Oil: The Barrel That Runs the World

Figures current as of October 2026

How oil is found, produced, refined, priced, and fought over, and how much of modern life runs on it: the resource and its grades, a history of its shocks, the producers and the companies, refining and the things made from oil, how the price is set, the Organization of the Petroleum Exporting Countries (OPEC) and OPEC+, the shock of 2026, oil in the economy and in food, petrostates and sanctions, America's turn to net exporter, the argument over peak demand, and what to watch.

MODULE 1 — What Oil Is, and Where It Lies

Goal: Understand what oil is, how it forms and is found, and why its grade and its reserves matter.

Formation, traps, and the few basins that hold most of the oil; light and heavy, sweet and sour, and why grade sets price; shale, oil sands, and deepwater; proved reserves of about 1.57 trillion barrels; and decline, the fall in output that new wells must make up every year.

MODULE 2 — A History in Shocks

Goal: Follow oil's history through the shocks that shaped it.

From the first well at Titusville in 1859 and Standard Oil's breakup to the Seven Sisters, OPEC's founding, the embargo of 1973 and the revolution of 1979, the collapses of 1986 and 2014-16, the spike of 2008, and the negative price of April 2020.

MODULE 3 — Who Pumps It

Goal: Map the world's producers and what a barrel costs them, and weigh whether American shale has peaked.

About 100 million barrels a day in 2025; the United States as the largest producer, with record crude output; the Gulf, Russia, Canada, Brazil, and Guyana; the cost of a barrel by basin; and the economics of a shale well.

MODULE 4 — The Companies

Goal: Understand who owns and moves the oil, and weigh whether the companies should return their cash or drill.

The majors and their 2026 windfall; the national oil companies that hold most of the world's reserves; the mergers of the shale fields; the service firms and the traders; and BP's reset under a new chief executive.

MODULE 5 — From Crude to Products

Goal: Follow a barrel through the refinery, and see what is made from oil.

Distillation, cracking, and what a barrel yields; the closures in California and Europe and the new refineries of Africa and Asia; the record margins and diesel prices of 2026; petrochemicals, plastics, asphalt, fibers, and medicine.

MODULE 6 — How the Price Is Set

Goal: Understand how oil is priced, from the benchmarks to the pump.

Brent, West Texas Intermediate (WTI), Dubai, and Murban; futures against the price of physical cargoes, which parted by $35 a barrel in April 2026; backwardation and inventories; who trades; and what is in a gallon of gasoline.

MODULE 7 — OPEC and OPEC+

Goal: Understand the producers' cartel and its limits, and weigh whether it still sets the price.

Members, quotas, and the spare capacity that is the market's real buffer; Saudi Arabia's choices; the exit of the United Arab Emirates (UAE) on May 1, 2026; Russia inside OPEC+; and the oil prices the producers' budgets need.

MODULE 8 — The Shock of 2026

Goal: Follow the Iran war's disruption of the Strait of Hormuz and what the market did.

The strait and the oil that passes it; the war from February 28, dated; shut-in production, record physical prices, and attacks on tankers; the largest release of emergency stocks in history; and the contested strait of October 2026.

MODULE 9 — Oil and the Economy

Goal: Measure oil's place in the economy, and weigh whether oil shocks still cause recessions.

Oil's share of the world's energy and what it moves; the oil used per dollar of output, more than halved since 1973; shocks, recessions, and inflation; households' fuel bills; and who wins when America exports more oil than it imports.

MODULE 10 — Oil in Food

Goal: See how much the food system depends on oil and gas, and weigh how far oil prices drive food prices.

Fertilizer made from natural gas and shipped through Hormuz; diesel for tractors, pumps, and trucks; pesticides and packaging from petrochemicals; the cold chain and fishing fleets; biofuels, which tie crop prices to oil; and the price of bread.

MODULE 11 — Oil and Power

Goal: Understand how oil shapes states and how states use it, and weigh whether sanctions work.

Petrostates and the resource curse, from Norway's fund to the Gulf economies shrinking in 2026; sanctions on Russia, Iran, and Venezuela; Venezuela after Maduro; and the shadow fleet of tankers that carries sanctioned oil.

MODULE 12 — America and Oil

Goal: Follow America's turn from importer to the largest producer, and weigh whether its strategic reserve is worth keeping.

Imports, exports, and the net-export record; the policy of energy dominance; the Strategic Petroleum Reserve at its lowest since 1982; gasoline and the midterm elections; and the trade with Canada and Mexico.

MODULE 13 — The Future of Oil

Goal: Weigh the forecasts of oil demand, and whether it has peaked.

The forecasts side by side, from a peak near 102 million barrels a day around 2030 to 124 million in 2050; electric vehicles and China's fuel peak; petrochemicals and aviation; the investment needed to offset decline; and the climate argument.

MODULE 14 — Where Things Stand, and What to Watch

Goal: Close with the argument, the contradictions, and a dated watch list.

The course's argument on a page; the contradictions no single module states; what to watch from October 2026 on; and a last word.

A note on the sources: the market's figures come mainly from the International Energy Agency (IEA), the Paris agency of the oil-importing countries, and from the US Energy Information Administration (EIA), the government's energy statistics agency, which publishes the monthly Short-Term Energy Outlook (STEO). The producers' figures come from OPEC and from the wider OPEC+ group that includes Russia. Reserves and the world's energy mix come from OPEC's Annual Statistical Bulletin and the Energy Institute's *Statistical Review of World Energy*.

Prices come from the exchanges that trade oil futures, the Intercontinental Exchange (ICE) for Brent and the New York Mercantile Exchange (NYMEX) for West Texas Intermediate (WTI), and from Platts, the price-reporting agency that assesses the physical cargo price called Dated Brent. Ship movements come from the trackers Kpler and Vortexa and from the Royal Navy's UK Maritime Trade Operations (UKMTO). Food and farm figures come from the Food and Agriculture Organization (FAO) of the United Nations, the US Department of Agriculture (USDA), and the World Bank, and the petrostates' figures from the International Monetary Fund (IMF).

Volumes are in barrels: one barrel is 42 US gallons, or 159 liters, and output is counted in barrels a day (b/d), thousands of barrels a day (kb/d), or millions of barrels a day (mb/d). Every price names its benchmark and date, because in 2026 the futures price and the physical price parted by as much as $35 a barrel. In the war that began on February 28, 2026, governments, armed groups, and companies make claims about attacks and shipping that cannot always be checked, so the course says who claims what. Amounts in other currencies are converted at the Federal Reserve's exchange rates for October 16, 2026. Where the field argues, over shale, the companies' cash, OPEC's power, recessions, food prices, sanctions, the strategic reserve, and the peak in demand, the course makes each case as its advocates make it, gives the evidence, and then states its own reading once.

Key Numbers, as of October 2026

The measurements the course relies on

Measure	Figure	Period	Source and release
Oil prices now	Brent futures $116.72 a barrel, the highest front-month settlement since late April; WTI futures $103.27 (December contract)	Settlements of October 23, 2026	ICE and NYMEX, via Reuters
The physical price	Brent spot $125.39 a barrel on October 22 in the EIA's daily series; Dated Brent's record $144.42 on April 7	2026	EIA; Platts, via S&P Global
Before the war, and the forecast	Brent spot averaged $69 and WTI spot $65 in 2025; the EIA forecasts Brent spot at $105 in the fourth quarter of 2026, $96 for 2026, and $84 for 2027	2025-27	EIA, *Short-Term Energy Outlook* (STEO), October 6, 2026
World demand and supply	Consumption of 104.4 million barrels a day (mb/d) in 2025 and 102.4 mb/d forecast for 2026; production of 106.3 mb/d in 2025 and 101.1 mb/d forecast for 2026, a surplus turned to a deficit	2025-26	EIA STEO (October 6, 2026), all liquids, biofuels included
Oil produced	100.6 mb/d of crude, condensate, and natural gas liquids in 2025; the United States produced 21.1 mb/d of them, a fifth of the world, including a record 13.7 mb/d of crude by the EIA's count	2025	Energy Institute, *Statistical Review of World Energy 2026*; EIA
Proved reserves	About 1,572 billion barrels; Venezuela 303.7 billion, Saudi Arabia 267.2 billion, Iran 208.6 billion	End of 2025	OPEC, *Annual Statistical Bulletin 2026*
The Strait of Hormuz	About 21 mb/d of crude and products in 2025, a fifth of world use; 4.9 mb/d in the second quarter of 2026; 12.65 mb/d in the seven days to October 23, 26% below Kpler's prewar count	2025-26	EIA; Kpler, via Dow Jones
Shut-in output	Middle East crude output shut in: 10.9 mb/d at the peak, in May 2026; 4.77 mb/d in September	2026	EIA STEO (October 6, 2026)
World stocks	Observed oil stocks fell about 509 million barrels between the end of February and the end of September	2026	International Energy Agency (IEA), *Oil Market Report*, October 14, 2026
Emergency stocks	IEA members agreed a 400-million-barrel release on March 11, 2026, the largest ever; about 331 million barrels had been delivered by October 15	2026	IEA
America's reserve	The Strategic Petroleum Reserve (SPR) held 282.7 million barrels, its lowest since 1982 and 40% of its 714-million-barrel capacity	Week to October 16, 2026	EIA
OPEC	11 members since the United Arab Emirates (UAE) left on May 1, 2026; OPEC+ crude output 39.07 mb/d in September	2026	OPEC, *Monthly Oil Market Report*
America's trade	Net exports of crude and products of 2.8 mb/d in 2025, forecast at 4.3 mb/d in 2026	2025-26	EIA STEO (October 6, 2026)
Shale's cost	A new well needs $66 a barrel (WTI) on average to drill profitably, $67 in the Permian; 603 drilling rigs at work in mid-October, 10% more than a year earlier	First quarter of 2026; October 2026	Federal Reserve Bank of Dallas Energy Survey; Baker Hughes
Refining	BP's refining indicator margin averaged $46.7 a barrel in the third quarter of 2026, against $29.6 in the second	2026	BP trading statement, October 13, 2026
Fuel at the pump	US regular gasoline $4.284 a gallon and diesel $6.276; diesel's record was $6.29 in the week of September 14	Week of October 19, 2026	EIA weekly averages

Measure	Figure	Period	Source and release
Prices in the economy	Gasoline up 34.2% in a year in the consumer price index (CPI); all items up 3.7%	Year to September 2026	Bureau of Labor Statistics (BLS), October 14, 2026
Oil in food	Urea, the most used nitrogen fertilizer, rose 80% from February to April 2026; US farm spending on fuels and oils is forecast up 28.8% in 2026	2026	World Bank; US Department of Agriculture (USDA)
World food prices	The Food and Agriculture Organization's (FAO) Food Price Index stood at 136.0 in September, its highest since November 2022	September 2026	FAO
China	Crude imports of 9.03 mb/d in September, 21.5% less than a year earlier, as China drew on its stockpiles	September 2026	China's customs agency, via Reuters
Electric vehicles	Electric vehicles (EVs) displaced about 1.7 mb/d of oil in 2025	2025	IEA, *Global EV Outlook 2026*
The long run	Demand peaks near 102 mb/d around 2030 in the IEA's Stated Policies Scenario, but reaches 113 mb/d in 2050 in its Current Policies Scenario; OPEC projects 124 mb/d in 2050	Published November 2025 and June 2026	IEA, *World Energy Outlook 2025*; OPEC, *World Oil Outlook 2026*
Sanctions	The EU's price cap on Russian crude was fixed at $44.10 a barrel until July 15, 2027	July 23, 2026	EU, 21st sanctions package
The Gulf economies	Forecast 2026 growth: Kuwait -16.7%, Iraq -16%, Qatar -15.6%, Saudi Arabia -3.3%	2026	International Monetary Fund (IMF), October 2026

Brent futures are the front-month contract on the Intercontinental Exchange (ICE); WTI is West Texas Intermediate on the New York Mercantile Exchange (NYMEX). The physical price of Brent cargoes ran up to $35 a barrel above futures in 2026, so every price in the course names its benchmark. Supply and demand totals differ by source because they count different liquids: the EIA's include biofuels, the Energy Institute's do not. One barrel is 42 US gallons.

Who's Who

The people who run oil and its politics, as of October 23, 2026

The producers

Name	Who they are	Why they matter to oil
Mohammed bin Salman	Crown Prince of Saudi Arabia since June 2017 and Prime Minister since September 2022; age 41	Runs the government of OPEC's largest producer, whose oil sites and airports came under Houthi attack in October 2026
Prince Abdulaziz bin Salman	Saudi Minister of Energy since September 2019, and also Minister of Industry and Mineral Resources since July 11, 2026	Speaks for Saudi oil policy in OPEC+; said on October 12 that a gas pipeline converted to crude could carry about 1 mb/d more to the Red Sea within eight weeks
Amin Nasser	President and chief executive of Saudi Aramco since 2015	Runs the world's largest oil company by output, which made $104.7 billion of adjusted net income in 2025
Mohamed bin Zayed Al Nahyan	President of the UAE since May 2022; age 65	His government took the UAE out of OPEC and OPEC+ on May 1, 2026
Suhail Al Mazrouei	UAE Minister of Energy and Infrastructure; energy minister since 2013	Called the UAE’s exit from OPEC, announced on April 28, 2026, a “sovereign national decision”
Sultan Al Jaber	Managing director and group chief executive of ADNOC, the Abu Dhabi National Oil Company, and the UAE's Minister of Industry and Advanced Technology	Runs the company whose expanded capacity the UAE left OPEC to use
Mojtaba Khamenei	Supreme Leader of Iran since March 8, 2026, after his father, Ali Khamenei, was killed in the strikes of February 28; age 57	Holds final authority over Iran's war and its terms for the Strait of Hormuz
Masoud Pezeshkian	President of Iran since July 2024; age 72	Heads the government that signed the June 17 memorandum, and discussed renewed Pakistani mediation in Tehran on October 20
Hamid Bovard	Acting oil minister of Iran since October 4, 2026, and head of the National Iranian Oil Company	Runs an industry whose crude output, by OPEC's secondary sources, fell from about 3.3 mb/d before the war to 1.96 mb/d in September, under an American blockade of Iran's ports
Ali al-Zaidi	Prime Minister of Iraq since May 14, 2026	Governs OPEC's second-largest producer, most of whose exports leave through the Gulf and Hormuz
Vladimir Putin	President of Russia, 2000-2008 and since 2012; age 74	Leads the largest producer in OPEC+ outside OPEC, and the main target of oil sanctions
Alexander Novak	Deputy Prime Minister of Russia for energy since November 2020, after eight years as energy minister; age 55	Represents Russia in OPEC+
Igor Sechin	Chief executive of Rosneft since 2012; age 66	Runs Russia's largest oil producer
Haitham Al Ghais	Secretary General of OPEC since August 2022	Leads the secretariat of an OPEC cut to 11 members
Delcy Rodríguez	Acting president of Venezuela since January 2026: designated January 3 and sworn in January 5	Leads the country with the world's largest proved reserves after Nicolás Maduro's removal
Paula Henao	Venezuela’s oil minister since March 2026, a petroleum engineer	Took over the ministry from Delcy Rodríguez as Venezuela reopened its oil to foreign companies

Name	Who they are	Why they matter to oil
Irfaan Ali	President of Guyana since August 2020, re-elected in September 2025; age 46	Governs a country that went from no oil output before December 2019 to about 900,000 barrels a day in 2026
Saad Sherida al-Kaabi	President and chief executive of QatarEnergy, and Qatar's Minister of State for Energy Affairs	Runs the gas exporter whose plants stopped after Iranian strikes in March 2026
Nicolai Tangen	Chief executive of Norges Bank Investment Management, which runs Norway's oil fund, since September 2020	Runs the fund built from Norway's oil revenue, worth about $2.27 trillion at the end of June 2026

Companies

Name	Who they are	Why they matter to oil
Darren Woods	Chairman and chief executive of ExxonMobil since January 2017	Runs the largest Western oil company, which leads the development of Guyana's fields
Mike Wirth	Chairman and chief executive of Chevron since February 2018	Runs the company that bought Hess and is raising its output in Venezuela
Wael Sawan	Chief executive of Shell since January 2023; born 1974	Has turned Shell back toward oil and gas, selling its onshore renewables business in 2026
Meg O'Neill	Chief executive of BP since April 1, 2026, the first woman to lead one of the oil majors	Took over BP after its 2025 reset, and sets out her strategy on December 15, 2026
Patrick Pouyanné	Chairman and chief executive of TotalEnergies, chief executive since October 2014; age 63	Runs the major that agreed in 2026 to buy Shell's onshore renewables business
Juan Carlos Carpio Fragoso	Named head of Pemex, Mexico's state oil company, on May 14, 2026	Runs the world's most indebted oil company, with about $77.5 billion of financial debt at the end of June 2026
Aliko Dangote	Founder of the Dangote Group; age 69	Built Africa's largest refinery, near Lagos
Russell Hardy	Chief executive of Vitol since March 2018	Runs the largest independent oil trader
Olivier Le Peuch	Chief executive of SLB since August 2019	Runs the largest oil-service company

Agencies and governments

Name	Who they are	Why they matter to oil
Fatih Birol	Executive director of the IEA since September 2015; age 68	Leads the agency that coordinated the largest release of emergency oil stocks in history
Chris Wright	US Secretary of Energy since February 2025	Oversees the SPR and America's energy policy
Doug Burgum	US Secretary of the Interior, confirmed on January 30, 2025, and chair of the National Energy Dominance Council; age 70	Runs federal oil and gas leasing on land and offshore, and ordered the new five-year offshore leasing program
Tristan Abbey	Administrator of the US Energy Information Administration (EIA) since September 25, 2025	His agency publishes the STEO and the weekly fuel prices the course uses
Abdul-Malik al-Houthi	Leader of Yemen's Houthi movement, Ansar Allah, since 2004	His movement's attacks on Saudi Arabia escalated in October 2026
Wang Hongzhi	Head of China's National Energy Administration since December 2024	Leads energy policy in the largest oil importer

Terms

The vocabulary of oil

Term	Meaning
Barrel, and barrels a day	The industry's unit of volume: 42 US gallons, or 159 liters. Output and demand are flows, counted in barrels a day (b/d), thousands (kb/d), or millions (mb/d)
Crude oil, condensate, and natural gas liquids	Crude is the liquid that comes out of an oil reservoir; condensate is a very light liquid that comes with natural gas; natural gas liquids, such as ethane, propane, and butane, are separated from gas. "Liquids" counts all three, with biofuels and refinery gains, so it runs above "crude"
API (American Petroleum Institute) gravity	Its measure of how light a crude is: the higher the number, the lighter the oil. Light crudes, above about 31°, yield more gasoline and diesel and fetch higher prices
Sweet and sour	Sweet crude has little sulfur (under about 0.5%); sour crude has more, which costs more to remove, so it sells at a discount
Benchmark crude	A crude whose traded price sets the price of others by a premium or discount: Brent for the Atlantic basin, West Texas Intermediate (WTI) for America, Dubai and Oman for the Persian Gulf's exports to Asia, Murban for the UAE's
Brent futures and Dated Brent	Brent futures are contracts traded on the Intercontinental Exchange for delivery in a future month; Dated Brent is Platts' assessment of physical North Sea cargoes loading in the next 10 days to a month. In 2026 the two parted by as much as $35 a barrel
Backwardation and contango	Backwardation: oil for prompt delivery costs more than oil for later delivery, a sign of scarcity now. Contango: the reverse, a sign of surplus, when storing oil to sell later pays
Crack spread and refining margin	The difference between the price of products, such as gasoline and diesel, and the price of the crude they are made from: a rough measure of what a refiner earns per barrel
Upstream, midstream, downstream	Upstream finds and produces oil; midstream moves and stores it, in pipelines, tankers, and tanks; downstream refines and sells it
Proved reserves	Oil that existing technology can recover profitably at current prices with reasonable certainty; resources are the larger amount that may become reserves one day
Decline rate	The rate at which a field's output falls each year once it passes its peak, unless more wells are drilled
Spare capacity	Output that is idle but could start within 30 days and be sustained for at least 90 days, by the EIA's definition; almost all of it sits in a few Gulf states
Shut-in production	Output stopped on purpose or by force, such as Gulf output that could not be exported in 2026
Breakeven price	For a well, the oil price at which it covers its full costs; for a government, the fiscal breakeven, the price at which its budget balances
National oil company (NOC)	A state-owned oil company, such as Saudi Aramco or Petrobras; the NOCs hold most of the world's reserves
Production-sharing contract	An agreement under which a foreign company bears the cost of finding and producing oil and recovers it from output, splitting the rest with the state
OPEC and OPEC+	OPEC is the Organization of the Petroleum Exporting Countries, founded in 1960. OPEC+ adds Russia and other producers that have coordinated output with it since 2016
The price cap	The ceiling, first set at $60 a barrel by the Group of Seven (G7) and the EU in December 2022, above which their firms may not ship, insure, or finance Russian crude
The shadow fleet	Aging tankers with opaque owners and insurers that carry sanctioned oil from Russia, Iran, and Venezuela
Strategic reserve and days of cover	Oil stockpiled by governments for emergencies, such as America's Strategic Petroleum Reserve (SPR); days of cover divides stocks by daily use or imports. IEA members must hold stocks equal to 90 days of net imports

Term	Meaning
Liquefied natural gas (LNG)	Natural gas chilled to a liquid so that it can travel by ship
Petrochemical feedstock	Oil and gas used as raw material rather than fuel: naphtha from refineries and ethane from gas are cracked into the building blocks of plastics, fibers, and chemicals
Haber-Bosch process	The method, from 1913, that makes ammonia, the basis of nitrogen fertilizer, from nitrogen in the air and hydrogen, which today comes mostly from natural gas
Electric vehicle (EV)	In this course, a vehicle that can run on electricity from the grid: battery-electric, or plug-in hybrid where a source counts both

Module 1 — What Oil Is, and Where It Lies

Formation, Grades, Reserves, and Decline

Recommended Reading / Reference

Book: Kenneth S. Deffeyes, *Hubbert's Peak: The Impending World Oil Shortage* (2001; revised edition 2008), a Princeton geologist's plain account of how oil forms, gathers in traps, and runs down, with a forecast of a world peak in the 2000s that later supply proved wrong

Reference: OPEC, *Annual Statistical Bulletin 2026* (April 29, 2026), for reserves by country, and the IEA's *The Implications of Oil and Gas Field Decline Rates* (September 16, 2025), for how fast fields run down

1a. What Oil Is

Crude oil is a mixture of hydrocarbons, molecules made of hydrogen and carbon atoms, ranging from small ones that boil away at room temperature to large ones as thick as tar. Crude also carries sulfur, nitrogen, and traces of metals such as nickel and vanadium, which refineries must remove or manage (Module 5). Every field yields its own blend, and the blend sets its value (section 1c).

Three liquids are counted as oil, and statistics differ by which ones they include. Crude oil is liquid both in the reservoir and at the surface. Condensate is a very light hydrocarbon that is a gas deep underground and turns to liquid as it rises and cools, mostly in gas fields. Natural gas liquids (NGLs), chiefly ethane, propane, and butane, are separated from natural gas at processing plants and carry less energy per barrel than crude. Counts of "total liquids" add all three, and some also add biofuels and the volume a refinery gains in processing, so one country's output can be stated in several ways (Module 3).

Oil is measured in barrels of 42 US gallons, about 159 liters, the size that Pennsylvania's producers settled on in the 1860s, when oil still traveled in wooden casks. Output is counted in barrels a day (b/d), and national and world volumes in million barrels a day (mb/d). Some countries report in tonnes, and a tonne of average crude is about 7.3 barrels, more for light oil and fewer for heavy. A barrel of crude holds about 5.8 million British thermal units (Btu), equal to about 1,700 kilowatt-hours, where one Btu is the heat that warms a pound of water by one degree Fahrenheit.

1b. How Oil Forms and Is Trapped

Almost all oil began as microscopic marine algae and plankton. Where they died in still, oxygen-poor water, their remains settled into fine mud instead of rotting, and the mud hardened into an organic-rich source rock, usually a dark shale. Buried under later sediment, the organic matter turned into a waxy solid called kerogen. Heat then cracked the kerogen into oil, mostly between about 60°C and 120°C, the range geologists call the oil window, which is reached two to four kilometers down. Deeper and hotter, the molecules crack further into natural gas.

Oil is lighter than water, so once formed it is squeezed out of the source rock and moves upward through cracks and porous layers, a process called migration. Where nothing stops it, it seeps out at the surface, and bacteria and air break it down into tar. The oil sands of Alberta are oil of this kind, degraded by bacteria at shallow depth after it migrated (section 1d).

A field forms only where oil collects in a trap. The oil fills the tiny spaces between the grains of a porous, permeable reservoir rock, usually sandstone or a carbonate such as limestone. Oil does not sit in underground lakes: a reservoir looks like solid rock and holds oil the way a sponge holds water. Above it lies a seal, a layer the oil cannot pass, such as shale or salt. An upward fold of the layers (an anticline), a fault, or a salt dome makes a structural trap, and a reservoir layer that thins out, or a buried reef, makes a stratigraphic one.

Geologists call the whole chain a petroleum system: a rich source rock, a migration route, a reservoir, a seal, a trap, and the right timing, since the trap must form before the oil passes. All six rarely line up, which is why most of the world's oil sits in a few basins. The Arabian basin had rich source rocks, thick porous carbonates, and seals of salt and anhydrite over broad, gentle folds, and that is why the Gulf holds the largest reserves (section 1e).

Explorers find traps by mapping buried layers with seismic surveys, which time sound waves reflected back from the rock, and then by drilling exploration wells. The search is slow, and the IEA puts the average time from an exploration license to first production at almost 20 years, close to a decade to make a discovery and another to appraise, approve, and build it (*Journal of Petroleum Technology*, September 19, 2025).

1c. Grades: Light and Heavy, Sweet and Sour

Two properties set what a crude is worth: its density and its sulfur. Density is measured on a scale of the American Petroleum Institute (API), in degrees of API gravity, which equal 141.5 divided by the oil's specific gravity (its density relative to water), minus 131.5. Water scores 10 degrees, and lighter oil scores higher. Crude above about 31 degrees is called light, crude between about 22 and 31 degrees medium, and crude below about 22 degrees heavy. Extra-heavy oil, below 10 degrees, is denser than water.

Crude with less than about 0.5% sulfur by weight is called sweet, and crude with more is called sour. Light crude yields more gasoline, diesel, and jet fuel from simple distillation. Heavy crude yields more residual fuel and asphalt unless the refinery has costly units, such as cokers and hydrocrackers, that break large molecules into small ones, and sulfur is unwanted both in processing and in the fuels (EIA). Heavy, sour grades therefore sell at a discount that roughly reflects the extra cost of processing them (Module 5).

Grade	Where it comes from	API gravity (degrees)	Sulfur (% by weight)	Class
West Texas Intermediate (WTI)	Inland US, priced at Cushing, Oklahoma	About 40	About 0.3	Light, sweet
Brent blend	North Sea, British sector	About 38	About 0.4	Light, sweet
Arab Light	Saudi Arabia	About 33	About 2	Light, sour
Dubai	Dubai, United Arab Emirates	About 31	About 2	Medium, sour
Urals	Russia, shipped from Baltic and Black Sea ports	About 31	About 1.5	Medium, sour
Maya	Mexico, offshore fields	About 22	About 3.3	Heavy, sour
Western Canadian Select	Alberta, Canada	About 21	About 3.5	Heavy, sour
Merey	Venezuela, a blend from the Orinoco belt	About 16	About 2.5	Heavy, sour

Typical values from producers' and price agencies' published assays, rounded. Individual cargoes vary, and the Brent price now covers several North Sea grades and a US one (Module 6).

Western Canadian Select (WCS), the main blend of Alberta's heavy oil and oil sands bitumen, shows how grade and geography combine. By the estimate of the Canadian Imperial Bank of Commerce (CIBC), WCS

averaged $11.30 a barrel below WTI in 2025, a narrower gap than before because the expanded Trans Mountain pipeline gave Alberta a route to Asia (Module 3). CIBC forecast a wider gap of $14.25 for 2026, as heavy crude from Venezuela returns to compete for the same Gulf Coast refineries (The Canadian Press, January 13, 2026). On July 28, 2026, WCS for September delivery traded $12.25 below WTI (CalRock, a brokerage).

The discount pays for distance as well as quality, because Alberta is far from the refineries that buy its crude. It also moves with supply, since what a grade fetches depends on how much of it is on offer and how many refineries are built to run it. In March 2026, when the war cut off most of the Gulf's medium sour crude, Dubai, the Gulf's sour benchmark, traded far above Brent, the reverse of the usual order (Module 8 has the prices).

1d. Conventional and Unconventional Oil

In a conventional field, oil flows through permeable rock to the well, pushed by the reservoir's own pressure. That primary stage typically recovers about 10% of the oil in place. Injecting water or gas to sweep the oil toward the wells, called secondary recovery, raises the total to 20-40%. Enhanced oil recovery (EOR), which injects carbon dioxide, steam, or chemicals, can lift it to 30-60% or more (US Department of Energy). Most oil that is found therefore stays in the ground, and better methods can add reserves without any new discovery.

Shale oil, also called tight oil, sits in rock so impermeable that the oil barely moves, usually the source rock itself or a layer beside it. Producers drill down and then sideways, often for two miles or more, and pump water, sand, and chemicals down at high pressure to crack the rock in dozens of stages, a method called hydraulic fracturing, or fracking. A shale well takes weeks to drill and months to bring on, against years for a conventional project, but its output falls fast (section 1f). Shale oil is not oil shale, a kerogen-rich rock that must be heated to yield oil and is produced only in small amounts.

Oil sands hold bitumen, oil so thick at reservoir temperature that it will not flow. Near the surface it is mined and washed out of the sand. Deeper deposits are heated in place, most often by steam-assisted gravity drainage (SAGD), in which steam from one horizontal well melts the bitumen so that it drains into a second well below. Bitumen is thinned with lighter hydrocarbons to move by pipeline, or upgraded into a light synthetic crude. A project costs a great deal up front, but once built it can run at a steady rate for decades (Module 3).

Deepwater fields lie under more than about 300 meters (1,000 feet) of water. They are produced through wells on the seabed tied to platforms or to floating production, storage, and offloading vessels (FPSOs), ships that process the oil at sea and load it onto tankers. Brazil's pre-salt fields lie beneath up to 2 kilometers of salt, which itself lies under about 2 kilometers of water. Guyana, where oil was found offshore in 2015, and the US Gulf of Mexico are the other main deepwater provinces (Module 3). Once past their peak, their fields decline faster than the onshore giants (section 1f).

Venezuela's Orinoco belt holds extra-heavy oil, denser than water, which must be diluted or upgraded before it can be shipped, and it accounts for most of Venezuela's reserves (section 1e). Each of these resources costs more per barrel to develop than the Gulf's conventional oil (Module 3).

1e. Reserves: How Much Is There?

Oil in place is all the oil in a reservoir, of which only part can be recovered, and only part of that is worth recovering at today's prices. Under the Petroleum Resources Management System of the Society of Petroleum Engineers, proved reserves are volumes that the data show can be recovered from known fields with reasonable certainty, at least a 90% chance, at current prices and costs. Proved plus probable reserves have at least a 50% chance of being recovered, and proved, probable, and possible together at least 10%. Resources found but not yet commercial are called contingent, and those not yet found are prospective.

OPEC's *Annual Statistical Bulletin*, published on April 29, 2026, puts the world's proved crude reserves at 1,572 billion barrels at the end of 2025, as read by StatRanker, a data site, since OPEC's own site could not be reached. The six largest holders report 72.6% of the total and the ten largest 85.8% (table). Five Gulf countries, Saudi Arabia, Iran, Iraq, the United Arab Emirates (UAE), and Kuwait, report 53.3%. At OPEC's count of 2025 crude output, about 27 billion barrels a year (Module 3), the total would last about 58 years.

That ratio is not a countdown, because reserves are an inventory of what companies and governments have shown they can produce, and the inventory grows as prices rise, technology improves, and fields become better understood. US proved reserves more than doubled between 2008 and 2019, as shale drilling turned resources into reserves (EIA). The world has not been short of oil in the ground, only, at moments, of oil that is developed, permitted, and able to reach a port.

Country	Proved reserves, end-2025 (billion barrels)	Share of OPEC's world total	What they are
Venezuela	303.7	19.3%	Mostly extra-heavy Orinoco oil
Saudi Arabia	267.2	17.0%	Ghawar and other giants (section 1f)
Iran	208.6	13.3%	Khuzestan onshore; offshore Gulf
Iraq	140.0	8.9%	Southern giants; Kurdistan
UAE	120.0	7.6%	Mostly Abu Dhabi
Kuwait	101.5	6.5%	Greater Burgan
Russia	80.0	5.1%	West Siberia; Volga-Urals; Arctic
Libya	48.4	3.1%	Africa's largest
United States	41.9	2.7%	Shale; Gulf of Mexico; Alaska
Nigeria	37.0	2.4%	The Niger Delta
China	34.5	2.2%	Onshore fields; Bohai Bay
Kazakhstan	30.0	1.9%	Tengiz; Kashagan; Karachaganak
Qatar	25.2	1.6%	Chiefly a gas producer
Brazil	16.8	1.1%	Offshore pre-salt
Canada	5.1	0.3%	Leaves out the oil sands

OPEC, *Annual Statistical Bulletin 2026*, Table 3.1, as read by StatRanker (July 26, 2026, updated October 7, 2026). Shares of OPEC's world total are computed for this course.

Two countries show how much the definitions matter. Venezuela reports the largest reserves in the world (table), mostly extra-heavy oil in the Orinoco belt, and it has reported more than Saudi Arabia since that oil was added to its proved reserves around 2010, yet it is not among the ten largest producers (Module 3). Canada's figure for OPEC leaves out the oil sands. Natural Resources Canada puts the country's reserves at about 171 billion barrels, of which up to 166.3 billion are in the oil sands, a figure that would rank Canada fourth in the world (as quoted by OilPrice.com, April 24, 2023).

