Electricity & the Grid

Figures current as of October 2026

The machine that must balance every second: the institutions and markets that run it, the fleet that feeds it, the demand shock that ended twenty flat years, the clocks on turbines, reactors, and wires, the capacity auctions that put the bill on every household, and who pays.

MODULE 1 — Foundations

Goal: Set the physics and the vocabulary.

What the grid is and how large; the physics that sets the economics, from instantaneous balance and frequency to location and the peak; and the vocabulary of power and energy, capacity and accreditation, and locational prices.

MODULE 2 — The Machine

Goal: Follow a kilowatt-hour from the plant to the plug.

Generation, the high-voltage network, substations, and distribution; the interconnections and balancing authorities; the operator's day; and what a blackout is, with Texas in 2021 and Iberia in 2025.

MODULE 3 — Who Runs It

Goal: Map the institutions.

Investor-owned, municipal, and cooperative utilities; the seven market operators and the regions without one; regulated against restructured states; FERC, NERC, and the state commissions; and the rate case that sets the bill.

MODULE 4 — The Markets

Goal: Understand how a price forms.

The merit order; the day-ahead and real-time markets; locational prices and their three parts; capacity and ancillary services; and a summer afternoon in PJM worked.

MODULE 5 — The Fleet

Goal: Read what generates the power and what it costs.

Gas at 40%, nuclear 18%, coal 17%, and renewables about a quarter; capacity factors; the retirements that did not happen; levelized cost and what it misses; and the fleet region by region.

MODULE 6 — The Demand Shock

Goal: Understand what ended twenty flat years.

Flat demand from 2007 to 2021, then data centers, manufacturing, and electrification; what a gigawatt of data center asks of a grid; and the forecasts and their uncertainty.

MODULE 7 — The Turbine Shortage and the Build

Goal: Read what can be built by when.

GE Vernova's 116-gigawatt book and slots selling into 2032; the cost of new gas; the menu of options against the clock; power behind the meter; and what gets built by when.

MODULE 8 — The Nuclear Revival

Goal: Follow the plants coming back and the ones being ordered.

The restarts, from Palisades' stalled return to Crane and Duane Arnold; uprates and life extensions; the small modular reactors and the technology companies' agreements; and the fuel.

MODULE 9 — Renewables and Storage

Goal: Read the resources arriving fastest and what they earn.

Solar and wind after the 2025 tax law; the battery boom; accreditation; curtailment and the Texas case; and a four-hour battery's revenues in PJM worked.

MODULE 10 — Interconnection

Goal: Understand the queue.

The 2,061-gigawatt queue; Order 2023's cluster reform and PJM's fast tracks; the large-load queue and the rules written for it; and co-location after the Talen-Amazon fight.

MODULE 11 — Transmission

Goal: Read the bottleneck.

Order 1920 and the regional plans; cost allocation and the Mid-Atlantic Resiliency Link; permitting, 765-kilovolt lines, and reconductoring; and the transformer shortage.

MODULE 12 — Capacity Markets and Reliability

Goal: Follow the auction that put the bill on every household.

PJM's prices from $29 to the cap, the shortfalls, and the suspended backstop purchase; the argument over what the price means; MISO, ISO New England, and ERCOT; and the capacity price on a household bill worked.

MODULE 13 — Who Pays

Goal: Read the bill and the fight over it.

The bill and its three parts; the large-load tariffs and Virginia's order; the state legislation wave and PJM's governance; and the argument between the data centers and the households.

MODULE 14 — Policy and the Federal Turn

Goal: Understand what Washington and the states did.

The emergency orders and the court that limited them; the argument over them; the executive orders and FERC's independence after the Supreme Court's 2026 ruling; the 2025 tax law; and the states' four paths.

MODULE 15 — Where Things Stand, and What to Watch

Goal: Assemble the argument and name the dates.

The argument on a page, the contradictions the evidence leaves, what the November vote will and will not change, a dated watch list, and a last word.

A note on the ground. The grid is contested in a specific way: the same auction result is read by generators as a market working, by consumer advocates as a transfer, by data-center developers as a cost of doing business, and by state legislators as a bill to be reassigned. The course gives the numbers as the operators, monitors, and regulators publish them, makes each side's case as its advocates make it, and marks disputed figures as disputed. Its subject is mechanism before politics: how the machine works, how the price forms, and only then who should pay. Figures are dated to October 2026, and the table before Module 1 names the source and release of each.

Key Numbers, as of October 2026

The generation, capacity, prices, and queues the course relies on

Measure	Figure	Period	Source and release
US electricity generated	About 4,430 terawatt-hours (TWh), a record, up about 3%; 4,545 TWh forecast for 2026	2025-26	US Energy Information Administration (EIA), *Short-Term Energy Outlook* (STEO), October 6, 2026
Generation mix	Gas 40%; nuclear 18%; coal 17%; wind 10%; utility-scale solar 7%, plus about 2% small-scale; hydro 6%	2025	EIA, *Electric Power Monthly*
Generating capacity	About 1,374 gigawatts (GW) installed	End-2025	Lawrence Berkeley National Laboratory, *Queued Up: 2026 Edition* (July 2026)
Capacity added	53 GW in 2025, the most since 2002; 86 GW planned for 2026 (solar 43.4, batteries 24, wind 11.8, gas 6.3)	2025-26	EIA, *Today in Energy* (February 20, 2026)
Battery storage	43.6 GW at end-2025; nearly 52 GW by June 2026; 14 GW more planned for the rest of 2026	2025-26	EIA, *Today in Energy* (August 7, 2026)
Peak demand (hourly records)	Lower 48: 759.2 GW (July 29, 2025). PJM Interconnection: about 168.2 GW (July 2, 2026, preliminary). Electric Reliability Council of Texas (ERCOT): 91.1 GW (July 22, 2026). Southwest Power Pool (SPP): 57.9 GW (July 27, 2026)	2025-26	EIA; PJM; ERCOT
Residential price	17.3 cents per kilowatt-hour (kWh) in 2025; 18.2 cents forecast for 2026 and 18.7 for 2027	2025-27	EIA STEO, October 2026
Wholesale prices	About $52 per megawatt-hour (MWh) averaged across eleven hubs, up 11%; PJM up 41%	2026 (forecast)	EIA STEO, October 2026
PJM capacity price	$325 per megawatt-day, the cap; 6,831 megawatts (MW) short of the reliability requirement; $16.4 billion in all	2028/29 delivery year	PJM, Base Residual Auction results (July 14, 2026)
Midcontinent capacity price	Annual average $126.19 per megawatt-day (summer $424.30), against $217.00 a year earlier	2026/27	Midcontinent Independent System Operator (MISO), Planning Resource Auction (April 28, 2026)
Interconnection queue	2,061 GW of generation and storage waiting, down 10% in a year: solar 773, storage 749, gas 253, wind 220; median 61 months to connect	End-2025	Lawrence Berkeley National Laboratory, *Queued Up: 2026 Edition*
Large-load requests in Texas	More than 230 GW of requests to connect large loads, against a record peak of 91.1 GW	January 2026	ERCOT
Gas turbine backlog	GE Vernova: 116 GW of orders and slot reservations, at least 125 GW expected by year-end; output 20 GW a year	June 30, 2026	GE Vernova, second-quarter results (July 22, 2026)
Data centers' share	4.4% of US electricity in 2023; 6.7-12% projected for 2028	2023-28	Lawrence Berkeley National Laboratory (December 2024)

Measure	Figure	Period	Source and release
Data centers worldwide	485 TWh, up 17%; about 950 TWh projected for 2030	2025	International Energy Agency (IEA), *Key Questions on Energy and AI* (April 16, 2026)
Nuclear fleet	94 reactors, about 97 GW, 18% of generation at a 92% capacity factor	2025	EIA; Nuclear Regulatory Commission (NRC)
Federal emergency orders	61 orders under Section 202(c) of the Federal Power Act; seven plants held open past their retirement dates	2026, through September 25	US Department of Energy (DOE)
Utility capital spending	About $200 billion a year, a record	2025-26	Edison Electric Institute

Prices and forecasts move; the third column gives the dates of the figures, not of this course. Peak records are hourly, and PJM's 2026 record is preliminary until the operator confirms it.

Module 1 — Foundations

The Physics and the Vocabulary

Recommended Reading / Reference

Book: Gretchen Bakke, *The Grid: The Fraying Wires Between Americans and Our Energy Future*

Reference: The EIA's *Electric Power Monthly* and *Short-Term Energy Outlook* (October 2026), the sources for the generation, capacity, and price figures throughout; the *Energy Primer* of the Federal Energy Regulatory Commission (FERC), 2024 edition, for the market mechanics

1a. What the Grid Is

The American grid generated about 4,430 terawatt-hours in 2025, a record and about 3% more than in 2024, after fourteen years of almost no growth. It draws on about 1,370 gigawatts of capacity: gas plants, nuclear reactors, coal plants, wind farms, solar fields, dams, and, increasingly, batteries. About 700,000 circuit miles of transmission lines and 5.5 million miles of distribution lines connect them to about 160 million customers. About 3,000 utilities, seven regional market operators, and 66 balancing authorities run the system, under federal and state regulators whose jurisdictions overlap in ways Module 3 maps.

It is the largest machine in the world and the only one that must balance supply and demand every second. Electricity cannot be stored at scale in the wires, so every kilowatt-hour consumed is generated at that instant somewhere on the same network. The frequency of the alternating current, 60 hertz, is the gauge: it rises when supply exceeds demand and falls when it does not, and a drift of a fraction of a hertz can trip protective equipment and start a cascade.

That physics sets the economics: a kilowatt-hour's value depends on when and where it is delivered, capacity available on the worst afternoon is worth more than energy on an ordinary one, and the wires that carry power to where it is needed are as scarce as the plants. The story of 2024-26 is that a machine sized for flat demand met the largest demand increase in a generation, and every part of it (the plants, the wires, the queue, the auctions, and the bill) is now the constraint on something.

1b. The Physics That Sets the Economics

- **Balance every second:** supply must equal demand at every instant, so the operator forecasts demand, schedules generation to match, and holds reserves that respond in seconds, minutes, and hours, and getting it wrong produces a frequency excursion and, past a threshold, a cascade.
- **Frequency and inertia:** the spinning mass of conventional generators resists changes in frequency and buys the operator seconds. Wind, solar, and batteries connect through power electronics and provide no inertia unless engineered to, which is the technical argument behind every debate about a grid with more of them.
- **No storage in the wires:** the grid itself stores nothing, and storage sits beside it, as batteries for hours, pumped hydro for a day, and the fuel pile at a plant for months. The difference between the grid's instantaneous balance and the fuel's stored energy is the difference between capacity and energy.
- **Location matters:** power flows by physics, not by contract, along every available path in inverse proportion to impedance. A line at its limit cannot carry more, so the same kilowatt-hour is worth different amounts on either side of it, which is what a locational price measures (Module 4).

• **The peak sets the size:** a grid is built for its worst hour, not its average one. The American load factor is about 55%, meaning the system runs at about half its peak on average, and the plants that exist only for the peak hours are why capacity has a price of its own.

• **Losses and voltage:** about 5% of generated power is lost as heat in transmission and distribution. Voltage must be held within limits at every point, and the reactive power that holds it cannot travel far, which is why the Iberian blackout of 2025 began as a voltage problem (Module 2).

1c. The Vocabulary

Term	Meaning	Where it appears
Watt, kilowatt, megawatt, gigawatt	Power, the rate of flow at an instant: a home draws about 1-2 kilowatts (kW) on average and 10 at peak; a data-center campus 100-1,000 MW; the Lower 48's record hourly demand 759 GW	Throughout
Watt-hour, kWh, MWh, TWh	Energy, power over time: a home uses about 10,000 kWh a year; the country generates about 4,400 TWh	Throughout
Capacity against energy	What a plant can deliver at peak (MW, paid by the capacity market) against what it delivers over a year (MWh, paid by the energy market)	Modules 4 and 12
Capacity factor	Energy delivered as a share of what running flat out would deliver: nuclear about 92%, combined-cycle gas 55-60%, wind 35%, solar 25%	Module 5
Nameplate and accredited capacity	Nameplate is the rating on the machine; accredited capacity, or effective load-carrying capability (ELCC), is the share the operator counts toward reliability, under 15% for new solar in PJM	Modules 9 and 12
Load factor, peak, base load	Average load over peak; the worst hour; the load that is always there	Module 1
Locational marginal price (LMP)	The cost of the next MWh at a specific point, in three parts: energy, congestion, and losses	Module 4
Day-ahead and real-time	The market that schedules tomorrow, and the one that balances the next five minutes	Module 4
Ancillary services	Regulation, reserves, and voltage support: the services that keep frequency and voltage right, bought separately from energy	Module 4
Interconnection (two meanings)	The three synchronized grids (Eastern, Western, Texas), and the process by which a new plant or load is connected, the queue	Modules 2 and 10
Market operator	An independent system operator (ISO) or regional transmission organization (RTO): the non-profit that runs the market and the transmission in a region; PJM is the largest	Module 3
Rate base and rate case	The capital a regulated utility has invested, on which it earns a return set by the state commission in a rate case: the mechanism that turns investment into the bill	Modules 3 and 13

Module 1 Key Points

Foundations

• The grid is the only machine that must balance supply and demand every second, with 60-hertz frequency as the gauge.

• The grid stores nothing, power flows by impedance rather than contract, and the system is built for its worst hour.

• The American load factor is about 55%: the system runs at about half its peak on average.

• Generation reached a record 4,430 TWh in 2025, up about 3% after fourteen flat years.

• Capacity is not energy, nameplate is not accredited capacity, and a locational price has three parts.

Module 1 Quiz

Check Your Understanding

1. Why must electricity supply and demand balance every second?

A) Because the grid stores nothing
B) Because federal regulators fine any operator whose system drifts from its schedule for a minute
C) Because generators are paid by the second under every operator's market rules
D) Because fuel at the plants cannot be stored for more than a day

2. What is the difference between a megawatt and a megawatt-hour?

A) Alternating against direct current, the two forms of flow
B) Nameplate against accredited capacity under ELCC
C) Power against energy over time
D) Peak against base

3. What does the American grid's load factor of about 55% mean?

A) Plants run at 55% of nameplate
B) 55% of power is lost in the wires
C) Gas plants set the price in 55% of all hours of the year across the markets
D) The system runs at about half its peak on average

4. Why do wind, solar, and batteries raise a question about inertia?

A) They run only in daylight or in wind
B) They connect through power electronics and provide no spinning mass unless engineered to
C) They cannot be dispatched by the operator
D) Their output is direct current that must be inverted first

5. How much did American electricity generation grow in 2025?

A) About 1%, to 4,180 TWh
B) About 3%, to a record 4,430 TWh
C) About 8%, the fastest growth since the 1970s
D) About 6%, a record

Module 2 — The Machine

From the Plant to the Plug, and What a Blackout Is

Recommended Reading / Reference

> **Reference:** The *State of Reliability* report of the North American Electric Reliability Corporation (NERC), published annually; the joint FERC-NERC report on the February 2021 Texas event (November 2021); and the final report of the expert panel of the European Network of Transmission System Operators for Electricity (ENTSO-E) on the April 28, 2025 Iberian blackout (March 2026)

2a. The Three Systems

A kilowatt-hour travels through three systems that are engineered, owned, and regulated differently. Generation converts fuel or flow into electricity, whether a gas turbine spinning a generator, a reactor boiling water for a steam turbine, a wind turbine's blades, or a solar cell's photons, and it produces power at 10-25 kilovolts (kV), which a transformer at the plant steps up to transmission voltage.

Transmission moves bulk power at 115 to 765 kV over the long distances that make a regional grid. Higher voltage means lower current for the same power and therefore lower losses, which is why interstate lines run at 345 and 500 kV and the newest plans call for 765. The network is meshed, so power has many paths, and its capacity at any point is set by thermal limits (a hot line sags), stability limits, and voltage limits.

