BP’s focuses $100 million on reducing emissions

HOUSTON – BP has announced that it has established a $100 million fund for projects that will deliver new greenhouse gas (GHG) emissions reductions in its upstream oil and gas operations. The new Upstream Carbon Fund will provide significant further support to BP’s work generating sustainable greenhouse gas emissions reductions in its operations.

In April 2018, BP set clear, near-term and specific targets aimed at reducing its emissions and advancing the energy transition, including achieving 3.5 million tons of sustainable GHG emissions reductions across the BP Group from 2016 to 2025 and targeting a methane intensity of 0.2%.

In the year since, BP’s total directa GHG emissions fell by 1.7 MMt CO_2equivalent, despite a 3% growth in upstream oil and gas production on the same basis. By the end of 2018, BP had generated 2.5 MMt of sustainable GHG emissions reductions throughout its businesses since 2016. BP's methane intensity for 2018 was 0.2% – in line with the target.

Upstream chief executive Bernard Looney said, "A year ago we challenged everyone at BP to reduce emissions in our operations and they have responded overwhelmingly. This $100 million investment is designed to build on that momentum. It will fund ideas both big and small because everything counts in our transition to a lower carbon future and everyone at BP has a role to play."

Under the new initiative, funding totaling up to $100 million will be made available over the next three years to support new projects in the upstream that will generate additional GHG emission reductions. Businesses and employees throughout BP's Upstream operating businesses are being invited to come up with ideas and propose projects for this funding.

The Upstream Carbon Fund will be in addition to the $500 million that BP invests in low carbon activities each year, including investment in venturing activities and into its significant alternative energy business. BP is also a founding member of the Oil and Gas Climate Initiative, which brings together 13 of the world's largest energy companies and has set up a $1 billion investment fund to address methane emissions and other issues.

BP's targets for reductions in operational emissions are part of its 'reduce-improve-create,' or RIC, approach to the energy transition, which also aims to improve its products to allow customers to reduce their emissions and to create and grow new low carbon businesses. The projects that are awarded funding will help to deliver the further emissions reductions necessary to achieve the RIC targets.

The announcement of the new fund is a further step in BP's work to meet its targets and advance the energy transition. In January, BP announced that progress towards the sustainable emissions reductions target has now been incorporated as a factor in the remuneration of 36,000 employees across the Group.

The ‘new reality’ of the oil and gas sector

The “new reality” that Oil & Gas UK has identified in its new Business Outlook highlights the significant pressures that those operating on the UKCS continue to grapple with, as the industry strives to remain competitive and sustainable.

Certainly, the current environment has challenges. Continued market uncertainty is reinforcing investor caution, indicating a conservative outlook for prices. This has meant that the laser focus on costs, budgets and efficiencies, which has been so crucial to the industry in recent years, must continue to be the norm across the sector.

However, it is important to stress that the latest Business Outlook also draws out some of the many positive outcomes that have resulted from better collaboration, new ways of working and greater focus on technology and innovation that have been adopted over the last 5 years. The industry is working better, smarter and more efficiently, and capable of maintaining global competitiveness.

The improvements in production, production efficiency and new field approvals which feature in this year’s Outlook help to demonstrate the industry’s ongoing resilience and optimism. Following 14 years of decline, production has increased by 20 percent over the past five years, while momentum around exploration activity has increased, with up to 15 exploration wells expected to be drilled this year, including some potentially high-impact prospects.

Additionally, the on-going levels of M&A activity indicate that the appetite to invest in the basin continues to be positive. That much of this activity in 2018 related to the transfer of assets, helping to ensure that investment opportunities are in the most appropriate hands, and creating a more diverse landscape, is hugely encouraging given the importance of this in achieving MERUK.

However, fresh and forward-thinking approaches to collaboration and business models that take into consideration trust, technology and transformation in the oil and gas industry remain crucial to ensuring the UKCS’s competitiveness and longevity as well as supporting that of its critical supply chain mass. While there have been positive changes towards this, there is much more that can still be done.

The industry needs to move forward together to unlock the £200bn that OGUK has reported to be required to achieve Vision

2035 – adding another generation of productive life to the basin. By building on the momentum now established, and with a continuing focus on our "new reality", this definitely looks to be achievable.