Reserves are also political, because they confer standing and, at times, a claim to output. In the 1980s, when OPEC members debated basing output quotas partly on reserves, the Gulf countries and Venezuela raised their reported reserves by 86% “without any significant increase in exploration” (Julian Lee, Bloomberg Opinion, January 13, 2019). Kuwait added 26 billion barrels in 1985, Iraq doubled its figure from 47 billion to 100 billion in 1988, and Saudi Arabia added 88 billion in 1990 (EIA data, via *The Geography of Transport Systems*). Lee also offers a more charitable reading: the countries may have been catching up on discoveries made earlier.

Saudi Arabia’s figure has stayed near 260 billion barrels since 1990, despite more than three decades of heavy production, which skeptics read as a sign that it is not a real count. Defenders answer that better recovery and newly booked fields have replaced what was pumped, and an outside audit supports them: DeGolyer and MacNaughton, a US consulting firm, confirmed 263.1 billion barrels at the end of 2017 (Bloomberg Opinion, January 2019). Other national figures differ by source: Iraq’s in the 2026 *Bulletin* (table) is lower than the 145 billion barrels in OPEC data quoted in 2023. Reserves are best read as claims, and output, decline, and cost as the measures that matter.

1f. The Giant Fields and Decline

A few fields hold a large share of the world’s oil. Ghawar in Saudi Arabia, found in 1948 and producing since 1951, is the largest conventional field ever found, an anticline about 280 kilometers long. Its capacity was not published until Saudi Aramco’s bond prospectus of 2019 put its maximum sustainable output at 3.8 mb/d. Most of the other giants were found before 1980 (table), and several are long past their peaks.

Field	Country	Found	Output (year)	What it shows
Greater Burgan	Kuwait	1938	1.7 mb/d (2025)	The second-largest field; Kuwait’s mainstay
Safaniya	Saudi Arabia	1951	1.2 mb/d (2025)	The largest offshore field
Rumaila	Iraq	1953	1.4 mb/d (2025)	Iraq’s largest producer
Samotlor	Russia	1965	0.33 mb/d (2025)	West Siberia’s giant, long in decline
Prudhoe Bay	US (Alaska)	1968	0.32 mb/d (2023)	North America’s largest conventional field
Cantarell	Mexico	1976	0.14 mb/d (2025)	About 2.1 mb/d at its 2004 peak
Tengiz	Kazakhstan	1979	0.93 mb/d (2025)	Deep and sour (Module 3 has its expansion)
Tupi	Brazil	2007	0.866 mb/d (February 2026)	Brazil’s top field, under the salt

Wikipedia, “List of oil fields” (accessed October 23, 2026), for discovery years and most outputs, which are company and analyst estimates. Tupi: Brazil’s National Agency of Petroleum, Natural Gas and Biofuels, via Datamar (April 2, 2026).

A field’s life has three stages: a build-up as wells are drilled, a plateau held by adding wells and managing pressure, and a decline once the reservoir can no longer keep up. Johan Sverdrup, Norway’s largest field, found in 2010 and producing since 2019, has a capacity of 755,000 b/d. It held its plateau for about three years, and Equinor’s chief executive said on February 4, 2026 that its output would fall by more than 10% but well below 20% in 2026 (*Journal of Petroleum Technology*, February 6, 2026).

Decline is the rate at which a field’s output falls without new drilling, and it varies widely. The IEA’s 2025 study of about 15,000 oil and gas fields found that the Middle East’s onshore supergiants decline by less than 2% a year and smaller offshore fields in Europe by more than 15%. Shale output, without new drilling, falls by more than 35% in its first year and a further 15% in its second (IEA, September 16, 2025). A shale basin must therefore keep drilling just to stand still.

Added up across the world, decline is the industry's treadmill. Without investment, the IEA estimates, world oil supply would fall by about 5.5 mb/d a year, up from 3.9 mb/d in 2010, a yearly loss equal to the output of Brazil and Norway combined. If all spending stopped at the end of 2025, output would fall to 42 mb/d by 2035 (Argus, September 16, 2025). Shale and deepwater fields, whose output falls faster than that of the onshore giants, supply a much larger share of the world's oil than in 2010, which is one reason the loss has grown. What replacing it costs is the subject of Module 13.

Worked example — One Field's Life, and the Wells That Hold It Flat

Take a field that reaches a plateau of 100,000 b/d. Assume, as an illustration, that once the plateau ends its wells lose 12% of their output each year, a rate between the Gulf's supergiants and Europe's small offshore fields, and that each new well adds 2,000 b/d and then declines at the same 12%. Left alone, the field gives $100{,}000 \times 0.88 = 88{,}000$ b/d after one year, $100{,}000 \times 0.88^{5} = 52{,}773$ b/d after five, and $100{,}000 \times 0.88^{10} = 27{,}850$ b/d after ten. To hold 100,000 b/d instead, the operator must replace $12\% \times 100{,}000 = 12{,}000$ b/d every year, which takes $12{,}000 \div 2{,}000 = 6$ new wells a year, or 60 in a decade. After ten years the original wells give 27,850 b/d and the wells drilled since give 72,150 b/d, so 72% of the output comes from wells that did not exist at the start. At a supergiant's 2% decline, the same field would need one new well a year, and its original wells would still give $100{,}000 \times 0.98^{10} = 81{,}707$ b/d after ten years. At 15%, like a small North Sea field, it would need 7.5 wells a year, and its original wells would fall to $100{,}000 \times 0.85^{10} = 19{,}687$ b/d. The IEA's world estimate (section 1f) is the same arithmetic summed over thousands of fields.

Module 1 Key Points

What Oil Is, and Where It Lies

• A barrel is 42 US gallons (159 liters), and counts of oil differ by whether they include condensate, natural gas liquids, and biofuels.

• Light, sweet crude is worth more: Western Canadian Select, heavy and sour, averaged an estimated $11.30 a barrel below WTI in 2025.

• OPEC counts 1,572 billion barrels of proved reserves at the end of 2025, and Venezuela, Saudi Arabia, and Iran report about half.

• Reserves are claims: the Gulf countries and Venezuela raised theirs 86% in the 1980s without significant new exploration.

• Without investment, the IEA estimates, world oil supply would fall about 5.5 mb/d a year, up from 3.9 mb/d in 2010.

• Decline ranges from under 2% a year for Gulf supergiants to over 35% in a shale field’s first year without new drilling.

Module 1 Quiz

Check Your Understanding

1. What does the API gravity scale measure?

A) Sulfur content
B) Density
C) The share of a crude that simple distillation turns into gasoline, diesel, and jet fuel
D) Thickness at room temperature

2. By OPEC's count, how much oil did the world hold in proved reserves at the end of 2025?

A) About 171 billion barrels
B) About 303.7 billion
C) About 4,000 billion barrels, counting the oil in place that today's methods cannot recover
D) About 1,572 billion barrels

3. Why does Western Canadian Select sell below WTI?

A) It holds less energy per barrel, so buyers pay less for each barrel.
B) OPEC+ quotas limit how much of it can be sold to US refiners.
C) It is heavy and sour, so it needs costlier refining, and it must travel far from Alberta to reach refineries.
D) US law taxes heavy crude at a higher rate than light crude.

4. What did the IEA's 2025 study find would happen to world oil supply without new investment?

A) It would fall by about 5.5 mb/d a year.
B) It would hold steady for a decade, because the Gulf's supergiants barely decline.
C) It would fall by about 1 mb/d a year, in line with demand.
D) It would fall 35% a year.

5. Why are national reserves figures best read as claims rather than measurements?

A) They are kept secret
B) They are reported in tonnes, not barrels
C) Oil companies, not governments, report every country's reserves, and they inflate them to lift share prices
D) Several OPEC members raised theirs sharply in the 1980s without new exploration

Module 2 — A History in Shocks

From Titusville to the Negative Price of 2020

Recommended Reading / Reference

Book: Daniel Yergin, *The Prize: The Epic Quest for Oil, Money & Power* (1991), the Pulitzer Prize-winning history from Titusville to the Gulf War of 1991, still the standard account

Reference: US Bureau of Labor Statistics, the Consumer Price Index for All Urban Consumers (CPI-U), the index this module uses to restate old prices in September 2026 dollars

2a. The First Wells and Standard Oil

On August 27, 1859, Edwin Drake's crew struck oil at a depth of 69 feet near Titusville, Pennsylvania (History.com). The first large market was kerosene for lamps, which replaced whale oil and oils distilled from coal, while gasoline was a waste product for decades, until the car gave it a use. The industry spread fast, and by 1909 the United States produced more oil than the rest of the world combined.

John D. Rockefeller built the first great oil company out of refining in Cleveland. In 1867, with his brother William, Henry Flagler, and Stephen Harkness, he formed the partnership that became the Standard Oil Company, incorporated in Ohio in 1870. Standard won through scale, secret rebates from the railroads, its own pipelines, and the purchase or ruin of its rivals. By the 1880s it controlled about 90% of American refining capacity (CMC Markets).

The federal government sued Standard under the Sherman Antitrust Act of 1890, and on May 15, 1911, the Supreme Court ordered the trust broken into 34 companies. Several of them survive inside today's largest companies (section 2b and Module 4). The breakup did not end the industry's pull toward size, and the contest moved abroad, where a handful of companies would soon control most of the oil outside the United States.

Texas made the next boom. The Spindletop gusher near Beaumont, on January 10, 1901, launched the companies that became Texaco and Gulf Oil. The East Texas field, found in October 1930, held about 5 billion barrels, and its flood of oil drove the local price to as little as 10 cents a barrel in 1931 (History.com). Texas answered with prorationing, in which the Texas Railroad Commission set how much each well could pump, and for four decades its limits steadied the American price.

2b. The Seven Sisters and the Concessions

Outside the United States, oil was found under concessions, contracts in which a government granted a foreign company the right to explore and produce across a huge area for decades, in return for a royalty. William Knox D'Arcy's concession of 1901 in Persia led to the discovery at Masjed Soleyman in 1908 and to the Anglo-Persian Oil Company (table). Oil followed in Iraq in 1927, Bahrain in 1932, and Saudi Arabia and Kuwait in 1938, while Venezuela's Lake Maracaibo boomed from 1922.

The companies learned to cooperate. In 1928 the owners of the Iraq Petroleum Company signed the Red Line Agreement, promising to act only jointly across most of the former Ottoman Empire. In the same year the heads of Standard Oil of New Jersey, Shell, and Anglo-Persian met at Achnacarry Castle in Scotland and agreed to hold their shares of the market "as is".

Enrico Mattei, who ran Italy's state oil company, Ente Nazionale Idrocarburi (ENI), called the seven companies that dominated the business the Seven Sisters. Until the 1970s they found, produced, refined, and sold most of the oil traded outside the United States and the Soviet Union. They also set the "posted prices" from which the host governments' taxes and royalties were calculated, so each company's pricing decision was also a decision about a country's budget.

Company in the 1950s	Origin	What it became
Anglo-Iranian Oil Company	Founded in 1909 as Anglo-Persian, to work the Persian concession	BP, renamed in 1954
Royal Dutch Shell	A Dutch and British alliance of 1907	Shell
Standard Oil of New Jersey (Esso)	The largest piece of Standard Oil after 1911	Exxon, which merged with Mobil in 1999 to form ExxonMobil
Standard Oil of New York (Socony, later Mobil)	Another piece of Standard Oil	Part of ExxonMobil since 1999
Standard Oil of California (Socal)	A piece of Standard Oil; held the Saudi concession from 1933	Chevron
Texaco	Founded in Texas in 1902, after Spindletop	Merged into Chevron in 2001
Gulf Oil	Founded by Pittsburgh's Mellon family, after Spindletop	Bought by Socal, which renamed itself Chevron, in 1984

Company histories. The seven are now four: BP, Shell, ExxonMobil, and Chevron (Module 4).

The producing countries pushed for a larger share. Venezuela legislated a fifty-fifty split of profits in 1948, and Saudi Arabia won the same in December 1950 from Aramco, the American consortium working its concession. Iran went further: in 1951, under Prime Minister Mohammad Mosaddegh, it nationalized the Anglo-Iranian Oil Company, and the companies answered with a boycott of Iranian oil. A coup backed by the United States and Britain removed Mosaddegh in August 1953, and a consortium of foreign companies returned to Iran in 1954 on fifty-fifty terms.

2c. OPEC and the Nationalizations

In February 1959 and again in August 1960, the companies cut their posted prices without consulting the producing governments, and so cut those governments' revenue. In response, at a meeting in Baghdad on September 10-14, 1960, Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela founded the Organization of the Petroleum Exporting Countries (OPEC). Its leading figures were Venezuela's oil minister, Juan Pablo Pérez Alfonzo, who had studied the Texas Railroad Commission's prorationing, and Saudi Arabia's chief oil official, Abdullah Tariki.

For a decade OPEC achieved little, because the companies still controlled output and the United States could make up any shortfall. When Arab producers embargoed the United States and Britain during the war of June 1967, American spare wells covered the gap and the embargo failed. Then the cushion vanished: US crude output peaked at 9.6 million barrels a day (mb/d) in 1970, and in March 1971 the Texas Railroad Commission allowed full production for the first time since the Second World War. From then on, the world's spare capacity, the output that can be added quickly, sat in the Gulf (Module 7 describes who holds it today).

The producers then took control in two steps. First they took over pricing: Libya, under Muammar Qaddafi, forced higher prices on the companies in 1970, and the Gulf producers won a further rise in the Tehran agreement of February 1971. Then they took ownership of the oil itself (table). By 1980 most of the large exporters owned their oil, and their national oil companies sold it, with the old majors as buyers, partners, or contractors (Module 4).

Country	When	What the state took	State company
Mexico	March 18, 1938	The assets of the foreign oil companies	Petróleos Mexicanos (Pemex)
Iran	1951	The Anglo-Iranian Oil Company’s concession	National Iranian Oil Company
Algeria	February 24, 1971	51% of the French companies’ interests, later all of them	Sonatrach
Libya	1971-74	BP’s share in 1971, majority stakes in the other foreign companies by 1974	National Oil Corporation
Iraq	June 1, 1972	The Iraq Petroleum Company	Iraq National Oil Company
Kuwait	1975	All of the Kuwait Oil Company, after 60% in 1974	Kuwait Oil Company
Venezuela	January 1, 1976	The whole industry, under a law of August 29, 1975	Petróleos de Venezuela (PDVSA)
Saudi Arabia	1973-80	Aramco, in stages, fully owned from 1980	Saudi Aramco, so named in 1988

Wikipedia, “Nationalization of oil supplies” and “1973 oil crisis” (accessed October 23, 2026), and company histories.

2d. 1973 and 1979

On October 6, 1973, Egypt and Syria attacked Israel, and on October 16 the Gulf members of OPEC raised the posted price of Saudi Arabian Light by 70%, from $3.01 to $5.12 a barrel, without negotiating with the companies. The next day the Arab producers of the Organization of Arab Petroleum Exporting Countries (OAPEC) agreed to cut their output by 5% a month. Saudi Arabia announced a total embargo on the United States on October 19, after President Richard Nixon asked Congress for $2.2 billion of emergency aid for Israel, and the Netherlands was embargoed as well.

In late December 1973 the Gulf producers set the posted price at $11.65 from January 1, 1974, almost four times its level of early October. In the United States, price controls and fuel allocation rules turned the shortage into lines at gasoline stations. The Arab oil ministers, except Libya’s, announced the end of the embargo on March 17, 1974 (Wikipedia, “1973 oil crisis”). The importers answered by founding the IEA in November 1974 and by building emergency stocks (Module 12).

The second shock came from Iran, where strikes in the oil fields from late 1978 and the revolution that drove the Shah out on January 16, 1979 cut exports, and panic buying by companies and governments did the rest. OPEC had held Saudi Arabian Light at $12.70 a barrel through 1978. Saudi Arabia raised it to $28 from April 1, 1980, and by December 1980 it charged $32 while the other members priced off a $36 benchmark (Wikipedia, “1980-1989 world oil market chronology”). Iraq’s invasion of Iran on September 22, 1980 began a war that lasted eight years.

The two shocks moved the power to set prices from the companies to the producing governments, and they changed the buyers too. Importers took oil out of power stations, cars became more efficient, and new supply arrived from Alaska, the North Sea, and Mexico. Each shock was followed by a recession in the United States, a link that Module 9 examines.

2e. The 1986 Collapse and the Cheap-Oil Years

High prices destroyed demand and called forth supply. World oil use fell for several years after 1979, while the Trans-Alaska Pipeline (from 1977), the North Sea’s Forties field (from 1975), and Mexico’s Cantarell (Module 1) added barrels outside OPEC. Saudi Arabia acted as the swing producer, cutting its own output to

hold the price while other members pumped above their quotas, and between 1981 and 1985 it cut its output by about two-thirds.

In the second half of 1985 Saudi Arabia gave up the role. It began selling on netback terms, which set the price of each cargo from the value of the products refined from it and so guaranteed refiners a margin, and it raised output to win back market share. In 1986 spot prices for crude fell by more than half, and the spot price of Brent cargoes dipped under $9 in July (Wikipedia, “1980s oil glut” and the 1980s chronology). In December 1986 OPEC agreed to aim for $18.

The collapse also ended the era of official prices. The New York Mercantile Exchange (NYMEX) had begun trading crude oil futures, contracts to buy or sell oil for delivery in a later month, in March 1983, and London’s International Petroleum Exchange added Brent futures in June 1988. By the end of the 1980s most exporters sold their crude at formula prices tied to benchmark grades, the system that still prices oil today (Module 6).

Cheap oil lasted, with interruptions, for most of the next 17 years. Iraq’s invasion of Kuwait on August 2, 1990 took both countries’ exports off the market and more than doubled the spot price of Brent, from under $20 in July to about $40 in October. Saudi output and emergency stocks then replaced the lost barrels (Module 12 covers the US reserve’s part). After the Asian financial crisis of 1997-98, Brent’s spot price fell to about $10 a barrel in December 1998, and in March 1999 *The Economist* suggested that $5 might follow.

The low prices drove the great mergers of 1998-2002, among them BP with Amoco and Conoco with Phillips (Module 4), and they left little spare capacity in place for the surge in demand that began after 2003.

2f. 2008’s Spike and the Shale Revolution

From 2003, demand from China and other emerging economies grew faster than supply, and OPEC’s spare capacity ran thin. Brent futures touched a record $147.50 a barrel on July 11, 2008. The financial crisis then cut demand, and by December 2008 Brent futures were below $40 (CMC Markets).

The high prices paid for a new technique. Drillers had learned to combine horizontal wells with hydraulic fracturing in many stages (Module 1), first on gas in the Barnett Shale of Texas around 2000, and then on oil in North Dakota’s Bakken and in Texas. American conditions suited it: landowners own the minerals beneath their land and can lease them, small firms could experiment quickly, and Brent futures stayed above $100 for most of 2011-14. US crude output rose from 5.0 mb/d in 2008 to 9.4 mb/d in 2015 (EIA).

The new supply broke the price, and at its meeting of November 27, 2014, OPEC left its output target unchanged, as Saudi Arabia’s oil minister, Ali al-Naimi, chose to defend market share rather than the price. Brent futures fell from $115 a barrel in June 2014 to below $28 in January 2016. Shale output dipped, but producers cut costs and drilled their best acreage, and the industry survived.

Saudi Arabia then sought partners outside OPEC. On November 30, 2016, OPEC agreed in Vienna to cut about 1.2 mb/d, and on December 10, 2016, 11 producers outside OPEC, led by Russia, agreed to cut about 558,000 barrels a day (b/d) under a Declaration of Cooperation. The combined group became known as OPEC+ (Module 7 describes how it works today).

The Gulf’s exposure showed on September 14, 2019, when drones and missiles struck Saudi Aramco’s processing plant at Abqaiq and its Khurais field and cut 5.7 mb/d, about half of Saudi output. Yemen’s Houthi movement claimed the attack, the United States blamed Iran, and Iran denied any part in it. Brent futures rose about 15% on the next trading day, then fell back as Aramco restored its output within weeks.

2g. The Negative Price of 2020, and 2022

The pandemic brought the largest fall in demand on record. On March 6, 2020, Russia refused the deeper cuts that Saudi Arabia proposed, and Saudi Arabia answered by cutting its prices and promising more output. As lockdowns spread, the IEA estimated that world demand in April 2020 was 29 mb/d lower than a year earlier. On April 12, OPEC+ agreed to cut 9.7 mb/d from May, the largest cut in its history.

On April 20, 2020, the WTI futures contract for May delivery settled at minus $37.63 a barrel, the day before it expired. A WTI contract ends in physical delivery at Cushing, Oklahoma, where storage was nearly full, so traders who held contracts and had nowhere to put the oil paid others to take it. Brent futures, which settle in cash, stayed above zero, and the episode showed that a price can fall below the cost of production, and even below zero, when there is no room to store the oil.

Two years later the shock ran the other way: Russia invaded Ukraine on February 24, 2022, and Brent futures traded above $139 a barrel on March 7, the highest since 2008. Western governments imposed sanctions, and the European Union stopped most imports of Russian crude by sea from December 5, 2022 (Module 11). Russian oil found new buyers in India and China, and IEA members released emergency stocks twice that year (Module 12).

Every shock in this history began above ground, with a war, an embargo, a revolution, a cartel’s decision, or a pandemic, not with the world running out of oil. Each high price also brought new supply and lower demand within a few years. The shock of 2026, when war closed the Strait of Hormuz, is the subject of Module 8.

Worked example — Every Peak in September 2026 Dollars

To compare prices across decades, multiply each by the US Consumer Price Index for All Urban Consumers (CPI-U, 1982-84 = 100) for September 2026, which was 336.940, and divide by the index for the month of the price (Bureau of Labor Statistics). Each peak is taken on the measure its era offers. December 1980: the $36 benchmark of the OPEC members other than Saudi Arabia, with the index at 86.3, gives 36 × 336.940 ÷ 86.3 = $140.55. July 2008: Dated Brent, the price of physical North Sea cargoes assessed by Platts, a price agency owned by S&P Global, reached $144.21-144.23 (S&P Global, April 16, 2026). Its midpoint, $144.22, with the index at 219.964, gives 144.22 × 336.940 ÷ 219.964 = $220.92. March 8, 2022: Brent futures settled at $127.98, their highest close of the year, and with the index at 287.504 that gives 127.98 × 336.940 ÷ 287.504 = $149.99. April 7, 2026: Dated Brent’s record of $144.42 (Module 8), with the index at 333.020, gives 144.42 × 336.940 ÷ 333.020 = $146.12. The 2026 record beat 2008’s by 20 cents in the dollars of each day, but in September 2026 dollars the 2008 peak was $74.80, or 51%, higher. On their own measures, the 1980 benchmark and the 2022 settlement came within 4% of the 2026 peak. Prices in general rose 53% between July 2008 and September 2026, so a record in today’s dollars need not be a record in real terms.

Module 2 Key Points

A History in Shocks

• Standard Oil controlled about 90% of US refining in the 1880s, and the Supreme Court split it into 34 companies on May 15, 1911.

• Five exporters founded OPEC in Baghdad in September 1960, after the companies cut the posted prices that set their revenue.

• In 1973-74 the posted price of Saudi Arabian Light rose from $3.01 to $11.65 a barrel in under three months.

• After Saudi Arabia stopped cutting output in 1985, the spot price of Brent cargoes fell below $9 in July 1986.

• WTI futures settled at minus $37.63 on April 20, 2020, because storage at Cushing, the delivery point, was nearly full.

• In September 2026 dollars, July 2008’s physical Brent peak was $220.92, 51% above April 2026’s record at $146.12.

Module 2 Quiz

Check Your Understanding

1. What did the Supreme Court order in 1911?

A) A ceiling on kerosene prices
B) A ban on railroad rebates
C) That Standard Oil be broken into 34 companies, several of which survive inside today's majors
D) The nationalization of Standard's pipelines

2. What prompted five exporters to found OPEC in 1960?

A) The 1973 Arab-Israeli war
B) Posted-price cuts
C) The closure of the Suez Canal
D) Aramco's nationalization

3. What happened to the posted price of Saudi Arabian Light between early October 1973 and January 1974?

A) It rose from $3.01 to $11.65 a barrel.
B) It fell, because the embargo cut demand in the United States and the Netherlands.
C) It doubled to about $6 and stayed there until the Iranian revolution.
D) It rose by 10%.

4. Why did WTI futures settle below zero on April 20, 2020?

A) OPEC+ had just agreed to double its output.
B) Holders of the expiring contract had to take oil at Cushing, where storage was nearly full.
C) An exchange error priced the contract in the wrong currency.
D) The US government paid producers to give oil away as part of its pandemic relief program for the energy industry.

5. In the worked example, how did July 2008's physical Brent peak compare with April 2026's record, in September 2026 dollars?

A) It was about the same, since both were near $144 in the dollars of their day.
B) It was lower, because the 2026 record came after more inflation.
C) It was 20 cents higher, the gap between the two prices as recorded.
D) It was about 51% higher.

Module 3 — Who Pumps It

The Producers and the Cost of a Barrel

Recommended Reading / Reference

Book: Gregory Zuckerman, *The Frackers: The Outrageous Inside Story of the New Billionaire Wildcatters* (2013), a *Wall Street Journal* reporter's account of the people who made shale work

Reference: The Federal Reserve Bank of Dallas's quarterly Dallas Fed Energy Survey, which asks producers about breakeven prices each March, and the Energy Institute's *Statistical Review of World Energy 2026* (June 30, 2026)

3a. World Output and the Top Ten

The world produced 100.59 million barrels a day (mb/d) of oil in 2025, counting crude, shale oil, oil sands, condensate, and natural gas liquids (NGLs), the light hydrocarbons separated from natural gas (Energy Institute, *Statistical Review of World Energy 2026*, via Rigzone, June 30, 2026). That was 3.5% more than in 2024, against an average rise of 0.9% a year in 2015-25. Crude and condensate alone came to 85.76 mb/d, and OPEC's narrower count of crude was 74.85 mb/d, 2.24 mb/d more than in 2024 (OPEC's *Annual Statistical Bulletin 2026*, via Shana, an Iranian news agency, since OPEC's site could not be reached).

The gap of about 15 mb/d between the first two figures is mostly NGLs, which carry less energy per barrel than crude. Counts also differ on whether they include biofuels and the volume that refining adds, so the same country's output can be stated in several ways, as Canada's shows (section 3d).

Growth in 2025 came mostly from the Americas and from OPEC+ members unwinding earlier cuts, by the IEA's account (Module 7). Argentina's output rose 17.2%, mostly from the Vaca Muerta shale, and Brazil's 12.4%, while Guyana and Venezuela also grew by double digits (Energy Institute, via the Institute for Energy Research, July 8, 2026). The ten largest producers pumped about 61 mb/d of crude between them, more than 70% of the world's (table). Most of their barrels come from state companies (Module 4).

Rank	Country	Crude, 2025 (mb/d)	Where it comes from
1	United States	13.58	Shale in the Permian Basin of Texas and New Mexico; the Gulf of Mexico; North Dakota; Alaska
2	Russia	9.87	West Siberia, the Volga-Urals, East Siberia
3	Saudi Arabia	9.51	Ghawar and other giant fields, on land and offshore
4	Canada	4.94	Alberta's oil sands; conventional and tight oil in Alberta and Saskatchewan
5	Iraq	4.39	Southern giants near Basra; the Kurdistan region
6	China	4.34	Old onshore fields such as Daqing and Changqing; Bohai Bay offshore
7	Iran	4.19	Onshore fields in Khuzestan such as Ahvaz; the offshore Gulf
8	United Arab Emirates (UAE)	3.82	Abu Dhabi's onshore fields and Upper Zakum offshore
9	Brazil	3.74	Pre-salt fields offshore, mainly in the Santos Basin
10	Kuwait	2.58	Greater Burgan

EIA data for crude oil including lease condensate (condensate separated at the well), January-November 2025 at an annual rate, as ranked by Visual Capitalist (May 13, 2026). The EIA's full-year figure for the United States is 13.66 mb/d. Saudi Arabia's crude was 9.73 mb/d on the Energy Institute's count and 9.48 mb/d on OPEC's.

3b. The United States

US crude output set an annual record in 2025 (table), and the records continued in 2026 with a monthly high of 13.934 mb/d in April, when New Mexico produced a record 2.37 mb/d and Texas 5.83 mb/d (EIA data released June 30, 2026). Output averaged 13.7 mb/d in the first half of 2026, 0.3 mb/d or 2% more than a year earlier. The EIA's Short-Term Energy Outlook of October 6, 2026 forecasts 13.9 mb/d for 2026 and 14.3 mb/d for 2027, each a record.

Counting NGLs and other liquids, US output was 21.065 mb/d in 2025, 20.9% of the world's and almost as much as Saudi Arabia and Russia together, at 22.145 mb/d (Energy Institute). The Permian Basin of west Texas and southeastern New Mexico is forecast to produce 6.8 mb/d of crude in 2026, about half the national total and 3% more than in 2025 (EIA, September 10, 2026). Offshore, the federal waters of the Gulf of Mexico, which US agencies have called the Gulf of America since 2025 (Module 12), produced 0.2 mb/d, or 10%, more in the first half of 2026 than a year earlier, as new floating platforms came on line.

The rigs tell a quieter story: Baker Hughes, an oilfield services company, counted 603 rigs drilling in the United States in the week to October 16, 2026, 55 more, or 10%, than a year earlier, and 459 of them were drilling for oil (Reuters, October 16, 2026). The week before, the count had reached its highest since 2024. That is a small rise for a year in which prices sat far above what a new well needs (section 3f).

Producers explain the restraint themselves. In the Dallas Fed's survey of 125 energy firms, taken on September 16-24 and released on September 30, 2026, half of the large producers said they expected to put additional cash flow toward returns to shareholders. One executive wrote that companies "must look at the steep backwardation and budget off of a $65 per barrel or $70 per barrel price" for WTI. Backwardation is the pattern in which oil for later delivery costs less than oil today, and in 2026 the futures for later years traded far below the nearest month (Module 6).

Better wells also mean fewer rigs. A services executive in the same survey reported that new equipment lets customers "make record wells and drill less wells to capture the same production." In the March survey, taken on March 11-19 while WTI spot averaged $94.65, 69% of large producers said they had made no change to their drilling plans (*Journal of Petroleum Technology*, April 6, 2026). In September, respondents expected WTI to end 2026 at $88 a barrel, and to stand at $79 and $82 two and five years after the survey. Mergers have also put the shale fields in fewer hands that favor payouts over growth (Module 4).

3c. The Gulf and Russia

Saudi Arabia ranked third in crude (table), and on the Energy Institute's count of all liquids it produced 11.408 mb/d in 2025, 5.1% more than in 2024, as OPEC+ unwound its cuts. Its oil comes from a few giant fields, Ghawar above all (Module 1). Iraq, Iran, the UAE, and Kuwait make up the rest of the Gulf's five largest producers, and together the five pumped about 24.5 mb/d of crude in 2025 (table).

The Gulf's oil is the cheapest in the world to develop (section 3f), because its fields are huge, its wells are prolific, and most of them lie on land or in shallow water. That cheap oil is also the most exposed. Most of it leaves through the Strait of Hormuz, which the war of 2026 closed (Module 8), and how much spare capacity the Gulf holds is the subject of Module 7.

Russia ranked second in crude (table), and on the Energy Institute's count of all liquids it produced 10.737 mb/d in 2025, 0.2% less than in 2024. Its oil comes mainly from West Siberia, where giants such as Samotlor are long past their peaks (Module 1), with newer output from East Siberia and the Arctic. Its place in OPEC+ is described in Module 7, and the sanctions on its exports in Module 11.

3d. Canada, Brazil, and Guyana

Canada set a record in 2025 of 5.35 mb/d of crude oil and equivalents, a measure that includes condensate and the synthetic crude made from bitumen, up from 5.14 mb/d in 2024, with 83.8% from Alberta (Canada Energy Regulator, June 17, 2026). The EIA's narrower count of crude was lower (table), and counting NGLs, output was about 6.3 mb/d (EIA). The oil sands produced 203.1 million cubic meters in 2025, about 3.50 mb/d and 65% of Canada's crude, of which about 2.19 mb/d was bitumen and 1.31 mb/d synthetic crude (Statistics Canada, June 2, 2026, at 6.29 barrels a cubic meter).

Trans Mountain, a pipeline from Alberta to the Pacific coast near Vancouver whose expansion entered service in May 2024, carried 761,000 barrels a day (b/d) in 2025, up 37% from 555,000 b/d in 2024, and used 85% of the 892,000 b/d of capacity available (Canada Energy Regulator, June 24, 2026). Exports to countries other than the United States rose 132.6%, to about 0.47 mb/d, or 10.9% of Canada's crude exports (Statistics Canada). Its sales to the United States are covered in Module 12.

Brazil set a record in February 2026 of 5.304 million barrels of oil equivalent a day, a measure that adds gas by its energy content, including 4.061 mb/d of oil (Brazil's National Agency of Petroleum, Natural Gas and Biofuels, via Datamar, April 2, 2026). The pre-salt fields supplied 80.2% of it. The largest single production unit was the Almirante Tamandaré, a floating production, storage, and offloading vessel (FPSO) on the Búzios field, at 197,900 b/d, and the largest field was Tupi (Module 1). In December 2025 the EIA expected Brazil's output to reach 4.0 mb/d in 2026.

Guyana's oil comes from the Stabroek block, operated by ExxonMobil with a 45% share alongside Chevron, with 30% through its purchase of Hess (Module 4), and the China National Offshore Oil Corporation (CNOOC), with 25%. Output began in December 2019 and passed 700,000 b/d gross in 2025, a record (ExxonMobil, January 30, 2026). In 2026 the block's four FPSOs, with a combined nameplate capacity, or design rate, of 810,000 b/d, have averaged above 900,000 b/d, some of them running above design (Industrial Info Resources, October 21, 2026).

The fifth vessel, the Errea Wittu, built for the Uaru project, arrived on August 21, 2026. It can handle 250,000 b/d of oil and 540 million cubic feet a day of gas, and the project cost $12.7 billion. As of October 21, ExxonMobil was making "final preparations", with first oil expected in the fourth quarter of 2026. Jaguar (250,000 b/d) is scheduled for 2027 and Hammerhead (150,000 b/d) for 2029, which would take nameplate capacity to 1.46 mb/d (Industrial Info Resources).