Distribution takes over at the substation, where transformers step the voltage down to 4-35 kV for the feeders along streets and to 120/240 volts at the transformer outside the house. It is radial rather than meshed, most outages happen in it (trees, storms, squirrels), and it is where rooftop solar, home batteries, and electric vehicles are changing the direction of flow. On a typical bill, generation is a third to a half, distribution most of the rest, and transmission 10-15%, though it is the fastest-rising part (Module 13).

2b. The Interconnections and the Balancing Authorities

North America runs three grids that are barely connected to each other: the Eastern Interconnection, from the Rockies to the Atlantic and into Canada, is the largest, and the Western is second. Texas's grid, run by ERCOT, stays inside the state's borders, largely to stay outside federal jurisdiction over interstate commerce, a choice that made national news in February 2021.

Within each interconnection every generator spins in synchrony at 60 hertz, so a disturbance anywhere is felt everywhere, and only a handful of direct-current ties, each of a few hundred megawatts, let power move between them. Inside them, 66 balancing authorities, the market operators of Module 3 and the large utilities outside them, each keep their own area in balance moment to moment, under reliability standards that NERC sets and enforces with fines.

The frequency is the shared gauge: at 60.00 hertz supply and demand match, and at 59.95 the operator is calling reserves. At 59.5 automatic load-shedding begins, and at about 59.0 generators start tripping off to protect themselves, which removes supply, lowers frequency further, and is the cascade.

2c. The Operator's Day

- **The forecast:** load is predicted from weather, the day of the week, and history to within a percent or two a day ahead, and that error, with the error in the wind and solar forecasts, is what reserves cover.
- **The commitment:** the day-ahead market (Module 4) decides which plants run tomorrow and when, since a combined-cycle gas plant needs hours of notice, a coal or nuclear plant a day, and a battery or a peaker minutes.
- **The dispatch:** every five minutes the operator's software re-solves which plants produce how much at the lowest cost, given the lines' limits, and the result is the real-time price at every node.
- **The reserves:** regulation follows the moment-to-moment wobble automatically, within seconds. Spinning reserve comes from plants already running within ten minutes and non-spinning reserve within thirty, while an operating reserve demand curve pays for scarcity before it becomes an emergency.
- **The emergency:** when reserves run short the operator issues alerts, calls demand response (customers paid to cut load), and imports from neighbors. Last, it sheds load in rotating blocks, the 'rolling blackout' that is a controlled failure to prevent an uncontrolled one.
- **The restoration:** after a total collapse comes a 'black start': designated plants that can start without grid power energize islands, which are synchronized and joined over hours or days, a capability every operator maintains and few have used.

2d. Two Blackouts

Texas, February 2021. A winter storm brought temperatures Texas plants were not built for. Gas wellheads and pipelines froze and cut fuel to gas plants, instruments and water lines froze at coal and nuclear units, and wind turbines iced, so that within hours ERCOT had lost about half its generation as demand hit a winter record. The operator shed 20,000 megawatts (MW) of load, by its own later account about four and a half minutes from a frequency collapse that would have taken the grid down for weeks, and held rolling blackouts for four days in cold that killed at least 246 people.

The inquiry found what the inquiry into the 2011 freeze had found: plants were not weatherized because nothing required it, an energy-only market paid for scarcity but not for winter readiness, and an island grid could import almost nothing. The state mandated weatherization, created a fund for backup gas plants, and kept the market design. Prices sat at the $9,000 per megawatt-hour (MWh) cap for much of the week, the market monitor later put the overcharge at about $16 billion, and Module 12 returns to the design question ERCOT poses.

Iberia, April 28, 2025. At 12:33 on a sunny spring day, with solar supplying more than half of Spain's demand, the Spanish and Portuguese grid lost 15 gigawatts (GW) of generation in five seconds and collapsed entirely, leaving most of both countries without power for up to a day. The inquiries, by the Spanish government in June 2025 and by ENTSO-E's expert panel, whose final report came in March 2026, traced a cascade of overvoltage. Too few plants were providing voltage control that morning, so voltage rose, generators disconnected to protect themselves, the disconnections raised voltage further, and the links to France tripped, isolating the peninsula.

The argument that followed, over whether the cause was a grid with less inertia from conventional plants or an operator that had not scheduled enough voltage control, is the technical version of the decade's argument. The panel found the second and warned about the first: the services that hold voltage and frequency must be scheduled and paid for as the fleet changes, or the physics of Module 1 collects. The American parallels are why both events are here, since Texas is what an unweatherized, isolated,

energy-only grid does in a freeze, and Iberia is what a grid whose services are not procured does on a sunny day.

Event	What failed	What it taught
Northeast, August 2003	A software alarm failed at one utility and sagging lines tripped; the cascade cut power to 50 million people in Ohio, the Northeast, and Ontario	Mandatory reliability standards, with NERC given enforcement power in 2005
Texas, February 2021	Unweatherized gas, coal, nuclear, and wind on an island grid; about half its generation lost; 20 GW of load shed; 246 dead	Weatherization mandates; the limits of the energy-only design; the cost of isolation
Winter Storm Elliott, December 2022	PJM lost about 46 GW of generation, mostly gas, to cold and fuel problems; a near miss on Christmas Eve	Performance penalties of $1.8 billion; the accreditation changes of Module 12
Iberia, April 2025	Too little voltage control scheduled; an overvoltage cascade; 15 GW lost in five seconds	Grid services must be procured as the fleet changes

FERC-NERC (2021); PJM (2023); ENTSO-E expert panel (March 2026).

Module 2 Key Points

The Machine

• A kilowatt-hour passes through generation, transmission at up to 765 kV, and distribution, where most outages happen.

• North America runs three barely connected grids, each spinning in synchrony at 60 hertz; a cascade is the failure mode.

• The operator's emergency ladder ends in rolling blackouts, the controlled failure that prevents an uncontrolled one.

• Texas 2021: an unweatherized island grid lost about half its generation and shed 20 GW of load.

• Iberia 2025: too little voltage control was scheduled, and 15 GW tripped in five seconds.

Module 2 Quiz

Check Your Understanding

1. Why does transmission run at very high voltage?

A) Generators produce power at 765 kV, so the lines match them
B) Federal law requires it for lines that cross state borders
C) Distribution transformers cannot accept lower voltages without overheating
D) Higher voltage means lower losses

2. Why does Texas run its own interconnection?

A) To stay outside federal jurisdiction
B) It was built first
C) The Rockies block a connection to the Western grid
D) ERCOT runs at 50 hertz, so its machines cannot synchronize with the East

3. What did the inquiries find caused the April 2025 Iberian blackout?

A) A cyberattack on the Spanish operator's control systems
B) A sudden loss of inertia from solar
C) An overvoltage cascade after too few plants were scheduled to provide voltage control
D) The failure of the link to Morocco during a heat wave

4. What is a rolling blackout?

A) A controlled shedding of load in rotating blocks
B) The restoration after a black start
C) An uncontrolled cascade across an entire interconnection
D) A string of line failures that spreads across a region in sequence over hours

5. How close did ERCOT come to total collapse in February 2021, by its own account?

A) About four hours
B) About four days, the length of the rolling blackouts
C) It collapsed for two days before a black start restored it
D) About four and a half minutes from a frequency collapse that would have lasted weeks

Module 3 — Who Runs It

The Institutions

Recommended Reading / Reference

> **Reference:** FERC's *Energy Primer: A Handbook of Energy Market Basics* (2024 edition); the Edison Electric Institute's industry statistics; and the National Association of Regulatory Utility Commissioners' materials on the rate case

3a. The Utilities

About 3,000 entities sell electricity to Americans, and they come in three kinds. Investor-owned utilities, about 170 of them, such as Duke, Southern, Dominion, Exelon, and Florida Power & Light, serve about 70% of customers. They are owned by shareholders and regulated as monopolies: in exchange for the exclusive right to serve a territory, they accept a state commission's control of their prices and a duty to serve everyone in it.

Publicly owned utilities, about 2,000 municipal systems from Los Angeles and Seattle to small-town light departments, plus federal agencies such as the Tennessee Valley Authority (TVA), serve about 15% of customers and answer to city councils and boards. Rural electric cooperatives, about 800 of them, serve about 13% of customers across more than half the country's land, and they are owned by the members they serve, most of them created after the Rural Electrification Act of 1936.

The distinction that matters most is not ownership but structure: a vertically integrated utility owns the plants, the wires, and the customer relationship, and it recovers the cost of all three through regulated rates. A utility in a restructured state owns only the wires, buys power in a market, and passes the price through, so the price shock of 2025-26 landed differently in each (3c).

3b. The Market Operators

The restructuring of the 1990s created a new institution, the independent system operator, and seven of them now serve about two-thirds of American demand. Each is a non-profit that runs the transmission system and the wholesale market for a region without owning either, so that generators can compete to sell into a grid that no one of them controls.

PJM is the largest, serving 67 million people in thirteen states and Washington, D.C., from Chicago to the Atlantic. It runs the capacity market of Module 12 and contains the data-center concentration of northern Virginia, and on July 2, 2026 it set a preliminary peak record of about 168 GW, breaking a record that had stood since 2006. MISO runs the middle of the country from Manitoba to Louisiana, SPP the plains, and ERCOT most of Texas, on the island of Module 2 with no capacity market.

The California Independent System Operator (CAISO) runs a grid whose solar fleet pushes noon prices below zero, while the New York Independent System Operator (NYISO) and ISO New England run the Northeast's two markets. The Southeast and much of the West have no full market operator, although western utilities trade in real-time markets run by CAISO and SPP. That is why a data center in Georgia negotiates with Georgia Power, while one in Virginia joins PJM's queue.

Governance became a fight in 2025-26, because PJM's board is elected by its members, the generators, utilities, traders, and consumer representatives who also shape its rules through a stakeholder process.

Governors of member states argued that the members' interests had produced the auction results, and in January 2026 all thirteen joined the White House in a statement of principles demanding changes (Module 12).

Operator	Territory and people	Peak demand	Market design	The 2026 issue
PJM	13 states and D.C., from Chicago to the Atlantic; 67 million people	Record about 168.2 GW (July 2, 2026, preliminary)	Energy; capacity bought ahead of delivery; ancillary services	Capacity prices at the cap; shortfalls; data centers; governance
MISO	15 states and Manitoba, from the Canadian border to the Gulf; about 45 million people	About 120-125 GW in summer	Energy; a seasonal capacity auction	Capacity prices fell in 2026; coal plants held open by federal orders
ERCOT	About 90% of Texas's load	Record 91.1 GW (July 22, 2026)	Energy-only, with scarcity pricing	The fastest solar and battery build; more than 230 GW of large-load requests
SPP	The plains, from the Dakotas to northern Texas	Record 57.9 GW (July 27, 2026)	Energy; a capacity requirement on its utilities	Wind supplies more than a third of its energy; the queue
CAISO	Most of California; about 32 million people	About 45-50 GW in summer	Energy; resource adequacy set by the state	Negative noon prices; batteries carry the evening peak
NYISO	New York State; about 20 million people	About 30-32 GW	Energy and capacity	Constraints into New York City; replacing old peakers
ISO New England	Six states; about 15 million people	About 24-26 GW	Energy; capacity, moving to a seasonal auction	High prices; gas pipeline limits
No full market operator	The Southeast and much of the West	Not applicable	Vertically integrated utilities; bilateral trade	Georgia Power's data-center build

PJM, ERCOT, and SPP peaks are 2026 hourly records; the others are typical recent summer peaks. Operators' own descriptions of their territories.

3c. Regulated and Restructured

The map of who sets the price has two colors. In the roughly thirty states that did not restructure, the utility is a regulated monopoly from end to end. It builds plants, the commission approves them and adds their cost to the rate base, and customers pay the average cost of the whole system plus a return on the capital. In this model a new data center means a new plant on the rate base and a rate case to allocate it, as in Georgia.

In the states that restructured in the late 1990s, including most of PJM's territory, New York, New England, Texas, and Illinois, the utilities sold their plants. The generation price comes from the market, and the utility passes it through in a default-service rate that changes with the auctions. Here a capacity price at the cap reaches the bill within the year, which is why the shock hit hardest in Maryland, New Jersey, Pennsylvania, and Ohio.

Neither model is clearly better in this crisis: the regulated states are building gas plants on the rate base at more than $2,000 a kilowatt and locking in the cost for decades. The restructured states are paying the market's signal that plants are scarce without, so far, getting many new plants.

3d. The Regulators and the Rate Case

• **FERC**, the five-member federal commission, has jurisdiction over wholesale sales, interstate transmission, the market operators' rules, interconnection, and pipelines. It approved every PJM auction rule of 2025-26 and ordered the reforms of Modules 10 and 11, but its independence from the White House is now an open question (Module 14).

• **NERC**, the industry body that FERC certified in 2006, writes and enforces reliability standards, with fines that can exceed $1 million a day per violation. Its seasonal and long-term assessments are the closest thing to an official warning, and they now rate several regions at high risk of shortfalls within five years.

• **The state commissions**, fifty of them, set retail rates, approve plants and lines in regulated states, site facilities, and decide who pays for what, so the large-load tariffs of Module 13 are their work.

• **The Department of Energy** holds the emergency powers of Module 14, the loan office that financed the nuclear restarts, and the national laboratories.

• **The rate case** is the mechanism that turns investment into the bill: the utility asks for revenue equal to its operating costs, depreciation, and a return on its rate base, the capital it has invested, with returns on equity of about 9.5-10% in 2026.

• **The cost-of-service study:** after a contested proceeding of a year or more, the commission sets rates and divides them among customer classes using this study. It decides how much of a new substation a data center pays and how much a household does, which is why Module 13 returns to it.

Module 3 Key Points

Who Runs It

• Investor-owned utilities serve about 70% of customers, but the distinction that matters is integrated against restructured, not who owns the utility.

• Seven market operators serve two-thirds of demand; PJM is the largest, with 67 million people and a new peak record in July 2026.

• Regulated states put new plants on the rate base; restructured states pass the market's capacity price through to bills within a year.

• FERC sets wholesale rules, NERC enforces reliability standards, and fifty state commissions set retail rates and decide who pays.

• The rate case turns investment into the bill: costs plus depreciation plus a return, divided among customer classes by a cost-of-service study.

Module 3 Quiz

Check Your Understanding

1. What does a regulated monopoly utility accept in exchange for its exclusive territory?

A) A ban on owning power plants inside the territory it serves
B) Federal ownership of its high-voltage lines, leased back to it
C) State price control and a duty to serve
D) Membership in a regional market operator and its capacity auction

2. Which market operator runs an energy-only market with no capacity auction?

A) PJM Interconnection
B) ERCOT, the Texas operator
C) MISO
D) The New York Independent System Operator

3. Why did the 2025-26 price shock reach bills fastest in Maryland, New Jersey, Pennsylvania, and Ohio?

A) They have no market operator
B) Their commissions approved new gas plants without hearings
C) Their plants are the oldest in the country and are retiring the fastest
D) They are restructured, so the capacity price passes through

4. What is a utility's rate base?

A) The capital it has invested, on which it earns a return
B) Its fuel and purchased-power costs
C) Its annual revenue from all classes of customers before taxes
D) The number of customers it serves in its territory, counted each year by the commission

5. What record did PJM set on July 2, 2026?

A) Its lowest capacity price since 2016, at $28.92 a megawatt-day
B) The most battery output ever recorded on an American grid in one hour
C) A peak of about 168 GW
D) Its first rolling blackout since the 2003 cascade in the Northeast

Module 4 — The Markets

How a Price Forms

Recommended Reading / Reference

> **Reference:** PJM's *Markets & Operations* training materials (pjm.com/training); the market monitor's quarterly *State of the Market* reports (Monitoring Analytics); and FERC's *Energy Primer* on electricity markets

4a. The Merit Order

A wholesale electricity market is an auction run every day for every hour, and every five minutes for every point on the grid. Its logic is the merit order: each generator offers the price at which it will produce, the operator stacks the offers from cheapest to dearest, and it dispatches up the stack until supply meets demand. Everyone who clears is paid the price of the last plant needed, the marginal one.

