

How the Permitting Deal Works

The Bipartisan American Affordability and Jobs Act is the most comprehensive permitting bill yet

By Aidan Mackenzie

Introduction

On September 30, 2026, a bipartisan group of senators released the Bipartisan American Affordability and Jobs Act (BAAJA), a comprehensive bill to reform federal permitting and electrical transmission policy. The bill is the culmination of years of bipartisan effort and includes targeted solutions to permitting challenges across several domains. If enacted, the bill would be the most ambitious effort to streamline infrastructure permitting in modern American history.

While the bill's primary focus is energy infrastructure, the package includes proposals that would benefit transportation, housing, and other infrastructure, and would reduce regulatory burdens on federal agencies. Together, the bill's provisions aim to reduce energy bills, improve energy security, and build critical infrastructure.

The bill addresses 12 topics:

1. **Transmission:** Reforms to build transmission lines between regions, connect new energy faster, reduce inefficient investment, and deploy advanced technologies.
2. **NEPA:** Reforms to the National Environmental Policy Act (NEPA) to codify public comment and streamline judicial review.
3. **Permitting certainty:** Firm deadlines and limits on political interference with federal permits.
4. **The Clean Water Act:** Reforms to Sections 401 and 404 of the Clean Water Act (CWA) to ensure that review focuses on water quality.
5. **Historic preservation:** Reforms to Section 106 of the National Historic Preservation Act (NHPA) to codify consultation and streamline judicial review.
6. **Geothermal:** Reforms to streamline geothermal leasing and permitting.
7. **Mining:** Reforms to allow mines to build supporting facilities and expand hardrock mine leasing.
8. **The Endangered Species Act:** Reforms to the Endangered Species Act (ESA) to allow state assumption of ESA § 7 responsibilities.
9. **Hydropower:** Limits on mandatory conditions and a new license program for small hydrokinetic projects.

10. **Protecting ratepayers from data centers:** New requirements to make data centers pay for their costs to the grid.
11. **Federal lands, leasing, and rights-of-way:** Streamlined rights-of-way for renewables, clearer drilling permit requirements, and more Tribal control over rights-of-way on Tribal lands.
12. **Judicial review for energy and mining projects:** A new 150-day statute of limitations for lawsuits against energy and mining projects.

1. Transmission

America's energy ambitions can only grow as fast as its electrical grid. But today, the way transmission is owned and built on the US grid creates bad incentives that limit our ability to grow, deliver reliable service, and keep prices down.

There are four key limitations to expanding transmission:

1. The electrical grid is divided into regions, and the process for building transmission lines across regional borders is broken, raising costs and reducing reliability.
2. The utilities that own and operate the grid have a perverse incentive to invest in expensive local projects rather than coordinate to build more cost-efficient regional or interregional transmission.
3. The process for connecting new power to the grid is slow, delaying the ability to add needed generation for years as projects wait for approval in the interconnection queue.
4. Grid operators are slow to implement modern advanced transmission technologies (ATTs) that save time and money.

Problem 1: We don't build enough interregional transmission

America's grid is really a set of smaller grids, most of which are managed by regional planners that coordinate the regulated-monopoly utilities that own and operate transmission infrastructure.¹ The region-utility model works well to build transmission infrastructure within regions, but the incentives break down when high-voltage power lines are proposed *between* regions.

Under today's rules, we aren't building the infrastructure needed to transfer electricity from low-cost regions to high-cost ones — there are currently [zero miles](#) of high-voltage

¹ Regions either coordinate through Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs). However, there is a high degree of heterogeneity between regions; not all regions have regional coordinating entities, and not all utilities participate in ISOs or RTOs.

interregional transmission being planned or built under the flagship federal process.² The failure of interregional planning causes enormous underinvestment in new interregional transmission lines that would reduce costs and improve grid reliability.

The few major interregional transmission projects under development are merchant transmission lines, which are built by private developers outside the utility model. Even so, merchant transmission lines still face a gauntlet of siting, permitting, and cost-allocation challenges, and most fail. Of the 23 merchant projects over 100 miles that began planning between 2000 and 2015, only six reached construction, and the average time to begin construction was 13.7 years. For example, the TransWest Express transmission line, which is slated for completion in 2031, began planning in 2008.

Solution: BAAJA would amend the Federal Power Act to require transmission regions to jointly plan interregional capacity with their neighbors. The bill allows the Federal Energy Regulatory Commission (FERC) to set planning standards but leaves it to regions to conduct studies and choose specific interregional lines. The bill also revamps an authority for federal siting and permitting of transmission projects in the national interest.

Problem 2: Utilities overinvest in expensive local projects

Electric utilities have a perverse incentive to overinvest in expensive local projects that they control, rather than coordinate to build more cost-effective regional or interregional projects. As a result, households and businesses end up paying more for electricity.

Annual transmission investment averaged \$27.2 billion in 2017–2023, 1.7 times the 2004–2016 average of \$15.8 billion. Yet transmission capacity grew only 0.6% annually in 2017–2024, compared with 1.2% in 2004–2016, largely because utilities shifted toward building local projects.

Solution: BAAJA extends federal permitting and siting authority under Section 216 of the Federal Power Act to lines selected in regional planning if states deny a regional project. BAAJA also creates a new section in the Federal Power Act that allows states to refer public utilities to FERC for investigation if the state believes the utility has invested in inefficient local projects. If FERC finds the utility selected inefficient local projects or held up cost-effective regional ones, it may impose penalties, including docking the utility's regulated rate of return.

² There are [zero miles](#) of active [projects](#) in the [FERC Order No. 1000](#) interregional planning process. While there are a handful of projects that cross regional boundaries — such as the MISO-SPP [Joint Targeted Interconnection Queue](#) projects proposed in 2024 — those are closer to system upgrades than major interregional transmission capacity projects.

Problem 3: The interconnection queue delays new power

Adding new energy to the grid is bottlenecked by the interconnection queue, a virtual waiting line for new projects to get reviewed by grid operators. The median waiting period for new generation projects in the interconnection queue is roughly [five years](#), delaying new power supply and creating uncertainty for developers.³

Solution: BAAJA directs FERC to issue a new rule requiring transmission planning regions to consolidate interconnection and transmission planning, offer fixed-price interconnection at certain locations, and charge developers fees for joining and withdrawing from interconnection cluster studies. The bill also requires transmission providers to track data needed for interconnection studies.

Problem 4: Advanced transmission technologies aren't deployed fast enough

Grid operators have been slow to make use of ATTs to increase capacity on existing infrastructure, because the technologies clash with utility incentives and management practices.

Solution: BAAJA directs FERC to issue a rule requiring public utilities to evaluate ATTs and sets penalties for utilities that fail to deploy ATTs that pass a defined cost-benefit test. The bill also makes it easier to deploy ATTs in existing rights-of-way and on previously disturbed lands through new exemptions under NEPA and NHPA.

Interregional transmission

Background

Nearly all American electrical transmission infrastructure is built by utilities⁴ — regulated monopolies that own and operate power infrastructure and sell power to consumers, known as ratepayers.⁵ Utilities hold a monopoly on distribution and transmission infrastructure, but they cannot charge monopoly prices because they are regulated.⁶ Instead, utilities make money by earning a regulated rate of return on their investments in

³ The measure of five years is for adding new generation and battery storage capacity, not adding new load.

⁴ The exception is merchant transmission lines built by private developers.

⁵ The utility model exists to solve a collective-action problem — every home and business wants the benefits of transmission infrastructure, but no single entity is willing to pay for the entire line. Because utilities maintain a monopoly on grid infrastructure, they are willing to pay for transmission infrastructure up front knowing they can pass along the costs to ratepayers.

⁶ Some utilities are “vertically integrated,” meaning they control a monopoly on the distribution, transmission, and energy generation infrastructure. In this model, utilities plan and build generation infrastructure and earn a regulated rate of return based on the utility's costs. In “deregulated” markets, utilities only own the distribution and transmission infrastructure; the energy production is carried out by private companies that sell energy to the utility at competitive prices.

power infrastructure. Since their returns are a function of infrastructure investment, utilities are motivated to build more. However, because the cost of new projects is passed on to ratepayers, states have set up utility regulators to review and approve projects in the public interest.

In much of the country, utilities coordinate with each other through entities called Regional Transmission Organizations (RTOs), non-profit organizations that do not own any utility assets but manage the regional grid and coordinate planning and cost allocation for high-voltage regional transmission lines.⁷ Large regional projects are often more efficient for moving more power across a wider market for less cost — by analogy, while each state could theoretically build small roads to accommodate interstate traffic, large interstate highways are far more efficient. Connecting utilities using regional infrastructure increases efficiency; connecting regions can increase it further. However, building interregional transmission lines introduces significant conflicts with utility incentives:

1. Neighboring regions almost never agree to approve (“select”) interregional lines in their planning processes because they can’t agree on how to model their benefits. For regions to select an interregional line, the project must clear each region’s planning process. But each region models needs and benefits independently, considering future capacity needs, load growth, and reliability strains. These studies also often undervalue the benefits of interregional lines, such as the insurance they provide against strains caused by severe weather. Differing priorities make it extremely difficult for a proposed interregional line to secure approval from both regions. Moreover, under FERC regulations, the cost of an interregional line must be split based on who benefits — but because the regions don’t agree on how to measure benefits, one region may see itself as paying too much. If regions fail to jointly select a project, there is no federal mechanism to resolve planning disagreements and advance the process, and no penalty for inaction.

2. Interregional transmission lines connect electricity generators in one region to buyers in another. This cuts into the monopoly on generation that vertically integrated utilities enjoy and forces market competition onto energy suppliers in generation-constrained regions.⁸ For example, the New England Clean Energy Connect (NECEC) transmission line was proposed to bring Canadian hydropower into generation-constrained New England. But NextEra, an incumbent generator in the Northeast that was able to set high energy

⁷ “Transmission region” is a term of art. Where an RTO exists, that counts as the region. Where there is no RTO, the region is defined more loosely. For the purposes of BAAJA, FERC will designate regions along the lines described in FERC Order No. 1000.

⁸ For vertically integrated utilities, the cheap electricity brought in by interregional lines doesn’t undercut their current investments — everything they’ve already invested in can be passed along to ratepayers — but it can eliminate the case for future generation investments. In deregulated regions, new supply from other regions can undercut regional energy suppliers, leading to opposition from those suppliers.

prices because of regional energy supply constraints, opposed the transmission line and spent [\\$20 million](#) to help pass a Maine state referendum to block it. NECEC only survived because the Supreme Court of Maine overturned the referendum after years of delay.⁹

3. Interregional lines often pass through states that they do not serve. Even when interregional transmission lines are built by merchant developers, the lines require approval by state commissions that are often obligated by state law to only certify lines that benefit their state.¹⁰ Rock Island Clean Line, which would have connected Iowa and Illinois, had its approval [vacated](#) in 2017 because the project developer did not qualify as an eligible public utility in Illinois.¹¹

The lack of federal authority over interregional transmission compounds the barriers to new lines. While interstate gas pipelines are sited and permitted at the federal level by FERC, interregional transmission lines are not federally sited, meaning they must painstakingly obtain land and permits on a case-by-case basis.

