117	13.050	11.466	10.725	10.725	10.725
Equity	14.998	15.680	16.598	17.668	18.872	20.267	21.890	23.727	25.830	28.186
Debt/Equity	111%	106%	96%	86%	75%	64%	52%	45%	42%	38%
Debt/Asset	36%	35%	33%	30%	28%	25%	22%	19%	18%	17%

Debt schedule	2015	2016	2017-2018	2019-2020	2021 and beyond
Existing Debt	17.312	15.279	12.763	11.563	11.563
Principal—total borrowings at face value		2.033	2.516	1.200	11.563

NOTES:

The absolute value for LT Debt of Anadarko has been stable ranging between 13k and 15k. The lower equity value explains the significant variation of the LTD to Equity ratio from 55% in 2013 to 102% in 2015.

The forecast for Anadarko's leverage was based on the schedule for debt obligations detailed in the company's Annual Report of 2015. Following that, Anadarko is expected to pay back $5.749M until 2020 which means to have a LTD of $10.725M in 2020. This amount was assumed to be stable over the forecast period.

The short-term debt was determined according to the obligations which will be faced in each specific year added to other short-term needs. Following this reasoning, the debt to equity ratio is expected to recovery from 111% in 2016 to 38% in 2025, with an average of 72% over the explicit forecast period. The higher level of short-term debt is needed to face more challenging periods over the next years of lower commodity prices.

The interest rates used to calculate the amount corresponding to debt related interest expenses were the existing rate associated with commercial paper for short-term debt and the weighted average interest rate calculated from the current obligations for the long-term debt. Thus, the short-term interest rate is 0,98% and the long-term interest rate is 5,26%.

In the working capital calculations, the current asset retirement obligations, interest payable, other taxes payable and accrued expenses are the current liability rubrics which were considered to be stable over the forecast period, since they are not correlated with sales and there is no further information to predict future variations.

Appendix 29: Anadarko's unleveraged cost of capital

Peer Group	BL	Debt/Equity
Devon Energy Corp	2,0	1,9
EOG Resources Inc	1,4	0,5
Apache Corp	1,7	3,4
Pioneer Natural Resources Co	1,4	0,4
Marathon Oil Corp	2,2	0,4
ConocoPhillips	1,1	0,6
Occidental Petroleum Corp	1,4	0,3
Source: Thomson Reuters (06/06)	1,6	1,1

UNLEVERAGED COST OF CAPITAL	
Risk Free Rate	2,53%
Beta a	0,92
Market Risk Premium	5,32%
Ka (unleverage)	7,45%

Appendix 30: Anadarko's valuation with APV

APV (million $)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EBIT	207	1.969	2.298	2.484	2.629	2.855	3.109	3.391	3.800	4.189
(+) Depreciation	2.272	2.520	2.783	3.059	3.351	3.658	3.983	4.326	4.688	5.042
(-) Tax on EBIT	(73)	(689)	(804)	(870)	(920)	(999)	(1.088)	(1.187)	(1.330)	(1.466)
(-) Δ working capital	279	(93)	88	57	46	(255)	(129)	(171)	(212)	(204)
(-) Capex	(3.044)	(3.546)	(3.749)	(3.950)	(4.166)	(4.394)	(4.638)	(4.895)	(5.180)	(5.052)
Free Cash Flow to the Firm (FCFF)	(358)	161	615	781	939	865	1.237	1.463	1.767	2.508
Discounted Cash Flow	(333)	139	496	586	655	562	748	824	926	1.223
Residual Value										30.628
Enterprise Value Unlevered	**36.454**									
Interest Expense	914	919	885	838	777	710	611	565	565	565
Interest Tax Shield	320	322	310	293	272	248	214	198	198	198
Terminal Value of Interest Tax Shield										2.592
Present Value of Tax Shield	305	293	269	243	215	188	154	136	130	124
Cumulative PV of Tax Shield	**4.650**									
Cumulative PV of Bankrupcy Costs	**163**									
Adjusted Present Value	**40.941**									