The stack has a shape: nuclear, wind, solar, and hydro offer at or near zero, because their fuel costs nothing or is already bought and they want to run. Coal and gas plants offer at their fuel cost times their heat rate, plus their variable costs. A combined-cycle plant burning $3 gas at 7,000 British thermal units (Btu) per kWh offers about $25 per MWh, and an old peaker at 11,000 Btu offers about $35-40. At the top sit the plants and demand-response contracts that run a few dozen hours a year and offer hundreds of dollars.

Because gas plants sit in the middle of the stack, gas sets the price in most hours in most markets, including PJM. That is why power prices track gas prices, and why PJM's average wholesale price doubled in 2022, the year gas prices spiked. A solar fleet with no fuel cost can push California's noon prices to zero or below and still leave the evening price set by gas.

4b. Day-Ahead and Real-Time

The market runs in two settlements, the first of which, the day-ahead market, clears each afternoon for every hour of the next day. Buyers, meaning the utilities and retailers serving load, bid what they expect to need, generators offer, and financial traders take positions. The operator's software then finds the least-cost dispatch that respects every transmission limit, a problem with millions of variables, and publishes a price for every hour at every node.

That schedule is financially binding: a generator that clears at $40 for the 3 p.m. hour is paid $40 even if the real-time price is higher. If it then trips off, it must buy the power it promised at the real-time price.

The real-time market balances what actually happens: every five minutes the operator re-dispatches for the load that arrived and the plants that did or did not perform, and deviations from the day-ahead schedule settle at the real-time price. That price is more volatile: $20 in an ordinary hour, $1,000 or more in a scarcity event, and negative when the grid has more power than it can use. The price a household sees is an average of thousands of such prices it never knows.

4c. The Three Parts of a Locational Price

The price at a node is the locational marginal price, the cost of serving one more MWh at that exact point, and it has three parts. **Energy** is the system marginal price, the cost of the marginal plant if the grid had no limits, and it is the same everywhere. **Congestion** is the cost of the limits: when cheap plants sit on one side of a line running at its thermal limit and the load is on the other, the operator must run a dearer plant on the load's side. The price difference across the line is congestion, positive where power cannot get in and negative where it cannot get out.

Losses is a small adjustment for the power lost as heat between the marginal plant and the node. The locational price is why a MWh in northern Virginia and one in western Pennsylvania are different products, and why the Dominion zone clears its own capacity price. It is also why a line that relieves congestion is worth what it saves, and why a map of prices is a map of where the grid is short. Within a single day prices routinely vary tenfold, and the EIA expects PJM's average wholesale price to rise 41% in 2026.

4d. Capacity, Ancillary Services, and the Rest

- **Capacity** is the payment for being available on the worst day, whether or not the energy is called. In PJM it comes from an auction held ahead of the delivery year (Module 12). ERCOT has none and relies on scarcity pricing in its energy market, while in regulated states the rate base does the job.
- **Regulation**, a second-to-second service, follows the wobble in load and is paid by the MW and by performance. Batteries dominate it because they respond in milliseconds, and it was the first market they took.
- **Reserves:** synchronized reserves, already spinning and available within ten minutes, and non-synchronized reserves, available within thirty, cover the loss of the largest unit. A demand curve prices them and rises steeply as reserves fall, which is the scarcity pricing that reached $9,000 per MWh in Texas in February 2021.
- **Voltage support and black start:** reactive power and the ability to restart a dead grid are bought by contract, and the Iberian blackout of Module 2 made them the engineering question of the year.
- **Financial transmission rights (FTRs) and virtual bids** let a load hedge congestion and let traders arbitrage the day-ahead price against real time, and they are the part of the market most people never see.
- **Bilateral contracts:** most power is sold under long-term contracts outside the operator's settlements: a utility's own plants, a corporate power purchase agreement (PPA) with a wind farm, or a data center's contract with a nuclear plant. The market prices the margin, and the contracts price the decade.

4e. A Summer Afternoon in PJM

Worked example — a summer-afternoon locational price in PJM

Take a hot July afternoon in 2026 at 5 p.m., with PJM's load at about 150 GW; the figures are illustrative but realistic. Walk up the stack, starting with nuclear, about 32 GW offered at zero, which runs flat out. Solar near its afternoon peak adds about 10 GW, wind 3 GW, and hydro and imports another 6, so about 51 GW come at or near a zero offer, and coal plants, about 25 GW offered at $25-40, run next.

The gas fleet fills most of the rest, and at 150 GW the marginal unit is an older combined-cycle plant or an early peaker offering about $65. That is the energy component, and everyone who cleared is paid it, including the nuclear plant that offered zero. The difference between the price and a plant's own cost is its 'inframarginal rent', the reward for being cheap.

Now the congestion: northern Virginia's data centers pull power into the Dominion zone across lines from the west that are at their limit, so the operator must run a Virginia peaker offering about $110 to serve the last load east of the constraint. Losses add about $2, and the Dominion node clears at about $112: $65 of energy, $45 of congestion, and $2 of losses. A node in western Pennsylvania, on the far side of the constraint with surplus coal and nuclear, clears at about $53: $65 of energy, minus $10 of congestion, minus $2 of losses.

A holder of a financial transmission right from the western node to the Dominion node collects the congestion difference, $45 minus negative $10, or $55 per MWh, while the retailer serving Loudoun County pays $112 for that hour's energy. A household's bill averages 8,760 such hours and adds the capacity charge of Module 12: at about $330 per MW-day and the 55% load factor of Module 1, that adds roughly $25 per MWh over the year. At 2 a.m. the same night, with load at 85 GW and the nuclear and coal fleets nearly covering it, the same Dominion node clears at about $22.

Module 4 Key Points

The Markets

• The market clears by merit order every five minutes at every node, and the marginal plant's price is paid to every plant that cleared.

• Gas plants sit in the middle of the stack and set the price in most hours, which is why power prices track gas.

• The day-ahead market schedules tomorrow and is binding; the real-time market balances every five minutes at prices from below zero to $1,000.

• A locational price is energy plus congestion plus losses, so a map of prices is a map of where the grid is short.

• In the worked example the Dominion node clears at $112 and a western node at $53, and $55 of the gap is congestion.

Module 4 Quiz

Check Your Understanding

1. Why do electricity prices track natural gas prices in most American markets?

A) Gas plants are the cheapest source in every hour
B) Gas plants sit in the middle of the merit order and set the marginal price in most hours
C) Most contracts are indexed to Henry Hub by convention
D) Gas is the only fuel with daily settlement on exchanges

2. What is 'inframarginal rent'?

A) The fee an operator charges generators for scheduling their output
B) The congestion payment collected on a constrained line
C) A charge levied on nuclear plants to fund decommissioning
D) The reward for being cheap

3. In the worked example, why does the Dominion node clear at about $112 while a western node clears at about $53?

A) Losses are larger in Virginia
B) Lines into the Dominion zone are at their limit, so a Virginia peaker sets the price there
C) The western node is paid the capacity price instead
D) Virginia's energy component is higher because of state taxes

4. What happens to a generator that clears day-ahead and then trips off in real time?

A) It buys the power it promised at the real-time price
B) NERC fines it for the shortfall
C) It is paid in full, since day-ahead schedules are only advisory
D) It loses its capacity accreditation for the following delivery year and must requalify

5. Why did batteries take the regulation market first?

A) It is the deepest market
B) Regulation pays only for energy
C) They respond in milliseconds, faster than any spinning machine
D) The operators pay storage twice the regulation price they pay gas plants

Module 5 — The Fleet

What Generates the Power and What It Costs

Recommended Reading / Reference

Reference: The EIA's *Electric Power Annual*, *Preliminary Monthly Electric Generator Inventory*, and *Today in Energy* note on 2026 retirements (February 23, 2026); and Lazard's *Levelized Cost of Energy+* (July 2026, version 19), the sources for the shares, capacity factors, and costs in this module

5a. The Fleet by Source

Source	Share of generation (2025)	Capacity	Capacity factor	Role in the system
Natural gas	40%	About 500 GW	Combined-cycle 55-60%; peakers 10-15%	Sets the price in most hours; the flexible middle of the stack; the only large firm source that can be built to order, if the turbines arrive
Nuclear	18%	About 97 GW (94 reactors)	About 92%	Runs flat out and offers at zero; average age over 42 years
Coal	17%	About 170 GW	About 50%	Retiring more slowly than planned; federal orders hold some plants open (Module 14)
Wind	10%	About 160 GW; about 170 GW by the end of 2026	About 33%	The plains and Texas; additions slowed in 2025-26
Solar (utility-scale)	7%, plus about 2% small-scale	About 150 GW; about 180 GW by the end of 2026	About 24%	The fastest-growing source, with a noon peak that the evening cannot use without storage
Hydro	6%	About 80 GW	About 38%	The Northwest's base and the West's flexible resource; depends on rain and snow
Batteries	Storage, not generation	43.6 GW at end-2025; nearly 52 GW by June 2026	Discharge for two to four hours	Shift solar to the evening peak (Module 9)
Other	2%	Biomass, geothermal, oil	Varies	Oil peakers run a few hours a year

EIA data for 2025; capacity at end-2025 unless stated, with end-2026 forecasts from the October 2026 STEO. Capacity factors are fleet averages and vary widely by region and vintage.

5b. The Retirements That Did Not Happen

For fifteen years the fleet's story was replacement: coal plants retired at 10-15 GW a year as cheap gas undercut them and environmental rules raised their costs, and gas and renewables took their share. That story stalled in 2025: owners had planned to retire 12.3 GW that year, two-thirds of it coal, but retired only 4.6 GW, the least since 2008.

Demand forecasts had turned up, capacity prices made old plants worth keeping, and federal emergency orders kept several coal plants open (Module 14). About 11 GW is planned for retirement in 2026, 58% of it coal, and how much of it actually closes is one of the year's open questions.

Nuclear reversed the same way: thirteen reactors closed between 2013 and 2022, but since then California has pushed Diablo Canyon's closure to 2029-30, nearly every remaining reactor has sought license extensions to sixty or eighty years, and closed plants are coming back (Module 8).

The result is a fleet older than anyone planned: the average coal plant is about 45 years old and the average reactor more than 42, and gas plants from the build-out of the early 2000s are entering their third decade. Old plants run harder than designed, with higher forced-outage rates in winter, and the accreditation of Module 12 now prices that risk.

5c. What It Costs, and What Levelized Cost Misses

The standard measure is the levelized cost of energy (LCOE): the all-in cost per MWh over a plant's life, combining capital, operating costs, and fuel. On Lazard's July 2026 figures, without subsidies, new utility-scale solar costs $40-98 per MWh and onshore wind $37-99. A combined-cycle gas plant costs $51-129, depending on the gas price and how often it runs, a gas peaker $144-276, and a new nuclear plant $175-255.

The measure is useful and misleading in equal parts. First, it counts energy, not capacity: solar's cheap MWh arrives at noon whether or not anyone needs it, and it cannot be summoned at 7 p.m. in January, so PJM counts new solar at 7-10% of its nameplate toward reliability. Its energy also arrives in the hours when prices are lowest, because every other solar plant is producing then too.

It also counts a plant, not a system: the transmission to reach a wind resource, the storage to shift solar, the backup for a dark, calm week, and the inertia and voltage support that conventional plants provide are all system costs that a resource's levelized cost leaves out. And it counts today's construction costs, which for gas have roughly doubled: a combined-cycle plant that cost about $1,000 a kilowatt in 2021 now costs $2,000-2,500, because of the turbine shortage of Module 7.

The honest comparison is the one the markets make: a resource is worth what it earns from energy, capacity, and ancillary services at the times and places it delivers, less what it costs. On that measure a battery beside a solar plant in Texas earns more than either alone, and a combined-cycle plant in PJM earns a capacity payment it had not seen in a decade, while a reactor from the 1970s is one of the most valuable assets in the system.

5d. The Fleet by Region

- **PJM:** roughly 45% gas, 30% nuclear, and 15% coal, with wind and solar under a tenth of its energy. It has the largest nuclear fleet of any region and the smallest wind and solar share of the large markets, and it is the fleet the data centers arrived on.
- **ERCOT:** roughly 40% gas, a quarter wind, and a fast-rising share of solar, with about 14 GW of batteries, the fleet that shows what a fast build looks like (Module 9).
- **MISO:** gas and coal each supply about a third, with nuclear and the wind of Iowa and Minnesota most of the rest. It has more coal than any other market operator, and several of its plants are among those held open by federal order.
- **CAISO:** solar supplies about 30% of its energy and gas about 35%, with hydro, Diablo Canyon, and about 16 GW of utility-scale batteries that now carry the evening peak, in a fleet that runs below zero at noon and imports at dusk.

• **The Southeast:** nuclear, including Vogtle and the TVA fleet, plus gas and coal, all vertically integrated, and Georgia Power's data-center build of about 10 GW, approved in 2025, is the regulated model in action.

• **The Northwest:** hydro supplies half or more of its energy from the Columbia system, and it peaks in winter, in a region that drought years and the salmon dams define.

Module 5 Key Points

The Fleet

• The fleet is gas 40%, nuclear 18%, coal 17%, wind 10%, solar about 9%, and hydro 6%, with batteries growing fastest after solar.

• Retirements stalled in 2025: 4.6 GW retired against 12.3 GW planned, the least since 2008.

• Levelized cost says solar and wind are cheapest; it misses capacity value, system costs, and the doubling of gas construction costs since 2021.

• Measured by what it earns when and where it delivers, an old reactor is one of the most valuable assets in the system.

• PJM's fleet is gas, nuclear, and coal, with the smallest wind and solar share of the large markets.

Module 5 Quiz

Check Your Understanding

1. How much generating capacity retired in 2025, against how much was planned?

A) All of it, as planned
B) About 20 GW, the most retirements since 2015
C) About 2 GW
D) 4.6 GW, against 12.3 GW planned

2. What is the American nuclear fleet's capacity factor?

A) About 55%
B) About 92%, the highest of any source in the fleet
C) About 25%, like solar
D) About 70%, after outages

3. What does the levelized cost of energy leave out, in the module's account?

A) The fuel a plant burns over its life
B) The plant's operating and maintenance costs
C) Capacity value
D) The cost of capital and the taxes on the plant

4. Roughly how much does a new combined-cycle gas plant cost in 2026, against 2021?

A) $2,000-2,500 a kilowatt, against about $1,000
B) About $1,000 a kilowatt, unchanged
C) About $600 a kilowatt, half the 2021 cost, as turbine makers competed
D) About $15,000 a kilowatt, the cost per kilowatt of Vogtle's new reactors

5. Why does the module call an old reactor one of the most valuable assets in the system?

A) It earns energy and capacity revenue at a low running cost
B) It is subsidized by the state
C) It sets the price in most hours
D) It is the only resource the operators accredit at 100% in the capacity auction each year

Module 6 — The Demand Shock

What Ended Twenty Flat Years

Recommended Reading / Reference

Reference: Lawrence Berkeley National Laboratory, *2024 United States Data Center Energy Usage Report* (December 2024); the IEA's *Energy and AI* (2025) and *Key Questions on Energy and AI* (April 2026); NERC's incident review of the July 2024 loss of data-center load in Virginia; and the load forecasts of PJM and ERCOT, which this module compares

6a. The Flat Years and the Turn

American electricity demand grew 2-3% a year for most of a century and then, around 2007, stopped growing. Efficient lighting, better appliances, tighter buildings, and the offshoring of heavy industry offset a growing economy and population for fourteen years, and utilities became a no-growth business whose planners forecast flat load and built accordingly.

The turn came in 2022-23, and the forecasts caught up in 2024. Generation grew about 3% in 2025 to a record 4,430 TWh, and the EIA expects 4,545 TWh in 2026 and 4,613 in 2027, with consumption in the third quarter of 2026 running about 4% above a year earlier. Ten-year forecasts that had shown growth of half a percent a year now show 2-3%, and over a decade that difference adds well over 100 GW of peak demand.

Three forces are behind the turn, and their proportions are the argument. Data centers are the largest and most visible: Lawrence Berkeley National Laboratory counted them at 4.4% of American electricity in 2023 and projects 6.7-12% by 2028, and the largest technology companies plan about $715 billion of capital spending in 2026, mostly on AI.

