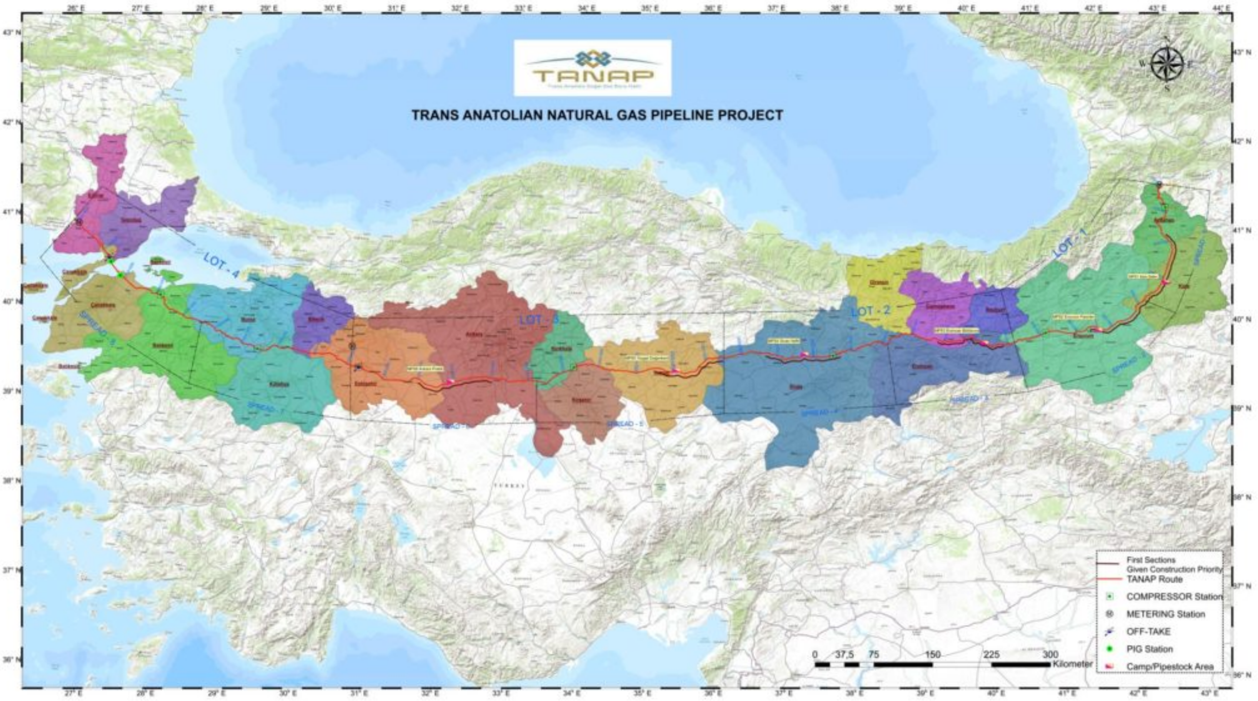
TANAP project to enter into service in June: Turkish minister

The Trans-Anatolian Natural Gas Pipeline (TANAP) project will enter into service as of June 12, Energy and Natural Resources Minister Berat Albayrak said on May 11.

"The opening ceremony will be held with the attendance of Turkish President Recep Tayyip Erdoğan and Azerbaijan President Ilham Aliyev on June 12," Albayrak said during his speech at a sector meeting in the northwestern province of Bursa.

Project officials announced in April that the first gas would be pumped on June 30.



TANAP, running from the eastern province of Ardahan on the border with Georgia towards borders with Greece and Bulgaria, is the central and longest section of the Southern Gas Corridor (SGC). The main aim of the SGC is to connect the giant Shah Deniz gas field in Azerbaijan to Europe through the South Caucasus Pipeline (SCP), TANAP, and the Trans Adriatic Pipeline (TAP). The SCP runs from Azerbaijan to Turkey through Georgia and the TAP starts in Greece and runs to Italy through Albania and the Adriatic Sea.

