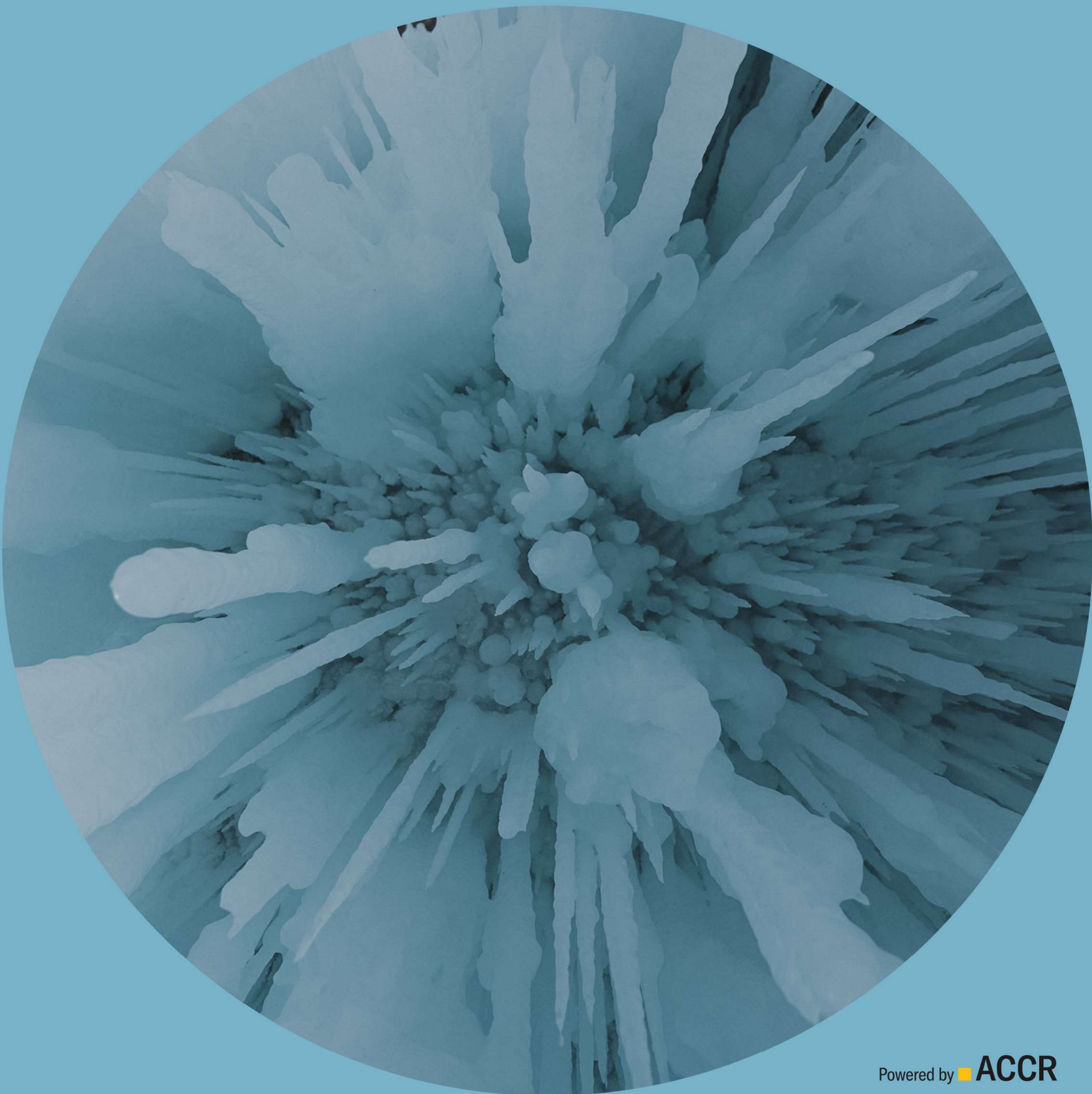
Global Climate Insights

March 2022

Part 2: BP in a decarbonising economy



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Global Climate Insights.

In-Depth, Timely, Company-level Analysis

We are

A team of professionals with deep energy, equity research and climate science expertise.

We believe

Climate change is the key driver of risks and opportunities in the 21st century. Companies that can thrive in a zero emissions economy will generate long-term value for investors.

What makes us different

We dive deep into company level analysis and test the credibility of information provided against climate assumptions.

We are uniquely positioned to

Bridge the gap between climate and capital, help investors assess and value a company's transition plans in alignment with a safe climate.

Our methodology

Our analysis of company climate transition plans is based on our emissions forecast. The key components of our forecast include carbon intensities by product, market share aspirations and market size assumptions. Our assumptions rely on company disclosure on production ambitions and strategy, as well as scenarios aligned with a 1.5C temperature outcome.

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Metrics and denominations

- All financial values unless specified are denominated in US$
- k = thousand
- M, m, mm = million
- bn, b = billion
- boe = barrel of oil equivalent. We use 'b' to refer to barrels of ethanol equivalent, unless specifically stated (e.g. kb/d oil, kb/b condensate or kb/d refining throughput).

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1.0 BP Financial Summary

1.1 BP's financial position

One of the key questions facing investors is what the financial cost and returns will be from the transformation of oil and gas majors into energy companies. At a group level BP has guided to EBITDA of $41-48bn in FY30, a 1-3% CAGR.

This year at its FY21 results BP provided an initial indication of FY30 EBITDA by its two strategic themes, as shown in the 'Transition business' and 'Oil and gas' columns in the table below. Oil and gas remains the predominant source of earnings (~80% of EBITDA) by FY30. BP's transition business is expected to deliver ~20% of Group EBITDA, at $9-10bn, from bioenergy, convenience, EV charging, renewables and hydrogen. Bioenergy is expected to contribute 20%, or $2bn, a material increase from FY21. BP's guidance implies a ~22%-23% CAGR in EBITDA for its transition business between FY21 and FY30, compared to oil and gas EBITDA which is expected to deliver CAGR broadly flat. The table below also shows BP's earnings guidance by strategic pillars (rows). Interestingly, BP now includes bioenergy as part of its resilient hydrocarbons pillar; the growth in bioenergy will help BP maintain its hydrocarbons EBITDA to FY30. Convenience and mobility EBITDA is expected to increase to $9-10bn (8-10% CAGR) and Low Carbon energy EBITDA to $2-3bn.

Table: BP financial contribution by strategic pillar and segment

Strategic theme/ Strategic pillars	**Transition business**	**Oil and gas**	**EBITDA FY21**	**EBITDA FY30**	***CAGR FY21-FY30***
Resilient hydrocarbons	Bioenergy	Oil and gas Refining (Rosneft included in FY21)	$33.5bn	$30-35bn	*-1% to flat*
Convenience and Mobility	Convenience EV charging	Mobility (retail fuels) Castrol Aviation Midstream (pipelines etc) Business to Business	$4.4bn	$9-10bn	*8% -10%*
Low Carbon Energy	Renewables Hydrogen	-	small	$2-3bn	*large*
BP Group EBITDA			**$37.2bn***	**$41-48bn**	***1-3%***
EBITDA FY21	~$1.5bn	$35.7bn			
EBITDA FY30	$9-10bn	$32bn-38bn			
CAGR FY21-FY30	*22-23% CAGR*	*-1% to +1%*			

Source: Company data, Global Climate Insights estimates. * Group EBITDA FY21 including Corporate and Other Businesses and Rosneft.

1.2 Earnings performance

In this section we look at how BP is financially positioned as it undertakes its transition. At BP's FY21 results it delivered a statutory net profit after tax of $7.6bn compared to a loss of $20.3bn in FY20 (a $27.9bn increase). This was BP's first full financial year reporting under its new segment structure.

FY21 underlying replacement cost loss (post-tax), which excludes the impact of impairments and other 'one-off' items, was $13.7bn, compared to a loss of $6.1bn in FY20 ($19.8bn increase).

Key 'one-off' items in its FY21 profit included a net impairment reversals of $1.1bn ($14.4bn impairments in FY20, $8bn FY19), restructuring provisions of $0.25bn, gains on sale of $1.9bn, $8.1bn of fair value gains and losses on derivatives reflecting the impact of high gas prices on LNG hedging (expected to unwind in later periods), and other adjusting items of ~$2.5bn. BP's Return on Average Capital Employed (RoACE, based on underlying profit) was 8.9% in FY21, and -2.9% in FY20. Ranging from -3 to 9% in the last five years. BP expects the RoACE to grow to 12-14% by FY25 ($50-60/bbl).