Recent efforts to fix incentives for interregional transmission have failed:

- a. The Energy Policy Act of 2005 created a path for federal siting and eminent domain, but this authority has failed to produce any new lines.¹²
- b. FERC [Order No. 1000](#), issued in July 2011, attempted to promote interregional transmission by requiring regions to coordinate, but failed to resolve interregional line selection conflicts.¹³ In the 15 years since, the order has not led to a [single](#) major interregional project.
- c. FERC [Order No. 1920](#), issued in 2024, requires adjoining regions to revise coordination procedures, but has again failed to solve the central problem that interregional lines must be selected in both regions' individual regional plans.

⁹ The Supreme Court of Maine [held](#) that the referendum couldn't apply if the project had vested rights, which a jury later [found](#) it did.

¹⁰ In addition to public convenience and necessity requirements, pass-through lines are often opposed by landowners and conservationists, further pushing states to oppose lines that pass through their territory.

¹¹ Lower courts found that the line did not meet the state's "public use" requirement. The final decision by the Illinois Supreme Court [vacated](#) the line's approval on the ground that the developer did not count as a "public utility" in Illinois because it did not own transmission in the state. The Illinois Supreme Court declined to answer the "public use" question because not being a public utility was sufficient to uphold vacatur.

¹² The Energy Policy Act of 2005 created an authority for interregional transmission that would unlock FERC authority to site and use eminent domain for lines in the national interest. However, the program — called the [National Interest Electric Transmission Corridors](#) — has never been used successfully.

¹³ FERC Order No. 1000 requires regions to set joint cost-allocation methods for interregional lines.

The problem: Interregional planning has failed; merchant lines can take decades

A modern, reliable power grid that can handle demand growth without raising costs requires the ability to transfer power across transmission regions. But the process to build interregional lines is broken; interregional planning under FERC Order No. 1000 has failed to produce a single major interregional transmission line. Without congressional action to require utility regions to plan and site interregional transmission lines, hardly any will get built.

Today, the only major transmission projects that cross regional boundaries are merchant transmission lines built outside the utility process. Even so, hardly any major merchant lines are built, and the few that do take more than a decade to even begin construction. Based on [analysis of 23 merchant lines](#) longer than 100 miles that began between 2000 and 2015, only six reached construction.¹⁴ And three of those projects were only built after public authorities agreed to take on the cost of the lines. On average, it took these six lines 13.7 years to go from proposal to beginning construction, including completing planning and permitting, and securing a buyer for the delivered power.¹⁵

BAAJA's solution: Interregional planning and developer-led transmission lines

BAAJA proposes to fix interregional transmission through a two-pronged approach: requiring interregional planning and enabling a private developer-led process.

Interregional planning

The first prong, Section 2103 of BAAJA, would add a new Section 225 to the Federal Power Act, mandating interregional planning. Each transmission planning region would be required to prepare a joint interregional planning process with neighboring regions, either as pairs or small groups. To address a core obstacle in interregional planning, regions must agree on a common method for modeling a project's benefits and cost allocation.

¹⁴ We define merchant transmission lines as developer-initiated projects that take on the financial risk of the project, rather than relying on the captive ratepayer utility model. For this set of examples, we count any project that began between 2000 and 2015, including lines that began as merchant lines but were later bought by utilities or became state-backed projects. Measurement ends in 2015 to avoid clogging the set with projects that haven't had enough time to reach an outcome. Although this count is not exhaustive, we did not find a single long-haul merchant transmission project initiated after 2015 that has reached construction.

¹⁵ For this measure we looked at the time needed to permit, site, and find a power contract buyer for long-haul (>100 miles) merchant transmission lines. Only six lines fit the criteria of being merchant lines, >100 miles, and beginning construction. Of those, the average time from proposal to construction is 13.7 years and the median is 13.5 years.

More specifically, the new interregional planning process must establish unified ways to evaluate six required benefits: improved reliability, reduced congestion, reduced power losses, improved carrying capacity, reduced operating reserve requirements, and access to cheaper generation. These benefit calculations will help determine who pays for the new line. Planners must also consider alternatives to building new lines, such as upgrading (“reconductoring”) existing lines.

FERC must approve each interregional planning process, but interregional planning and deciding whether or not to select interregional lines are left to the regions. These reforms keep regions in the driver's seat while incentivizing them to build interregional lines.

Once an interregional line is selected, the line's owner must propose a cost-allocation schedule based on a “beneficiary pays” method. FERC will then review the proposal and approve or deny it based on whether the schedule accurately assigns costs to the ratepayers who benefit.

BAAJA incentivizes regions to build interregional lines by deeming lines selected in interregional planning to automatically satisfy every criterion required for federal siting and permitting authority under Section 216 of the Federal Power Act, except the requirement for state action.¹⁶ In other words, if an interregional line is selected in interregional planning, but individual states along the route refuse to grant siting or permitting to the selected line, the project becomes eligible for federal backstop siting and permitting under Section 216. This would be a major boost for interregional transmission: planners would have more discretion to select lines that meet their benefits criteria, without being beholden to the political interests of each state.

BAAJA sets clear requirements for interregional planning and makes it easier for regions to build interregional transmission. But these provisions deliberately don't have teeth: if planners ignore FERC's directions, there are no clear punishments. The teeth to enforce interregional planning are built into the bill's second prong, a developer-led process for building interregional transmission.

Developer-led planning

The second prong of interregional reform is the developer-led process in Section 2101 of BAAJA. This new process would allow developers to circumvent states, utilities, and regional planning authorities to build needed transmission infrastructure. To create this authority, BAAJA fixes an existing provision in the Federal Power Act — called National Interest Electric Transmission Corridors (NIETCs) — that already allows FERC to site and

¹⁶ This bypasses the requirement that a line be at least 230 kV, meaning selected interregional lines below 230 kV may still qualify for Section 216.

permit interstate transmission lines under Section 216.¹⁷ Under current law, federal authority to site and permit lines within NIETCs requires the Department of Energy (DOE) to designate corridors, a process that takes at least several years and comprehensive NEPA review. BAAJA would remove the need for corridors and allow developers to propose lines in the national interest, subject to certain criteria.¹⁸

Under the updated process, developers would be required to propose either intraregional or interregional lines and apply for state approval. If the state denies the permit or ignores the developer's application for more than a year, FERC "shall" consider the proposal. If the project meets certain criteria and FERC judges the line to be in the national interest, FERC "shall" grant federal siting and permitting to the line — bypassing state authorization and allowing the line to use federal eminent domain. This creates a path outside the region-led planning process, opening a market for developer-led proposals to fill gaps in the grid left by poor incentives.

To bolster the developer-led solution, BAAJA allows FERC to begin processing applications for large transmission lines (at least 345 kV) as soon as the application is submitted to the states. However, FERC cannot site the line unless the state denies it or fails to act within a year. The bill also designates FERC the lead agency for any required federal permits for developer-led lines that receive federal backstop authority under Section 216, and for all lines selected under Section 225.

For developer-led lines granted federal siting and permitting, BAAJA creates a process for determining cost allocation. The developer of the proposed line would file its own rate schedule with FERC, assigning the costs to the customers who benefit. FERC would review the proposed schedule under the "just and reasonable" standard, evaluating it based on the same six benefits prioritized in interregional planning — improved reliability, reduced congestion, reduced losses, carrying capacity, reduced reserve requirements, and increased access to generation. FERC would then issue a ruling accepting or rejecting the rate schedule, ensuring customers that do not benefit are not required to pay.

¹⁷ NIETCs were established in the Energy Policy Act of 2005. The authority has been unused since its creation for two reasons. First, the law was intended to apply to lines in the national interest that states had ignored or denied permits to. But a drafting error resulted in a court finding in [Piedmont Environmental Council v. FERC](#) that the law did not cover affirmative denials — making NIETCs useless until 2021, when the authority was fixed in the Infrastructure Investment and Jobs Act. Second, NIETCs require DOE to designate transmission corridors, a process that can take ten or more years and requires several lengthy reviews, including the preparation of a comprehensive NEPA review covering the entirety of the corridor.

¹⁸ To be eligible for Section 216, the applicant must propose a project that (1) has been denied or ignored by the state regulator for over a year, (2) is an interstate, international, or offshore project, (3) fits the public interest, (4) improves reliability, (5) is at least 230 kV, and (6) makes the most of existing infrastructure and corridors if the project involves upgrading existing infrastructure. See BAAJA Section 2101(b)(3).

BAAJA helps merchant transmission lines by creating a path for developers to convert their projects into transmission lines funded by ratepayers through cost allocation. Between that and granting qualifying developer-led lines federal siting and permitting, BAAJA addresses all three of the major challenges merchant lines face.

The bill's two prongs work together to build interregional transmission. Interregional planning is the primary solution, giving transmission regions the first crack at planning and selecting interregional lines. If the region-led planning process fails, the developer-led process offers a viable alternative. This strongly incentivizes regions to plan effectively and handle interregional connections themselves — if they fail to build the needed lines, developers will be in a strong position to go to FERC and take projects away from regions and utilities.

Inefficient utility investment

Background

Investor-owned electric utilities make a profit by investing in new infrastructure, passing the cost to ratepayers and recovering a regulated rate of return. For utilities, the model works best within their geographic area of control — for local projects, the utility is guaranteed to be the sole proprietor and collect the regulated rate of return. At the regional level, however, projects are often split between several utility areas, introducing conflict over planning, ownership, and cost allocation. Moreover, some regional projects are awarded through a competitive bidding process, further reducing an individual utility's certainty that it will own the new investment.¹⁹

The uncertainty of regional projects strongly incentivizes utilities to prefer local projects they know they will control. A study by the Congressional Budget Office (CBO) [shows](#) the resulting shift in utility investment over the past decade — in the MISO and PJM regions, the share of transmission investment going to local lines increased from 30% to 80%.²⁰ Local projects, such as replacing existing capacity or reliability enhancements, are also preferable for utilities because they receive far less regulatory scrutiny — regulators have little visibility into whether the local projects are necessary or whether they could be handled more efficiently at the regional level.

¹⁹ FERC Order No. 1000 removed the federal “right of first refusal,” allowing regions to set up competitive bidding. Only some regions have embraced competition.

²⁰ MISO is the Midcontinent Independent System Operator, covering most of the northern Midwest; PJM is the RTO covering Pennsylvania, New Jersey, Maryland, Washington DC, Virginia, Ohio, West Virginia, and parts of North Carolina, Indiana, and Illinois.

While FERC acted in [Order No. 1920](#) to require regional planners to consider whether lines due for replacement could instead be upgraded to carry more power, neither FERC nor regional planners have authority to override utility decisions.

The problem: Utilities overinvest in expensive local projects

Utilities' perverse incentive leads them to [overinvest](#) in local projects and underinvest in regional ones. This skew is highly inefficient — building high-voltage regional lines is far less expensive on a cost-per-capacity basis than building many lower-voltage local lines.