European Parliament approves Clean Energy for All Europeans package

The European Parliament has adopted the new Electricity Regulation and Electricity Directive, concluding the political negotiations on the Clean Energy for All Europeans package. The regulation now requires to be formally approved by the Council. It will then enter into force immediately (with a date of application of 1 January 2020 for the Electricity Regulation) and has to be transposed into national law within 18 months.

The revised Electricity Regulation opens up electricity markets to renewables, energy storage and demand response. It also introduces stricter and harmonised rules for capacity mechanisms and enhances regional coordination in order to improve market functioning and competitiveness. Under the new rules, new thermal power plants emitting more than 550 gCO_2/kWh will not be allowed to benefit from the capacity mechanism, while existing power plants emitting more than the 550 gCO_2/kWh threshold will be allowed to participate in capacity mechanisms until July 2025 only.

The Clean Energy for All Europeans package is expected to enable the European Union to realise the energy transition, follow up on the 2030 climate legislation and meet the Paris Agreement commitments.

America emerges third-biggest holder of LNG export capacity

Bloomberg/New York

Just three years after it began sending liquefied natural gas overseas, America now trails only Australia and Qatar in the volume of the fuel it’s capable of exporting.

The US jumped ahead of Malaysia with the startup of Cheniere Energy Inc’s LNG terminal in Corpus Christi, Texas, data from BloombergNEF show. And the race is just getting started: US export capacity, currently accounting for 8% of the world total, will more than double as projects under construction are completed.

More than a dozen projects are vying to be part of the so-called second wave of US LNG development, seeking to capitalise on the surge of production from shale basins. Though global gas demand is climbing as nations switch to the cleaner-burning fuel from coal, American shipments will compete with supplies from Qatar and Russia.

Cheniere shipped the first cargo from Corpus Christi in December, and a fifth LNG production unit at its Sabine Pass terminal in Louisiana received US approval this month to start service.

Though the US is already in third place in terms of global export capacity, the Cheniere projects “will be what nudges the US up to third place in terms of supply into market – overtaking Malaysia on export volumes, including on a monthly basis," Fauziah Marzuki, an analyst with BNEF in Singapore, said in an e-mail. "Russia isn't too far behind" as it exports from Siberia, but America should have the lead with the startup of three more terminals this year, she said.

Shell makes aggressive move into UK retail power market

Bloomberg/London

Royal Dutch Shell Plc took a step forward in its aim to become the world's biggest power company with an aggressive move into the UK retail market by offering one of the cheapest tariffs available.
Shell Energy, formerly known as First Utility Ltd, said yesterday it has a fixed rate power-supply tariff for UK customers of about £970 ($1,278) a year, or about 81 pounds a

month until July 2020. The move is part of its rebranding of its UK utility business.

This undercuts former cheapest UK power supplier Bulb Energy Ltd, which has a deal available for £981 a year, and is around 18% cheaper than power supplied by Centrica Plc-owned British Gas, according to data from UK power regulator Ofgem.

Shell plans to become the world's biggest power company within 15 years and is spending as much as $2bn a year on its new-energies division, a move that suggests it sees climate change as a significant threat to the fossil fuel business.

"Shell has been increasingly vociferous about its ambitions in electricity markets, and we see it as a significant competitive/disruptive force over the coming years for traditional utility energy suppliers/retailers," RBC Capital Markets LLC said in a note yesterday.

The bank said Shell's plan to invest about $1bn-$2bn a year on its new energies division is only 5% of the company's annual capex and "hence has significant room to grow." It added that it's "difficult to rule out" Shell buying other UK-based utilities such as the retail unit of SSE Plc or Npower Ltd, which are both up for sale.

The move will bring yet more pressure to the UK power market which has seen swaths of customers abandon the traditional Big Six utilities for smaller, cheaper suppliers. Surging wholesale prices for power and gas have driven several companies out of business. Last year, more businesses folded than in the previous 16 years combined. Brilliant Energy, which has about 17,000 domestic customers, became the 10th firm to cease trading in the past 12 months on March 11.