Chart: BP group underlying profit (US$bn) and RoACE(%)

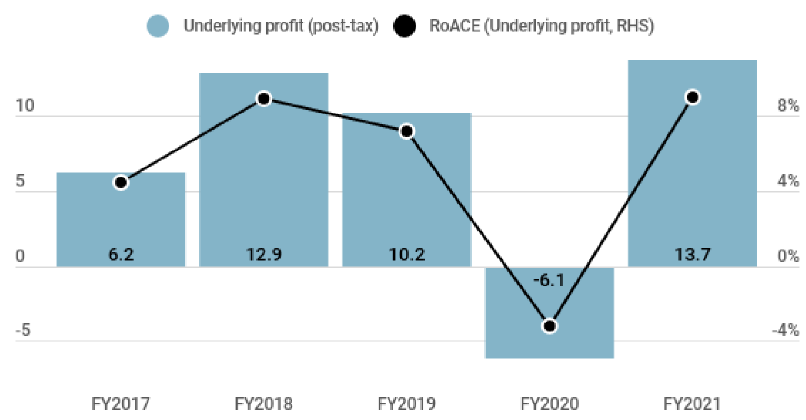

Chart: GCI | Source: Company Data, Global Climate Insights Estimates Global Climate Insights

Underlying profit was $13.7bn in FY21, and RoACE 8.9%

The improvement on FY21 reflected higher oil and gas prices and lower impairments

Chart: BP Group EBITDA, statutory profit (post-tax) (FY17 - FY21 US$bn)

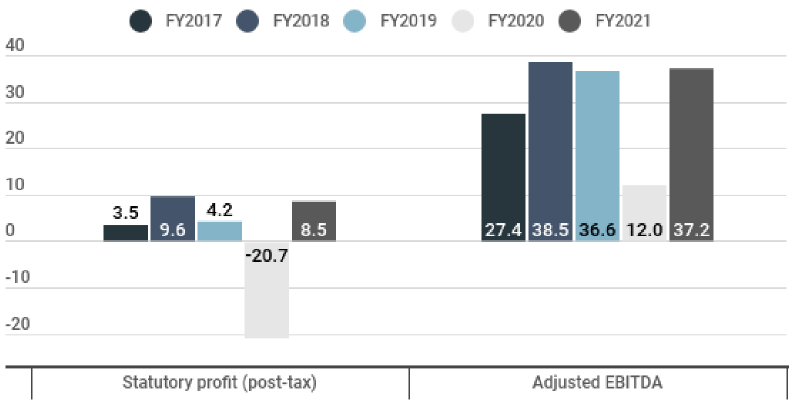

Chart: GCI | Source: Company Data, Global Climate Insights Estimates

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BP Adjusted EBITDA was $37.2bn in FY21, this has been broadly consistent with performance in FY18, FY19

Chart: BP segment underlying profit after-tax (ex other business and financing cost, US$bn)

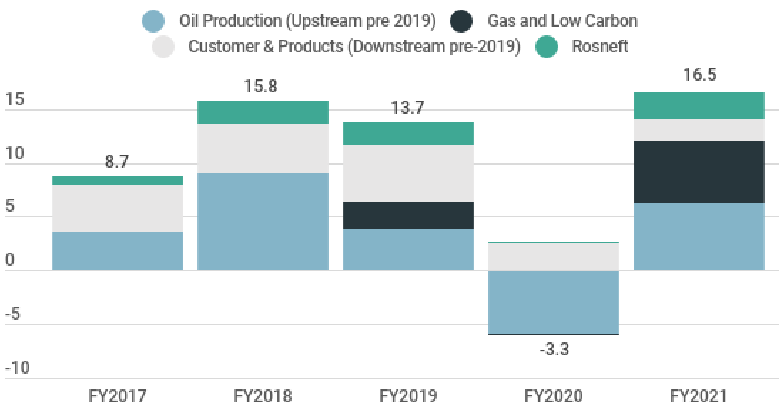

Chart: GCI | Source: Company Data, Global Climate Insights Estimates

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Earnings remain driven by upstream oil and gas businesses.

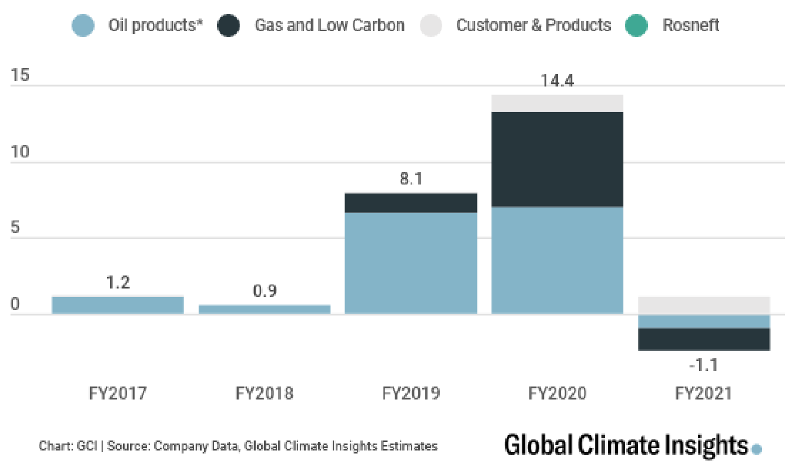
Downstream was impacted by sale of Chemicals business in December 2020, which contributed $233m to underlying profit pre-tax in FY20, and $402m pre-tax in FY19

1.3 Impairments

One of the key risks to oil and gas companies through the transition is increasing impairments, risk of stranded assets and potential underestimation of decommissioning costs that result when assets are no longer required. Impairments will also be realised where assets are sold for a lower value than currently held on BP's balance sheet. When assessing potential impairment BP has stated that the future prices it uses are in line with the Paris agreement climate goal. To assess this, in FY21 BP's auditors (Deloitte) reviewed BP's 'best estimate' prices against a range of scenarios, including Paris 'well below 2°C goal' and Paris '1.5°C ambition', this is a change from solely reviewing a 'well below 2°C goal' in FY20. Deloitte did not specify which scenarios were reviewed. Deloitte found that prices included within BP's valuations were at the higher end of price ranges for oil and towards the midpoint for gas. BP's auditor noted that due to the wide range of price forecasts in scenarios that BP's view was reasonable. Whilst it is good to see auditors slowly include climate risk in assessment of financial valuations there is some way to go to truly understand the impact for oil and gas companies from credible 1.5°C scenarios. As BP's exit from Rosneft demonstrates, impairments can occur suddenly, and if required to be taken at once may be in excess of the value of equity that can support it. With the current level of buybacks, equity is decreasing, further deteriorating the ability to absorb losses.

In FY21 BP's results included a write-back of impairment and losses on sale of businesses and fixed assets of $1.1bn. This compared to impairment net write-offs in FY20 of $14.4bn and FY19 $8.1bn. The FY21 impairment reversal was driven by increases to the assumption of oil and gas prices for producing assets, including a $1.5bn reversal for Gas and Low Carbon Energy, and a $0.8bn reversal in the Oil Production and Operations, largely from BPX Energy (BP's onshore US oil and gas business) and BP's North Sea assets.

Chart: BP Impairment and losses on sale of businesses and fixed assets (US$bn)



BP's FY21 result include a net-write back of $1.1bn, compared to net impairments of $14.4bn in FY20, largely from upstream assets across oil and gas segments

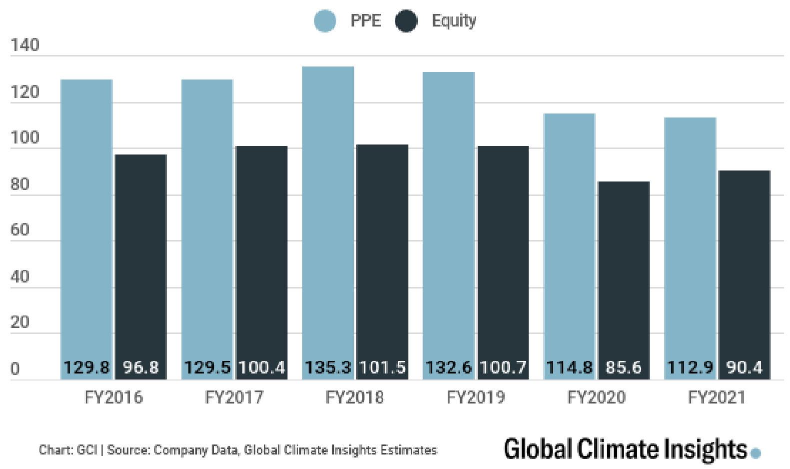
In FY20 impairments were $14.4bn driven by Upstream (prior reporting segment) reflecting lower oil and gas price assumptions for Azerbaijan, BPX Energy, Canada, India, Trinidad, Mauritania and Senegal, and the North Sea, along with charges relating to the disposal of the interest in Alaska (BP Exploration and BP Pipelines), and equity accounted impairments. Downstream impairments were $0.8bn in FY20 driven by changes to the portfolio including conversion of the Kwinana refinery to an import terminal.