Data reflects this inefficiency. The Energy Information Administration's (EIA) data shows annual transmission capital investment increased from \$15.8 billion in 2004–2016 to \$27.2 billion in 2017–2023.²¹ But despite a 70% increase in spending in 2017–2023, new transmission capacity on the grid only grew 0.6% a year in 2017–2024, down from 1.2% in 2004–2016. The added investment has overwhelmingly gone to local projects: roughly two-thirds of new transmission mileage completed since 2021 is low-voltage, and 90% of transmission projects are driven by reliability needs.²²

The utility preference for local projects undercuts America's ability to build a newer, more effective grid, rather than merely replace the system we already have. Much of the US grid was built in the '60s and '70s, and the bill for replacing that infrastructure is now coming due. While updating existing infrastructure is necessary, it does not add capacity. Moreover, there is a huge opportunity cost when utilities pursue local projects over regional ones.²³

BAAJA's solution: Boost regional projects and allow FERC to investigate utilities

Section 2103 of BAAJA requires regions to conduct regional planning. As with interregional planning, regions would have to establish common inputs, measures for the six benefits, cost allocation based on the "beneficiary pays" principle, and selection criteria. Unlike interregional planning, these processes largely already exist under FERC Order Nos. 1000 and 1920.

BAAJA's novel intervention is that lines selected in regional planning are also made eligible for federal permitting and siting authority under Section 216 of the Federal Power Act if a state denies or fails to review a proposal. This creates a path forward for critical

²¹ These figures are based on the chart showing annual transmission investments in EIA's 2024 [report](#).

²² CBO's 2026 [report](#) defines low voltage as <230kV.

²³ For commentary on the missed opportunities of replacing existing lines without considering optimal regional lines, see Brattle Group's 2021 [report on transmission planning](#) and this [FERC statement](#).

regional projects that might otherwise be blocked by a state that the project passes through.

The real teeth in BAAJA to discourage overinvestment in local projects come from Section 2104, which allows states to petition FERC to investigate a public utility's local planning and development process. The bill requires FERC to act on a state referral and gives FERC full authority to investigate and determine whether the utility is failing to select cost-effective local facilities or interfering with the selection of cost-effective regional projects. If FERC makes this finding, it may impose penalties, including cutting the utility's rate of return on its investments in local transmission facilities, ordering changes to the utility's planning process, removing the presumption of prudence (regulatory deference to utilities on local projects) for local facilities, and issuing fines of up to \$5 million per facility, paid to the state.

Finally, Section 2105 of BAAJA bans a federal right of first refusal, codifying an existing limit established under FERC Order No. 1000 in 2011. Prior to the order, incumbent utility owners had the right to build a project in their service territory, preventing competitive bidding; FERC Order No. 1000 eliminated the federal right of first refusal, allowing regions to use competitive bidding processes for regional projects if they choose. BAAJA prevents federal regulation from recreating a federal right of first refusal, ensuring a federal ban on competitive bidding cannot be enacted.²⁴ The restriction would not limit state rights of first refusal, which some states have enacted.

Interconnection queue

Background

Before new energy supply or large buyers can connect to the grid, projects must wait in an interconnection queue while grid operators check whether the current infrastructure can manage. Operators need to verify grid capacity and confirm that the existing electrical lines, substations, and other infrastructure can move a larger volume of power. They also need to preserve reliability by verifying that the grid can provide sufficient power under maximum strain, such as when storms knock out power lines or weather drives up heating or cooling demand. If the existing infrastructure is insufficient, grid operators determine which upgrades are needed and pass those costs to developers.

²⁴ This provision likely eliminates the partial federal right of first refusal within FERC Order No. 1920, which allows incumbent utilities to build regional replacements of local projects without going through competitive bidding.

The problem: The interconnection queue delays new power

New power is bottlenecked by the interconnection queue. As of 2025, [2,061 gigawatts](#) of proposed power and storage across 8,200 projects were waiting in interconnection queues with an expected wait time of roughly [five years](#).²⁵ The long lead times often deter developers from pursuing projects or lead to cancellations if the project's economics sour during the wait — input costs may rise or tax policy may change in the meantime.

The interconnection queue is clogged by speculative applications. Because the approval process is so long, developers are incentivized to apply early to begin moving up the queue, even if they may not move forward with the project. This adds delay by inflating the number of projects in line, and complicates review because operators cannot be sure proposed projects will actually get built. When projects do get canceled, operators need to redo their models of how the grid will function with added generation or load. That new analysis may pass a greater upgrade cost to later applicants, potentially causing a cascade of cancellations.

The interconnection queue also creates uncertainty because developers cannot know the cost to connect until they reach the front of the queue. Developers cannot do their own estimates because interconnection studies are opaque and based on bespoke measurements and models of the existing infrastructure. This means even after waiting through the queue, developers may find their project is not financially viable.

Attempts to improve this process have seen middling success. FERC [Order No. 2023](#) directed utilities to change their interconnection process from “first-come, first-served” review of individual projects to “first-ready, first-served” review of clustered projects, aiming to prioritize fully committed projects and review projects together as a group. However, uptake has been fraught and inconsistent because the order requires a substantial rewrite of many transmission providers’ interconnection processes.

BAAJA’s solution: Require regions to overhaul interconnection

BAAJA proposes three new requirements to improve interconnection review:

1. Section 2106 of BAAJA directs FERC to establish new rules that:
 - a. Require transmission regions to consolidate their generation and transmission planning processes. Regions would be required to consolidate interconnection and regional transmission planning to establish how needed generation and transmission can be planned together.

²⁵ The five-year expected wait time is based on the [median time](#) for projects that made it to the top of the queue and underwent review. Changing conditions like market fluctuations, varying project mixes, or fewer projects dropping out of the queue could affect wait times.

- b. Require regions to publish planned connection points and establish a fixed cost to connect to the grid.
- c. Require regions to carry out cluster studies to review multiple proposed projects together.
- d. Require regions to implement nonrefundable financial security and withdrawal penalties for developers that enter the queue.
- e. Require regions to define a “single decision point” in the interconnection review process at which developers must decide to either move forward or withdraw from the queue.²⁶

2. Section 2110 of BAAJA requires FERC to initiate rulemaking to facilitate automated interconnection queue review for large-generator interconnection. FERC is to require transmission providers to “share and employ, as appropriate” queue management practices, including the use of “artificial intelligence, machine learning, and automation.”²⁷ The language of Section 2110 is relatively sparse, leaving the details to FERC.

3. Section 2111 of BAAJA requires transmission providers to collect and share grid data needed for interconnection studies, including facilities studies, feasibility studies, and affected-systems studies. If providers do not already track this data, they must begin doing so. Transmission providers are also given authority to request data from any user, owner, or operator of assets on the bulk power system, who must respond within 15 days. Lastly, Section 2111 tasks FERC and DOE with establishing standard formats for the needed data.

The proposed set of interventions comprehensively targets the interconnection queue’s current failures. Queue automation, cluster review, and joint generation and transmission planning would accelerate review. Mandating cluster studies and instituting withdrawal penalties would reduce speculative applications, and establishing a fixed connection cost would cut uncertainty for developers.

Advanced transmission technologies

Background

Advanced transmission technologies (ATTs) can improve grid efficiency and reliability without requiring traditional infrastructure expansion. These include:

²⁶ BAAJA, Section 2106.

²⁷ BAAJA, Section 2110(a).

1. Modern sensors installed on power lines to give real-time feedback on temperatures, allowing the grid to operate at a higher capacity most days of the year;²⁸
2. Software that can optimize capacity within existing systems, such as [advanced power flow control](#) and [topology optimization](#); and
3. Hardware upgrades, like advanced conductors, which can add capacity by allowing infrastructure to carry more current at higher temperatures.

The problem: Advanced transmission technologies aren't deployed fast enough

While some utilities do adopt ATTs, perverse incentives have slowed broad uptake. Utilities prefer more capital-intensive projects such as full rebuilds of existing lines over ATTs, which could offset the need for bigger projects that are more likely to increase a utility's rate base.

FERC has repeatedly [encouraged](#) operators to adopt ATTs, but its orders have been limited, merely requiring utilities to consider deploying ATTs rather than mandating their usage outright or setting penalties.²⁹

BAAJA's solution: Require utilities to prioritize ATTs

BAAJA creates requirements and incentives for ATTs, which include optimization technologies as well as advanced conductors, HVDC, and energy storage. The bill directs FERC to require the use of ATTs when they pass cost-benefit analysis, and streamlines regulatory review to ease uptake of ATTs.

Section 2109 of BAAJA directs FERC to assume use of ATTs is prudent and use its authority under Sections 205 and 206 of the Federal Power Act to require public utilities to use ATTs when building or upgrading facilities in FERC's jurisdiction. It further directs FERC to issue a rule ordering public utilities to run cost-benefit analyses for using ATTs and deploy ATTs wherever their use exceeds a benefit-cost ratio of one. If a public utility finds a benefit-cost ratio greater than one but fails to deploy the ATT, then FERC must impose a penalty, which will be set in the rule. The bill also directs FERC, with DOE, to establish a method for determining what counts as a "best-available" conductor. The bill excludes public power, many co-ops, and most of ERCOT, the grid that covers most of Texas, from FERC's order.³⁰

²⁸ The capacity of power lines is affected by high temperatures. Grid operators typically handle this by keeping line capacity low enough to ensure there is enough headroom during peak temperatures. Sensors can be used to measure temperature and wind and provide real-time data on a line's capacity, allowing operators to get more out of existing lines.

²⁹ [FERC Order No. 881](#) is an exception: it mandated "ambient-adjusted" line ratings.

³⁰ ERCOT is traditionally separate from FERC's control.

Section 2103 requires regional and interregional planning processes to consider the use of reconductoring and advanced conductors when completing planning, further boosting adoption of ATTs.

Sections 2102 and 2214 reduce regulatory friction to implementing ATTs:

- Section 2102 creates a blanket exemption from NEPA and NHPA § 106 review for activities within existing rights-of-way that maintain or increase grid capacity. This covers virtually all ATT deployments and related upgrades, including reconductoring, switching to higher operating voltages, adding circuits, installing advanced conductors, and adding storage. The exemption applies so long as ATTs are installed within an existing right-of-way where a transmission or distribution facility already exists.
- Section 2214 directs the Department of the Interior and the Department of Agriculture to develop or adopt existing categorical exclusions that cover reconductoring, battery installation, and implementing other grid-enhancing technologies. While these categorical exclusions would be redundant where the Section 2102 exemptions apply, they would cover projects outside Section 2102's parameters, such as installing batteries on previously disturbed federal lands that are not within an existing right-of-way. Section 2214 categorical exclusions would also apply to new transmission lines within approved federal right-of-way corridors, such as energy corridors approved under Section 368 of the Energy Policy Act of 2005.