Britsh Gas, which lost 742,000 customers last year, held a 19% share of the UK's electricity market in the third quarter of 2018, according to Ofgem. Bulb, which has about 1mn customers, had a 3% stake in the market.

As well as announcing the rebranding, Shell also said it has switched its existing 700,000 UK customers to power supplied entirely by renewable sources of energy such as wind, solar and biomass.

“Shell recognises the world needs more energy with lower emissions and this will give customers more flexibility, greater control and cleaner energy,” said Mark Gainsborough, executive vice president of Shell New Energies US LLC.

Newly rebranded Shell Energy will also offer a range of smart home devices, such as thermostats, and discounts on home electric vehicle chargers for its customers.

“We are building on the disruptive nature of First Utility to give customers something better,” said Colin Crooks, chief executive officer of Shell Energy Retail Ltd. “We know that renewable electricity is important to them and we are delivering that, while ensuring good value and rewarding loyalty.”

Alongside First Utility, Shell has made other acquisitions in power including car-charging operator NewMotion and a stake in US solar company Silicon Ranch Corp. It has also announced it’s bidding for Dutch utility Eneco Group NV, which provides low-carbon power to industrial users and offers apps and other technology to manage electricity consumption. Shell also entered a bid to expand an offshore wind farm in the Netherlands.

Norway Deals a Blow to an Oil Industry That’s Quickly Losing Friends

The decision of the world's largest sovereign wealth fund to reduce holdings in oil stocks wasn't as far-reaching as the industry feared, but dealt a symbolic blow to fossil fuels that will reverberate for energy companies and their investors.

While the divestment by Norway's $1 trillion fund doesn't include Big Oil, instead rooting out $7.5 billion of companies that focus purely on exploration and extraction, the impact of the announcement rippled through the sector. Shares of all oil companies initially plunged on the news, suggesting the move sets the industry up for greater disruption.

It's a bitter taste of the new reality for oil producers, which increasingly have to fight for investor dollars rather than enjoying the perks of being indispensable to the global economy.

"The Norwegian sovereign wealth fund is seen as something of a poster-child amongst sovereign wealth funds," said Alejandro DeMichelis, director of oil and gas research at Hannam & Partners LLP. "This decision could also trigger other large investors to review their stance toward investing in the oil and gas sector."

Life is changing for oil companies. Ten years ago, they accounted for about 15 percent of the S&P 500 index. Today, they make up just 5 percent, having been mostly displaced by technology giants such as Facebook Inc. and Apple Inc.

Driving this shift is a smorgasbord of new energy sources that's bringing unprecedented competition for capital. Consumer choices are set to drift farther from the hydrocarbons of the 20th century, with renewables potentially meeting about a quarter of demand by 2040, according to oil major BP Plc.

It's no surprise, then, that investors are increasingly questioning the wisdom of betting on oil and gas. A divestment campaign started by activist group 350.org in 2012 has already persuaded funds holding $8 trillion to back away from fossil fuels, according to its website.

Scrutiny could intensify as AGM season approaches. Catherine Howarth, chief executive officer of ShareAction – a group that has targeted Royal Dutch Shell Plc in the past – said she expects a "ramp-up" of pressure at annual general meetings that start in the spring.

'Vulnerable' Industry

"Institutional investors are withdrawing their capital from oil and gas companies on the grounds that quicker-than-expected growth in clean energy and associated regulation is making oil and gas business models highly vulnerable," Howarth said in an email.

It's not only oil companies facing pressure. One of the world's biggest sellers of coal, Glencore Plc, yielded to investor demands earlier this year by promising to limit production of the fuel and align the business with Paris climate targets. In oil and gas, Shell and BP have made pledges around transparency and climate after facing the wrath of shareholders.

The list of companies to be excluded from the Norwegian fund includes Anadarko Petroleum Corp., Cnooc Ltd. and Tullow Oil Plc. Shale producers like EOG Resources Inc., which extract fuel from the heartland of America’s oil and gas boom, are also included.

Higher Costs

In the longer term, a dearth of capital will push up the cost of borrowing to explore for oil and gas, with those costs likely passed on to consumers, according to Georgi Slavov, head of research at energy broker Marex Spectron. That makes renewables comparatively cheaper, further pushing fossil fuels out of the market.