Manufacturing is second: the chip plants, battery factories, and reshored industry encouraged by the laws of 2021-22, each drawing a few hundred megawatts. Electrification is the slow third, through electric vehicles, heat pumps, and industrial heat, each small in any one year and large over a decade.

The IEA's judgment is the one this course adopts: data centers are the shock of this decade and electrification the trend of the next, and the grid must build for both. Worldwide, data centers used about 485 TWh in 2025, up 17%, and the IEA expects about 950 TWh by 2030.

6b. What a Gigawatt of Data Center Asks

A data center is a load unlike any the grid has served. It is large: a single AI campus of 1-2 GW draws as much as a city of a million people. It is flat, running at 80-95% of its peak day and night, so it uses about twice the energy of a city with the same peak. It is fast, because a campus can be built in eighteen months, where a transmission line takes seven years and a gas plant five.

It is concentrated: northern Virginia's 'data center alley' in Loudoun County draws more than 5 GW, about a fifth of Dominion's load. And it is mobile in a way a factory is not, choosing among states for power, land, fiber, and tax terms, so a state's answer to the tariff question of Module 13 is also its answer to whether a campus is built there.

The physics adds one more trait: in July 2024 a fault on a transmission line in northern Virginia caused about 60 data centers drawing some 1,500 MW to switch to their backup power at once. NERC has since

warned that sudden drops in large loads can upset a grid's frequency and voltage, and the interconnection rules of Module 10 now address them.

What a gigawatt of data center asks of a grid, then, is a gigawatt of firm capacity available every hour. In PJM's accounting for 2028/29, that is about 1.3 GW of combined-cycle gas, or about 4 GW of solar paired with 1 GW of four-hour batteries. It must arrive within two years at a place the wires may not reach, and someone must pay for it.

6c. The Forecasts and Their Uncertainty

The forecasts drive everything, since the capacity auctions buy for the forecast, the utilities build for it, and the rate cases allocate it, yet they are the least certain numbers in this course. Utilities count requests, and a developer seeking a connection may file the same request with three utilities in three states, so the requests add up to several times any plausible build.

ERCOT counted more than 230 GW of large-load requests in January 2026, against a record peak of 91.1 GW. PJM screens its forecast for duplicates and still shows tens of gigawatts of summer-peak growth within a decade, most of it data centers. The Berkeley lab's range spans a factor of two, and the IEA notes that chip efficiency and the AI industry's own economics could move the total sharply in either direction.

The result is a planning problem with no good answer. If the grid builds for the high forecast, households pay for plants that a bust leaves idle, as they did after the gas build-out of the early 2000s, which left many combined-cycle plants running at about 40% of capacity for years. If it builds for the low forecast, the shortfalls of Module 12 become blackouts. The market's answer in 2025-26, a capacity price at the cap and a reserve margin short of target, is the forecast being believed.

Measure	Figure	Source and note
US generation	4,430 TWh in 2025, a record, up about 3%; 4,545 TWh forecast for 2026 and 4,613 TWh for 2027	EIA STEO, October 2026; nearly flat from 2007 to 2021
Data centers' share of US electricity	4.4% (2023); 6.7-12% projected (2028)	Lawrence Berkeley National Laboratory (December 2024)
Data centers worldwide	About 485 TWh in 2025, up 17%; about 950 TWh projected for 2030	IEA (April 2026)
Technology companies' capital spending	Over $400 billion in 2025; about $715 billion planned for 2026	Company reports; mostly AI
ERCOT large-load requests	More than 230 GW, against a record peak of 91.1 GW	ERCOT (January 2026); most will not be built
Northern Virginia	More than 5 GW of data centers in Loudoun County, about a fifth of Dominion's load	Dominion; PJM
A sudden drop	About 1,500 MW of data centers switched to backup power at once (July 2024)	NERC incident review

Module 6 Key Points

The Demand Shock

• Demand was nearly flat from 2007 to 2021 as efficiency offset growth; it turned in 2022-23, and generation hit a record in 2025.

• Data centers are the shock of this decade, electrification the trend of the next, and the grid must build for both.

• A gigawatt of data center is a city's load, running flat out, built in eighteen months, and free to choose among states.

• Requests overstate demand: ERCOT counted more than 230 GW of large-load requests against a record peak of 91.1 GW.

• Build for the high forecast and households pay for idle plants; build for the low one and shortfalls become blackouts.

Module 6 Quiz

Check Your Understanding

1. Why was American electricity demand nearly flat from 2007 to 2021?

A) The population stopped growing after the 2008 recession
B) The grid could not deliver more power to new customers in those years
C) Efficiency offset a growing economy
D) Prices doubled

2. What share of American electricity did data centers use in 2023, by the Berkeley lab's count?

A) About 1%, rising slowly
B) About 4.4%
C) About 15%, the same as all of manufacturing
D) About 10%, after a decade of fast growth

3. How many gigawatts of large-load requests had ERCOT counted by January 2026?

A) About 20 GW
B) About 91 GW, equal to the peak
C) About 500 GW, five times the peak
D) More than 230 GW, against a record peak of 91.1 GW

4. Which precedent does the module cite for building to a high demand forecast?

A) The gas build-out of the early 2000s, which left many combined-cycle plants running at about 40% of capacity
B) The 1990s restructuring
C) The Texas wind build-out of the 2010s
D) The interstate highways of the 1950s

5. What happened in northern Virginia in July 2024 that the module cites?

A) A rolling blackout
B) Loudoun County banned new campuses
C) About 1,500 MW of data centers switched to backup power at once
D) Dominion cut power to every data center in its territory for three days during a heat wave

Module 7 — The Turbine Shortage and the Build

What Can Be Built by When

Recommended Reading / Reference

Reference: GE Vernova's quarterly investor materials (second quarter of 2026), the source for the backlog figures; the EIA's *Preliminary Monthly Electric Generator Inventory* and its February 2026 note on planned additions, for what is actually being built; and Lazard's *Levelized Cost of Energy+* (July 2026)

7a. The Backlog

When demand rises, the grid reaches for the gas turbine, and in 2026 it cannot get one quickly. Three companies make the large heavy-duty turbines: GE Vernova, Siemens Energy, and Mitsubishi Power. GE Vernova, the largest, ended the second quarter of 2026 with 116 GW of turbines on order or reserved, up from 100 GW in March, and it expects at least 125 GW by the end of the year.

It builds about 20 GW a year now and plans 24 GW in 2028 and 30 GW in 2030. In September 2026 its chief executive said the company was contracting delivery slots for 2030-31 and had begun selling slots for 2032. A developer ordering a large turbine in late 2026 therefore waits until the next decade for it.

The price has risen with the wait: a new combined-cycle plant that cost about $1,000 a kilowatt in 2021 costs $2,000-2,500 now. The turbine itself is perhaps a quarter to a third of that, and Wood Mackenzie expects large turbines to cost about $600 a kilowatt by the end of 2027, while transformers, switchgear, skilled labor, and interconnection make up the rest.

The shortage is the signature of a boom, not a failure: the manufacturers cut capacity after the bust of the late 2010s, demand turned in 2023, and a factory that makes turbine blades takes years to expand. The risk is an air pocket after the backlog: plants ordered for 2030 that arrive in a market whose demand forecasts (Module 6) disappointed.

7b. The Menu and the Clock

Option	Time from decision to power	Cost (2026)	Scale	The catch
Utility-scale solar	12-24 months	$40-98/MWh	43 GW planned for 2026	Noon energy; counted at 7-10% in PJM; the tax-credit deadline; the queue
Batteries (four-hour)	12-18 months	About $250/kWh installed	24 GW planned for 2026	Shift energy rather than make it; accreditation falls as more are added; Chinese cells and tariffs
Solar plus storage	18-24 months	$61-156/MWh	The fastest near-firm option	Multi-day gaps; the Texas model
Onshore wind	2-3 years	$37-99/MWh	11.8 GW planned for 2026	Federal policy; siting; lines from the plains
Gas peaker	2-4 years	$144-276/MWh	Limited by the same turbine makers	Runs a few hundred hours a year; smaller aeroderivative units ship faster
Engines and fuel cells	12-24 months	Above grid prices; varies	Behind the meter; a few GW a year	Small units; permits and emissions

Option	Time from decision to power	Cost (2026)	Scale	The catch
Combined-cycle gas	5-7 years, set by the turbine	$2,000-2,500/kW; $51-129/MWh	6.3 GW planned for 2026; slots sold into 2032	The firm resource the auctions want, on the turbine makers' clock
Nuclear restart	Three to four years, and longer at Palisades	About $1.5-2 billion a plant	Three plants	Module 8
Nuclear uprate or life extension	1-3 years	The cheapest firm capacity available	A few GW	Module 8
Small modular reactor	First units around 2030	More per kilowatt than large reactors, at first	None operating	Module 8
Large new reactor	Ten years or more	$175-255/MWh	None ordered	Vogtle's history; federal financing
Transmission	7-10 years	Varies	The binding constraint	Module 11
Demand response and efficiency	Months	The cheapest	About 5% of PJM's capacity	Pays customers not to use power on the worst day; data centers' own flexibility is the frontier

Times run from decision to commercial operation for a project with a site; the queue and permitting delays of Modules 10-11 add to every row. Levelized costs are Lazard's ranges without subsidies (July 2026); planned additions for 2026 are the EIA's (February 2026).

7c. Behind the Meter and Off the Grid

The clock explains the decade's most striking development: data centers building their own power. Facing a wait of years for a grid connection and for a large turbine, developers have bought what they can get: aeroderivative turbines and reciprocating engines that ship within a year or two, fuel cells, and whatever gas the pipeline can deliver.

They install it beside the campus, 'behind the meter', so the load touches the grid only for backup or not at all. The AI company xAI ran its Memphis campus on dozens of mobile gas turbines while its permits were argued.

The largest version is co-location, in which a campus is sited at an existing power plant or at a new gas plant built for it and takes power directly, paying the grid only for the backup and wires it still uses. FERC ruled on the arrangement in December 2025, directing PJM to create transmission services for co-located load so that each pays for the service it relies on (Module 10).

The economics are the grid's own: a campus paying $2,500 a kilowatt for its own gas plant is buying certainty that the queue cannot sell. A grid that loses that load also loses the revenue that would have paid for its wires, which is the argument of Module 13 in its sharpest form.

7d. What Gets Built by When

Set the clock against the demand curve and the shape of 2026-30 becomes visible. Through 2027 the additions are what is already queued and under construction: solar and batteries at 50-60 GW a year, with 86 GW of all types planned for 2026 after 53 GW in 2025, the most since 2002. They also include uprates, the Crane restart, and the few combined-cycle plants ordered before the shortage.

From 2028 to 2031 the ordered turbines arrive, 20-30 GW a year of gas across the country, and the question is whether the demand they were ordered for arrives too. Until then the firm capacity the auctions lack comes from nuclear that exists, coal that was supposed to retire, gas ordered in 2024-25, and solar and storage counted at a fraction of their nameplate.

That is why PJM's 2028/29 auction fell 6,831 MW short at the cap, and why the capacity price, not the table of levelized costs, decides what gets built.

Module 7 Key Points

The Turbine Shortage and the Build

• GE Vernova's turbine book reached 116 GW in mid-2026, and it is selling delivery slots for 2032.

• A new combined-cycle plant costs $2,000-2,500 a kilowatt, about double the 2021 cost.

• Solar and batteries take one to two years, gas five or more, restarts several, and new transmission seven to ten.

• Data centers are building their own power behind the meter, and FERC has ordered PJM to create rules for co-location.

• Until about 2028 the firm capacity comes from existing nuclear, coal kept from retirement, and gas ordered in 2024-25.

Module 7 Quiz

Check Your Understanding

1. How large was GE Vernova's book of gas-turbine orders and reservations at the end of June 2026?

A) About 20 GW
B) About 116 GW, up from 100 GW in March
C) About 300 GW, nearly twice PJM's record peak
D) About 60 GW, down by a third since early 2025 as buyers cancelled orders

2. Which delivery years was GE Vernova contracting or selling in September 2026?

A) 2027 and 2028, for plants already permitted
B) Only 2026, from units that other buyers cancelled
C) 2035 and later, after its factories expand
D) 2030-32

3. Why did the cost of a new combined-cycle plant roughly double after 2021?

A) Gas prices doubled
B) New federal carbon rules
C) Turbine prices rose with the shortage, and the rest rose with them
D) Tariffs on imported steel, transformers, and switchgear doubled the cost of every input

4. Why are data centers building power behind the meter?

A) It is cheaper than grid power
B) A grid connection can take years and large turbines are sold out, so they buy smaller units that ship quickly
C) Federal rules require it for campuses above 100 MW
D) Their insurers demand it

5. Which option does the module's table call the fastest near-firm one?

A) Solar plus storage
B) Combined-cycle gas plants
C) Small modular reactors from the 2030s
D) Onshore wind on the plains

Module 8 — The Nuclear Revival

The Plants Coming Back and the Ones Being Ordered

Recommended Reading / Reference

Book: Robert Bryce, *A Question of Power: Electricity and the Wealth of Nations*, for the case; read it with the cost history of Vogtle beside it

Reference: The NRC's licensing dockets for the restarts and new reactors; the DOE Loan Programs Office's announcements; and the IEA's *Key Questions on Energy and AI* (April 2026) for the technology companies' agreements

8a. Why Nuclear, and Why Now

The 94 American reactors produce 18% of the country's electricity and about two-fifths of its carbon-free electricity, at a capacity factor of about 92%. They offer at zero, and by the accounting of Module 5 they are among the most valuable assets in the system in 2026, which is a reversal.

Between 2013 and 2022 thirteen reactors closed, most because cheap gas made them uneconomic, and the industry's future looked like extending what existed and nothing more. Vogtle's two new units in Georgia, the only ones finished in a generation, cost about $35 billion and came in seven years late, which many took as proof that new reactors could not be built in America.

Three things changed the arithmetic, beginning with the demand shock of Module 6, which turned firm carbon-free power from a cost into a scarce good. The technology companies, with climate commitments and a need for power around the clock, became buyers willing to sign twenty-year contracts at prices the markets would not pay.

And federal policy across two administrations treated nuclear as strategic: the 2022 climate law created a production credit, the loan office financed restarts, and executive orders in May 2025 set goals of 400 GW by 2050 and ten large reactors under construction by 2030. In October 2025 the government announced a partnership to build $80 billion of Westinghouse's AP1000, the design built at Vogtle.

The revival has three parts on three clocks, and this module takes them in the order they deliver.

8b. The Restarts

Plant	Owner and buyer	Size	Status (October 2026)	Cost and note
Palisades (Michigan)	Holtec; power sold to the Wolverine and Hoosier cooperatives	800 MW	Approved to restart in 2025; a fuel assembly tipped over during fuel loading on August 30, 2026; Holtec filed a recovery request with the NRC on September 30, and no new date is set	Closed 2022; a DOE loan of about $1.5 billion
Crane Clean Energy Center (Three Mile Island Unit 1, Pennsylvania)	Constellation; twenty-year contract with Microsoft	835 MW	Restart expected in the second half of 2027	Closed 2019; a $1 billion DOE loan

Plant	Owner and buyer	Size	Status (October 2026)	Cost and note
Duane Arnold (Iowa)	NextEra; 25-year contract with Google	615 MW	Restart targeted for the end of 2028 or early 2029; a DOE loan of up to $1.9 billion closed on September 8, 2026	Closed 2020 after a storm damaged its cooling towers
Diablo Canyon (California)	Pacific Gas and Electric	2,240 MW	Closure moved from 2024-25 to 2029-30	The state reversed itself; a longer extension is under discussion

Restarts are the fastest nuclear power there is: the plant exists and the site is licensed, so the work is inspection, repair, and requalification of equipment that sat idle for a few years. They cost $1.5-2 billion a plant, far less per kilowatt than new reactors, for the most reliable power in the system.

But Palisades shows that the fastest route still means years and setbacks, and only a handful of closed plants could be restarted at all, because the rest were dismantled.