Additional transmission provisions

Federal court review for transmission lines

Section 2101(f) requires decisions issued by states that affect a federal authorization for a transmission line to be reviewed in federal court — either the federal circuit court of appeals where the utility is located, or the DC Circuit. This means state decisions such as denying a certification under § 401 of the Clean Water Act get reviewed in federal court rather than state court. This provision extends an existing policy for natural-gas pipelines to transmission lines.

Payments for pass-through communities

Section 2101(h) allows transmission lines that receive federal permitting and siting under Section 216 or lines selected in regional or interregional planning to pay local jurisdictions that they pass through for disruption. The section allows the project owner to recover

those costs through cost-allocated transmission rates. This gives pass-through communities a stake in federally sited transmission projects.

Reforms for distributed energy resources

Section 2108 lets distributed energy resources, including small batteries, generators, and fuel cells in homes, earn money in wholesale power markets. The section specifies that, 18 months after enactment, it will not be “just and reasonable” for a grid operator to keep rules that prevent qualified aggregations of distributed energy resources from participating in energy, capacity, and ancillary-services markets. Facilities must be at least 5 kW, and aggregated resources must be at least 100 kW.

Added staff capacity for FERC and DOE

Section 2241 expands FERC’s special hiring authority to cover economists and lawyers, allowing FERC to expand staff capacity needed to implement its expanded authority. Section 2112 gives the Power Marketing Administrations, regional agencies within DOE that sell power from federal hydroelectric dams and operate transmission networks, authority to set competitive salaries to increase staff capacity.

2. NEPA

The National Environmental Policy Act (NEPA) mandates environmental review for all major federal actions, requiring agencies to evaluate the effects of a proposed action, analyze potential alternatives, collect public input, and make a reasoned decision based on that information. While NEPA originally required a short report, judicial review has transformed NEPA compliance into a process that can take years, delaying infrastructure of all kinds and straining federal agency capacity. The average NEPA Environmental Impact Statement (EIS) is [1,703 pages](#) and takes [4.5 years](#) to complete.³¹

Litigation has become a defining feature of NEPA. After agencies prepare NEPA reviews and issue decisions, third-party litigants can challenge the government’s decision in court. These lawsuits take years and can even shutter projects during construction.³² The mere threat of litigation is costly — developers and agencies prepare exceedingly thorough reviews to reduce the risk of losing on technical details in court. NEPA’s delays and the threat of litigation create a silent graveyard of projects that never begin.

³¹ These measures are based on CEQ’s 2020 [NEPA data](#) (which covers 2010–2018). The 1,703-page count includes both EIS base documents and attached appendices. CEQ’s January 2025 report (covering 2010–2024) is harder to evaluate but, when controlled for the same start and end times (time from notice of intent to record of decision), finds a 4.4-year average.

³² For example, the [Mountain Valley Pipeline](#), the [Dixie Meadows](#) geothermal project, and the [Cardinal Hickory Creek](#) transmission line were all halted or forced back into review during construction by NEPA lawsuits.

BAAJA proposes significant reforms to NEPA. The bill clarifies NEPA's process and requirements, sets deadlines, reduces uncertainty for agencies, and ensures public input is protected in statute. The bill also proposes limits on judicial review, setting a 150-day statute of limitations, new standing requirements, and preventing courts from halting construction based on an insufficient NEPA review alone.

Background

NEPA establishes environmental review, requiring agencies to look before they leap: for all "major federal actions," the lead federal agency must determine whether or not the action has significant effects on the environment. If the action will have significant effects or if the significance of the effects is unknown, the agency must produce a report analyzing whether, and how, the proposed action would significantly affect the environment, evaluate potential alternatives, and make a reasoned decision on how to proceed based on that analysis. NEPA is a procedural law, meaning it prescribes a process but does not mandate any specific outcome or require the federal government to prioritize environmental protection over other goals.

Since its enactment in 1970, NEPA has become a sprawling, open-ended obligation on federal agencies. The original NEPA statute was short, but questions such as what constitutes a "major federal action" or a "significant effect on the human environment" were left unanswered by the law. In 1978, the Council on Environmental Quality (CEQ) issued regulations to interpret NEPA and structure agency compliance. CEQ established the three tiers of NEPA review: Environmental Impact Statements (EISs), Environmental Assessments (EAs), and Categorical Exclusions (CEs). The regulations reduced legal uncertainty but increased the work required to complete environmental review.

While Congress never established a process for judicial review under NEPA, federal courts allow lawsuits to challenge an agency's NEPA compliance through the Administrative Procedure Act (APA).³³ These lawsuits impose significant costs on federal agencies and developers. Lawsuits can take several years and, if plaintiffs win, courts may overturn the agency's decision, forcing the agency to conduct more review. Even if litigants lose their challenges, they are often able to stall projects for years because courts typically issue preliminary injunctions to halt development until the lawsuit concludes.

Recent reform efforts and court rulings have attempted to limit NEPA's scope:

³³ The APA creates a private right of action for private citizens to challenge agency decisions, legally defined as "final agency actions." Private parties can bring an APA suit to challenge whether an agency decision was "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." This creates a hook for challenging an agency's compliance with NEPA, allowing a litigant to allege that the agency either failed to comply with NEPA entirely, or failed to analyze one or more environmental effects of the proposed action in their review.

- The Fiscal Responsibility Act of 2023 established NEPA review timelines, requiring agencies to complete EISs in two years and EAs in one year. However, significant uncertainty remains, and the timelines have mostly been ignored because agencies would rather conduct an exhaustive review that reduces litigation risk than meet an unenforced statutory deadline.³⁴
- In 2025, the Trump administration [eliminated](#) the NEPA regulations issued by CEQ, following a DC Circuit decision that [undercut](#) CEQ's rulemaking authority.³⁵ The result has been fewer formal regulatory requirements on federal agencies under NEPA, but at the cost of increased uncertainty. Agencies must still do much of the same work because many courts continue to enforce NEPA based on precedents that require extensive NEPA review.
- In [Seven County Infrastructure Coalition v. Eagle County](#), the Supreme Court directed courts to give greater deference to federal agencies when deciding NEPA cases. However, this is unlikely to result in a [durable change](#) — NEPA cases are complex and unique, giving judges ample room to pay lip service to agency deference while still ruling against infrastructure projects.

The problem: NEPA reviews are burdensome and vulnerable to litigation

NEPA reviews burden both federal agencies and private project developers. And because litigation of NEPA reviews is so common, federal agencies often focus more on "litigation-proofing" their reviews — adding details and analysis in anticipation of legal challenges — than they do on writing documents that are useful for the public.

NEPA is the most litigated environmental statute because the law requires wide-ranging analysis but does not provide clear benchmarks or thresholds. Consequently, project opponents have a large attack surface — how much analysis is required, what the threshold for a "significant impact" is, and how many "reasonable alternatives" agencies must consider are all underspecified. Courts must decide whether the agency adequately evaluated a project's effects on a complex, often unique environment, including concerns beyond traditional environmental policy, making litigation outcomes unpredictable and costly.

³⁴ The timelines are also difficult to enforce because agencies can control the formal initiation and conclusion markers for the timelines. For example, an agency may delay issuing a formal "notice of intent" to prepare an EIS until after completing a significant amount of the required documentation. This allows the agency to complete the review within the deadline, while in fact the real time cost exceeds two years.

³⁵ In [Marin Audubon Society v. FAA](#), the DC Circuit held that CEQ did not have authority under NEPA to issue binding regulations. Before that decision could be tried in other circuits or go to the Supreme Court, the Trump administration adopted the position, repealed the Carter-era Executive Order establishing CEQ rulemaking, and began rescinding the regulations. The regulations were formally withdrawn in January 2026.

Environmental impact analysis can serve as a pretext for project opponents to impose lengthy delays and higher costs on any new infrastructure that requires a federal permit. [Cape Wind](#), an offshore wind farm proposed in 2001, required multiple NEPA reviews and faced dozens of lawsuits. The lawsuits, which litigated environmental minutiae of [seafloor surveys](#), were backed by wealthy Cape Cod and Nantucket landowners who didn't want to see wind turbines from their beachfront properties. Bill Koch, who put \$5 million behind the opposition, publicly [stated](#) the goal of the lawsuits was to "delay, delay, delay," opposing the project because he "didn't want it in [his] backyard." While the project opponents ultimately lost almost every lawsuit, their delay strategy succeeded in drowning Cape Wind in litigation until the project was finally [canceled](#) in 2017.

Litigation can have major costs even when the government wins in court. It can take years to get to a final ruling and years longer if the case is appealed. For example, the Uinta Basin Railway project was stalled for 3.5 [years](#) in court before being saved by the *Seven County* decision.

The uncertainty of the NEPA process and the risk of litigation have a chilling effect on the development of all major new infrastructure that has a federal nexus. Many projects that might have been built die in the planning stages because NEPA review creates uncertainty and a substantial risk of eventual failure in court, which developers and investors must price into their decisions.

BAAJA's solution: Clarify NEPA's scope, limit litigation

BAAJA clarifies NEPA's requirements, sets new deadlines for action, provides for interagency dispute resolution, codifies public engagement, and puts limits on judicial review.

Clarifying NEPA's requirements

BAAJA clarifies NEPA's purpose, when it applies, and what agencies must consider. The bill:

1. Confirms that NEPA is procedural: it requires an "informational document" but does not mandate a "particular outcome;"
2. Creates new exclusions from the definition of "major federal action":
 - a. Routine administrative actions;
 - b. Repairing or replacing lifeline infrastructure, including expansion of not more than 20%;³⁶
 - c. Projects already reviewed under NEPA by another federal agency;

³⁶ Covered lifeline expansion may not alter the function of the existing infrastructure or expand capacity by more than 20%.

- d. Actions where the only federal involvement is receiving loans or loan guarantees;
 - e. Grants that the agency does not have “predominant” control over.
- 3. Lets agencies skip NEPA documents if they find that a state or Tribal environmental review, or their own compliance with another federal law, “serves a similar function”;
- 4. Expands categorical exclusions by allowing agencies to approve actions by combining existing categorical exclusions, and directs CEQ to maintain a public registry of exclusions;
- 5. Exempts grid infrastructure in existing rights-of-way (§§ 1102, 2102), gas pipeline repairs and upgrades (§§ 1102, 2102), geothermal test wells (§§ 1102, 2221), certain oil, gas, and geothermal activities (§ 2229), and small Army Corps water projects (§ 1102);
- 6. Extends the validity period of a programmatic environmental review — an umbrella review of a whole plan or group of related projects — from five years to ten;
- 7. The bill requires agencies to incorporate the sponsor’s goals and bars them from considering alternatives that would not serve the stated purpose and need, except for considering a no-action alternative; and
- 8. Specifies that agencies are not required to consider new scientific or technical research that is published after the beginning of review.

Enforceable deadlines

BAAJA builds on the Fiscal Responsibility Act’s timelines for NEPA documents and makes the deadlines enforceable.