Appendix 31: Anadarko's WACC Calculation

Cost of Debt	
Interest Coverage Ratio	-0,09
Rating	BBB
Spread	2,25%
Risk Free Rate	2,53%
Kd	4,78%

Cost of Equity	
Risk Free Rate	2,53%
Market Risk Premium	5,32%
Beta Leverage	1,40
Ka (leverage)	10,0%

WACC Calculations	
Cost of Equity	9,96%
Cost of Debt	4,78%
Corporate Tax Rate	35,00%
E/V	56,00%
D/V	44,00%
D/E	78,57%
WACC	6,94%

Appendix 32: Anadarko's Valuation with WACC

WACC (million$)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EBIT	207	1.969	2.298	2.484	2.629	2.855	3.109	3.391	3.800	4.189
(+) Depreciation	2.272	2.520	2.783	3.059	3.351	3.658	3.983	4.326	4.688	5.042
(-) Tax on EBIT	(73)	(689)	(804)	(870)	(920)	(999)	(1.088)	(1.187)	(1.330)	(1.466)
(-) Δ working capital	279	(93)	88	57	46	(255)	(129)	(171)	(212)	(204)
(-) Capex	(3.044)	(3.546)	(3.749)	(3.950)	(4.166)	(4.394)	(4.638)	(4.895)	(5.180)	(5.052)
Free Cash Flow to the F	(358)	161	615	781	939	865	1.237	1.463	1.767	2.508
Discounted Cash Flow	(335)	141	503	597	671	578	773	855	966	1.282
Residual Value										**36.559**
Enterprise Value	**42.590**									

Appendix 33: Anadarko's Relative valuation

Having only upstream activities results in being exposed to a similar risk in terms of commodity prices and having a significant part of their activities susceptible to the same exploration challenges (mainly in U.S.).

Appendix 34: Market Consensus of Anadarko's Valuation

	Yahoo Finance	Stock Analysis on Net	Ycharts	4Traders
Enterprise Value	**45.830**	**45.789**	**47.260**	**35.567**
(-) Net Debt	14.761	14.761	14.761	14.761
(-) Minority Interest	2.638	2.638	2.638	2.638
Equity Value	**28.431**	**28.390**	**29.861**	**18.168**
Common Shares	508	508	508	508
Per Share	**55,97**	**55,89**	**58,78**	**35,76**