3e. Norway, Kazakhstan, and the New Frontiers

Norway produced 1.71 mb/d of oil in 2025, close to 40% of it from Johan Sverdrup (Norwegian Offshore Directorate, via Rigzone, March 20, 2026). Its output was higher in early 2026: 1.97 mb/d of oil in February, 15.3% more than a year earlier and 5.7% above the directorate's forecast, with total liquids at 2.18 mb/d. Sverdrup itself began to decline in 2026 (Module 1), so newer fields must carry any further growth.

Kazakhstan produced 87.7 million tonnes of oil and condensate in 2024 and planned 96.2 million for 2025, 9.7% more (*The Times of Central Asia*, March 11, 2025). The jump came from the Chevron-led expansion of the Tengiz field in January 2025, which added about 270,000 b/d. In February 2025 Kazakhstan pumped 1.77 mb/d, far above its OPEC+ quota (S&P Global Commodity Insights, via the Italian Trade Agency, March 13, 2025; Module 7). Most of its exports cross Russia through the Caspian Pipeline Consortium's line to the Black Sea.

New frontiers take years to reach first oil. In Namibia's Orange Basin, TotalEnergies plans to develop its Venus discovery, in about 3,000 meters of water, with an FPSO of about 150,000 b/d and about 750 million barrels in a first phase (*Offshore Magazine*, July 29, 2026). The company had aimed to take its final investment decision (FID), the formal commitment to build, by the end of July 2026. As of September 15, the decision was still pending while fiscal terms were negotiated, and it was expected in the fourth quarter of 2026, with first oil around 2030 (Blackridge Research).

TotalEnergies has also become operator of Galp's Mopane discovery, taking a 40% stake in a swap that Namibia approved in mid-July 2026, and expects to decide on it around 2028. The two fields could together produce about 350,000 b/d after 2030 (*Offshore Magazine*). In Suriname, next door to Guyana, TotalEnergies and APA Corporation approved the $10.5 billion GranMorgu project in October 2024, with an FPSO of 220,000 b/d, more than 750 million barrels of recoverable oil, and first oil expected in 2028 (Baird Maritime, October 2, 2024).

3f. What a Barrel Costs to Produce

Two measures of cost answer different questions. Lifting cost is what it takes to keep oil flowing from wells already drilled: labor, power, water handling, and repairs. Full-cycle cost adds the capital to find and develop the oil and a return on that capital. A producer keeps pumping an existing well as long as the price covers its lifting cost, but it drills a new one only if the price covers the full cycle.

The Dallas Fed's March 2026 survey measures both for US producers (fieldwork March 11-19, released March 25). Its 80 exploration and production (E&P) firms put the average WTI price needed to drill a new well profitably at $66 a barrel, against $65 a year earlier, with regional answers from $62 to $70. Permian firms needed $67, large firms $59, and small firms $68. Covering the operating costs of existing wells took only $43 on average, $32 for large firms and $46 for small ones (Rigzone, March 27, 2026).

The Permian's breakeven has risen. Novi Labs, a data firm, puts it at $63-70, up 30-40% from about $45-50 in 2020, and the EIA's reading of the survey gives about $69 in the Midland Basin and about $63 in the Delaware Basin (Novi Labs, March 30, 2026; EIA, September 10, 2026).

Rystad Energy, a consultancy, estimates full-cycle breakevens for new projects worldwide, priced in Brent (table). Its figure for North American shale is far below the Dallas Fed's, for three reasons. Rystad models projects on its own assumptions, while the Dallas Fed asks operators what price they need, including their own return targets. Rystad's figures date from October 2024, while the survey is from March 2026. And Brent usually trades a few dollars above WTI (Module 6), so each number is useful only with its definition.

Supply segment	Breakeven for new projects (Brent, $ a barrel)	Where
Onshore Middle East	27	Saudi Arabia, Iraq, Kuwait, Abu Dhabi
Offshore shelf	37	Shallow waters such as the North Sea's
Deepwater	43	Brazil's pre-salt, Guyana, the Gulf of Mexico
North American shale	45	The Permian, the Bakken, the Eagle Ford
Oil sands	57 on average, up to about 75	Alberta's mines and steam projects
Average new project outside OPEC	47, up 5% in a year	All segments outside OPEC

Rystad Energy, as reported by the *Oil & Gas Journal*, October 1, 2024. Rystad's breakevens are full-cycle estimates for projects not yet built.

Production cost is not the price a producing country needs. Saudi Arabia's oil costs little to produce, but its government needs a much higher price to balance its budget, its fiscal breakeven (Module 7). And a cheap barrel is cheap only if it can reach a buyer, as the Gulf learned in 2026 (Module 8).

3g. Has US Shale Peaked? The Cases as Their Advocates Make Them

The case that shale has peaked: in May 2025, Travis Stice, then Diamondback Energy's chief executive, told shareholders that US onshore oil output had likely peaked. Advocates of this view point to what high prices failed to buy in 2026: the rig count barely rose, and producers held to their plans and budgets (section 3b). They read rising breakevens as a sign that the best Permian acreage is being drilled out (section 3f). A shale field without new wells loses output fast (Module 1), so each year's growth needs more drilling than the last. A services executive described "limitations on growth and bottlenecks in bringing new wells online" (Dallas Fed, September 30, 2026). On this view, output can only drift sideways from here.

The case that shale has not peaked: its advocates point to the records. Output set an annual record in 2025 and a monthly one in April 2026, and the EIA expects new highs in 2026 and 2027 (section 3b). The Permian is still growing. Technology keeps raising what each well yields, so fewer rigs produce more oil, and the Dallas Fed's index of oil production rose to 20.7 in the third quarter of 2026, from 15.0, where any reading above zero signals growth. On this view, shale is held back by its owners' choice to pay out cash, not by geology, and a longer spell of high prices would bring more drilling.

What the evidence says: output has not peaked, but its response to price has weakened. In 2018, with WTI averaging about $65, US crude grew by 1.6 mb/d, and in 2011-14 it grew by about 1 mb/d a year (EIA). In 2026, with WTI averaging about $84 in January-August (EIA), growth was a fraction of that (section 3b), and the EIA's forecasts imply gains of about 0.2 mb/d in 2026 and 0.4 mb/d in 2027. Costs have risen only slowly (section 3f), and the surveys show that most of the restraint is chosen, since large firms put shareholder returns first. The rising Permian breakeven suggests that geology is beginning to bind as well, but it has not yet stopped growth.

The course's reading, stated once: US shale has not peaked, but it is no longer the fast answer to a supply shock that it was in 2011-19. High prices in 2026 bought a few hundred thousand barrels a day of growth a year, not the million or more of earlier booms, because owners chose payouts and new wells cost more. Output is likely to keep edging to records for now, but in a crisis the world cannot count on American drillers to replace lost barrels quickly. That leaves the Gulf's spare capacity and emergency stocks as the main buffers (Modules 7 and 8).

Worked example — A Permian Well’s Economics

All inputs are illustrative assumptions. A well with a horizontal section, or lateral, two miles long costs $9 million to drill and complete. It produces 150,000 barrels of oil in its first year. Output halves in year two, to 75,000 barrels, falls 30% in year three, to 52,500, and then falls 15% a year, so the well yields 479,628 barrels over ten years, 31% of them in the first year and 58% in the first three. Royalties to the mineral owner and production taxes take 25% of revenue, and operating and transport costs are $15 a barrel. To earn a 10% annual return, divide each year’s barrels by 1.10 for every year they wait, which makes the ten years’ output worth 349,839 barrels today. The capital then costs $9,000,000 ÷ 349,839 = $25.73 per discounted barrel. Adding $15 of operating cost gives $40.73, and grossing up for the 25% take gives $40.73 ÷ 0.75 = $54.30, the WTI price at which this well breaks even. At a 15% return the breakeven is $59.00. A weaker well, with 120,000 barrels in its first year, needs $62.88 at 10% and $68.75 at 15%, a range that brackets the survey average in section 3f. At the $88 WTI that the Dallas Fed’s respondents expect for the end of 2026, each barrel nets $88 × 0.75 − $15 = $51, the first year brings in 150,000 × $51 = $7.65 million, and the well repays its cost in about 16 months. Most of a shale well’s value comes in its first three years, which is why shale can respond within months but must keep drilling to hold output flat.

Module 3 Key Points

Who Pumps It

• The world produced 100.59 mb/d of oil in 2025 counting gas liquids, and 85.76 mb/d of crude and condensate alone (Energy Institute).

• US crude output set a monthly record of 13.934 mb/d in April 2026, and the EIA forecasts 14.3 mb/d for 2027.

• Only 603 rigs were drilling in the US in mid-October 2026, 10% more than a year earlier, as producers favored payouts.

• Dallas Fed respondents need $66 WTI on average to drill a new well, but only $43 to keep existing wells running.

• Guyana passed 900,000 b/d in 2026, and the Uaru vessel, with 250,000 b/d of capacity, is due to start in the fourth quarter of 2026.

• The course’s reading: US shale has not peaked, but high prices now buy only a few hundred thousand b/d of growth a year.

Module 3 Quiz

Check Your Understanding

1. Why do counts of world oil output for 2025 range from 74.85 mb/d to 100.59 mb/d?

A) They include different liquids, such as condensate and NGLs.
B) The higher one adds oil in storage.
C) The lower one leaves out every country outside OPEC, including the United States.
D) The lower one covers only the months before OPEC+ began unwinding its cuts in 2025.

2. Why did the US rig count rise only about 10% in the year to October 2026?

A) A federal ban on new permits
B) Rigs were scarce
C) Producers chose to return cash and budgeted near $65-70, since futures for later years were far lower
D) Shale wells had stopped declining, so fewer new wells were needed

3. In the Dallas Fed's March 2026 survey, what WTI price did firms need on average to drill a new well profitably?

A) It was $43, the same as to keep existing wells running.
B) It was $27, close to new projects on land in the Middle East.
C) It was $94.65, the spot average during the survey's fieldwork.
D) It was $66 a barrel.

4. What capacity will Guyana's Uaru vessel add when it starts?

A) About 50,000 b/d
B) 250,000 b/d
C) About 900,000 b/d
D) 1.46 mb/d

5. What is the course's reading on whether US shale has peaked?

A) It has not peaked, but high prices now buy only a few hundred thousand barrels a day of growth a year.
B) It peaked in 2019 and has declined since.
C) It will double by 2030 if prices stay above $90.
D) It peaked in May 2025, when output began to fall.

Module 4 — The Companies

Majors, National Champions, Service Firms, and Traders

Recommended Reading / Reference

Book: Steve Coll, *Private Empire: ExxonMobil and American Power* (2012), a Pulitzer Prize-winning reporter's account of how the largest Western oil company ran its business and dealt with governments, from the *Exxon Valdez* spill of 1989 to the Tillerson years

Reference: The companies' own results releases and their filings with the US Securities and Exchange Commission, the source of most figures here, and Enverus, a data firm, for deals

4a. The Shape of the Industry

The oil business has three stages: upstream companies find and produce crude, midstream companies move and store it in pipelines, tankers and terminals, and downstream companies refine it and sell the products (Module 5). Integrated companies such as ExxonMobil work in all three, while others specialize: independents in production, Enbridge and Kinder Morgan in pipelines, Valero and Marathon Petroleum in refining. Two more groups serve them all: service firms drill and equip wells for a fee, and traders buy, ship, store and sell oil they mostly do not produce.

Who owns the oil matters more than who pumps it. In most producing countries the state owns what lies underground, and a national oil company (NOC) produces it or decides who may, so national oil companies control most of the world's reserves. On the figures in OPEC's *Annual Statistical Bulletin 2026*, the eight largest holders among OPEC's members at the end of 2025 had 78% of the world's proved reserves, the oil judged recoverable with reasonable certainty (Module 1 gives them by country). Adding Russia, China, Qatar and Brazil, where state companies lead production, takes the share to about 88%. Ownership is not the same as operation, since foreign companies hold stakes in some of these fields, as in Qatar's gas and Brazil's deepwater.

The five Western majors are ExxonMobil and Chevron in the United States and Shell, BP and TotalEnergies in Europe. Their output is counted in barrels of oil equivalent (boe), which add natural gas to oil by its energy content, about 6,000 cubic feet of gas to the barrel. ExxonMobil produced 4.7 million boe a day in 2025, its most in more than 40 years, while Chevron produced 3.72 million, TotalEnergies 2.53 million, and BP 2.31 million in its upstream business.

4b. The Majors in 2025, and the Windfall of 2026

2025 was a lean year for the majors. Brent averaged $69 a barrel (EIA spot price, Module 6), and the five earned about $72 billion between them on their reported accounts while spending about $99 billion on capital projects. Each company leads with its own measure of profit, and the table gives the one it headlines, with payouts as a share of operating cash flow, the cash its operations bring in. BP's reported profit, after write-downs and one-off items, was $55 million.

Company	2025 profit (the company's headline measure)	2025 capital spending	2025 dividends and buybacks (share of operating cash flow)	Second-quarter 2026 profit
ExxonMobil	$28.8 billion; $30.1 billion before one-off items	$29.0 billion	$37.2 billion (71.5%)	$14.5 billion

Company	2025 profit (the company's headline measure)	2025 capital spending	2025 dividends and buybacks (share of operating cash flow)	Second-quarter 2026 profit
Chevron	$12.3 billion, down from $17.7 billion in 2024	$17.3 billion	$24.9 billion (73%)	$12.07 billion
Shell	$18.1 billion attributable to shareholders	$20.9 billion	About $22.3 billion (52%)	About $9.8 billion
TotalEnergies	$15.6 billion adjusted, down 15%; $13.1 billion under international accounting rules	$17.1 billion of net investment	$15.6 billion (56%)	About $6 billion, up 67%
BP	$7.5 billion of underlying replacement cost profit	$14.5 billion	$9.5 billion (39%); buybacks suspended February 10, 2026	$5.73 billion, against $2.35 billion a year earlier

Company results releases for 2025 (January 30 to February 11, 2026); second quarter of 2026 from Chevron's filing of July 31 and reports by Al Jazeera and Global Witness, August 4, 2026. Shares of operating cash flow are this course's arithmetic; Chevron's leaves out $2.2 billion it spent buying Hess shares. Replacement cost profit values fuel stocks at what they would cost to replace, removing gains and losses from price changes.

The war turned the lean year into a windfall (Module 8 tells its course). By the count of Global Witness, a campaign group, the five earned $48 billion in the second quarter of 2026, against $22 billion in the first, which it called half a billion dollars a day. Chevron earned almost as much in that quarter as in all of 2025, and its refining arm made $4.9 billion, its best since the early 2010s (Al Jazeera). Counting Saudi Aramco, Equinor and Eni, eight large companies earned about $93 billion, against under $50 billion a year earlier (Gulf News, citing OilPrice.com).

The gains were uneven: ExxonMobil missed analysts' estimates because the war disrupted its production in Qatar. Chevron's output rose 19.8% from a year earlier to 4.07 million boe a day, with a US record of 2.08 million, despite curtailments in the Partitioned Zone that Saudi Arabia and Kuwait share. The latest market values this course could find date from May 5, 2026, when ExxonMobil was worth $637 billion, Chevron $380 billion, Shell $249 billion, TotalEnergies $206 billion and BP $121 billion (CompaniesMarketCap data compiled by Visual Capitalist). Shell reports its third quarter on October 29, 2026, and ExxonMobil, Chevron and BP report on October 30.

4c. BP's Reset

BP entered 2026 with the weakest 2025 results of the five. In February 2025 it had cut its spending on low-carbon energy and raised its budget for oil and gas, with the activist fund Elliott Management among its shareholders (its stake was reported at nearly 5% that April). On December 17, 2025, BP announced that Murray Auchincloss would step down as chief executive with immediate effect. Carol Howle ran the company as interim chief executive until Meg O'Neill, formerly chief executive of Woodside Energy of Australia, took over on April 1, 2026, the first woman to lead one of the Western majors.

The first step came before she arrived: on February 10, 2026, with net debt (borrowings less cash) at $22.2 billion at the end of 2025, BP suspended its share buybacks to put spare cash toward its balance sheet. The war did the rest. Its trading statement of October 13, 2026 expected net debt of $13.5-14.5 billion at the end of September, down from $22.3 billion at the end of June. Higher refining margins (Module 5) added $1.9-2.1 billion to its third-quarter result against the second, while write-downs of $3.0-4.5 billion after tax, mostly in gas and low-carbon businesses, cut its reported profit.

BP is also selling assets: it completed the sale of its Gelsenkirchen refinery in Germany on July 31, 2026, sold its stake in the Bay du Nord project off Canada, and expects $8-9 billion of proceeds in 2026, including

$6 billion from an announced deal for its Castrol lubricants business. Weakness has invited takeover talk. Shell said on June 26, 2025 that it did not intend to bid, which under British takeover rules barred it from doing so for six months. No approach in 2026 appears in the sources this course read, and O'Neill presents her first strategy in New York on December 15, 2026.

4d. The National Champions

National oil companies answer to governments, so their aims include budget revenue, jobs and foreign policy as well as profit. Saudi Aramco is the largest. The Saudi state owns more than 80% of it directly, and the Public Investment Fund (PIF), the kingdom's sovereign wealth fund, owns 16%. In 2025 Aramco earned $104.7 billion of adjusted net income, invested $52.2 billion and paid out $85.5 billion in dividends, and it plans $50-55 billion of capital spending in 2026. It was worth about $1.8 trillion on May 5, 2026, and its East-West pipeline kept part of its exports moving around Hormuz (Module 8).

The Gulf's other state companies follow the same model. Abu Dhabi National Oil Company (ADNOC), whose capacity plans and exit from OPEC with the United Arab Emirates are in Module 7, works with foreign partners that hold stakes in its main fields. Kuwait Petroleum Corporation runs Kuwait's industry. Iraq's state companies, led by the Basra Oil Company in the south, run its fields with foreign contractors paid a fee per barrel, and the State Organization for Marketing of Oil (SOMO) sells the crude. The National Iranian Oil Company (NIOC) exports under American sanctions, and Russia's largest producer, Rosneft, is a target of Western sanctions (Module 11 covers both).

China has three state champions. China National Petroleum Corporation (CNPC), through its listed arm PetroChina, is the country's largest producer. China Petroleum and Chemical Corporation, known as Sinopec, is its largest refiner, and China National Offshore Oil Corporation (CNOOC) produces offshore. PetroChina was worth $273 billion on May 5, 2026, more than Shell, and CNOOC $173 billion. All three invest abroad as well as at home.

Latin America's champions show the range. Petrobras, controlled by Brazil's government, earned 52.4 billion reais ($10.3 billion) in the second quarter of 2026 on record production, carried gross debt of $70.8 billion, and was worth $142 billion on May 5. Mexico's Pemex is the cautionary case: its financial debt was $77.5 billion on June 30, 2026, down 9.1% since the end of 2025, and it moved 255.4 billion pesos ($13.8 billion) owed to suppliers into an eight-year payment plan. Its chief executive, Víctor Rodríguez Padilla, left on May 14, 2026, and Juan Carlos Carpio Fragoso was named to replace him. Its second-quarter profit fell 69.7% to 18.0 billion pesos ($974 million) even as sales rose 30.3%. Moody's, the rating agency, said support for Pemex "will continue to limit fiscal consolidation" in Mexico. Dollar figures converted from reais and pesos use the Federal Reserve's rates for October 16, 2026.

4e. Independents and the Shale Mergers

Independents produce oil and gas without refining it. They range from ConocoPhillips, worth $152 billion on May 5, 2026, to hundreds of private firms, and in the United States they built the shale industry (Module 3). Since 2023 the largest have been merging, and the majors have bought their way into the best acreage (table). The logic is inventory: shale wells decline fast, so a producer's value rests on how many good drilling locations it has left. Buying a neighbor adds locations and lets the two drill longer wells across old lease lines at lower cost.

Deal	Value	Completed	What the buyer gained
ExxonMobil and Pioneer Natural Resources	$59.5 billion	2024	Permian acreage; ExxonMobil's Permian output reached a record 1.6 million boe a day in 2025
Chevron and Hess	$53 billion	2025, after an arbitration over Hess's stake in Guyana	A share of Guyana's Stabroek block; Hess added 261,000 boe a day to Chevron's 2025 output
Diamondback and Endeavor	$26 billion	2024	Permian acreage
ConocoPhillips and Marathon Oil	$22.5 billion	2024	US shale fields
Devon and Coterra	All-stock; about $25 billion of equity (Enverus)	May 2026	Coterra's Permian and gas acreage
Mitsubishi and Aethon	$7.5 billion, including $2.33 billion of debt	First quarter of 2026	Haynesville shale gas for a Japanese trading house

Kings Research (February 2026); Enverus via OilPrice.com (May 17, 2026); World Oil (February 2, 2026) and The Energy Year (May 8, 2026) for Devon and Coterra.

Devon Energy and Coterra Energy announced their merger on February 2, 2026 and completed it in May. Coterra's holders received 0.70 Devon shares for each of theirs, leaving Devon's holders with about 54%. The combined company, run by its chief executive, Clay Gaspar, produced more than 1.6 million boe a day on a combined basis in the third quarter of 2025 and holds nearly 750,000 net acres in the Delaware Basin, part of the Permian. It targets $1 billion of annual savings by the end of 2027.

Deals sped up in 2026: Enverus counted about $38 billion of US upstream mergers and acquisitions in the first quarter, the most in two years, and its analyst Andrew Dittmar said in May that "we are likely heading into another tsunami of consolidation." Buyers now include Asian companies, such as Mitsubishi of Japan (table). Fewer, larger producers answer to shareholders who want cash returned, which is the question of section 4g.

4f. Service Firms and Traders

Service firms are paid to drill, complete and maintain wells and to supply equipment and data. The three largest are SLB (formerly Schlumberger), Halliburton and Baker Hughes, and their results show where drilling is moving. SLB reported on October 23, 2026: third-quarter revenue of $9.45 billion, up 6% from a year earlier, and net income of $735 million. Its North American revenue rose 24% to $2.40 billion, helped by $956 million from ChampionX, which it acquired. Its Middle East revenue was about 12% lower than a year earlier, and its data-center business grew 76%.

Olivier Le Peuch, SLB's chief executive since 2019, called the outlook for 2027 "very compelling," citing deepwater work and the activity increases it expects in Venezuela. Halliburton, reporting on October 20, had revenue of $5.70 billion and net income of $417 million. Its North American revenue fell 5% from the second quarter to $2.2 billion as US fracking, the pumping of water and sand into shale at high pressure to crack it, slowed. Its plan for 2027 assumes flat North American activity, with any recovery in fracking "purely upside." Baker Hughes, about half of whose revenue comes from equipment for gas, LNG and power, reports on October 27, 2026. Its second-quarter orders rose 49% to $10.5 billion.

Traders buy oil where or when it is cheap and sell it where or when it is dear, so they profit most when prices swing. Vitol, the largest independent trader, earned about $4.5 billion in 2025, down from about $8 billion in 2024, on revenue of $343 billion, according to sources cited by Reuters. Trafigura earned $2.7 billion in its year to September 2025 and then $4.1 billion in the six months to March 2026. Its volumes of oil, fuels and

gas rose to 8.7 million barrels a day from 6.6 million. Mercuria earned $1.43 billion in 2025 and Gunvor $104 million, in a year of a buyout by its managers. Glencore, a listed miner, also runs a large oil-trading arm.

4g. Return the Cash or Drill More? The Cases as Their Advocates Make Them

The case for returning the cash: investors who hold the majors, and the executives who answer to them, point to the 2010s. The industry spent heavily on growth while prices were high and earned poor returns when they fell. Spending discipline, they argue, protects owners from the next collapse, and cash returned lets owners decide where to invest it. Long-lived projects carry the added risk that demand peaks before they pay back (Module 13). Buybacks, unlike dividends, can be cut when prices fall, so they hand owners a windfall without committing the company to it. TotalEnergies set its 2026 buybacks at $3-6 billion on an assumption of Brent at $60-70.

The case for drilling more: its advocates, among them the IEA in its warnings on field decline, argue that existing fields lose output fast without investment (Module 1) and that most upstream spending already goes to standing still (Module 13). 2026 showed what thin buffers cost (Module 7). High prices, they say, are the signal to invest, and a company that pays out more than it earns is borrowing against its future. Consumers and governments add that windfall profits should fund new supply rather than buybacks, an argument that also feeds calls for windfall taxes (Module 12).

What the evidence says: in 2025 the payouts in the table exceeded free cash flow, the cash left from operations after capital spending, which ExxonMobil also credits with the proceeds of asset sales. ExxonMobil's ran $11.1 billion above its free cash flow of $26.1 billion and Chevron's $8.3 billion above its $16.6 billion, or 143% and 150% of it. The windfall did not bring a drilling boom. Chevron's second-quarter capital spending, $4.5 billion, was close to its 2025 quarterly average of $4.3 billion and took 20% of its $22.6 billion of operating cash flow, while dividends and buybacks took 29%. BP used its cash to cut debt, by $7.8-8.8 billion in the third quarter on its own estimate. Futures for 2028-2030 imply prices far below 2026's (Module 6). The IEA's net-zero pathway needs no new fields, a point Oil Change International, a campaign group, stresses, but its other scenarios need new supply (Module 13).

The course's reading, stated once: the majors are right not to drill more on wartime prices, and wrong to promise fixed payouts that 2025's prices could not fund. The futures curve says the windfall will not last, so a capital budget set for the lower prices it implies after 2027 is prudent. The decline of existing fields argues for keeping that budget steady rather than cutting it. Fixed buybacks that ran ahead of free cash flow in 2025 were paid for by drawing on balance sheets, which leaves less room when prices fall. Payouts that rise and fall with the price, as TotalEnergies' formula does, serve both owners and the security of supply better than either pure case.

Worked example — Where a Major’s $100 Barrel Goes

Take one barrel sold for $100 by an illustrative major, with these assumptions: royalties (the share of revenue owed to the owner of the oil) and production taxes of 20% of the price, an operating cost of $12, depreciation of $15, an income tax of 35%, capital spending of $20, and dividends and buybacks set in advance at $12 each. Depreciation is the past cost of wells and platforms written off as the oil is produced, so it is a cost in the accounts but not cash spent this year. Step 1: royalties and production taxes take $20.00, leaving $80.00. Step 2: subtract the $12.00 operating cost and $15.00 of depreciation, leaving pre-tax profit of $53.00. Step 3: income tax at 35% is $18.55, leaving net profit of $34.45. The $100 has now gone $20.00 to royalties and production taxes, $12.00 to operating cost, $15.00 to depreciation, $18.55 to income tax and $34.45 to profit, and governments have taken $38.55 of it. Step 4: cash flow adds back the depreciation, $34.45 + $15.00 = $49.45. Step 5: capital spending of $20.00 leaves free cash flow of $29.45. Step 6: dividends and buybacks of $24.00 take 48.5% of the cash flow and leave $5.45 to cut debt. Now sell the same barrel for $69, the 2025 Brent average (EIA spot price, Module 6). Royalties and production taxes fall to $13.80, pre-tax profit to $28.20, income tax to $9.87, net profit to $18.33 and cash flow to $33.33. After the same $20.00 of capital spending, free cash flow is $13.33, so the $24.00 of payouts, 72.0% of cash flow, leaves a gap of $10.67 to borrow or draw from cash. A price 44.9% higher lifts net profit 87.9% and free cash flow 2.2 times, because most costs do not rise with the price. That leverage is how second-quarter profits doubled in 2026, and why fixed payouts outran free cash flow at 2025’s prices.

Module 4 Key Points

The Companies

• The five Western majors earned $48 billion in the second quarter of 2026, against $22 billion in the first (Global Witness).

• In 2025 ExxonMobil paid shareholders $37.2 billion, more than its $26.1 billion of free cash flow.

• State-owned companies control most oil: OPEC’s eight largest holders had 78% of proved reserves at the end of 2025.

• BP suspended buybacks on February 10, 2026; Meg O’Neill became chief executive on April 1 and presents her strategy on December 15.

• Pemex’s financial debt was $77.5 billion on June 30, 2026, down 9.1% since the end of 2025.

• In the worked example a 45% higher price lifts free cash flow 2.2 times, because most costs do not rise with price.

Module 4 Quiz

Check Your Understanding

1. What did ExxonMobil's 2025 results show about its payouts to shareholders?

A) It paid out less than half of its operating cash flow.
B) It suspended buybacks to cut its debt.
C) It paid out $37.2 billion, more than its free cash flow.
D) Its payouts were paid for by the windfall of the second quarter of 2026.

2. How much did the five Western majors earn in the second quarter of 2026, by Global Witness's count?

A) $22 billion
B) About $93 billion, counting eight
C) $72 billion, as in all of 2025
D) About $48 billion

3. Who controls most of the world's proved oil reserves?

A) The five Western majors
B) National oil companies
C) Independent US shale producers
D) Commodity traders such as Vitol and Trafigura, which hold oil in storage tanks and at sea

4. What did BP do on February 10, 2026?

A) Sold Castrol
B) Agreed to a merger with Shell
C) Suspended its share buybacks to put spare cash toward its balance sheet
D) Held its strategy day in New York

5. What is the course's reading on returning cash or drilling more?

A) Steady spending, payouts that flex
B) Drill more at wartime prices
C) Return all the cash
D) Tax the windfall and spend it on new fields

Module 5 — From Crude to Products

Refining, Petrochemicals, and the Things Made from Oil

Recommended Reading / Reference

Book: William L. Leffler, *Petroleum Refining in Nontechnical Language* (4th edition, 2008), a guide for readers who are not engineers to what each unit of a refinery does and why refineries are built as they are

Reference: The EIA's *Refining crude oil: inputs and outputs* (Energy Explained, updated June 2024) for what a barrel yields, and its daily spot prices for crude and products

5a. What a Refinery Does

Crude oil is a mixture of hydrocarbons, from gases to tar (Module 1), and is of little use until it is refined. A refinery does three things: it separates crude into fractions, converts heavy fractions into lighter and more valuable ones, and removes impurities. Separation comes first, by distillation, in a tall column where the parts of heated crude condense at different heights by boiling point: gases at the top, then naphtha for gasoline, kerosene for jet fuel, diesel and heating oil, and a heavy residue at the bottom. A second column, under vacuum, splits the residue further without overheating it.

Distillation alone yields more heavy fuel than the market wants, so refineries convert it. A fluid catalytic cracker breaks heavy molecules into gasoline and diesel over a hot powdered catalyst, a hydrocracker does the same with hydrogen under high pressure, and a coker heats the heaviest residue until it splits into lighter liquids and solid petroleum coke. The products are then upgraded and cleaned: reforming and alkylation raise gasoline's octane, its resistance to knocking in an engine, and hydrotreating removes sulfur, which the refinery recovers and sells (Module 10 follows it into fertilizer).

Refineries differ in how much of this they can do. A simple refinery, which distills crude and reforms naphtha, turns much of each barrel into low-value fuel oil and needs light, sweet crude to make money. A complex one, with crackers and cokers, can turn cheaper heavy and sour crudes into high-value fuels. Many US Gulf Coast refineries were built to run heavy sour crude, and Reliance's Jamnagar complex in India, the world's largest, can run almost any grade. Analysts compare configurations with the Nelson complexity index, which scores each unit by its cost relative to the distillation column.

5b. Where the Refineries Are, and Where They Are Closing

The world could refine 103.66 million barrels a day in 2025 and ran 86.89 mb/d through its plants, about 84% of capacity (OPEC, *Annual Statistical Bulletin 2026*). The United States had 18.2 million barrels a day of distillation capacity, measured per calendar day to allow for downtime, at 130 refineries on January 1, 2026, about 250,000 b/d less than a year earlier, after two closed (EIA). Capacity is shifting from Europe and North America toward Asia, the Middle East and Africa, where demand is growing and the new plants are larger (table).

Refinery	Capacity (b/d)	Status, with dates
LyondellBasell, Houston (US)	263,776	Closed in March 2025
Phillips 66, Los Angeles (US)	138,700	Closed in October 2025; about 5% of West Coast capacity
Valero, Benicia, California (US)	145,000	Stopped refining; dropped from the EIA's monthly estimates from March 2026

Refinery	Capacity (b/d)	Status, with dates
Grangemouth, Scotland (UK)	145,000	Stopped processing crude on April 29, 2025; being turned into an import terminal
Lindsey, England (UK)	110,000	Owner insolvent in June 2025; operations halted
Dangote, Lagos (Nigeria)	700,000	Raised from 650,000 after work in February 2026; a second 750,000 b/d unit planned by 2028
Olmeca, Dos Bocas (Mexico)	340,000	Ran at 57% of capacity in September 2025, its best since opening in 2022
Al-Zour (Kuwait)	615,000	Partly shut by a power outage in 2026
Jizan (Saudi Arabia)	400,000	Suspended on July 27, 2026 after a Houthi attack, as reported by Reuters

Oil & Gas Journal on the EIA's Refinery Capacity Report (June 29, 2026); Tank Terminals (September 12, 2025); Argus (January 5, 2024); EIA Today in Energy (August 24, 2026); Oil Price Information Service (December 29, 2025); Reuters, July 2026. US capacities are per calendar day.

Britain shows how far the retreat has gone: it now has four major refineries with just over 1 mb/d of capacity, about a third less than in the early 2010s, and in 2024 it imported 265,000 b/d of diesel, 42% of its imports of light products (Tank Terminals). Argus, a price-reporting agency, counted six European refinery closures from 2020 to the start of 2024. Two more were then announced, at Grangemouth and at Shell's Wesseling plant in Germany, for a loss of 935,000 b/d in all.

Nigeria shows the other direction: with Dangote running, its imports of products fell from nearly 400,000 b/d in 2023 to under 130,000 b/d, and it exported 350,000 b/d of products in the second quarter of 2026, about 130,000 of them to Europe (EIA, August 24, 2026). Before the war, traders expected Dangote and Dos Bocas to cut gasoline margins around the Atlantic and push more small refineries to close (Oil Price Information Service, December 2025).

