Carbon Tracker Initiative

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Margin Call:

Refining Capacity in a 2°C World

November 2017

Acknowledgements

This report was authored by Andrew Grant, Senior Analyst at Carbon Tracker, with contributions from Paul Spedding and Luis Ahn.

We are grateful for the expert input and advice of our data partners Wood Mackenzie, especially the contributions of Alan Gelder to the methodology.

Thanks for reviews and comments are also due to Bob Buhr and our colleagues James Leaton, Sam Catalano and Stefano Ambrogi.

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About Carbon Tracker

Carbon Tracker is an independent financial think tank that carries out in-depth analysis on the impact of the energy transition on capital markets and the potential investment in high-cost, carbon-intensive fossil fuels.

www.carbontracker.org

Contents

Executive summary

In this paper, we look at how a scenario for oil demand that is compliant with limiting the rise in global warming by 2035 to 2°C (a "2D" scenario) might affect the oil industry's refining assets. The IEA's 450 Scenario is used as the basis of 2D demand, under which oil demand peaks in 2020 and declines at 1.3% p.a. thereafter. This follows on from our recent analysis '2 Degrees of Separation' which focused on the upstream activities of the sector.

Key high level findings

At the simplest level:

lower oil volume = less refining capacity = smaller margins

Less volume = fewer refineries needed

Under a 2D scenario, **global oil demand could decline by 23% over a 15 year period. Historically, falling or weak demand has often been accompanied by weak refining margins.** With demand falling, refinery output would need to fall commensurately. Market forces would drive margins down in order to force the least competitive refiners out of the market. Accordingly, under a 2D scenario, the industry is likely to see major rationalisation with many players exiting the market rather than haemorrhaging cash. **Our analysis implies rationalisation equivalent to 25% of 2016 capacity.**

Margins suffer across the board

To drive this rationalisation, we estimate that **a sustained refinery margin contraction of the order of $3.50/barrel by 2035 would be necessary.** This compares to a global composite margin in 2016 of $5.00/bbl. We consider this estimate to be conservative. For example, BP's history of global refining margins since 1990 shows an annual standard deviation of nearly $5/barrel. Past periods of weak demand have led to higher declines in margins. For example, in 2008 US demand fell by 5%: BP's US indicator margin fell by over $6/barrel.[1]

Earnings fall

The combination of reduced refining throughputs and the consequent fall in margins could have profound implications for the industry. We estimate that **EBITDA for the refineries we have analysed (94% of 2015 global capacity) could fall by over 50% by 2035 from an estimated $147bn in 2015.** There is likely to be a fall in valuations of refinery assets of a similar order although the impact will be disproportionate. Complex refineries, which tend to have higher margins, are likely to suffer least; simple, low quality assets could become worthless.

Transport fuel most profitable but most at risk

Diesel, gasoline and jet fuel products offer the highest margins across the product mix from refineries, and they also constitute around 70% of global product yield. As covered in our previous research 'Expect the unexpected' the rate of technological change in road transport may surprise the industry and erode demand for these fuels faster than currently anticipated.

1 *BP Statistical Review of World Energy*

OECD capacity hit hardest

Under a 2D scenario the existing refinery stock is already sufficient to meet future demand; **no new refinery capacity needs to be added globally**. However, differences in regional demand trends may mean that new capacity is needed in areas such as the Middle East and Asia. Some countries may add new unprofitable capacity for strategic reasons such as security of supply. As a result, mature regions, predominantly within the OECD, are likely to need larger cuts than the global demand trend might imply. Were this to occur, the eventual reduction in capacity needed to balance the market would be that much greater. In such a market, refining margins would most likely be lower than would be the case in a rational market.

Margins squeezed

Accordingly, we consider that **prospective investors should be wary of all new refinery investments**, whether the build out of greenfield capacity or upgrades and expansions to existing facilities. When demand growth stalls and turns negative, new investments will carry the risk of failing to earn an adequate return – wasting capital – even if they result in improved competitive positioning or reduced losses for existing capacity. **Margin assumptions in particular should be questioned and sensitised over a broad range of values**, as they are likely to prove optimistic should oil demand follow the 2D pathway.

History lesson

An historical analogue can be seen in the early 1980s, when high prices led to a 10% decline in global demand for crude oil between 1979 and 1983 before recovering: global refining capacity fell by 8% in response. Capacity reduction in the OECD was over double this amount. This was a period of significant duress for the refining industry, with international oil companies slashing capital expenditure and closing capacity. In a 2D demand scenario, where oil demand falls at a somewhat slower rate but for a longer, sustained period, we suspect the same might happen again. While strategic interests may keep capacity open for non-economic reasons, the financial cost for doing so is likely to grow increasingly punitive.

New & complex beats old & simple

We emphasise that the results of this report should not be taken as precise forecasts. Components of the refining margin curve we use could well change over time. Also, the behaviour of industry actors is impossible to predict. Aggressive rationalisation might reduce the fall in margin; lack of action could do the opposite. However we consider the results reasonable in terms of a general exploration of the implications of a 2D demand scenario for the refining sector. The industry faces two unenviable choices: "toughing it out" and seeing cash-flows and earnings hit by margin pressure; or taking aggressive action which brings its own on related costs. The pressure is likely to be greater for the weaker players, which will tend to be the owners of sub-scale, low complexity refineries in regions where demand is already mature.

1. Overview of methodology

Introduction to approach

2°C Scenario analysis

In June 2017, Carbon Tracker published the upstream equivalent of this analysis, looking at the implications of the IEA 450 scenario for the oil and gas supply activities of the largest listed companies. It used a supply cost approach, where 2D demand scenarios were compared to industry supply cost curves. High cost projects that were outside the 2D aggregate level of demand for that fuel, or "carbon budget", were assumed to have a higher risk of delivering poor returns for investors, and any capital expenditure associated with these running the risk of being wasted.

Focus on margins

But to date, little attention has been paid to the risk climate change poses to refining and marketing assets, the downstream side of the oil industry. For the majors, these assets can and do have balance sheet values measured in tens of billions of dollars. They can make up roughly a quarter of their asset bases if petrochemicals are included. This report looks at the impact of a 2D demand environment on the refining industry. It uses a similar approach to our upstream studies but focusses on margins rather than costs. All refineries are likely to suffer under a falling demand scenario but higher margin, more diversified players will suffer less.

Age discrimination

The downstream industry differs from the upstream industry in several ways: one key distinction is that oil fields decline steadily but refineries do not – refining capacity remains stable over time. The risk to upstream assets lies mainly in new, undeveloped high-cost assets. Refining is different. New refineries tend to be large scale, high margin units. As there is no natural decline in refining capacity, it is the older, low margin assets that are most at risk from falling demand. Whereas existing upstream production carries little risk, the opposite is true for refining. The newest capacity is likely to be more competitive with the older assets at risk of closure. With refining, margin is the key performance indicator.

It is likely that new refinery investment would be mainly added in areas where demand for oil products could continue to grow – in China and India for example. OPEC countries could also see investment in new capacity (distillation and upgrading) in a potentially misguided attempt to capture more of the value chain for their main export, crude oil. Both types of investment can be seen as strategic in nature.

Rationalisation options

Elsewhere in the world, particularly in the OECD, new investment is likely to be limited to upgrading capacity rather than primary distillation capacity. To improve profitability, refiners have to increase the percentage of high value, light products such as gasoline. But there is no guarantee that these investments will make an acceptable return, especially in a 2D demand scenario. Capital costs for such investments are high and falling demand for transport fuels in a 2 degree scenario could undermine profitability. But the alternative to such investment may be to suffer weaker margins, potentially leading to closure. In general, it will be the sub-scale, simple refineries in regions of soft demand that are the main candidates for rationalisation.

Product yields vs margin

In our upstream analysis, we used cost curves but these are not applicable in the downstream. This is because of the differing product yields from refineries. For example, a low cost refinery is likely to have a high yield of heavy fuel oil and a low yield of transport fuels. Heavy fuel oil is a loss-making project so unsophisticated or simple refineries are likely to make a loss irrespective of how low cost they are. In contrast, a complex refinery may have much higher costs but its yield of high value transport fuels is also likely to be higher. The key measure, therefore, is margin rather than cost. Accordingly, curves have been constructed based on the net cash margin (NCM) for each refinery; i.e. the value of the products less cash costs.

Methodology

The general approach taken by Carbon Tracker is as below:

- Demand scenario established – the IEA 450 scenario has been used as the basis for 2D demand in this case;

- 2D refinery capacity scenario developed (see below) – a minimum baseline of future capacity, consisting of 2015 capacity plus "firm" future investments, plus minor new additions in India (the only major country that experiences significant demand growth for oil, at a CAGR of 2.6% p.a. over the 450 period of 2014-2040).

- Comparison of 2D capacity and 2D demand – establishing the implied industry-wide utilisation for the refining industry (demand divided by capacity). Utilisation rates are a key determinant of refining margins.

- Overcapacity initially leads to lower utilisation rates followed by capacity closures – under a 2 degree scenario, demand plateaus and falls post 2020. With capacity expanding due to new investments coming onstream at a quicker rate than retirements, utilisation rates fall. We assume that no capacity closure takes place until average utilisation rates drop to 75%. Thereafter, we assume that sufficient refinery capacity is closed to prevent any further fall.

- Use of net cash margin (NCM) curve to establish closure order and estimate margin decline – in order to force the closure of refinery capacity, refining margins must drop sufficiently to force the requisite amount of low margin capacity out of the market. So, if a 10% reduction in capacity is needed and all those refineries had a cash margin of $2/barrel, margins would need to fall by $2/barrel to incentivise closure. We assume this fall is replicated across the whole margin curve.

- Closure subject to strategic considerations – in reality, there may be strategic reasons to keep a refinery operating even if it is loss-making. For example, many state-owned refineries will continue running for reasons of security of supply – even if loss making. We have identified refining assets that could fall in to this "strategic" category and assume they stay open no matter what the margin. (See "Refinery closure methodology" in the appendix.) This results in a greater fall in margins than would occur in a rational refining market.