While Shell, BP and other oil majors were spared in Norway’s decision on Friday, they may yet be earmarked for divestment in the future.

“The country may eventually revisit the issue and target such holdings,” said Rob Barnett, an analyst at Bloomberg Intelligence. In particular, the fund could consider shedding “integrated companies not allocating a portion of their capital spending toward clean energy.”

For those oil companies moving to diversify, there’s light at the end of the tunnel. In its statement, Norway said some of the biggest investments in renewables now come from Big Oil. The fund “should be able to participate in this growth,” the Finance Ministry said.

“While the fund was initially built on revenue from oil and gas, the Ministry of Finance understands that the future belongs to those who transition away from fossil fuels,” said Mark Campanale, founding director of energy researcher Carbon Tracker. “Now is the time for smart investors around the world to follow their lead and make decisions driven by the reality of the energy transition.”

CCUS is a stopgap to a big hydrogen world

As a proponent of hydrogen being key to the UK’s atmospheric decarbonisation drive, I am concerned that hydrogen receives so little press when compared with carbon capture and storage (CCS).

CCS, to my mind, has some serious flaws; the major concern being that CCS has a large parasitic energy load.

To provide the energy required for CCS means that more hydrocarbons have to be combusted, which in turn means more carbon dioxide (CO_2) is produced.

The parasitic load for the CCS compressors, dryers and CO_2 absorption plant typically requires 15-30% more fuel.

Of course around 90% of the CO_2 is captured by the CCS plant so what’s the problem?

The additional 15-30% fuel has to be supplied by the oil and gas producers, the consequence being that the associated energy use in production will increase.

The upshot is the additional harmful emissions of CO_2, nitrous oxide, sulphur dioxide and particulates from the producing plant. Also CCS does not address the huge swathe of emissions from transport.

CCS could be combined with hydrogen production. The main industrial process for hydrogen production is steam methane reforming (SMR).

Here, methane (natural gas) is combined with water (steam) to produce hydrogen and CO_2. The two reaction products are separated with the CO_2 vented to the atmosphere and hydrogen used as a feedstock to multiple processes.

A CCS plant is bolted on to deal with the CO_2, thus a combined CCS and SMR plant would produce low carbon hydrogen; the hydrogen being used as carbon free fuel for power and transport.

This combined process is termed carbon capture utilisation and storage (CCUS). Hydrogen-based CCUS is an improvement over CCS but, like CCS, it requires more hydrocarbons to be produced to feed and fuel the process.

An alternative is to produce hydrogen by seawater electrolysis using renewable energy – a process that produces no CO_2 or other harmful emissions. A process that can also use surplus renewable energy and has an almost limitless, free feedstock.

Electrolysis though is viewed as too expensive when compared to SMR but that is changing.

Shell and others are investigating electrolysis as a competitive route to large scale hydrogen production. Are we in a similar position with hydrogen by electrolysis as wind power was a decade or so back?

Wind was viewed as commercially unattractive but that position has changed as offshore wind technology has driven the cost of electricity production down.

“CCS is a false climate solution that bolsters big oil” claim Greenpeace. I am not quite there but I do understand Greenpeace’s position – CCS requires the extraction of more fossil fuels hence could be viewed as a favourable option for oil and gas companies.

Whilst the government and other commentators believe CCS/CCUS is essential to meet the UK’s climate goals, I remain to be convinced. CCS/CCUS feels like a blunt, end of pipe, short term solution.

There is some excellent hydrogen research and development being undertaken through government and industry initiatives, but are we putting sufficient effort and funding into its development? CCS/CCUS is a stopgap to a big hydrogen world. We should bypass CCS/CCUS and deliver on hydrogen.

Finally, hydrogen will not solely deliver on decarbonisation – energy efficiency, land use, renewables and battery power all have their part to play.

Carbon emissions leap as global growth strengthens fossil fuel demand

Carbon emissions from fossil fuel use hit a record last year after energy demand grew at its fastest pace in a decade, reflecting higher oil consumption in the U.S. and more coal burning in China and India.