The initial capacity of TANAP is expected to be 16 billion cubic meters (bcm) of gas per year, gradually increasing to 31 bcm. Around 6 bcm of gas will be delivered to Turkey and the remaining volume will be supplied to Europe.

Albayrak also said Turkey would start its first solo oil and gas deep-sea drilling in the Mediterranean before the end of this summer.

Oil at $100 not to hurt world economy as much as in 2011

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A general view of the Amuay refinery complex which belongs to the Venezuelan state oil company PDVSA in Punto Fijo, Venezuela (file). The global economic impact of oil hitting $100 a barrel won’t be as big as when that happened in 2011 thanks to changes in the US. An analysis by Bloomberg Economics estimated that oil touching the triple-digit mark would shave 0.4% off US gross domestic product in 2020, compared with a baseline price of $75 a barrel. Yet that’s less of a hit than in the past because overall price levels have risen, the amount of energy required to produce a unit of economic output has slipped and the US has become less of an oil importer thanks to its shale industry. That mutes the effect of oil price shocks on the world’s biggest economy, and in turn on other countries. As such, “$100 oil won’t feel like it did in 2011,” and will actually feel “more like $79” a barrel, economists Jamie Murray, Ziad Daoud, Carl Riccadonna and Tom Orlik found. “With the US still firing on close to all cylinders, the rest of the world would suffer less as well — global output would be down by 0.2% in 2020.” The economists also estimated that oil would have to hit $200 a barrel before seriously stymieing the global economy.

Goldman Tells Big Oil: Take the Gas Risk, Demand Will Follow

The world’s largest energy producers will probably start hitting the gas on new projects, according to Goldman Sachs Group Inc.

Suppliers are better placed than buyers to bear the cost and risk of new liquefied natural gas projects, and may drive the next wave of investment, the bank said in a note. While the industry’s aware of the need for more output, the traditional model, where financing for new LNG capacity is dependent on binding sales agreements, has become an impediment, Goldman said.

The oversupplied LNG market is at risk of swinging into a deficit early in the next decade if new projects aren’t commissioned soon enough to meet increasing global demand. Large energy companies — including Royal Dutch Shell Plc and BP Plc, which have projects in the pipeline — will probably drive investments, according to Goldman.

“Natural gas is gaining market share relative to other fossil fuels, but new sources of supply must be developed to sustain this trend post 2020,” analysts including Christian

Lelong said in the May 15 note. “A greater willingness to take on price risk should reduce the historical dependency on long-term contracts and leave producers firmly in the driving seat.”

Many consumers lack the risk appetite for long-term LNG supply agreements because the visibility on downstream demand is limited, particularly in the power sector given the rise of renewables, the New York-based bank said. Producers, which have stronger balance sheets, are better placed to mitigate these risks, according to Goldman.

Gas buyers are delaying decisions and declining to go into long-term contracts, even as key markets including China and India need to clean up their air, said Charif Souki, chairman of U.S. LNG developer Tellurian Inc., in an interview at the Flame gas conference in Amsterdam.

“U.S. gas can be delivered to Asia very efficiently,” and so can low-cost Russian gas, Souki said. The fuel is a very attractive way for Asia to shift to cleaner energy, and buyers will need to convince sellers to invest in new capacity, he said.

Gas ‘spaghetti’ past prompts Australia cost-cut teamwork

The energy industry in Australia, looking back on an era of waste and profligacy, is now preaching the gospel of thrift and collaboration as it tries to attract more investment in an age of fiscal discipline.
Firms like Royal Dutch Shell Plc are bemoaning the erosion of shareholder value from the go-it-alone mentality during the $200bn splurge on Australian LNG projects over the past decade. Rivals Chevron Corp and Woodside Petroleum Ltd have proposed a massive offshore pipeline in Western Australia, which could be shared by several companies.