Property Plant and Equipment

Property Plant and Equipment (PPE) is the largest asset on BP's balance sheet at US$113bn in FY21 (39% of total assets and 125% of equity). Of the total, $74bn relates to upstream oil and gas assets, $47bn from Oil Production and Operations and $32bn from Gas and Low Carbon[1]. BP has stated that at current rates of depreciation, depletion and amortisation (DD&A), the average remaining life of upstream PPE is seven years and downstream fifteen years[2]. This represents the time over which the assets will have been fully expensed, as PPE decreases this will reduce the risk from large write-downs. However, as BP undertakes new exploration in oil and gas, this will add to future PPE balances.

One question we think about is what is the optimal balance sheet structure that oil and gas companies should adopt as they undertake the energy transition. There may be a rationale for future projects to be expensed over a much shorter period of time than historically, thereby accelerating the depreciation.

Chart: BP Equity and PPE (US$bn) and PPE/Equity (LHS, %)



Total Property Plant and Equipment was ~125% of total equity at FY21.

Goodwill

Total goodwill at FY21 was $12.4bn (~4% of total assets), with $7.6bn relating to upstream assets. BP auditors indicated an excess of $36.5bn between recoverable amount and carrying amount (includes assets in both upstream segments)[3]. Downstream goodwill is $4.7bn, of which $2.8bn relates to the lubricants business. Headroom is not specified for downstream but BP notes that the amount attributable to lubricants is substantial as at FY18. BP's ambition to become an integrated energy company will require more detailed assessments of downstream goodwill, especially the transferability of its brand to one that is removed from hydrocarbon production and more anchored to electricity.

[1] BP, 2022, Annual report 2021, p. 166
[2] BP, 2022, Annual report 2021, p. 150
[3] BP, 2022, Annual report 2021, p. 211

At FY21, BP's total intangibles (net of amortisation) were $6.5bn, ~2% of total assets, of which ~$4bn is attributable to exploration. During FY20 BP wrote-off $9.9bn of exploration expenditure; and $0.167bn in FY21. Future write-offs in exploration are likely to be lower if BP focuses on near hub exploration. BP revised its price assumptions for impairment testing in 2Q21 and 4Q21: Brent oil was increased to $70/bbl in FY22 reflecting supply constraints, and then decreasing to $55 by FY40, and $45 by FY50 (compared to IEA NZS $35 by FY30, $28 by FY40 and $24 by FY50). Henry Hub was increased to $4/mmBtu in FY22 decreasing to $3/mmBtu in FY25 and to $2.75 in FY50 (compared to IEA NZS $1.9 by FY30, $2 by FY40 and $2 by FY50 in US markets).

1.4 Cash capital expenditure (organic and inorganic)

In the last few years BP has focused on decreasing cash capital expenditure to enhance return to shareholders, with capital expenditure peaking in FY18 at $25bn ($15bn organic, excluding acquisitions). BP has stated that this reflects a high period of investments in oil and gas hubs which has now normalised. Despite higher surplus cash flow, driven by divestments and high oil and gas prices, this has not translated into an equivalent increase in capital expenditure for transition. BP's FY21 cash capital expenditure was $12.8bn, in line with its guidance of $13bn, and 10% lower than FY20. This was driven by Oil Production and Operations $4.8bn (FY20 $5.8bn), Gas $3.2bn (FY20 $4bn), Low Carbon $1.6bn (FY20 $0.6bn), Customers $1.6bn (FY20 $2.2bn), Products $1.3bn (FY20 $1.1bn), and Corporate $0.4bn (FY20 $0.3bn). Unlike Shell, BP separates the investment on low carbon energy from gas.

Capital expenditure guidance

BP has guided total cash capital expenditure of $14-16bn p.a. over FY22-25, with transition spend expected to rise to 40% ($5.6bn-$6.4bn p.a.) of total spend by FY25 and 50% by FY30 ($7-$8bn p.a.). Transition spend includes bioenergy, convenience, EV charging, renewables and hydrogen (likely to include gas hydrogen).

Chart: BP capital expenditure (US$bn)

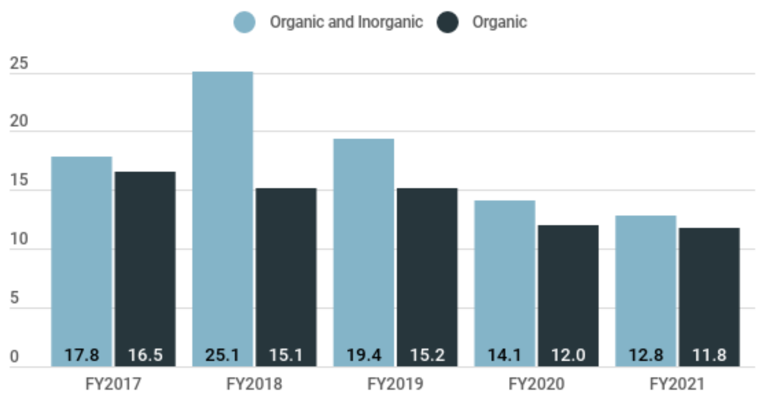


Chart: GCI | Source: Company Data, Global Climate Insights Estimates

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BP has reduced its group capex. over the last four years, spending $12.8bn in FY21

Chart: BP total capital expenditure (US$bn) - by segment

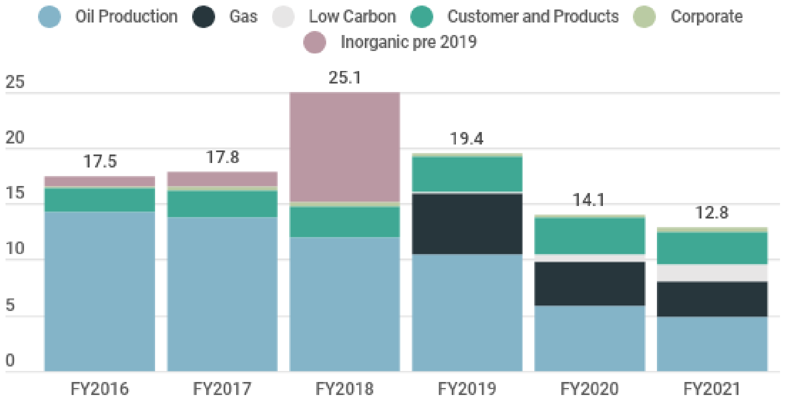

Chart: GCI | Source: Company Data, Global Climate Insights Estimates

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Oil and gas capex. accounted for ~62% of capex. in FY21

Chart: BP capital expenditure (US$bn) - low carbon

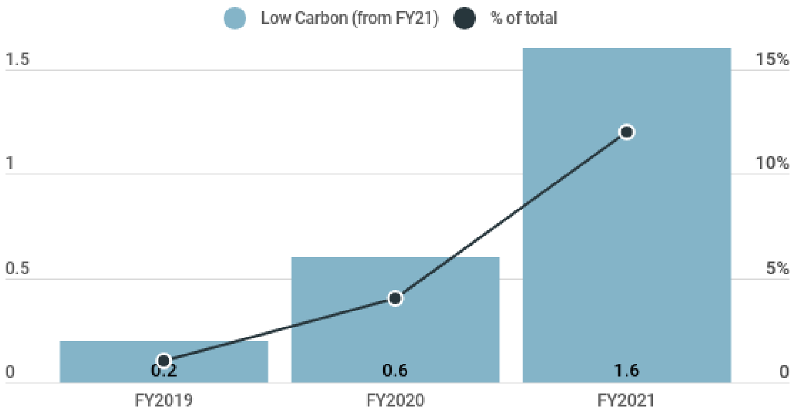

Chart: GCI | Source: Company Data, Global Climate Insights Estimates

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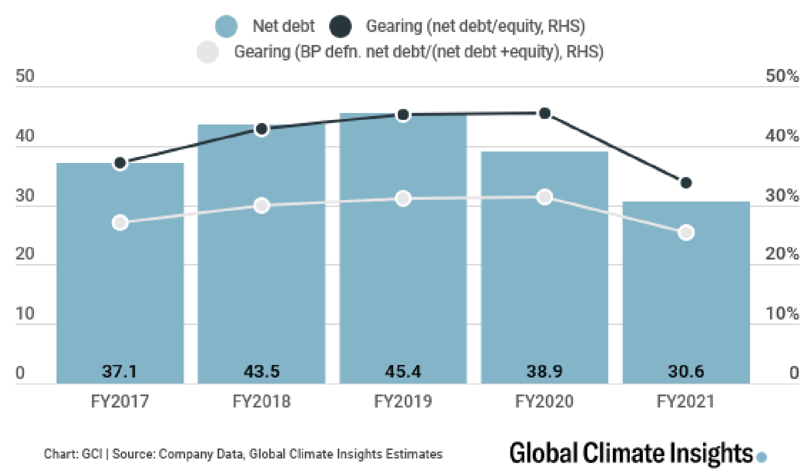
In FY21 BP spent $1.6bn in capex. for its low carbon business, this represented ~12% of group capex.

In FY21 BP states it spent $3.1bn in transition business capex. The remaining $1.5bn attributable to bioenergy, convenience and EV charging.