The war changed the arithmetic of closing a refinery. A plant that loses money in normal years is a cost to its owner, but in a supply shock it is a region's buffer. When Gulf exports of fuels fell in 2026, places that had closed plants, California and Britain among them, had to compete for imports at the highest margins on record (section 5c). California paid most: its diesel averaged $8.242 a gallon in the week of October 19, against $5.903 on the Gulf Coast (EIA). Closing a loss-making plant is sound business for its owner, but it leaves the region exposed, and in 2026 the cost fell on its drivers and truckers.

5c. Refining Margins and the Crack Spread

A refiner earns the difference between what its products sell for and what its crude costs. Traders measure it with crack spreads, named after the cracking that splits heavy molecules. A single-product crack is the price of a barrel of the product less the price of a barrel of crude. The 3-2-1 crack approximates a US refinery: three barrels of crude make two of gasoline and one of diesel, and the spread is the margin per barrel of crude. A crack is a gross margin, before the refinery's costs of energy, labor and capital.

In 2026 margins set records. On July 16 the 3-2-1 crack on the New York Mercantile Exchange (NYMEX) hit $69.66 a barrel, the heating-oil crack, the futures measure for diesel, passed $91, and the gasoline crack reached about $59, its highest since June 2022 (Reuters). By the end of July the US diesel crack set a record of $93.44, and on July 31 Europe's gasoil crack, its measure for diesel, reached an all-time high of $74.66. The IEA put margins around the Atlantic at an all-time high in August. BP's refining indicator margin, a gauge of what its refineries could earn, averaged $46.7 a barrel in the third quarter of 2026, against $29.6 in the second.

Margins rose for three reasons. First, the war cut exports of diesel and jet fuel from the Gulf's large export refineries (Module 8). Attacks and outages took out more capacity, at Jizan and Al-Zour (table), and drone strikes on Russian refineries pushed their runs near a 20-year low in July (IEA); on July 31 one hit a crude unit at Lukoil's Perm plant. Western refineries also had less spare capacity after the closures above, which Reuters said had "kept diesel inventories tight for years."

Refiners that could run took the gains: Kpler, a shipping-data firm, said Western refiners profited as Gulf exports fell, and the US refiner Valero spoke of "a new phase characterised by structurally higher profit margins" (Module 4 has the companies' results). US refineries ran at 97% of capacity in the week to September 11 and at 93.4% in the week to October 16, in the autumn maintenance season (EIA). In its October 6 outlook the EIA expected cracks to fall but to stay high into early 2027.

5d. The Products and Their Prices

Diesel runs trucks, trains, farm machines and backup generators, and in 2026 it was the scarcest fuel. The US retail price reached a record $6.29 a gallon in the week of September 14, the highest since the EIA's weekly series began in 1994, and $6.29 was also its average for September. In the week of October 19 it was $6.276, up 9.7 cents from the week before and $2.656 above a year earlier (EIA). When diesel averaged $5.60 in May 2026, crude was 42% of its price and refining 25%, the EIA estimates. In its October 6 outlook it expected diesel to average $5.19 a gallon in 2026 and $4.49 in 2027.

The shortage shows in the stocks: US distillate inventories were 13% below their 2021-2025 average for the season on September 11 and 9% below the five-year average on October 16, and East Coast stocks were 32% short in September (EIA). US refiners made 5.1 mb/d of distillate in January-August, the most since 2019, and from March to mid-September the distillate crack averaged 74 cents a gallon more than gasoline's. Worldwide, the IEA estimated in October that diesel supply from Russia and the Middle East was down about 1.3 mb/d, with global diesel exports in September about 700,000 b/d below a year earlier. In October the EIA forecast heating oil, a close cousin of diesel, at $5.26 a gallon for the winter of 2026-27, up 34%, and a household heating with it to spend $2,115, up 21%.

Jet fuel tightened too: on the US Gulf Coast it averaged $3.91 a gallon in March-May, about double its level at the start of 2026, and reached a spring high of $4.20 in the week of May 15 (EIA; American Action Forum). A refinery can tilt its output toward the dearest fuel by changing its crude and the way it runs its units, and US refiners did so. They made more than 2.0 mb/d of jet fuel for the first time in the week to May 1, and the American Action Forum, a Washington think tank, wrote in June that the jet premium was changing refiners' priorities. The International Air Transport Association (IATA) put the world average at $157 a barrel in August, up 79% in a year, and Europe's jet margin came near a record $109 a barrel in March. On October 20, Gulf Coast jet fuel cost $4.632 a gallon on the EIA's spot series.

Ships burn bunker fuel, the heavy residue of refining or blends made from it. Since 2020 the International Maritime Organization (IMO) has capped its sulfur content at 0.5%, so most ships burn very-low-sulfur fuel oil (VLSFO), while those fitted with exhaust scrubbers can burn high-sulfur fuel oil (HSFO). On October 6, 2026, VLSFO averaged $876.50 a tonne across 20 ports tracked by Ship & Bunker, HSFO $751.50 and marine gasoil, a diesel, $1,500. VLSFO ranged from $682.50 in Rotterdam to $979.50 at Fujairah, the bunkering port outside Hormuz. Gasoline's price, and what makes it up, are in Module 6.

5e. Petrochemicals

Petrochemical plants turn oil and gas into the building blocks of plastics, fibers, rubber, solvents and detergents. The main feedstocks are naphtha, a light liquid from refining, and ethane, propane and butane, light hydrocarbons separated from natural gas. Propane and butane are sold as liquefied petroleum gas (LPG). A steam cracker heats them to make ethylene, propylene and other basic chemicals, which are then joined into polymers such as polyethylene. Naphtha dominates in Europe and Asia, while plants in the United States and the Middle East use more ethane, which is cheap where gas is plentiful.

Petrochemicals take about 14% of the world's oil, about 13 mb/d, and 8% of its gas, by the IEA's count in its 2018 study of the industry. The IEA's *Oil 2025* report put feedstocks at 15.8% of oil consumption in 2023 and expected 17.4% by 2030, "one in every six barrels," with feedstock demand reaching 18.4 mb/d: 10.2 mb/d of naphtha and 8.2 mb/d of LPG and ethane. From 2019 to 2024 feedstocks rose about 2.3 mb/d, more than 95% of the net growth in world oil demand.

In June 2025 the IEA expected petrochemicals to be the main source of growth in oil demand from 2026 (Module 13 has the long-run forecasts). The growth is not steady: feedstock use rose only 1.2% in 2025, against 2.6% in 2024, although China's rose about 200,000 b/d, most of that country's 220,000 b/d increase in oil demand (IEA, *Global Energy Review 2026*). The IEA estimated in December 2023 that China's additions of ethylene and propylene capacity from 2019 to 2024 would equal those of Europe, Japan and Korea combined. That surplus, and governments' plastics policies, are the open questions for this source of demand.

5f. The Things Made from Oil

Plastics are the largest petrochemical product. World output rose 4.1% in 2024, and 16.3% since 2018, by the count of Plastics Europe, an industry association. Asia made 57.2% of it and China alone 34.5%, while Europe's share fell from 22% in 2006 to 12%, or 54.6 million tonnes. Recycled plastics reached 43.9 million tonnes, passing 10% of world output for the first time. Plastics made from plants remain marginal: Europe made 0.6 million tonnes of them, about 1% of its plastics, and that was down 25%. The IEA's list of what petrochemicals make runs from plastics and packaging to clothing, digital devices, medical equipment, detergents and tires. Demand for plastics has grown faster than for any other bulk material, nearly doubling since 2000, the IEA said in 2018, and advanced economies use up to 20 times as much plastic per person as developing ones. Closing even part of that gap as incomes rise would add to oil demand.

Clothing has moved to oil: of 132 million tonnes of fiber made worldwide in 2024, polyester, made from oil and gas, was 78 million tonnes, or 59%, and synthetic fibers together were 69%, up 9 points since 2020, while cotton was 19% (Textile Exchange, *Materials Market Report 2025*). Other products come straight from the refinery. Asphalt, the heaviest residue, binds the surface of about 94% of America's paved roads, by the asphalt industry's count. Lubricating oils for engines, gearboxes and machines are refined from heavy fractions or made from petrochemicals. Petroleum coke, the solid left by cokers, fuels cement kilns, and a purer form, needle coke, is the raw material for synthetic graphite, used in steel furnaces' electrodes and in the anodes of batteries.

Medicine depends on oil mostly through plastics: the IEA lists medical equipment among petrochemical products, and syringes, tubing, blood bags and gloves are made of them. Some of these uses have substitutes and some do not. Road fuels have electric vehicles and biofuels (Module 13). Plastics can be recycled or made from plants, but plant-based plastics barely register at Europe's 2024 volumes. By-product sulfur cannot easily be increased, since the amount recovered depends on how much oil and gas is

processed rather than on how much sulfur farmers need (Module 10). The products hardest to replace are those in which oil is the material rather than the fuel.

Worked example — A Barrel into Products, and the 3-2-1 Crack in October 2026

Start with the EIA's average US refinery yield for 2023. From each 42-gallon barrel of crude, US refineries made 44.65 gallons of products. The extra 2.65 gallons, 6.3%, is the processing gain: products are less dense than crude, so the same mass fills more gallons. The barrel gave 19.57 gallons of gasoline (46.6% of the 42), 12.47 of distillate, mostly diesel (29.7%), and 4.41 of jet fuel (10.5%), 36.45 gallons or 86.8% in all. The rest was 2.06 gallons of petroleum coke, 1.68 of still gas burned as refinery fuel, 1.55 of hydrocarbon gas liquids such as propane, 0.84 of asphalt, 0.71 of residual fuel oil, 0.34 of naphtha for petrochemicals and about 1.02 of other products. Now price the three fuels at the EIA's spot prices for October 20, 2026: $2.897 a gallon for gasoline in New York Harbor, $5.265 for ultra-low-sulfur diesel there, and $4.632 for jet fuel on the Gulf Coast. The gasoline is worth $56.69, the diesel $65.65 and the jet fuel $20.43, $142.78 in all, against $107.89 for a barrel of crude on the EIA's spot price for WTI at Cushing that day. Diesel is about a third of those gallons but 46% of their value. The 3-2-1 crack puts the margin in one number. Three barrels of WTI cost $323.67. Two barrels of gasoline, 84 gallons at $2.897, sell for $243.35, and one of diesel, 42 gallons at $5.265, for $221.13, or $464.48 in all. The margin is $140.81, or $46.94 per barrel of crude. Split by product, the gasoline crack was $13.78 a barrel ($121.67 less $107.89) and the diesel crack $113.24 ($221.13 less $107.89), so four-fifths of the margin came from the one barrel of diesel. The WTI spot price stood $10.07 above December futures that day, the last day of trading in the November contract, and against December futures (Module 6) the crack would be $57.01. Either way, the crack is a gross margin before the refinery's own costs, and a real refinery's yields and crude costs differ from the formula's.

Module 5 Key Points

From Crude to Products

• A US refinery turns a 42-gallon barrel into 44.65 gallons of products, 19.57 of them gasoline (EIA, 2023).

• BP’s refining indicator margin averaged $46.7 a barrel in the third quarter of 2026, against $29.6 in the second.

• US diesel set a record $6.29 a gallon in the week of September 14, 2026; distillate stocks were 9% below average on October 16.

• Petrochemicals take about 14% of world oil (IEA, 2018); feedstocks were over 95% of oil demand growth in 2019-2024.

• Western refineries are closing as Dangote and Gulf plants grow; in 2026 the regions that closed plants paid most for diesel.

• On October 20, 2026, the 3-2-1 crack was $46.94 a barrel, four-fifths of it from diesel.

Module 5 Quiz

Check Your Understanding

1. What did BP’s refining indicator margin average in the third quarter of 2026?

A) About $29.6, the second-quarter level
B) About $9
C) $46.7 a barrel
D) $93.44, the US diesel crack record

2. Which of these helped lift refining margins in 2026?

A) Crude prices fell
B) New refineries opened in Europe
C) American drivers bought more gasoline than in any year since the 1970s, outrunning what refineries could make
D) Gulf exports of fuels were cut by the war

3. In the worked example, why was the 3-2-1 crack high on October 20, 2026?

A) Crude was cheap
B) Diesel sold far above crude, while the gasoline crack was only $13.78 a barrel
C) Jet fuel was scarce
D) Gasoline and diesel both earned record margins over crude that day

4. By the IEA’s 2018 count, about how much of the world’s oil do petrochemicals take?

A) They take about 14%.
B) They take less than 2%, mostly as asphalt.
C) They take about half, more than road transport.
D) They take about 30%, the same as oil’s share of energy.

5. Why do US refineries get more than 42 gallons of products from a 42-gallon barrel?

A) Ethanol is added
B) Refineries add water and dyes
C) Products are less dense
D) Gas liquids are bought in and blended

Module 6 — How the Price Is Set

Benchmarks, Futures, Physical Cargoes, and the Pump

Recommended Reading / Reference

Book: Javier Blas and Jack Farchy, *The World for Sale: Money, Power, and the Traders Who Barter the Earth's Resources* (2021), two Bloomberg commodity reporters on how Vitol, Glencore, Trafigura and the other trading houses came to stand between the world's producers and its buyers

Reference: The EIA's weekly *Gasoline and Diesel Fuel Update*, with its monthly breakdown of the pump price, and its daily spot prices for Brent, WTI and the main products

6a. The Benchmarks

Oil is not one commodity but hundreds of crude grades that differ in density, sulfur and location. Most are priced as a benchmark plus or minus a differential, so a few benchmark prices set the value of the rest. Brent is the main one, a price for light, sweet North Sea crude based on five grades (Brent, Forties, Oseberg, Ekofisk and Troll), with WTI Midland from Texas added in 2023. Platts, which assesses it (section 6b), uses whichever of these grades is the most competitive each day, after adjusting for quality. By the count of the Intercontinental Exchange (ICE), which lists the Brent futures contract, Brent prices about two-thirds of internationally traded crude.

West Texas Intermediate (WTI) is the US benchmark. Its futures trade on the New York Mercantile Exchange (NYMEX) and end in delivery at Cushing, Oklahoma, a hub of pipelines and tanks, so WTI reflects American supply and the pipes that carry it. Dubai and Oman, both sour, price Gulf crude sold to Asia, and Saudi Arabia sets its monthly prices for Asian buyers as a premium or discount to their average. Murban, a light crude from Abu Dhabi, has had a futures contract on ICE Futures Abu Dhabi since 2021, and Shanghai's International Energy Exchange has traded a crude contract in yuan since 2018. The OPEC Reference Basket averages the export grades of OPEC's members.

There are several benchmarks because grade and place matter: a sour crude yields more heavy fuel and costs more to refine, so it normally sells below Brent, and a barrel in Texas must pay freight to reach Asia (Module 1 explains grades). In 2025 Brent's spot price averaged $4 above WTI's (table). The war reversed one normal relation: the OPEC basket, mostly Gulf sour grades, averaged $110.59 a barrel in September 2026, $8.57 above the $102.02 average of Brent futures, because Gulf barrels were the ones missing (OPEC). The gap between Brent and WTI futures widened from $6.33 on September's averages to $12.79 on October 8, and it was $10.97 on October 20. A wide spread makes US crude cheap abroad and pulls it toward Europe and Asia (Module 12 has US exports).

The table gives the course's reference prices, each with its measure and date. Futures prices are for the front-month contract, the one nearest expiry, and a settlement is the official price an exchange sets at the end of each day. The newest settlements in the table are those of October 23, when Brent futures closed at their highest since late April, up about 6% in a week, after Houthi attacks on Saudi Arabia and Iranian claims of strikes on tankers (Reuters, via FinanceFeeds; Module 8).

Measure	Price ($ a barrel)	Date	Source
Brent futures (ICE front month), settlement	104.28	October 8, 2026	ICE
Brent futures (ICE front month)	About 106	October 14, 2026	ICE, as reported

Measure	Price ($ a barrel)	Date	Source
Brent futures (December contract), settlement	108.79	October 20, 2026	Express Tribune and Nation Thailand, citing the exchange
Brent futures (December contract), settlement	116.72	October 23, 2026	Reuters, via FinanceFeeds
Dated Brent (physical; the EIA's Brent spot series)	126.55	October 14, 2026	EIA
Dated Brent (physical; the EIA's Brent spot series)	115.22, 117.37, then 125.39	October 20, 21 and 22, 2026	EIA
WTI futures (NYMEX front month), settlement	91.49	October 8, 2026	NYMEX
WTI futures (December contract), settlement	97.82	October 20, 2026	Express Tribune, citing the exchange
WTI futures (December contract), settlement	103.27	October 23, 2026	Reuters, via FinanceFeeds
Averages for 2025 (EIA spot prices)	Brent 69; WTI 65	2025	EIA
Brent spot forecast, EIA Short-Term Energy Outlook (STEO)	105 (fourth quarter of 2026); 96 (2026); 84 (2027)	October 6, 2026	EIA

Dated Brent is Platts' daily assessment of physical North Sea cargoes, which the EIA's Brent spot series tracks. The November WTI contract expired on October 20, so the December contract is shown. The October 14 prices are rounded as the course gives them. EIA spot prices accessed October 23, 2026.

6b. Futures and the Physical Market

A futures contract is an agreement to buy or sell a set quantity at a set price on a set future date, traded on an exchange that stands between buyer and seller. ICE's Brent contract covers 1,000 barrels and settles in cash against a Brent index when it expires, while NYMEX's WTI contract ends in physical delivery at Cushing. The front-month contract is the price the news quotes. Most traders close their positions before expiry, so futures are mainly a market in price risk rather than in barrels.

The physical market is where cargoes change hands. Dated Brent is the price of a North Sea cargo due to load within about a month, assessed each day by Platts, a price-reporting agency owned by S&P Global. Argus is the other main agency. The agencies gather bids, offers and deals from traders and publish prices to which contracts around the world refer. In normal times physical and futures prices move together, because traders can switch between the two. Dated Brent rests on a handful of North Sea and WTI Midland cargoes a day, so a few trades can move it.

In 2026 the two came apart: after Hormuz closed, refiners in Asia and Europe bid for prompt replacement cargoes from the Atlantic Basin, the very grades that set Dated Brent. Futures priced later delivery, since in April the front month was June, and they fell whenever traders expected the strait to reopen, while prompt cargoes stayed scarce. After the April ceasefire (Module 8), the consultancy Energy Aspects said that "operators will not restart refineries and fields" during a two-week truce. The physical premium reached about $35 a barrel in April, and Module 8 has the peak prices.

By October 20 the gap had mostly closed: the physical price was $25.90 above futures on October 8, about $20 above on October 14 and $6.43 above on October 20, as Gulf exports recovered and futures rose on new attacks (Module 8). That remainder was close to what the slope of the futures curve explains, but the gap widened to about $12 on October 22, when the physical price jumped 6.8% in a day (EIA) while Brent

futures settled near $113. With the first two contracts about $3.90 apart (section 6c), a cargo loading a month or two before the December contract's barrels should cost about $4-8 more.

The gap also explains a confusion in reporting. Measured from the last settlement before the war (Module 8), the physical price about doubled at its April 7 peak, when futures were up about half. Both are true, and a headline saying that "the oil price doubled" describes the cargo, not the futures price that most charts show.

6c. The Futures Curve

Futures trade for delivery months years ahead, and the line through their prices is the futures curve. When later months cost more than nearer ones, the market is in contango. That happens when stocks are ample: the higher later price pays for storage, so traders can buy now, store and sell forward, even in tankers at sea, as they did in 2020, when tanks on land were nearly full (Module 2). When nearer months cost more, the market is in backwardation. That happens when oil is scarce now, so buyers pay a premium to have it at once, holding stocks loses money, and stocks are drawn down. Before the war the Brent curve was in contango, with inventories building and OPEC+ adding supply.

In October 2026 the curve sloped down steeply. In delayed quotes on October 21, the December 2026 contract traded at $110.33, January 2027 at $106.47, December 2027 at $87.43, December 2030 at $72.27 and February 2035 at $63.10 (Investing.com). The step between the first two months was $3.86, and the drop to December 2027 was $22.90, or 21%. The far end of the curve barely moved through the war. In mid-May, with the front month far higher, December 2026 traded nearly $10 below July 2026, while contracts for 2027 and later were about $70-80, "only slightly above pre-conflict levels" (Bajaj Broking, May 19, 2026). Shocks move the front of the curve, and the back moves only when traders change their view of supply and demand years ahead.

Steep backwardation says the market expects today's shortage to end. Oil for delivery in 2030 cost about what the front month did before the war (Module 8), so traders were pricing a severe but temporary disruption, followed by the surplus that the IEA and the EIA forecast in October for 2027. The curve is not a forecast in the strict sense, since it also carries premiums for risk, but it is where producers and consumers can lock in prices. A producer that sold its 2027 output forward in October 2026 locked in far less than the front-month price, one reason US drilling did not leap with the price (Module 3).

6d. Inventories, the Price's Shock Absorber

Stocks let supply and demand differ for a while without the price having to close the gap at once. When a tanker is late or a refinery stops, the market draws on its tanks, and when supply runs ahead, the tanks fill. Analysts measure stocks in days of cover, the stock divided by daily use. Ample stocks hold prices down and keep the curve in contango, while thin stocks let a small shortage move the price a lot and tip the curve into backwardation.

US commercial crude stocks, which exclude the Strategic Petroleum Reserve, were 412.5 million barrels in the week to October 16, 2026, 3% below the five-year average for the season (EIA). US refineries were running 16.6 mb/d of crude that week, so the tanks held about 25 days of refinery runs. They had stood at 424.1 million barrels, 1% above that average, in the week to October 2, and at the end of June they were the lowest for the season since 2014 (EIA). Stocks of diesel and other products were tighter (Module 5).

The world's observed stocks, including oil at sea, stood below 7.9 billion barrels in the IEA's August report, about 77 days of world demand at its 2026 rate (Module 8). That overstates the cushion, because much of

any stock is working inventory: oil that fills pipelines, tank bottoms and cargoes in transit, which cannot be drawn without stopping the system. The share that can be released is much smaller, so a disruption the size of 2026's had to be met with emergency reserves and lower demand as well as with commercial stocks (Module 8).

Governments hold strategic stocks on top of commercial ones. Members of the IEA must hold minimum emergency stocks (Module 12 gives the rule and the US reserve), and the 2026 releases are in Module 8. Commercial stocks move with the curve, a link the economist Holbrook Working described in 1949: the gap between a near and a later contract, which pays for storage, shrinks as stocks fall and turns negative when they are scarce. In backwardation, storing oil loses money, so companies run their tanks down, and the curve and the stocks tell the same story.

6e. Who Trades

Futures markets exist so that those who produce and use oil can pass price risk to someone else. Producers sell futures or swaps to lock in revenue for their drilling budgets and their lenders, and refiners hedge their crack spreads (Module 5) by buying crude and selling products forward. Airlines, for which fuel is one of the largest costs, buy swaps or options to cap the price of jet fuel. A swap exchanges a floating price for a fixed one without any oil changing hands, and an option gives the right, but not the duty, to buy or sell at a set price, for a fee. Banks act as swap dealers, writing tailored contracts for these companies and hedging them on the exchanges. Physical traders such as Vitol and Trafigura (Module 4) hedge each cargo from the day they buy it to the day they deliver it.

Take a producer that sold December 2027 Brent futures at $87.43 in October 2026 (section 6c). If the contract settles at $70, the hedge pays it $17.43 a barrel, making up for the lower price of its oil. If it settles at $100, the producer pays $12.57 a barrel on the hedge and gives up the gain. Either way it has fixed its price, which is what its lenders and its drilling budget need.

Then there are investors with no oil to hedge. Hedge funds and commodity trading advisers, many of which follow price trends with computer models, take positions on where prices are going, and pension funds buy commodity indexes. They take the other side of producers' and consumers' hedges and make the market deeper, but they also add to swings when they move together.

Positioning, the balance of bets held by each type of trader, is published every week. The US Commodity Futures Trading Commission (CFTC) reports each Friday the positions held on the Tuesday before in WTI and other US contracts, divided into producers and merchants, swap dealers, managed money and others, and ICE publishes the same for Brent. A large net long position held by managed money, more bets on a rise than on a fall, means that funds have a lot to sell if the news turns. The widest gap of 2026 opened in physical cargoes, which funds do not trade, a sign that the physical spike came from a shortage of deliverable oil rather than from speculation.

6f. The Pump

Crude is the largest part of the price of a gallon of US gasoline, but not all of it. The EIA splits the retail price into four parts: crude oil; refining, the refiner's costs and profit; distribution and marketing, which covers pipelines, terminals, trucks and the station; and taxes. In May 2026, when regular gasoline averaged $4.48 a gallon, crude was 52%, refining 22%, distribution and marketing 15% and taxes 12% (the EIA's rounded shares). The federal tax has been 18.4 cents a gallon on gasoline since 1993, and states and some localities add their own.

The national average for regular stayed above $4.50 a gallon from May 6, 2026 into the summer, by the count of AAA, the motoring club. The EIA's weekly average was $4.354 in the week of October 5, $4.331 in the week of October 12 and $4.284 in the week of October 19, $1.265 or 41.9% above a year earlier. AAA said on October 8 that 2026 is the first year in which the average has stood above $4 in October. In its October 6 outlook the EIA expected an average of $3.91 for 2026 and $3.56 for 2027, against $3.10 in 2025.

Where a driver buys matters as much as when. In the week of October 19 regular cost $3.784 on the Gulf Coast, near most refineries, and $5.557 on the West Coast as a whole (EIA). In California it cost $6.031, $2.247 more than on the Gulf Coast, reflecting the state's own cleaner blend, high state taxes and lost refineries (Module 5). Gasoline imports, which supply much of the East Coast, ran 32% below their 2021-2025 average from March to August (EIA).

Pump prices follow crude with a lag: stations price off wholesale gasoline, which moves daily, and they tend to pass on rises faster than falls, a pattern economists call "rockets and feathers." The economists Severin Borenstein, A. Colin Cameron and Richard Gilbert found it in US gasoline in a 1997 study. The politics of the pump in an election year, from tax holidays to the question of who sets prices, are in Module 12.

Worked example — From $110 Crude to $4.29 at the Pump

Take AAA's national average for regular gasoline on October 23, 2026, $4.2926 a gallon, and assume a refiner paid $110 a barrel for its crude, about where Brent futures traded on October 21 (an illustrative assumption, since many US refiners pay prices nearer WTI's). Step 1, crude: $110 ÷ 42 gallons = $2.619 a gallon, 61.0% of the price. Step 2, taxes: the EIA's 12% share for May, applied to May's $4.48, gives about 53.8 cents of federal, state and local tax, 12.5% of the price. The federal 18.4 cents is part of that, so states and localities add about 35 cents. Step 3, refining: gasoline sold on the Gulf Coast spot market for $3.157 a gallon on October 20, which is 53.8 cents above the crude cost, also 12.5%. Step 4, distribution and marketing: the rest, $4.2926 − $3.157 − $0.538 = 59.8 cents, or 13.9%, pays for pipelines, terminals, trucks and the station. Step 5: add $10 to the barrel. Each gallon carries 1/42 of a barrel, so the rise is $10 ÷ 42 = 23.8 cents a gallon. That lifts the crude cost to $2.857 and, if nothing else changes, the pump price to $4.53, a rise of 5.5%. The rule of thumb is that each $1 on a barrel adds about 2.4 cents to a gallon, though the lag of section 6f spreads the rise over time.

Module 6 Key Points

How the Price Is Set

• Brent futures settled at $108.79 on October 20, 2026; Dated Brent, the physical price, was $115.22 that day (EIA).

• The physical premium over Brent futures reached about $35 a barrel in April 2026, narrowed to $6.43 on October 20, and widened to about $12 on October 22.

• On October 21 the Brent curve was in steep backwardation: December 2027 traded $22.90 below December 2026.

• US commercial crude stocks were 412.5 million barrels on October 16, 2026, about 25 days of refinery runs.

• Crude was 52% of a $4.48 gallon of gasoline in May 2026; each $10 a barrel adds about 24 cents a gallon.

• US regular gasoline averaged $4.284 a gallon in the week of October 19, 2026 (EIA), 41.9% above a year earlier.

Module 6 Quiz

Check Your Understanding

1. What is Dated Brent?

A) A physical cargo price
B) The ICE front-month futures price
C) Brent futures on a stated date
D) The average price that OPEC's members charge Asian refiners for Gulf crude under long-term contracts

2. By how much did the physical Brent price exceed Brent futures on October 20, 2026?

A) $35, as in April
B) About $6.40 a barrel
C) About $1.50
D) About $20, as on October 14, when Dated Brent was near $126

3. What does steep backwardation in the futures curve say?

A) Storing oil is profitable
B) Prices will rise
C) Futures and cargoes cost the same
D) Oil is scarce now and the market expects the shortage to end

4. All else equal, what does a $10 rise in the price of a barrel add to a gallon of gasoline?

A) About 24 cents
B) $2.40
C) About $1.00
D) About 42 cents, the gallons in a barrel

5. Why do inventories matter for the price of oil?

A) They are counted in OPEC's quotas.
B) Inventories set the price of Dated Brent each day.
C) Governments buy oil whenever prices rise, which lowers them.
D) Stocks absorb gaps between supply and demand, so thin stocks let a small shortage move the price a lot.

Module 7 — OPEC and OPEC+

The Cartel, Its Quotas, and Its Limits

Recommended Reading / Reference

Book: Ellen R. Wald, *Saudi, Inc.: The Arabian Kingdom's Pursuit of Profit and Power* (2018), a history of Saudi Aramco and the rulers who used it, and the clearest account of why Riyadh holds the spare capacity that gives OPEC its weight

Reference: OPEC's *Monthly Oil Market Report*, whose tables of "secondary sources" estimate each member's output, and the IMF's *Regional Economic Outlook* for the Middle East and Central Asia, which estimates the oil price each budget needs

7a. What OPEC Is and How It Decides

The Organization of the Petroleum Exporting Countries (OPEC) is a group of governments that coordinate how much crude oil they produce. Module 2 tells how it was founded and what it did before 2016. Its secretariat has been in Vienna since 1965, led since August 2022 by Haitham Al Ghais of Kuwait, its secretary general. Since the United Arab Emirates (UAE) left on May 1, 2026 (section 7d), OPEC has had 11 members: Algeria, the Republic of the Congo, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, and Venezuela.

OPEC's supreme body is the Conference of its members' oil ministers, which meets in ordinary session twice a year and decides by unanimity, so that any member can block a decision. The ministers set each member's quota, which OPEC calls its "required production", measured in thousands of barrels a day (kb/d). The secretariat runs research and publishes the *Monthly Oil Market Report*, the main public record of what each member produces.

A quota binds only as far as a government chooses to honor it, because OPEC has no means of enforcement beyond persuasion and the threat of a price war. Members also have reasons to overstate their discipline, so OPEC judges output by its "secondary sources", an average of estimates by independent agencies and firms, as well as by members' own reports. Iran and Venezuela, under American sanctions, and Libya, troubled by civil conflict, are exempt from quotas.

7b. OPEC+ and the Quotas

OPEC+ joins OPEC to 10 producers outside it under a Declaration of Cooperation that dates from 2016 (Module 2): Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, South Sudan, and Sudan; Equatorial Guinea, the 11th signatory of 2016, joined OPEC in 2017. Russia, the largest producer outside OPEC, leads the group's decisions with Saudi Arabia, and Alexander Novak, its deputy prime minister for energy since 2020, speaks for it. In September 2026 OPEC+ produced 39.07 million barrels a day (mb/d) of crude, 25.10 mb/d from OPEC and 13.97 mb/d from the others, by secondary sources (OPEC, October 13).

From 2022 the group cut its output in three layers. All members agreed a cut of 2 mb/d in October 2022, due to last until the end of 2026. Nine of them added voluntary cuts of 1.65 mb/d in April 2023, and eight added another 2.2 mb/d in November 2023, for 5.85 mb/d in all at the peak.

The eight with the voluntary cuts were Saudi Arabia, Russia, Iraq, the UAE, Kuwait, Kazakhstan, Algeria, and Oman. They began returning the 2.2 mb/d layer in April 2025 and finished in September 2025, a year ahead of plan. They then returned 137 kb/d a month of the 1.65 mb/d layer from October to December 2025, paused for the first quarter of 2026, and on March 1, 2026 resumed with 206 kb/d for April. The group raised its quotas each month from April to September 2026, by 188 kb/d for July and for September after the UAE had gone, and then held them for October. On October 4 the seven, the eight less the UAE, held them again for November (OPEC). They meet next on November 1, 2026, to set December's output, and the full OPEC+ ministerial meeting follows on November 29 (Bernama; TASS, the Russian news agency). Between full meetings, a Joint Ministerial Monitoring Committee (JMMC) of OPEC+ ministers reviews whether members keep to their quotas. In June the full group had kept its policy unchanged through 2026 and agreed to review each member's capacity before setting the baselines for 2027 (Reuters).

The quotas no longer describe what the members produce. In September 2026 the members bound by quotas produced 30.75 mb/d against baselines of 36.21 mb/d, 5.45 mb/d below their targets (OPEC secondary sources, via TASS). The war explains most of the gap, since much of the Gulf's oil could not be shipped (Module 8). Russia's gap, beyond the strait's reach, has causes of its own, among them sanctions and Ukrainian strikes (Module 11), and Kazakhstan produced above its quota (table). Members that produced above their quotas since January 2024 have until the end of 2026 to compensate with deeper cuts. On the EIA's current definition of OPEC, the group's output of crude and other liquids falls from 29.3 mb/d in 2025 to 23.9 mb/d in 2026, and the EIA expects it back at 29.2 mb/d in 2027 (October 6).

Member	Required production, September-November 2026	Crude output, September 2026	Output less required
Saudi Arabia	10.478	8.001	−2.477
Russia	9.949	8.643	−1.306
Iraq	4.431	3.920	−0.511
Kuwait	2.676	1.766	−0.910
Kazakhstan	1.628	1.851	+0.223

Million barrels a day. Required production as set for September and held for October and November (OPEC statements of September 7 and October 4, 2026, via Gulf News and TradeArabia). Output by OPEC's secondary sources (*Monthly Oil Market Report*, October 13, 2026, via TASS); Saudi Arabia reported its own output as 8.372 mb/d. Algeria (1.007) and Oman (0.841) are the other two of the seven.