8c. Uprates and Extensions

The quietest and largest part of the revival is the existing fleet running longer and harder. Nearly every reactor has received or sought a license extension to sixty years, and a growing number to eighty. Uprates, which upgrade turbines, pumps, and fuel to extract more power from the same reactor, add a few hundred megawatts at a time at the lowest cost of any firm capacity available.

The economics are the inframarginal rent of Module 4 compounded by the capacity price of Module 12. A reactor that earns energy prices in every hour of the year plus a capacity price near $330 per MW-day is worth more than it has ever been. That is why plants that faced closure a decade ago now sign twenty-year contracts with the largest companies in the world, as Constellation did with Meta for its Clinton plant in Illinois in 2025.

Talen Energy, after the co-location fight of Module 10, signed Amazon to a contract for 1,920 MW from its Susquehanna plant in Pennsylvania.

8d. The Small Modular Reactors

The small modular reactor (SMR) is the revival's promise and its unproven part: reactors of 50-300 MW built in factories, installed in series, and, the theory goes, cheap once the learning curve is climbed. As of October 2026 no commercial SMR generates power in the United States.

The field is advancing in permits and concrete: Ontario Power Generation is building the first of four BWRX-300 units, a GE Vernova Hitachi design, at Darlington, aiming for power around 2030, and TVA received a construction permit for the same design at Clinch River in Tennessee in September 2026. TerraPower's sodium-cooled Natrium reactor in Wyoming received its construction permit on March 4, 2026, and NuScale's 77-MW design won NRC approval in May 2025.

X-energy, backed by Amazon, and Kairos Power, backed by Google, are building toward first units around 2030, and the technology companies have signed conditional agreements for about 45 GW of SMR capacity. The honest reading of the dates is that the first commercial units arrive around the end of the decade, and that the agreements are options rather than orders.

The first units will cost more per kilowatt than large reactors before any learning curve. Most designs also need high-assay low-enriched uranium (HALEU), a fuel that only Russia produced at scale until recently and for which the United States is building a supply chain. The SMR answers the demand of the 2030s, while the demand of 2026-29 is met by restarts, uprates, and the gas of Module 7.

Measure	Figure	Note
Fleet	94 reactors, about 97 GW; 18% of generation at a 92% capacity factor	Average age over 42; licenses extended to 60 and 80 years
Restarts	Palisades (800 MW, delayed); Crane (835 MW, second half of 2027); Duane Arnold (615 MW, end-2028 or early 2029)	$1.5-2 billion a plant
Contracts for existing plants	Meta with Constellation (Clinton); Amazon with Talen (1,920 MW from Susquehanna); Microsoft (Crane); Google (Duane Arnold)	Twenty years or more
Vogtle 3 and 4	2,200 MW; about $35 billion; seven years late	The only new large reactors finished in a generation
SMR agreements	About 45 GW, conditional (April 2026)	Options, not orders; first units around 2030
SMR permits	Natrium construction permit (March 4, 2026); TVA's Clinch River permit for a BWRX-300 (September 2026)	Darlington, Ontario, is building the first BWRX-300
Federal goals	400 GW by 2050; ten large reactors under construction by 2030; an $80 billion Westinghouse partnership	Executive orders of May 2025; agreement of October 2025

NRC; DOE; company announcements; IEA (April 2026) for the SMR agreements.

Module 8 Key Points

The Nuclear Revival

• Nuclear is 18% of generation at a 92% capacity factor and, on the market's accounting, one of the most valuable assets in the system.

• Crane restarts in 2027 and Duane Arnold by early 2029, but Palisades stalled after a fuel assembly tipped over in August 2026.

• License extensions and uprates are the quietest and largest part of the revival, at the lowest cost of any firm capacity.

• No commercial SMR runs in the United States, and the 45 GW of agreements with technology firms are options, not orders.

• Vogtle's $35 billion is the one recent large-reactor data point, and federal goals call for ten under construction by 2030.

Module 8 Quiz

Check Your Understanding

1. What set back the Palisades restart in 2026?

A) The NRC revoked its license after an inspection found cracks in the reactor vessel
B) A storm damaged its cooling towers, as at Duane Arnold in 2020
C) Its buyers cancelled their contracts
D) A fuel assembly tipped over during loading

2. Why are restarts the fastest nuclear capacity available?

A) The NRC exempts them from review
B) They use small modular parts
C) The plant and its site license already exist, so the work is inspection, repair, and requalification
D) Technology companies pay for all of them

3. Which company contracted to take power from the restarted Crane plant?

A) Amazon
B) Meta, through a contract for its Ohio campuses
C) Google, under a twenty-five-year agreement with NextEra
D) Microsoft, for twenty years

4. What is the status of small modular reactors in the United States in October 2026?

A) Several supply power in Tennessee and Wyoming
B) First units are about 2030
C) They supply about 5% of nuclear output
D) The NRC has stopped licensing them pending a new safety rule

5. How does the module characterize the 45 GW of SMR agreements with technology companies?

A) Options rather than orders, conditional on licensing and cost
B) Firm orders with delivery dates
C) A federal procurement
D) Contracts for power from existing reactors, signed for twenty years or longer at fixed prices

Module 9 — Renewables and Storage

The Resources Arriving Fastest, and What They Earn

Recommended Reading / Reference

Reference: The EIA's *Today in Energy* notes on planned additions (February 20, 2026) and battery storage (August 7, 2026); PJM's ELCC class ratings, published before each auction; and Modo Energy's battery revenue benchmarks by market

9a. Solar and Wind After the 2025 Tax Law

Solar and batteries are most of what is being built: of the 86 GW of capacity planned for 2026, solar is about half and batteries more than a quarter, and solar also led the 53 GW added in 2025. The reasons are cost and speed: on Lazard's 2026 figures new solar costs $40-98 per MWh, and a solar farm can be built within a year or two of the decision.

The July 2025 tax law changed the economics without stopping the build. The production and investment credits for wind and solar end for projects that begin construction after July 4, 2026, unless they enter service by the end of 2027. The storage credit survives, with restrictions on Chinese components, so the law produced a rush to start construction before the deadline, followed by a cliff whose depth developers dispute.

Wind is the source that stalled: onshore additions slowed under permitting delays, federal hostility, and the same interconnection queue that delays everything, and offshore wind has faced federal stop-work orders, suspensions, and lease cancellations since 2025. Wind remains about a quarter of Texas's energy and a large share of the plains', but it adds little that is new.

The technical fact that governs both is accreditation (Module 12): for the 2028/29 auction PJM counts fixed solar at 7% of its nameplate, tracking solar at 10%, and onshore wind at 34%, so a gigawatt of tracking solar counts as 100 MW in the auction. That arithmetic makes storage the other half of every solar project.

9b. The Battery Boom

American utility-scale batteries reached 43.6 GW at the end of 2025 and nearly 52 GW by June 2026, after 8.3 GW were added in the first half of the year. Developers plan about 14 GW more for the rest of 2026, 26 GW in 2027, and 14 GW in 2028, according to the EIA.

Two states carry the fleet: California has about 16 GW of utility-scale batteries, more than 21 GW counting those in homes and businesses, and they now carry the evening peak that solar created. ERCOT has about 14 GW, and its batteries discharged more than 10 GW at once seven times, five of them in July 2026. PJM, by contrast, has little storage operating and tens of gigawatts in its queue.

A four-hour lithium-iron-phosphate battery costs about $250 per kilowatt-hour installed in the United States in 2026, and its cells are mostly Chinese, a fact that tariffs and the tax law's content rules now price in. What a battery does for a grid is shift energy in time: it charges when power is cheap, at noon in a solar market or at 3 a.m. anywhere, and discharges when power is dear, during the evening ramp.

It also provides regulation better than any spinning machine, and it counts toward capacity, at 59% of its nameplate in PJM for 2028/29. That rating tends to fall as more batteries join a grid, because a fleet of four-hour batteries runs out before a long winter evening ends.

9c. Curtailment and the Texas Case

Texas is the experiment the rest of the country watches. It has an energy-only market with no capacity payment, and it uses a 'connect and manage' approach that puts a plant on the grid quickly and curtails it when the wires are full, rather than making it wait for upgrades. The result is the fastest build in the country: tens of gigawatts of solar and about 14 GW of batteries on a system whose record peak is 91.1 GW.

The results cut both ways: solar floods the midday and batteries flatten the evening, and the grid has met record summer demand without repeating the rolling blackouts of 2021. But battery revenues fell as the growing fleet saturated the markets for arbitrage and ancillary services. And curtailment, the cost of connecting first and building wires later, runs highest in West Texas, where solar and wind outrun the lines.

PJM adopted the Texas lesson in its own way in 2026. Its proposed Interim Resource Adequacy Service (Module 10) applies the approach to demand rather than supply: a large load may connect without bringing new capacity if it accepts curtailment ahead of other customers when the system is short.

9d. A Four-Hour Battery in PJM

Worked example — a four-hour battery's revenue stack in PJM

Take a battery of 100 MW and 400 MWh connected in PJM in 2026 at about $250 per kWh, or $100 million installed, and stack what it earns. **Capacity** comes first, because it is contracted ahead, and PJM counts a four-hour battery at 59% for 2028/29, so 100 MW of nameplate counts as 59 MW. At the $325 clearing price that is 59 × $325 × 365, about $7.0 million a year, or $70,000 per MW of nameplate. It pays for the obligation to be charged and available when the operator calls, with penalties if the battery is not.

Energy arbitrage is the durable layer: one cycle a day, buying at the trough and selling at the peak on a spread of about $40 per MWh, on 400 MWh at 85% round-trip efficiency, earns 400 × 0.85 × $40 × 365, about $5 million a year, or $50,000 per MW. It earns more in the congested Dominion zone, where spreads run wider, and more again on scarcity days.

Regulation is the windfall layer: since PJM redesigned its regulation market in October 2025, letting batteries follow a single signal, the few batteries in PJM have earned an average of about $62 per kW-month, mostly from regulation, against about $20 before, by Modo Energy's benchmark. At that rate a battery would pay for itself in a year or two. But the regulation market is only about 750 MW deep, every developer in the queue can see the same number, and ERCOT and California show what happens next: the price falls as the fleet grows.

A lender therefore counts regulation as a fading layer, worth perhaps $20,000-30,000 per MW-year averaged over the battery's life, and **reserves** add about $5,000 per MW.

The stack comes to roughly $145,000-155,000 per MW-year, or $14.5-15.5 million a year, before operating costs of about $1 million a year and degradation of 2-3% a year. The investment tax credit, which the 2025 law kept for storage, takes 30% off the cost and leaves about $70 million, so the simple payback is about five years. Take regulation away, as the growing fleet will, and the payback stretches toward seven.

A lender asks about three things, in this order, and the first is the capacity price, held near $325-333 by the collar through May 2030 and put by PJM at $555 without it. The second is the accreditation, which falls as batteries arrive, and the third is the regulation revenue, the layer that disappears. A battery financed on capacity and arbitrage alone, with regulation as upside and a lower accreditation in the model, is the one that survives the fleet it joins.

Measure	Figure (2026)	Note
Utility-scale batteries	43.6 GW (end-2025); nearly 52 GW (June 2026)	About 14 GW more planned for late 2026 and 26 GW in 2027 (EIA, August 2026)
Leaders	California about 16 GW utility-scale (more than 21 GW with homes and businesses); ERCOT about 14 GW	ERCOT batteries discharged above 10 GW seven times, five of them in July 2026
Installed cost	About $250/kWh for a four-hour system	Chinese cells; tariffs and content rules
PJM battery revenue	About $62 per kW-month on average since October 2025, mostly regulation, against about $20 before	Modo Energy (April 2026); a regulation market about 750 MW deep
PJM accreditation, 2028/29	Four-hour battery 59%; tracking solar 10%; fixed solar 7%; onshore wind 34%	PJM ELCC class ratings
Solar plus storage	$61-156/MWh	Lazard (July 2026)
Tax credits	Wind and solar credits end for projects starting after July 4, 2026 unless in service by the end of 2027; storage credit kept with content rules	The July 2025 law

Module 9 Key Points

Renewables and Storage

• Solar and batteries are more than three-quarters of the 86 GW planned for 2026, and PJM counts a gigawatt of tracking solar as 100 MW.

• Batteries reached nearly 52 GW by mid-2026 and now carry the evening peak in California and Texas.

• Texas is the experiment: energy-only, connect-and-manage, the fastest build in the country, and battery revenues squeezed by saturation.

• A lender underwrites a PJM battery at about $150,000 per MW-year, treating today's regulation windfall as the part that disappears.

• The 2025 tax law ends wind and solar credits for late starters and keeps the storage credit, with limits on Chinese parts.

Module 9 Quiz

Check Your Understanding

1. How does PJM accredit a four-hour battery for the 2028/29 auction?

A) At 100% of nameplate, like a gas plant
B) At 10%, the same as tracking solar
C) At 34%, the same as onshore wind
D) At 59%

2. What did the July 2025 tax law do to the credits for wind, solar, and storage?

A) It extended all three through 2035
B) It repealed the storage credit and kept the wind and solar credits for projects already in the queue
C) It ended wind and solar credits for late starters and kept storage's
D) It turned all three into direct grants paid by the Energy Department to developers

3. Why did battery revenues fall in Texas as the fleet grew?

A) Texas taxes storage
B) The growing fleet saturated the arbitrage and ancillary-service markets it competed in
C) ERCOT has no ancillary-service markets
D) Prices are lower in every hour than in PJM

4. In the worked example, which revenue layer does the module expect to disappear as the fleet grows?

A) Regulation, a shallow market
B) Capacity
C) Arbitrage
D) Reserves, once the operators stop paying for synchronized capacity

5. What is 'connect and manage'?

A) A FERC rule on queue deadlines
B) PJM's three-year auction
C) Connecting a plant quickly and curtailing it when the wires are full, instead of making it wait for upgrades
D) A battery dispatch strategy for the evening ramp

Module 10 — Interconnection

The Queue

Recommended Reading / Reference

> **Reference:** Lawrence Berkeley National Laboratory, *Queued Up: 2026 Edition* (July 2026); FERC Order 2023 and PJM's compliance filings; FERC's December 2025 order on co-located load in PJM and its June 18, 2026 show-cause orders on large loads; and PJM's August 13, 2026 filing of its Interim Resource Adequacy Service

10a. The Queue

A plant that wants to connect to the grid files a request with the market operator or utility and enters a queue, where it waits for studies of what the connection will do to the network and which upgrades it must pay for. At the end of 2025 the American queue held 2,061 GW of generation and storage, down 10% in a year but still one and a half times the installed fleet of 1,374 GW: solar made up 773 GW, storage 749 GW, gas 253 GW, up 86%, and wind 220 GW.

Projects built in 2025 took a median of 61 months from request to operation, against 36 months for those built in 2015. Most projects never arrive: of the requests filed from 2000 to 2020, only 19% of projects, and 13% of the capacity, reached operation, while 71% of the projects withdrew.

The queue's dysfunction was structural: projects were studied one at a time in the order they filed, each study depended on the projects ahead, and a withdrawal ahead set off new studies for every project behind. Developers filed speculative requests by the dozen to hold places, so the queue measured intent rather than plans.

FERC's Order 2023, issued in July 2023, rewrote the rules. Projects are now studied in clusters rather than in sequence, must post larger deposits and show control of their sites to enter, and pay penalties for withdrawing late, while the operators face penalties for missing study deadlines.

PJM, which had frozen new entry in 2022 to clear a backlog, moved to cluster studies and added two fast tracks. Its Reliability Resource Initiative of 2025 pulled 51 shovel-ready projects of about 9 GW, mostly gas and batteries, to the front. Its Expedited Interconnection Track, which FERC approved on June 9, 2026, runs to the end of 2027 for large projects ready to build. The queue still measures in years, because the studies are the wires' constraint in another form (Module 11).

10b. The Large-Load Queue

The decade's new queue is for demand: a data center wanting a gigawatt files a large-load request with the utility, which studies the substations, feeders, and transmission the load will need and quotes a timeline and a cost. Requests filed in multiples produced the same dysfunction on the demand side that Order 2023 addressed on the supply side.