- a. **Complete application (60 days):** Agencies have 60 days from receiving an application to notify an applicant seeking a federal permit whether its application is complete.
- b. **Threshold determination (60 days):** Within 60 days of a complete application, agencies must decide whether the action falls outside NEPA, qualifies for a categorical exclusion, or requires an EA or an EIS. Applicants may request a more thorough review.
- c. **Review (one or two years):** Agencies must complete an EA in one year or an EIS in two. Within seven days of completing the EA, the agency must issue a finding of no significant impact or issue a notice of intent to prepare an EIS.
- d. **Record of decision (45 days):** Within 45 days of publishing a final EIS, the agency must issue a record of decision on the action.
- e. **All other reviews (90–120 days):** Agencies that worked on the NEPA document have 90 days to issue decisions on other permits; agencies that did not work on the NEPA document have 120 days.
- f. **Extensions:** Extensions are only available if the sponsor and agency agree.

Interagency coordination

BAAJA creates procedures for interagency coordination:

1. CEQ shall resolve disputes over which agency will serve as the lead within 21 days;
2. The lead agency's purpose and need are binding on cooperating agencies;
3. Cooperating agencies must be invited at the outset and have seven days to respond to the invitation;
4. Agencies are instructed to comment on topics limited to their own jurisdiction;
5. Agencies must use a single document and conduct reviews concurrently, pursuant to a schedule set at the beginning of review by the lead agency;
6. CEQ must resolve interagency disputes (see Section 3, Permitting certainty).

Codifying public engagement

Section 1106 of BAAJA requires agencies preparing an EIS to hold a public comment period for 45–60 days, or up to 75 days if the sponsor agrees. To inform the public, at the notice of intent, agencies must publish a description of the project and its location, including geospatial data — this does not necessarily require a Draft EIS. The comment period must request information on environmental impacts, relevant studies, and potential alternatives.

Section 1109 of BAAJA creates a new requirement for a record of stakeholder engagement, completed by the sponsor prior to application. The report must include a summary of any feedback from affected state, local, and Tribal officials, and local groups, as well as any pre-application meetings with federal agencies. The sponsor must explain how the feedback was used or incorporated. By requiring stakeholder engagement to be conducted before application, BAAJA incentivizes the sponsor to conduct consultation early, when it is easiest to change course on a project's scope or location.

Limiting judicial review

BAAJA's most important reform to NEPA is putting limits on judicial review:

1. Under BAAJA, lawsuits must be brought within 150 days of the agency's decision. If a public comment period was offered, plaintiffs must have participated in it and must allege direct harm on the basis of an error that was the subject of their comment. Cases go directly to the federal court of appeals for the region where the project is located, skipping a district court process that could take months or years.
2. Courts are directed to give "substantial deference" to agencies on the scope and content of their analysis, codifying Supreme Court case law such as the recent *Seven County* decision. Greater deference reduces judicial flyspecking (nitpicking on a minor element of a lengthy review) and allows federal agencies to exercise more discretion over which elements of review are needed for their decision.

3. BAAJA limits the remedies courts may impose when plaintiffs demonstrate NEPA review was insufficient. In the status quo, the default remedy for insufficient review is to “set aside” or nullify the agency’s underlying substantive decision (“vacatur”). For instance, if the agency’s environmental review of a permit to cross federal land is determined to have insufficient review, a court will typically nullify (“vacate”) the underlying permission to cross federal land — rendering illegal and thus halting any construction or operating project happening pursuant to that permit. Under current law, courts are also empowered to issue injunctions, which are orders to take or stop certain actions, such as halting construction activity.

Under BAAJA, courts would not be permitted to nullify the underlying decision, nor to issue injunctions, if the only problem is a defect in the NEPA review. Instead, the only remedy is to send the matter back to the agency (“remand”), with instructions to fix the violation within 180 days — work on the project may continue during remand. This limit also applies to preliminary injunctions, which occur at the outset of a case and can stop a project before it has been decided on the merits.

BAAJA’s limits on remedy apply only to NEPA and the NHPA (see Section 5): decisions that are separately arbitrary on the merits, or that violate substantive laws like the Endangered Species Act or the Clean Water Act, remain subject to the full range of judicial remedies, such as vacatur and injunctive relief.

In sum, BAAJA would streamline environmental review by clarifying NEPA’s applicability and requirements, setting deadlines, and limiting judicial review, while leaving NEPA’s goal of requiring informed agency decision-making intact.

3. Permitting certainty

Permitting laws assume that federal agencies will make a good-faith effort to process permit applications in a timely manner. But the executive branch has eroded this norm over time and used permitting requirements to delay or block politically disfavored projects. While past presidents have interfered in the permitting process, the current administration has gone further by revoking permits for fully approved projects already under construction.

The ability to use permits as a political weapon compromises both current and future infrastructure projects of all kinds. Developers have to price in the risk that an administration will delay a permit and hold their project in limbo. This is particularly biting for major projects that take multiple presidential terms to plan, permit, and build — builders planning in a friendly political climate still have to worry about future political risk. The result is a stasis where blocking is easy and building is hard.

BAAJA creates permitting certainty for project developers on three levels. First, the bill restricts agencies from revoking any permit or authorization for an approved project and sets penalties for violation. Second, BAAJA sets enforceable deadlines for agencies to issue permits. Third, BAAJA makes industry-scale mistreatment illegal and creates large monetary penalties.

Background

Political abuse of permitting to delay or cancel politically disfavored projects has been on the rise. Under the Biden administration, the Keystone XL pipeline was [canceled](#) mid-construction and reviews for liquefied natural gas export terminals were indefinitely [paused](#). The Trump administration has taken abuse to its [logical extreme](#), revoking permits for offshore wind projects already under construction and effectively blockading new solar and wind projects by refusing to process permits.

Federal permitting laws do not authorize the president or federal agencies to block individual projects for arbitrary political reasons, but they unintentionally enable it.³⁷ Federal law requires each infrastructure project to secure a series of permits and authorizations before it is legal to build; most federal approvals require federal agencies to prepare project-specific review materials and exercise discretion. The discretion that Congress delegates to agencies is premised on a norm of trust that the executive branch will faithfully execute the law and review projects on their merits in a timely manner.

This delegation of responsibility allows the executive to delay ongoing reviews or even revoke permits for fully approved projects under construction. The ability to delay or overturn a permit is latent in the responsibility to prepare and execute project-specific reviews — the executive branch can use any number of excuses to delay or shelve a project's permit, including arguing that a permit was granted in error, that review should have been more thorough, or that the ongoing project poses a threat to national security.³⁸

³⁷ Several laws, such as the [Outer Continental Shelf Lands Act](#), the [Natural Gas Act](#), and the [Federal Land Policy and Management Act](#), give the executive discretion to exercise approvals as it sees fit for the policy areas the laws govern. However, these neither explicitly nor implicitly grant the president the authority to pause or ban particular energy sources.

³⁸ While the government has recently [lost](#) several high-profile offshore wind lawsuits, those cases are the most egregious examples of executive overreach. The government's reason for revoking the permits was contrived and the projects were well into construction. The government's arguments that offshore wind poses a national security risk due to radar clutter fail to account for the lengthy discussion of radar clutter in the projects' approved permits. In general, the government succeeds when it revokes permits — even in the current administration, tactics like [voluntary remands](#) or political pressure have worked against offshore wind. For example, President Trump's opposition to offshore wind caused several offshore wind projects to be shelved even before he formally took office, and several others have been indefinitely shuttered by voluntary

The problem: Political abuse threatens all infrastructure projects

Now that both sides recognize that permitting can be abused for political reasons, congressional action is needed to reinstate fair treatment. But putting limits on permitting abuse is challenging — the executive branch has enormous discretion and a deep reservoir of legal excuses for why permits could be delayed or revoked.

Political abuse of permitting creates enormous uncertainty for developers. Major infrastructure projects can take many years to permit, and several more to build. This means even projects that begin under friendly administrations should expect the political winds to change before their investment is complete; projects that apply for permitting on day one of a presidential term will be lucky to receive all their federal permits, survive litigation, and break ground within four years. Political risk is unpredictable and very costly: how the president and his appointees will view a project four or six years in the future cannot be predicted or modeled like market conditions can, and cancellation during construction can potentially bankrupt a developer.

Permitting abuse creates a vicious cycle against building. Canceling projects is far easier and quicker than building them — a president who needs short-term wins will always be tempted by the ability to quickly delay or cancel a project with the stroke of a pen. But the long-term costs of permitting abuse are bad for both parties because uncertainty applies to all new long-term projects, no matter who controls the presidency. Today, even developers of energy sources favored by the Trump administration have warned of the uncertainty costs of permitting abuse. As a respondent in a Dallas Fed survey stated:

“Investors (rightly) avoid investing in energy (of all types, now) because of the volatility of underlying business results as well as the ‘stroke of pen’ risk that the federal government wields as it relates to long duration energy developments.”³⁹

Permitting abuse creates a trap: the executive may have reasons to bend or abuse permitting rules, but over the long term, abuse makes everyone worse off.

BAAJA's solution: Limits on agency permitting authority, backed by strong remedies

BAAJA addresses three permitting uncertainties: revocations of permits for fully approved projects, agencies delaying permits, and industry-scale mistreatment.

remands. In another example, DOI agreed to [pay](#) TotalEnergies to abandon its offshore wind lease and instead invest in natural gas.

³⁹ Federal Reserve Bank of Dallas. “Dallas Fed Energy Survey — First Quarter 2025,” March 2025.

Protecting fully approved projects

BAAJA restricts executive action against fully permitted projects. The bill strictly limits the ability of any federal agency to “revoke, rescind, withdraw, terminate, suspend, amend, or alter a Federal authorization or permit” or to take any other action to interfere with the construction or operation of a project that has received all of its federal permits. This prohibition is quite broad, covering virtually every authorization that an agency might attempt to claw back.⁴⁰

BAAJA establishes a narrow set of exceptions to this ban. To be allowed to revoke, rescind, or otherwise stop work on a fully approved project, federal agencies must demonstrate, with clear and convincing evidence, that one of the following criteria holds:

1. The federal agency is required to take the action by a court;
2. The permit holder materially breached the terms of its permit or otherwise violated the law;
3. The permit was obtained through fraud;
4. The action is needed to prevent specific, urgent, substantial, and proximate harm to life, property, national security or defense, and the harm was identified based on new information not considered in the original review; or
5. The project sponsor requested the agency take the action.

BAAJA also sets out provisions to ensure the ban is enforced.

1. Section 1401(b)(3) requires that, prior to taking an action against a fully permitted project, the acting federal agency notify the project sponsor in writing, identify its statutory authority to take the action, and provide evidence supporting its action.

2. Section 1401(b)(4)(A) establishes judicial review of actions against fully permitted projects, allowing the sponsor to petition a district court for review. Section 1401(b)(4)(B) puts the burden of proof on the federal agency, “notwithstanding” the APA. Section 1401(b)(4)(C) allows “in camera” court review — sealed court review to accommodate cases involving national security.

3. Section 1401(b)(4)(D)(i)–(v) lays out the remedies a court must grant when it finds an agency has violated the new rules.