7c. Spare Capacity, the Real Buffer

Spare capacity is output that is idle but could start within 30 days and be sustained for at least 90 days, by the EIA's definition. It matters more than any quota, because it is the only supply that can be added quickly when another source fails. It sits almost entirely in the Gulf, where governments with low costs and large reserves can afford to leave capacity idle for years.

Before the war, Energy Intelligence, a trade publication, estimated OPEC+'s spare capacity at about 5.2 mb/d, provided oil could flow freely through the Strait of Hormuz. Saudi Arabia held 2.16 mb/d of it, the UAE about 1.36 mb/d, Russia 0.73 mb/d, and Iran, Iraq, Kuwait, Algeria, and Oman 0.97 mb/d between them (May 7, 2026). Saudi Arabia's capacity is about 12 mb/d and the UAE's about 4.85 mb/d. The UAE's exit took about a quarter of the group's spare capacity with it.

The war stranded that buffer behind the strait. In 2026 the Gulf's problem was oil that could not be shipped, not oil that could not be produced, so idle capacity did not help. Energy Intelligence calculated on March 5 that OPEC still had more than 4 mb/d of spare capacity on paper, nearly all of it in Saudi Arabia, the UAE,

Kuwait, and Iraq, whose exports through the strait were cut off, and concluded that talk of large volumes of spare capacity had been “rendered moot”. Jorge León, head of geopolitical analysis at Rystad Energy, a consultancy, said in June that “an OPEC+ production increase means very little while the Strait of Hormuz remains closed.” On October 15 Jihad Azour, director of the IMF’s Middle East and Central Asia Department, said that “spare capacity is tighter”.

When a route opens, the buffer works. Saudi Arabia raised its output by 744 kb/d in September by secondary sources, and by 2.13 mb/d by its own count, once its oil found ways out (Module 8). The IEA said OPEC+ supply rose 2.1 mb/d that month, led by Saudi Arabia. When ships can move freely, the Gulf’s shut-in output becomes spare capacity again, and the decision to release it will lie with Riyadh, Baghdad, and Kuwait City.

7d. The UAE’s Exit

The UAE announced on April 28, 2026 that it would leave OPEC and OPEC+, effective May 1, ending 59 years of membership that began when Abu Dhabi joined in 1967. It was the largest producer ever to leave OPEC (Enerdata). Its energy minister, Suhail Al Mazrouei, called the move a “sovereign national decision” after “a very careful and long review”, and said the UAE wanted to be “outside any constraint”. Sultan Al Jaber, the UAE’s industry minister and chief executive of the Abu Dhabi National Oil Company (ADNOC), said it reflected the country’s “true production capability and its national interest”.

The reason was the gap between capacity and quota. The UAE spent about $150 billion to raise its capacity toward 5 mb/d by 2027, yet its quota was 3.5 mb/d, and before the war it produced 3.4 mb/d, close to 30% below its capacity (Enerdata; The National). In 2025 it produced 3.15 mb/d of crude, a narrower count than the EIA’s 3.82 mb/d with lease condensate (Module 3), plus 1.1 mb/d of natural gas liquids and condensate, and it is considering capacity of 6 mb/d after 2027 (Energy Intelligence). Analysts also pointed to its long quarrel with Riyadh over quotas and to a group that decides by consensus with Iran. Al Mazrouei said the timing suited because Hormuz was “closed and restricted”, so leaving would barely move prices at first, and the UAE promised “gradual and measured” increases once shipping is restored.

Outside OPEC, the UAE can produce whatever it can ship, and it has its own pipeline to a port beyond the strait (Module 8). In September it led the growth in supply from producers outside OPEC+ (IEA). Energy Intelligence judged that the exit leaves the remaining members less spare capacity with which to manage the market.

Others have left before, each for its own reasons. Qatar left on January 1, 2019, to concentrate on natural gas, Ecuador in January 2020, and Angola on January 1, 2024, after a dispute over its quota. None of them came close to the UAE’s output or its spare capacity.

7e. Budgets and Breakevens

A government’s fiscal breakeven price is the oil price at which its budget balances. The IMF estimates it each year for the Middle East, and the newest series it has posted, from November 2024, appear in the table beside estimates by the Institute of International Finance (IIF), an association of global banks. The IMF scheduled its next regional report for release in Dubai on October 22, 2026, and its new breakevens were not available as this course was written. The figures show why the Gulf’s producers want different prices: Qatar’s and the UAE’s budgets balance near $50 a barrel, while Iran’s needs more than $120.

Country	IMF, 2024	IMF projection, 2025	IIF estimate, 2025
Saudi Arabia	$98.4	$90.9	$85
Kuwait	$88.9	$81.8	$78
Iraq	not posted	not posted	$99
UAE	$53.9	$50.0	$57
Qatar	$46.9	$44.7	about $50
Iran	$121.8	$124.1	not given

Fiscal breakeven oil prices, dollars a barrel. IMF Middle East and Central Asia *Regional Economic Outlook* data via the Federal Reserve Bank of St. Louis (FRED), last updated November 6, 2024. IIF estimates as reported by bne IntelliNews, September 13, 2024. Breakevens move with output, spending, and non-oil revenue.

A breakeven assumes the oil can be sold. In 2026 the Gulf's governments had high prices and too little oil to sell, so their revenue fell as prices rose. The IMF estimated in October 2025 that each extra 1 mb/d of Saudi output improves the kingdom's fiscal balance by 3.2% of GDP. Breakevens also leave out spending outside the budget: Bloomberg Economics put Saudi Arabia's at $94 in October 2025, or $111 counting the domestic spending of the Public Investment Fund (PIF), its sovereign wealth fund.

Saudi Arabia's choices follow from this arithmetic. Its oil policy is set by Prince Abdulaziz bin Salman, energy minister since 2019 and also industry minister since July 11, 2026. The kingdom holds most of the spare capacity, so it decides whether to defend the price by cutting output or to defend its share of the market by producing more. It cut in 2023-24, and in 2025 it led the early return of the 2.2 mb/d layer, a move analysts read as an effort to regain market share and to discipline members that produced above their quotas.

Its 2026 budget, approved on December 2, 2025, planned spending of 1.313 trillion riyals ($350 billion) against revenue of 1.147 trillion ($306 billion), a deficit of 3.3% of GDP (Al Arabiya). In 2025, by the finance ministry's estimate, oil brought in 590 billion riyals, 54% of revenue of 1,091 billion, against spending of 1,336 billion, for a deficit of 245 billion riyals ($65.3 billion) in a year of low prices (Argaam). The dollar figures in this module are the sources' own, or riyals converted at the riyal's fixed rate of 3.75 to the dollar. The war then narrowed Saudi Arabia's choice to finding routes for its oil (Module 8).

7f. Does OPEC+ Still Set the Price? The Cases as Their Advocates Make Them

The case that it no longer does: its advocates point out that in 2026 the barrels that moved prices were decided by Iran's Islamic Revolutionary Guard Corps (IRGC), the US Navy, and the drones of Yemen's Houthis, not by ministers in Vienna. The members bound by quotas produced far below their targets (section 7b), so the quotas had become statements of intent. The seven's autumn decisions were to hold output unchanged, while prices rose and fell with each attack and each truce (Module 8). The UAE, the second-largest holder of its spare capacity, has left (section 7c), and supply from outside OPEC+ keeps growing: OPEC itself expects those producers to add 0.6 mb/d in 2026 and again in 2027.

The case that it still does: its advocates argue that the shock hid OPEC+'s power rather than ending it. Once the strait reopens, the path of prices will depend on how fast Saudi Arabia, Iraq, and Kuwait restore their shut-in output, and that is their decision to make. Saudi Arabia's September jump (section 7c) showed how fast its barrels answer once a route exists. In 2025 the group chose to return its 2.2 mb/d layer a year early, and the IEA expects world supply to rise by 7.7 mb/d in 2027, far faster than demand, which it sees rising 2 mb/d (Module 8). Only OPEC+ can hold back barrels on the scale needed to keep that surplus from sinking prices.

What the evidence says: the two cases describe different conditions. In the shock, geography and force set the price, since futures moved with the strait's closures and truces (Module 8), and quota increases of 188 kb/d were small beside shut-ins measured in millions of barrels a day. In a surplus, the producers with spare capacity set the floor. The IEA's figures imply a surplus of about 4 mb/d in 2027, supply of 108.4 mb/d against demand of 104.4 mb/d, unless OPEC+ holds back. The futures curve, which falls steeply from the front month into 2027 and beyond, prices a market that expects the shortage to end (Module 6). The UAE's exit weakens the group's power to hold back, because the UAE no longer shares any cut.

The course's reading, stated once: OPEC+ does not set the price in a crisis of this kind, but it will set the path out of one. In 2026 the strait and the forces fighting over it decided how much oil reached buyers, and the quotas followed the war. When the strait reopens, the Gulf's shut-in output and the surplus the agencies foresee for 2027 return the decision to Riyadh: produce and let prices fall, or hold back to defend budgets that need $80-100 oil. Without the UAE, holding back costs the remaining members more, which makes the first path the likelier one.

Worked example — Saudi Arabia's Budget at $60, $90, and $110

Take the 2026 budget's spending of $350 billion (section 7e) and four assumptions. First, Saudi Arabia produces 9.5 mb/d of crude, about its pre-war level, or 3,467.5 million barrels a year. Second, the state collects 65% of each barrel's value at the world price, through royalties, income tax, and Aramco's dividends. That share is calibrated to 2025, when oil brought the budget 590 billion riyals ($157.3 billion) and Brent's physical price averaged $69 (Module 6): 3,467.5 million barrels at $69 and 65% give $155.5 billion, close to the actual figure. Third, non-oil revenue stays at 2025's 501 billion riyals ($133.6 billion). Fourth, the price is the average Saudi Arabia receives over the year. Each $1 of price then brings the budget $2.254 billion. At $60 the state collects $39.00 a barrel and $135.2 billion in all, so revenue is $268.8 billion and the deficit $81.2 billion. At $90 it collects $58.50 a barrel and $202.8 billion, for revenue of $336.4 billion and a deficit of $13.6 billion. At $110 it collects $71.50 a barrel and $247.9 billion, for revenue of $381.5 billion and a surplus of $31.5 billion. The budget balances at $350 billion less $133.6 billion, divided by $2.254 billion: $96.0 a barrel, close to the IMF's estimates. Now change the volume, as the war did. At $110 and 8 mb/d, about the September output, oil brings $208.8 billion, the deficit is $7.6 billion, and the breakeven rises to $114.0. At 6 mb/d, close to the August level by Saudi Arabia's own count, $110 oil brings $156.6 billion, what $69.47 would bring at full output, and the deficit is $59.8 billion. In 2026 volume, not price, decided Saudi Arabia's budget.

Module 7 Key Points

OPEC and OPEC+

• OPEC has 11 members since the UAE left on May 1, 2026, and its Conference decides by unanimity.

• OPEC+ produced 39.07 mb/d of crude in September 2026; its quota-bound members were 5.45 mb/d below their targets.

• Before the war OPEC+ held about 5.2 mb/d of spare capacity, 2.16 mb/d in Saudi Arabia (Energy Intelligence); the war stranded it.

• OPEC+ raised quotas monthly from April to September 2026; the seven held them for October and November and meet next on November 1.

• The IMF’s latest posted breakevens run from about $45 a barrel (Qatar) to $124 (Iran); Saudi Arabia’s 2025 projection was $90.9.

• OPEC+ did not set the price in the 2026 shock, but its shut-in barrels and the 2027 surplus will set the path down.

Module 7 Quiz

Check Your Understanding

1. How does OPEC’s Conference of oil ministers take its decisions?

A) By a two-thirds majority
B) By votes weighted by output
C) By unanimity
D) By majority

2. Which country held the most spare capacity before the war, by Energy Intelligence’s estimate?

A) The UAE, with 1.36 mb/d
B) Saudi Arabia
C) Russia, OPEC+’s co-leader
D) Iraq, with its southern fields

3. When did the UAE’s exit from OPEC and OPEC+ take effect?

A) May 1, 2026
B) January 1, 2019, alongside Qatar
C) April 28
D) January 1, 2024

4. What does the worked example find about Saudi Arabia’s budget at $110 oil?

A) A surplus whatever the output
B) A surplus at 9.5 mb/d, but a deficit at 6 mb/d
C) A deficit at any output
D) Balance at exactly $96

5. What is the course’s reading on whether OPEC+ still sets the price?

A) Yes: its monthly quota decisions moved prices throughout the 2026 war, and the UAE’s exit changed nothing
B) No; prices now follow US shale output
C) Only Russia now sets the price, not Riyadh
D) Not now; it will set the path out

Module 8 — The Shock of 2026

The Iran War and the Strait of Hormuz

Recommended Reading / Reference

Book: David Crist, *The Twilight War: The Secret History of America's Thirty-Year Conflict with Iran* (2012), by a US government historian, on the clashes between Iran and the United States in the Gulf since 1979, including the tanker war and the American convoys of 1987-88

Reference: The EIA's monthly *Short-Term Energy Outlook*, whose tables track the Gulf's shut-in output, and the IEA's monthly *Oil Market Report*, on demand and stocks

8a. The Strait

The Strait of Hormuz joins the Persian Gulf to the Gulf of Oman, between Iran to the north and Oman's Musandam peninsula to the south. It is about 33 kilometers (21 miles) wide at its narrowest, and tankers use two shipping lanes about 3 kilometers wide, one in each direction (EIA). In 2025 about 21.2 million barrels a day (mb/d) of oil passed through it, 15.2 mb/d of crude oil and condensate and 6.1 mb/d of refined products, by the EIA's quarterly estimates, or 20.3% of the world's oil consumption.

The strait matters because so little of the Gulf's oil can avoid it. Saudi Arabia and the United Arab Emirates (UAE) built pipelines to ports beyond it, but Iraq's northern outlet is small, and Kuwait and Qatar have none (table). Fertilizer and sulfur from the Gulf take the same route (Module 10).

Exporter	Oil exported through the strait before the war	Route around it
Saudi Arabia	Most of about 7 mb/d	The East-West pipeline to Yanbu on the Red Sea, rated at 5 mb/d and expandable to about 7
Iraq	About 3.5 mb/d	The Kirkuk-Ceyhan pipeline to Turkey, 0.5-1 mb/d when operating
UAE	About 3 mb/d	The Habshan-Fujairah pipeline to the Gulf of Oman, 1.5-1.8 mb/d
Kuwait	About 2 mb/d	None
Iran	About 1.5 mb/d	The Goreh-Jask pipeline to the Gulf of Oman, little used
Qatar	Condensate, and about a fifth of the world's liquefied natural gas	None

Approximate volumes and capacities before February 28, 2026: EIA; Kpler; company statements. Bahrain's smaller exports also pass the strait.

Together the pipelines could carry roughly 7-9 mb/d at most, well under half of what the strait carried. In 2026 Saudi Arabia ran its line near capacity, and loadings at Yanbu peaked at about 5.3 mb/d in April. On October 12 Prince Abdulaziz bin Salman, Saudi energy minister since 2019, said a gas pipeline converted to crude could carry about 1 million barrels a day more, a conversion he put at eight weeks (Semafor). Kuwait's oil, most of Iraq's, and Qatar's gas had no way out, so much of their production stopped when the ships did.

8b. The War, February to July

The war began on February 28, 2026, when American and Israeli strikes on Iran killed its Supreme Leader, Ali Khamenei. On March 8 the Assembly of Experts named his son, Mojtaba Khamenei, to succeed him. The Islamic Revolutionary Guard Corps (IRGC), the force whose navy patrols the strait, radioed ships that none could pass. An IRGC official confirmed the closure on March 2, and Iran declared the strait “closed” on March 4. On March 5 the protection and indemnity (P&I) clubs, the mutual insurers that cover ships against claims for spills, collisions, and injury, withdrew cover, so the strait was shut in practice though no law closed it. The IEA has called the result the largest disruption in the history of the oil market (Gulf News, August 17).

A two-week ceasefire mediated by Pakistan began on April 7-8. Talks in Islamabad, led for the United States by Vice President JD Vance, failed on April 12 after 21 hours, and on April 13 the US Navy began a blockade of Iran’s ports. Iran said on April 17 that ships could pass, but shipowners did not return, and within a day Iran closed the strait again while the blockade stood. On May 5 Iran set up a Persian Gulf Strait Authority to issue a permit for each transit.

On June 17 the US and Iran signed a memorandum of understanding in Islamabad, a temporary 14-point deal. Iran was to make “best efforts” for safe passage, the US was to lift its restrictions on Iran’s ports, and nuclear talks were to follow (Axios). A round of talks in Switzerland on June 19-21 opened a two-month negotiating period (Agence France-Presse). In the same days Iran said the strait was closed again over Israeli strikes in Lebanon, while US Central Command (CENTCOM), which commands American forces in the region, said safe passage “remained intact”. On June 29-30 the two sides agreed to “stop all kinetic activities” (Axios).

The truce broke down on July 7-8. Strikes resumed on July 7, and on July 8 the interim agreement collapsed and the US reimposed sanctions on Iran’s oil exports (EIA). The IRGC declared the strait closed again on July 12, and the US reinstated its blockade of Iran’s ports about July 14. Fighting between Saudi Arabia and Yemen’s Houthis, an Iran-aligned movement that holds Yemen’s capital, Sanaa, resumed in mid-July, when Houthi missiles fired at Saudi Arabia on July 13 broke an informal truce that had held since 2022 (Reuters).

8c. The War Renewed, August to October

A month of relative calm, in Reuters’ description, ended at the close of August. Saudi Arabia said an Iranian strike on its tanker *Sidr*, near Khasab in Oman, killed two crew members on August 31, and in the same days Kuwait reported that an Iranian drone had set fire to a residential building. On September 1 the US and Iran exchanged their heaviest fire since July. The next day President Donald Trump said US strikes had destroyed an Iranian rocket built to drop sea mines and hit radar and missile sites near the strait, and that the campaign would not last “too long” (Outlook Business, September 3).

A second, larger wave followed. On September 5 Iran declared a “prohibited zone” from the American blockade line to its loading ports, and in early September the US extended its blockade to Iran’s oil exports. On September 8-9 CENTCOM said it had destroyed five Iranian tankers overnight, part of 10 hit in a week under the new policy. The IRGC said it had attacked 10 ships near the strait and fired missiles at a base used by US forces in Jordan, which said it intercepted 18 of 20 (Reuters). Reuters called it the largest declared wave of attacks on shipping since the war began.

On September 11 an attack shut Saudi Arabia’s East-West pipeline. Riyadh blamed fighters in Iraq backed by Iran (Reuters, September 15), and another report described a drone launched from Iraq (Business Today, October 5). The line partly restarted on September 22 (EIA), and Saudi Arabia raised loadings at its terminals inside the Gulf.

In October the Houthis stepped up their missile and drone attacks on Saudi Arabia. They claimed attacks on King Khalid International Airport in Riyadh and an Aramco refinery at Rabigh on October 5, on which Saudi authorities made no immediate comment (Bernama), and the Riyadh airport closed after a severe attack on October 10 (AP). A Houthi strike damaged Aramco's headquarters, Bloomberg reported on October 14. On October 19 the Houthis claimed strikes on an Aramco site at Yanbu, the Shaybah oil field, and the airports of Riyadh and Abha, which Reuters could not verify. On October 21 Saudi Arabia's energy ministry said debris from an intercepted drone aimed at Shaybah killed two people, and aviation officials said an attack on Dammam's airport killed at least one person and wounded eight (Agence France-Presse).

The same day the State Department ordered non-emergency staff at the US embassy in Riyadh and its consulates to leave (AP), and its spokesman, Tommy Pigott, said that "Iranian-supported Houthis have increasingly engaged in hostilities against Saudi Arabia" (Agence France-Presse). Talks with Iran have stalled. In late September the *Wall Street Journal* reported, citing US officials, that Trump had rejected an Iranian offer to reopen the strait within seven days if the US met its conditions, and that he expected to resume bombing after the US elections of November 3. On October 8 he said the US "will not be attacking Iran at any time prior to the Midterm Elections" (AP). On October 20 Iran's president, Masoud Pezeshkian, discussed renewed mediation with Pakistan's military chief, Field Marshal Asim Munir, in Tehran, but by October 22 Trump said the US was not negotiating with Tehran. Late on October 21 Iranian state media reported explosions near Sirik, on Iran's coast, without giving a cause, and as of October 23 no round of talks was scheduled.

The week ended with both sides raising the stakes. Aramco ordered staff out of its headquarters in Dhahran on October 22 (Reuters). That day the IRGC claimed hits on seven tankers, four during transfers between ships in the northern Gulf and three by mines west of the strait. The UK Maritime Trade Operations (UKMTO) center, run by Britain's Royal Navy, confirmed only two attacks that night (AP), and Trump said Iran was "making up fake hits" (CBS News). On October 24 he told reporters that the US was "thinking about" striking Iran again, "maybe tomorrow," or might reach a deal (Anadolu Agency).

8d. The Market in the Shock

Oil crossing the strait fell from 21.6 mb/d in the fourth quarter of 2025 to 4.9 mb/d in the second quarter of 2026, by the EIA's estimates. The output behind that fall is counted as shut-in production: oil that fields could produce but that stopped because it could not be shipped. The EIA's count for the Middle East peaked at 10.9 mb/d in May and fell as tankers found routes (table). It expects 4.47 mb/d to remain shut in during the fourth quarter of 2026 and 2.68 mb/d in the first quarter of 2027.

Country	March-July average	August 2026	September 2026
Saudi Arabia	2,750	3,270	1,700
Iraq	2,646	780	760
Kuwait	1,466	630	930
UAE	740	0	0
Iran	424	900	1,200
Qatar	350	100	100
Bahrain	136	80	80
Total	8,512	5,760	4,770

Shut-in crude oil production in the Middle East, thousand barrels a day (kb/d). EIA, *Short-Term Energy Outlook*, October 6, 2026. Iran's rose after the US blockade of its exports.

Prices measured the shock in two ways, and Module 6 explains the benchmarks and why they parted. Brent futures, the front-month contract on the Intercontinental Exchange, settled at $72.48 on February 27, the last trading day before the strikes, and Brent's physical spot price had averaged $67 in January (EIA). Dated Brent, Platts' assessment of physical North Sea cargoes, reached a record $144.42 on April 7 (S&P Global), double the pre-war futures close, while futures that day were near $109, about half higher. Futures touched their 2026 high of $126.41 during trading on April 30, the June contract's last day, and settled lower (Reuters).

The price of the Gulf's own oil rose furthest, because that oil could not sail. Dubai, the benchmark for the sour, high-sulfur crude the Gulf sells to Asia, set a record of $153.25 a barrel for cash cargoes on March 16 (Platts) and reached a record near $167 on March 19 (Quantum Commodity Intelligence). After the June memorandum Brent futures fell to about $72 on June 26 and again on July 1 (EIA). With the September escalation they settled at $101.21 on September 9, their highest close since late May (Reuters).

Shipping priced the risk as well. War-risk premiums, the extra insurance a ship buys for a voyage through a war zone, softened after the June memorandum, Neil Roberts, head of marine and aviation at the Lloyd's Market Association, said on July 10. By July 22 Marcus Baker, global head of marine, cargo, and logistics at the broker Marsh, put them at 7.5-10% of a ship's hull value, against 1-3% weeks earlier (S&P Global), or $7.5-10 million on a tanker worth $100 million. A very large crude carrier (VLCC), which carries 2 million barrels, earned about $723,000 a day on September 18, against $79,700 a year earlier (Baltic Exchange).

Attacks on ships rose again in October. The VLCC *Kazimah III* was struck on October 1, and from October 2 UKMTO reported at least one attack a day in Hormuz or the Gulf of Aden (Reuters). Kpler, a firm that tracks ships and cargoes, counted at least 18 vessels attacked in the two weeks to October 19.

8e. The Buffers

On March 11 the 32 member countries of the IEA agreed to release 400 million barrels from emergency stocks, the largest collective action in the agency's history and its sixth, after 1991, 2005, 2011, and two in 2022. The United States pledged 172 million barrels, 43% of the total, Japan 80 million, South Korea 22.5 million, Germany 19.5 million, and Britain 13.5 million (Enerdata). The whole release equaled about four days of the world's consumption. Module 12 explains how the American share was lent from the Strategic Petroleum Reserve and what is left there.

The oil came out more slowly than it was pledged. About 290 million barrels had been released by July 21, but only 8 million moved in September. By October 15 the total was about 331 million, 240 million from government stocks and 91 million from stocks that companies must hold by law (S&P Global). On October 2 the leaders of the Group of Seven (G7), the largest industrial democracies, set a four-month deadline for the remaining 100 million barrels and asked for diesel first. On October 15 the IEA's governing board asked members to release the rest, and more than 20 million barrels of diesel, as soon as possible.

China, which is not a member of the IEA, held the largest stocks of all and used them on its own terms. It added an average of 1.1 mb/d to its stocks in 2025, and the EIA estimated them at nearly 1.4 billion barrels in December 2025, about 360 million of them held by the state. Its crude imports were 23% lower than a year earlier from March to July (*Wall Street Journal*), and its onshore crude stocks, a separate count from the EIA's, reached a record 1.354 billion barrels on May 4. It then drew them down to 1.192 billion barrels by the week to October 19 (Reuters, October 22). The September draw was the largest monthly draw on record in two trackers' data: 57 million barrels by the count of Vortexa, another firm that tracks cargoes, and 47.5 million by Kpler's.

Across the world, the stocks that the IEA can observe stood about 509 million barrels below their end-February level at the end of September, a draw of 2.4 mb/d, and stocks on land were near their lowest since at least 2016 (IEA, October 14).

8f. The Strait in October

As of October 23, 2026, control of the strait is contested. Iran requires each ship to obtain its authorization, the IRGC calls the strait “under our definitive control”, and the IRGC says its forces attack ships on routes it has not approved. One ship reportedly paid $2 million for passage, assessed in Chinese yuan (Lloyd’s List). The United States blockades Iran’s ports and oil exports and guards a two-way corridor along Oman’s coast, which Al-Monitor, a news site, called “a makeshift shipping system supported by the US Navy”. Each side has claimed control (Reuters, August 14), and neither holds it alone.

More oil moves than the ship counts suggest. In the week to about October 20, Kpler counted about 14 mb/d passing through the strait, including oil moved between ships in the Gulf of Oman, 82% of the flow before the war by its measure. By October 23 its seven-day average had fallen to 12.65 mb/d, 26% below its prewar baseline of 17.15 mb/d (Dow Jones). About 40% of the crude that Gulf states other than Iran exported in September left by routes avoiding the strait, against 17% before the war (Kpler, via Al-Monitor, October 21). Module 11 gives Iran’s own exports under the blockade.

Two measures that seem to contradict each other are both right. The EIA’s shut-in figure counts production that has stopped, while Kpler counts what tankers load, which includes oil drawn from tanks filled during the closure. So the region’s crude exports could exceed their prewar level on four days in late September (Reuters, citing Kpler) while output was still shut in (section 8d). Counts of ships understate the flow, because many tankers sail with their transponders off, and the EIA warns that tracking data for Hormuz have been “especially unreliable” since late February.

8g. Demand’s Answer

The rest of the gap closed because the world used less oil, and the forecasters disagree on how much less. The EIA expects world consumption to fall by about 2.0 mb/d in 2026 (Module 9 gives the 2025 level). The IEA, in its report of October 14, expects a fall of 2.6 mb/d, to 102.4 mb/d, the first annual fall since 2020. OPEC, in its report of October 13, still expects demand to grow by 0.18 mb/d, after cutting its forecast for the sixth month in a row.

The fall was deepest in the spring, when the IEA estimated demand 4.9 mb/d below a year earlier in the second quarter, and it expects a fall of 2.5 mb/d in the fourth quarter. Diesel accounts for about a quarter of its 2026 decline. The agencies also start from different baselines, since the IEA puts 2025 demand at about 105.0 mb/d and OPEC at about 105.5. OPEC’s higher figures imply a much smaller loss of stocks than the draws the IEA observed.

The agencies expect only a partial recovery. The IEA sees demand rising by 2 mb/d in 2027, which would still leave it 620,000 barrels a day below 2025, with growth over a year earlier returning in March 2027 at the earliest (IEA, via TASS).

Worked example — The Chokepoint’s Arithmetic, March to September 2026

How did the world cover the loss? Start with the barrels lost, using the EIA’s shut-in figures (section 8d). From March to July, 153 days at 8.512 mb/d, the loss was 1,302 million barrels. August added 179 million (31 days at 5.76 mb/d) and September 143 million (30 days at 4.77 mb/d). That is 1,624 million barrels over 214 days, an average of 7.6 mb/d. Second, assume that the market would otherwise have kept adding to stocks at its 2025 rate, an assumption. The EIA’s figures for 2025, production of 106.3 mb/d against consumption of 104.4 mb/d, give a surplus of 1.9 mb/d, or 407 million barrels over 214 days. The net shortfall is therefore 1,624 less 407, or 1,217 million barrels, 5.7 mb/d. Third, stocks: observed stocks fell 509 million barrels from the end of February to the end of September (IEA), including the emergency stocks released, and covered 42% of the net shortfall. That leaves 1,217 less 509, or 708 million barrels, 3.3 mb/d, which had to come from lower consumption. That lies between the IEA’s estimates of a fall of 4.9 mb/d in the second quarter and 2.6 mb/d for the year, so the sum roughly closes. Without the prewar surplus, demand would have had to fall 5.2 mb/d, twice the IEA’s figure for the year. Of the 1,624 million barrels lost, then, about 25% came out of a surplus that never formed, 31% out of stocks, and 44% out of consumption. The arithmetic leaves out supply growth outside the Gulf and stocks that no one can observe, so it is only approximate.

Module 8 Key Points

The Shock of 2026

• About 21.2 mb/d of oil, 20.3% of world consumption, passed Hormuz in 2025; pipelines around it carry roughly 7-9 mb/d at most.

• The war began February 28, 2026; the Islamabad memorandum of June 17 collapsed on July 7-8, and fighting widened again from late August.

• Shut-in Middle East crude output peaked at 10.9 mb/d in May and was 4.77 mb/d in September (EIA).

• Dated Brent hit a record $144.42 on April 7, double the pre-war futures close of $72.48 on February 27; futures rose about half.

• The IEA’s record 400-million-barrel release had delivered about 331 million barrels by October 15; observed world stocks fell 509 million.

• In October Kpler counted about 14 mb/d through the strait, 82% of prewar on its measure, under contested Iranian and American control.

Module 8 Quiz

Check Your Understanding

1. What became of the memorandum the US and Iran signed in Islamabad on June 17, 2026?

A) It reopened the strait for good and ended the US blockade.
B) It was never signed, because the April talks had failed.
C) It collapsed on July 7-8, when strikes resumed and sanctions returned.
D) It became a final peace treaty, signed in Geneva on June 19, which ended both the war and the blockade.

2. Which country pledged the largest share of the IEA's 400-million-barrel release of March 11, 2026?

A) Japan, with 80 million barrels
B) China, the largest holder of stocks
C) The United States
D) Germany, the largest share in Europe

3. What record did Dated Brent, the physical price, set during the shock?

A) $126.41 on April 30
B) $144.42 on April 7, 2026
C) $166 on March 19
D) $72.48 on February 27, 2026

4. Who controlled the Strait of Hormuz in October 2026?

A) Neither side alone: Iranian permits and a US-guarded corridor
B) Iran, under the June deal
C) The US Navy alone
D) Oman, by agreement with both

5. By how much did the IEA, on October 14, 2026, expect world oil demand to change in 2026?

A) Up 0.18 mb/d
B) A fall of 4.9 mb/d, its estimate for the whole year
C) A fall of about 2.0 mb/d, matching the EIA
D) A fall of 2.6 mb/d

Module 9 — Oil and the Economy

Growth, Inflation, and Who Wins

Recommended Reading / Reference

Book: Robert McNally, *Crude Volatility: The History and the Future of Boom-Bust Oil Prices* (2017), by a former White House energy adviser, on why oil swings between glut and shortage and what the swings do to economies

Reference: The Bureau of Labor Statistics' monthly Consumer Price Index releases, with each item's weight, and Känzig, Stock, and Zanotti, "From Importer to Exporter: Oil Shocks and the US Economy," *Brookings Papers on Economic Activity* (Fall 2026)

9a. What Oil Does

Oil supplied 33.5% of the world's energy in 2025, 201 of about 600 exajoules (EJ, each a billion billion joules), by the count of the Energy Institute's *Statistical Review of World Energy*, published on June 30, 2026. Fossil fuels as a whole supplied 86%. The IEA uses a wider total that includes wood, dung, and other traditional biomass, and on that count oil's share fell below 30% in 2024 for the first time, from a peak of 46% about fifty years earlier. On either count oil is still the largest single source of energy, and its share has been falling for half a century.

The world used 104.4 million barrels a day (mb/d) of oil in 2025, by the EIA's estimate of October 6, 2026. Module 13 gives that year's growth, and Module 8 covers the fall forecast for 2026.

Transport takes more than half of the world's oil (table), and in trucks, ships, and aircraft no other fuel yet does its work at scale. Electric cars are displacing some of the oil used on roads (Module 13), while oil has largely left power generation, where gas, coal, and renewables took its place after the 1970s.

Use	2025, mb/d	Share	What it burns or makes
Cars	27.0	26%	Gasoline and some diesel
Trucks and buses	18.3	17%	Diesel
Two- and three-wheelers	1.4	1%	Gasoline, mainly in Asia and Africa
Aviation	7.5	7%	Jet fuel; the fastest-growing use (Module 13)
Shipping	6.0	6%	Fuel oil and marine diesel
Petrochemical feedstocks	14.8	14%	Naphtha, ethane, and liquefied petroleum gas (LPG) for plastics and chemicals (Module 5)
Industry	7.8	7%	Heat, engines, and machinery
Buildings	6.8	6%	Heating oil, kerosene, and LPG for heating and cooking
Power generation	2.8	3%	Fuel oil and diesel burned in power plants
The oil industry's own use	6.3	6%	Fuel burned in oil fields and refineries
Other	6.0	6%	Lubricants, asphalt, farming, and rail
Total	104.7	100%	

Aker BP, a Norwegian oil producer, oil demand outlook (February 2026), from Rystad Energy's sector model; shares computed. The EIA puts 2025 demand at 104.4 mb/d. Rystad counts less oil as petrochemical feedstock than the IEA, whose 15.8% for 2023 is in Module 5, so its lower share reflects the source, not a fall in the share.