Date: July 2016

Appendix 35: Merged Entity without Synergies

Balance Sheet (million $)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2.021	2022	2023	2024	2025
Assets															
Current assets															
Cash and cash equivalents	15.361	12.053	8.342	11.985	4.644	4.306	5.453	5.725	6.024	6.385	10.237	18.519	27.506	37.895	49.744
Cash and cash equivalents - restricted	404	341	269	42	-	-	-	-	-	-	-	-	-	-	-
Notes and accounts receivable, less estimated doubtful amounts	41.901	37.734	35.874	30.536	22.344	17.882	23.237	25.038	26.893	28.929	31.089	33.428	35.940	38.720	41.689
Inventories															
Crude oil, products and merchandise	11.665	10.836	12.117	12.384	12.037	6.541	8.511	9.149	9.811	10.551	11.327	12.163	13.061	14.039	15.099
Materials and supplies	3.359	3.706	4.018	4.294	4.208	2.189	2.848	3.061	3.283	3.531	3.790	4.070	4.370	4.698	5.052
Algeria exceptional profits tax settlement	-	730	-	-	-	-	-	-	-	-	-	-	-	-	-
Other current assets	7.204	5.855	5.796	4.168	3.372	2.805	3.642	3.930	4.226	4.547	4.890	5.263	5.663	6.110	6.584
Total current assets	79.894	71.255	66.416	63.409	46.605	33.722	43.690	46.903	50.237	53.943	61.333	73.442	86.540	101.462	118.170
Investments, advances and long-term receivables	34.333	34.718	36.328	35.239	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245
Property, plant and equipment, at cost, less accumulated depreciation and depletion	252.165	265.347	284.579	294.257	285.356	290.091	293.457	296.668	299.637	302.427	304.990	307.322	309.404	310.617	310.771
Other assets, including intangibles, net	16.439	15.064	15.266	17.555	16.966	16.966	16.966	16.966	16.966	16.966	16.966	16.966	18.124	20.514	23.374
Total assets	**382.831**	**386.384**	**402.589**	**410.460**	**383.172**	**375.024**	**388.358**	**394.782**	**401.085**	**407.580**	**417.534**	**431.975**	**448.312**	**466.839**	**486.559**
Liabilities															
Current liabilities															
Notes and loans payable	7.881	3.653	16.308	17.468	18.795	19.383	21.715	18.565	14.710	7.129	2.325	741	-	-	-
Accounts payable and accrued liabilities	61.796	54.424	52.879	46.415	35.686	26.799	34.742	37.433	40.182	43.203	46.163	49.592	53.274	57.335	61.687
Income taxes payable	12.727	9.758	7.831	5.270	3.120	4.134	5.284	5.656	6.042	6.474	6.927	7.414	7.938	8.509	9.128
Current asset retirement obligations	-	298	409	257	309	309	309	309	309	309	309	309	309	309	309
Interest payable	-	-	-	247	247	247	247	247	247	247	247	247	247	247	247
Tronox-related contingent liability	-	-	-	5.210	-	-	-	-	-	-	-	-	-	-	-
Total current liabilities	82.404	68.133	77.427	74.867	58.157	50.871	62.297	62.210	61.489	57.362	55.971	58.303	61.768	66.400	71.370
Long-term debt	24.382	21.197	19.956	26.745	35.643	30.632	26.899	23.823	20.748	20.748	20.748	20.748	20.748	20.748	20.748
Postretirement benefits reserves	24.994	25.267	20.646	25.802	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647
Deferred income tax liabilities	45.097	46.329	49.775	47.757	42.218	42.218	42.765	43.377	43.973	44.531	45.195	45.940	46.742	47.733	48.686
Long-term obligations to equity companies	1.808	3.555	4.742	5.325	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417
Asset retirement obligations	1.737	1.587	1.613	1.796	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750
Tronox-related contingent liability	-	-	850	-	-	-	-	-	-	-	-	-	-	-	-
Other long-term obligations	22.682	26.774	23.435	24.786	25.073	25.073	25.073	25.073	25.073	25.073	25.073	25.073	25.073	25.073	25.073
Total liabilities	**203.104**	**192.842**	**198.444**	**207.078**	**190.905**	**178.609**	**186.848**	**184.297**	**181.097**	**177.528**	**176.801**	**179.877**	**184.145**	**189.768**	**195.691**
Equity															
Common stock, par value $0.10 per share	51	51	52	52	52	52	52	52	52	52	52	52	52	52	52
Common stock without par value	9.512	9.653	10.077	10.792	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612
Paid-in capital	7.851	8.230	8.629	9.005	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265
Earnings reinvested	342.558	379.556	401.788	420.509	417.324	421.369	426.345	435.108	444.388	454.216	464.647	475.747	487.537	500.142	513.620
Accumulated other comprehensive income	- 9.735	- 12.824	- 11.010	- 19.474	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894
Common stock held in treasury	- 177.736	- 198.174	- 213.676	- 226.760	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729
ExxonMobil share of equity	172.501	186.492	195.860	194.124	183.630	187.675	192.651	201.414	210.694	220.522	230.953	242.053	253.843	266.448	279.926
Noncontrolling interests	7.226	7.050	8.285	9.258	8.637	8.741	8.859	9.071	9.294	9.530	9.779	10.044	10.324	10.623	10.942
Total equity	**179.727**	**193.542**	**204.145**	**203.382**	**192.267**	**196.416**	**201.510**	**210.485**	**219.988**	**230.052**	**240.733**	**252.098**	**264.168**	**277.071**	**290.868**
Total liabilities and equity	**382.831**	**386.384**	**402.589**	**410.460**	**383.172**	**375.024**	**388.358**	**394.782**	**401.085**	**407.580**	**417.534**	**431.975**	**448.312**	**466.839**	**486.559**