- a. Reinstatement of the authorization;
- b. An injunction barring any further action against the project, unless the agency first petitions the same judge to consider a new approved reason for action;

⁴⁰ The prohibition also applies to individual permits, meaning agencies may not revoke or reopen permits that have been issued, even if the project is still waiting for other permits.

- c. Reasonable attorney fees and litigation costs;
- d. Any costs associated with the delay; and
- e. 25–50% of the total costs already expended by the project sponsor.

These new remedies are substantial. The injunction bars any further agency action against the project unless the agency petitions the same judge. This prevents the government from bringing multiple pretextual actions against a project and making the developer continually fight legal battles. By forcing the agency to petition the court, the remedy limits pretextual attacks; by forcing the agency to petition the same judge, the remedy puts the government in the tough position of convincing the judge who previously ruled against it that the new excuse is sufficient.

The monetary damages ensure developers are made whole. Awarding a portion of expended project costs to the sponsor offsets the risk of having to pause ongoing construction.

Section 1401(b)(4)(E) creates a special rule to protect offshore wind projects. The rule covers projects whose stop-work orders were issued in the year before enactment and were later enjoined by a court. The rule requires that challenges to any future agency action against those projects be heard by the same judge who reviewed the prior case.

Section 1401(b)(4)(F) establishes that monetary damages awarded to project sponsors for illegal agency action against fully permitted projects shall be paid out of the Judgment Fund. Section 1401(b)(4)(G) bars claims under Section 1401 from being brought in the Court of Federal Claims while a claim in a district court is pending, and permanently if relief is granted.

Setting deadlines to compel agency action

BAAJA also limits the executive's ability to withhold permits through continued delay. The bill requires federal agencies to meet clear deadlines and backs the new requirements with a process for resolving interagency disputes and a private right of action for sponsors to petition courts to compel agencies to issue decisions.

Under BAAJA, federal agencies must meet the following timelines:

1. **Certifying complete applications:** Within 60 days of receiving an application for review, agencies must notify applicants whether their application is complete. If the application is incomplete, agencies shall notify the applicant and identify the missing information.
2. **Deadline to initiate review:** Within 60 days of determining an application is complete, agencies must determine whether the project requires an EA, an EIS, or

neither (such as projects that qualify for a categorical exclusion under NEPA or that do not qualify as a major federal action).

3. **Deadline for projects requiring an EA or EIS:** The one- and two-year timelines for an EA or EIS, which are established in current law, begin on whichever date is earlier — the date when the application is complete, or the date when the agency makes a determination to begin an EA or EIS. The deadline can be extended with the consent of the sponsor. Once the NEPA document is completed, agencies that worked on the NEPA document have 90 days to issue all decisions on other outstanding permits; agencies that did not work on the NEPA document have 120 days.⁴¹
4. **Deadlines for projects not requiring an EA or EIS:** For projects that do not require an EA or EIS, there is no deadline for making a decision on permits unless the project is covered by one of 47 types of energy and mining projects.⁴² For those covered projects, all decisions on permits must be made within one year of the last complete application.

BAAJA sets deadlines across two paths. For projects requiring an EA or EIS under NEPA, the deadline to decide on all federal permits is one or two years plus 120 days, respectively. For projects that do not require an EA or EIS but are covered by BAAJA's protections for energy and mining projects, the deadline is one year from completeness of the final application.⁴³

BAAJA also defines a process for enforcing the new timelines. The bill directs lead agencies to establish a schedule for completing permits with cooperating agencies and a process for dispute resolution through CEQ. Under current law, while the lead agency may set a schedule, the agency has no authority to compel action from other agencies that are

⁴¹ BAAJA's provision in Section 1106 specifies that agencies are not required to consider research published after the notice of intent to prepare an environmental document and may not delay the deadline to wait for research. This applies to all permits that are tied to an EA or EIS deadline.

⁴² The full list includes: electricity generation from onshore wind, offshore wind, solar, coal, natural gas, oil, nuclear fission, geothermal, hydrogen, biomass and fusion; energy storage; long-duration battery storage; hydropower; pumped-storage hydropower; onshore and offshore electricity transmission; natural gas, oil, hydrogen, carbon dioxide, natural gas liquids, ammonia, produced-water and helium pipelines; production of coal, onshore natural gas, offshore natural gas, onshore oil, offshore oil, biomass and uranium; hardrock mining (with each mineral treated as a separate type); hardrock mineral processing; refining or processing of petroleum products; refining or processing of crude oil; refining of natural gas or natural gas liquids; coal gasification; enrichment, conversion, fabrication, reprocessing or storage of nuclear material; LNG export or import; natural gas liquefaction or LNG regasification; export or import of crude oil, refined petroleum products and coal; geologic carbon dioxide storage; enhanced oil and gas recovery; and any other energy-related project type that a federal district court certifies as sharing "common industrial characteristics" with the classes.

⁴³ Separately, BAAJA creates a 60-day timeline for processing ESA § 7 consultation, extendable up to 100 days or longer with the applicant's consent, and a timeline that may go up to 315 days for completing NHPA § 106 consultation.

required to complete the permits. BAAJA fixes this by tying the new deadlines for all permits to the timelines for EAs and EISs and establishing authority to enforce the new deadlines.

To ensure federal agencies are accountable to the new timelines, BAAJA creates a dispute resolution process overseen by CEQ:

- a. The lead agency must notify CEQ if its deadlines have been missed or will not be complied with and must name the responsible agency.
- b. For a dispute or delay involving two or more federal agencies, the project sponsor may notify CEQ for dispute resolution.
- c. Within 30 days of notification, CEQ, together with the relevant agencies, must try to resolve the issue to the "maximum extent practicable" to meet the new timelines.
- d. If the parties do not agree after 30 days, CEQ is given 14 days to issue a final order to the agencies on how to proceed.
- e. The directions in CEQ's order count as legal compliance with any applicable procedural requirements that were the subject of the dispute. The order itself is not reviewable in court.⁴⁴
- f. Thirty days after the chair of CEQ finds that an agency failed to follow CEQ's order and missed a statutory deadline, the lead permitting officials must spend at least half of their work week on the outstanding issue.
- g. Sixty days after an agency missed a statutory deadline, the head of the agency may not travel on official business more than 25 miles from their place of work.⁴⁵

BAAJA also allows project sponsors to sue agencies for violating the new timelines. To bring a lawsuit, sponsors of projects requiring an EA or EIS must demonstrate at least one of the following:

1. The agency failed to issue an EA or EIS within one or two years, respectively;
2. The agency failed to issue a finding of no significant impact or a notice of intent to prepare an EIS within seven days of completing an EA;
3. The agency failed to issue a record of decision within 45 days of publishing an EIS;
4. The agency failed to decide on an outstanding permit within 90 days of the publication of an EA or EIS if the agency worked on the NEPA review;
5. If the agency did not work on the NEPA review, the agency failed to decide on a permit within 120 days of publication of the EA or EIS.

⁴⁴ For example, if CEQ resolved a disagreement between two agencies over whether NHPA § 106 consultation was sufficient, CEQ's ruling on how to proceed would be final and override the procedural requirements stated in regulation or law. CEQ's authority likely does not extend to substantive obligations.

⁴⁵ The Secretary of Defense is exempt from this provision.

For projects that do not require an EA or EIS but are covered by BAAJA's 47 categories of protected energy and mining projects, sponsors must demonstrate the agency failed to decide on a permit within one year after the final permit application was certified as complete.

If a sponsor sues over a missed deadline, the agency may excuse its delay only by demonstrating, with clear and convincing evidence, at least one of the following reasons:

- a. A natural disaster or war affected its review;
- b. A national emergency for which delay is the only response;
- c. Meeting the deadline would violate the agency's statutory obligations;
- d. The applicant engaged in fraud or misrepresentation;
- e. The sponsor withheld needed information;
- f. The agency's funding lapsed for more than two weeks.

If the agency cannot demonstrate one of these approved justifications, courts shall rule in the sponsor's favor and issue an injunction that includes an expedited schedule for the agency to rule on the issue within 60 days. BAAJA requires the court to review and decide on a sponsor's petition within 120 days. Sponsors are not eligible for any monetary damages for missed deadlines alone.

Sections 1131 and 1132 require CEQ to set up an online tracker showing the status of federal reviews, the responsible agencies, and whether the project is in compliance with statutory deadlines. The tracker must cover all projects requiring an EIS and projects requiring an EA that is still incomplete 13 months after the one-year deadline.

Preventing industry-scale mistreatment

BAAJA addresses industry-scale permitting abuse by federal agencies. While deadlines, processes for interagency dispute resolution, and court-ordered deadlines help, BAAJA's deadlines may not have enough teeth to stop an administration determined to damage a disfavored industry. To address this, BAAJA establishes a strong standard to protect classes of projects from political mistreatment.

Section 1402 of BAAJA establishes protected project categories, listing 47 classes of energy and mining projects. These include onshore and offshore wind and solar; fossil-fuel extraction and electricity production; refining of raw materials; transportation of electricity, fuels, or gases; storage of energy or fuel; and any other "energy-related" project type a court certifies.⁴⁶

⁴⁶ Listed in footnote 42.

To bring a claim alleging a “pattern of disparate treatment,” a plaintiff must be a permit applicant and have either an outstanding permit that is more than 60 days past the applicable deadline or a permit that was improperly denied. Next, the plaintiff must demonstrate a pattern of disparate treatment, proving all three of the following:

1. Empirical evidence showing a substantial increase, compared to the previous five calendar years, in delays or improper denials of the covered class of projects;⁴⁷
2. A persistent trend of delay or denial that has lasted at least 180 days for projects that do not require an EA or EIS and 280 days for projects that do require them;
3. Intent on the part of the federal government to create a pattern of disparate treatment of the covered class of projects.

The applicant must also show that its own delay or denial resulted from the pattern of disparate treatment, not from an incomplete application, fraud or intentional concealment, or a violation of federal law.

Each of these criteria is hard to prove, and the plaintiff bears the burden of proof.⁴⁸ To show intent to discriminate against a class of projects, Section 1402(d)(1)(B)(ii)(I)(bb) directs courts to consider any pattern of statements made by executive branch officials, agency policies, or executive orders that demonstrate a bias in the permitting process against the covered class of projects as supporting evidence. However, statements that merely express a preference and are unrelated to the permitting of projects are excluded as supporting evidence.

If a court finds a “pattern of disparate treatment” and that the applicant was subject to it, the court shall impose the following remedies:

- a. An injunction;
- b. Reasonable attorney fees and litigation costs;
- c. Economic damages, including the costs of the denial or delay; and
- d. 50–100% of the total expected cost of construction.⁴⁹

The applicant must show technical and financial ability to construct the project and, if it wins and receives remedies, it must build the project or pay back all the remedies received. All payments are made available through the Judgment Fund.

⁴⁷ Delays are counted as inaction when they are 60 days past the applicable deadline.

⁴⁸ Section 1402(d)(1)(B)(iii) shifts the burden to the government to produce raw data on permitting once a plaintiff makes a prima facie showing of the claims.

⁴⁹ To determine how much to award, the court must weigh three factors: bad faith, any pattern of similar interference, and actual economic harm.