9b. Less Oil per Dollar of Output

The world needs much less oil to produce a dollar of output than it did in 1973. Christof Rühl and Titus Erker of Columbia University's Center on Global Energy Policy calculated that the world used a little less than one barrel of oil for each $1,000 of GDP in 1973, at 2015 prices, and 0.43 barrels in 2019, a fall of 56% (September 9, 2021). The decline was steady, just under 0.01 barrel a year for three and a half decades and "almost perfectly linear" since 1984. Rothschild & Co, the bank, put the figure at about 0.4 in 2026 (May 7, 2026).

The usual explanations are three. Oil largely left power generation and much home heating, engines and furnaces became more efficient, and economies grew fastest in services that burn little fuel. What remains is concentrated in uses that are hard to replace, transport above all (section 9a).

Lower intensity shrinks the cost of a given price rise. At 0.43 barrels per $1,000 of output, a $10 rise in the price of a barrel costs $4.30 for every $1,000 of world output, or 0.43% of GDP, against about 1% at the 1973 intensity, both in 2015 dollars (computed). A shock of the same real size now takes less than half the share of income it took in 1973.

9c. Shocks and Recessions, 1973 to 2026

Most American recessions since 1973 followed a jump in the oil price. The table sets the main oil shocks, as dated by the economist James Hamilton, beside the recessions dated by the National Bureau of Economic Research (NBER), the private research group whose committee dates US business cycles. Module 2 tells the history of each shock and its prices.

Shock	Oil disruption or price rise	US recession (NBER)
Arab oil embargo	October 1973 to March 1974	November 1973 to March 1975
Iranian revolution	November 1978 to July 1979	January to July 1980
Iran-Iraq war	October 1980 to March 1981	July 1981 to November 1982
Iraq's invasion of Kuwait	August to October 1990	July 1990 to March 1991
Price surge of 2007-08	Strong demand against stagnant world output	December 2007 to June 2009
Libya's civil war (2011); Russia's invasion of Ukraine (2022)	Price rises	None
The Iran war and Hormuz, 2026	From February 28, 2026 (Module 8)	None so far: real GDP grew at annual rates of 2.5% in the first quarter and 2.2% in the second

Shock dates from Hamilton, *Brookings Papers on Economic Activity* (Spring 2009), Table 2; recession dates from the NBER; 2011 and 2022 from Känzig, Stock, and Zanotti (September 2026); 2026 growth from the Bureau of Economic Analysis, September 30, 2026.

Hamilton, an economist at the University of California, San Diego, found that the 2007-08 shock had "significant effects on consumption spending and purchases of domestic automobiles" (2009). The mechanism is direct. Households facing a sudden rise in a bill they cannot quickly cut spend less on other things and put off buying cars, firms that burn fuel see their costs rise, and central banks may raise interest rates to hold down inflation, slowing the economy further.

Shocks have also come and gone without recessions, in 2011 and 2022, and the US economy kept growing through the first half of 2026 (table). The Bureau of Economic Analysis (BEA) publishes its first estimate for the third quarter on October 29, 2026.

9d. Oil and Inflation in 2026

Energy is a small share of what Americans buy, but the most volatile. In the Consumer Price Index (CPI) of the Bureau of Labor Statistics (BLS), energy carried a weight of 7.418% in August 2026 and gasoline 3.853%, each weight being the item's share of the spending the index tracks. In the year to September 2026 energy prices rose 20.4%, gasoline 34.2%, and fuel oil 74.2%, while all items rose 3.7% and core prices, which leave out food and energy, rose 2.6% (BLS, October 14, 2026). Gasoline accounted for more than half of September's monthly rise of 0.6%.

A rough split of the 3.7% follows. A year earlier, before prices moved, energy's weight was about 6.4%, so its 20.4% rise added about 1.3 percentage points to the index, and gasoline's rise added about 1.0 point (computed, adjusting each weight back by its own price change). Core prices, about four-fifths of the index, added about 2.1 points. The 1.1-point gap between headline and core inflation is almost all energy.

Oil also reaches prices through services that burn fuel. Airline fares rose 22.4% in the year to September, against 5.0% for piped gas and 4.4% for electricity (BLS, October 14, 2026). Core inflation of 2.6% suggests that little of the shock had spread beyond fares into wages and the wider run of prices by September. The price index for personal consumption expenditures (PCE), which the Federal Reserve (the Fed) prefers, rose 3.4% in the year to August, and 3.0% without food and energy.

The Fed responded. On September 16, 2026 it raised its target range for the federal funds rate, the rate at which banks lend to each other overnight, to 3.75-4.00%, and its next decision is due on October 28, 2026. A paper posted on September 23, 2026 for the *Brookings Papers on Economic Activity*, by the economists Känzig, Stock, and Zanotti, explains the logic: in a net-exporting United States, consumer prices still respond to oil much as they did when it was a large importer, so the Fed "can raise interest rates somewhat more." The IMF expects US inflation of 3.6% in 2026, up from 2.7% in 2025, and world inflation of 4.7%, up from 4.1%, mainly because of energy and food (*World Economic Outlook*, October 13, 2026).

9e. What Households Pay

Households buy fuel every week and cannot cut much of it quickly. The average American household, which the BLS calls a consumer unit, spent $2,411 on gasoline, other fuels, and motor oil in 2024, 3.1% of its total spending of $78,535, and $13,318, or 17.0%, on all transportation (Consumer Expenditure Survey, December 19, 2025). The share of spending on gasoline and other fuels was near 5% in 2008, 2011, and 2012, by the Bank of America Institute's reading of the same survey.

The burden falls hardest on lower-income households. Bank of America's data on its customers' accounts show that in March 2026 the median lower-income household spent 4.2% of its income on gasoline, up from 3.9% a year earlier, against 2.7% for higher-income households, and that about 10% of lower-income households spent more than 10% (Bank of America Institute, April 28, 2026).

The national bill rose fast after the war began. Americans' spending on gasoline and other energy goods ran at an annual rate of $521.2 billion in the second quarter of 2026, up 18.0% from the first quarter and 28.0% from a year earlier, an increase of $114.0 billion (BEA, via the Federal Reserve Bank of St. Louis). That is about $840 a year for each of the 135.8 million consumer units (computed).

9f. Winners and Losers

A higher oil price moves income from those who buy oil to those who sell it. Economists call this a change in the terms of trade, the price of what a country sells relative to what it buys. On the 104.4 mb/d the world used in 2025, each $10 on the barrel moves about $381 billion a year from buyers to sellers (computed). The IMF assumes an average oil price of $95.74 a barrel in 2026, the mean of Brent, Dubai Fateh, and WTI based on futures prices, up 41.3% from $67.74 in 2025 (October 13, 2026). At 2025 volumes the rise is worth about $1.07 trillion a year (computed).

The IMF draws a finer line than exporters against importers. In its October outlook, “energy exporters outside the immediate conflict zone benefit from favorable terms of trade,” while “energy-importing economies with little connection to the technology value chain face the most difficult configuration.” It lists higher import bills, pressure on currencies, weaker real incomes, and tighter budgets. The IMF expects inflation in the euro area to rise from 2.1% in 2025 to 3.1% in 2026, and in India from 2.0% to 5.0%. Exporters inside the conflict zone lost output instead of gaining (Module 11).

The United States sits on both sides. It now exports more crude oil and petroleum products than it imports (Module 12), so a higher price raises national income, and the gain flows to producers, landowners who collect royalties, shareholders, and the budgets of producing states. American drivers, airlines, truckers, and farmers pay the higher price. The Brookings paper finds that after a supply shock employment outside mining rises by similar amounts in oil and non-oil states, but its authors warn that their findings “do not imply that higher oil prices are unambiguously beneficial for every U.S. household or firm.”

9g. Do Oil Shocks Still Cause Recessions? The Cases as Their Advocates Make Them

The case that they do: James Hamilton, the economist most associated with this view, notes that all but one of the 11 US recessions since World War II followed a sharp rise in the price of crude oil (*NBER Reporter*, June 2011), a pattern he first saw in 1983. He measures shocks as the net oil price increase, the amount by which the price exceeds its highest level of the previous three years, because households react to new highs more than to rises that only reverse a fall. On that measure his model finds that, without the 2007-08 shock, US real GDP growth from the fourth quarter of 2007 to the third quarter of 2008 would have been 4.2% rather than the actual 0.7%. Energy prices, he estimates, explain about half of the shortfall in consumer spending. Those who share his view add that 2026 brought shut-ins of Gulf output that peaked at 10.9 mb/d (Module 8), a Fed rate rise, and gasoline taking more of poorer households’ income (section 9e).

The case that they no longer do: Lutz Kilian and Robert Vigfusson, in a Federal Reserve paper of August 2014, argue that Hamilton’s model fits the data worse on average than a simple linear one. His model blames oil for a 3% cumulative fall in US GDP in the late 1970s and early 1980s and 5% in the financial crisis, while the linear model implies effects “of at most 1 percent.” A model in Hamilton’s own paper, built on the work of Olivier Blanchard and Jordi Galí, gives oil only 0.7 point of the 2007-08 slowdown. The newest evidence is the Brookings paper’s main finding: now that the country is a net exporter, “the U.S. economy no longer responds to adverse oil supply news,” because producers’ gains in income and wealth support industrial production and household spending. And the economy now uses less than half as much oil per dollar of output as in 1973 (section 9b).

What the evidence says: the historical link is strong, but how much oil caused is disputed even by its leading advocate. Of his finding that the US would have escaped recession without the 2007-08 shock, Hamilton wrote that it was “a conclusion that I don’t fully believe myself,” and he noted that housing cut

annual growth by close to a point (VoxEU, 2009). Rises in 2011 and 2022 passed without recession, and the US kept growing through mid-2026 (section 9c). The IMF expects US growth of 2.3% in 2026, against 1.1% for the euro area, an importer. It estimates that the Hormuz disruption would have cut world growth by 0.9 point in 2026 without rerouting, extra output elsewhere, and stock draws, and cuts it by 0.3 point after them, leaving its world forecast at 3.1%. Inflation responded much as before, and so did the Fed (section 9d).

The course's reading, stated once: oil shocks no longer cause American recessions by themselves, but they have not become harmless. As a net exporter, the United States keeps much of what its drivers pay at home, so a shock now moves income from consumers to producers more than it drains the economy, and growth through mid-2026 fits that account. The danger runs through inflation: if the Fed raises rates far enough to stop the price rise, the cure can bring the recession that the shock alone did not. For importers such as the euro area, the old mechanism still works. The Fed's decision on October 28 and the first estimate of third-quarter growth on October 29, 2026 are the next tests.

Worked example — A Household's Fuel Bill, and the Nation's Trade Gain

Take a household that buys 700 gallons of gasoline a year, for example 17,500 miles at 25 miles a gallon (an illustrative assumption). At $3.00 a gallon its bill is $2,100. At $4.29, about the US average in the week of October 19, 2026 (Module 6), it is $3,003, and at $5.00 it is $3,500. The move from $3.00 to $4.29 adds $903 a year, or 43%, and the move to $5.00 adds $1,400, or 67%. For a household with an income of $40,000 (an assumption), the bill rises from 5.3% of income at $3.00 to 7.5% at $4.29 and 8.8% at $5.00. For one with $150,000, it rises from 1.4% to 2.0% and 2.3%. Now the nation. The EIA expects US net exports of crude oil and petroleum products to average 4.3 mb/d in 2026 (October 6, 2026), and Module 12 covers the trade. At $100 a barrel of crude those exports earn 4.3 million × 365 × $100 = $157.0 billion a year, and at $69, the 2025 average of Brent's spot price (Module 6), $108.3 billion. A rise from $69 to $100 therefore adds $48.7 billion a year to US national income, about $15.7 billion for each $10, or $358 for each of the 135.8 million consumer units. That is an upper bound, because much of the net export is natural gas liquids such as propane, which sell for well below the price of crude. Against it, Americans' spending on gasoline and other energy goods rose $114.0 billion a year from the second quarter of 2025 to the second quarter of 2026 (section 9e), 2.3 times the trade gain. Because the country exports more oil than it imports, the extra spending stays in the country on net, moving from drivers to American refiners, producers, royalty owners, and governments. The nation gains on its trade in oil, while the household in this example pays $903 more a year at $4.29 than at $3.00.

Module 9 Key Points

Oil and the Economy

• Oil supplied 33.5% of world energy in 2025 on the Energy Institute’s count, and under 30% in 2024 on the IEA’s wider count.

• Transport uses more than half of the world’s oil, and road vehicles alone about 45%.

• The world used 0.43 barrels of oil per $1,000 of GDP in 2019, 56% less than in 1973.

• Energy added about 1.3 points to US inflation of 3.7% in the year to September 2026; core inflation was 2.6%.

• US spending on gasoline and other energy goods rose $114.0 billion a year between mid-2025 and mid-2026.

• A Brookings paper of September 2026 finds the US, now a net exporter, no longer slides into recession on oil supply shocks.

Module 9 Quiz

Check Your Understanding

1. How much oil did the world use per $1,000 of GDP in 2019, against a little under one barrel in 1973?

A) About 0.8 barrels, a fall of a fifth
B) 0.43 barrels
C) About 1.5 barrels, as cars multiplied
D) Still about one barrel, since growth needed oil

2. What did the Brookings paper by Känzig, Stock, and Zanotti find in September 2026?

A) Oil shocks now cause deeper US recessions
B) Oil no longer moves US consumer prices
C) The US no longer responds to adverse oil supply news with recession, though consumer prices still respond
D) The US now gains so much from exports that higher oil prices benefit every household and firm, provided the Fed holds rates steady

3. By the module's estimate, about how much of the 3.7% rise in US consumer prices in the year to September 2026 came from energy?

A) About 1.3 percentage points
B) All of it
C) About 3 points
D) Under 0.1 point

4. In March 2026, what share of its income did the median lower-income US household spend on gasoline, by Bank of America's data?

A) About 10%
B) 3%
C) Nearly a fifth
D) 4.2%

5. What is the course's reading on whether oil shocks still cause recessions?

A) Yes, as reliably as in the 1970s
B) No, oil no longer matters to growth
C) Not by themselves in the US, a net exporter, though they raise inflation and remain a risk through the Fed's response and for importers
D) Only in countries that import all their oil

Module 10 — Oil in Food

Fertilizer, Farm Fuel, Packaging, and the Price of Bread

Recommended Reading / Reference

Book: Vaclav Smil, *Enriching the Earth: Fritz Haber, Carl Bosch, and the Transformation of World Food Production* (2001), by the Czech-Canadian energy scientist, on how nitrogen made with fossil fuels came to feed billions

Reference: The USDA Economic Research Service's monthly *Food Price Outlook* and its Food Dollar Series, and the World Bank's monthly commodity prices (the "Pink Sheet") for fertilizer and grain

10a. How Much Energy Food Takes

The food system, from fertilizer plant to kitchen, uses about 30% of the world's energy, by the estimate of the FAO and the International Renewable Energy Agency (IRENA) in 2021. About 70% of that energy is used after the farm gate, in processing, packaging, transport, retail, refrigeration, and cooking. An earlier FAO study, *Energy-Smart Food for People and Climate* (2011), put farming and fishing at about a fifth of the total.

Rich and poor countries use that energy differently. In high-GDP countries, processing, transport, and preparation take three to four times the energy used to grow the food, and farming consumes about 20.4 gigajoules (GJ, billions of joules) of fossil fuel a hectare, against 11.1 in low-GDP countries (FAO, 2011). In some African countries cooking takes up to 75% of the food system's energy, and most of it comes from wood, charcoal, and other biomass. The richer the country, the larger the fossil share of its food's energy.

The FAO gives no single figure for that fossil share, but the reverse measure exists. A 2023 study for the Global Alliance for the Future of Food, a group of philanthropic foundations, by the consultancy Dalberg Advisors, estimated that food systems use at least 15% of the world's fossil fuels.

The United States has measured its own system in detail. The USDA's Economic Research Service (ERS) put food's share of the country's energy at an estimated 15.7% in 2007, up from 12.2% in 1997 (March 2010). Households used 28% of the food system's energy in 2002 and processors about 19%.

10b. Fuel on the Farm and at Sea

Farms burn diesel in tractors, combines, and trucks, gasoline in pickups, and liquefied petroleum gas (LPG, mostly propane) to dry grain, and they pump irrigation water with diesel, electricity, or gas. On the maize farms of a 2010 USDA survey of nine states, each acre took 4.95 gallons of diesel, 1.95 of gasoline, and 1.81 of LPG, at an average yield of 164 bushels an acre (USDA, February 2016). Pumping irrigation water cost American farms $3.3 billion in energy in 2023 (USDA).

The 2026 shock shows in farm budgets. The ERS forecast on September 3, 2026 that American farms will spend $21.6 billion on fuels and oils in 2026, up $4.8 billion or 28.8%, and $39.6 billion on fertilizer, lime, and soil conditioners, up $5.3 billion or 15.3%. Total production expenses rise 4.5%, to $492.8 billion. Fuel and fertilizer take 12.4% of farm spending, against 10.8% in 2025, and account for almost half of the year's rise in costs (computed).

The cost reaches the field within weeks. Farm diesel in North Dakota rose 34.7% in about three weeks after the war began on February 28 (Module 8), and North Dakota State University calculated that the rise adds $8.48 an acre to the cost of growing maize, $5.20 to wheat, and $4.98 to soybeans (March 31, 2026).

The world's fishing fleets burned about 40 billion liters of fuel in 2011, by the estimate of Parker and colleagues in *Nature Climate Change* (2018). Converted, that is about 0.69 million barrels a day (mb/d), close to 0.7% of the 104.4 mb/d the world used in 2025 (Module 9).

10c. Fertilizer, the Main Channel

Crops need nitrogen in bulk, and most of the nitrogen farms apply is made by the Haber-Bosch process, which combines nitrogen from the air with hydrogen usually taken from natural gas to make ammonia. Gas is both the feedstock and the fuel, and the World Bank calls it "the main production cost for nitrogen fertilizers" (May 14, 2026). Making nitrogen fertilizer takes about 5% of the world's natural gas (FAO, 2011). Jan Willem Erisman and colleagues estimated in *Nature Geoscience* in 2008 that synthetic nitrogen fed 48% of the world's people.

Phosphate fertilizer has its own link to oil. Phosphate rock is dissolved in sulfuric acid, which takes about 90% of the world's sulfur, and most sulfur is a by-product recovered at oil refineries and natural-gas processing plants, the US Geological Survey (USGS) reported in February 2026. Its supply therefore depends on how much oil and gas is processed rather than on farmers' demand, and the Gulf states are large producers (table).

The war that began on February 28, 2026 (Module 8) cut both chains at once. The World Bank reported that Qatar suspended urea, ammonia, and sulfur production after damage and that Iran halted ammonia output. The Bank's urea price rose 80% from February to above $850 a tonne in April, the highest since April 2022, and sulfur prices had doubled since January (May 14, 2026). Nitrogen moved most because so much traded urea comes from the Gulf. Before the war, producers that depend on the strait shipped 43% of the world's seaborne urea and 44% of its seaborne sulfur (International Trade Centre (ITC), August 4, 2026), and other measures give other shares (table).

What is measured	Share	Source and date
All global urea exports that pass through the strait	Nearly a quarter	World Bank, May 14, 2026
Middle East share of global urea exports, as projected for 2026	38.5%	S&P Global Commodity Insights, April 1, 2026
Seaborne fertilizer of all kinds passing the strait, before the war	About a third	UN Trade and Development (UNCTAD), via *farmdoc daily*, April 24, 2026
Share of world sulfur output made by Saudi Arabia, the United Arab Emirates, Qatar, Iran, and Kuwait, 2025	23.8% of 84 million tonnes	USGS, February 2026 (share computed)
US urea use supplied from the Persian Gulf, 2023	17%	*farmdoc daily*, April 24, 2026

These shares differ from the ITC's, and from each other, because they measure different things: seaborne trade or all exports, the strait's producers or the whole Middle East, and trade or production.

The world urea price has since fallen below its February level. Middle Eastern urea averaged $693.5 a tonne in the second quarter and $407.5 in September (World Bank Pink Sheet, October 2026), after China relaxed its limits on urea exports and spring planting ended. American farmers paid more for longer. In the week of April 13, DTN, a farm-data company, found anhydrous ammonia at $1,114 a short ton (2,000 pounds), up 29.2% from mid-February, and urea at $858, up 41.1% (*farmdoc daily*, April 24, 2026). In DTN's survey for the week to October 2, urea cost $683, 12% more than a year earlier, and anhydrous ammonia $979, up 20%.

Farmers planned to plant less of the crop that needs the most nitrogen. On March 31, farmers told the USDA they intended to plant 95.3 million acres of maize, 3% fewer than a year earlier, and 84.7 million acres of soybeans, 4% more. Soybeans need little nitrogen fertilizer, because bacteria in their roots take nitrogen from the air.

10d. Chemicals, Plastics, and the Road to the Shelf

Most herbicides, insecticides, and fungicides are synthetic chemicals built from petrochemical feedstocks made from oil and gas (Module 5). Farmers use little by weight, about 2.2 pounds an acre on the maize farms of the USDA's 2010 survey. But each pound took about 154,000 British thermal units (Btu, each the heat that warms a pound of water by one degree Fahrenheit) to make, more than six times the energy needed for a pound of nitrogen.

Plastics also come from oil and gas. The FAO counts about 12.5 million tonnes of plastic products used each year in farming, fishing, and aquaculture, as mulch films, greenhouse covers, silage wrap, nets, and coatings on seeds and fertilizer, and 37.3 million tonnes in food packaging (December 7, 2021). The FAO's title for its findings, "the good, the bad and the ugly," states the trade-off: films and packaging raise yields and cut waste, while plastic left in fields pollutes the soil.

Moving food runs almost entirely on oil, in diesel trucks and trains and in ships burning fuel oil. In the ERS's accounts for 2008, energy industries earned 8.2 cents of each dollar spent on food eaten at home, transportation 5.1 cents, and packaging 4.9 cents, together slightly less than farms and agribusiness at 18.3 cents (*Amber Waves*, June 2011). Energy's share of the whole food dollar, meals out included, was 6.8 cents. The ERS rebuilt the series in March 2026. On its new basis, not comparable with the old, farmers received 11.8 cents of the food dollar in 2024, labor across the chain takes 54.1 cents in the March report, and the next release, with 2025 data, is due on November 17, 2026.

Keeping food cold takes energy, and the lack of it wastes food. The UN Environment Programme (UNEP) and the FAO estimated in 2022 that 526 million tonnes of food a year are lost or wasted for lack of refrigeration, and that cold chains could save 144 million tonnes a year in developing countries.

10e. Biofuels, the Bridge

Biofuels tie crop prices directly to oil. The USDA expected 5.6 billion bushels of maize to go to ethanol in the 2025/26 marketing year, which runs from September to August, 32.9% of a crop of 17.0 billion bushels (Agricultural Outlook Forum, February 19, 2026). Part of the grain returns to farms as distillers' grains, an animal feed, so the net share is smaller. Biofuels were to take 14.8 billion pounds of soybean oil in 2025/26, 48.8% of its use, and 17.3 billion pounds, 54.1%, in 2026/27.

Brazil makes its ethanol from both cane and maize. Its Center-South region made 33.7 billion liters in the 2025/26 harvest year, 9.2 billion of it (27%) from maize, by the count of UNICA, the cane industry's association (via Czarnikow, May 5, 2026). Early in 2026/27 its mills sent more than two-thirds of their cane to ethanol, which paid better than sugar. Brazil raised the ethanol in its gasoline to 30% in August 2025, and a temporary six-month blend of 32% runs through January 2027 (*The AgriBiz*, September 24, 2026).

Mandates, laws that set how much biofuel must be blended into fuel, such as the US Renewable Fuel Standard (RFS), decide how tight the tie is. When oil is cheap, blenders use about what the law requires, and crop prices follow the mandate more than the barrel. When oil is dear enough that ethanol costs less than the gasoline it replaces, blenders use more than the law requires, and maize prices rise with oil. In its

October release the FAO said that uncertainty over Hormuz “provided additional support to prices of biofuel feedstocks such as maize.”

10f. Food Prices in 2026

World food commodity prices and American grocery prices have moved apart in 2026 (table). The FAO’s index rose for a third straight month in September, and the FAO blamed transport disruptions, weather, and uncertainty in Hormuz over “fuel, fertilizer and freight costs” (October 2, 2026). Máximo Torero, its chief economist, warned the same day that “if sustained, these pressures will soon pass through to consumer food prices, especially in food and energy import dependent countries.” The index remained 15.1% below its record of March 2022, and the FAO publishes its October reading on November 6, 2026.

Price measure	Level or change	Source and date
FAO Food Price Index, September 2026	136.0, up 5.8% on a year, the highest since November 2022	FAO, October 2, 2026
FAO cereals index	122.8, up 17.2% on a year	FAO, October 2, 2026
FAO vegetable oils index	198.6, up 18.3% on a year	FAO, October 2, 2026
FAO dairy index	119.1, down 19.1% on a year	FAO, October 2, 2026
US food at home (CPI), year to September 2026	Up 1.8%	US Bureau of Labor Statistics (BLS), October 14, 2026
US food away from home (CPI), year to September 2026	Up 3.5%	BLS, October 14, 2026

The FAO index tracks world export prices of food commodities, with 2014-2016 equal to 100. The CPI tracks what American consumers pay, and Module 9 gives the CPI as a whole.

American grocery prices barely moved. Seven months into the war, food at home had risen less than half as fast as the CPI as a whole (3.7%, Module 9), and on September 25, 2026 the ERS lowered its forecast for food-at-home prices in 2026 to 2.4%, from 2.8% in June. It expects all food prices to rise 2.9% in 2026, with eggs down 29.4%, and 2.0% in 2027. Farm prices show pressure building upstream: the ERS expects the prices farmers receive for wheat to rise 18.3% in 2026 and for vegetables 16.0%. The BLS publishes the CPI for October on November 10, 2026.

10g. How Much Do Oil Prices Drive Food Prices? The Cases as Their Advocates Make Them

The case that oil drives food prices: its advocates start with the World Bank’s research. John Baffes, a World Bank economist, found in papers of 2007 and 2009 that fertilizer prices follow energy more closely than any other commodity group, with an elasticity of 0.33 over 1960-2005 and 0.55 over 1960-2008, so that a 10% rise in energy prices goes with a 3.3-5.5% rise in fertilizer. A World Bank study of 2013 found that crude oil explained more than half of the rise in food prices between 1997-2004 and 2005-12. With food taking 30% of the world’s energy (section 10a), nitrogen made from gas (10c), and biofuel laws (10e), they see food as a form of energy. They often cite the claim that the American diet takes about 10 fossil-fuel calories for each calorie eaten (Center for Ecoliteracy).

The case that oil’s role is modest: the same research gives farm and food prices much smaller elasticities, 0.17 for agriculture over 1960-2005 and 0.27 for food over 1960-2008, and the 2013 study gave stocks relative to use and exchange rates about 15% of the rise each. At the checkout, energy, transport, and packaging took less than a fifth of each American grocery dollar in 2008, and labor takes more than half

of the food dollar (section 10d). In the 2026 test, US food at home was up 1.8% in the year to September, when gasoline rose 34.2% (Module 9), and the ERS lowered its food forecast during the shock (10f). Nor does food literally eat oil: on the farm the largest fossil input is natural gas, in fertilizer (worked example), much of the system's energy is electricity and home cooking, and in poor countries most cooking fuel is wood and other biomass.

What the evidence says: pass-through weakens at each step from the gas well to the plate. It is strongest for fertilizer, weaker for farm commodities, and weakest at an American checkout, where the farm's share is about 12 cents in the dollar (10d). Applied to the IMF's assumed 41.3% rise in the oil price (Module 9), the World Bank's elasticities for farm and food prices imply world food commodity prices 7-11% higher over time (computed). The FAO index stood 5.8% above a year earlier in September, with cereals and vegetable oils, the crops most tied to fertilizer and biofuels, up 17-18%, and dairy down 19% (10f). The "10 calories" figure covers the whole American system, meat and home kitchens included, and a *Scientific American* blog traced it to a lecture by the writer Michael Pollan, with no study cited (2010). At the farm gate the ratio runs the other way (worked example). The lag is long, since fertilizer bought in spring shapes a harvest months later, and the FAO expects importers of food and fuel to feel it first (10f).

The course's reading, stated once: oil and gas drive food prices hard at the farm, gently at the shelf, and slowly everywhere. The food system runs on fossil fuels: gas grows the crop, and oil moves it, packs it, and fishes the sea. But labor, processing, and retail make up most of what a shopper in a rich country pays, so a 40% rise in oil moves world food commodities by a sixth to a quarter as much, and American groceries by less. The burden falls hardest, and a harvest or more later, on poor countries that import both food and fuel and spend much of their income on staples. In October 2026 the shock is still working through: grain and vegetable-oil prices are up, American farmers pay more for fertilizer than a year ago, and grocery prices are the last link to move.

Worked example — The Fossil Energy in a Bushel of Maize, and the Fertilizer in a Loaf

Start with a bushel of US maize, 56 pounds (25.4 kilograms), and the fossil energy used to grow it, from the USDA's energy balance built on its 2010 survey (February 2016). The 0.83 pounds of nitrogen applied per bushel took 20,397 Btu to make, most of it from natural gas. Diesel added 4,600 Btu, gasoline 1,715, and LPG for drying 948, together 7,263 Btu of petroleum fuels. Farm chemicals took 2,072 Btu, and ten other inputs, from lime and electricity to seed, hired field work, and hauling, the remaining 7,933. The total is 37,665 Btu. Nitrogen from gas is 20,397 ÷ 37,665 = 54.2% of it and petroleum fuels 19.3%, or 23.7% if hired field work and hauling are assumed to run on diesel. At 5.8 million Btu in a barrel of crude (Module 1), the bushel took 0.0065 barrels, about 1.0 liter of crude-oil equivalent, or 1.07 barrels an acre at the 2010 yield. The USDA's food data give yellow maize 365 kilocalories per 100 grams at 10.4% water, or 344 at the 15.5% moisture at which a bushel is weighed. So the bushel holds about 87,400 kilocalories, or 347,000 Btu, 9.2 times the fossil energy used to grow it. If the rest of the chain uses three to four times the farm's energy, as in rich countries (section 10a), the whole chain uses four to five times as much, and maize eaten as grain still returns about two calories for each fossil calorie (9.2 ÷ 4 = 2.3, and 9.2 ÷ 5 = 1.8). Now the loaf. Goucher and colleagues traced an 800-gram British loaf from the field to the retailer (*Nature Plants*, 2017). It carries 0.589 kilograms of greenhouse gases, measured as carbon dioxide equivalent: 0.388 from growing the wheat (66%), 0.028 from milling (5%), and 0.173 from baking (29%). Ammonium nitrate fertilizer alone accounts for 0.256 kilograms, 43% of the total. About a third of that, 0.083 kilograms, is nitrous oxide from the field, and the other 0.173, as much as the bakery's whole share, comes mostly from making the fertilizer. At 246 kilograms of nitrogen and 9.5 tonnes of wheat a hectare, each kilogram of wheat takes 25.9 grams of nitrogen. At the USDA's factor of about 57 megajoules (millions of joules) a kilogram, assumed here to apply to British fertilizer, that is 1.5 megajoules, or 0.24 barrels of oil equivalent per tonne of wheat. In the bushel the largest fossil input, and in the loaf the largest source of emissions, is nitrogen fertilizer made from gas.

Module 10 Key Points

Oil in Food

• The food system uses about 30% of the world’s energy, and about 70% of that is used after the farm gate.

• Synthetic nitrogen made from natural gas fed an estimated 48% of the world’s people in 2008; gas is its main cost.

• Urea rose 80% from February to April 2026; before the war, Hormuz-dependent producers shipped 43% of seaborne urea.

• US farms are forecast to spend 28.8% more on fuels and oils in 2026, $21.6 billion in all (ERS).

• Biofuels take about a third of the US maize crop and about half of US soybean oil, tying both to oil.

• US food-at-home prices rose only 1.8% in the year to September 2026: oil moves food hard at the farm, gently at the shelf.

Module 10 Quiz

Check Your Understanding

1. In the worked example, which input supplies the largest share of the fossil energy used to grow a bushel of US maize?

A) Diesel for tractors and combines does, about half.
B) Nitrogen made from natural gas does.
C) Pesticides made from petrochemicals do.
D) Electricity for pumps and dryers does, about a third.

2. Before the war, what share of the world's seaborne urea did producers that depend on the Strait of Hormuz ship, by the ITC's count?

A) About 43%
B) 17%
C) Nearly 90%
D) About two-thirds

3. By the module's account, why do high oil prices pull maize prices up?

A) Farmers burn more maize for heat
B) Maize is priced in barrels
C) The Renewable Fuel Standard fixes the maize price by law as a share of the oil price
D) Ethanol becomes cheaper than gasoline, so blenders use more than the law requires

4. What is the course's reading on how much oil prices drive food prices?

A) Hard at the farm and gently at the shelf, with the heaviest and latest burden on poor countries that import both food and fuel
B) Oil explains most of every food price rise since 1997
C) Hardly at all, since energy is a few cents of the food dollar
D) Only through biofuel mandates

5. How much did US prices for food at home rise in the year to September 2026?

A) About 34%, in step with gasoline
B) 3.7%, the same as the CPI as a whole
C) About 5.8%, matching the FAO index, as world prices pass straight to shelves
D) 1.8%

Module 11 — Oil and Power

Petrostates, Sanctions, and the Shadow Fleet

Recommended Reading / Reference

Book: Michael L. Ross, *The Oil Curse: How Petroleum Wealth Shapes the Development of Nations* (2012), by a political scientist at the University of California, Los Angeles, the standard account of what oil wealth does to governments, conflict, and women's work

Reference: The Centre for Research on Energy and Clean Air's monthly analysis of Russian fossil-fuel exports and sanctions, and the Kyiv School of Economics Institute's sanctions tracker

11a. Petrostates

A petrostate is a country whose government lives mainly on oil. Iraq is the plainest case. Oil provided 88% of its federal revenue in 2025, 109.2 trillion dinars ($83 billion) of 124.2 trillion ($94 billion), and the salaries and pensions of state employees took about 65% of all revenue (Iraq's finance ministry, via Shafaq News, March 4). In January-May 2026, with its southern exports trapped behind the Strait of Hormuz, revenue of $25.65 billion ran about a third below 2025's monthly pace, while spending reached $34.25 billion (Shafaq News, July 16). Oil still provided four-fifths of revenue in those months, and a new government under Prime Minister Ali al-Zaidi took office on May 14, 2026. Dollar figures in this module are the sources' own.