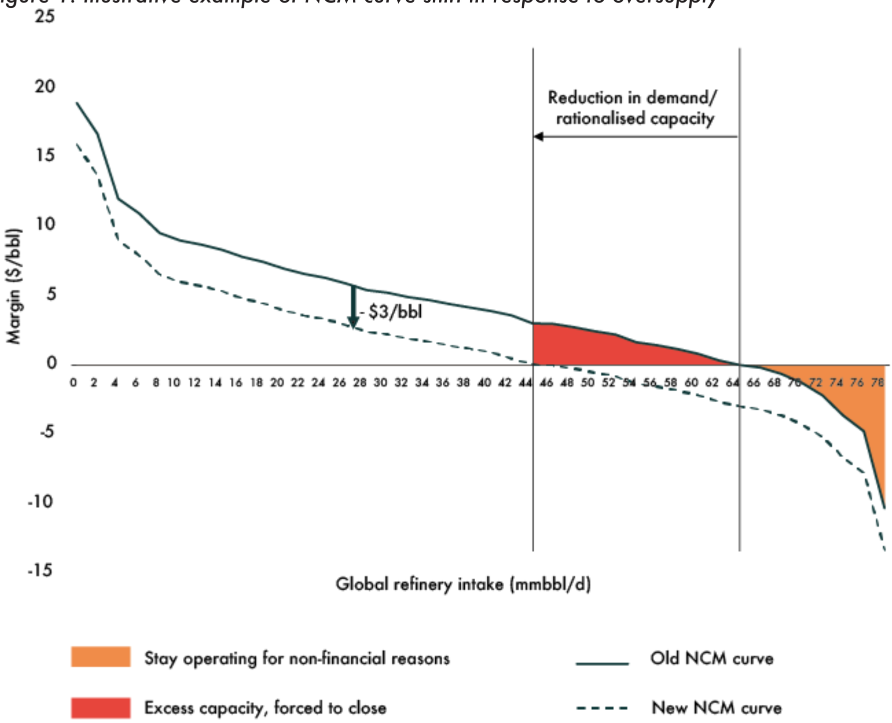
Worked example

The following is an illustrative example of the cost curve approach to closure order assumption and margin decline calculation, using round numbers for the sake of simplicity (the actual figures are given later in this report, in the "Outcomes" section.

Say global refinery crude intake is 78 mmbbl/d, where refineries processing 14 mmbbl/d of crude operate at negative margins but stay open for strategic reasons. This therefore leaves refineries processing 64 mmbbl/d that the closure methodology can be applied to. These will have higher margins than the "strategic" refineries.

In this example, let's assume demand falls by 20 mmbbl/d. If capacity utilisation is already down to 75%, refineries processing 20 mmbbl/d of crude will need to close to maintain that rate. Refineries are assumed to close in order of margin, starting with the lowest margin. These are the low margin refineries on the right hand side of the cost curve of Figure 1. However, as 14 mmbbl/d is processed by loss-making "strategic" refineries, the 20 mmbl/d of closures needs to come from further up the margin curve (red in Figure 1). So, the refinery closures come from the 44-64 mmbbl/d section of the curve.

Figure 1: Illustrative example of NCM curve shift in response to oversupply



In a rational market, the 14 mmbbl/d of "strategic" refineries would close first. No margin change would be needed as they are loss making anyway. The next 6 mmbbl/d needed would only need a fall in margins of under $1/bbl to force them to close.

However, the role of "strategic" refineries willing to operate when uneconomic means a fall in margin of $3/bbl rather than $1/bbl is necessary to trigger rationalisation.

It should be emphasised that the following exercise is intended to be a scenario rather than an explicit forecast. The refining industry is more complex than modelled here. We have favoured simplicity to minimise the number of assumptions needed. This means that our conclusions should be seen as a "top-down" industry approach rather than being based on calculations of any sophistication at the individual asset level.

We consider our approach to highlight the risks in a transparent and replicable way. It is hoped that the exercise will encourage debate and consideration of how risks to the refining industry should be understood and considered in investment decisions and the formation of company strategy.

Further details on methodology can be found in the appendix.

2D and BAU scenarios

Demand

Two demand scenarios are referenced in this study; a 2D scenario which is the focus, and a business as usual (BAU) scenario for comparison.

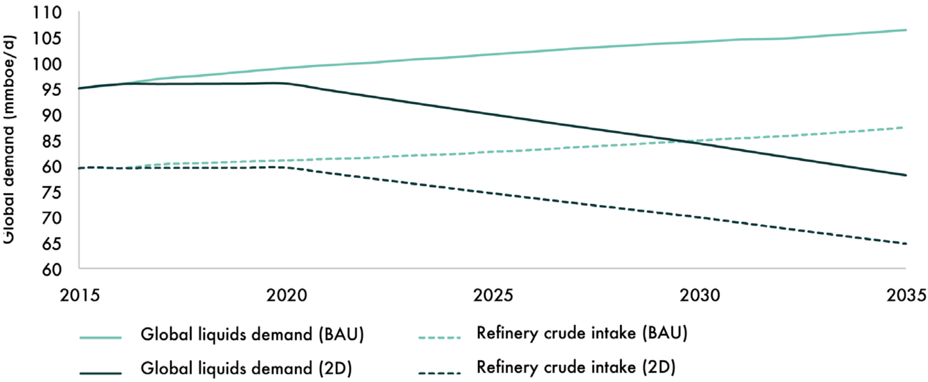
- **2D** (based on the IEA 450 Scenario) – the 450 Scenario is the International Energy Agency (IEA's) carbon-constrained scenario. It is based on delivering an atmospheric CO_2 content of 450ppm, estimated to result in 2°C of global warming above pre-industrial times with a 50% probability of success. The scenario is then worked back to come up with a plausible pathway to deliver this outcome, including assumed technological advances and policy developments. In this scenario, crude oil demand peaks in 2020 before declining over the remainder of the period at an average rate of -1.3% p.a., resulting in a 2017-2035 CAGR of -1.1%.

- **BAU** (Wood Mackenzie's Product Markets Service H2 2016 base case) – represents Wood Mackenzie's base case view of crude oil demand, included here as a proxy for general industry expectations. Oil demand grows throughout the period, although at a gradually slowing rate, resulting in a 2017-2035 CAGR of 0.5%.

The below chart shows global demand for liquids and refinery crude oil intake. Global demand for liquid fuels (solid line in Figure 2) is greater than the amount of crude taken in by the refineries system (dotted line). This gap is due to:

1. Non-crude intake (e.g. natural gas liquids);
2. Processing gains (oil products overall are less dense than crude oil, so a refinery produces a greater volume of product than it takes in crude);
3. Products not produced in refineries such as biofuels.

Figure 2: Liquids demand and refinery crude intake in the BAU and 2D scenarios



Source: Wood Mackenzie, IEA, Carbon Tracker analysis

Data sources

All downstream data has been sourced from Wood Mackenzie's Refinery Evaluation Model (REM) as of end 2016 and Product Market Service (PMS) H2 2016. Ownership details have been updated to reflect changes effective prior to April 2017. Wood Mackenzie have further inputted into the methodology used in this study, and reviewed the conclusions.

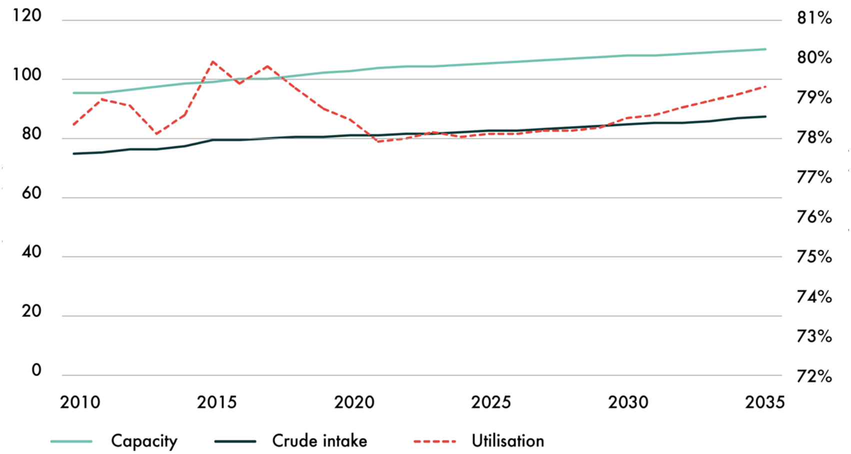
2. Outcomes – the refining industry under a 2D scenario

Industry level outcomes

Under the BAU scenario, demand for crude rises steadily throughout the timeframe, averaging 0.5% p.a. over 2017-2035. The rate slows somewhat from the average 0.7% CAGR prevailing between 2017-2020, but is still rising at 0.4% p.a. in 2030-35. Accordingly, refinery throughput also increases throughout the period.

The inclusion of firm refinery investments to 2022 results in capacity growth slightly outpacing demand growth and lowers utilisation rates from 79.8% in 2017 to a low of 77.9% in 2021. In Wood Mackenzie's projections, global composite margins fall from $5.00/bbl in 2016 to $4.10/bbl by 2019 before recovering in the early 2020s. Beyond this point, our assumed capacity additions in India, China and the Middle East satisfy rising demand and utilisation rises gently throughout the period, approaching 80% by 2035, which may incentivise a greater degree of capacity additions than we have included here.