Section 1402 is clearly intended to be a disincentive for federal agencies rather than a typical path for project sponsors. The bill makes it very challenging to establish a claim of disparate treatment, but creates severe remedies once established. The goal is to deter political appointees from leveraging permitting to damage disfavored industries — federal agencies should not even get close to tripping these conditions.

4. The Clean Water Act

BAAJA proposes changes to Sections 401 and 404 of the Clean Water Act (CWA), the main federal law that governs water pollution.

Section 401

Under § 401 of the CWA, applicants for a federal license or permit for a project that “may result in any discharge” into waterways must obtain a certification from state authorities verifying the project complies with measurable limits on pollution.⁵⁰

The controversial element of § 401 review is that it makes a federal permit depend on state approval. When states are hostile to a project for political reasons, they can exploit their discretion to unilaterally block the project.

BAAJA narrows the scope of § 401 review, limiting the ability of states to deny projects on pretextual grounds but maintaining state authority to deny certification to projects that pose genuine water quality harms.

The bill requires:

1. State § 401 review to focus only on water quality;
2. States to explain, when denying certification, why the certification could not have been approved with conditions;
3. States to explain why imposed conditions are the least burdensome way to solve a genuine water quality issue; and
4. State § 401 review of transmission lines and natural-gas pipelines to be limited to the effects of “direct point-source discharges” on waterways.

BAAJA's § 401 reforms are elegant: states remain in charge of § 401 water quality certification, and no substantive water quality requirements are relaxed. The changes are limited to narrowing the scope of § 401 review and putting the burden on states to explain their denials or conditions in terms of water quality.

⁵⁰ See [33 U.S. Code § 1341 - Certification\(a\)\(1\)](#).

Section 404

Section 404 of the CWA requires that any federal or private activity — the construction of roads, bridges, housing, mines, pipelines, transmission lines, etc. — that proposes to discharge dredged or fill material into a waterway must obtain a dredge and fill permit from the US Army Corps of Engineers.

Nationwide Permits, the most widely applicable type of general permit, are often hard to qualify for because they require applicants to meet specific conditions, such as acreage caps. Linear infrastructure faces additional challenges because the projects cross many waterways across multiple states that set different regional conditions on Nationwide Permits. Litigation risk creates further uncertainty for developers, as lawsuits can be initiated years after a project begins construction.

BAAJA creates certainty in § 404 by ensuring Nationwide Permits can cover fill activities under two acres and last up to ten years, and by mandating Nationwide Permits for linear infrastructure. The bill also creates certainty after a permit is issued by limiting the Environmental Protection Agency's (EPA) veto authority and judicial review. It requires lawsuits against § 404 permits to be brought within 150 days and bars courts from overturning agency decisions unless plaintiffs establish imminent and substantial harm, for which there is no other remedy.

Section 401

Background

Section 401 of the Clean Water Act applies to applicants for a federal license whose projects "may result in any discharge" into "navigable waters," requiring that they be certified by the relevant state or Tribal government where the discharge would be located.⁵¹ In rare cases where there is no state or Tribal authority, EPA completes the certification.

The statute says that state certification shall evaluate "that any such discharge will comply with the applicable provisions of [Sections 301, 302, 303, 306, and 307 of the Clean Water Act]."⁵² States certifying a project may choose to set conditions to bring it into compliance with the relevant sections or into accordance with "appropriate requirements of State law."⁵³ Section 401 also specifies that if the state fails to act on a request for certification within one year after receipt of the request, it waives its right to certify.⁵⁴

⁵¹ [33 U.S. Code § 1341 - Certification \(a\)\(1\).](#)

⁵² [33 U.S. Code § 1341 - Certification \(a\)\(1\).](#)

⁵³ [33 U.S. Code § 1341 - Certification \(d\).](#)

⁵⁴ [33 U.S. Code § 1341 - Certification \(a\)\(1\).](#)

The statutory text of CWA § 401 is imprecise:

First, the law does not specify whether certification should focus on discharges alone or consider the project's broader effects on waterways. For example, in its § 401 [denial](#) of the Constitution pipeline, New York's Department of Environmental Conservation argued that removing vegetation within the pipeline corridor would raise water temperatures by removing a small amount of shade that covered the waterway, potentially affecting cold-water species. Setting aside how marginal the effect would be, loss of shade is not a "discharge" into waterways.

Second, the law does not specify how causally close the evaluated effects should be to the waterway itself. For example, should § 401 review be limited to direct discharges into water, or should it also cover the effects of carbon emissions caused by burning the gas that a pipeline delivers to power plants, on the theory that those emissions marginally worsen global climate change, which may ultimately affect the specific waterway in question?

Third, the law specifies that the certifying agency must "act upon" the certification request within a year, or else waive its right to review. But this does not prevent pretextual denials, and has introduced additional ambiguity that has led sponsors and states to fight over whether withdrawing and resubmitting resets the one-year timeline.⁵⁵

The ambiguities in CWA § 401 have led to [regulatory](#) whiplash. In 2020, the first Trump administration's EPA attempted to resolve the ambiguity around the scope of analysis by issuing a rule to limit certification to the effects of discharge only. In 2023, the Biden EPA reverted to the earlier "activity as a whole" reading of the law. In 2026, the second Trump administration initiated a [rewrite](#) to move back to the 2020 framework.

The problem: § 401 enables state denials unrelated to water quality

Section 401 certification can become a lightning rod for political disagreement over a project. States that oppose a project may use § 401 review to deny certification or impose conditions. If a state denies certification under § 401, the project cannot move forward — there is [no federal override](#) of a valid denial available.

The Northeast Supply Enhancement (NESE), a proposed [37-mile](#) pipeline to expand natural gas supply into New York City, offers a case study. Because NESE crosses Pennsylvania, New Jersey, and New York, it requires a § 401 certification from each state. From 2018 to 2020, New York [denied](#) the certification three times and New Jersey denied it twice. The denials came after a public [campaign](#) against the project. The 2019 and 2020

⁵⁵ See [Hoopa Valley Tribe v. FERC](#) and [Turlock Irrigation District v. FERC](#).

denials by New York's Department of Environmental Conservation mentioned the climate effects of natural gas and a preference for clean energy, despite the fact that neither issue is strictly germane to the scope of state § 401 certification.⁵⁶

NESE was canceled in 2024 but revived in 2025. When the second Trump administration issued a [stop-work order](#) and threatened to permanently revoke federal permits for New York's offshore wind project Empire Wind, New York and New Jersey quickly relented; both states [certified](#) NESE under CWA § 401 on the same day in November 2025. NESE's developer [stated](#) that its 2025 application for § 401 certification was essentially identical to its denied 2020 application. But that wasn't the end of the saga — within weeks, NESE's state certifications were [sued](#). The Court of Appeals for the Second Circuit upheld New York's certification, but the Court of Appeals for the Third Circuit [vacated](#) New Jersey's, throwing the project back into limbo.

The lack of clarity in CWA § 401's scope has led to regulatory whiplash and litigation. Project opponents can use § 401's ambiguities to push states to expand their review or challenge a certification in court.

Pretextual denial of § 401 certification could theoretically also be weaponized against interstate transmission lines. Historically, interstate transmission lines have not been blocked by § 401 certification because, if a state opposes a transmission line, it can block it via the state utility commission or through another discretionary state approval. Today, § 401 is used against pipelines because they receive federal siting and permitting, making the certification one of the few levers states have left to block a project. However, if Congress enables federal siting and permitting for interstate transmission lines, as BAAJA proposes, § 401 certification may become the veto of last resort.

While transmission lines do not have any direct discharges into waterways they cross, state certification does not currently require proof of clear harm directly caused by discharge. Instead, states can engage in wide-ranging speculation about potential harms from construction and second-order effects. The same logic that states have used against pipelines could be turned on transmission lines: New York's shade argument could also be applied to transmission lines, positing that construction or noise impacts could affect wildlife. States would also be able to set mandatory conditions on transmission lines through § 401 certification, potentially damaging a project's finances.

⁵⁶ New York DEC's 2020 denial [stated](#) that National Grid had identified alternatives, making the pipeline unnecessary. Whether other projects are better or worse is irrelevant to the scope of CWA § 401, which is limited to the effects of discharges into waterways, set by CWA §§ 301, 302, 303, 306, and 307.

BAAJA's solution: Narrow § 401 to water quality only

Section 1202 of BAAJA proposes to reform CWA § 401 by limiting the scope of state certification analysis to water quality only and requiring states to explain denials and conditions. The bill does not relax or change any substantive requirements for water quality or remove state control of the process.

The bill proposes general reforms that apply to every project requiring a § 401 certification, and specific reforms that apply only to transmission and pipelines projects. BAAJA proposes multiple new subsections to CWA:

1. Subsection (e)(2) would limit the scope of § 401 certification to analysis of the specific water quality issues enumerated in Sections 301, 302, 303, 306, and 307 of the Clean Water Act and in state laws implementing those sections. The changes eliminate evaluation under state law unrelated to water quality, like land use, climate, or wildlife effects. BAAJA also prevents § 401 from applying to non-federal waters.
2. Subsection (e)(2) would also tighten the requirements for states to deny certification under § 401. Under BAAJA, when a state denies a § 401 certification, it must explain why "no modification to or reasonable condition on the certification" could have brought the project into compliance. This requirement focuses certification on water quality: if the project truly compromises water quality, the state will be able to justify denial; but if the state attempts to use § 401 as a pretext, the applicant will be able to demonstrate project compliance.
3. Subsection (e)(2) would strengthen the requirement for states to set conditions when approving certifications. The bill requires that, when states stipulate conditions, they must demonstrate why the conditions were the "least burdensome" option to address the water quality issue and necessary and consistent with the federal license. This requirement guards against states adding unnecessarily costly conditions to make a project practically infeasible, or imposing conditions unrelated to water quality. For example, a state concerned that a transmission line could cause erosion could still require retaining walls within the corridor, but may not impose conditions unrelated to water quality and must demonstrate that the conditions chosen are the least burdensome solution.
4. Subsection (e)(3) would establish a new process and milestones for § 401 certification:
 - States must establish public notice procedures for all applications. If an applicant requests a prefiling meeting, states must respond within 30 days and hold the meeting within 60 days. BAAJA defines what counts as a complete application for state certification under § 401; states must acknowledge receipt of an application within three days. Within 90 days of that acknowledgment, states must notify the

applicant that the application is complete or identify missing information, showing it to be relevant to water quality. When states deny certification to individual projects, they must provide their reasoning in writing and, if the denial was based on missing information, identify it.

5. Subsection (e)(4) would establish a one-year deadline for state action, with an option for an extension if the state and applicant agree to it. BAAJA establishes that failure to act within the period constitutes a waiver of the state's right to certify. The bill clarifies that under (e)(4), voluntary withdrawal and resubmission does restart the clock.

6. Subsection (e)(1) would clarify the legal effect of a certification — once a certification is given, federal agencies shall assume water quality requirements are satisfied.