That approach contrasts with the “spaghetti junction” of crisscrossing pipelines built in the past decade as ventures approached projects independently, according to energy analyst Martin Wilkes. The hand-wringing and newfound spirit of collaboration come as Australia, on the cusp of becoming the world’s biggest LNG exporter, tries to convince purse-holders in faraway headquarters to green-light more projects while investors call for more restrained spending.
“Everyone in the industry is feeling the scars from the lack of cooperation,” Graeme Bethune, a consultant with

EnergyQuest, said in Adelaide. “They were quite extraordinary circumstances with $100 oil prices driving a slew of greenfield projects. I would hope that egos have been suppressed now. Boards are going to be much more critical on any bullish, go-it- alone proposals.”

Chevron proposed building a massive pipeline that would connect the Scarborough, Thebe and Exmouth fields, which lie hundreds of kilometres off the coast of northwest Australia, to the existing Wheatstone, Pluto and North West Shelf LNG plants, which sit along a 200-kilometer stretch of the coast. The plan would minimize duplication and would have superior economics over individual point-to-point concepts, Nigel Hearne, Chevron’s managing director for the country, said in a speech on Tuesday at the annual conference of the Australian Petroleum Production & Exploration Association.

Woodside, which owns stakes in all three of those LNG plants and in two of the fields, supports the plan for shared infrastructure, chief executive officer Peter Coleman said at the same event in Adelaide.
Collaboration along those lines was missing last decade when energy companies were planning the slate of LNG plants that have been coming online in recent years.
In Queensland, three separate LNG plants built adjacent to each other shared virtually no infrastructure such as jetties and storage tanks. In northern Australia, two gas fields that are connected to each other are being developed in two separate projects, one using a floating liquefaction plant and one using a 900-kilometer (560-mile) pipeline to the shore.

And in Western Australia, gas pipelines splay out west and east from offshore fields, crisscrossing each other as they connect to four different liquefaction plants located on the mainland and an island. The developments in Western Australia and Queensland cost about $36bn more than they would have if companies had collaborated from the beginning, according to a 2016 study by Wilkes, a Perth-based principal adviser at RISC

Advisory.
“Real collaboration happens at the start of projects,” Wilkes said in an interview on Wednesday in Adelaide. “And had real collaboration occurred, you wouldn’t have the spaghetti junction on the West Coast.”
Failure to collaborate eroded shareholder value in the projects, Shell Australia chairwoman Zoe Yujnovich said in a speech at the conference. Australian companies will have to overcome that history to convince investors to fund drilling projects needed to keep LNG plants full.
“Unless we can improve the attractiveness of our projects to investors, the spectre of growing ‘ullage’ in LNG trains may fast become an unmanaged reality,” she said, using an industry term for unused space in a storage tank. “And that is not a situation that will be easily recovered.”

Shale’s Public Enemy No. 1 Says Short the Permian and Eagle Ford

(Bloomberg) — The geologist who earned the wrath of shale drillers a decade ago with forecasts that natural gas was about to run out is now warning that the Permian Basin has just seven years of proven oil reserves left.

Arthur Berman, a former Amoco scientist who now works as an industry consultant near Houston, said the Permian region of Texas and New Mexico that currently pumps more oil than any other North American field won’t last for long. And the Eagle Ford shale about 350 miles (560 kilometers) away in South Texas isn’t looking good either.

Berman’s grim outlook, based on analyses of reserves and production data from more than a dozen prominent shale drillers, flies in the face predictions from the U.S. Energy Department, Chevron Corp. and others that the Permian is becoming one of the dominant forces in global crude markets.

Permian output already exceeds that of three-fourths of OPEC members.

“The best years are behind us,” Berman told a gathering of engineers, geologists, lawyers and financiers at the Texas Energy Council’s annual gathering in Dallas on Thursday. “The growth is done.”

Berman came to prominence as a shale skeptic and peak-oil advocate during the first decade of the new century, when intensive fracking and sideways drilling techniques were just beginning to unlock vast reserves of gas from shale fields in Texas and Louisiana. At the time, his dire warnings that shale gas was mostly hype drew the ire of fracking pioneers including Devon Energy Corp. and Chesapeake Energy Corp.