Those findings from the International Energy Agency mark a setback for the effort to rein in the pollution blamed for global warming just three years after a landmark deal in Paris where all nations committed cut emissions.

The figures showed that natural gas is becoming a preferred fuel for factories and utilities while the pace of installing renewable forms of energy is lagging. The report also indicated the strength of the global economic expansion last year, with gains in electricity consumption and more notably in the U.S.

“We have seen spectacular growth of the economy in the U.S.,” said Fatih Birol, executive director of the Paris-based institution advising nations on energy policy. “We have seen several new petrochemical projects coming on line.”

Energy demand grew 2.3 percent last year, the most in a decade, according to the IEA. It showed a record 33 gigatons of carbon emissions from energy, up 1.7 percent from the previous year. Global electricity demand rose 4 percent and was responsible for half the growth in overall energy demand.Global coal demand grew for the second consecutive year in 2018, driven by Asia’s appetite for the dirtiest fossil fuel. Even as coal’s share of the global energy mix declined, it remains the world’s largest source of electricity. Natural gas use rose 4.6 percent, its fastest growth since 2010.

The U.S. increased its use of oil products at a faster rate than any other country for the first time in 20 years, overtaking China. The U.S. boosted oil use by 540,000 barrels a day, a fifth more than China even though the Asian nation has four times the population and is moving toward a less oil-intensive model in order to improve its urban air quality.

The pace of energy efficiency improvements fell, and renewables growth is didn’t keep pace with surging electricity demand, falling below 50 percent of new power supply last year.

Global output of greenhouse gases from energy-related sources rose to a record as energy demand jumped at its fastest pace in a decade.

“Renewables growth is not keeping pace with the electrification of our society,” Birol said on a call with reporters. “We need to see more support for renewables.”

Global energy-related emissions hit an all-time high in 2018 of 33 billion tons of carbon dioxide, a growth rate of 1.7 percent, which represents the fastest increase since 2013. Coal-fired power plants, which are closing across western

Europe, were the single largest contributor to the growth in emissions, accounting for 30 percent of the increase, the IEA said.

Emissions are still increasing in China and India. The U.S. saw an increase of emissions after they fell in 2017. Germany, Japan, Mexico, France and the U.K. all saw declining output.

The world needs to cut the use of coal-fired power to almost nothing by 2050 to get anywhere close to limiting global warming to 1.5 degrees Celsius, a panel of United Nations scientists said in a report last year.

Shell boosts its bet on U.S. LNG exports

Royal Dutch Shell PLC and Energy Transfer LP said they are pursuing plans to convert a liquefied-natural-gas import facility in Louisiana into an export terminal, a bet that the future of U.S. shale gas lies in selling it for higher prices in overseas markets.

The Anglo-Dutch energy giant and U.S. pipeline operator said they are putting contracts out for bid to engineers and construction companies to reconfigure Energy Transfer's existing import facility in Lake Charles, La. The proposed facility would have the capacity to ship 16.5 million tons of U.S. natural gas a year, the companies said Monday.

"You can model and study it but the best way is to go out to tender and get a price that someone is willing to commit to," Maarten Wetselaar, Shell's director of integrated gas and new energies, said in an interview Monday in New York. "We are done theorizing on it; we just want to find out."

The move comes amid a prolonged period of low natural-gas prices in the U.S., where futures for April delivery settled Monday at $2.755 per million British thermal units. That is up 5% from a year ago but still low enough to put financial pressure on the producers that have flooded the domestic market with shale gas in recent years.

Shell and Energy Transfer own equal economic stakes in the Lake Charles project, which was built at a time when many believed the U.S. was running low on gas and would rely on imports. The partners will decide together whether they should proceed with converting the Louisiana terminal pending the outcome of bidding and their analysis of the global LNG market.

One key factor, Mr. Wetselaar said, would be finding the 5,000 workers the companies estimate they will need to build the export facility. Labor might be particularly tight at a time when Exxon Mobil Corp. and Qatar Petroleum have announced they will build a rival export terminal nearby in Texas.

Mr. Wetselaar said the Lake Charles plant should have advantages over competitors because much of the necessary infrastructure has already been built. “If you can be the cheapest Gulf Coast project, then you’ll always be in the money because it’s such a big source of supply,” he said.