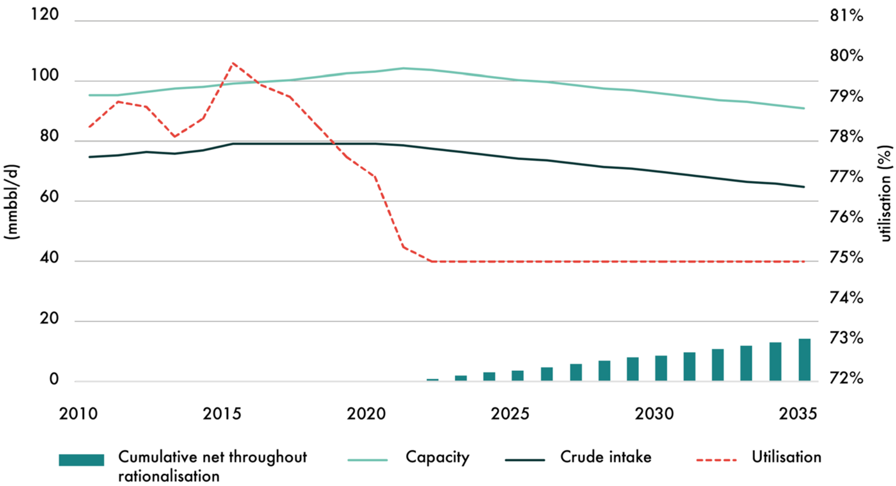
Figure 3: Refinery industry under BAU scenario



Source: Wood Mackenzie, Carbon Tracker analysis

In contrast, under the 2D Scenario, oil demand plateaus before declining post-2020. The additional capacity being added in this period results in utilisation rates falling to 75% in 2022. From this point, onwards, we assume that sufficient refinery closures are made to keep utilisation rates steady. Without further closures, industry utilisation would fall to 62% by 2035.

Figure 4: Refinery industry under the 2D scenario



Source: Wood Mackenzie, Carbon Tracker analysis

Capacity requirements

In upstream oil & gas extraction, once an asset has begun producing, the rate at which it produces oil/gas declines over its lifetime (absent further investment). This means that the industry has to keep investing just to maintain production at a steady level. Furthermore, even if demand is falling, new investment will be required if production is declining at a faster rate. Globally, natural production decline rates of existing facilities are typically estimated at 4-7% annually, compared to the 1.3% p.a. reduction in oil demand under the 2D scenario; accordingly, there remains a need for new investment in upstream oil assets even in a world where demand is curtailed significantly[2].

Conversely in the downstream sector, a refinery can keep converting crude oil into various products at a steady rate as long as feedstock is available.

Furthermore, the industry is comprised of a large base of fixed assets with very long lifetimes, assuming that refineries are maintained. For example, many refineries have been in operation for over 50 years (albeit with particular units subject to e.g. replacement or upgrade). Few oil fields have a similar record.

As noted, only "firm" capacity investments are included to 2022; we note that even if these future additions were not included (i.e. global refinery capacity stayed at 2016 level of 100 mmbbl/d), peak throughput in 2020 of 79.6 mmbbl/d implies a 79.5% global average utilisation rate, below the 80.0% average utilisation in 2015. Accordingly, there is already sufficient existing capacity to cover 2D demand levels, and on a purely volume basis there is no need for any new refinery capacity to be added globally from 2017 onwards.

2 *See Carbon Tracker, "The $2 trillion stranded assets danger zone: How fossil fuel firms risk destroying investor returns", 2015.*
Available at http://www.carbontracker.org/report/stranded-assets-danger-zone/

Further, should demand fall along the lines of the 2D scenario and global refining capacity remain stable or even rise, industry profitability is likely to fall to levels sufficient to force redundant capacity to close.

Forced closures

The implications for the refinery industry could be profound – with utilisation at 75%, a net 14.1 mmbbl/d of throughput must be rationalised by 2035.

However, newly added refineries process a further net 4.5 mmbbl/d of crude. As these are assumed not to close, the implication is an 18.5 mmbbl/d drop in throughput for the 2016 refinery stock. To maintain a 75% utilisation rate, this needs a global reduction of 19.6 mmbbl/d net capacity. Allowing for the new capacity, this means 24.7 mmbbl/d of the 2016 refining stock that would need to be closed – approximately a quarter of existing capacity.

Table 1: 2017-2035 rationalisation in the 2D scenario

	Throughput (mmbbl/d)	**Capacity** (mmbbl/d)
Net rationalisation by 2035	14.1	19.6
Net firm investments 2017-2022	3.8	4.3
Assumed India additions 2023+	0.6	0.7
Gross rationalisation of 2016 refineries by 2035	**18.5**	**24.7**
2016 level	79.5	100.1
Rationalisation % of 2016	23%	25%

Source: Wood Mackenzie, Carbon Tracker analysis

Rationalisation is modelled as being met by a mixture of lower utilisation rates and then increasingly by permanent closures of refinery capacity. Closures are led by cash-negative refineries, but as time goes by, refineries that are profitable today would also need to close.

Closures may well begin at higher average utilisations, for example as has been seen in Europe and Australia since 2011 despite average utilisations of 80% or more.

For reference, each 1% increase in the assumed utilisation floor results in an additional required net rationalisation of approximately 1 mmbbl/d by 2035 (from the 14.1 mmbbl/d resulting from 75% utilisation).

In reality, the implications will naturally be more complicated than modelled here, for example some refineries might reduce their distillation capacity rather than shutting entirely. However, this is an approach that is probably only open to very large refineries with multiple distillation units. The broad trend is likely to be that the low margin refineries will face the greatest pressure to close capacity. More complex refineries are more likely to remain open simply because they have higher margins. A $10 margin refinery would be hurt by a $3 margin fall but not fatally. That may not be the case for a low margin simple refinery, which could become loss-making under the same scenario.

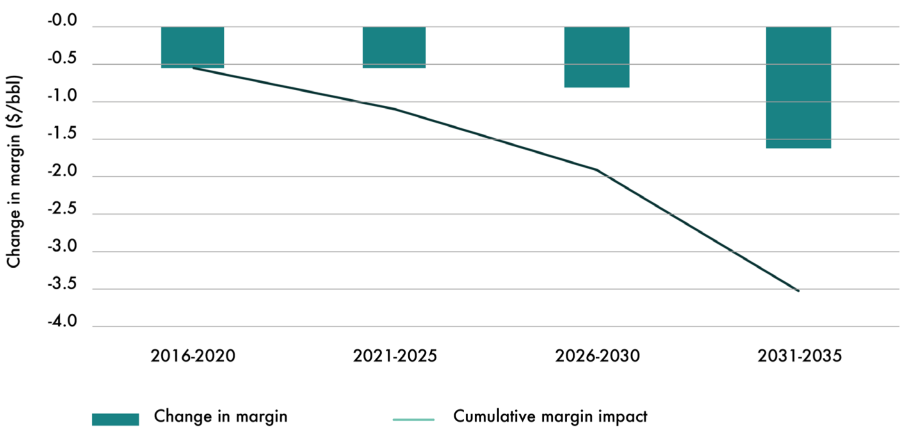
Financial outcomes

Margins

As demand falls, less refinery capacity is needed. The mechanism for forcing excess refinery capacity to close is a fall in margins sufficient to make the required amount of capacity uneconomic. At this point it is assumed that the refinery owner will close the uneconomic capacity rather than continue to lose money, subject to strategic exceptions. We model this by moving the global margin curve downwards until the amount of capacity that needs to be closed is operating with a margin of 0 or less. The extent of the downward movement is the required contraction in margins.

Based on our calculations, the decline in crude demand implies a fall in margin of c.$3.50/bbl across industry by 2035, compared to 2013-2015 average margins. For reference, 2016 global composite margins were estimated to be $5.00/bbl[3].

Figure 5: Impact on refining margins under 2D scenario



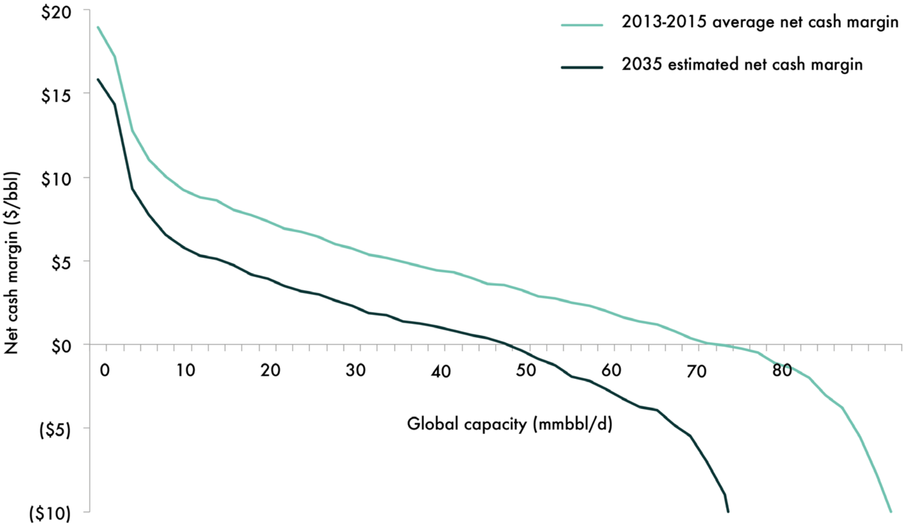
Source: Wood Mackenzie, Carbon Tracker analysis

3 *Wood Mackenzie, Product Markets Service, December 2016*

The impact over the next 5-10 years is less than this, meaning refiners have time to change strategy before financial performance deteriorates significantly. But on a 10-15 year time frame, the industry could face significant economic pressure.

The impact of this, and the reduction in volumes, can be seen in the comparison of the base and 2035 NCM curves; the 2035 curve has been shifted downwards and truncated.

Figure 6: NCM curves – 2013-2015 average and 2035



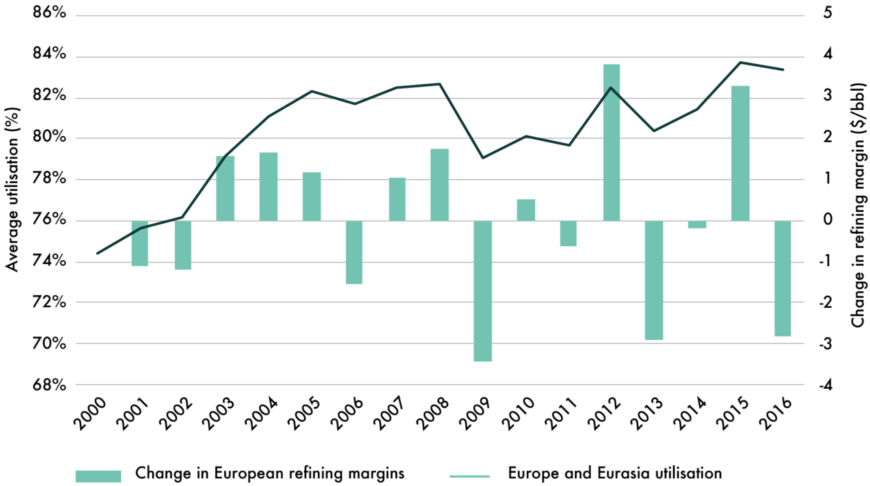
Source: Wood Mackenzie, Carbon Tracker analysis

Given the pressures on the industry under a 2 degree scenario, we would expect there to be some cost cutting by operators, which might lessen the impact of falling margins. This has not been modelled. It is possible that if all refiners cut costs, they would neutralise each other leading to no offsetting effect on margins. If all refiners reduced costs by $1, which is unlikely given the degree of cost cutting already undertaken, one might expect margins to rise by $1. However, that would incentivise previously loss-making refineries to increase runs, bringing the margin curve back down to where it started.