Income Statement	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstream Revenues	25.304	32.716	35.582	38.501	41.584	44.982	48.704	52.717	57.296	62.066
Downstream Revenues	171.564	222.379	237.927	253.911	271.716	290.412	310.460	331.856	355.057	380.058
Chemical Revenues	21.236	28.550	31.683	35.070	38.926	42.879	47.244	52.047	57.392	63.316
Corporate and Financing Revenues	10	12	13	14	15	16	18	19	20	22
Income from equity affiliates	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644
Total Revenue	225.757	291.301	312.849	335.140	359.885	385.934	414.069	444.283	477.409	513.105
Crude oil and product purchases (Oil and gas operating)	118.897	154.399	166.019	178.050	191.489	205.574	220.765	237.076	254.869	274.136
Oil and gas transportation	909	754	854	931	1.004	1.090	1.187	1.291	1.420	1.544
Production and manufacturing expenses (Gathering, processing, and marketing)	29.672	38.411	30.670	32.904	35.389	38.001	40.821	43.848	47.162	50.739
Selling, general and administrative expenses (General and administrative)	8.201	10.193	10.980	11.792	12.681	13.627	14.653	15.753	16.970	18.270
Exploration expenses, including dry holes (Exploration)	2.284	2.987	2.935	3.176	3.420	3.675	3.976	4.300	4.680	5.064
Sales-based taxes(1)	1.324	20.678	22.228	23.837	25.636	27.520	29.551	31.732	34.110	36.686
Other taxes and duties (Other taxes)	27.892	24.341	26.189	28.101	30.224	32.458	34.871	37.462	40.302	43.363
Total Operating Expenses	189.180	251.764	259.875	278.790	299.842	321.945	345.824	371.464	399.513	429.803
EBITDA	36.577	39.537	52.974	56.350	60.043	63.989	68.245	72.819	77.895	83.303
Depreciation and depletion	21.508	23.380	25.382	27.516	29.797	32.233	34.834	37.613	40.535	43.580
Total EBIT	15.069	16.157	27.592	28.834	30.246	31.756	33.411	35.206	37.360	39.722
Interest expense	1.597	1.530	1.392	1.240	1.131	1.039	940	893	893	893
Income Before Income Taxes	13.472	14.627	26.200	27.595	29.115	30.718	32.471	34.313	36.467	38.829
Income taxes	4.715	5.119	9.170	9.658	10.190	10.751	11.365	12.010	12.763	13.590
Net income	**8.757**	**9.507**	**17.030**	**17.936**	**18.925**	**19.966**	**21.106**	**22.303**	**23.703**	**25.239**

WACC (million$)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EBIT	15.069	16.157	27.592	28.834	30.246	31.756	33.411	35.206	37.360	39.722
(+) Depreciation	21.508	23.380	25.382	27.516	29.797	32.233	34.834	37.613	40.535	43.580
(-) Tax on EBIT	- 5.274	- 5.655	- 9.657	- 10.092	- 10.586	- 11.115	- 11.694	- 12.322	- 13.076	- 13.903
(-) Δ working capital	5.010	- 875	- 150	- 199	- 253	- 577	- 475	- 543	- 617	- 643
(-) Capex	- 26.244	- 26.746	- 28.593	- 30.485	- 32.586	- 34.796	- 37.166	- 39.695	- 41.749	- 43.499
Free Cash Flow to the Firm (FCFF)	10.069	6.261	14.574	15.574	16.618	17.502	18.910	20.259	22.454	25.258
Discounted Cash Flow	9.401	5.457	11.859	11.831	11.785	11.588	11.689	11.691	12.097	12.704
Residual Value										**345.937**
Enterprise Value	**456.037**									

Appendix 36: The impact of not have control over market prices in Revenue Synergies

In this industry, the revenues are dependent on market prices for oil, gas and NLG which are determined based on supply and demand. Consequently, if in some industries a merger can be a source of lower customer bargaining power, this is not an option in this case. For a company as Anadarko or even ExxonMobil which is part of the big oil, they together still very small in the global scheme to impact on the price determination. In fact, the Middle East companies, which have a bit more power, wouldn't be able to have control over the commodity price.