U.S. LNG exports have surged since early 2016. There are now three export facilities operating from the U.S. mainland, with several more slated to come online over the next few years as big energy companies seek to mop up the cheap shale gas and ship it in liquefied form to customers overseas, where the price is better.

China has emerged as a key buyer of U.S. gas as the country combats air pollution by replacing coal-fired power plants with those that produce electricity from cleaner inputs, such as natural gas, wind and solar.

Lately, LNG prices in Asia have sunk below $5 per million British thermal units, their lowest level in nearly three years. Shell, which supplied roughly 25% of China’s LNG last year, is bullish on the market regardless of current price moves because of the Chinese government’s goal to boost the amount of gas used to produce electricity there to 15% from about 7% by 2030, Mr. Wetselaar said.

“Even if the Chinese economy decelerates, the quest to clean up the air in the big cities is going to continue,” he said.

Houston investment bank Tudor, Pickering, Holt & Co. told clients on Monday that the recent weakness in global LNG prices may prompt U.S. exporters to schedule extended downtime for maintenance this summer or to delay starting up new facilities if international prices languish. LNG export facilities have been counted on to absorb domestic production that has been soaring to new highs, and delays could push local prices lower.

“With the U.S. accounting for more than 80% of global new export capacity expected online through 2020, U.S. gas prices will become progressively more influenced by the strength of the Chinese economy," Barclays analysts said in a report last week.

Shell, which last year accounted for about a quarter of all LNG sold globally, has already committed, along with several large Asian investors, to build a $30 billion LNG export facility in British Columbia that will transport gas gathered in western Canada to markets abroad.

Shell's leadership staked the company's future on natural gas in 2016 with the $50 billion purchase of rival BG Group PLC, a major player in LNG markets.

In the U.S., natural gas surpassed coal in 2016 as the top fuel for generating electricity. The U.S. Energy Information Administration on Monday said gas widened its lead over coal in 2018, accounting for 35% of electricity generation, compared with coal's 27%. Overall, domestic natural-gas consumption rose 10% last year to an all-time high, the EIA said.

Claim that LNG is no greener than coal gets new scrutiny

One of the biggest bites ever taken out of greenhouse gas (GHG) emissions in any developed country is one that environmentalists and renewable energy advocates never seem to mention.

Since 2005, energy-related GHG emissions in the U.S. have fallen by 14%.

While some of those lower emissions can be attributed to renewable energy investments, the emissions decrease was “mainly” due to natural gas displacing coal power, according to the U.S. Energy Information Administration (EIA).

When burned for power, natural gas produces 50% to 60% fewer carbon dioxide emissions than coal does.

Proponents of B.C.’s nascent liquefied natural gas (LNG) sector, including the BC NDP government, have therefore promoted the environmental advantage of LNG, since the biggest market is Asia, where LNG would presumably replace coal power and backstop intermittent renewable energy.

But environmentalists opposed to fossil fuels claim that “fracked gas” is as bad as coal or even worse, in terms of its global warming potential, due to fugitive methane emissions.

David Suzuki recently made the claim, accusing Prime Minister Justin Trudeau of hypocrisy in committing to climate change targets while supporting the $40 billion LNG Canada project.

“He proudly announced approval of a $40 billion facility to liquefy fracked gas, calling it a transition fuel to help China reduce coal dependence, even though fracked gas has a carbon footprint at least as bad as coal (because of fugitive methane release),” Suzuki recently wrote.

So are natural gas and LNG really worse than coal?

“I don’t know,” said John Werring, senior science and policy adviser for the David Suzuki Foundation, who was co-author of a study that estimated fugitive methane emissions in the Montney play of B.C. to be 2.5 times higher than those reported by industry and government.

“There’s not enough information to make that determination,” Werring said.

Measuring and monitoring of methane from the oil and gas sector in B.C., and elsewhere, is still inadequate, according to a recent report for the C.D. Howe Institute.

And until there is better baseline data, the LNG industry will remain vulnerable to the claim that it’s no better than coal. It will also be impossible to apply carbon taxes to upstream methane emissions, or properly report on whether it is meeting a 45% reduction target.