Margin volatility

Overall, we consider the c.$3.50/bbl global industry margin decline by 2035 implied by our model to be reasonable. Annual margin variations of $1-3/bbl are not unusual, and single year swings of greater magnitude have occurred in response to changes in refining conditions of a much lower scale than required under the 450 Scenario. We would expect refinery margins to continue to be volatile in future, although around an increasingly lower mean as the total number of refineries declines.

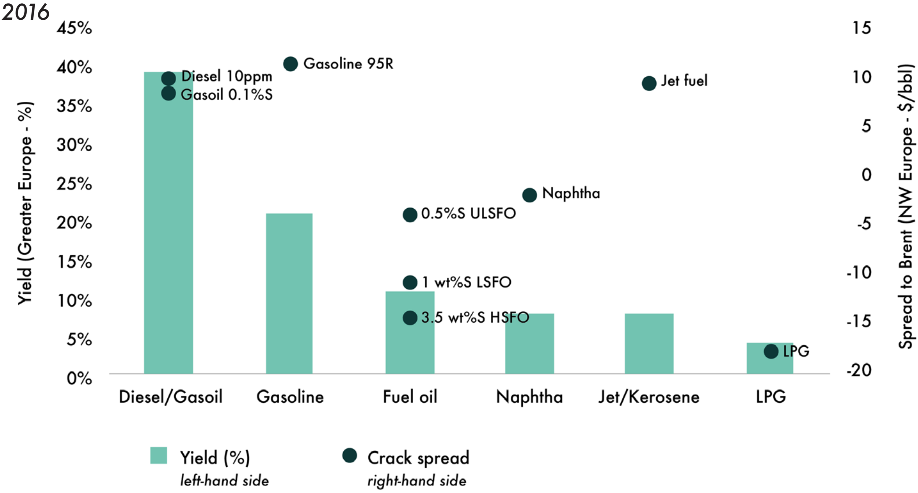
Figure 7: Utilisations and year-on-year changes in refinery margin, Europe 2001-2016



Note: Margin figures based on NWE Light Sweet Cracking benchmark
Source: BP Statistical Review of World Energy, Carbon Tracker analysis

Refinery industry profitability at present is dominated by transport fuels. Gasoline, diesel/gasoil and kerosene make up c.70% of product yield globally, and have far greater margins than lower value products like fuel oil.

Figure 8: Product yield (Greater Europe) and crack spreads for main products (NW Europe), 2016



Source: Wood Mackenzie, Carbon Tracker analysis

Margins may therefore be most sensitive to oil product substitution in the transport sector.

In "normal" or BAU conditions, when weak conditions force refining capacity to be rationalised, there is normally a scope for a recovery as demand growth resumes. Anticipation of a resumption in growth may lead refiners to adopt a "wait-and-see" strategy before closing capacity. For the stronger refineries this has sometimes been a valid approach. The recovery in demand can lead to improved margins but there is almost invariably the need to close some low-quality assets – as the history of European refining shows.

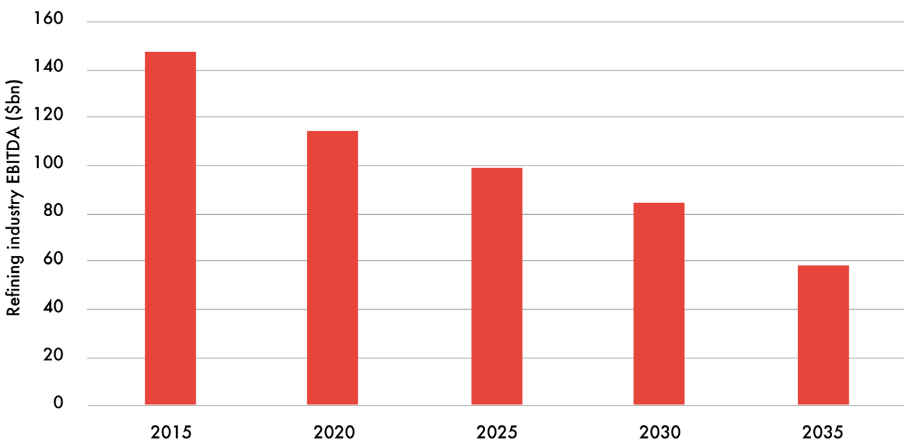
By contrast, the trajectory of global oil demand under a scenario of 2°C global warming is for a steady decline post-2020. This means that refinery capacity rationalisation needs to be a continuous process.

The "wait-and-see" strategy fails under this scenario as the failure to remove capacity from the market would lead to ever-falling utilisation rates and hence margins. In our 2 degree modelling, utilisation rates stay low and there is a need for ongoing closures.

Earnings and valuations

The combination of a) the margin effect of lower margins across industry; and b) the volume effect of less crude being processed leads to a steep fall in industry cash flows. The measure of financial impact used here is EBITDA; EBITDA is Earnings before Interest, Tax, Depreciation and Amortisation. It is a simple surrogate for cashflow and is used in valuation measures for a wide range of industries. It is approximated here as NCM per barrel multiplied by throughput. For existing refineries covered by Wood Mackenzie's margin data (and excluding refineries that make an EBITDA loss), EBITDA falls by over 50% by 2035 from our estimate of $147bn for 2015.

Figure 9: Existing industry EBITDA under 2D scenario

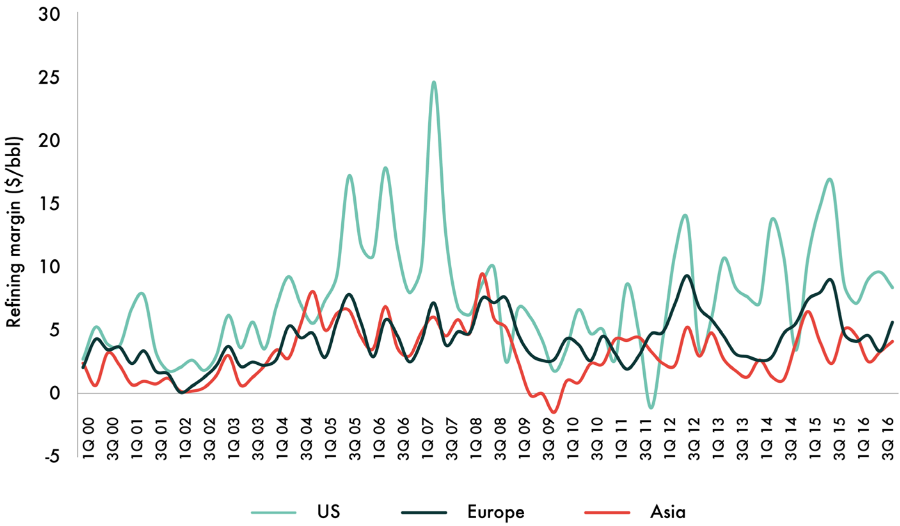


Note: excludes refineries earning negative EBITDA
Source: Wood Mackenzie, Carbon Tracker analysis

While this decline may seem extreme, refining earnings are notoriously volatile, at times delivering negative margins even outside recessionary periods, as they reflect the supply–demand balance dynamics across a number of oil products.

Note that the earnings calculation is based on those refineries that WM provide NCM data for, equivalent to 94% of 2015 global capacity. Accordingly it is not intended to exactly reflect industry EBITDA decline. The actual % decline would be variously affected by inclusion of the two main categories of excluded capacity, namely the remaining 6% existing capacity not covered by NCM data and/or future capacity. The small refineries that make up the absent existing capacity are likely to suffer margin declines greater than average; conversely new refineries (firm investments and assumed additions in India, amounting to 6% of 2015 capacity) are likely to outperform.

Figure 10: Regional refining margins



Note: "US" represents USGC Medium Sour Coking benchmark, "Europe" represents NWE Light Sweet Cracking, "Asia" represents Singapore Medium Sour Hydrocracking
Source: BP Statistical Review of World Energy, Carbon Tracker analysis

With our estimate of EBITDA falling over the period, it seems logical that valuations should fall too. Valuations are frequently estimated using a multiple of earnings or cashflow. Enterprise value (EV – the sum of a companies debt and stock market value) relative to EBITDA is one such example. If this multiple were to stay the same throughout, valuations can be assumed to drop proportionately to EBITDA.

It should be reiterated that assumed valuation declines on this basis would relate to enterprise value (the value of equity plus net debt), rather than market capitalisation (the market value of equity alone).

To the extent that refinery stakeholders have debt in their capital structure, assuming that the value of debt stays approximately constant, the effect on the value of equity is even greater. The constituents of the S&P Global Oil index in the "Oil Refining and Marketing" sub-industry have an aggregate total debt to total capital ratio of c.40% based on recent filings. For those in the "Integrated Oil & Gas" sub-industry (those companies that also have exposure elsewhere in the oil & gas value chain) the figure is 45%, although the integrated majors tend to be less leveraged with an average debt to capital ratio of 29%.

Relative performance

Forecasting future earnings even a few years out is a complex process – even some industry experts have little success. So, forecasting earnings for a few decades hence is clearly a major challenge. The key difference with our approach is that we are looking at relative moves in rather than the absolute level of earnings. Such scenario analysis is likely to have more relevance than absolute forecasts. Clearly, our analysis shows the potential for large scale value destruction.