The only way which could be a source of synergies from the revenue side would be a potential adjustment on the hedging strategy of both companies. But in fact, there is not enough information to measure potential synergies that could arise from canceling any derivatives instruments used by both companies or by change hedging positions.

Appendix 37: Increase production in oil and gas industry

Normally projects have a development cycle between 5 and 10 years thus no near-term synergies would be expected on the revenue side. Furthermore, Exxon Mobil is a global company which has activity almost everywhere in the world while Anadarko is a company with production mainly from North America, thus even if revenues synergies would be considered, they would have a slight impact.

Appendix 38: Common exploration and production areas of Anadarko and ExxonMobil

In the Gulf of Mexico Anadarko has active floating platforms in 34 fields and 60% interest in 279 blocks, which includes Lucius and Heidelberg. In 2015, ExxonMobil had an average net production in the Gulf of Mexico of 64 thousand barrels of liquids and 257 million cubic feet of gas per day, from a portfolio of 1.1M net acres. In this area, ExxonMobil has deep water exploration in Keathley Canyon (KC) (including a participation of 23% in Anadarko-operated Lucius development) and in

Walker Ridge (WR) (including 95% in the Anadarko-operated Heidelberg project). ExxonMobil also has conventional and LNG production activities in these areas.

Anadarko's Southern and Appalachia Region properties are mainly located in Texas, Pennsylvania, Louisiana, and Kansas and the main exploration areas are Eagleford shale in South Texas, the Delaware Basin in West Texas, the Marcellus shale in north-central Pennsylvania, and the Haynesville shale in East Texas and Northern Louisiana. In these regions, Anadarko explores and produces both natural gas and liquids. ExxonMobil also has a substantial position in this area: 527.000 net acres in the Marcellus Shale and explorations in Eagleford shale (common area with Anadarko).

Finally, in the Rocky Mountains region, Anadarko has assets located in Colorado, Utah, and Wyoming (Land Grant) which totals 11.000 wells and interests in near 4.000 non-operated wells. This area is considered by Anadarko one of the most valuable areas since it creates completive advantage through higher returns from production, drilling without expiration and royalties from third-party activity. ExxonMobil also has exploration activities in the Mid-continent states, including the Land Grant. In the company operating report there is no further information, but since they are operating in the same regions potential synergies should arise.

Appendix 39: Deal of Exxon and Mobil

"The major motivations behind the Exxon-Mobil merger, completed in November 1999, were both cost- and market-based. By combining complementary assets, Exxon-Mobil sought a stronger presence in the regions of the world with a high potential for future oil and gas discoveries. Complementary exploration and production operations existed in West Africa, Russia and Eastern Canada. Because of the increased size of the company it would also be in a stronger position to invest in programmes involving large outlays and high prospective risks and returns. At the time of the merger operating synergies of $2.8 billion were predicted. Two-thirds of the benefits would come from eliminating duplicate facilities and excess capacity. Additional synergy benefits would come from combined general and administrative costs, and by applying each company's best business practices through the world. By 2000 Exxon-Mobil reported that synergies reached $4.6 billion." (Christopher, Harris, & Chavan, 2012)

Appendix 40: WACC of Merged Entity with Synergies

Cost of Equity	
Risk Free Rate	2,53%
Market Risk Premium	5,32%
Beta Leverage	0,93
Ka (leverage)	7,48%