1.5 Debt

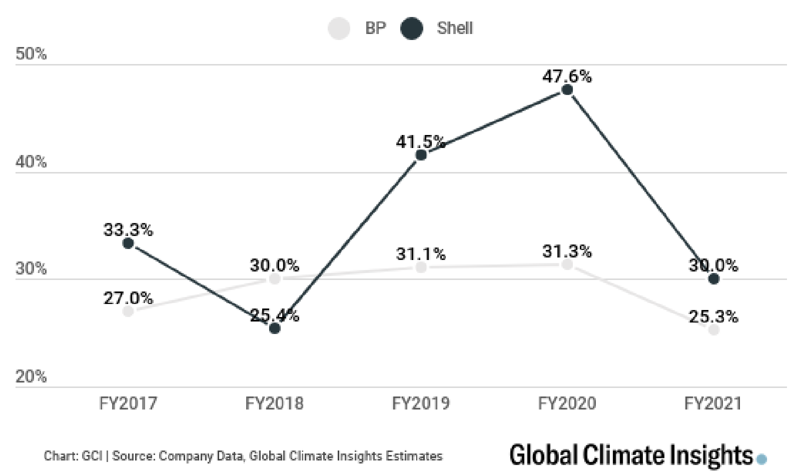
In FY21 results BP announced it had achieved a net debt of $30.6bn, surpassing its $35bn net debt target. Total debt reduced from $72bn in FY20 to $61bn by FY21. Gearing (net debt/equity) was 45.5% in FY20, reducing to 33.8% by FY21. Gearing as defined by BP (net debt/net debt + equity) was 31.3% in FY20, reducing to 25.3% by FY21.

Chart: BP Net Debt (US$bn) and Gearing (RHS, %)



BP had net debt of ~$30bn, and gearing had declined from 31.3% in FY20 to 25.3% in FY21

Chart: BP vs Shell (net debt/net debt + equity, %)



In the last three years BP's gearing has been lower than Shell.

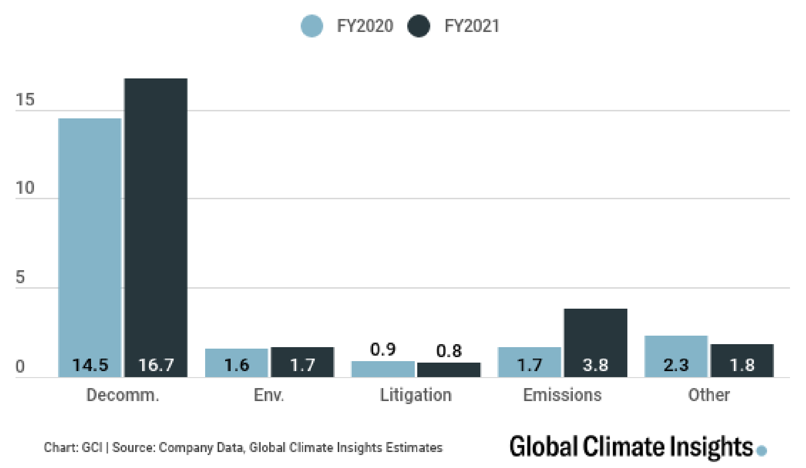
BP gearing at FY21 was 25.3% compared to Shell at 30%

1.6 Decommissioning and other provisions

As at FY21 BP had $25bn of provisions, of which $16.7bn was attributable to decommissioning provisions; this provision represents the present value of future expected costs from decommissioning (the nominal amount was ~$23.8bn)[4]. The remainder of provisions related to the control, clean-up and elimination of environmental pollution ($1.75bn), provisions related to litigation ($0.8bn), obligation for emission allowances under various country regulations ($3.8bn, more than doubled from FY20) and other ($1.8bn). BP reviews the potential costs for decommissioning and environmental liabilities annually.

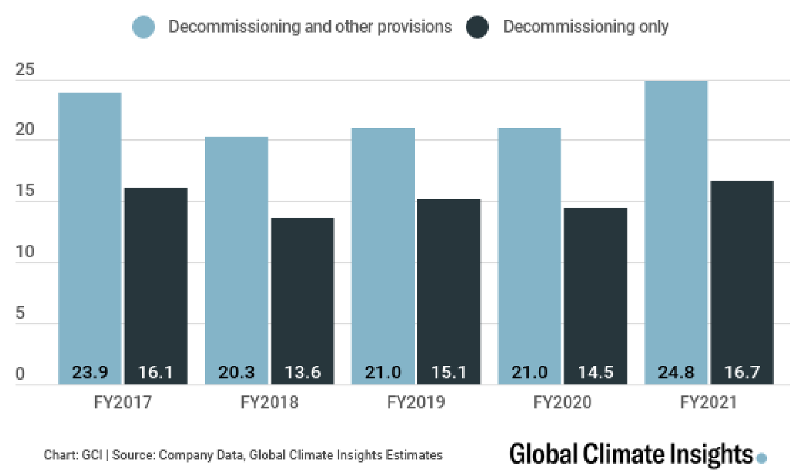
The emissions provision was disclosed for the first time in FY20. BP expects these obligations to be largely settled with allowances included in the inventory line item on its balance sheet.

Chart: FY21 BP Total provisions by type (US$bn)



BP's total provisions in balance sheet were ~$25bn in FY21, decommissioning is the largest accounting for ~67%

Chart: BP Decommissioning provision (US$bn)



BP's decommissioning and other provisions increased by 18% between FY20 and FY21 driven by decommissioning and emission provisions

[4] BP, 2022 [Annual report 2021, p.343]

BP does not provide detail on the key assets that have driven the change in decommissioning provision. The provision relates to the cost of decommissioning upstream oil and gas wells, facilities and pipelines, and does not include downstream assets, given the uncertainty regarding the operational life and requirements of decommissioning these assets. Notably, in FY21 BP recognised a \decommissioning provision relating to assets previously sold to third parties. This is an important outcome given BP's significant divestment program.

Climate change and the pace of the energy transition away from fossil-fuels are likely to influence the level of provisions that are needed in the next decade, across all categories stated above. For the decommissioning provision, we see the key risk being understatement of provisions for upstream assets (reflecting regulatory risk and changing societal expectations), provisions being brought forward, inclusion of provisions for downstream assets, and increasing requirements to fund provisions for divestments - specifically where acquirers are unable to finance the decommissioning costs.

In the FY20 Annual Report, BP provides a sensitivity analysis for assets that are currently included in the decommissioning provisions, noting that a 10% increase in decommissioning costs would increase the group's Upstream decommissioning provision by ~$1.6bn, resulting in an $0.4bn pre-tax charge (reflecting the impact from discounting)[5]. Regarding timing, BP notes in its accounts that bringing forward the timing of decommissioning expenditures by two years would increase its provision by around $0.2bn.

In relation to downstream assets, BP's auditor Deloitte stated in its FY21 review that "in taking into consideration of both the IEA 2021 demand forecasts and management's plans for the production of low carbon and sustainable field, we are satisfied that it is not currently possible for management to estimate reliable a settlement date for any decommissioning obligations prior to a decision being made to cease refining operations"[6]. As at FY21 on BP's balance sheet includes $13.17bn[7] in payables relating to the Gulf of Mexico oil spill.

[5] BP (2022) Annual report 2021, p. 191
[6] BP (2022) Annual report 2021, p. 155
[7] BP (2022) Annual report 2021, p. 233

2.0 Segments

As at FY21, BP reported under four segments; this is expected to be reduced to three post the decision by BP to exit its stake in Rosneft earlier this year. The table below summarises how BP's divisions contribute to its returns. Today BP is still very much a company driven by oil and gas, accounting for ~71% of capital employed and ~73% of underlying profit[8]. The RoACE from oil and gas is largely driven by oil and gas prices, with oil production and operations RoACE ranging from -9 to 10% and gas and low carbon RoACE in the range of 0-17% over the last three years. The contribution of BP's renewable business to returns is unclear given the inclusion of gas within the low carbon segment.

Table: BP segment summary FY20 and FY21 (US$bn)

	Underlying profit (US$bn)		Share of profit	Average capital employed	Underlying profit/ Average capital employed (%)		Key businesses
Segment	**FY20**	**FY21**	**FY21**	**FY20**	**FY20**	**FY21***	
Oil production and operations	-$5.8 bn	$6.2 bn	37%	$64.5 bn	-9%	9.6%	Oil producing regions
Gas and low carbon energy	-$0.08 bn	$5.9 bn	35%	$35.4 bn	-0.2%	16.5%	Gas producing regions, LNG portfolio, Gas marketing and trading, renewables, hydrogen
Customers and products	$2.6 bn	$2.0 bn	12%	$29.4 bn	8.7%	7.0%	Refining and products, bioenergy, convenience, fuels, EV charging, Castrol, aviation, B2B midstream
Rosneft	$0.05bn	$2.5 bn	15%	$12.4 bn	0.4%	19.8%	Rosneft 19.75% share

Source: Company data, Global Climate Insights estimates. * FY21 Underlying replacement cost profit post-tax (pre interest) divided by FY20 average capital employed. Share of profit denominator excludes other business and corporate and consolidation adjustments, the denominator used in FY21 was $16.5bn.