The first responses came from utilities and states: utilities imposed the large-load tariffs of Module 13, with minimum terms of a decade or more, minimum charges for the capacity requested, collateral, and study fees, so that a speculative request costs something. Texas's Senate Bill 6 of 2025 requires large loads in ERCOT to disclose duplicate requests elsewhere, pay for studies, and install equipment that lets the operator curtail them in a grid emergency.

PJM's answer is the Interim Resource Adequacy Service (IRAS), which its board approved on July 27, 2026 and filed at FERC on August 13, asking for a ruling by October 12. From June 1, 2027, a new load of 50 MW or more that does not bring new capacity with it may be curtailed before PJM calls on its pre-emergency demand response. A load that brings new capacity, through its own plant or a contract with a new one, reduces that exposure.

FERC then made the question national: on June 18, 2026 it ordered the six market operators it regulates, PJM, MISO, SPP, CAISO, ISO New England, and NYISO, to show why their rules for large loads were just and reasonable or to propose new ones within sixty days. The orders define a large load as 50 MW or more connected above 69 kV, and they cover transmission service, cost responsibility, co-location, flexible loads, and the study of generation that large loads bring with them.

The principle across these answers is the one the physics requires: a load that cannot wait for the queue must either bring its own supply or accept being among the first to lose it.

10c. Co-Location and the Talen-Amazon Fight

The sharpest interconnection question of the decade is whether a data center may sit behind the meter of an existing power plant and take its output directly. In 2024 Talen Energy sold Amazon a campus beside its Susquehanna nuclear plant in Pennsylvania and sought to expand the arrangement to 480 MW of the plant's output, delivered without crossing the grid.

FERC rejected the expansion in November 2024 by a vote of 2-1, reasoning that the arrangement would shift onto other customers the cost of transmission the campus still relied on, for backup, for stability, and for the moment the plant tripped, and that no rules yet governed it. Generators argued that co-location is the fastest way to serve the new load and that a plant's output is its own to sell. Utilities and consumer advocates answered that a campus drawing a gigawatt from a plant that had served the grid removes that gigawatt from everyone else's supply and pays nothing for the wires that still protect it.

FERC's December 2025 order set the terms, requiring PJM to create new transmission services for co-located loads so that each pays for the service it uses. The deals adapted in the meantime: Talen and Amazon restructured theirs in June 2025 as a grid-connected contract for 1,920 MW, and Constellation's contract with Microsoft for Crane is grid-connected too.

The physics reasserted itself in the rules: a co-located load is still a load on the network it sits in, and the fight is over who pays for the part of the grid it thinks it does not use.

Measure	Figure	Note
Generation queue	2,061 GW at end-2025, down 10%: solar 773, storage 749, gas 253, wind 220	Berkeley lab; one and a half times the installed fleet
Time to connect	Median 61 months for projects built in 2025, against 36 months in 2015	Berkeley lab
Completion	19% of projects requested in 2000-2020 (13% of capacity) reached operation; 71% withdrew	Berkeley lab
PJM fast tracks	Reliability Resource Initiative (2025): 51 projects, about 9 GW; Expedited Interconnection Track (approved June 9, 2026; runs to end-2027)	Mostly gas and batteries
ERCOT large loads	More than 230 GW requested (January 2026), against a record peak of 91.1 GW	Senate Bill 6 (2025): disclosure, study fees, curtailment equipment

Measure	Figure	Note
PJM's IRAS	From June 1, 2027, loads of 50 MW or more without new capacity may be curtailed before pre-emergency demand response	Board approval July 27, 2026; filed August 13; ruling requested by October 12
FERC show-cause orders	Six market operators; loads of 50 MW or more above 69 kV; five areas	June 18, 2026; answers due within sixty days
Co-location	FERC's December 2025 order: new transmission services, each load paying for what it uses	The Talen-Amazon rejection of November 2024 was the origin

Module 10 Key Points

Interconnection

• The queue held 2,061 GW at the end of 2025, and projects built that year took a median 61 months to connect.

• Most requests never arrive: of those filed in 2000-2020, only 19% of projects reached operation.

• Order 2023 replaced one-at-a-time studies with clusters, deposits, and withdrawal penalties, and PJM added two fast tracks.

• Under PJM's IRAS, from June 2027 a large load without new capacity may be curtailed early; FERC's show-cause orders made the question national.

• A load that cannot wait must bring its own supply or be among the first to lose it.

Module 10 Quiz

Check Your Understanding

1. How large was the American interconnection queue at the end of 2025?

A) About 2,061 GW, down 10%
B) About 500 GW
C) About 5,000 GW, four times the installed fleet
D) About 1,000 GW, almost all of it gas plants waiting for turbines

2. What did FERC's Order 2023 change?

A) It moved interconnection decisions from the operators to the state commissions
B) Cluster studies and penalties
C) It capped the queue at 500 GW and closed it to new solar requests
D) It abolished study deposits so that small developers could enter

3. Under PJM's Interim Resource Adequacy Service, what happens to a new large load that brings no new capacity?

A) It pays a $1 billion deposit
B) It waits five years in the queue
C) It must build its own line to the nearest 500-kV substation before it can connect
D) It may be curtailed before pre-emergency demand response

4. Why did FERC reject the Talen-Amazon expansion in November 2024?

A) Nuclear plants may not sell to private buyers
B) Amazon lacked an NRC license
C) Pennsylvania objected
D) It would shift the cost of transmission the campus still relied on onto other customers

5. What threshold did FERC's June 18, 2026 show-cause orders use for a large load?

A) 50 MW or more, above 69 kV
B) 20 MW
C) 1 GW or more at a single campus, at any voltage
D) Any load connected at transmission voltage that runs more than half the hours of the year

Module 11 — Transmission

The Bottleneck

Recommended Reading / Reference

> **Reference:** The Department of Energy's *National Transmission Needs Study* (2023) and *National Transmission Planning Study* (2024); FERC Orders 1920 and 1920-A (2024); Grid Strategies and Americans for a Clean Energy Grid, *Fewer New Miles* (July 2025); and the regional plans of PJM and MISO

11a. Why the Wires Decide

Every constraint in this course resolves to the wires: the queue of Module 10 is slow because its studies are studies of the transmission a new plant needs. The congestion of Module 4 is the price of a line at its limit, and the curtailment of Module 9 is a plant the wires cannot carry. The capacity shortfalls of Module 12 are partly plants on the far side of a constraint, and the co-location fight is over who pays for the wires a campus still uses.

The country's high-voltage network was mostly built between 1950 and 1990, for a fleet and a load that no longer exist. In recent years the country has added fewer than 1,000 miles a year of new lines at 345 kV and above, against nearly 4,000 miles in 2013 alone. The Department of Energy's 2024 planning study found that transmission would need to grow to roughly 2.4-3.5 times its 2020 size by 2050 to carry new resources to new loads at the lowest cost.

A major line takes seven to ten years from plan to power, and the reason is not engineering but the three questions a line raises: who plans it, who pays for it, and who may stop it.

11b. Who Plans It: Order 1920

FERC's Order 1920 of May 2024 is the largest change to transmission planning since the market operators were created. It requires every transmission provider to plan twenty years ahead, at least every five years, across scenarios that include the load growth, resource changes, and extreme weather that older plans ignored. Planners must weigh a list of benefits, including reliability, congestion relief, and production-cost savings, rather than the single reliability test that had justified most lines.

The order also requires them to consider advanced conductors and grid-enhancing technologies that raise a line's capacity without a new right of way. Order 1920-A of November 2024 gave the states a larger role in deciding how costs are shared, after they objected that the original had not. Compliance filings ran through 2025 and 2026, and states and utilities that see federal overreach have challenged the orders in court.

The regional plans are the largest in the operators' history: MISO approved its $21.8 billion Tranche 2.1 portfolio in December 2024, built around a 765-kV backbone across the Midwest, and PJM has approved its first 765-kV lines, aimed at moving power into northern Virginia. The lines between regions, which the studies say are worth the most, remain mostly unbuilt, because a line that benefits two regions needs both to agree to pay.

11c. Who Pays for It: The Allocation Fight

The rule is that beneficiaries pay, and the fight is over who benefits. A line that carries cheap power into a constrained zone lowers prices there and raises them where the power came from. It relieves congestion for loads on one side and, in 2026, serves the data centers whose demand justified it, and states, utilities, and consumer advocates then argue over the shares.

The case in point is the Mid-Atlantic Resiliency Link (MARL), NextEra's 500-kV line of about 107 miles running from Pennsylvania through West Virginia and Maryland into Virginia. PJM chose it in 2023 to relieve the constraints into northern Virginia at an estimated $441 million, and its cost estimate has since roughly doubled to about $960 million. NextEra filed its Maryland application at the end of January 2026, and the route crosses 388 properties.

Maryland officials argue that Maryland's households will pay for a line whose main beneficiaries are Virginia's data centers, while the constraint the line would relieve keeps setting the Dominion zone's congestion price. The pattern repeats across PJM: the Union of Concerned Scientists counted more than $4 billion of transmission connections for data centers in 2024 alone that were charged to all customers in seven PJM states.

That is why the large-load tariffs of Module 13 increasingly charge a data center for the transmission its request triggers, as Virginia's regulators ordered Dominion to do in July 2026. The allocation fight is the bill of Module 13 in its wholesale form.

11d. Who May Stop It, and What Is Short

- **Permitting:** a line crossing state lines needs each state's siting approval, and any state may say no. The federal backstop authority that Congress created in 2005 and expanded in 2021 has never overridden a state. The Grain Belt Express, a 5-GW line from Kansas to Indiana first proposed in 2010, lost its federal loan guarantee in July 2025.
- **The right of way:** one 765-kV line carries about what four to six 345-kV lines do, on a much narrower corridor, which is why 765 kV is the decade's answer. Reconductoring, which restrings an existing line with advanced conductors that carry up to about twice the power, is the fastest transmission there is, at a fraction of a new line's cost and with no new siting.
- **Transformers:** the large power transformers at every substation come from a handful of makers, mostly abroad, and their lead times stretched to two to four years while prices of transformers, cables, and switchgear nearly doubled in five years. Data centers, solar plants, and new lines all need them, which makes the transformer the most cited equipment constraint after the turbine.
- **Ties between regions:** the seams between PJM and MISO, between the Eastern and Western interconnections, and between ERCOT and everyone else are where the studies find the largest unbuilt value and the least construction.
- **Grid-enhancing technologies:** dynamic line ratings, power-flow controllers, and topology optimization squeeze 10-30% more from existing lines within months. Order 1920 requires planners to consider them, but adoption is slow, because a utility earns a return on new steel and not on software.

Measure	Figure	Note
New high-voltage lines	Fewer than 1,000 miles a year at 345 kV and above in recent years; nearly 4,000 miles in 2013	FERC data compiled by Grid Strategies
Need	Transmission 2.4-3.5 times its 2020 size by 2050	DOE, *National Transmission Planning Study* (2024)

Measure	Figure	Note
Lead time	Seven to ten years for a major new line; months for reconductoring	Siting, cost allocation, and permitting, not construction
Order 1920	Twenty-year, scenario-based planning that weighs several benefits; 1920-A gave states a larger role in cost allocation	May and November 2024; challenged in court
Regional plans	MISO Tranche 2.1, $21.8 billion (December 2024); PJM's first 765-kV lines	The largest in the operators' history
MARL	About 107 miles at 500 kV; cost estimate from $441 million to about $960 million	Maryland application filed January 2026; 388 properties
Data-center connections	More than $4 billion charged to all customers in seven PJM states (2024)	Union of Concerned Scientists
Transformers	Lead times of two to four years; equipment prices nearly doubled in five years	IEA; the constraint after turbines

Module 11 Key Points

Transmission

• Every constraint in the course resolves to the wires, and the country now builds fewer than 1,000 miles of high-voltage line a year.

• Order 1920 requires twenty-year planning that weighs several benefits, and it produced the largest regional plans in the operators' history.

• Beneficiaries pay, and the fight is over who benefits; Maryland contests paying for a line that serves Virginia's data centers.

• A major line takes seven to ten years because any state, permit, or landowner can stop it.

• 765 kV and reconductoring are the decade's answers, and transformers are the equipment constraint after turbines.

Module 11 Quiz

Check Your Understanding

1. How many miles of new 345-kV-and-above lines has the country built in recent years, against 2013?

A) About 5,000 miles a year, more than in 2013
B) Under 1,000 a year
C) About 3,000 miles a year, a little below 2013
D) About 2,000 miles a year, half of what was built in 2013

2. What did FERC's Order 1920 require?

A) A national grid operator
B) Federal siting of all interstate lines
C) Twenty-year, scenario-based planning that weighs several benefits
D) That every new line be built at 765 kV and paid for by the customers in the region where it ends

3. What is the dispute over the Mid-Atlantic Resiliency Link mainly about?

A) Whether a 500-kV line can cross the Chesapeake Bay safely
B) Whether NextEra may own transmission in Maryland under state law
C) Who pays for it
D) Whether it should be buried underground through the national parks it crosses in West Virginia

4. Why is 765 kV the decade's answer to transmission?

A) It needs no transformers
B) One line carries what several 345-kV lines do
C) It is exempt from state siting under the 2005 energy law
D) It is cheaper per mile than any lower voltage and can be built in about two years

5. What happened to lead times for large power transformers?

A) They fell to weeks
B) They held at about six months
C) They doubled to a year
D) They stretched to two to four years as equipment prices nearly doubled in five years

Module 12 — Capacity Markets and Reliability

The Auction That Put the Bill on Every Household

Recommended Reading / Reference

Reference: PJM's Base Residual Auction reports (December 17, 2025 and July 14, 2026) and the market monitor's analyses (Monitoring Analytics); FERC's September 29, 2026 order on PJM's Reliability Backstop Procurement; NERC's *Long-Term Reliability Assessment*; and the MISO and ISO New England auction reports

12a. What a Capacity Market Is

An energy market pays for megawatt-hours delivered, while a capacity market pays for megawatts available on the worst day, whether or not they are called. It exists because an energy market alone, in the theory behind PJM's design, does not pay a plant that runs fifty hours a year enough to keep it from closing.

PJM's version is the Reliability Pricing Model, and its main event is the Base Residual Auction (BRA). For each delivery year, which runs from June to May, PJM sets a reliability requirement, the forecast peak plus a reserve margin near 20%, and a demand curve that pays more as supply falls short. Generators offer their accredited capacity, and the auction clears at a price per MW-day that every load in the region pays in proportion to its share of the peak.

The auction is designed to run three years ahead of delivery, but delays after 2022 compressed the schedule, and PJM returns to the three-year lead with the auction of May 2027.

Accreditation is the hinge: since the 2025/26 auction PJM has counted every resource at its effective load-carrying capability, the share of its nameplate that actually reduces the risk of a shortfall in the hours that matter. For 2028/29 a combined-cycle gas plant counts at 78%, nuclear at 96%, a four-hour battery at 59%, onshore wind at 34%, and tracking solar at 10%.

A resource that clears and then fails to perform in an emergency pays a penalty. Winter Storm Elliott in December 2022, when PJM lost about 46 GW of generation in the cold, produced about $1.8 billion of such penalties, and the accreditation reform followed.

12b. The Series

Delivery year	Auction held	Clearing price (regionwide)	Total	Shortfall and note
2024/25	December 2022	$28.92/MW-day	About $2.2 billion	A surplus; the last of the low years
2025/26	July 2024	$269.92, about nine times the year before	$14.7 billion	The first auction after the accreditation reform; the market monitor attributes $9.3 billion to data-center load
2026/27	July 2025	$329.17, the cap	$16.1 billion	The first auction under the cap won by Pennsylvania
2027/28	December 2025	$333.44, the cap	About $16.4 billion	6,623 MW short of the reliability requirement, the first regionwide shortfall; reserve margin 14.8%; 774 MW of new generation and uprates

Delivery year	Auction held	Clearing price (regionwide)	Total	Shortfall and note
2028/29	July 2026	$325.00, the cap (lower because the reference unit's accreditation rose)	$16.4 billion; $29.7 billion without the collar	6,831 MW short; reserve margin 14.7% against a target near 20%; 525 MW of new generation and uprates; $6.3 billion attributed to data centers; uncapped price $555, or $777 in the ComEd zone

PJM; Monitoring Analytics. The collar comes from a settlement with Pennsylvania that FERC approved in 2025 and extended on April 28, 2026 through the 2029/30 delivery year, and it runs from about $175 to about $333 per MW-day. The 2029/30 auction runs December 9-15, 2026, with results on December 22, and the 2030/31 auction on May 12, 2027.