Earnings and value impacts are likely to fall disproportionately on simpler, lower margin refineries. There have been recent examples of operating European refineries changing hands for close to "inventory value", indicating that value can be substantially wiped out for weaker units even if they continue running; e.g. Shell's agreed sale of the 66k bbl/d Fredericia refinery in Denmark to Dansk Olieselskab for $80m including working capital, and Vitol's purchase of the 21k bbl/d Petroplus Antwerp for $25m.

Company implications

As the cost curve is composed of individual refineries, it could also be aggregated at the company level although the results should be considered illustrative. We consider this analysis of most use as a top-down industry level approach, so full forward-looking company outcomes are not reproduced here in detail.

However, as would be expected from a cost curve based approach, the impact on a company's refining earnings and capacity are highly correlated with that company's overall margins that are used as the starting point. Higher margin companies outperform those that start from a position of lower margin. In contrast, the companies with the lowest margin operations overall would be expected to experience the greatest proportion of capacity being closed or turning negative margin during this period.

For a basket of companies[4], the below table shows:

- the 2013-15 average margins that were used in this study, weighted by refining capacity;
- the change in company EBITDA over the period 2015-2035 modelled in this study. This should be considered indicative, and is shown in 10% bands;
- each company's estimated 2015 refining segment EBITDA as a proportion of its adjusted EBITDA in order to provide context of the relative importance of refining within the overall business.

4 *The 35 companies in the S&P Global Oil Index categorised as either "Integrated Oil & Gas" or "Refining and Marketing" (excluding 4 companies with no refining operations) plus the (probably) soon-to-be listed Saudi Aramco.*

Table 2: Selected companies by capacity-weighted margin

Rank	Company	Country	Capacity weighted average 2013-5 margin ($/bbl)	Change in real refining EBITDA under 2D scenario 2015-2035 (% bands)	Refining segment estimated % of 2015 Adjusted EBITDA (%)
1	Imperial Oil (public traded part)	Canada	17.6	-20% to -10%	25%
2	Suncor Energy	Canada	14.7	-30% to -20%	28%
3	Cenovus Energy	Canada	14.1	-10% to 0%	52%
4	Western Refining	United States	12.9	-40% to -30%	63%
5	HollyFrontier Corporation	United States	11.3	-30% to -20%	97%
6	Husky Energy	Canada	10.3	-10% to 0%	N/A
7	Marathon Petroleum	United States	9.8	-40% to -30%	91%
8	Surgutneftegaz	Russia	8.9	-20% to -10%	16%
9	Gazprom	Russia	8.6	0% to 10%	4%
10	Tesoro	United States	8.5	-70% to -60%	92%
11	Phillips 66	United States	7.9	-50% to -40%	101%
12	LUKOIL	Russia	7.4	-10% to 0%	18%
13	BP	United Kingdom	7.3	-50% to -40%	21%
14	Valero Energy Corporation	United States	7.0	-60% to -50%	75%
15	Sinopec Corp	China	6.4	-70% to -60%	49%
16	GS Holdings	South Korea	5.9	-70% to -60%	50%
17	Chevron	United States	5.9	-70% to -60%	23%
18	ExxonMobil	United States	5.4	-50% to -40%	29%
19	Ecopetrol	Colombia	5.4	-60% to -50%	N/A
20	S-Oil (public traded part)	South Korea	5.3	-80% to -70%	63%
21	Shell	Netherlands	5.0	-70% to -60%	29%
22	Rosneft	Russia	5.0	-40% to -30%	6%
23	PetroChina	China	4.6	-90% to -80%	18%

24	Neste Oil	Finland	4.6	-80% to -70%	37%
25	Petrobras	Brazil	3.8	-90% to -80%	13%
26	Repsol	Spain	3.4	-100% to -90%	29%
27	Eni	Italy	3.0	-80% to -70%	5%
28	Total	France	3.0	-80% to -70%	12%
29	Galp Energia	Portugal	2.9	-90% to -80%	35%
30	Saudi Aramco	Saudi Arabia	2.2	-140% to -130%	N/A
31	Caltex Australia	Australia	2.2	-100% to -90%	20%
32	OMV	Austria	2.1	-100% to -90%	13%
33	SK Innovation	South Korea	2.0	-100% to -90%	65%
34	JX Nippon Oil & Energy Corp	Japan	2.0	-100% to -90%	N/A
35	Showa Shell Sekiyu	Japan	0.9	-100% to -90%	177%
36	Statoil	Norway	-0.5	-100% to -90%	1%

Source: Wood Mackenzie, Carbon Tracker analysis, Bloomberg
Note: Segment definitions for the purposes of disclosure of assets varies by company, and is likely to include other downstream activities e.g. distribution and marketing. But if refining sees an economic downturn, this is likely to be mirrored in other downstream segments.
Note: Where one company has a majority interest in another, the subsidiary's interests are attributed by equity share between the parent and subsidiary (e.g. for Imperial Oil, numbers reflect c.30% minority interest only with other c.70% attributed to Exxon). Where one company has a minority stake in another, the subsidiary company's interests are attributed 100% to the subsidiary (e.g. Showa Shell Sekiyu, c.31% owned by Idemitsu)

Not all barrels are the same

A couple of companies are worth noting with regard to their modelled change in EBITDA over 2015 to 2035 as they highlight points of methodology. Saudi Aramco swings to an EBITDA loss; as an NOC it is assumed to keep refineries open even when loss-making, whereas private sector companies are assumed to walk away from or close refineries that have negative margins. Gazprom is shown as increasing EBITDA over the period despite falling margins; this is due to forward-looking earnings being based on 2013-2015 average margins, which in Gazprom's case were significantly higher than 2015 margins. Gazprom's change in EBITDA from 2015-2035 therefore reflects starting from a low point.

It is interesting to note integrated oil sands companies are at the top of the list. At the upstream level, oil sands projects are generally considered to be high risk in a 2D world due to their breakeven costs. However, the low-quality crude they produce trades at a significant discount to other types, and provides a cost advantage to the high-complexity refineries that can refine it. So oil sands refineries are only competitive because of the special circumstances of oil sands production. Were a 2 degree scenario to lead to the closure of oil sands projects, that competitive advantage would disappear – possibly along with the associated refinery (due to the specialised nature of oil sands upgraders).

3. Recommendations for downstream strategy

Historically, refining has been a low return business for the industry and has resulted in material asset writedowns over the past fifty years or so. Given that the existing refinery stock can meet a 2D demand scenario even before planned capacity additions are taken in to account, the longer-term risks to earnings lie to the downside. Our analysis suggests the scope for a material decline in margins leading to value destruction in this scenario. Investors should therefore engage around and review company exposure to different types of assets:

New investments

Investment plans by private sector companies are already very limited; we believe shareholders should continue to be wary of any refining investment, even in the so-called growth regions. This paper focuses on distillation capacity, in a significant simplification of a complex market. However, we believe the risk of wasting capital extends to all new investments, including expansions or upgrades to existing facilities.

Demand assumptions used by corporates to support such investments should be stress-tested and scrutinised carefully. Margin assumptions, including the spreads between different products, should be subject to sensitivity analysis. For example, several European companies invested heavily in gasoline producing units in the 1980s and 1990s, failing to anticipate the way diesel would gain market share. Much of this investment proved sub-commercial. In the same way, corporates need to examine whether proposed additions to distillation capacity (unlikely in most of the OECD) and upgrading units make sense under a 2D planning scenario. Failure to anticipate a shortfall in demand for oil products (collectively and individually) runs the risk of material margin pressure leading to potential destruction of shareholder value.

Primary distillation capacity

At the primary distillation level, refinery overcapacity will have margin effects across the entire industry; even high-margin new refineries close to demand growth centres will not be immune from such pressures. Having said that, the large scale, complex refineries that service growth areas will probably fare best. Sub-scale refineries with low complexities servicing mature markets are the most vulnerable to market pressures and possible closure.

Upgrading capacity

While investment in an existing refinery may enhance the likelihood that the refinery survives in a 2D world, it does not ensure delivering adequate returns over cost of capital for investors. For example, we note ExxonMobil's recent $1bn investment in a new delayed coker unit at its Antwerp refinery; whereas business-as-usual assumptions may justify the investment, that may not be the case under a 2D scenario. The investment may enable the refinery to remain operating with positive cash margins, but that does not necessarily mean that the capital investment is being rewarded.

Some companies may be forced into new investment in upgrading capacity in order to survive. For example, continued toughening of OECD regulations on product quality may force the industry to invest in new desulphurisation equipment just to enable a refinery to continue operating. And in Europe, the backlash against diesel may also pose problems for the industry. But these investments are not necessarily economic: they might be forced onto companies to avoid the far greater loss of value that results from a refinery closure for example. So investment could be seen as the lesser of two evils, at least in the short term.

Existing assets

Overcapacity will affect the economics of all refineries, new and old. When margins are weak, many players keep producing in the hope that a recovery will arrive so that the costly process of closing or mothballing a refinery can be avoided. This is essentially a game of "chicken" with each refinery hoping that a competing refinery will close first. However, in a scenario where oil demand is declining, this strategy is less justifiable as margins are likely to continue to be pressured as the market undergoes structural decline.

In the 1980s, the IOCs initially chose to keep refineries open in the hope that things would get better. But demand continued to fall, due to the 1979 oil price spike, and margins remained depressed. Eventually the industry saw a wave of refinery closures as the penny dropped. An early mover might well have avoided some of the ongoing losses. But the resistance to rationalisation meant that utilisation rates went far lower than was needed, making the financial pain that much greater. We believe that a 2D scenario will provide an industry backdrop very similar to that in Europe and the US during the 1980s. The industry might benefit from examining its own history.

Conclusion

Following the barrel of oil down the value chain brings up a different set of issues for the industry. A scenario with falling consumption of oil poses challenges for existing refining assets. For the integrated companies this potentially compounds the challenge of deploying the right amount of capital into upstream production. Given that downstream performance suffers under this lower demand scenario, this should be a concern for companies which have relied on earnings from this business in recent times.