[8] Includes Oil production and operations, and Gas and low carbon energy

2.1 Oil production and operations

Oil production and operations (prior segment Upstream) includes BP's nine oil producing regions: Canada, BPX energy (onshore oil and gas - including its shale business in Louisiana and Texas), Gulf of Mexico (deepwater), Latin America, North Sea, Angola, Russia, Azerbaijan and the Middle East. It includes the production of both oil and gas.

In FY21 the segment delivered $6.2bn in underlying profit (post-tax) an increase from a loss of $5.8bn in FY20. RoACE has ranged from -9 to ~10% over the last five years. FY21 production of oil was 978 kb/d, a 14% decrease from 1,133 kb/d in FY20; this was impacted by the sale of BP's Prudhoe bay oil field. In FY21 BPX energy contributed 116 kb/d (~12%) to oil production. FY21 natural gas production was 1,903 mmcf/d, a decline of 16% from FY20.

BP's oil production and operations segment included in its resilient hydrocarbons stream (which as at FY21 included Rosneft oil and gas production, sales of refined products, bioenergy, and gas marketing and trading). BP aims to sustain resilient hydrocarbons EBITDA at $33bn to FY25, and $30-35bn until FY30. Resilient hydrocarbon capital expenditure is expected to be $9-10 bn p.a. from FY23 to FY25 (~$7.5bn in oil and gas), and $8bn p.a. from FY26 to FY30. Around 70% of BP's oil and gas capital expenditure is expected to be spent on existing hubs and 80% in six regions (which we believe includes Angola, Azerbaijan, Middle East, UK and Norway, US Gulf of Mexico and US onshore).

As part of BP's 2020 strategy update its upstream business has been restructured to deliver operating efficiencies, with BP targeting $1.5 bn of annual cost savings by FY23, relative to FY19. BP has stated this will come from consolidation of hydrocarbon teams, streamline processes and creating digital enabled workflows. BP's target set in FY17 to deliver 900 thousand barrels per day from major projects by the end of FY21 has been met. It is also on track for its target to divest 1.1m boe/d by FY30, with a 0.4m boe/d decline since FY19; this is expected to be predominantly from divestment.

Table: BP oil and gas projects started up in 2021

Project	Hydrocarbon	Description	Peak Gross Production	BP Stake
KG D6 Satellites	Natural Gas	Gas field off the east coast of India	~45 kboe/d	33.33%
Manuel	Oil	Deepwater oil field located in the US Gulf of Mexico	~20 kboe/d	50%
Matapal	LNG	A three-well subsea gas expansion to the existing Juniper platform in Trinidad	~70 kboe/d	70%
Platina	Oil	Expansion to the existing Greater Plutonio floating production located in Angola	~25 kboe/d	46%
Thunder Horse South Expansion Phase 2	Oil	Oil field located in US Gulf of Mexico, around 240 km southeast of New Orleans	~25 kboe/d	75%
West Nile Delta - Raven	Oil	Third phase of the West Nile Delta development in Egypt. The project includes eight wells.	~165 kboe/d	82.75%
Zinia Phase 2	Oil	Nine wells off the coast of Angola	~30 kboe/d	15.84%

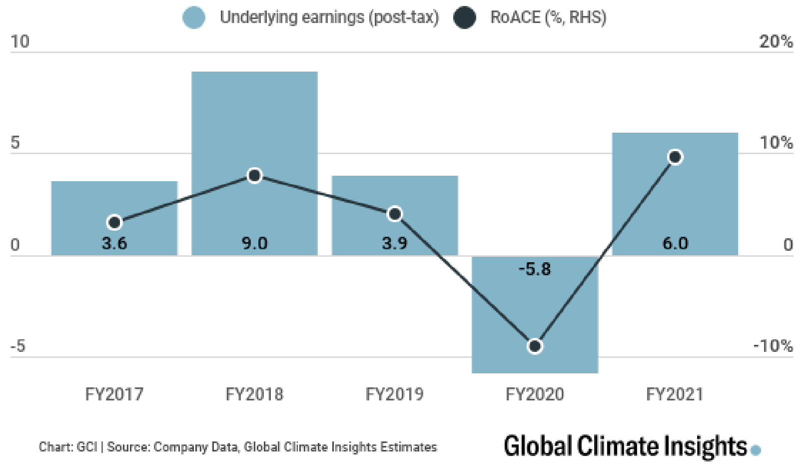
Source: Company data

Table: BP oil and gas projects to be started up in 2022

Project	Hydrocarbon	Description	Peak Gross Production	BP Stake
Cassia Compression	LNG	Construction of a new platform ~56 km off the south-east coast of Trinidad	~1.2 bcf/d ~55 kboe/d	70%
KG D6 MJ	Natural Gas	Third phase of Block KG D6, ~32 km off the east coast of India	~90 kboe/d	66.67%
Mad Dog Phase 2	Oil	New platform ~10 km southwest of existing Mad Dog platform located in the US Gulf of Mexico	~120 kboe/d	60.5%
Tangguh Expansion	LNG	Expansion of the Tangguh facility in Indonesia, including a third LNG process train, 3.8 Mtpa of additional production capacity, two offshore platforms, 13 new production wells, an expanded LNG loading facility, and supporting infrastructure	~115 kboe/d	40.22%

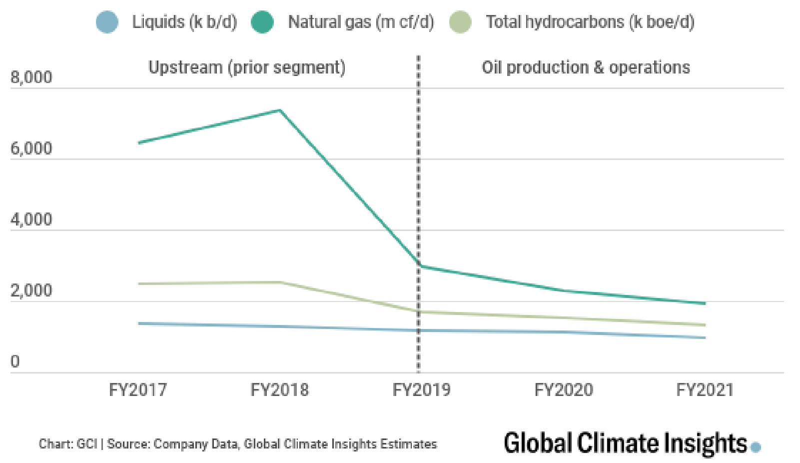
Source: Company data

Chart: BP Oil Production and Operations - underlying profit and RoACE (%)



The last two years since the establishment of the Oil Production and Operations segment has been volatile, delivering RoACE (%) in the range of -9% and +9%

Chart: BP Oil Production and Operations - production



Total production of oil and gas in this segment was 1,307 kboe/d, -14% (-217 kboe/d) on FY20, largely driven by divestments

2.2 Gas and low carbon energy

The Gas and Low Carbon energy segment includes BP's gas producing regions, LNG portfolio, gas marketing and trading (including shipping and risk management), renewables and hydrogen. Bioenergy is part of BP's Customers and Products segment. The Gas and Low Carbon segment includes the production of both oil and gas. BP's renewable business includes its 50% stake in Lightsource bp. Under BP's segment structure (pre FY20) the renewables business was reported as part Alternative Energy in the Other Businesses and Corporate segment.

We are not yet clear of the synergies to oil and gas majors of combining their gas and low carbon businesses, and believe reporting should evolve so there is clearer understanding of the distinct drivers of returns in each business.

In FY21 underlying profit attributable to Gas and Low Carbon was $5.9bn, an increase from an $0.08bn loss in FY20. BP does not at this stage disclose underlying earnings from Low Carbon separately. Underlying profit excludes the impact of 'one-off' adjustments of -$5.4bn. In FY21 the adjustments were driven by -$7.7bn of fair value accounting effects from large increases in forward gas prices (expected to net out once LNG is delivered and if gas prices decline) and ~$1bn gain on sale. The underlying result benefited from strong trading conditions, higher sales and lower write-offs compared with the same period in the prior year.