“The magnitude of these emissions is unresolved,” says the C.D. Howe Institute report, written by Sarah Jordaan at Johns Hopkins University and Kate Konschnik at the Nicholas Institute for Environmental Policy Solutions at Duke University. “Policy-makers are thus left without defensible evidence describing the trends in methane emissions from the oil and gas value chain over time.”

The claim that natural gas may be as bad as, if not worse than, coal, from a global warming perspective, appears to be based largely on a 2011 study by Cornell University ecologist Robert Howarth, who concluded that, due to methane emissions, the GHG footprint of natural gas from shale production could be 20% to 50% higher than that of coal.

That study was rebutted by Howarth's own colleagues at Cornell, who said in a paper that Howarth had significantly overestimated fugitive methane emissions.

A scientific panel report on fracking in B.C. that was published last week points out the Howarth study assumed that natural gas is released in large volumes as blowback during well completions. In B.C., that blowback is contained, by regulation, either through "green completions" or flaring, the panel noted.

Methane, the GHG problem child

Methane is the problem child of GHGs. It does not persist in the atmosphere as long as CO2, but it is magnitudes worse in terms of its heat-trapping properties.

Whereas the CO2 produced from combustion is easy to calculate, getting a handle on methane emissions is more difficult.

For one thing, there are many natural and other manmade sources of methane – swamps, dairy farms, landfills – so it can be difficult to pinpoint where it's coming from.

There are thousands of oil and gas wells in B.C., so it's difficult to test them all for methane leakage.

The most common GHG associated with natural gas and LNG is CO2, from combustion. But extraction also produces methane.

If natural gas extraction produces large amounts of methane, it could indeed put it on par with coal, according to the EIA.

But even if the methane produced in B.C. from natural gas extraction is 2.5 times higher than the government estimates – as one study has suggested – it is still well below the threshold that the EIA has determined would be needed to put it on the same level as coal.

That threshold is 3%. That is, if 3% of the natural gas produced escapes, either through venting or fugitive emissions, then it would indeed be as bad as coal in terms of its global warming potential, the EIA calculates.

B.C.'s methane emissions intensity is 0.3%, according to the B.C. government.

But a study by St. Francis Xavier University – in which Werring was a co-author – estimated upstream methane emissions in the province are 2.5 times higher than the government estimates – 111,800 tonnes annually in B.C.'s Montney formation alone, as opposed to industry estimates of 78,000 tonnes provincewide.

Other studies elsewhere have come to similar conclusions.

But even if the methane emissions overall in B.C. are indeed 2.5 times what the government estimates, that's still an emissions intensity of just 0.7%. That's far below the global average of 1.7%, according to the EIA.

"Gas on average generates far fewer greenhouse gas emissions than coal when generating heat or electricity," the EIA states.

But how could B.C.'s methane emissions be so low? Either the emissions are dramatically underestimated or the industry and regulators are doing a better job of limiting methane emissions.

One way the industry in the province has reduced methane is through "green completions" – a method of capturing "blowback" and preventing venting when a well is first fracked and put into production.

In 2017, 85% of the wells drilled were green completions.

Electrification of the Montney has also allowed some companies, like Royal Dutch Shell, to electrify their plants and install electric actuator valves instead of pneumatic valves that release natural gas every time they are activated.

Shell estimates the methane emissions intensity from its Groundbirch operations in northeastern B.C. is 0.1%.

That may explain why regulators in Washington have insisted that a proposed LNG plant in Tacoma source its natural gas from B.C.

A life-cycle analysis done by the Puget Sound Clean Air Agency last year concluded that natural gas from U.S. producers could have emissions that are as much as eight times higher than emissions from gas produced in B.C. It cited tighter regulations for drilling and natural gas processing in B.C. for the low emissions profile of B.C. gas.

“British Columbia has adopted comprehensive drilling and production regulations that are intended to reduce methane emissions,” the agency stated.

Taxing methane emissions “not possible”

When the Pembina Institute developed its shale scenario tool to model the total GHGs from a B.C. LNG industry, the methane appeared to be insignificant compared to the CO2.