In 2026 volume, not price, decided which petrostates suffered. The IMF's October 2026 forecasts, published on October 13, have Kuwait's economy shrinking by 16.7% in 2026, Iraq's by 16%, Qatar's by 15.6%, and Bahrain's by 11.3%, with smaller contractions of 3.9% for the United Arab Emirates (UAE) and 3.3% for Saudi Arabia (The National). The UAE and Saudi Arabia are the two with large pipelines around the strait (Module 8). For the IMF's Middle East and North Africa region, with Afghanistan and Pakistan, it expects a contraction of 1.3% in 2026 and growth of 6.6% in 2027. Jihad Azour, director of its Middle East and Central Asia Department, said on October 15 that the recovery depends on "how quickly energy production and trade return to normal".

Producers outside the Gulf gained, among them Russia (section 11c), Norway, the United States, Canada, Guyana, and Brazil, which sold their oil at higher prices. The Gulf states also have savings to draw on. Saudi Arabia's Public Investment Fund (PIF), its sovereign wealth fund, managed about 3.4 trillion riyals ($906 billion) at the end of 2025, its first fall this decade, by its annual report (Asia Asset Management, August 20). Its accounts show a larger total, 4.5 trillion riyals ($1.2 trillion), on a different measure (AGBI). Module 7 gives the oil prices the Gulf's budgets need.

11b. The Resource Curse and Its Exceptions

The resource curse is the finding that countries rich in oil or minerals often grow more slowly, are governed worse, and suffer more civil war than their wealth would predict. Jeffrey Sachs and Andrew Warner found in 1995 that economies rich in natural resources had grown more slowly in the two decades after 1970. Michael Ross linked oil wealth to authoritarian rule, civil conflict, and fewer women in paid work, mainly since the nationalizations of the 1970s (*The Oil Curse*, 2012).

The mechanisms are well described. Oil revenue lets rulers govern without taxing their citizens, it swings with the price, and oil exports raise the value of the currency until other exports cannot compete, a pattern called Dutch disease after the Netherlands' experience with natural gas. Others find the curse conditional.

Stephen Haber and Victor Menaldo, using data reaching back before oil was found, reported no long-run link between oil and authoritarian rule (*American Political Science Review*, 2011). On this view the institutions a country has when the oil arrives decide the outcome, and Norway is the usual proof.

Norway saves its oil money and spends only the return. Since 1996 the government has moved its whole net cash flow from petroleum into the Government Pension Fund Global, set up by a law of 1990, and its fiscal rule lets it spend only the fund's expected real return, now estimated at 3% a year (Norsk Petroleum). The fund was worth 22.683 trillion kroner, about $2.27 trillion, at the end of June 2026, and it owns about 1.5% of the world's listed companies (Norges Bank Investment Management). The 2027 budget plans to withdraw 608.4 billion kroner ($63.7 billion), 2.7% of the fund, the same share as in 2026 (Reuters, October 7).

Guyana, an oil producer only since 2019 (Module 3), set up a Natural Resource Fund by law that year to receive the state's oil revenue. The government may draw up to $2.37 billion from it to support its 2026 budget (OilNOW). Critics say changes made in 2021 weakened parliament's oversight of the fund and its disclosure. The fund tests whether a new producer can build Norway's discipline while the money is arriving.

11c. Sanctions on Russia

Western sanctions on Russian oil work through services rather than purchases. Since December 2022 the Group of Seven (G7) industrial democracies, the EU, and Australia have barred their firms from shipping, insuring, or financing Russian crude sold above a price cap, first set at $60 a barrel. From September 3, 2025 the EU made its cap dynamic, resetting it every six months at 15% below the average price of Urals, Russia's main export crude, over the previous 22 weeks. Britain followed, and the cap fell to $47.60 and then, on February 1, 2026, to $44.10 (European Commission).

The war would have raised the cap, because the price of Urals rose with the world price. Instead the EU's 21st sanctions package, adopted on July 23, 2026, fixed the cap at $44.10 for 12 months, subject to an interim review for which no date has been set. The original procedure for resetting it resumes on July 15, 2027 (Steptoe, a law firm). The package also listed 41 more ships (section 11f) and banned dealings with Georgia's Kulevi refinery from January 25, 2027. The United States did not adopt the lower caps. It sanctioned Rosneft and Lukoil, Russia's two largest oil companies, on October 22, 2025, but in March 2026 it licensed purchases of Russian oil already at sea to ease the price shock. The Atlantic Council, a Washington research group, said that step "effectively superseded the price cap".

Russia earned more from the war (table). The measures differ: the IEA counts the value of all the crude and products Russia exports, the Centre for Research on Energy and Clean Air (CREA), a research group in Helsinki, counts the extra seaborne revenue from higher prices, and the Kyiv School of Economics (KSE) Institute forecasts the year's export revenue. Urals averaged $90.7 a barrel in September 2026, about twice the cap and $23 below the physical Brent price (Dated Brent), by CREA's count. The IEA put Urals loaded at Primorsk, on the Baltic, at $94.3.

Measure	Figure	Period	Source
Revenue from exports of crude and products	About $11 billion a month, half the level before the invasion of Ukraine	December 2025	IEA
Revenue from exports of crude and products	$17.67 billion, $3.6 billion more than in August	September 2026	IEA, via TASS
Exports of crude and products	6.52 million barrels a day (mb/d)	September 2026	IEA, via TASS
Extra seaborne export revenue from higher oil and gas prices	$35.9 billion	The six months after the strikes on Iran	CREA

Measure	Figure	Period	Source
Oil-export revenue, forecast	$183 billion, against $158 billion in 2025	2026, base case	KSE Institute

Russia’s oil revenue by measure; the measures overlap and cannot be added. IEA, December 2025 and October 14, 2026; CREA, October 16, 2026; KSE Institute, July 1, 2026.

Asia buys most of the oil. From December 2022 to September 2026 China took 50% of Russia’s crude exports and India 37% (CREA). The United States raised its tariff on Indian goods to 50% in August 2025, half of it a penalty for India’s purchases of Russian oil, and cut it to 18% in February 2026 after Indian refiners agreed to limit those purchases. India still bought about 1.82 mb/d of Russian crude in September by the count of Kpler, a ship-tracking firm, though CREA measured a fall of 13% from August.

11d. Iran

Iran’s oil has been under American sanctions since 2018, when the United States left the 2015 nuclear agreement, and United Nations sanctions returned in September 2025. Before the war most of Iran’s exports went to China’s independent refiners in Shandong province, known as teapots, which bought at a discount, and China’s imports of Iranian crude more than doubled from 2022 to 2025 (*Wall Street Journal*). About 90% of Iran’s exports leave from Kharg Island, which US forces struck in mid-March 2026, by press accounts.

The war and the American blockade did what sanctions had not (Module 8 dates the blockade). Iran’s crude output fell to 1.96 mb/d in September by OPEC’s secondary sources. China imported only about 0.5 mb/d of Iranian crude that month by the count of Vortexa, another tracking firm, and Kpler says Iran’s new exports have “effectively collapsed”. Iran stored what it could not sell, and its strategic stocks rose to 88 million barrels at the end of June from 71 million at the end of 2025 (EIA). Iranian state media claimed exports of 1.4 mb/d in May.

Washington bent its own rules under the price shock. It licensed the sale of Iranian oil already at sea until April 19, at a time when Iran was earning an estimated $139 million a day (Bloomberg, via the Atlantic Council, April 8). Iran’s oil minister since 2024, Mohsen Paknejad, resigned on October 4, 2026, and Hamid Bovard, head of the National Iranian Oil Company, is acting minister.

11e. Venezuela After Maduro

Venezuela, which holds the largest proved reserves (Module 1), saw its output fall from near 2 mb/d in 2017 to about 0.7 mb/d at its lowest, after years of mismanagement and American sanctions. It had recovered to about 1.1-1.2 mb/d when the United States began a naval blockade of its oil exports on December 10, 2025 (Kpler; Reuters). By the final week of December exports had fallen from about 960,000 barrels a day to about 300,000, and those to China, which had averaged 688,000 barrels a day in September-November, had stopped (Kpler, January 5, 2026).

On January 3, 2026, US forces captured President Nicolás Maduro. Delcy Rodríguez, his vice president, was sworn in as acting president on January 5, and in March she handed the oil ministry, which she had also held, to Paula Henao, a petroleum engineer. Washington moved quickly to restart the oil. In January it let the traders Vitol and Trafigura join Chevron in exporting Venezuelan crude and lifted some sanctions, and in March it recognized the interim government, though sanctions have not been fully lifted. Output was estimated at 1.1-1.25 mb/d in early September 2026 (Latin Times).

On September 2, 2026, at Miraflores Palace in Caracas and with Chris Wright, US energy secretary since February 2025, present, Venezuela signed agreements with Chevron, the Italian company Eni, and GE Vernova. Chevron, producing about 280,000 barrels a day there, aims for about 600,000 within five years, with more than $7 billion of investment. A century-long concession over 17 fields, named NABEP, holds about 65 billion barrels by the White House's account. The Pentagon's strategic-capital office claims a 35% stake in it, and the State Department has the right to buy a fifth of its output at cost, while Rodríguez has called it a "25-year" project. She also dropped the rule that Petróleos de Venezuela (PDVSA), the state company, must hold a majority in joint ventures (Latin Times, September 2).

11f. The Shadow Fleet

The shadow fleet is the set of aging tankers, with opaque owners and insurers outside the Western market, that carries oil sold outside the sanctions rules. How large it is depends on who counts and what they count (table).

Counter	Date	Count	What is counted
S&P Global	September 3, 2025	About 980 tankers, about 18.5% of the world's oil tankers	Tankers it judges to be trading outside Western rules
Ukraine's government	February 2026	More than 1,300 vessels	Ships it identifies in Russia's sanctioned oil trade
KSE Institute	June 17, 2026	653 tankers	Tankers on the sanctions lists of the US, Britain, the EU, Australia, Canada, and New Zealand
European Union	July 23, 2026	673 vessels	Ships banned from EU ports and services under its 21st package

S&P Global, September 3, 2025; Ukraine's government, February 2026; KSE Institute tracker, July 1, 2026; EU Council, as summarized by Steptoe, July 2026. Sanctions lists name only part of the fleet that trackers count.

The fleet carries most of Russia's seaborne oil and nearly all of Iran's. In September 2026 sanctioned shadow tankers carried 57% of Russia's seaborne oil, while tankers owned or insured in the G7 and allied countries still carried 40% (CREA). Russia has moved ships to its own flag. Fifty Russian-flagged shadow tankers carried 36% of the fleet's Russian volumes in September, and the number sailing under false flags fell to 48, from 120 a year earlier (CREA).

Its ships are old, which raises the risk of accidents. Among shadow tankers carrying Russian crude in April 2026, 92% were more than 15 years old (KSE Institute). Many sail without cover from the International Group of protection and indemnity (P&I) clubs, the mutual insurers that cover most of the world's ships against spills and collisions, so a spill may leave a coastal state with the bill. Finnish investigators say the *Eagle S*, a tanker flagged in the Cook Islands that carried Russian oil, dragged its anchor across the Estlink 2 power cable between Finland and Estonia on December 25, 2024, and European navies have since boarded shadow tankers.

The attacks of 2026 reached well beyond the Gulf. Ukraine's drones struck Russian refineries and oil ports during the year, the Houthis aimed missiles at Saudi oil fields (Module 8), and both sides in the Gulf attacked tankers. Each case shows the same exposure: fields, pipelines, ports, and refineries are easy to hit and slow to repair, so the states that own them are more vulnerable than their reserves suggest.

11g. Do Sanctions Work? The Cases as Their Advocates Make Them

The case that they work: their advocates point to Venezuela, whose output collapsed under sanctions and whose exports fell by about two-thirds within weeks of the December 2025 blockade (section 11e). Russia's export revenue had fallen to about half its pre-invasion level by December 2025 (section 11c). The EU's dynamic cap fell mechanically as Urals fell, and each tanker listed raises the cost of moving Russian oil, which shows in the discount on Urals. Sanctions, on this view, need not stop the oil. They need only make each barrel earn less.

The case that they do not: their advocates point out that Russia sold above the cap to buyers outside the G7, using the shadow fleet, and that China's imports of Russian crude rose 26% from 2022 to 2025 while its imports of Iranian crude more than doubled (*Wall Street Journal*). In 2026 Russia earned more, not less (section 11c), and the United States itself licensed Russian and Iranian oil at sea to hold prices down. Venezuela's government changed by military action, not by sanctions. Jack Smith of Eurointelligence, a research service, called the caps a "fig leaf".

What the evidence says: the answer depends on the goal. If the goal is less revenue per barrel, sanctions work when oil is plentiful and enforcement is steady, as Russia's revenue showed by December 2025. If the goal is fewer barrels, they fail without force, because the shadow fleet and Asian buyers absorb the oil (section 11f). If the goal is a change of policy or of government, the 2026 record shows force deciding it, in Iran's collapsing exports under blockade and in Venezuela. Sanctions also bind least when markets are tight: when the shock raised costs for consumers in 2026, the sanctioning states relaxed them.

The course's reading, stated once: sanctions on oil work as a tax, not a wall. They lower what a producer earns on each barrel when oil is plentiful and the sanctioning states enforce them steadily, but they cannot stop the barrels from reaching a buyer, and in a shortage the sanctioning states loosen them first. Where oil exports stopped, in Venezuela at the end of 2025 and in Iran in 2026, warships stopped them, not sanctions alone.

Worked example — Russia's Revenue per Barrel Under the Cap

Take a buyer who would pay a given price for a barrel of Urals carried on a Western tanker with Western insurance. Western firms may carry it only if it is sold at $44.10 or less. The shadow fleet can carry it at any price but costs Russia more: assume it lowers what Russia receives by $5 a barrel, through dearer freight and insurance and the wider discount buyers demand (an assumption, since the cost varies with routes and seasons). Russia picks the route that pays more. At a price of $40 the cap does not bind: Russia sells at $40 on Western ships, against $35 on the shadow fleet, and the cap costs nothing. At $60, Western ships could carry the oil only at $44.10, while the shadow route pays $55, so Russia uses the shadow fleet and the cap costs it $5 a barrel, 8.3% of the price. At $90, near September 2026's Urals average, the Western route still pays only $44.10 and the shadow route $85, so the cap again costs $5, now 5.6%. The shadow route pays more at any price above $49.10, the cap plus the $5. On an assumed 3.5 mb/d of seaborne crude, 105 million barrels a month, the $5 costs Russia $525 million a month at any price above that level. A fully enforced cap would be different: at $90 it would take $45.90 a barrel, 51% of the price, and cut monthly revenue from $9.45 billion to $4.63 billion. The gap between $5 and $45.90 a barrel is why the fight over sanctions has become a fight over the fleet, since each tanker listed or boarded raises the cost of the shadow route.

Module 11 Key Points

Oil and Power

• Oil provided 88% of Iraq’s federal revenue in 2025; in 2026, lost volume hurt the petrostates without routes around Hormuz most.

• The IMF expects Kuwait’s economy to shrink 16.7% in 2026, against 3.3% for Saudi Arabia, which can pipe oil around the strait.

• Norway spends only its oil fund’s expected real return, about 3% a year; the fund held about $2.27 trillion in June 2026.

• The EU fixed its Russian price cap at $44.10 on July 23, 2026; resets resume on July 15, 2027.

• Sanctioned shadow tankers carried 57% of Russia’s seaborne oil in September 2026, by CREA’s count.

• Sanctions on oil act as a tax, not a wall: in Venezuela and Iran, warships, not sanctions, stopped the exports.

Module 11 Quiz

Check Your Understanding

1. Where does the EU's 21st sanctions package, adopted on July 23, 2026, leave the price cap on Russian crude?

A) At $60, the G7's level of 2022
B) Reset to 15% below Urals
C) Fixed at $44.10 until July 15, 2027
D) Raised automatically to about $65, because the dynamic formula tracked Urals up with the war's prices

2. What does Norway's fiscal rule let its government spend from the oil fund?

A) All new oil revenue
B) The expected real return, about 3%
C) Half of each year's oil revenue, at most
D) 2.7% of all petroleum revenue since 1996, by law

3. Which Gulf economy does the IMF expect to shrink most in 2026?

A) Kuwait
B) Saudi Arabia
C) The UAE, now outside OPEC
D) Qatar, with its gas halted

4. What is the course's reading on whether sanctions on oil work?

A) They stop the barrels
B) They have no effect on revenue
C) They work only when the United States enforces them alone, as it did against Russia in 2026
D) They act as a tax that lowers revenue per barrel when oil is plentiful, but warships, not sanctions, stopped exports

5. In the worked example, why does the cap cost Russia only $5 a barrel when Urals is at $90?

A) India pays the difference
B) Western tankers can carry oil above the cap if the buyer pays a $5 fee per barrel to the EU
C) It ships on the shadow fleet
D) The cap rises with the Urals price

Module 12 — America and Oil

The Producer, the Consumer, and the Reserve

Recommended Reading / Reference

Book: Meghan L. O'Sullivan, *Windfall: How the New Energy Abundance Upends Global Politics and Strengthens America's Power* (2017), by a Harvard professor and former deputy national security adviser, on how shale changed America's power abroad

Reference: The EIA's *Weekly Petroleum Status Report*, published on Wednesdays, for the reserve's level, and its *Petroleum Supply Monthly* for trade by month

12a. From Importer to Net Exporter

The United States uses and, since the shale boom, produces more oil than any other country (Module 3). For decades it was also the largest buyer of foreign oil, and its net imports, the crude and products it buys abroad minus those it sells, peaked in 2005 (table).

Two changes reversed the flow: shale drilling raised crude output to records (Module 3), and in December 2015 Congress lifted the ban on most crude exports that had stood since the Energy Policy and Conservation Act of 1975. Net imports of crude and products fell below zero in late 2019, and every month since October 2021 has been one of net exports (EIA data, via Eco3min).

The war pushed the surplus to records. Exports of crude and products reached 13.6 mb/d in April 2026 (EIA, July 8), and in May net exports set a record of 5.93 mb/d as crude exports reached a monthly record of 5.73 mb/d. Net imports of crude that month fell to 225,000 b/d, the lowest since August 1948 (EIA data, via Eco3min).

The surplus is in products, not crude. The country still imported 2.21 mb/d more crude than it exported in 2025, and crude has been a net import in every month since August 1944, so its net exports are refined products and gas liquids such as propane.

Year	Net trade in crude and products	What it reflects
1973	Net imports of 6.03 mb/d	The year of the Arab embargo (Module 2)
2005	Net imports of 12.55 mb/d, 10.09 mb/d of it crude	The all-time high
2020	Net exports of 0.64 mb/d	The first full year as a net exporter
2025	Net exports of 2.85 mb/d	Exports of 10.79 mb/d against imports of 7.94 mb/d
2026 and 2027	Net exports of 4.3 and 3.9 mb/d (forecast)	The EIA's Short-Term Energy Outlook (STEO), October 6, 2026

Annual averages of EIA data, as compiled by Eco3min (October 9, 2026), except the forecasts.

America imports crude because its refineries want a different crude from the one its wells produce. Shale yields light, sweet oil (Module 1), while many Gulf Coast and Midwest refineries were built with cokers, units that crack the heaviest part of the barrel into lighter fuels, to run cheaper heavy, sour crude (Module 5). So the country sells light crude abroad and buys heavy crude, above all from Canada's oil sands (Module 3).

In 2025 the US imported 6.2 mb/d of crude, 3.9 mb/d of it from Canada and 490,000 b/d, or 8%, from the Persian Gulf, with Mexico supplying slightly less than the Gulf (EIA). Canada's share by volume has risen from 41% in 2015 to 64%, by the count of the Congressional Research Service (CRS). The Gulf's barrels

count for more than their share: 88% of them were medium sour crude, and 47% went to the West Coast (EIA, April 6, 2026), whose refineries depend on crude arriving by tanker.

12b. “Energy Dominance”: Leases, Methane, and Exports

“Energy dominance” is the administration’s name for its oil and gas policy, and President Donald Trump set up a National Energy Dominance Council in February 2025. Its main oil measure is the tax law he signed on July 4, 2025, the One Big Beautiful Bill Act (OBBBA). Onshore, the law requires at least four lease sales a year, auctions of the right to drill on federal land, in each of nine states (American Oil & Gas Reporter). It also cuts the minimum royalty, the government’s share of the value a lease produces, back to 12.5% from the 16.67% set by the Inflation Reduction Act (IRA) of 2022 (BCLP, a law firm).

Offshore, the law orders at least 30 sales over 15 years in the Gulf of America, as the administration renamed the Gulf of Mexico in January 2025, and at least six in Alaska’s Cook Inlet from 2026 to 2032 (BCLP). The first Gulf sale since 2023, on December 10, 2025, drew $279.4 million in high bids for 181 blocks from 30 companies, at a deep-water royalty of 12.5%, the lowest since 2007 (Offshore Technology). The second, on March 11, 2026, drew $47.0 million for 25 blocks from 13 companies, which Wood Mackenzie, a consultancy, put down to the three months between the sales (*Journal of Petroleum Technology*).

The law also postponed a fee on methane, the main component of natural gas and a potent greenhouse gas. The IRA’s Waste Emissions Charge on large facilities’ excess methane was $900 a tonne for 2024 emissions, rising to $1,500 from 2026 (*Oil & Gas Journal*). In February 2025 Congress voided the Environmental Protection Agency (EPA) rule for collecting it, under the Congressional Review Act, which lets it strike down a recent rule by simple majorities, and the president signed the repeal on March 14, 2025. The charge itself stayed in the statute (Vinson & Elkins), and the July 2025 law postponed it for about ten years (Harvard Environmental and Energy Law Program).

On February 12, 2026, the EPA rescinded its 2009 endangerment finding, the conclusion that greenhouse gases endanger public health on which its climate rules rested, and with it every greenhouse-gas standard for cars, trucks, and their engines. The EPA calls this the “single largest deregulatory action” in US history and claims savings of more than $1.3 trillion. For oil the effect runs through demand, since the repeal removes one federal pressure on carmakers to sell vehicles that burn less fuel.

The policy’s other half is selling abroad: exports of liquefied natural gas are forecast to rise from 15 billion cubic feet a day in 2025 to 18 in 2026 and 19 in 2027 (STEO).

12c. The Strategic Petroleum Reserve

The Strategic Petroleum Reserve is crude oil that the federal government stores in salt caverns at four sites in Texas and Louisiana. Congress created it in the Energy Policy and Conservation Act of 1975, after the Arab embargo (Module 2). It is rated today to hold 714 million barrels; its stocks peaked at 726.6 million on December 27, 2009, when its rated capacity was larger (Political.org).

The Department of Energy (DOE) can release oil by an emergency sale that the president orders, by a sale that Congress mandates, or by an exchange, a loan that companies repay later in barrels. The reserve was designed to deliver 4.415 mb/d for up to 90 days when nearly full. The Government Accountability Office (GAO) found in December 2025 that it could deliver only 61% of that rate, and three of the six caverns at

Bayou Choctaw in Louisiana have only one drawdown left before they risk losing their structural integrity (Atlantic Council, October 2, 2026).

Emergency sales were rare and small until 2022 (table), but Congress has also ordered sales “multiple times since 2017” to pay for unrelated spending (Atlantic Council). Repurchases that ended in November 2024 secured close to 200 million barrels, 59 million bought and 140 million in mandated sales that Congress canceled, and stocks stood at 415.4 million in the week to March 6, 2026.

Year	Emergency	Released	How
1991	The Gulf War	17.3 million barrels	Sale
2005	Hurricane Katrina	11.0 million barrels	Sale
2011	Libya’s civil war, in an IEA collective action	30.6 million barrels	Sale
2022	Russia’s invasion of Ukraine	180.0 million barrels, the largest sale	Sale
2026	The Iran war, in an IEA collective action	The US share of the release (Module 8)	Exchange (section 12d)

DOE release history as compiled by Eco3min (October 8, 2026); sales that Congress mandated for revenue are excluded.

Because the US now exports more oil than it imports, it has not been bound since 2020 by the IEA’s rule that members hold stocks equal to 90 days of net imports, but it must still supply just over 40% of any collective IEA release (Atlantic Council).

12d. The Reserve in 2026

In 2026 the DOE lent oil instead of selling it. Its share of the IEA’s collective release, 172 million barrels (Module 8), went out as exchanges, by the account of the Oil Price Information Service (OPIS), a price-reporting firm, on June 15. Borrowers in the first round, offered on March 13, had to return 18-22% more oil than they took, against 3-8% in a 2021 exchange, and later rounds pushed the premium as high as 28%. Shipments began on March 20, nine days after the IEA’s decision (Atlantic Council).

By mid-October about 133 million barrels had been awarded, and the DOE expects the oil lent to come back in 2027 with its premiums, “at no cost to taxpayers” (Political.org, October 19; OPIS). Releases ran at 1.4 mb/d in late March and averaged 800,000 b/d through August 28, then slowed in September (Atlantic Council; EIA). Further requests on September 29 and October 16 offered up to 40 million and 17 million barrels, and deliveries under awarded exchanges are scheduled for November and December 2026 (Eco3min; Political.org).

The reserve held 282.7 million barrels in the EIA’s weekly report of October 21, 2026, 132.7 million fewer than on March 6 and 39.6% of its capacity, its lowest level since 1982 (EIA data; Reuters). The DOE expects it to bottom near 243 million barrels once its full share is delivered, below the floor of 252.4 million barrels that the law sets for limited drawdowns but not for exchanges (Atlantic Council). Amos Hochstein, a senior energy adviser to President Joe Biden from 2021 to 2025, told CNBC that he knew no one who thought the reserve could safely go “much below 300 million barrels”.

Refilling will be slow. The DOE has estimated that buying about 250 million barrels would cost about $20 billion at about $80 a barrel, and the 2025 tax law gave it $171 million for purchases, enough for about 2 million barrels, plus $218 million for repairs (Atlantic Council). The four sites that can take oil in manage about 672,000 b/d at best, so even the 133 million barrels lent need at least 198 days to come back.

12e. Gasoline and Politics

Americans elect a new House and a third of the Senate on November 3, 2026, with regular gasoline at $4.284 a gallon in the week of October 19 (Module 6). A president has few levers over that price, because crude, its largest part, is priced in a world market. What Washington controls are the reserve, the federal fuel taxes, the rules on shipping between US ports, and its pressure on the companies: President Trump has pressed ExxonMobil and Chevron to “return money to consumers” (FreightWaves, August 5).

The Jones Act, section 27 of the Merchant Marine Act of 1920, requires goods moving between US ports to travel on ships built, owned, flagged, and crewed in the United States. The administration waived it on March 18, 2026, for 60 days for oil, gas, fertilizer, and coal, extended it in April to August 16, and on August 10 extended it 90 days more, with each voyage reviewed case by case (NPR; Reuters, August 11). About 208 exemptions had been granted by August 3, and analysts put the saving at pennies a gallon or less. The American Maritime Partnership, which speaks for US shipowners and shipbuilders, called case-by-case review “an improvement over the previous blanket Jones Act waiver”.

The federal government taxes gasoline at 18.4 cents a gallon (Module 6) and diesel at 24.4 cents. President Trump told CBS News in May that he wanted the tax suspended “for a period of time”, and on May 12 Senator Josh Hawley, a Missouri Republican, introduced a bill to suspend both for 90 days (NPR; E&E News). By NPR’s arithmetic the gasoline tax was about 4% of the average price in May, or $2.21 on a 12-gallon fill-up. Some senior Republicans balked at cutting a major source of money for roads, and as of September 25 Congress had not acted (Spectrum News).

Democrats aim at the companies instead. Senator Sheldon Whitehouse of Rhode Island and Representative Ro Khanna of California reintroduced their Big Oil Windfall Profits Tax Act in March 2026, early in the war, and calls for it grew as the majors’ profits rose (Module 4). It would tax 50% of the gap between the current price of a barrel and the previous year’s average, on companies producing or importing at least 300,000 b/d, and rebate the money to households. About a dozen senators, Democrats and the independent Bernie Sanders, back it, and Whitehouse calls passage “an uphill struggle” (NPR, July 16). The American Petroleum Institute (API), the industry’s main lobby, calls it “fundamentally misguided”.

12f. Tariffs and Trade: Canada, Mexico, and Venezuela

Tariffs have so far spared crude. In March 2025 the US put tariffs on Canada under the International Emergency Economic Powers Act (IEEPA), 25% on most goods and 10% on energy and potash, exempting goods that met the rules of the US-Mexico-Canada Agreement (USMCA), as about 90% of Canadian exports did (Osler; CRS). On February 20, 2026, in *Learning Resources v. Trump*, the Supreme Court ruled 6-3 that IEEPA does not authorize tariffs, and those tariffs ended.

Their replacements also left energy alone. A 10% surcharge under Section 122 of the Trade Act of 1974 ran for 150 days from February 24, 2026, exempting energy, fertilizers, and USMCA goods. In July a 10% tariff under Section 301 of the same act hit most Canadian goods outside the USMCA, and in August a 50% tariff under Section 338 of the Tariff Act of 1930 hit dairy, alcohol, paper, wood, and other listed goods, not energy (CRS, August 28). Canada answered with tariffs on C$27.6 billion of US goods from September 8, 2026, or $19.5 billion at the Federal Reserve’s rate for October 16, 2026.

The larger risk is to the agreement itself. At the USMCA’s six-year review in July 2026, Canada and Mexico asked to renew it and the US declined, so without a later renewal it expires in 2036 (CRS). For crude the dependence runs both ways. In 2025 the US remained the largest buyer of Canada’s crude and sent

Canada 383,000 b/d of its own light crude, and complex American refineries “tend to prefer heavy crude oils, such as those produced in Canada” (EIA, July 29).

Mexico now matters less for crude, with Pemex’s output falling and its Dos Bocas refinery running Mexican crude at home (Modules 4 and 5). Venezuela’s extra-heavy crude suits the same Gulf Coast cokers, and since Nicolás Maduro’s removal on January 3, 2026, US licenses have reopened that trade (Module 11). A 25% tariff on buyers of Venezuelan oil, announced in March 2025, had also rested on IEEPA.

12g. Is the Reserve Worth Keeping, and at What Size? The Cases as Their Advocates Make Them

The case for a full reserve: its defenders, the DOE among them, say 2026 proved its worth. US oil began moving nine days after the IEA agreed the largest stock release in its history (section 12d), as the Gulf’s shut-in output headed toward its May peak (Module 8). The country still imports heavy crude. Oil is priced worldwide, so a shortage abroad raises American pump prices even when the US exports more oil than it imports. The exchanges, they add, refill the reserve at the borrowers’ expense and bring back more oil than went out.

The case for a smaller reserve: its advocates argue that a net exporter no longer needs a reserve sized for an importer. The US has been free of the IEA’s 90-day rule since 2020, and its own wells and commercial stocks can respond to high prices. Since a US release lowers the world price for every importer, they say, Europe and Asia should pay more of the cost. Dated Brent, the physical price, still set its record of $144.42 a barrel on April 7, four weeks after the release was agreed (Module 8). Congress, they add, has treated the reserve as a source of budget money.

What the evidence says: 2026 showed what a reserve can and cannot do. It moved oil fast but not in volume, peaking at under a third of its design rate in a system the GAO had found at 61% of design before the war (sections 12c and 12d). The release did not stop April’s price spike, which came from a chokepoint no stockpile could reopen, but it supplied barrels while the Gulf’s were shut in. The exchange premiums mean the reserve will regain more oil than it lent, though only as fast as its sites can take oil in. A Brookings paper of September 2026 (Module 9) finds that the US economy, as a net exporter, no longer falls into recession after oil supply shocks, while consumer prices still rise.

The course’s reading, stated once: the reserve is worth keeping at about its pre-war size, near 400 million barrels, refilled from the exchange returns rather than with oil bought at wartime prices. A net exporter still pays the world price and still carries 40% of IEA releases, so the reserve’s job has shifted from covering imports to damping the price spikes that American buyers pay. For that job the binding limit in 2026 was the pumping rate, not the stock. Money spent restoring the design rate therefore buys more protection than new barrels, because at today’s rate the reserve can replace no more than about 2.7 mb/d however much oil it holds (worked example).

Worked example — How Long 282.7 Million Barrels Last

Of the 282.7 million barrels in the reserve in the week to October 16, 2026, the DOE expects to keep about 243 million once its remaining exchange deliveries are made, so 282.7 − 243.0 = 39.7 million barrels are already spoken for, and 243.0 million are free for a new emergency. The second limit is speed: at the GAO's 61% of the 4.415 mb/d design rate, the reserve can pump 4.415 × 0.61 = 2.69 mb/d. Three illustrative shocks test it. First, a loss of the 490,000 b/d that came from the Persian Gulf in 2025: the reserve can match it, and 243.0 ÷ 0.49 = 496 days, about 16 months. Second, a loss of all 3.9 mb/d from Canada: the reserve can replace only 2.69 ÷ 3.9 = 69% of it, and pumping flat out it is empty in 243.0 ÷ 2.69 = 90 days. Third, suppose the IEA set out to replace a loss of 10.9 mb/d, the size of May 2026's shut-ins (Module 8). The US share of just over 40% would be 0.4 × 10.9 = 4.36 mb/d, of which the reserve covers 2.69 ÷ 4.36 = 62%, again for 90 days. By the IEA's yardstick of days of imports, the full 282.7 million barrels equal 282.7 ÷ 6.2 = 46 days of 2025's gross crude imports, or 282.7 ÷ 2.21 = 128 days of its net crude imports. Refilling is slower than emptying: at the best fill rate of 0.672 mb/d, climbing from 243.0 back to March's 415.4 million barrels takes 172.4 ÷ 0.672 = 257 days. The second and third cases carry the lesson, since any loss larger than 2.69 mb/d outruns the pumps however much oil is stored.