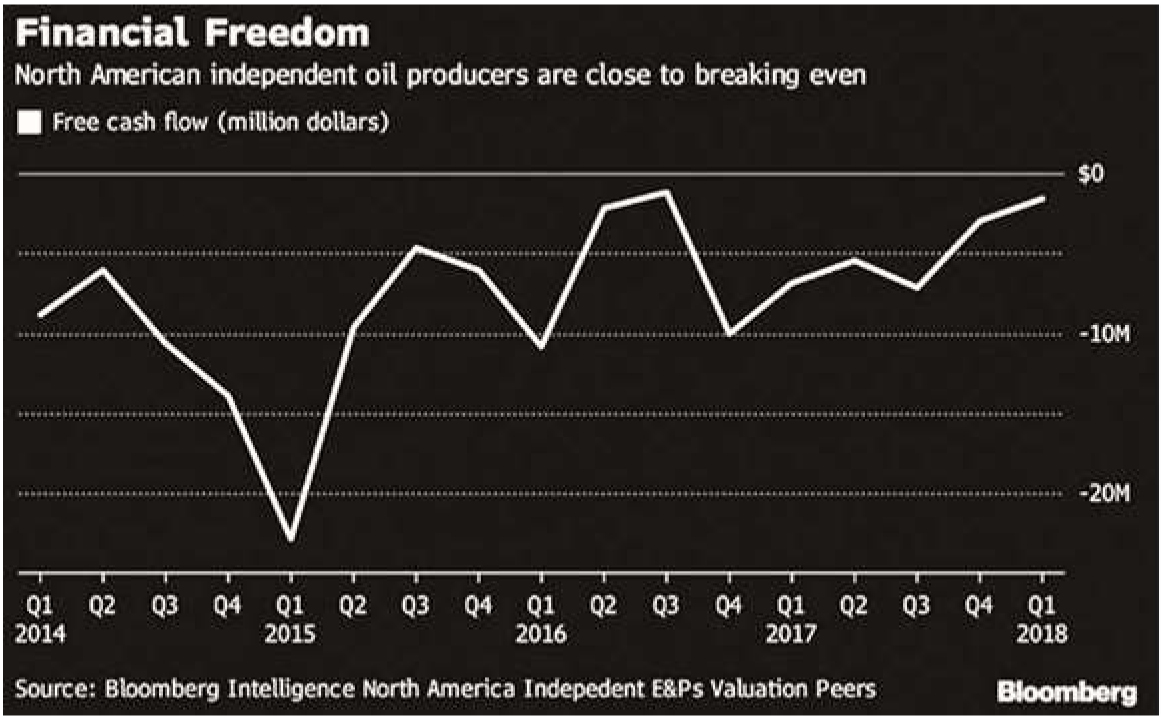
In 2009, Devon’s exploration chief Dave Hager — who has since risen to CEO — published an op-ed piece in an Oklahoma City newspaper to refute Berman’s thesis. In it, Hager likened shale to a World Series-winning home run and said Berman “is in the stands speculating on whether the slugger is on steroids.”

Berman on Thursday said investors banking on shale fields to make major contributions to future global crude supplies will be disappointed: “The reserves are respectable but they ain’t great and ain’t going to save the world.”

Still, he hasn’t sold the stock of shale driller EOG Resources Inc. that he inherited from his deceased father “because they’re a pretty good company.”

His parting advice to the assembled was, “Conserve what you’ve got, learn to live with less, open your eyes and enjoy the rest of your day." No one participated in the Q and A session.

Shale's big boost comes with newfound thrift as oil hits $70



The shale boom's back in full swing, with fracking crews the busiest since 2014. The novelty this time around: Oil executives stressing their prudence, along with their production.

The combination of surging output, oil prices at three-year highs and spending under control means that the shale patch — which has notoriously burnt more cash than it makes as investors bankroll their expansion — got closer to a milestone in the first-quarter: Positive free cash flow. As oil rises above $70 a barrel, the outlook for the coming quarters looks even brighter.