Table: BP Gas and Low carbon volumes (FY21 vs FY20):

Fuel	FY21 volume	Change on FY20	Targets
Natural Gas production	4,632 mmcf/d	+6%	-4.5% p.a. between FY19-30 (implied CAGR to reach 40% decline)
Liquids production	113 kboe/d	+18%	-4.5% p.a. between FY19-30 (implied CAGR to reach 40% decline)
LNG portfolio (equity share and third-party)	18 Mtp.a.	-10%	25 Mt p.a. by FY25, 30 Mt p.a. by FY30
Installed renewables capacity	1.9 GW	+26%	20 GW of renewable capacity by FY25 and 50GW by FY50 (at least Final Investment Decision
Renewable pipeline	23.1 GW	+120% (largely from wind)	No target
Traded electricity	Not disclosed	214 TWh in FY20	350 TW/h by FY25, 350 TW/h by FY30

Source: Company data

Market position

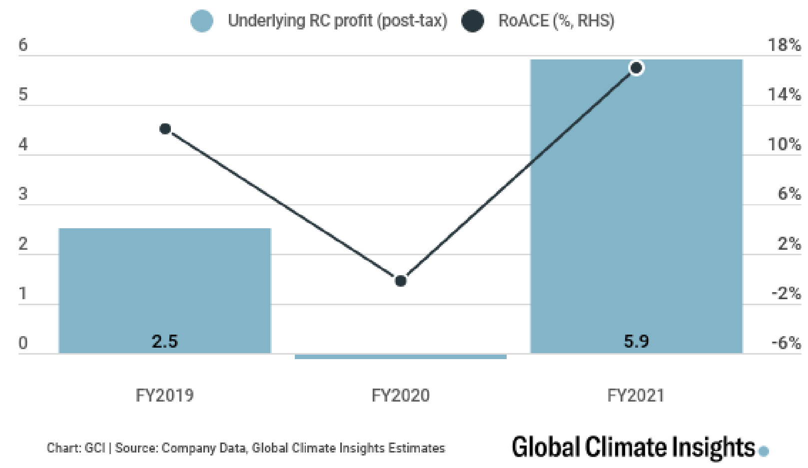
BP has a large presence in the US gas market, and has stated it is the largest US gas and power marketing company. Outside of the US, BP is a large producer of LNG in Indonesia, delivering 37% of production,[9] and has aspirations to grow its domestic gas position in India. BP has a stake in LNG liquefaction facilities in Abu Dhabi

[9] BP (2020) Resilient Hydrocarbons p.21

(Adnoc LNG, 10%), Angola (Angola LNG, 13.6%), Australia (North Western Shelf, 16.67%), Indonesia (Tangguh LNG, 40.22%) and Trinidad (Atlantic LNG, ~39%). BP has stated its LNG is supplied to customers in markets including Argentina, China, the Dominican Republic, India, Japan, Kuwait, South Korea, Taiwan and Thailand.

BP's current bioenergy business appears to largely be based on its 50/50 joint venture bp Bunge Bioenergia, a producer of ethanol from sugar cane waste. Through its 50% stake in Lightsource BP it is one of the largest developers of solar projects, with installed capacity of 1.9GW (BP share) as at FY21.

Chart: Gas and Low Carbon underlying RC profit (US$bn) and RoACE (%)

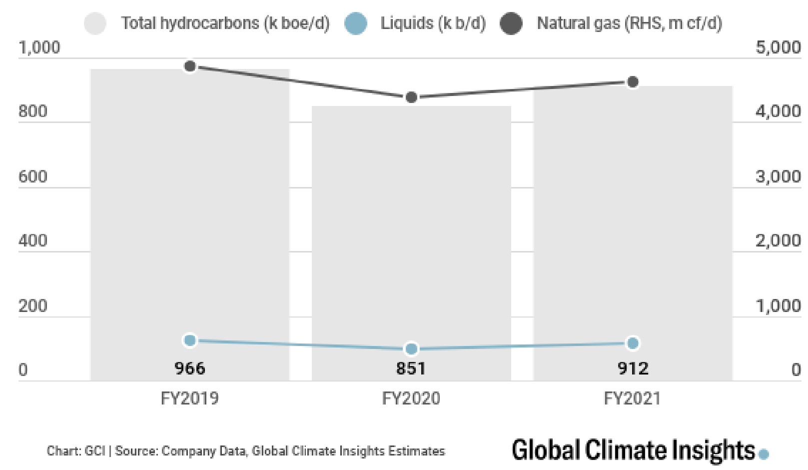


The Gas and Low Carbon segment has been disclosed from FY19, during this time RoACE has been volatile.

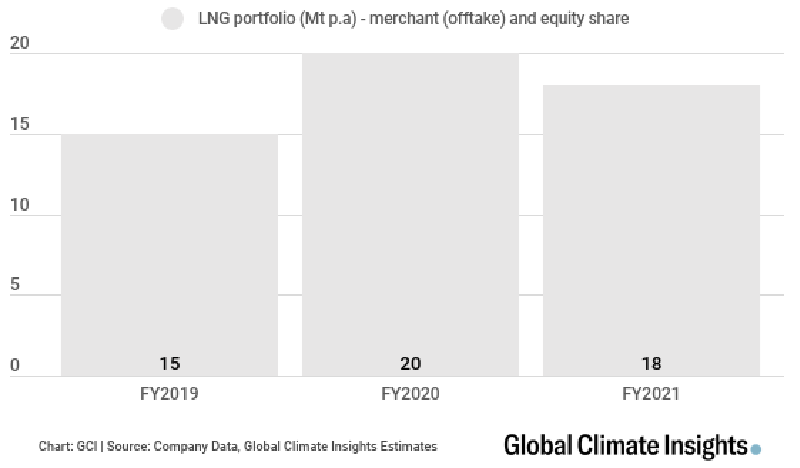
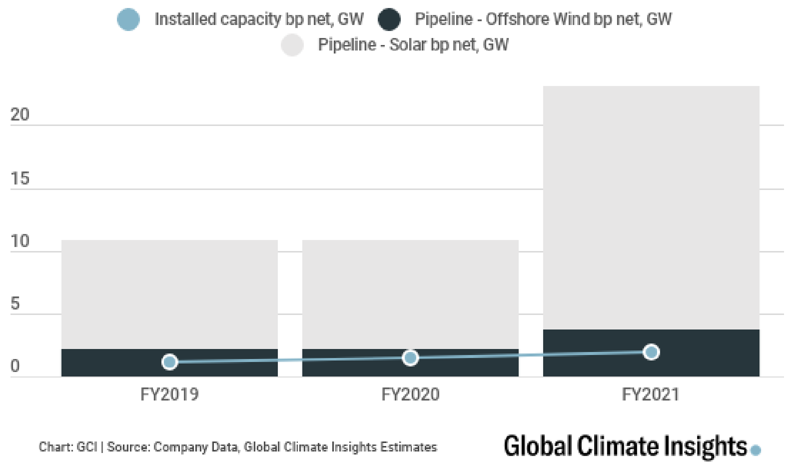
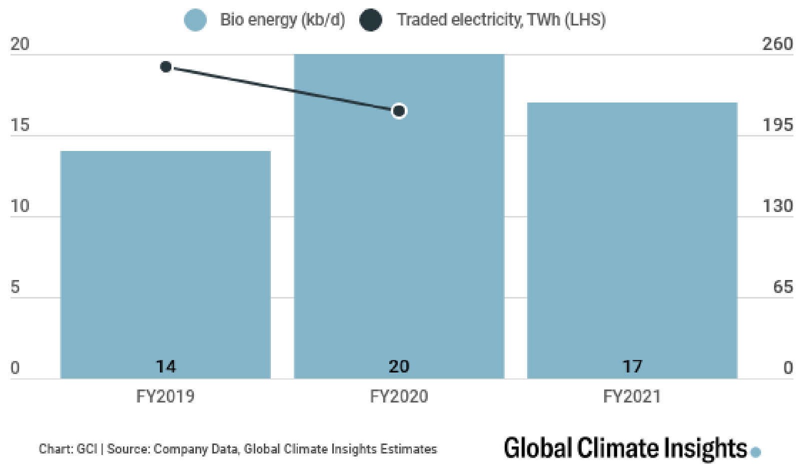
In FY21 the segment delivered RoACE of ~17%.

We see the benefit of BP separately disclosing earnings for Low Carbon businesses to better understand underlying performance.

Chart: Gas segment production



FY21 oil and gas production increased 7% within the Gas and Low Carbon segment to 912 kboe/d.

Chart: BP LNG portfolio (Mt p.a., equity share and third-party) 	BP's LNG portfolio declined in FY21 to 18Mt.
Chart: BP Renewables generation and pipeline (GW) 	As at FY21 BP has installed renewables capacity of 1.9GW, and a pipeline of projects for 23.1GW (more than double FY20).
Chart: BP Low Carbon segment energy generation 	BP's produced 17 kb/d of bioenergy in FY21, a 15% decline from FY20. Traded electricity was not disclosed in FY21. As at FY20 traded electricity of 214 TWh, just under half of its target of 500 TWh by FY30.

2.3 Customers and products

BP's Customers and Products division includes its retail network (fuel and convenience), marketing of fuels, Castrol lubricants, aviation fuels, EV charging businesses, refining, bioenergy and midstream infrastructure.

BP has 20,500 retail sites, a slight increase on FY20; this is still much smaller than Shell at ~46,000. BP has ~13,100 EV charging points, with over half rapid or ultra fast charging which it sees as being higher margin, but is reliant on appropriate electrical infrastructure. BP aims to grow its own and joint venture operated EV charging points from 13,100 in FY21 to over 100,000 by FY30.