Cost of Debt	
Interest Coverage Ratio	9,42
Rating	Aaa/AAA
Spread	0,008
Risk Free Rate	2,53%
Kd	3,28%

WACC	
Cost of Equity	7,48%
Cost of Debt	3,28%
Corporate Tax Rate	35,00%
E/V	93,04%
D/V	6,96%
D/E	7,48%
WACC	7,11%

Appendix 41: FS of Merged Entity with Synergies and WACC valuation

Income Statement (million $)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Upstream Revenues	25.304	32.716	35.582	38.501	41.584	44.982	48.704	52.717	57.296	62.066
% Anadarko	0	0	0	0	0	0	0	0	0	0
Downstream Revenues	171.564	222.379	237.927	253.911	271.716	290.412	310.460	331.856	355.057	380.058
Chemical Revenues	21.236	28.550	31.683	35.070	38.926	42.879	47.244	52.047	57.392	63.316
Corporate and Financing Revenues	10	12	13	14	15	16	18	19	20	22
Income from equity affiliates	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644	7.644
Total Revenue	225.757	291.301	312.849	335.140	359.885	385.934	414.069	444.283	477.409	513.105
Crude oil and product purchases (Oil and gas operating)	118.897	154.399	166.019	178.050	191.489	205.574	220.765	237.076	254.869	274.136
Oil and gas transportation	909	754	854	931	1.004	1.090	1.187	1.291	1.420	1.544
Production and manufacturing expenses (Gathering, processing, and marketing)	29.672	38.411	30.670	32.904	35.389	38.001	40.821	43.848	47.162	50.739
Selling, general and administrative expenses (General and administrative)	8.201	10.193	10.980	11.792	12.681	13.627	14.653	15.753	16.970	18.270
Exploration expenses, including dry holes (Exploration)	2.284	2.987	2.935	3.176	3.420	3.675	3.976	4.300	4.680	5.064
Sales-based taxes(1)	1.324	20.678	22.228	23.837	25.636	27.520	29.551	31.732	34.110	36.686
Other taxes and duties (Other taxes)	27.892	24.341	26.189	28.101	30.224	32.458	34.871	37.462	40.302	43.363
Total Operating Expenses	189.180	251.764	259.875	278.790	299.842	321.945	345.824	371.464	399.513	429.803
Cost Operating Synergies	39	53	60	66	71	78	85	93	103	113
	0	0	0	0	0	0	0	0	0	0
EBITDA	36.616	39.590	53.034	56.416	60.114	64.067	68.330	72.913	77.998	83.415
Depreciation and depletion	21.508	23.380	25.382	27.516	29.797	32.233	34.834	37.613	40.535	43.580
Adjustment for CAPEX Synergies	- 56	- 112	- 179	- 251	- 327	- 409	- 496	- 589	- 687	- 789
Total EBIT	15.052	16.098	27.473	28.649	29.990	31.425	33.000	34.710	36.776	39.045
Interest expense	1.597	1.530	1.392	1.240	1.131	1.039	940	893	893	893
Financial Synergies	465	508	497	476	425	402	360	338	332	328
Income Before Income Taxes	13.919	15.076	26.578	27.886	29.283	30.788	32.420	34.155	36.214	38.480
Income taxes	4.872	5.276	9.302	9.760	10.249	10.776	11.347	11.954	12.675	13.468
Net income	**9.048**	**9.799**	**17.276**	**18.126**	**19.034**	**20.013**	**21.073**	**22.200**	**23.539**	**25.012**
Dividends	4.524	4.900	8.638	9.063	9.517	10.006	10.536	11.100	11.770	12.506
Earnings Reinvested	4.524	4.900	8.638	9.063	9.517	10.006	10.536	11.100	11.770	12.506
Attributable to noncontrolling interests	110	119	209	220	231	242	255	269	285	303
Attributable to Combined Entity	4.414	4.900	8.638	9.063	9.517	10.006	10.536	11.100	11.770	12.506