It’s a shift that came with the help of new high-tech well systems, and at the insistence of investors pushing payback over growth. Here are five key takeaways from the first quarter to track moving forward: Production is thriving
EOG Resources Inc and Pioneer Natural Resources Co are among producers that posted record output, while keeping capital expenditures in check.
But how can they keep growing without overspending?

Producers have sought to cut costs since prices crashed more than three years ago, but those efforts can only go so far. It’s mainly better technology that’s allowing them to get more from each well without blowing their budgets.
Pioneer, in a recent presentation, offered insight into how its high-tech wells are delivering at a faster rate, a theme repeated over and over again in earnings calls. Devon Energy Corp said it completed the two highest-rate wells in the Delaware section of the Permian in its 100-year history, helping it to a 20% production boost.

Almost living within their means
Buybacks, dividend increases and a cap on capital expenditures. Oil executives couldn’t keep from crowing about their thriftiness while producing record amounts of product, and how their efforts can be a benefit to both their shareholders, and to continued growth.
The numbers back them up, showing a pretty good rise in free cash flow, starting from the end of 2016.

The oil rally’s flip side: HedgingA big risk facing some producers now is the amount of wrong-way bets on oil prices that they hold. When crude markets slumped, explorers used hedging contracts to lock in payments for future barrels that could now turn sour as futures trade above $70 a barrel.
Wood Mackenzie Ltd’s Andrew McConn estimates top producers will lose $7bn on their hedging contracts in 2018.

The reality on the ground

To make record production a reality, oil-service providers are sending a growing number of fracking crews to shale fields to blast the oil-rich layers of rock with water, sand and chemicals.

But for the service providers, that hasn’t translated into better profits yet.

The rush to respond to heightened demand has inflated costs for materials like sand and has triggered transportation bottlenecks and labour shortages. All that has weighed down on their first-quarter results. Schlumberger Ltd, the world’s biggest oilfield service provider, and Halliburton Ltd, the top fracker, have both promised investors things will improve. If that means increasing prices for their services, costs will rise for producers.

Russian Oil Giants Get Record Prices, But Not Profits to Match

The price of crude in rubles has surged to an all-time high, but Russian oil producers will miss out on record first-quarter profit because of a rising tax burden.

Investors in Lukoil PJSC or Rosneft PJSC — which is due to publish earnings on May 14 — will probably have to wait until later in the year to see the full benefit of the surge in crude. So far, Russia’s government has done a better job of translating record prices into revenues, said Denis Borisov, a director at the Ernst & Young Oil and Gas Center in Moscow.

“The golden rain will likely fall on the companies in the second quarter if key conditions — the oil price and ruble exchange rate — remain in place,” Borisov said on Thursday.

The price of international benchmark Brent crude averaged 3,823 rubles a barrel ($67.23) in the first quarter, just a hair away from the previous quarterly record in 2014. It’s risen further to as high as 4,881 rubles this month. Yet the price of Urals crude in Russia’s currency, net of taxes, was 3 percent lower from January to March compared with the fourth quarter due to higher oil-extraction levies, according to Deutsche Bank AG.

Tighter Burden

Tax costs of Russia’s producers have been rising since last year

The industry also faced a jump in petroleum-product excise tax — an additional support to the state budget to fund road construction that may reach 40 billion rubles this year, according to Finance Ministry’s estimates made last year. However, Russia’s domestic gasoline price increases lagged crude in the first quarter, possibly showing that companies were holding back from shifting part of this burden onto consumers ahead of presidential elections in March, said Ildar Davletshin, an energy analyst at Wood & Co.

The revenue of state-run Rosneft, which pumps more than 40 percent of Russia’s oil, could have hit a record of 1.73 trillion rubles in the first quarter, according to Renaissance Capital. However, it expects net income to drop 19 percent from the fourth quarter to 81 billion rubles.