“What we learned from that is that the leakage for B.C. is around 0.2% according to government reporting, which is extremely low,” said Maximilian Kniewasser, who developed the shale tool.

“The U.S. [Environmental Protection Agency] did some really detailed analysis, and they found that over the same part of the supply chain methane emission rates are around 1.3%. So B.C. is like one-sixth of what it is in the U.S. So there seems to be a discrepancy."

The problem for any scientist trying to estimate methane emissions is a dearth of baseline data. The measuring, monitoring and reporting is still insufficient, so all modelling is based on snapshot data that may not provide accurate estimates.

Until there is better baseline data, it will be difficult to measure the success of methane reduction regulations, and impossible to apply carbon taxes to upstream methane emissions.

"At the current level of detail that we have, it would not be possible to tax methane," Kniewasser said. "That is my opinion. And that's just because we don't have a good enough sense of what those emissions are exactly."

The absence of good baseline data also poses a challenge for the government in demonstrating that its new regulations requiring a 45% reduction of methane emissions are hitting their targets. In B.C., new drilling and processing regulations come into effect in 2020.

"When we're talking about reducing methane emissions in the oil and gas industry by 45%, the question then becomes 45% of what?" Werring said. "What is your baseline? And we don't have a handle on that baseline, unfortunately. But there is technology and there are opportunities here to move forward with regulations that require companies to be more proactive in their reporting."

But both Kniewasser and Jordaan say that the absence of good baseline data is no reason not to establish a better regulatory regime.

“You can mandate what kind of equipment you can implement or how often you have to check your facility,” Kniewasser said. “So even if you don’t have great data right now, it’s totally possible to regulate and mandate better practices.

“There’s uncertainty around what the problem is in B.C. with methane emissions, no doubt. What we do find is that there is a lot of opportunity to reduce methane pollution, or carbon pollution, across the LNG and natural gas supply chain.

“It’s a young field, but there is so much opportunity to reduce methane pollution. It is really the cheapest opportunity in the whole economy.”

Werring would like to see better monitoring of gas wells on an ongoing basis, especially older ones.

“The wells that are in production, they are probably pretty well monitored,” Werring said. “But then there all these other wells – they’re abandoned and suspended wells – that are not being appropriately monitored.”

Methane detection improving

By 2025, the B.C. government hopes, new regulations will result in a 45% reduction in methane leakage from the province’s natural gas sector.

The new regulations will force the natural gas industry to adopt new technologies and best practices that reduce methane emissions from natural gas wells, pipelines and processing plants.

But it may be hard to determine if it has hit its targets, because methane measuring and monitoring are still spotty.

Technology is evolving, however, that can give regulators a better idea of just how much methane is coming from the oil and gas sector.

GHGSat, for example, is a Canadian company that is using satellites to detect large methane sources from space. The company has one satellite in orbit and plans to launch a second one this summer.

“We are going to be able … to do direct measurements of oil and gas installations across the world, including British Columbia, and be able to offer a more efficient and lower-cost method of detecting and quantifying emissions from natural gas facilities,” said GHGSat president Stephane Germain. “We can help them identify where the big leaks are fast so they can fix them faster.”

While some Canadian companies have been using GHGSat, the BC Oil and Gas Commission has not yet used it.

While satellite imaging can identify the big emitters, it’s still something of a low-resolution approach.

Once the bigger emitters are identified, more refined detection technologies to pinpoint sources can be used to zero in on specific wells, pipelines and plants that may be emitting methane at high rates.

Geoscience BC has been piloting a project that uses “sniffer” drones developed by NASA that can take aerial surveys to detect methane emissions from natural gas infrastructure and other sources, including feedlots.

It is also using carbon isotope fingerprinting that can identify the signatures of molecules from a specific area. It is using the technologies to develop an “atlas” that will allow Geoscience BC not only to detect methane, but also to identify which well it may have come from.

“It gives us what I call the postal code of that molecule of gas,” said Carlos Salas, chief science officer at Geoscience BC. “So if there was to be a leak, and you were flying this drone, it would tell the company not only which wellhead is leaking, but it also gives you the depth as to where they think it’s coming from.

“We haven’t found any mega-emitters or anything like that. They tend to be just small emissions.”