12c. Signal or Transfer: What the Series Means

The case that the price is a signal. Generators and many economists read the series as the market working as designed: demand rose and supply did not, so the price rose to signal that capacity is scarce. That signal has kept old plants from retiring, financed uprates and restarts, and drawn gas orders (Modules 7 and 8). A cap that holds the price at $325 when the uncapped price is $555 suppresses the very signal that would close the shortfall, and on this view the shortfall is partly the cap's consequence.

The case that the price is a transfer. Consumer advocates, many state officials, and the market monitor read the same series as a transfer of tens of billions of dollars from households to the owners of existing plants. Those plants cost no more to run than they did when capacity sold for $29, and much of the increase is attributable to data-center load that arrived after they were built. New supply cannot answer a signal of two or three years when turbines take five and the queue takes more. And the accreditation reform, which cut the counted capacity of the existing fleet at a stroke, manufactured part of the shortage.

The evidence. The signal has not yet produced new capacity at the scale the shortfall requires: 774 MW of new generation and uprates cleared in the 2027/28 auction and 525 MW in 2028/29, against shortfalls of more than 6,600 MW each time. Retirements did slow, existing plants captured most of the revenue, and the cap limited the transfer while leaving the shortfall in place. The monitor attributes 63% of the 2025/26 auction's revenue and 38% of the 2028/29 auction's to data-center load, while generators reply that prices would have risen anyway as the fleet aged.

The course's reading. Both sides describe the same auction accurately, and the price is a real signal that cannot be answered on the auction's clock, so it acts as a transfer until the supply it calls for arrives. That is why PJM, the states, and the White House turned to a separate purchase outside the auction.

12d. The Backstop Purchase, Suspended

On January 16, 2026 the White House's National Energy Dominance Council and the governors of all thirteen PJM states issued a statement of principles, and the same day PJM's board directed its staff to design a similar purchase of its own. The statement called for an emergency purchase of new capacity on fifteen-year contracts, with costs falling first on new data centers that had not brought their own supply, and for extending the collar.

PJM filed its Reliability Backstop Procurement on July 31, 2026, seeking 6,831.3 MW of capacity on contracts of up to fifteen years, with a weighted price cap of $555 per MW-day and new resources required to be online by June 1, 2032. On September 29 FERC accepted the design but suspended it until February 28, 2027, subject to refund.

FERC set three problems for further review: how the costs are allocated, how transmission owners may exit, and the collateral required of the utilities that serve load, and it rejected an opt-out for cooperatives and municipal utilities. Chairman Laura Swett called the filing a 'mess', and PJM postponed the procurement's September 30 opening with no new date.

12e. The Other Markets, and NERC's Warning

- **MISO's** seasonal auction, run just before each delivery year, cleared the 2026/27 summer season at $424.30 per MW-day in most zones, against $666.50 a year earlier, and its annual average fell to $126.19 from $217.00, so the same kind of instrument produced a falling price.
- **ISO New England's** last forward auction, held in 2024, cleared at $3.58 per kilowatt-month for 2027/28. The region's constraint is the gas pipeline more than the fleet, and from 2028 it is moving to a seasonal auction held just before each delivery year.
- **ERCOT** has no capacity market: an operating reserve demand curve raises the energy price toward a cap of $5,000 per MWh as reserves fall. That design produced prices at the old $9,000 cap in February 2021 and the country's fastest build since, and the rest of the country watches whether scarcity pricing alone can keep a grid reliable.
- **The regulated states** hold no auction: the utility's resource plan and the commission's approval put new capacity in the rate base at cost plus a return, so Georgia Power's data-center build is a capacity market in another form, with the rate case as the auction.
- **NERC's long-term assessment** rates several regions, PJM and MISO among them, at high risk of shortfalls within five years, given retirements, demand growth, and how little of what is being added counts toward peak needs, which makes it the official version of the auctions' shortfall.

12f. The Capacity Price on a Household Bill

Worked example — the capacity price on a household bill

Take a household in the zone of Baltimore Gas and Electric (BGE) in Maryland, a restructured state where the capacity price passes through, using 1,000 kWh a month. The capacity charge is levied not on energy but on the household's share of the peak: its 'peak load contribution', the average demand in the five hours of the previous summer when PJM's system peaked, which for a house with central air is about 2.5 kW.

In the 2024/25 delivery year, at $28.92 per MW-day, the charge was $28.92 × 365 ÷ 1,000, or $10.56 per kW-year. Times 2.5 kW, that is about $26 a year, or $2 a month, which no one noticed. In 2025/26 the regional price of $269.92 gives $98.52 per kW-year, about $246 a year or $20 a month, and the BGE zone, which cleared separately at $466.35, gives about $35 a month. At the cap of the following years, about $120 per kW-year, the charge is about $300 a year, or $25 a month.

The household's total bill of about $180 a month therefore rose $20-35 from the capacity line alone between 2024 and 2026, an increase of roughly 10-20% from one auction result, which is the arithmetic behind the utilities' filings and the states' complaints.

Now the attribution: the market monitor attributes 63% of the 2025/26 auction's revenue and 38% of the 2028/29 auction's to data-center load, so of the household's monthly capacity charge of $20-25, roughly $8-15 is, on the monitor's estimate, the cost of load that is not the household's. Generators reply that the charge would have risen without the data centers as the fleet aged. On the monitor's own numbers they are partly right, since the 2025/26 auction would still have cost more than twice the year before without that load.

The legislative response of Module 13 is an attempt to move that $8-15 from the household's bill to the data center's. The honest arithmetic is that the increment can move and the base cannot: capacity is scarce for everyone, and the household would have paid more than $2 a month in any version of 2026.

Module 12 Key Points

Capacity Markets and Reliability

• A capacity market pays plants to be available on the worst day, and every load pays in proportion to its share of the peak.

• PJM's price rose from $28.92 to the cap in two years, and the last two auctions fell short of the reliability requirement.

• Read as a signal, the price is working; read as a transfer, it pays existing plants for scarcity new supply cannot yet answer.

• FERC accepted PJM's backstop purchase of 6,831 MW on fifteen-year contracts but suspended it until February 28, 2027.

• On a Maryland bill the capacity line rose from about $2 to $20-35 a month; the data-center increment is assignable, the base is not.

Module 12 Quiz

Check Your Understanding

1. What does a capacity market pay for?

A) Being available on the worst day, whether or not called
B) Fuel stored at the plant
C) Energy delivered in the peak hour
D) Transmission upgrades needed to deliver a plant's output to the load centers it serves

2. Which sequence matches PJM's clearing prices from 2024/25 to 2028/29?

A) $29 in every year
B) $100, $200, $300, $400, and $500 per MW-day, rising evenly
C) $29, $270, $329, $333, $325
D) $329, $270, $150, $100, and $29, falling as solar arrived in the region

3. What did FERC do with PJM's Reliability Backstop Procurement on September 29, 2026?

A) Accepted it, but suspended it
B) Rejected it outright and ordered PJM to lift the price cap instead
C) Approved it in full, with the procurement opening on September 30 as planned
D) Sent it back for a stakeholder vote

4. What does the module conclude about the capacity price signal?

A) It is false
B) It is real but cannot be answered on the auction's clock, so it acts as a transfer until new supply arrives
C) It has already produced the needed supply
D) It reflects the cost of fuel alone

5. In the worked example, how much did the capacity line on a Maryland household's bill rise between 2024 and 2026?

A) It fell
B) About $2 a month
C) About $100 a month more, more than doubling the household's total bill
D) About $20-35 a month

Module 13 — Who Pays

The Bill and the Fight Over It

Recommended Reading / Reference

Reference: The EIA's *Electric Power Monthly* retail price tables and *Short-Term Energy Outlook* (October 2026); the Public Utilities Commission of Ohio's July 2025 order on the data-center tariff of American Electric Power (AEP) in Ohio; the Virginia State Corporation Commission's July 31, 2026 order on Dominion's transmission rider; and MultiState's tracker of state data-center legislation

13a. The Bill

The average American household paid about 17.3 cents per kWh in 2025, and the EIA forecasts 18.2 cents in 2026 and 18.7 cents in 2027. The average was 13.2 cents in 2020, so the price has risen almost 40% in six years, well ahead of general inflation.

The bill has three parts that rose for different reasons: generation, a third to a half of the bill depending on the state, rose with gas prices and, in restructured states, with the capacity charges of Module 12. Transmission, 10-15% of the bill, is the fastest-rising part, driven by the utilities' record capital spending of about $200 billion a year on wires, substations, storm hardening, and wildfire protection, recovered at a return of about 9.5-10%, and distribution, the rest, rose with the same spending on the local system.

The regional pattern follows the map of this course: PJM's restructured states and New England have high bills and the sharpest increases, while the regulated Southeast has lower bills that are rising as new gas plants enter the rate base. Texas is lower still, with the volatility of its energy-only market passed to the customers who chose it, and California, on wildfire costs and the shift to rooftop solar, has the highest prices on the mainland.

13b. The Large-Load Tariffs

The instrument of 2025-26 is the large-load tariff, a new rate class for the largest customers with terms no ordinary customer faces. The model is AEP Ohio's tariff, approved by the state's commission in July 2025 for data centers above 25 MW. It requires twelve-year contracts with a four-year ramp, minimum charges of 85% of the capacity requested whether or not it is used, collateral, and an exit fee equal to three years of payments.

The tariff did what it was meant to do: it separated requests from plans. AEP Ohio had cited more than 30 GW of interest from data centers, but under the tariff developers requested studies for about 13 GW, and by February 2026 they had signed agreements for 5.6 GW.

Virginia followed: its State Corporation Commission (SCC) approved a new rate class for Dominion's largest customers in November 2025, with minimum demand charges and fourteen-year terms. On July 31, 2026 it went further and ordered Dominion to charge data centers directly for transmission built solely to serve them, which cut the planned increase in the household transmission charge from $2.90 a month to $0.94.

Maryland's Public Service Commission (PSC) has drafted rules for loads of 100 MW or more under the state's 2025 Next Generation Energy Act, Pennsylvania's regulators adopted a model large-load tariff in May 2026, and Texas has Senate Bill 6. FERC's June 2026 show-cause orders (Module 10) then put the same

question to the six market operators it regulates, for loads of 50 MW or more. The logic across all of them is this course's: the increment can be assigned to the load that caused it, and the base cannot.

13c. The Legislative Wave and the Politics

The states moved faster than the utilities: hundreds of data-center bills were filed in the 2026 legislative sessions, a turn from the incentive-writing of 2015-24 toward regulation. They fall into five kinds: large-load rate classes, rules making data centers pay the full cost of their grid connections, demand-response and curtail-first provisions, rollbacks of sales-tax exemptions, and moratoria.

PJM's governance became the states' second front, as governors facing bills their voters blamed on an operator they do not elect demanded a board more answerable to the states, and some threatened to leave the market. They won the price collar through Pennsylvania's complaint and the backstop purchase through the statement of principles of January 2026 (Module 12). No state has left, and a state running its own procurement would inherit the same shortage.

The politics are the midterms': electricity prices became a campaign issue in Virginia's and New Jersey's elections in 2025 and are one again before the vote on November 3, 2026. Candidates of both parties are running against the data centers' bills and for the data centers' jobs. The position that has emerged across the aisle, that the campuses pay their own way and households are held harmless, is easier to state than to carry out, for the reason 13b gives.

13d. Data Centers or Households: Who Should Pay

The data centers' case. The campuses are among the largest private investments in the country's history, with the largest technology companies planning about $715 billion of capital spending in 2026. They bring tax revenue to counties that had little, tens of thousands of construction jobs, and an industry the country has decided it must lead. They pay the rates of their class, fund the substations and lines that connect them, and sign the long contracts that make nuclear restarts and new gas plants financeable.

On this view the grid is being rebuilt after two decades of neglect, and every customer will use the rebuilt grid. The capacity price rose because the fleet was allowed to age on a flat forecast, and the campuses merely exposed it.

The households' case. A household that has used the same 1,000 kWh a month for twenty years now pays $20-35 a month more for capacity, because campuses that did not exist in 2022 draw a city's worth of power. The market monitor puts $9.3 billion of one auction and $6.3 billion of another on that load, and the long contracts secure the campuses' supply, not the region's.

The tax revenue goes to the county with the campus, while the capacity charge reaches every county in the zone. A line built to reach a campus in Loudoun County can end up on a household's bill in Baltimore. The rebuilding is real, but the households did not order it.

The evidence. Both cases are partly borne out: the monitor's estimates put a large share of the auction revenue on data-center load, but its own numbers also show prices would have more than doubled without that load. Where tariffs and direct assignment exist, as in Ohio and Virginia, they have moved costs to the campuses and thinned speculative requests. The base cost of an aged fleet sized for flat demand remains a cost everyone shares.

The course's reading. The increment is assignable and the base is not: the tariffs and the FERC orders are moving the increment, and the base is the aged fleet and the flat forecast that both cases name. The household would have paid more than $2 a month in any version of 2026, but not $25.

Module 13 Key Points

Who Pays

• The average residential price is forecast at 18.2 cents per kWh in 2026, almost 40% above the 2020 level.

• AEP Ohio's large-load tariff turned more than 30 GW of interest into 5.6 GW of signed agreements, separating requests from plans.

• Virginia now charges data centers directly for transmission built solely to serve them, cutting the household increase from $2.90 to $0.94.

• The states filed hundreds of data-center bills in 2026 and won a price collar and a backstop purchase; none has left PJM.

• The increment is assignable to the data centers and the base is not: households would have paid more in any version of 2026.

Module 13 Quiz

Check Your Understanding

1. What is the EIA's forecast of the average residential electricity price for 2026?

A) About 13.2 cents per kWh, the same as in 2020
B) About 25 cents per kWh, after a 40% rise in one year
C) About 15 cents per kWh, down from 2025 as gas prices fell
D) 18.2 cents per kWh

2. What happened to AEP Ohio's data-center pipeline under its large-load tariff?

A) It doubled
B) It moved entirely to Indiana and Pennsylvania within weeks of the tariff's approval
C) More than 30 GW of interest became 5.6 GW of signed agreements
D) It was frozen by the state commission until the 2027 rate case could be heard and decided

3. What did Virginia's State Corporation Commission order on July 31, 2026?

A) A moratorium on data centers
B) That Dominion charge data centers directly for transmission built solely to serve them
C) Dominion's exit from PJM
D) A cap on household bills at 2024 levels

4. Why does the module say no state has left PJM despite the threats?

A) A state procurement would inherit the same shortage
B) FERC forbids exit
C) The governors lost interest
D) PJM paid the states to stay, in a settlement that FERC approved with the price collar in 2025

5. What does the module conclude is assignable to the data centers?

A) The increment, not the base
B) Everything
C) Only transmission costs, and only in the regulated states of the Southeast
D) Only the capacity charge, and only after FERC rules on the show-cause orders

Module 14 — Policy and the Federal Turn

What Washington and the States Did

Recommended Reading / Reference

Reference: The Department of Energy's Section 202(c) orders and the Federal Register for the executive orders of 2025-26; the D.C. Circuit's September 11, 2026 decision on the first Campbell order; the Supreme Court's June 29, 2026 opinion in *Trump v. Slaughter*; and the Congressional Research Service's summaries of the July 2025 tax law's energy provisions

14a. The Emergency Powers

Section 202(c) of the Federal Power Act lets the Secretary of Energy order any plant to run when an emergency threatens the grid, and until 2025 it was used for storms and heat waves, a few days at a time. In May 2025 the department ordered Michigan's Campbell coal plant to keep running past its planned closure, and it has renewed the order every ninety days since.