Rosneft plans to start its first-ever share buyback program this quarter, spending $2 billion over three years. That means investors will also be closely watching cash flow. Renaissance Capital expects the company to generate 75 billion rubles in the first quarter, almost 16 percent lower than a year ago, Bloomberg calculations show.

Several of Rosneft’s peers are planning or implementing buybacks as a way to share the rewards from rising crude prices with investors. Lukoil announced a five-year repurchase scheme worth as much as $3 billion back in January — four months before Rosneft. The move boosted the stock’s appeal to investors and helped close the gap in the market value of the rivals.

For 2018 as a whole, Lukoil and Gazprom Neft PJSC are expected to post big gains in net income, according to analysts surveyed by Bloomberg. Rosneft’s cash flow should more than double to some 550 billion rubles, which is enough to cover interest payments, dividends and as much as half of the planned share purchases, Davletshin said. Another Rosneft plan – to cut its debt by 500 billion rubles this year – may need proceeds from selling non-core assets, he said, a move the company is already considering.

Still, the size of the tax burden remains a risk, particularly as Russia forms a new government. President Vladimir Putin’s administration will soon lay out targets for the economy and budget for his fourth term. While the state has promised to avoid significant changes in oil taxes this year, Prime Minister Dmitry Medvedev said this week that Russia will need at least 8 trillion rubles in additional spending to fulfill its plans

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Europe Awakens for LNG to Rival China as Own Gas Runs Out

Europe is starting to steal some of the limelight from China’s booming liquefied natural gas demand as imports pick up after several lackluster years.

Europe and China will be comparable in significance as importing regions in the coming years, Cheniere Energy Inc. said, citing data from Wood Mackenzie Ltd. That follows “absolutely phenomenal” growth in China last year, Andrew Walker, vice president for strategy at the company that pioneered the transformation of the U.S. shale boom into global exports, said in Amsterdam.

China’s LNG consumption leapt 42 percent last year to almost match European imports, which climbed 20 percent. Whereas the Asian nation needs the fuel mostly to replace dirtier coal, Europe needs it to offset rapidly declining domestic production.

The re-emergence of Europe as an LNG market has caught the eye of the coming wave of U.S. fuel producers. Venture Global LNG, Inc., which is developing export terminals in Louisiana, sees Europe as “one of the biggest surprises,” it said at the Flame conference in Amsterdam.

Europe’s location may give it an edge over generally higherpriced markets in Asia when it comes to attracting the increasing volumes produced in the Atlantic. North America and Russia were seen providing most of the new supply from 2025 to 2030, according to a poll at Flame.

Demand growth in China and South Korea, the second and third biggest LNG importers, will cool during the rest of this year after continued expansion through April, according to Cedigaz, a Paris-based industry research group. With less appetite also from Japan, the biggest buyer, northern Europe will step in to balance the markets, Cedigaz’s secretary general Geoffroy Hureau said at Flame.

U.K. supply this summer may be low but the Netherlands will see a pick up as it rushes to offset lower own production and higher demand for storage, Nick Boyes, a senior gas and LNG analyst at Axpo Trading AG, said by email. France will also need more for storage, he said.

The Netherlands is taking the lead also because of lack of storage demand in Britain after the closure of the Rough facility. The Dutch market is so hot that the country’s Title Transfer Facility hub will be the main reference for LNG trading in the next three to four months, Ruben Tomas, lead LNG trader at Germany’s Uniper SE’s commodity unit, said on a panel.

“We see a well-supplied Atlantic Basin this summer” as Russia’s Yamal LNG and U.S. projects fill the market with cargoes, Axpo’s Boyes said. Trinidad & Tobago and Angola are also boosting supply, while demand in southern Europe and Egypt is declining, he said.

While the usage rate of LNG terminals in Europe was just 23 percent last year, things are looking up, according to Arturo Gallego Diaz, head of LNG trading and operations at Centrica Plc.

“There are more and more people looking at northwest Europe as an opportunity to deliver volumes that are produced in the

Atlantic basin," he said.