In FY21 the Customer and Products segment delivered underlying earnings of $2bn, a 20% decrease on FY20. This was partly impacted by the sale of the petrochemicals business in FY20. We estimate the RoACE was ~7% in FY21 vs ~9% in FY20. In FY21 the majority of underlying earnings pre-tax was attributable to customers (of which Castrol was ~$1bn), with 6% from refining and trading ($0.2bn). The performance of Castrol was negatively affected by higher oil prices and shortages of base chemical additives. BP's average refining margin almost doubled on FY20 to $13.2/bbl.

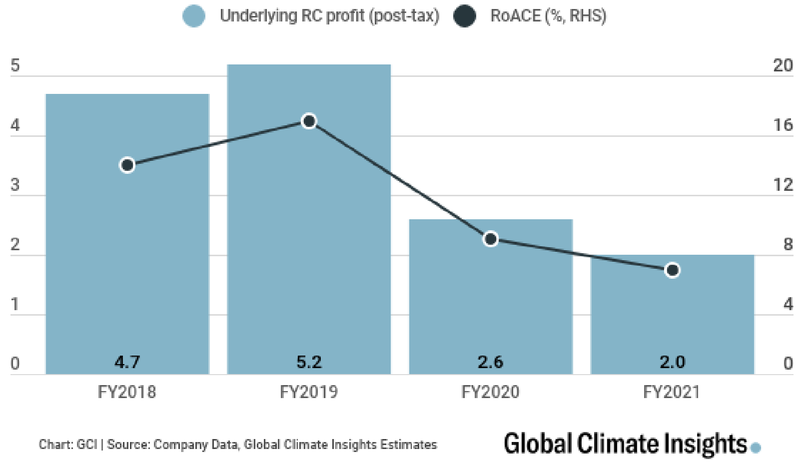
BP has indicated as part of its strategy that it will continue to reduce refining throughput by divesting lower margin assets. In FY21 refining throughput was 1,594 kb/d, a 2% decrease on FY20. BP targets 1,005 kb/d of refining throughput by FY25 and 1,200 kb/d by FY30. Total sales of refined products were 2,832 kb/d, a 5% increase from FY20. BP does not disclose its volume of Sustainable Aviation Fuels separately.

BP plans to increase the size of the convenience and mobility business, doubling FY19 EBITDA by FY30, and delivering a return on average capital employed of 15-20%. Underlying this is a doubling of the FY19 convenience gross margin to ~$2bn by FY30. BP also aims to increase its share of margin from convenience and mobility from 29% in FY21 to ~50% by FY30. At its 3Q21 results BP stated that the number of customers that visit its retail sites that don't buy fuel has risen to between 60% and 70%.[10]

As discussed in our assessment of BP's biofuels aspirations, it plans to increase production of biofuels from 17 kb/d in FY21 to 100 kb/d by FY30.[11] This growth is expected to come from biogas, refinery co-processing and biofuels. BP has also set an aspiration for a 20% market share in Sustainable Aviation Fuel, which under the IEA NZS would equate to ~40 kb/d of SAF by FY30. As we understand, BP currently produces small amounts of SAF at its Castellón refinery in Spain, but mostly appears to be focused on reselling third-party production.

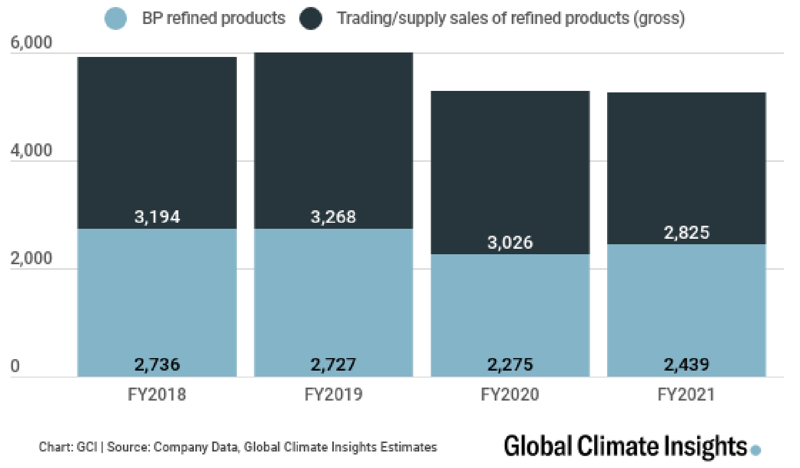
[10] BP (2021) Q3 2021 results Q&A
[11] kb/d biofuels on an ethanol equivalent basis

Chart: Customers and Products underlying profit (US$bn) and RoACE (%)



BP's Customers and Products segment delivered an RoACE of ~7% in FY21, lower than the prior three years.

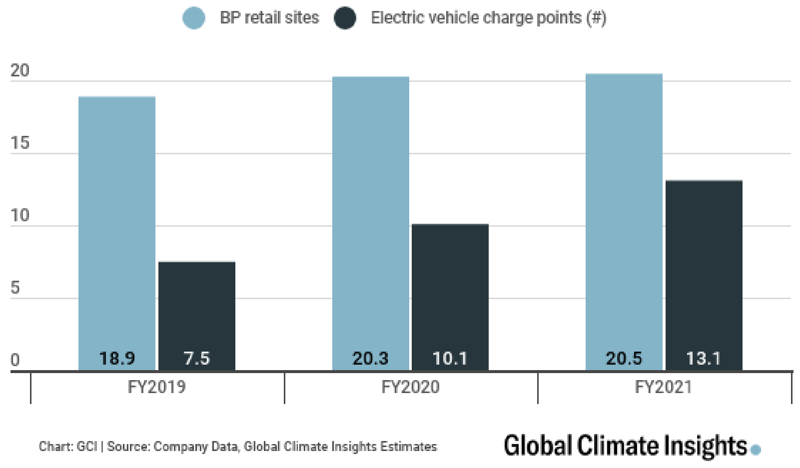
Chart: BP refined product sales (thousand b/d)



BP refined product sales were flat in FY21 at 5,298 kb/d.

We have estimated gross Trading and Supply Sales in FY21 as this has not been disclosed by BP.

Chart: BP distribution network (Thousands)



BP has increased its retail sites by 30% (+3,000) in FY21, electric vehicle charging points increased to 13,100

2.4 Rosneft

Following BP's announcement to exit its stake in Rosneft, and for BP's representatives on the Rosneft board to resign, we have not included BP's share of Rosneft GHG emissions in our analysis. For historical context we have summarised the earnings and production that has been attributable to BP from its 19.75% stake.

Rosneft is Russia's largest oil company. Rosneft has a large upstream operation, producing 5,750 kboe/d of oil and gas in FY19; it owns and operates approximately 13 refineries in Russia and holds stakes in three refineries in Germany, one in India and one in Belarus. BP has stated that Rosneft is a low-cost producer with operating costs at ~US$3/boe. BP's economic interest (share of profit and loss) in Rosneft in FY21 was 22.03%.

Rosneft is listed on the Moscow Exchange (ROSN) and 40.4% is held by a Russian state-owned enterprise. Prior to 2022 BP had two board members on Rosneft, Bernard Looney (CEO) and Bob Dudley (former BP CEO). BP and Rosneft had a Strategic Collaboration Agreement on carbon management and sustainability. Rosneft released a 2035 Carbon Management plan in December 2020.

In FY21 BP's share of underlying earnings (post-tax) was $2.5bn, compared to a $0.05bn in FY20. The higher earnings were driven by higher oil prices and favourable exchange rate movements. BP's share of Rosneft production in FY21 was 1,098 kboe/d and was broadly flat compared to FY20. Rosneft accounted for 24% of BP's oil and 8% of BP's gas production. A total of $2.7bn in dividends has been paid to BP from its holding in Rosneft over the last four years.

Chart: BP share of Rosneft underlying profit (US$bn)

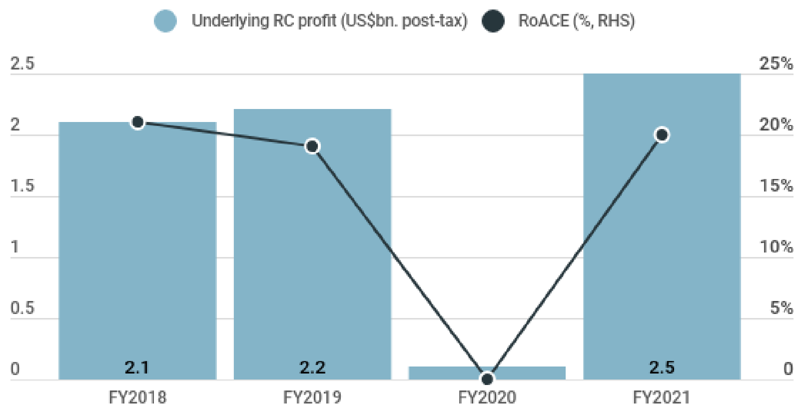


Chart: GCI | Source: Company Data, Global Climate Insights Estimates

BP's share of Rosneft profit was $6.7bn over the last four years.