The department issued 61 orders under the section in 2026 through September 25, and seven plants were being held open past their retirement dates. They are Campbell in Michigan, Eddystone 3 and 4 in Pennsylvania, Craig 1 in Colorado, Culley 2 and Schahfer 17 and 18 in Indiana, Centralia 2 in Washington, and Stanton 1 in Florida, and all but Eddystone burn coal.

The orders also reached beyond retirements: in late January 2026, during a winter storm, the department ordered plants to run at maximum output despite their permit limits, and it let operators and utilities from PJM and ERCOT to Duke Energy call on data centers' backup generators. On May 18, 2026, with more than 40 GW of PJM's plants out for maintenance and reserves forecast below 5,800 MW, it authorized PJM to move data centers onto their backup generation for three days, and it repeated the order on June 30 and through the summer.

The costs are measurable: Campbell's net cost reached $259 million through June 30, 2026, recovered from customers across the region under the orders' terms. On September 11, 2026 the federal appeals court in Washington vacated the first Campbell order and called Section 202(c) a 'limited backstop'. The ruling addressed the first order, and what it means for the renewals and the other plants is now being argued.

14b. Emergency or Overreach: The Argument Over the Orders

The case for the orders. The department and its supporters argue that the grid faces a real emergency: demand is rising faster than supply, the auctions are short, and NERC rates several regions at high risk of shortfalls. Retiring a working plant in that situation removes capacity that cannot be replaced for years, and the cost of keeping it, a few hundred million dollars, is small next to the cost of a blackout. The data-center orders, on this view, keep homes powered by asking the newest and largest loads to use the backup they already own.

The case against. States, consumer advocates, and environmental groups argue that a retirement planned years in advance is not an emergency, and that the statute was written for sudden events, not standing policy. They say the orders keep old, costly plants running at customers' expense without a vote and override the planning of operators and states. On this view the shortfall calls for faster connection of new resources, not an emergency power used as a resource plan.

The evidence. The shortfalls are real, as Module 12 shows, but the kept plants are small next to them, and only one of the seven, Eddystone, is in PJM, where the auction shortfall of 6,831 MW sits. Their costs can be counted, at $259 million net for Campbell through June 2026, and a federal appeals court has now held that the power is a limited backstop rather than a standing tool.

The course's reading. The emergency power can buy time at a measurable cost, but it cannot build supply. Used for days during a storm, it does what the statute intended, but used as a standing substitute for resource planning, it now stands on weak legal ground.

14c. The Executive Orders and FERC's Independence

- **Nuclear (May 2025):** four orders set goals of 400 GW by 2050 and ten large reactors under construction by 2030, imposed an eighteen-month deadline on NRC licensing decisions, ordered a rewrite of the licensing rules, and launched a fuel program for HALEU (Module 8).
- **Reliability and coal (April 2025):** orders directed the department to identify plants whose retirement would threaten reliability and to use Section 202(c) to keep them, and others promoted coal and set in motion the repeal of the Environmental Protection Agency's 2024 power-plant rules.
- **Wind:** the administration halted, suspended, or reviewed offshore wind projects from 2025 and slowed permits for wind on federal land, and the July 2025 tax law then ended the wind and solar credits for late starters (14d).
- **Large loads:** in October 2025 the energy secretary used a rarely invoked power to direct FERC to consider rules for connecting large loads to the transmission system, and FERC's show-cause orders of June 2026 took up the question (Module 10).
- **FERC's independence:** on June 29, 2026 the Supreme Court ruled 6-3 in *Trump v. Slaughter* that the president may remove a member of the Federal Trade Commission at will, overruling *Humphrey's Executor*, the 1935 precedent that had protected independent commissioners. The Court set the Federal Reserve apart, and lawyers read the ruling as almost certainly reaching FERC, whose commissioners could then be removed at will.

14d. The 2025 Tax Law

The July 2025 budget law rewrote the energy credits of 2022. The production and investment credits for wind and solar end for projects that begin construction after July 4, 2026, unless they enter service by the end of 2027. The credits for storage, nuclear, geothermal, and hydro survive on their original schedules, but projects using components from 'prohibited foreign entities', above all Chinese firms, lose them, a rule that bites hardest on batteries.

The production credit that supports existing reactors survives, as does the manufacturing credit for domestic solar, battery, and component plants, with the same content rules, while the credit for buying an electric vehicle ended on September 30, 2025.

The effects follow from Module 9: the build faces a rush before the deadline and a cliff after it, and the fastest resources the queue can deliver lost a large part of their economics just as demand rose. States with renewable standards, such as California and New York, now pursue their targets with less federal money, while states without them build gas in the rate base.

14e. The States' Four Paths

Most of the year's decisions were made in the states, and their choices sort into four paths. The first is the regulated build: Georgia's commission approved about 10 GW of new gas and battery capacity for Georgia Power, mostly for data centers, and let it sign campuses to long contracts, a model the Southeast follows.

The second is the restructured-state fight: Pennsylvania's complaint that capped PJM's auction, Maryland's challenge to the transmission it is asked to pay for and its rules for large loads, and Ohio's tariff. These are states that cannot build plants trying to govern the market that does.

The third is the Texas way: Senate Bill 6's rules for large loads, a state fund for new gas plants, and an energy-only market kept intact, after the 2025 legislature declined to pass bills penalizing renewables. The fourth is the pause: moratorium bills in several states, rollbacks of data-center tax incentives, and local zoning fights from Loudoun County to Arizona over where campuses may go.

Module 14 Key Points

Policy and the Federal Turn

• Section 202(c), once used for storms, held seven plants open past retirement, and the department issued 61 orders in 2026 alone.

• On September 11, 2026 the D.C. Circuit vacated the first Campbell order and called Section 202(c) a limited backstop.

• The emergency power buys time at a measurable cost, but it cannot build supply.

• *Trump v. Slaughter* overruled *Humphrey's Executor* in June 2026, and lawyers expect it to reach FERC's commissioners.

• The 2025 tax law ended wind and solar credits for late starters, and the states chose four paths: build, fight, Texas, or pause.

Module 14 Quiz

Check Your Understanding

1. How many plants were being held open past their retirement dates under Section 202(c) in September 2026?

A) About seventy, nearly all of them coal
B) One, the Campbell plant in Michigan
C) Seven
D) Twenty-two, across every market operator's region

2. What did the D.C. Circuit decide on September 11, 2026?

A) It upheld every order
B) It vacated the first Campbell order and called Section 202(c) a 'limited backstop'
C) It struck down the tax law
D) It ordered Campbell closed within ninety days

3. What did the Department of Energy authorize on May 18, 2026?

A) A rolling blackout in Maryland
B) The closure of the Campbell plant
C) A price cap on ERCOT's energy market for the rest of the summer, at $1,000 per MWh
D) PJM moving data centers onto their backup generation

4. What did the Supreme Court decide in Trump v. Slaughter?

A) That FERC must merge into the Energy Department
B) That the 202(c) orders are lawful emergency measures under the Federal Power Act
C) It overruled Humphrey's Executor
D) It upheld the tax law

5. Which credits did the July 2025 tax law end for projects starting construction after July 4, 2026, unless in service by the end of 2027?

A) Storage, nuclear, and geothermal, with limits on Chinese parts
B) Wind and solar
C) The manufacturing credits for domestic factories
D) The production credit that supports existing reactors

Module 15 — Where Things Stand, and What to Watch

The Argument, the Contradictions, and the Dates

Recommended Reading / Reference

Reference: PJM's auction schedule and the market monitor's reports; FERC's dockets on the backstop procurement, the Interim Resource Adequacy Service, and the show-cause orders; NERC's seasonal assessments; GE Vernova's quarterly results; and the NRC's dockets for the restarts and SMRs, which together will show whether the argument below holds

15a. The Argument

The grid in October 2026 is a machine that met the largest demand increase in a generation with the fleet it had. Generation set a record in 2025, and PJM, ERCOT, and SPP set peak records in July 2026. Retirements stalled, and PJM's auctions cleared at the cap three times running and fell short of the reliability requirement twice. The residential price is the highest ever, and PJM has asked FERC to let it curtail new large loads ahead of other customers from June 2027.

The build is real but on the wrong clock: solar and batteries arrive at 50-60 GW a year now, ordered gas from 2028, restarts from 2027, SMRs around 2030, and wires on a schedule of seven to ten years, the constraint to which every other one reduces. The demand is real and uncertain by a factor of two.

The money is moving, through tariffs, direct assignment, and the show-cause orders, toward the loads that caused the increment. The base cost of an aged fleet sized for a flat forecast has landed on households in the restructured states and on the rate base in the regulated ones.

The question the course opened with, mechanism before politics, has a provisional answer: the machine works, and the markets priced the scarcity as designed. The signal has not yet produced the supply, because supply runs on a slower clock than the signal. Who pays for the gap is being decided in fifty commissions, six market operators, one federal commission whose independence is in question, and an election.

15b. Five Contradictions

- **The signal and the supply:** the capacity price sat at the cap for three auctions, yet only 525 MW of new generation and uprates cleared in the latest one, so the price is right about scarcity and too early for supply.
- **The fastest resources and the firmest:** solar and batteries can be built in a year or two but count for 10% and 59% of their nameplate in PJM, while the firm resources count for 78-96% and arrive last.
- **The forecast and the requests:** the peak records of 2026 show that the growth is real, yet requests run at several times any plausible build, as ERCOT's 230 GW against a 91.1 GW peak shows, and building too much and building too little would both cost households.
- **The emergency and the law:** Washington used emergency orders to keep seven plants open and to move data centers onto backup power. A federal appeals court has now called the power a limited backstop, and the kept plants are small next to the shortfalls.

• **The increment and the base:** tariffs and FERC's orders can move the cost of new load to the campuses that caused it, but they cannot move the cost of an aged fleet that every customer relies on.

15c. What the Vote Will and Will Not Change

• **It will not change the physics or the clocks:** turbines arrive in 2028-32, restarts on their own dates, and wires in seven years, whoever wins on November 3, 2026. How much demand materializes depends on the economics of AI, not on the ballot.

• **It could change the federal posture:** a Congress with a different majority could hold hearings on the emergency orders and FERC's independence, attach conditions to appropriations, and revisit the tax credits. The executive branch's posture toward wind, solar, and the regulators remains the president's to set until January 2029.

• **It will shape the state agenda:** governors, legislators, and in some states elected utility commissioners will write the rate classes, cost rules, moratoria, and incentives of the 2027 sessions, and those choices decide where the next wave of campuses is built.

• **The calendar will move regardless:** PJM's December auction, FERC's rulings on the Interim Resource Adequacy Service and the show-cause answers, and the backstop procurement after February 28, 2027 all proceed on their own schedules.

15d. The Watch List

What	When	Why it matters
FERC's ruling on PJM's Interim Resource Adequacy Service	Requested by October 12, 2026	Whether new large loads without new capacity can be curtailed first from June 1, 2027
The midterm elections	November 3, 2026	The bill as a ballot issue; the limits on federal policy
PJM's 2029/30 Base Residual Auction	December 9-15, 2026; results December 22	Whether new capacity clears in volume under the collar
NERC's winter assessment, and the winter itself	November 2026 to February 2027	Whether the kept fleet and the new batteries hold through the cold
FERC's rulings on the operators' answers to the show-cause orders	Pending	Who pays for the wires that serve large loads, across six markets
The end of FERC's suspension of the backstop procurement	February 28, 2027	Whether PJM can buy 6,831 MW of new capacity on fifteen-year contracts
PJM's 2030/31 Base Residual Auction	May 12, 2027	The return to an auction three years ahead of delivery
The Interim Resource Adequacy Service, if approved	June 1, 2027	The curtail-first rule in practice
The Crane restart	Second half of 2027	The revival's first firm capacity in PJM
The wind and solar credit deadline; the end of PJM's expedited track	End of 2027	The cliff after the rush
Palisades	A new date after the NRC reviews Holtec's recovery request	Whether restarts can hold their schedules
The Duane Arnold restart	End of 2028 or early 2029	Iowa's reactor back, for Google
The end of the collar	After the 2029/30 delivery year, in May 2030	The auction without a cap, where PJM puts the price at about $555
The backstop's deadline for new resources	June 1, 2032	Whether long contracts produced new supply

15e. The Last Word

The throughline of fifteen modules is that the grid is the largest machine on earth and the only one that must balance every second, and every question about it resolves to that physics and the clocks it imposes. A generation of flat demand let the country stop building, and when demand returned, it came as a load that is large, flat, fast, and mobile, so the machine sized for the old world is being rebuilt while it runs.

Turbines arrive in five years, reactors in ten, and wires in seven, and in the meantime the markets price the gap as they were designed to, while households pay the price the design produces. The decision ahead, in the commissions, the market operators, the states, and the vote, is whether the increment goes to the campus and the base stays with the household, or whether the rebuilding the campuses set off is one everyone was going to need.

A reader who has followed the kilowatt-hour from the plant to the plug, through the merit order, the accreditation, the queue, and the rate case, can now read the next auction result, tariff docket, and blackout report for what they are: the physics collecting, and the argument over who pays.

Module 15 Key Points

Where Things Stand, and What to Watch

• The grid met the largest demand increase in a generation with the fleet it had: peak records, a capped price, and a shortfall.

• The build is real but on the wrong clock: solar and batteries now, gas from 2028, restarts by 2029, wires in seven years.

• The markets priced scarcity as designed, but supply runs on a slower clock than the signal.

• The November vote will not change the clocks; the auctions, FERC's dockets, and the 2027 state sessions move on the calendar.

• The decision is whether the increment goes to the campus and the base to the household, or whether everyone needed the rebuilding.

Module 15 Quiz

Check Your Understanding

1. Which contradiction does the module call 'the signal and the supply'?

A) The capacity price sat at the cap for three auctions while only 525 MW of new generation and uprates cleared in the latest
B) Prices fell while supply rose
C) Solar counts for 10% of nameplate
D) The forecasts were too low for the turbines ordered

2. When is PJM's 2029/30 Base Residual Auction held?

A) May 2030
B) July 14, 2026
C) February 28, 2027, once FERC's suspension of the backstop purchase ends
D) December 9-15, 2026, with results on December 22

3. Which of these does the module say the November vote will not change?

A) The federal posture
B) The physics and the clocks of turbines, restarts, and wires
C) The state rate classes
D) The agenda of the 2027 state sessions, including rate classes, cost rules, and moratoria

4. When does PJM's price collar expire, and what does PJM estimate the price would be without it?

A) December 2026; about $325
B) It is permanent
C) At the end of the 2029/30 delivery year, in May 2030; about $555 per MW-day regionwide
D) June 2027, when the new service starts; about $175

5. Which resources does the module say are fast to build but count for only part of their nameplate?

A) Solar and batteries
B) Gas
C) Nuclear restarts and uprates, which take two to four years
D) Transmission lines at 765 kV, which take seven to ten years to plan and build

Answer Sheet

Answers to every module's Check Your Understanding quiz.

Module	Answers
Module 1 Quiz	1. A 2. C 3. D 4. B 5. B
Module 2 Quiz	1. D 2. A 3. C 4. A 5. D
Module 3 Quiz	1. C 2. B 3. D 4. A 5. C
Module 4 Quiz	1. B 2. D 3. B 4. A 5. C
Module 5 Quiz	1. D 2. B 3. C 4. A 5. A
Module 6 Quiz	1. C 2. B 3. D 4. A 5. C
Module 7 Quiz	1. B 2. D 3. C 4. B 5. A
Module 8 Quiz	1. D 2. C 3. D 4. B 5. A
Module 9 Quiz	1. D 2. C 3. B 4. A 5. C
Module 10 Quiz	1. A 2. B 3. D 4. D 5. A
Module 11 Quiz	1. B 2. C 3. C 4. B 5. D
Module 12 Quiz	1. A 2. C 3. A 4. B 5. D
Module 13 Quiz	1. D 2. C 3. B 4. A 5. A
Module 14 Quiz	1. C 2. B 3. D 4. C 5. B
Module 15 Quiz	1. A 2. D 3. B 4. C 5. A