Declining production in the North Sea and the Dutch Groningen field as well as the closing of coal plants in Europe have a "big impact on LNG production" and are "a very big demand surprise," Venture Global LNG Chief Commercial Officer Tom Earl said at Flame. The company recently signed a supply contract with Portugal's Galp Energia SGPS SA.

'Fairly Stable'

Creditworthy counterparts, liquid hubs and physical demand help make Europe attractive for LNG, according to Gallego Diaz.

Uniper expects "fairly stable" demand for gas in Europe, while seeing growth in gas-to-power and potentially transport, said Gregor Pett, executive vice president for market analytics.

Russia, Europe's biggest gas supplier, sees higher demand for its pipeline gas, undermining the region's efforts at diversification, according to Sergei Komlev, head of the contract structuring and price formation directorate at Gazprom PJSC's export unit.

While Russia will continue to pipe natural gas to Europe in competition with LNG, both can co-exist, the Centrica and Uniper executives said.

"I don't think they exclude each other," Uniper's Pett said. "Everyone has a place."

For Big Oil, reserve size matters less than ever

LONDON (Reuters) – A decade ago, the news that the world's top oil and gas companies had less than 12 years of production left in their reserves might have caused a panicked sell-off in their shares.

But as consumers try to move away from fossil fuels to cleaner and cheaper energy sources, investors and executives say reserve size is no longer the gold standard for measuring the value and health of a company.

The cost of developing existing reserves and the amount of carbon those reserves produce has now become more important, they say. This is leading to a profound shift in company strategies.

“The quality of reserves and the commercial viability of reserves has eclipsed the quantity of reserves by far in recent years,” said Adi Karev, Global Leader for Oil and Gas at EY.

The sector is emerging from one of its longest and deepest downturns after an oil price slump that started in 2014.

The largest publicly-traded oil companies – Exxon Mobil, Royal Dutch Shell, Chevron, ConocoPhillips, France’s Total, BP, Equinor (formerly Statoil) and Italy’s Eni – have adapted. They saved money by cutting jobs and increasing technology spending and now make more money with oil at $60 a barrel than they did at $100.

But they also cut spending on exploration for new resources and development of new fields. This led to a decline in reserves.

An analysis by Reuters and Guinness Asset Management of the annual reports of those eight companies shows that the size of their oil and gas reserves, when added together, fell to 91 billion barrels in 2017. That was the lowest since the same amount in 2005.

The reserves of Exxon Mobil, the largest company, shrank by 16 percent since the slump began in 2014. Shell’s reserves fell 6.5 percent since then despite the $54 billion acquisition of BG Group in 2016.
BP and Chevron’s oil and gas reserves increased by a small 5 percent since 2014. Eni was the only one to significantly boost its reserves by over 20 percent thanks to the discovery of the giant Zohr gas field off the coast of Egypt.

The cumulative reserve life – the number of years a company can sustain its current production levels with existing reserves – of the eight companies fell to 11.7 years in 2017. That was the lowest level in at least 20 years although that drop is also the result of a sharp increase in production.

Reuters does have access to data going back beyond 1998.

Exxon’s reserves life shrank from 17 years in 2014 to 15 in 2017. Eni’s from 10.6 to 10.1 years despite its discoveries. Shell slipped from 12 to 9 years over the period.

“There is clear deterioration (in reserves) and this will be a problem in time,” according to Jonathan Waghorn, manager of the energy fund at Guinness Asset Management.

But for now, “10-12 year’s reserve life should be fine, so it is not a materially important component between the Majors.”

“THE BEST BARRELS”

With electric vehicles on the ascent and a peak for fuel demand on the horizon, the focus on the reserves is shifting to the quality of the reserves rather than the quantity

“Some reserves are more efficient than others,” Eldar Saetre, chief executive officer of Norwegian oil giant Equinor told Reuters.
“At some point we see a shrinking oil and gas industry, when that will be I do not know, but then it is really important that the best barrels come in and that will be increasingly a competitive factor.”