Chart: BP dividends from Rosneft (US$m)

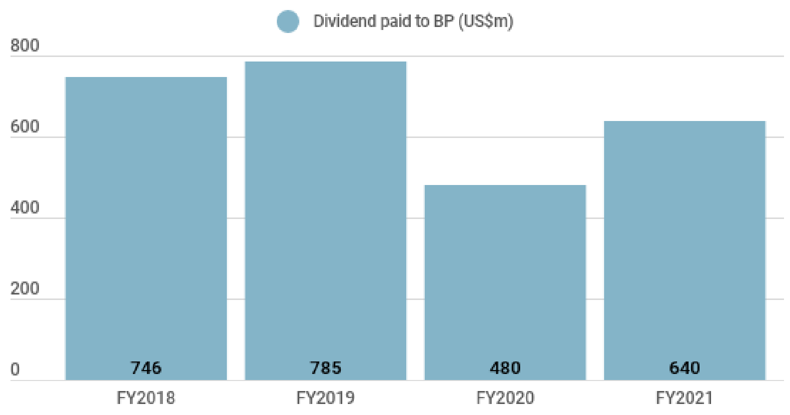


Chart: GCI | Source: Company Data, Global Climate Insights Estimates

BP had received $2.7bn in dividends from its holding in Rosneft over the last four years.

Chart: BP share of Rosneft production (thousand boe/d)

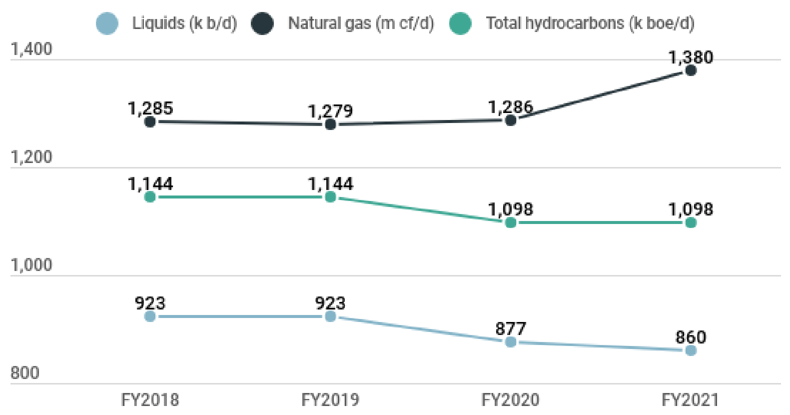


Chart: GCI | Source: Company Data, Global Climate Insights Estimates

BP's share of production from Rosneft has been 4% lower in FY20 and FY21 at ~1,098 kboe/d.

3.0 Definitions

The key terms we use in this report are listed in the table below.

Term	Meaning
Abbreviated definitions of BP terminology	
Physically traded energy	Physically settled derivative sales. Primarily sales to large unbranded resellers and other oil companies.
Marketed energy	The scope of marketing emissions relates to total sales of energy products to an end-user (customer or business). Marketing sales of refined products includes branded and unbranded sales of refined fuel products to business-to-business and business-to-consumer customers, including service station dealers, jobbers, airlines, small and large resellers such as hypermarkets, and the military.
Liquids	Liquids for oil production and operations, gas and low carbon energy and Rosneft comprises crude oil, condensate and natural gas liquids. For oil production and operations and gas and low carbon energy, liquids also include bitumen.
Third-party sales	Energy products purchased from external producers and subsequently sold by BP.
Replacement cost profit	Replacement cost profit before interest and tax (excludes inventory holding gains and losses from profit or loss).
Underlying replacement cost profit	Underlying replacement cost profit before interest and tax (Replacement cost profit as above but also excludes “adjusting items” considered one-off or not reflective of underlying business performance).
Adjusted EBITDA	Adjusted EBITDA is defined as BP’s replacement cost (RC) profit before interest and tax, excluding net adjusting items, adding back depreciation, depletion and amortisation and exploration write-offs (net of adjusting items).
Cash Capital expenditure	As stated in BP’s cash flow statement. Includes organic capital expenditure (investments in building and maintaining assets) and inorganic capital expenditure (external business transactions and acquisition of shares).
Average Capital Employed	Average of beginning and end balance of total equity plus finance debt, excluding cash and cash equivalents and goodwill.

Climate	
Total GHG emissions	In our analysis we use this term to refer to the total GHG emissions from products a company sells. We believe this provides a more holistic picture of the GHG emissions of a business, and is the best way for investors to understand how a company is tracking in its transition away from hydrocarbons.
Absolute GHG emissions	Absolute GHG emissions are the total amount of emissions being released into the atmosphere through a company's value chain. For climate change to slow down, an absolute emissions reduction target is needed. It is also the more effective measure of the climate impact of emissions reduction, in comparison to an intensity reduction.
Carbon budget	There are several types of carbon budgets. In this report, the term refers to the total net amount of emissions that can still be emitted by human activities while limiting global warming to 1.5°C above pre-industrial levels. Net zero emissions describe a situation in which all the anthropogenic emissions are counterbalanced by deliberate removal so that on average, no emission is added or removed from the atmosphere by human activities.
Historical carbon budget (CO_2e)	The historial carbon budget is based on the historical annual mean greenhouse gas emissions from 1750 to 2019, accessed from https://rcmip-protocols-au.s3-ap-southeast-2.amazonaws.com/v5.1.0/rcmip-emissions-annual-means-v5-1-0.csv (see further details on rcmip.org) and 100-year Global Warming Warming (GWP) potentials for greenhouse gases listed in Table 7.SM.7 of the Ch. 7 Supplementary Material (https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter_07_Supplementary_Material.pdf).
Remaining carbon budget (CO_2e)	The Remaining CO_2e carbon budget is calculated using the method outlined here (https://www.climatechange.vic.gov.au/__data/assets/pdf_file/0018/421704/Deriving-a-1.5C-emissions-budget-for-Victoria.pdf) in order to calculate a remaining CO_2e budget to 2050. It is based on the remaining CO_2 budget of 300Gt CO_2 for a likelihood of 83% to stay below 1.5°C global warming relative to 1850-1900 (IPCC (2021) Summary for Policymakers in Climate Change 2021: The Physical Science Basis, Table SPM.2). To be able to use 2020 as a starting year a new intercept is calculated and the linear relationship becomes 1.235x + 249.2. This method accounts for the future earth system feedback and assumes no net negative emissions after 2050. It does not account for the additional warming that occurred prior to 1850-1900. While the term *pre-industrial* is defined by the

	starting year 1750, all IPCC modelling starts at 1850. There is however data and research that shows there has been anthropogenic warming prior to 1850-1900 (IPCC (2021) Summary for Policymakers in Climate Change 2021: The Physical Science Basis, Chapter 5, section 5.5). This would reduce the remaining carbon budget even further.
Carbon neutral	Carbon neutral means any CO_2 released into the atmosphere from a company's activities is balanced by the equivalent amount being removed through post-emissions compensation. It does not account for other greenhouse gases such as methane which can still contribute to increasing levels of global emissions.
Climate Action 100+ Net Zero Company Benchmark	Climate Action (CA) 100+ is an investor-led initiative engaging companies on improving climate change governance, cutting emissions and strengthening climate-related financial disclosures. In 2021 CA100+ launched a framework for assessing company performance on climate transition for high-GHG emitting stocks. The framework includes key indicators covering targets, strategy and governance.
IEA Net Zero Emissions Scenario (NZE), IEA NZS	A scenario produced by the IEA (2021) as part of its report Net zero by 2050: A roadmap for the global energy sector. It is one scenario that illustrates how energy demand and the energy mix will need to evolve if the world is to achieve net zero emissions by 2050.
Net GHG emissions	Net emissions, typically associated with 'net zero', are a company's emissions footprint after accounting for post-emissions compensation. These are not necessarily 'negative emissions', as envisaged by the IPCC illustrative mitigation scenarios. Corporations should aim to thrive in a zero emissions economy, rather than 'net zero' in any particular year.
Post-emission compensation technology	Carbon offsets and carbon capture are both post-emission compensation measures. We consider both in our assessment of company targets but separately from the measures that reduce emissions from being released in the first instance.
Task Force on Climate-Related Financial Disclosures (TCFD)	The TCFD was created in 2015 by the Financial Stability Board (FSB) to develop consistent climate-related financial risk disclosures for use by companies, banks, and investors in providing information to stakeholders to support informed capital allocation.
Science Based Target initiative (SBTi)	The SBTi is a partnership between CDP, the United Nations Global Compact, World Resources Institute (WRI) and the World Wide Fund for Nature (WWF). It aims to define and promote best practice in emissions reductions and net-zero targets in line with

	climate science. It independently assesses and approves company targets in line with strict criteria.

Source: Company data, Global Climate Insights

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