Balance Sheet (million $)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2.021	2022	2023	2024	2025
Assets															
Current assets															
Cash and cash equivalents	15.361	12.053	8.342	11.985	4.644	4.308	5.459	5.737	6.043	6.412	10.284	18.601	27.629	38.058	49.946
Cash and cash equivalents - restricted	404	341	269	42	-	-	-	-	-	-	-	-	-	-	-
Notes and accounts receivable, less estimated doubtful amounts	41.901	37.734	35.874	30.536	22.344	17.882	23.237	25.038	26.893	28.929	31.089	33.428	35.940	38.720	41.689
Inventories															
Crude oil, products and merchandise	11.665	10.836	12.117	12.384	12.037	6.541	8.511	9.149	9.811	10.551	11.327	12.163	13.061	14.039	15.099
Materials and supplies	3.359	3.706	4.018	4.294	4.208	2.189	2.848	3.061	3.283	3.531	3.790	4.070	4.370	4.698	5.052
Algeria exceptional profits tax settlement	-	730	-	-	-	-	-	-	-	-	-	-	-	-	-
Other current assets	7.204	5.855	5.796	4.168	3.372	2.805	3.642	3.930	4.226	4.547	4.890	5.263	5.663	6.110	6.584
Total current assets	79.894	71.255	66.416	63.409	46.605	33.724	43.697	46.915	50.256	53.969	61.379	73.524	86.663	101.625	118.371
Investments, advances and long-term receivables	34.333	34.718	36.328	35.239	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245	34.245
Property, plant and equipment, at cost, less accumulated depreciation and depletion	252.165	265.347	284.579	294.257	285.356	289.346	292.023	294.455	296.653	298.677	300.482	302.064	303.404	303.905	303.155
Other assets, including intangibles, net	16.439	15.064	15.266	17.555	16.966	16.966	16.966	16.966	16.966	16.966	16.966	16.966	18.124	20.514	23.374
Total assets	**382.831**	**386.384**	**402.589**	**410.460**	**383.172**	**374.281**	**386.931**	**392.581**	**398.119**	**403.857**	**413.073**	**426.799**	**442.437**	**460.290**	**479.144**
Liabilities															
Current liabilities															
Notes and loans payable	7.881	3.653	16.308	17.468	18.795	18.264	19.990	16.192	11.793	3.772	-	-	-	-	-
Accounts payable and accrued liabilities	61.796	54.424	52.879	46.415	35.686	26.799	34.742	37.433	40.182	43.203	46.163	49.592	53.274	57.335	61.687
Income taxes payable	12.727	9.758	7.831	5.270	3.120	4.134	5.284	5.656	6.042	6.474	6.927	7.414	7.938	8.509	9.128
Current asset retirement obligations	-	298	409	257	309	309	309	309	309	309	309	309	309	309	309
Interest payable	-	-	-	247	247	247	247	247	247	247	247	247	247	247	247
Tronox-related contingent liability	-	-	-	5.210	-	-	-	-	-	-	-	-	-	-	-
Total current liabilities	82.404	68.133	77.427	74.867	58.157	49.753	60.571	59.837	58.573	54.005	53.646	57.562	61.768	66.400	71.370
Long-term debt	24.382	21.197	19.956	26.745	35.643	30.632	26.899	23.823	20.748	20.748	19.409	17.684	16.944	17.119	17.241
Postretirement benefits reserves	24.994	25.267	20.646	25.802	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647	22.647
Deferred income tax liabilities	45.097	46.329	49.775	47.757	42.218	42.218	42.765	43.377	43.973	44.531	45.195	45.940	46.742	47.733	48.686
Long-term obligations to equity companies	1.808	3.555	4.742	5.325	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417	5.417
Asset retirement obligations	1.737	1.587	1.613	1.796	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750	1.750
Tronox-related contingent liability	-	-	850	-	-	-	-	-	-	-	-	-	-	-	-
Other long-term obligations	22.682	26.774	23.435	24.786	25.073	25.073	25.073	25.073	25.073	25.073	25.073	25.073	25.073	25.073	25.073
Total liabilities	**203.104**	**192.842**	**198.444**	**207.078**	**190.905**	**177.491**	**185.122**	**181.925**	**178.181**	**174.170**	**173.137**	**176.072**	**180.340**	**186.139**	**192.185**
Equity															
Common stock, par value $0.10 per share	51	51	52	52	52	52	52	52	52	52	52	52	52	52	52
Common stock without par value	9.512	9.653	10.077	10.792	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612	11.612
Paid-in capital	7.851	8.230	8.629	9.005	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265	9.265
Earnings reinvested	342.558	379.556	401.788	420.509	417.324	421.738	426.638	435.276	444.339	453.856	463.862	474.398	485.499	497.268	509.774
Accumulated other comprehensive income	- 9.735	- 12.824	- 11.010	- 19.474	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894	- 23.894
Common stock held in treasury	- 177.736	- 198.174	- 213.676	- 226.760	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729	- 230.729
ExxonMobil share of equity	172.501	186.492	195.860	194.124	183.630	188.044	192.944	201.582	210.645	220.162	230.168	240.704	251.805	263.574	276.080
Noncontrolling interests	7.226	7.050	8.285	9.258	8.637	8.747	8.865	9.075	9.294	9.525	9.767	10.022	10.291	10.577	10.880
Total equity	**179.727**	**193.542**	**204.145**	**203.382**	**192.267**	**196.791**	**201.809**	**210.656**	**219.939**	**229.686**	**239.935**	**250.727**	**262.096**	**274.151**	**286.960**
Total liabilities and equity	**382.831**	**386.384**	**402.589**	**410.460**	**383.172**	**374.281**	**386.931**	**392.581**	**398.119**	**403.857**	**413.073**	**426.799**	**442.437**	**460.290**	**479.144**