Appendix I – Refining basics

Introduction to refining

As the name suggests, a refinery turns crude oil into refined products such as gasoline, diesel, and heavy fuel oil. It can also produce specialty products such as lubricants, chemical feedstocks and asphalt. Refining is not a single step activity but a series of connected processes. The initial step for most refineries is distillation: this vapourises the oil which rises up a long column. As crude oil is a mixture of many products with different boiling points, the lighter more volatile fractions such as gasoline condense higher up the column than heavier products. In the distillation process these different products can be separated. However, the chemical make-up of the crude oil does not change.

Unfortunately for the industry, the product slate yielded from distilling crude oil does not match the global demand profile. It produces too little transport fuels (diesel and gasoline) and too much heavy fuel oil. The high yield of unneeded, low value heavy fuel oil means that the distillation process is almost always loss-making. To be profitable, a refinery needs to convert as much heavy fuel oil as possible in to higher value products, such as transport fuels. This means investing in upgrading facilities.

In simple terms, there are three main upgrading processes, those that break down molecules, those that change their shape and those that join them together. These processes all upgrade the quality of products from the distillation process and are known as upgrading units.

What is an oil refinery?

An oil refinery converts crude oil into various useful oil products. These may be finished products for use outside the refinery industry, or "feedstocks" which will then undergo further processing by other refineries or the petrochemical sector.

No two refineries are alike; there is wide variation between refineries in terms of capacity and configuration, and hence crude types that can be processed and oil products that can be produced.

Nearly all refineries have a crude oil distillation unit (CDU), which separates crude oil from a mixture of hydrocarbons into different individual fractions based on their boiling points without changing the chemical structure of the constituent molecules. They may then be equipped with varying combinations of secondary units (for example hydrocrackers and cokers) which use chemical and thermal processes to create other products or purify outputs.

Refineries are often considered in terms of complexity, with the simplest refineries having a CDU alone, and then each additional piece of equipment adding to the refinery's overall complexity based on its cost and potential value addition. Larger, more complex refineries require greater investment, but can capture greater efficiencies of scale, process cheaper crudes, and/or produce yields of higher value products such as gasoline.

Refineries can be broadly categorised as below:

- Topping – the simplest type of refinery, equipped with a distillation unit and no other units. Can produce naphtha, kerosene (jet fuel), diesel oil, gas oil and fuel oil.

- Hydroskimming – equipped with a distillation column plus naphtha reforming and treating processes that allow it to produce gasoline.

- Cracking – equipped with additional units that allow it to crack (break down) heavier hydrocarbon molecules into lighter ones, either with heat and pressure often with the use of a catalyst. Catalytic cracking's main role is to increase yields of gasoline, while hydrocracking is used to increase yields of distillates (kerosene and gasoil/diesel).

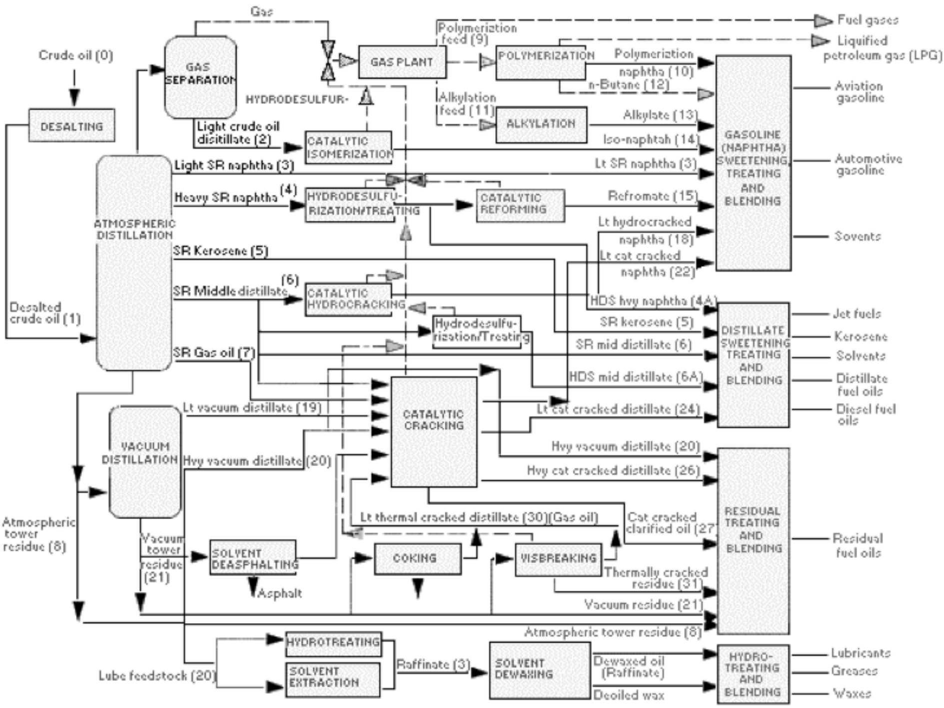
- Isomerisation, reforming and alkylation – units aimed at increasing the octane level of gasoline. Some components can be used as petrochemical feedstock.

- Coking – equipped to process heavy residual fuel oils into lighter distillates and petroleum coke.

- Integrated – can upgrade naphtha (or LPG) into basic petrochemicals (e.g. ethylene, propylene, or benzene, tolene and xylene – "BTX").

The above is a brief overview of some of the main refinery categories, but there are also a number of important processes that are not mentioned here. An example refinery schematic flow diagram showing the various processes is shown below.

Figure 11: Example refinery flow diagram



Source: US Department of Labor

Refineries can therefore be configured differently to deliver different balances of products. However, the balance of products supplied may still not match that of local demand. For example, Europe needs to import diesel to meet local demand. Cross-border trade is therefore an important feature of oil product markets. It also means that regional markets are all interconnected so that overcapacity of (say) gasoline in the US will affect other markets.

Economics

The profitability of a refinery is a complex balance of several factors, including:

- **Crude slate:** crude oil is the primary input for a refinery, hence ideally should be easily available in close proximity. Refineries can be optimised differently to process different grades of crude - heavy oil requires more upgrading than light, sweet oil, but usually trades at lower prices as it contains a higher proportion of lower value oil products.

- **Product slate:** given the variety of products that can be produced, the particular products that are required in the region are an important consideration in refinery configuration. Simpler refineries produce significant volumes of low-value fuel oil, which has primarily industrial applications. These often face particular economic challenges as markets shift towards lighter, lower sulphur fuel products.

- **Location:** ideally in close proximity (hence occurring lower distribution costs) to local demand for products. Inland refineries can be advantaged compared to coastal refineries, which effectively have to compete with other coastal refineries globally (providing the inland market needs to import oil products from other locations).

- **Other costs:** e.g. labour and energy costs, fiscal regime.

- **Other factors:** e.g. regulatory environment, strategic considerations.

Appendix II – Methodology

Assumed capacity additions

The PMS contains projections of possible new refinery investment through to 2022. "Firm" refinery investments (and closures) in the 2017-2022 period have been assumed to be executed in both the BAU and 2D cases ("likely" and "unlikely" opportunities have been assumed not to go ahead). These amount to a net 4.3 mmbbl/d of new capacity in this period.

In addition to these firm capacity additions to 2022, an assumption has been made for capacity added from 2023 onwards. In the BAU case it has been assumed that capacity has been added in India, China and the Middle East at a rate proportionate to each country's demand growth rate (1.0x oil demand growth rate for India and the Middle East, 0.5x in China). This amounts to a cumulative 5.8 mmbbl/d of capacity additions between these three regions. While this gives the impression of a smooth rise in refinery capacity in each locale, in reality capacity additions are likely to be "lumpy" as large 400+ kbbl/d units are added in discrete intervals; in aggregate, the smooth increase can be thought of as investment taking place in different places in each year such that new additions alternate between countries. These assumptions create a reasonably stable supply/demand balance from 2023 onwards, where utilisation rates are consistently in the c.78-80% range (within the "normal" run-rate for the industry).

Conversely, in the 2D scenario no new capacity build has been assumed for 2023+ with the exception of some minor additions in India, the only major country that experiences significant demand growth (liquids demand in India growing at a rate of 2.6% p.a. over the 450 period of 2014-2040). 0.7 mmbbl/d of capacity has been assumed to be added in 2023-2035.

Table 3: 2017-2035 assumed capacity additions in the 2D and BAU scenarios

		2D (mmbbl/d)	**BAU** (mmbbl/d)
Firm investments 2017-22		4.3	4.3
Assumed additions 2023-35	India	0.7	2.5
	China	0.0	0.7
	Middle East	0.0	2.5
Total capacity additions		**5.1**	**10.1**

Source: Wood Mackenzie, Carbon Tracker analysis

Net cash margin (NCM)

Definition

Net cash margin (NCM) is defined in Wood Mackenzie's model (REM) as:

Net Cash Margin = Gross Margin ($/bbl) - Cash Operating Expenses ($/bbl)

(where Gross Margin = Gross Product Worth (GPW) – Delivered Crude Cost)

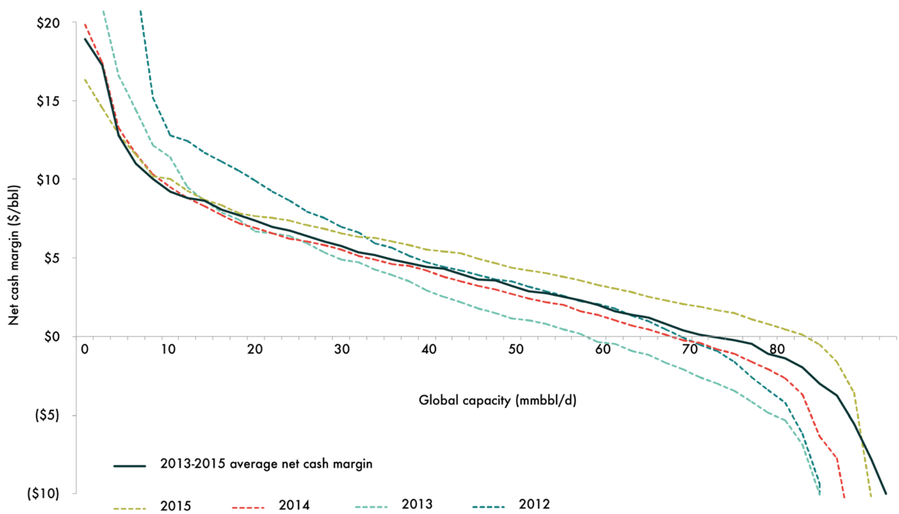
This can be regarded as similar to Earnings before Interest, Tax, Depreciation and Amortisation, or EBITDA per barrel. Multiplying NCM by throughput is used to approximate total EBITDA for each refinery.