Some companies are already changing strategies to adapt to the new focus.

Oil prices are not expected to rise sharply in the long-term and governments are seeking to reduce pollution and greenhouse gas emissions. This means firms are adjusting by setting ceilings for the cost of projects, often below $35 a barrel. Oil reached a $80 a barrel this month, the highest since late 2014.

Crude oil and natural gas have different grades and the cost of pumping them can vary hugely. Saudi Arabia’s oil is easier and therefore cheaper to extract than Angola’s complex deepwater wells.

Canada’s oil sands have become less attractive due to their high cost of extraction and high carbon intensity. Exxon wrote down a large part of its Canadian oil reserves in 2017. Its largest rival, Shell, has sold most of its Canadian assets in recent years.

North American shale which has emerged over the past decade can be developed relatively quickly and at low cost, in contrast to multi-billion dollar deepwater projects that take years to develop.

The Permian basin in Texas, the heartland of the shale oil boom in recent years, saw production costs drop sharply to as low as $30 a barrel.

Exxon and U.S. rival Chevron have both acquired large acreage in the Permian in recent years. Shell is also expanding in U.S. shale.

The Gulf of Mexico also has low extraction costs because it has large reservoirs of oil and some infrastructure is already located there such as services companies and onshore bases.

Statoil and Total have bought exploration acreage in the U.S. Gulf of Mexico in recent months.
Brazil’s pre-salt reserves also have low costs as there are huge reservoirs and also some existing infrastructure. All eight companies are there and several have recently sharply increased their production in the basin.

“We are now getting to the point that the focus on efficiencies and producing reserves at a low level is what investors expect,” Karev said.

Higher oil prices offer 'temporary relief' to Mena exporters: IIF

Higher oil prices offer "temporary" relief to the oil exporters of the Middle East and North Africa (Mena) whose economic prospects are improving, according to the Institute of International Finance (IIF), the Washington-based economic think tank.

Oil prices rose rapidly in the past six months on unanticipated sharp output fall in Venezuela, the extension of the producers' pact on production cuts to the 2018- end, the escalation of tensions in the Mena, which enhanced risks of oil supply disruption; and higher global oil demand. We have revised upward our average Brent oil price assumption to $72 per barrel for 2018 (33% increase form 2017)," IIF said.

With the projected $18 increase in average oil prices in 2018 against last year, it expects the cumulative current account surplus for the nine Mena oil exporters (Saudi Arabia, the UAE, Kuwait, Qatar, Oman, Bahrain, Algeria, Iraq and Iran) to increase from $56bn in 2017 to $233bn (9.5% of gross domestic product) in 2018. "The fiscal situation for Mena oil exporters (except Bahrain and Oman) is now on firmer footing. The respective authorities in the region have implemented serious fiscal adjustment in recent years," it said.

Higher oil prices, combined with additional non-hydrocarbon revenue, should more than offset the 7% average increase in public spending, leading to narrower deficits (excluding investment income), according to the IIF. "We expect the consolidated fiscal deficit for the nine Mena oil exporters to decrease from 7.5% of GDP in 2017 to 3% in 2018," it said, adding when included investment incomes, which are very large in Kuwait, the UAE and Qatar, the cumulative deficit will be much smaller.

Highlighting that gross public foreign assets will resume its rise to $2.9trn by end-2018; it said about 70% of these assets are in the form of sovereign wealth funds. With relatively little public external debt, the region's net public external assets position of $2.6bn (108% of GDP) is substantial, the report added. Expecting non hydrocarbon growth to accelerate from 2.3% in 2017 to 2.8% in 2018 (still well below the average growth of 6.2% in 2001-2014); IIF said the growth pickup will be supported by the shift to fiscal expansion following three years of consolidation. A tighter monetary stance in the six GCC countries and Iraq, whose currencies are pegged to the US dollar, could offset some of the gains from expansionary fiscal stances. "We expect a cumulative increase of 100 bps in key policy rates, in line with the four Fed hikes of 25 bps each," it said.