WACC (millionS)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EBIT	15.052	16.098	27.473	28.649	29.990	31.425	33.000	34.710	36.776	39.045
(+) Depreciation	21.564	23.493	25.561	27.767	30.124	32.642	35.330	38.202	41.223	44.370
(-) Tax on EBIT	- 5.268	- 5.634	- 9.616	- 10.027	- 10.497	- 10.999	- 11.550	- 12.149	- 12.871	- 13.666
(-) Δ working capital	5.010	- 875	- 150	- 199	- 253	- 577	- 475	- 543	- 617	- 643
(-) Capex	- 25.442	- 25.946	- 27.634	- 29.463	- 31.494	- 33.629	- 35.920	- 38.364	- 40.349	- 42.040
Free Cash Flow to the Firm (FCFF)	10.916	7.135	15.635	16.727	17.872	18.862	20.385	21.857	24.161	27.066
Discounted Cash Flow	10.191	6.219	12.724	12.709	12.677	12.492	12.605	12.617	13.022	13.619
Residual Value										**371.344**
Enterprise Value	**490.220**									

Appendix 42: Anadarko's Takeover Defences

Anadarko has the following takeover defences: fair price provisions, cumulative voting, advance notice procedures for director nominations and stockholder proposals, the prohibition of stockholder action by written consent, special meetings of stockholders and preferred stock issuances.

Appendix 43: Delaware Anti-Takeover Law

"Provisions in our corporate documents and Delaware law could delay or prevent a change of control of Anadarko, even if that change would be beneficial to our stockholders.
Our restated certificate of incorporation and by-laws contain provisions that may make a change of control of Anadarko difficult, even if it may be beneficial to our stockholders, including provisions governing the nomination and removal of directors, the prohibition of stockholder action by written consent and regulation of stockholders' ability to bring matters for action before annual stockholder meetings, and the authorization given to our Board of Directors to issue and set the terms of preferred stock.
In addition, Section 203 of the Delaware General Corporation Law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock." (Anadarko Petroleum Corp, 2016)

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