NCM curves

Wood Mackenzie data covers 739 refineries globally, with a cumulative capacity of 98.2 mmbbl/d. Within that universe, with full margin data are 492 refineries with 92.1 mmbbl/d of cumulative capacity (94% of global 2015 capacity). The refineries covered generally those with capacity above 50k bbl/d.

NCM curves are constructed for the refineries for which data is available. Each refinery's NCM is based on the average for 2013-2015 to smooth out annual variability to an extent; although 2015 is the most recent year for which NCM data is available, it was also an exceptionally strong year for refining profitability. Note in the below chart that, although 2012-2015 were very different in terms of refining conditions, the NCM curve remained broadly the same shape.

Figure 12: Historic net cash margin curves for 2013-2015



Source: Wood Mackenzie, Carbon Tracker analysis

The NCM curve is then compared to future demand at 5 year intervals. Effectively, it is assumed that the merit order of refineries continues to be as it is now; although the NCM curve is moved vertically in order to reflect industry margin changes, these are applied equally to all.

A single NCM curve is used for global capacity. This is similar to the approach taken in Carbon Tracker's analysis of upstream oil markets, in contrast to the more regionally traded coal and gas. Clearly this is something of an approximation; while we have attempted to consider regional markets where this could be done reasonably and methodically, there may be regional nuances. Further, dynamics may also change or increase/decrease in effect in a scenario of decreasing demand. However, for the purposes of this thought experiment, we consider this a reasonable approach. The oil market is dependent on trade being as open as possible, and this is increasingly the case; the share of oil production that is traded internationally has increased from about half in 1980 to over 70% in 2016[5] and fuel standards are converging globally.

NCM forward projection

We are conscious of the limitations of the methodology outlined above. While oil demand under a 2D demand profile peaks in 2020 and declines thereafter, the differing oil products may have differing demand profiles, being more resilient or falling by greater or lesser degrees. Accordingly, prices for the different products may behave differently, changing the shape of the NCM curve over time as refineries best equipped to deliver more resilient products are relatively advantaged compared to those that produce products facing greater demand declines.

Theoretically, it might be possible to model this in detail; future demand out to 2035 for each product might be estimated (the 450 scenario does not include demand by product), and a price for each product estimated. These could then be used to calculate NCMs for each year going forward.

However, given the compounding uncertainties of all the assumptions required, and the practical impossibility of reliably predicting future prices based on supply and demand figures alone, we believe that a simpler approach, where the NCM curve is assumed to remain the same shape, is preferred. Furthermore, any attempt to adjust margins would only change the merit order of refineries – the amount of capacity that would need to be rationalised would stay the same. Given the backdrop of falling oil demand, increased profitability at one refinery which means it stays open pushes another out. While this may mean that there are differences at more granular levels of analysis, at the industry level as presented here, differences are likely to be small.

5 *BP Statistical Review of World Energy, 2017*

Refiners also have some slight flexibility to change relative proportions of yields to cater for variation in expected demand for different products[6]. In light of the above, and given that industry profitability is overwhelmingly driven by transport fuels rather than speciality products, we believe that differences between methodologies will generally be at the margin. Accordingly, we consider that a generalised approach is reasonable provided that the outcomes are understood in this context and an unwarranted level of accuracy is not assumed. The more granular analysis in this paper, for example that at the company level, is therefore indicative only.

Refinery closure methodology

Closure order dictated by NCM curve once industry utilisation reaches 75%

In the 450 scenario, the refining environment weakens as oil demand growth slows and then begins to fall, lowering industry utilisation levels and margins. Utilisation is the volume of feedstock that a refinery actually processes divided by its nameplate capacity (i.e. a refinery capable of processing 500 kbbl/d that actually processes 400 kbbl/d on average is operating at 80% utilisation).

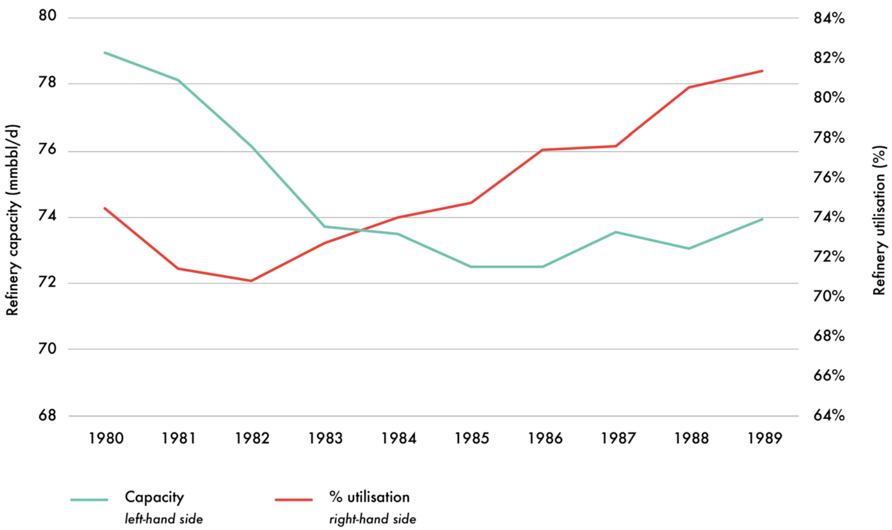
Initially, it is assumed that the industry responds by trying to stay open and wait for competitors to close, hoping for conditions to improve in future. It is assumed that refineries will start being rationalised when industry-wide utilisation reaches 75%, based on historic analogues. Following the Iranian Revolution of 1978-79, supply disruption led to high prices for crude, incentivising energy efficiency measures and use of other fuels. Global crude oil demand accordingly fell by c.10% from 1979-1983[7] (a higher rate than the 2020-2035 average -1.3% annual decline in crude demand under the 450 scenario, although over a less prolonged period - clearly with other differentiating factors). The refining industry suffered declining utilisation and margins, and 8.2% of global capacity was rationalised over 1980-1985. In the period 1980-1989 global utilisation troughed at 71% before rising again in the latter half of the decade, averaging 75% overall[8]. Accordingly, we consider 75% to be a reasonable average level which will start motivating meaningful refinery capacity shut in. In the 2D scenario, this level is reached in 2022.

6 *Albeit to a limited degree without material additional investment. For example, in Europe over the period 2000-2015, refiners in North West Europe shifted their product yields towards diesel/gasoil by c.3% in a period of limited investment (Wood Mackenzie PMS)*

7 *BP Statistical Review of World Energy*

8 *BP Statistical Review of World Energy*

Figure 13: Global refining capacity and average utilisation, 1980-1989



Source: BP Statistical Review of World Energy

At this point, the extended period of reduced profitability begins forcing closure of relatively weaker units. The order in which refineries are closed is dictated by the NCM curve detailed above, starting with lowest margin units to the right hand side of the curve.

We consider the 75% utilisation floor to be conservative – recent experience from Australia and Europe suggests that rationalisations can start when utilisation is closer to 80%. The higher the utilisation floor assumed, the greater the amount of capacity that must be rationalised to maintain it. For example, if rationalisation was assumed to start at 78% instead of 75%, there would be a net 17.2 mmbbl/d of excess supply to remove rather than 14.1 mmbbl/d, implying that margins would have to fall correspondingly further.

Exceptions and non-economic forces

It may be noted that a significant proportion (21%) of the refinery industry already operates at a negative margin (see figure 12 above). There are a number of reasons that a refinery may continue to run at a loss rather than closing, particularly those that are owned by state-owned enterprises, for example strategic motivations or social considerations. In order to attempt to model this dynamic with the minimum of subjectivity or arbitrariness, Carbon Tracker has applied some broad rules for exceptions when considering which refineries will close under the 2D scenario modelling.

An existing refinery will be assumed not to close (i.e. will continue to run, even if at a loss) if any of the following circumstances apply to it:

- Petrochemical integration: Petchem integrated facilities are assumed not to close due to a) the contribution to overall site profitability from petrochemical manufacture not being captured in this refining-focused study; and b) higher social cost of closing integrated sites. For the purposes of this exercise, we count as petchem integrated refineries that produce speciality products or have a steam cracker unit as a proxy.

- Last major refinery in-country: It is assumed that countries will want to retain at least one operational major refinery for strategic purposes.

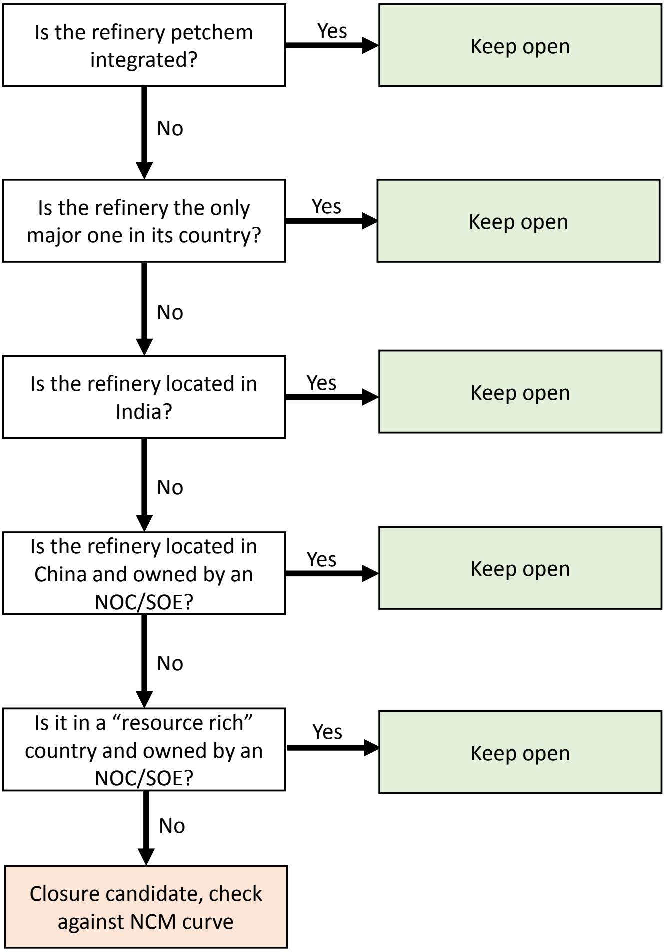
- Located in India: as India shows material growth in oil demand in the 450 Scenario (2.6% p.a.), it has been assumed that domestic demand will sustain local refineries.