Module 12 Key Points

America and Oil

• US net exports of crude and products set a record of 5.93 mb/d in May 2026, yet America still imports heavy crude.

• Canada supplied 3.9 of the 6.2 mb/d of crude the US imported in 2025; tariffs have so far spared crude.

• The 2025 tax law orders at least 30 Gulf of America lease sales over 15 years; the second drew only $47.0 million.

• The Strategic Petroleum Reserve held 282.7 million barrels in the week to October 16, 2026, its lowest since 1982, after 2026’s exchanges.

• The reserve can pump only 61% of its 4.415 mb/d design rate, so its speed, not its stock, limits it.

• Neither a 90-day federal gas-tax holiday nor a 50% windfall tax on big oil companies had been enacted by October 2026.

Module 12 Quiz

Check Your Understanding

1. What record did US net exports of crude and products set in 2026?

A) 4.3 mb/d
B) 5.93 mb/d, in May 2026
C) 13.6 mb/d, the record for gross exports, set in April 2026
D) 3.61 mb/d, in July

2. Why does the US still import about 6.2 mb/d of crude while exporting more oil than it imports?

A) A federal ban on crude exports
B) Many of its refineries were built for heavy, sour crude, while its shale wells yield light, sweet oil
C) The IEA requires it to import 90 days of supply
D) US shale output is falling

3. By the module's account, what limited the Strategic Petroleum Reserve most in 2026?

A) Its pumps could deliver only part of their design rate.
B) A law barred releases that would take the reserve below 400 million barrels.
C) The IEA's 90-day rule stopped the US from lending more than a fifth of its stock.
D) Congress had sold its stocks down to about 100 million barrels before the war began.

4. How did the Department of Energy release the reserve's oil in 2026?

A) It sold the oil at auction, as in 2022, and the Treasury kept the money.
B) It gave the oil free to refiners.
C) It shipped the oil to allied governments under IEA rules.
D) It lent the oil, to be repaid with extra barrels.

5. What is the course's reading on the Strategic Petroleum Reserve?

A) Sell it, as the US is a net exporter
B) Fill it to its 714-million-barrel rating
C) Keep it near its pre-war size and restore its pumping rate
D) Replace it with stocks that refiners must hold, at 90 days of their runs

Module 13 — The Future of Oil

Peak Demand, Electric Cars, and the Climate Argument

Recommended Reading / Reference

Book: Dieter Helm, *Burn Out: The Endgame for Fossil Fuels* (2017), an Oxford economist's argument that technology and climate policy, not running out of oil, will end the fossil-fuel era, and what that means for producers

Reference: The IEA's *World Energy Outlook 2025* and *Global EV Outlook 2026*, read beside OPEC's *World Oil Outlook 2026*

13a. The Forecasts Side by Side

The forecasts of oil demand start within about 5 mb/d of one another and end 90 mb/d apart in 2050 (table). The IEA's World Energy Outlook 2025, published on November 12, 2025, brought back a Current Policies Scenario, which counts only policies already in force and finds no peak before 2050. Its Stated Policies Scenario adds the policies that governments have announced and has demand peaking around 2030. The IEA had last published a current-policies case in 2019 (Qatar Tribune).

The change came after criticism from Washington. Chris Wright, US energy secretary since February 2025, had called the agency's peak-demand projections "nonsensical" (Qatar Tribune), and Fatih Birol, the IEA's executive director since 2015, cited "growing uncertainties in the political, economy and energy context" (Fortune). The gap between the IEA's two scenarios comes mainly from how fast people buy electric vehicles (Hydrocarbon Processing).

The other forecasters sit on either side. BP's Energy Outlook 2025 moved its peak from 2025, where its 2024 edition had put it at about 102 mb/d, to 2030, citing slower gains in efficiency (Reuters). ExxonMobil, in the outlook it presented with its 2025 results, sees demand above 100 mb/d through 2050 (DieselNet), and OPEC, the producers' group, sees it rising to 2050. The IEA's medium-term report, Oil 2025 (June 17, 2025), put a peak in 2029 at about 105.5 mb/d (Argus).

Three things explain the spread. The starting levels differ by about 5 mb/d because the forecasters count different liquids, such as biofuels, so the changes matter more than the levels. The IEA's scenarios, for example, start from about 100 mb/d in 2024, against about 105 mb/d for 2025 in its monthly reports (Module 8), so their peak near 102 lies above their own starting point. The scenarios assume different policies, above all on electric vehicles. And each forecaster has a position: OPEC speaks for exporters, the IEA was founded by importers, and the oil companies plan projects that last decades.

Forecast	2030	2035	2050	Assumes
IEA, *World Energy Outlook 2025*, Current Policies	Still rising	105	113	Only the policies in force
IEA, same report, Stated Policies	Peak near 102	About 100	About 97	Announced policies; EVs more than half of car sales by 2035
OPEC, *World Oil Outlook 2026*	113.3	No figure	124.1	Demand of 105.1 in 2025; 105.5 in OPEC's October monthly report (Module 8)
BP, *Energy Outlook 2025*, Current Trajectory	Peak of 103.4	No figure	83	Slower efficiency gains

Forecast	2030	2035	2050	Assumes
BP, same report, Below 2°C	Falling from a peak of 102.2 in 2025	No figure	33.8	Warming held below 2°C
ExxonMobil, *Global Outlook*	No figure	No figure	Above 100	Notes that scenarios the Intergovernmental Panel on Climate Change (IPCC) rates likely below 2°C average 65 in 2050

Oil demand in mb/d. IEA: Fortune and Hydrocarbon Processing, November 12, 2025, and the Bank of Finland Institute for Emerging Economies (BOFIT), November 28, 2025, on a 2024 base of about 100 mb/d. OPEC: Astana Times, July 2, 2026. BP: Reuters via BNN Bloomberg, September 25, 2025. ExxonMobil: DieselNet, February 26, 2026.

13b. Electric Vehicles and the Oil They Displace

Electric cars, counting battery-electric cars and plug-in hybrids, sold more than 20 million in 2025, up 20% and about a quarter of new cars (IEA, Global EV Outlook 2026). Chinese carmakers made 60% of them, and in April 2026 electric cars took a record of more than 60% of China's car sales, by preliminary data (bne IntelliNews). In the US their share was about 10% after the federal tax credit ended for cars bought after September 30, 2025 (IEA). Sales worldwide were 15.5 million in January-September 2026, up 3% on a year earlier (Rho Motion, a data firm).

By the IEA's count, electric vehicles of all kinds displaced about 1.7 mb/d of oil in 2025, up from 0.4 mb/d in 2020. Electric cars and vans were about 80% of it, roughly 1.4 mb/d, and electric trucks in China more than 10%. China alone accounted for about 1 mb/d, about 15% of the road fuel its vehicles would otherwise have used. BloombergNEF (BNEF), a research firm, counts 2.3 mb/d, mainly because it credits more oil to electric two- and three-wheelers, while Ember, a think tank, estimates 1.7 mb/d (Transport Topics, March 18, 2026).

The IEA expects displacement to triple to about 5 mb/d by 2030 in both its main scenarios, and by 2035 to reach about 9 mb/d in the Current Policies Scenario and 10 mb/d in the Stated Policies Scenario, more than 4 mb/d of it in China. Electric trucks and buses would supply 1.3-1.5 mb/d of the 2035 total. In the IEA's scenario that reaches net-zero emissions by 2050, with emissions balanced by removals, displacement passes 15 mb/d in 2035.

China's fuel use is already falling. Sinopec, China's largest state-owned refiner, forecast in December 2024 that the country's total oil demand would peak by 2027 at no more than 800 million tonnes a year, about 16 mb/d, and reported that trucks running on liquefied natural gas were 22% of truck sales in the first three quarters of 2024 (Hydrocarbon Processing). In September 2026 its research institute forecast that China's demand for refined fuels would fall 8.9%, about 600,000 b/d, in 2026, the third fall in a row, with gasoline down 8.7%, diesel down 11.4%, and jet fuel up 1.3% (Arabian Post). Part of 2026's fall is the war's doing (Module 8), but the IEA's Oil 2025 had already put China's peak in 2027, at 16.95 mb/d.

13c. Where Growth Would Come From

Growth has already narrowed. World demand rose 0.65 mb/d, or 0.7%, in 2025, less than half the average of 1.4 mb/d a year in 2010-19 (IEA, Global Energy Review 2026). Jet fuel use rose 3.6%, petrochemical feedstocks grew more slowly than in 2024 (Module 5), and gasoline and diesel were "virtually unchanged". In the IEA's words, since 2021 "transport demand has plateaued, with jet fuel the only meaningful growth sector".

What growth remains comes from three places. Petrochemicals use oil as a raw material that electric motors do not replace, and Module 5 gives their share of demand and the IEA's view of them as the main source of growth. Aircraft have no battery or other fuel ready to replace jet fuel at scale. And emerging economies, above all India, are still adding cars, trucks, and flights.

OPEC's outlook shows how much rides on those sources. To 2050 it adds 5.7 mb/d for road transport, 4.6 mb/d for petrochemicals, and 4.2 mb/d for aviation. Countries outside the Organisation for Economic Co-operation and Development (OECD), the club of 38 mostly rich countries, add 26.9 mb/d, 7.4 mb/d of it by 2030, while the OECD uses almost 8 mb/d less. India adds 8.1 mb/d, the largest increase of any country (Astana Times, July 2, 2026).

The IEA's outlook points the same way on a smaller scale. India's demand rises from about 5.5 mb/d to 7.5-8 mb/d by 2035, while China's eases from 16.2 mb/d to 15.2-15.8 mb/d (BOFIT's summary of the World Energy Outlook 2025). Sinopec expects petrochemicals to rise from 22% of China's oil use in 2024 to 55% by 2060.

13d. Paying to Stand Still: Investment and Decline

Most oil investment buys no growth. Fields lose output every year (Module 1 gives the rates), and the IEA finds that nearly 90% of upstream oil and gas investment each year since 2019 has gone to offsetting that decline. That is about $500 billion a year, against the $360 billion that the decline rates of the 1980s would have required (Argus, September 16, 2025). Holding oil output flat to 2050 would take more than 45 mb/d from new conventional fields, and new projects take almost 20 years from license to first oil (Module 1).

ExxonMobil's reckoning is steeper. Without new investment, it says, output would fall about 15% a year, and spending only on fields already producing would slow the fall to about 4% a year (DieselNet, February 26, 2026). It notes that exploration spending, about $50-60 billion a year, is roughly half its 2013 peak of about $115 billion. Discoveries of conventional oil and gas fell from more than 30 billion barrels of oil equivalent a year in the 2000s, counting gas by its energy content, to under 10 billion a year so far in the 2020s (S&P Global).

Spending is falling anyway. The IEA's World Energy Investment 2026 report of May 28 expects record energy investment of $3.4 trillion in 2026, $2.2 trillion of it in clean energy and $1.2 trillion in fossil fuels. Investment in oil supply falls for a third straight year, to about $500 billion, with US shale spending down 7%. About 75% of 2026's spending was committed before the war, and at least 30 energy facilities were damaged in it, with repairs that could cost "tens of billions" (S&P Global, May 28, 2026).

OPEC calls for the opposite. Its World Oil Outlook 2026 says oil needs $17.7 trillion of investment from 2026 to 2050, more than $700 billion a year: $14.5 trillion upstream, $1.3 trillion midstream, and $1.9 trillion downstream (Astana Times). Haitham Al Ghais, OPEC's secretary general since August 2022, argues that "the scale of humanity's energy needs requires sustained investment today across all energies and technologies".

13e. The Climate Argument

Burning oil is about a third of the problem. Energy-related carbon dioxide (CO_2) emissions reached a record of nearly 38.4 billion tonnes in 2025, up 0.4%, and oil added about 60 million tonnes of the increase (IEA, Global Energy Review 2026). By the accounts of the Global Carbon Project (GCP), oil emitted about 12.5 billion tonnes of CO_2 in 2024, 32% of the CO_2 from fossil fuels and cement, against 41% for coal and 21%

for gas (computed from its Global Carbon Budget 2025 data). The GCP puts the CO2 that can still be emitted while holding warming to 1.5°C at 170 billion tonnes, about four years of current emissions. In the IEA's Stated Policies Scenario energy CO2 falls to about 35 billion tonnes by the mid-2030s, and in its Current Policies Scenario it shows no decline through 2050 (Fortune; Energy Institute).

The case against new oil turns on time. A field approved today takes years to build and decades to pay back, so if demand follows the IEA's Stated Policies path or a path that holds warming below 2°C, some projects would become stranded assets, ones that lose their value before they have paid for themselves. Oil Change International, a campaign group, argues from the IEA's own net-zero scenario that no new fields are needed. In that scenario oil output falls 42% from 2023 to about 55 mb/d by 2035, while fields already producing or approved could supply about 64 mb/d (September 16, 2025).

The industry answers with decline. Because existing fields lose output every year, even a world that uses less oil needs some new oil (worked example), and ExxonMobil notes that the scenarios the IPCC rates likely to hold warming below 2°C still use about two-thirds of today's oil in 2050 (table).

Governments have not agreed to leave oil behind. COP30, the 30th Conference of the Parties to the United Nations climate treaty, ended in Belém, Brazil, on November 22, 2025, about 27 hours late, with a decision that does not mention fossil fuels (Health Policy Watch). More than 80 countries, led by the EU and the UK, backed language on a roadmap away from them, while Saudi Arabia, Russia, and others opposed it (Climate Home News). Brazil's presidency is drafting a global roadmap outside the formal talks, to present at COP31, the 31st conference.

In April 2026 Colombia and the Netherlands hosted the first conference on transitioning away from fossil fuels, at Santa Marta in Colombia. The Colombian government counted 57 countries, about a third of the world economy, but China, Russia, and the US were not invited. The result was a report rather than a signed text: national roadmaps are voluntary, and working groups will study fossil-fuel subsidies and trade (Carbon Brief). Tuvalu and Ireland will host a second conference in 2027.

COP31 meets in Antalya, Türkiye, on November 9-20, 2026. Türkiye hosts and leads the action agenda under Murat Kurum, its environment minister, while Australia's climate and energy minister, Chris Bowen, presides over the negotiations. The IEA publishes its World Energy Outlook 2026 on November 18, during the conference, framed by what it calls the "ongoing energy crisis stemming from the conflict in the Middle East".

13f. Has Oil Demand Peaked? The Cases as Their Advocates Make Them

The case that demand is at or near its peak: its advocates, the IEA prominent among them, point to growth of 0.7% in 2025 (section 13c) and to China, where fuel use is falling for a third year. Electric vehicles displace more oil every year, and the IEA expects the amount to triple by 2030. Even OPEC expects the OECD to use almost 8 mb/d less by 2050, and BP's and the IEA's central cases both peak around 2030. The 2026 shock, they add, is speeding the switch: the IEA reports that it raised electric-car drivers' savings on running costs by 20-45% by April 2026, and 30 countries set monthly records for EV sales in March (S&P Global, July 30).

The case that demand will keep growing: OPEC argues that growing populations and cities in Asia, Africa, and the Middle East, led by India, will lift demand to 2050, and that meeting it needs $17.7 trillion of investment (section 13d). ExxonMobil sees demand above 100 mb/d through 2050, and the IEA's own Current Policies Scenario has no peak before 2050. In the US, electric cars stayed near 10% of sales after

the tax credit ended, and federal limits on vehicle emissions were repealed (Module 12). Petrochemicals and aviation have no ready substitute for oil. To these advocates, forecasts of a peak have been wrong before, and BP moved its own by five years in a single edition.

What the evidence says: the data so far show a slowdown, not a fall. Demand still rose in 2025, and the 2026 fall comes from a supply shock rather than a lasting change in use (Module 8). China's fuel decline is real, but India and petrochemicals offset part of it in every outlook. OPEC's path needs about 1.6 mb/d of growth a year to 2030, against 0.65 mb/d in 2025, while the Current Policies Scenario needs about 0.5 mb/d a year to 2035. The IEA's scenarios differ mainly in the speed of electric vehicles, so the forecasts disagree more about policy than about geology or engineering. Forecasters' positions matter too: OPEC's members sell oil, and the IEA changed its scenarios after American criticism.

The course's reading, stated once: world oil demand has not peaked, but it is nearing a plateau rather than heading for either a steep fall or OPEC's steady climb. Growth has shrunk to less than half its old pace and narrowed to petrochemicals, aviation, and a few emerging economies, while electric vehicles take a larger share of road fuel each year. The likeliest path is the one that BP's and the IEA's central cases share: a broad top close to today's level around 2030, with India and petrochemicals holding demand up as China and the OECD decline. A plateau does not end investment, because fields decline, and even flat demand needs new oil on the scale of the worked example.

Worked example — How Much New Oil Each Forecast Needs by 2035

Take world supply of about 100 mb/d in 2025, a round number near the forecasters' starting levels (an assumption), and let supply meet demand. Fields producing today lose output every year. Case A uses the IEA's figure in Module 1, about 5.5 mb/d a year lost if no new money is spent, so over the ten years to 2035 the loss is $5.5 \times 10 = 55$ mb/d. Case B assumes that companies keep spending on fields already producing, which ExxonMobil says slows the decline to about 4% a year: $100 \times 0.96^{10} = 66.5$ mb/d remains, so 33.5 mb/d is lost. New oil needed by 2035 is that loss plus each forecast's change in demand from its own starting level, because the bases differ. The Stated Policies Scenario ends 2035 about where it began, so it needs 55 mb/d in Case A and 33.5 mb/d in Case B. The Current Policies Scenario adds 5 mb/d (100 to 105), so it needs 60 and 38.5. OPEC gives no 2035 figure, so draw a straight line from 113.3 in 2030 to 124.1 in 2050 (an assumption): $113.3 + 10.8 \times 5 \div 20 = 116.0$, a rise of 10.9 from 105.1, so it needs 65.9 and 44.4. BP's Current Trajectory, on a straight line from 103.4 in 2030 to 83 in 2050, reaches 98.3 in 2035, 3.9 below its 2025 level of 102.2, and needs 51.1 and 29.6. Even BP's Below 2°C path, on a straight line from 102.2 in 2025 to 33.8 in 2050, falls 27.4 to 74.8 by 2035 and still needs 27.6 mb/d in Case A and 6.2 mb/d in Case B. Growth adds at most 10.9 mb/d, in OPEC's case, while decline takes 33.5-55 mb/d in every case. Replacing decline, not meeting growth, is most of the bill whichever forecast proves right.

Module 13 Key Points

The Future of Oil

• Forecasts of oil demand in 2050 run from 33.8 mb/d (BP, below 2°C) to 124.1 mb/d (OPEC), mostly on policy assumptions.

• Electric vehicles displaced about 1.7 mb/d of oil in 2025 by the IEA’s count, and it expects about 5 mb/d by 2030.

• Sinopec’s research institute forecasts China’s refined-fuel demand down 8.9% in 2026, the third yearly fall.

• Nearly 90% of upstream oil and gas investment since 2019 has only offset decline, about $500 billion a year (IEA).

• Oil emitted about 12.5 billion tonnes of CO2 in 2024, a third of fossil emissions; COP30’s decision did not mention fossil fuels.

• Even flat demand needs 33.5-55 mb/d of new oil by 2035 in the worked example, because existing fields decline.

Module 13 Quiz

Check Your Understanding

1. How much oil did electric vehicles displace in 2025, by the IEA's count?

A) About 1.7 mb/d, mostly through cars and vans
B) 0.4 mb/d
C) About 2.3 mb/d
D) About 5 mb/d, the level the IEA expects in 2030 in both of its main scenarios

2. When does Sinopec expect China's total oil demand to peak?

A) In the mid-2030s
B) By about 2027
C) In 2021
D) Not before 2045

3. What share of upstream oil and gas investment has gone to offsetting decline each year since 2019, by the IEA's count?

A) About half
B) About a quarter, as in the 1980s
C) About 75%, the share of 2026's spending committed before the war
D) Nearly 90%, about $500 billion a year, leaving little to spend on growth

4. What did COP30's decision in Belém say about fossil fuels?

A) It set 2050 as the deadline to phase out coal, oil, and gas
B) It adopted Brazil's roadmap away from them
C) It did not mention them
D) It asked countries to triple renewable power and halve oil use by 2035

5. What is the course's reading on whether world oil demand has peaked?

A) Not yet: it is nearing a plateau, not a fall
B) Yes, it peaked in 2019
C) No: OPEC's path to 2050 is right
D) Yes: the fall in 2026 is the permanent peak, because electric vehicles now displace more oil each year than the world adds

Module 14 — Where Things Stand, and What to Watch

The Argument, the Contradictions, and the Calendar

Recommended Reading / Reference

Book: Helen Thompson, *Disorder: Hard Times in the 21st Century* (2022), a Cambridge political economist's account of how oil, from the shocks of the 1970s to shale and the Gulf, shaped the geopolitical and economic crises of the last half-century

Reference: The calendars that date the watch list below: OPEC+'s meeting statements, the oil companies' results releases, and the release schedules of the EIA, the IEA, and the FAO

14a. The Argument on One Page

The course has made one argument from thirteen directions. The world is not short of oil in the ground: OPEC counts 1,572 billion barrels of proved reserves (Module 1), and the United States pumps more crude than ever (Module 3). What is scarce is oil that can reach a buyer quickly. Supply is exposed in three places above ground: one strait, which carried a fifth of the world's oil in 2025; spare capacity, most of it in a few Gulf states behind that strait; and the stocks that must bridge any gap until supply returns or demand falls (Modules 7 and 8).

In 2026 all three were tested at once. The war that began on February 28 cut the oil crossing the strait from 21.6 mb/d at the end of 2025 to 4.9 mb/d in the second quarter of 2026 and shut in up to 10.9 mb/d of Gulf output (Module 8). The physical price of a cargo doubled while futures rose about half, because the scarcity was of barrels for prompt delivery and the futures curve priced a shock that would end (Module 6). The largest release of emergency stocks in history covered about four days of the world's use. By the course's arithmetic, about a quarter of the lost oil came out of a surplus that never formed, almost a third out of stocks, and the largest share, 44%, out of lower consumption (Module 8).

The shock reached the rest of the economy through prices more than through shortages. In the United States, now a net exporter, it moved income from drivers to producers and added about 1.3 points to inflation without, so far, a recession (Module 9). Food felt it first at the farm. Nitrogen fertilizer is made from natural gas, not oil, but the war stopped Gulf producers who had shipped 43% of the world's seaborne urea, and urea rose 80% from February to April. Oil itself enters food as diesel for tractors, trucks, and fishing boats, as the chemicals in pesticides and packaging, and through biofuels (Module 10). Grocery prices moved last, because most of what a shopper pays covers labor, processing, and retail (Module 10).

Power moved with the barrels. OPEC+ did not set the price in this crisis, since the war decided how much oil reached buyers, but it will set the path out of it, when the shut-in output returns into the surplus the agencies foresee for 2027 (Module 7). The United Arab Emirates (UAE) left the group to use the capacity it had paid for (Module 7). Sanctions on Russian, Iranian, and Venezuelan oil worked as a tax, not a wall: they cut what the sellers earned and moved cargoes onto a shadow fleet of tankers, and where exports stopped, warships stopped them (Module 11). America produced more oil than ever and still paid the world price, and its strategic reserve, at its lowest since 1982, could pump at only 61% of its design rate (Module 12).

The long run is a plateau, not a cliff. Electric vehicles displaced about 1.7 mb/d of oil in 2025 and China's use of road fuels is falling, but petrochemicals, aviation, and India keep world demand near today's level

around 2030 in the central forecasts (Module 13). Because existing fields lose about 5.5 mb/d of output a year without new drilling, even flat demand needs new oil on a large scale (Modules 1 and 13).

14b. Five Contradictions

Each module states its own findings. Read together, they produce tensions that no single module states.

The buffer sits behind the bottleneck. Spare capacity, the output that can start within weeks to ease a shortage, is the market's main cushion, and most of it lies in Saudi Arabia and its Gulf neighbors (Module 7). Their exports pass the strait whose closure caused the shortage, so in 2026 the cushion was stranded as shut-in output, and the pipelines around the strait carry less than half of what it does (Modules 7 and 8). The more the world relies on the Gulf's idle capacity, the more it relies on the strait.

A record price, a small drilling response. A new American shale well needs about $66 a barrel to pay, and WTI averaged about $84 in January-August 2026 (EIA), yet the number of rigs drilling rose only 10% in a year (Module 3). The futures curve told producers the high price would not last, with contracts for late 2027 far below the front month (Module 6), and the companies had promised their shareholders cash rather than growth (Module 4). The market's forward prices discouraged the supply response that its spot price called for.

The largest producer still pays the world price. The United States set a record for net exports of crude and products in May 2026 (Module 12), yet its drivers paid 34.2% more for gasoline in the year to September (Module 9). Being a net exporter changes who receives the money, American producers rather than foreign suppliers, but not the price, which is set in a world market. And its strategic reserve, built after the 1973 embargo to protect an importer, fell to its lowest since 1982 in the kind of crisis it was built for (Module 12).

Biofuels tie food to oil. Ethanol and biodiesel were promoted to replace part of the oil in fuel, and they take about a third of the American maize crop and half of its soybean oil (Module 10). That makes those crops trade partly as fuel, so an oil shock lifts their prices through a second channel, alongside fertilizer and diesel. Mandates meant to make fuel less dependent on oil made food prices more dependent on it.

The year demand fell was not the peak. The IEA expects world oil use to fall 2.6 mb/d in 2026, the first annual fall since 2020 and more than all the world's electric vehicles displace (Modules 8 and 13). The fall came from high prices and scarcity rather than substitution, and the IEA expects most of it back in 2027 (Module 8). A year of lower demand tells little about the peak, because the demand that returns when prices fall is the demand the forecasts are about (Module 13).

14c. What to Watch

The dates below are the ones that would confirm or overturn the course's readings. Each entry says what the event would show, not what the course has already reported about it.

When	What	Why it matters
From October 25, 2026	Renewed American strikes on Iran, or a deal	On October 24 President Trump said the US was thinking about striking Iran, "maybe tomorrow," or reaching a deal, after saying on October 8 that it would not attack before the midterms; either would change how much oil crosses the strait (Module 8)

When	What	Why it matters
October 28, 2026	The Federal Reserve's rate decision	Whether the Federal Reserve raises rates again against the inflation the oil shock added (Module 9); on October 23 futures traders put the odds of a rise on October 28 near 10%, and of one by December at 80% or more, by CME Group's FedWatch tool
October 29-30, 2026	Third-quarter results: Shell on October 29; ExxonMobil, Chevron, and BP on October 30. The first estimate of US third-quarter growth comes on October 29	How much of the wartime windfall the majors pay out (Module 4), and whether the American economy kept growing through the shock (Module 9)
October 30, 2026	The December Brent futures contract expires	An expiry day, April 30, brought the year's highest futures price, touched during trading (Module 8)
November 1, 2026	The seven OPEC+ countries with voluntary cuts set their output for December	Whether the group keeps its quotas unchanged while Gulf output stays below them (Module 7)
November 3, 2026	The US midterm elections	Gasoline is a campaign issue (Module 12), and the *Wall Street Journal* reported, citing US officials, that strikes on Iran could resume after the vote (Module 8)
November 6, 2026	The FAO Food Price Index for October	Whether the rise in world food prices that followed the shock reaches a fourth month (Module 10)
November 9-20, 2026	COP31, the UN climate conference, in Antalya, Türkiye	Whether governments agree on anything about fossil fuels, which the decision of COP30 did not mention (Module 13)
November 10, 2026	The EIA's *Short-Term Energy Outlook*; the October CPI	The EIA's next estimates of shut-in output and prices (Module 8), and whether energy keeps adding to American inflation (Module 9)
November 13, 2026	The IEA's *Oil Market Report*	The IEA's next count of stocks and of how much demand the shock has cut (Module 8)
November 18, 2026	The IEA's *World Energy Outlook 2026*	Where the IEA now puts the peak in world oil demand (Module 13)
November 29, 2026	The full OPEC+ ministerial meeting	The capacity baselines for 2027, and whether the group holds back output against the surplus the agencies foresee (Module 7)
November-December 2026	Delivery of the last emergency barrels lent from the SPR	How low the reserve falls; the Department of Energy expects about 243 million barrels once the loans are delivered (Module 12)
Fourth quarter of 2026	First oil from Uaru, Guyana's fifth project, at 250,000 b/d	Supply growth outside the Gulf, which adds to the surplus forecast for 2027 (Modules 3 and 7)
December 15, 2026	BP's strategy update under Meg O'Neill	Whether BP's new chief executive turns it further back toward oil and gas (Module 4)
During 2027	The forecast surplus, the reserve's refill, and the recovery in demand	The IEA sees supply about 4 mb/d above demand unless OPEC+ holds back, the oil lent from the SPR is due back with its premiums, and demand growth returns in March at the earliest (Modules 7, 8, and 12)
July 15, 2027	The EU's price cap on Russian crude, fixed at $44.10, returns to its regular resets	Whether the cap again follows the market price, and with it the tax that sanctions place on Russian oil (Module 11)

Dates are as announced by October 24, 2026. The OPEC+ dates come from news reports of the groups' statements, and Uaru's timing is ExxonMobil's schedule. TotalEnergies had not announced the date of its third-quarter results.

14d. The Last Word

The course began with a barrel of 42 gallons and ends with a strait 33 kilometers wide. For most of oil's history the fear was of running out, and each time new fields, new methods, and higher prices answered it, from the Gulf's giants to deepwater and shale (Modules 1-3). The shocks that mattered came from above ground: an embargo, a revolution, wars, and price wars (Module 2). The largest of them came in 2026, after a year in which the world had produced more oil than it used.

The reader who follows oil from here will learn more from a few measurements than from statements: the barrels that trackers such as Kpler count crossing Hormuz each week, the gap between the physical price and futures, the stocks that remain, and the slope of the futures curve. Claims of control over the strait, of victory, and of deals are claims until those numbers move. On October 23, Brent futures settled at $116.72 a barrel, their highest since late April (Module 6), and Kpler's seven-day average put the strait's flow at 12.65 mb/d, about a quarter below its count before the war (Module 8). The course's figures are current as of that date, and the watch list above is where they will next change.

Module 14 Key Points

Where Things Stand, and What to Watch

• The world is not short of oil underground; supply is exposed above ground, in one strait, a few states' spare capacity, and limited stocks.

• In 2026 all three were tested at once: shut-ins peaked at 10.9 mb/d, and the physical price doubled while futures rose about half.

• Spare capacity sits behind the bottleneck: the Gulf's idle output passes the same strait whose closure caused the shortage.

• A record net exporter still pays the world price: Americans paid 34.2% more for gasoline in the year to September 2026.

• Gas carries the shock into fertilizer and oil carries it into diesel, chemicals, and biofuels; food prices rise at the farm before the shelf.

• Demand is nearing a plateau around 2030, not a cliff, and field decline means even flat demand needs large new investment.

Module 14 Quiz

Check Your Understanding

1. What, in the course's argument, is the world short of?

A) It is short of oil in the ground, since proved reserves have fallen every year since 2015.
B) It is short of spare capacity, because OPEC+ used all of it up in 2025.
C) It is short of oil that can reach buyers quickly.
D) It is short of new discoveries, since no large field has been found since the 1970s.

2. Why was the world's spare capacity of little use in 2026?

A) OPEC+ voted to keep it idle
B) Saudi Arabia had used it all in 2025
C) Its oil was too heavy to refine
D) It sat in Gulf fields behind the strait that the war closed

3. Which contradiction does the module draw from America's oil?

A) It imports more oil than ever
B) A record net exporter still pays the world price
C) It exports gasoline yet imports nearly all of its diesel
D) Its shale output collapsed when prices rose above $100 a barrel, because drillers could not find crews or sand

4. By the course's arithmetic, how did the world cover the Gulf oil lost from March to September 2026?

A) Mostly lower consumption, then stocks, then a lost surplus
B) Entirely from the IEA's emergency release
C) By American shale output, which rose about 5 mb/d in six months to fill the gap
D) By pipelines around the strait, which carried most of the Gulf's oil from April onward

5. What does the module say a reader should watch to test claims of control over the strait?

A) Statements by Iran's IRGC and the US Navy
B) How many warships each side keeps in the Gulf
C) Measured tanker flows
D) The official count of permits issued by Iran's Persian Gulf Strait Authority, which records every transit

Answer Sheet

Answers to every module's Check Your Understanding quiz.

Module	Answers
Module 1 Quiz	1. B 2. D 3. C 4. A 5. D
Module 2 Quiz	1. C 2. B 3. A 4. B 5. D
Module 3 Quiz	1. A 2. C 3. D 4. B 5. A
Module 4 Quiz	1. C 2. D 3. B 4. C 5. A
Module 5 Quiz	1. C 2. D 3. B 4. A 5. C
Module 6 Quiz	1. A 2. B 3. D 4. A 5. D
Module 7 Quiz	1. C 2. B 3. A 4. B 5. D
Module 8 Quiz	1. C 2. C 3. B 4. A 5. D
Module 9 Quiz	1. B 2. C 3. A 4. D 5. C
Module 10 Quiz	1. B 2. A 3. D 4. A 5. D
Module 11 Quiz	1. C 2. B 3. A 4. D 5. C
Module 12 Quiz	1. B 2. B 3. A 4. D 5. C
Module 13 Quiz	1. A 2. B 3. D 4. C 5. A
Module 14 Quiz	1. C 2. D 3. B 4. A 5. C