- Located in a resource rich country and owned by an SOE: It is assumed that countries with significant oil production and government influence in industry will be more likely to keep refineries open in order to ensure a market for their crude, capture a greater part of the value chain, and avoid having to import products. This has been applied to the following countries: Bahrain, Brazil, Brunei Darussalam, Ecuador, Iran, Iraq, Kuwait, Oman, Qatar, Russia, Saudi Arabia, the UAE and Venezuela.

- Located in China and owned by an SOE: This is a similar situation to that in India, although Chinese demand ends the period approximately where it started rather than experiencing sustained demand growth. We assume that the Chinese government will support publicly-owned refineries to an extent, albeit for different reasons (e.g. social considerations). Privately-owned refineries in China are subject to the normal cost curve methodology.

Application of these general principles is illustrated in the below flowchart.

Figure 14: Closure determination flowchart



Source: Carbon Tracker

The above logic applies to existing capacity only; newly built capacity is also assumed to be safe from closure, as new refineries tend to be large units enjoying economies of scale and efficiency and be first quartile in terms of margins (as well as more likely to stay open due to recently sunk costs).

Regarding the smaller refineries for which we have no NCM data, these are assumed to be closed at a rate proportionate to the rest of the market, starting with the smallest units first.

Petrochemical integration

Petrochemical feedstocks are a rare bright spot for oil use as demand outperforms that in other sectors in the 450 Scenario, growing by 1.0% CAGR to 2040 and increasing their proportion of oil demand from a current 12% to over 20%[9].

As noted above, future refining margins are calculated based on the 2013-15 average, rather than building them up from the different demand trends for each product. Accordingly, the more favourable demand trends for petrochemical feedstocks may arguably mean that petchem integrated facilities outperform other refineries in terms of profitability, which is not reflected in the assumed future margins used here.

As well as the additional estimates and uncertainty required, we feel justified in not attempting to separately calculate future margins for petchem integrated refineries based on their products:

- Production of natural gas liquids grows somewhat through much of the period (production in 2030 is 9.5% higher than in 2014). Accordingly, some of the demand growth for olefins will be satisfied by non-refinery supply sources, which are outside the scope of this analysis.

- Petrochemical feedstocks generally account for a small percentage of refinery output (typically less than 5%), and hence make a minor contribution to overall profitability at a sector level.

Accordingly, while there will be exceptions for individual specialist refineries, in general we do not anticipate that attempting to model petrochemicals separately would lead to materially larger margins when looking at the industry top-down, and prefer to err on the side of simplicity and transparency.

Thus, the sectoral impact on refinery profitability of petrochemical feedstock is assumed to be small. However, our modelling assumes that integrated facilities stay open throughout the study period to 2035:

- As the report focuses on refinery earnings only, it does not capture the contribution to overall site profitability from the manufacture of chemicals in an integrated facility, which may support the sustained operation of the combined assets. For simplicity, we have not tried to allocate this additional contribution to integrated site earnings to the refinery, and ownership structures may differ between refinery and petrochemical manufacturing plant.

- Large, integrated sites would carry a higher social cost of closure due to the high numbers of people employed at and in support of such industrial clusters, which governments may wish to avoid or put off.

9 *IEA, World Energy Outlook 2016, p112*

Financial impact

EBITDA used as primary measure
We can use the net cash margin (NCM), refinery capacity and utilisation rate to calculate the cash flow or EBITDA for a given refinery. By aggregating, we can do the same for companies.

As per the above (see Exceptions and non-economic forces), there are situations in our modelling when a refinery would be expected to stay open for strategic reasons despite operating at a loss. These refineries will normally be in the hands of government-backed companies; however, there are some circumstances when a refinery that would be expected to stay open due to the country's strategic interests is owned by a private company. For example, if the last refinery in a country is owned by an IOC and would be loss-making, the country's government may wish to keep the refinery operating, but the IOC may wish to cut its exposure. In such cases it has been assumed that, for 2025 onwards, the private company will pass ownership to the country's government (or NOC), and the company will not incur any negative cash flows. However, the negative cash flows have not been allocated to any company or government. An historical analogue can be seen in the BAPCO refinery in Bahrain; founded by the predecessors of Chevron and Texaco, ownership of the refinery eventually passed to the Bahraini Government (60% in 1981, before assuming 100% control in 1997)[10].

Our estimates of financial impact do not include:

- Maintenance capex – refineries typically undergo "turnaround" every 5-7 years, when process units are refurbished, renewed or upgraded.

- Closure or remediation costs – no additional costs are assumed when refineries are closed. At present, refineries are typically repurposed as storage when closed. This may be less likely in a scenario of declining oil demand, making estimation of costs uncertain.

Financial impacts relate to existing refineries only.
As EBITDA is calculated based on 2013-2015 net cash margin, it is calculated for the 94% of global 2015 capacity that Wood Mackenzie's data includes NCMs for. It cannot be calculated for refineries where this data is unavailable, comprising three main groups:

- **Small refineries:** Generally, existing refineries with capacity below 50kbbl/d are included in modelling (including closure) but do not have margin data available. Equivalent to 6% of 2015 capacity.

- **Firm future refinery investments:** The data provided by Wood Mackenzie on investments to 2022 does not include margin data. These new refineries are assumed to be first quartile in terms of margins in our modelling, and hence stay open, but earnings are not calculated. Equivalent to 5% of 2015 capacity.

10 *http://www.bapco.net/en-us/about-bapco/our-history*

- **Assumed 2023+ capacity additions:** Estimates of capacity additions (e.g. in India in the 450 Scenario) are notional rather than being associated with any specific site. Equivalent to 0.7% of 2015 capacity.

Key limitations

As noted above, a number of simplifications of the refining industry have been made for this exercise. Some of the key limitations are highlighted below:

- **A single NCM curve has been used for global capacity** – while we considered and adjusted for regional/sub-markets issues where such adjustments could be made objectively and methodically, there are bound to be further regional nuances currently not considered.

- **No distinction is made between coastal/inland refineries** – these often experience different demand dynamics, with inland refineries being more reliant on local demand. However, while location benefits are factored into WM's NCM calculation, the premium/discount is difficult to quantify on a forward looking basis, and may reverse in effect during the period as demand declines.

- **NCMs are backward looking** – NCMs are based on 2013-15 averages. While this average will smooth out some annual effects, these will not necessarily reflect future conditions, for example due to fiscal changes.

- **Product and crude slates have not been factored into future margins** – ideally, with knowledge of future product balances and available crudes, refineries that are better equipped for relative highlights in product demand trends (e.g. petrochemical feedstocks) may be expected to outperform. However, this is difficult to reflect in practical terms and would require a large number of assumptions and certain refiners may elect to invest for survival.

- **Part closures or investments in response to 2D** – we have assumed that overcapacity is eliminated by closing refineries in discrete units when uneconomic. However, real world behavior is likely to be far more complex, and might include for example part closure of refineries and/or investments in order to stay open, as evidenced by Total in its partial closure of its UK site.

- **Non-financially driven behaviour is impossible to predict** – capacity that is assumed to stay open, despite being loss-making, has a significant effect on results. Will SOEs "play chicken" with IOCs by staying open despite financial losses, or rationalise capacity as well?

Source of conservatism and mitigating factors

As noted above, we have attempted to be conservative with assumptions where possible, in order to partially allow for the simplistic nature of the exercise and the ability of the industry to respond to changing conditions and mitigate negative effects. A few of these sources of conservatism and unmodelled behaviours that may mitigate the effects are listed below.

Sources of conservatism:

- **Margins/EBITDA do not include all costs**. Turnarounds every 5-7 years involve non-trivial capital costs, which are not included – for example, Neste Oil budgeted nearly €100m for their 2015 turnaround at their Porvoo refinery[11]. Closure and rehabilitation costs are also not included.

- **Closures do not begin until utilisation falls to 75%**. Closures may well begin at higher average utilisations, for example as has been seen in Europe and Australia since 2011 despite average utilisations of 80% or more. For reference, each 1% increase in the assumed utilisation floor results in an additional required net rationalisation of approximately 1 mmbbl/d by 2035 (from the 14.1 mmbbl/d resulting from 75% utilisation).

- **No future capacity additions have been assumed in the 2D scenario**, with the exception of some minor additions in India. However, it is arguable that China (and maybe other countries, particularly in the Middle East) may continue adding capacity.

Potential mitigating behaviours:

- **Costs are likely to be cut**, partially offsetting the fall in NCM/ EBITDA. However, much of the possible scope for savings are likely to have already been achieved, given the sustained pressures faced by the industry in recent years.

- **Partial closure of distillation capacity** at refineries that have more than one crude distillation unit, increasing the average complexity.

- **All refineries have been treated equally in terms of utilisation and margins**, meaning that all refineries are assumed to experience the same relative percentage decline in utilisation and absolute contraction in margin. In reality, high complexity refineries are likely to be able to sustain utilisations and margins to a better degree than low complexity units.

There are no doubt other ways in which the industry will react to increasing pressure on margins. However some possible responses, such as investment in upgrades, will require difficult capital allocation decisions in the face of uncertain future oil demand.

11 https://www.neste.com/en/largest-maintenance-turnaround-history-be-started-neste-oils-porvoo-refinery

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