7. Subsection (f) sets requirements on judicial review of § 401 certifications. If a denial or condition is challenged, states bear the burden of proof and must justify their decision with clear and convincing evidence. The standard of proof does not apply for challenges to an approval.

8. Subsection (g) would apply to transmission lines and natural-gas pipelines only — for these projects, § 401 review would be limited to effects on water quality from “direct point-source discharges.” This is a narrower definition, limited to discharges from a discrete conveyance. For example, leakage from a pipeline or a factory dumping waste into a river is a point-source discharge; runoff that moves fertilizer into a waterway is not, because there is no single point where the discharge was conveyed to the waterway. BAAJA further requires that states act on § 401 certification for transmission lines and natural-gas pipelines within nine months instead of one year.

While interstate natural-gas pipelines will most immediately benefit, these reforms also apply to transmission lines. Because transmission lines do not have direct point-source discharges from operation, § 401 review will be limited to the effects of construction, like filling wetlands or constructing foundations for transmission towers at the edge of a waterway. The provisions will also make it harder for states to pretextually use § 401 against a transmission line sited under Section 216 of the Federal Power Act, which BAAJA aims to make usable.

Section 404

Background

Section 404 of the CWA regulates the discharge of dredged or fill material into waterways, [defined](#) in statute as “waters of the United States.” Unlike NEPA, which applies to federal actions, § 404 applies to any federal or private activity that will

discharge dredged or fill material into a waterway. Permits under § 404, called “dredge and fill permits,” are administered by the US Army Corps of Engineers.

There are two types of § 404 permit: an individual permit and a general permit. Individual permits require the developer to demonstrate that the proposal is the least environmentally damaging project compared to practicable alternatives. If a project has substantial impacts on waterways and requires filling more than the acre limit for a general permit, then it must apply for an individual permit.

General permits are established by the Army Corps for classes of similar activities that have minimal effects on waterways. There are three types of general permits:

1. Programmatic permits, which are specific to a particular local, state, or federal regulatory program;
2. Regional permits, which are specific to a particular Army Corps district; and
3. Nationwide Permits, which are the largest and most commonly applied general permits, cover broad categories of activities and set specific conditions for whether projects may qualify for the permit.

Like NEPA and NHPA § 106, CWA § 404 has no judicial review provision and is instead adjudicated under the APA.

The problem: § 404 permits are difficult to obtain

The cost of § 404 depends on whether a project is covered under a general permit. Individual permits take much longer to process, cost more money, and require the developer to show that the proposal is the least environmentally damaging alternative. In 2024, the median time to receive an individual permit was 354 days, compared to 112 for a Nationwide Permit.⁵⁷ Moreover, a § 404 individual permit triggers NEPA and other federal permitting reviews — for a private project that would not otherwise be subject to federal permitting laws, this can be an enormous cost.⁵⁸

General permits are desirable but often difficult to qualify for.

- a. Nationwide Permits typically set acreage caps, limiting the permit to projects that propose to fill 0.5 acres or less. This limit warps project designs by forcing developers to design projects around the 0.5-acre limit.
- b. Regions set different requirements and conditions on top of the base requirements the Corps sets in Nationwide Permit, adding cost and uncertainty for developers.
- c. Nationwide Permits are valid for only five years — when they are reissued, the requirements may change, forcing developers to pivot.

⁵⁷ See US Army Corps’ 2026 report, “[Regulatory Impact Analysis for the Proposed 2026 Nationwide Permits](#).” Measures are the median time from applicant submission to receipt of the individual permit, or date of verification of compliance with the Nationwide Permit.

⁵⁸ General permits comply with NEPA once when they are issued, relieving the developer of the cost.

- d. When Nationwide Permits are issued, states must approve, deny, or approve them with conditions. If states deny a Nationwide Permit, the permit no longer applies in that state; projects must separately obtain state approval if building within that state, undercutting much of the streamlining.⁵⁹

Section 404 is especially challenging for linear infrastructure. Long infrastructure corridors — whether pipelines, transmission lines, roads, or rail — are inherently more likely to cross one or several waterways and several states and Army Corps districts, risking conflicts between Nationwide Permits and regional conditions. If a linear project fails to qualify for a Nationwide Permit, or qualification is thrown out in court, the project will be forced to apply for individual permits for each waterway crossed.

The chief harms of judicial review of § 404 permits are timing and court remedies. Because challenges against § 404 compliance are brought under the APA, the default statute of limitations is six years. This means plaintiffs can challenge projects and cause delays well into construction. The court's default remedy for successful lawsuits is to throw out the agency's approval and delay the project. Litigation can also threaten the legality of Nationwide Permits — if a Nationwide Permit is overturned, thousands of other projects approved under that permit may be called into question and hundreds of ongoing requests may be thrown into limbo.⁶⁰

While the Army Corps administers § 404, the EPA holds statutory authority to prohibit or withdraw permission to conduct dredge and fill activities, which amounts to an effective veto of § 404 permits. This authority has only ever been used 14 times, but its existence poses a risk for developers, especially in the current era of politically charged permitting decisions.⁶¹

BAAJA's solution: Create certainty for Nationwide Permits and limit judicial review

BAAJA proposes to add certainty to § 404 review by clarifying what Nationwide Permits may cover, limiting EPA's authority to block fill activities, and limiting judicial review challenges to permits issued under § 404.

⁵⁹ If states approve the Nationwide Permit with conditions, those additional requirements may be burdensome.

⁶⁰ For example, a Montana district court [ruled](#) that no oil and gas pipelines could use Nationwide Permit 12. The order was stayed by the US Supreme Court and scope of the ruling was limited to the Keystone XL pipeline.

⁶¹ For example, the EPA's veto was applied to [revoke](#) the permit for West Virginia's Spruce No. 1 Coal Mine in 2011 and in 2023 to [block](#) a mine in Pebble Alaska.

1. Section 1204(b) of BAAJA extends the statutory applicability of Nationwide Permits from five to ten years.⁶² This halves the need to reissue Nationwide Permits, giving applicants longer-lasting certainty and reducing Army Corps staff burdens.

2. BAAJA creates a safe harbor to allow Nationwide Permits to cover activities that discharge fill into less than two acres. This clear statutory limit would reduce uncertainty for federal agencies considering how to scope Nationwide Permits — agencies would know they are on solid legal footing when they propose to cover activities that fill less than two acres.

3. BAAJA requires the Army Corps to maintain existing Nationwide Permits for linear infrastructure, including for transmission lines, pipelines, highways and rail, water and other utility lines, and stormwater management facilities. This explicit legislative directive gives the Army Corps more leeway when reissuing permits — courts will view the Corps as fulfilling a statutory obligation rather than engaging in a discretionary action.

4. The bill limits EPA's authority to veto fill activities under § 404 to the period between the permit application and the permit issuance. Prospective or retroactive vetoes are forbidden.

5. Section 1205 of BAAJA limits judicial review, setting a 150-day statute of limitations to file challenges to individual permits, general permits, verifications that an activity is covered by a general permit, and approvals of state § 404 programs. To challenge a decision on a general permit, plaintiffs must have participated in the public comment period, if one was conducted, and their claim must relate to their comment. The bill also specifies that the default remedy courts may issue for § 404 claims is to remand the decision — they may not vacate, enjoin, or limit a permit unless the plaintiff demonstrates that the failure to comply with § 404 will cause imminent and substantial harm to human health or the environment. Courts would have to set a deadline of 180 days or fewer for agency action upon remand.

6. BAAJA creates a qualified exemption from ESA § 6, ESA § 7 consultation, and NHPA 106 consultation for reissuing a Nationwide Permit, provided the reissued permit does not narrow or eliminate preconstruction requirements or raise their thresholds. This applies to the action of reissuing the Nationwide Permit itself — individual projects that later make use of the Nationwide Permit to comply with § 404 would still need to comply with both ESA § 7 and NHPA § 106 if conditions apply to trigger those reviews. In addition, the bill deems a programmatic environmental assessment sufficient to satisfy the requirements of NEPA for a qualifying reissued Nationwide Permit.

⁶² This change applies to all general permits.

7. For general permits, the bill also narrows the scope of analysis to the effect of discharges on water quality requirements as they are defined in § 401, as amended by BAAJA. Impacts unrelated to water quality, like wildlife habitat, are removed from § 404's minimal-effects analysis for general permits.

BAAJA's reforms to § 404 work within the existing structure of the section, expanding the use of Nationwide Permits and increasing certainty for applicants who use the permits. The section also creates certainty by ensuring judicial review challenges are brought promptly and demonstrate clear harm.

Additional Clean Water Act reforms

Rulemaking requirement for EPA water quality updates

Section 1201 requires EPA to issue water quality criteria updates through notice-and-comment rulemaking. EPA periodically updates its advisory water quality criteria, which states take into account as they implement the substantive requirements of the Clean Water Act. Currently those criteria are updated through guidance; BAAJA would change that to require notice-and-comment rulemaking. The section also moves challenges to EPA's water quality criteria updates and its definition of "waters of the United States" to the federal court of appeals and adds a 120-day filing deadline.

Expanding CWA § 402 permit duration to ten years

Section 1203 allows discharge permits under the Clean Water Act's main pollution-permit program to last up to ten years instead of up to five years. This change affects § 402 of the Clean Water Act, which requires point-source discharges of pollutants into waterways to obtain a National Pollutant Discharge Elimination System permit.

5. Historic preservation

Section 106 of the National Historic Preservation Act (NHPA) requires federal agencies to review the effects of projects on historic properties before taking action. Review requires agencies to conduct a multi-step consultation process with affected parties that include State Historic Preservation Officers (SHPOs) and affected Tribal Historic Preservation Officers (THPOs).

NHPA § 106 review is costly for infrastructure and strains federal agency capacity. The review is disproportionately burdensome for tall and long infrastructure — like transmission lines and wind turbines — because these projects can be seen from great distances and can have "visual impacts" on historic properties, which developers may be expected to mitigate. Studying visual impacts on the thousands of square miles from which a power line or wind turbine is visible can take years.

BAAJA proposes comprehensive reforms to NHPA § 106, codifying much of the current regulatory process that was set by the Advisory Council on Historic Preservation (ACHP) under previous administrations, while also streamlining the timeline for review and narrowing judicial review. BAAJA adds certainty to the § 106 process by defining terms, clarifying what agencies must analyze and consider, and identifying when agencies may proceed to a decision. The bill also codifies Tribal consultation rights in § 106 and authorizes \$200 million a year for the Historic Preservation Fund through 2036 and \$20 million a year specifically for Tribal consultation through 2030.

Background

Section 106 of NHPA is [short](#): it requires federal agencies to review the effects of each undertaking (a federal project, activity, or program) on historic properties and provide ACHP with an opportunity to comment. But through [regulations](#) issued by ACHP, the review has expanded into a lengthy, multi-step consultation process. Under ACHP's regulations, federal agencies must:

1. Identify the proposed project's Area of Potential Effects (APE) — the geographic area where the project may disturb (including be visible to) historic properties;
2. Identify all historic properties, including properties that may be eligible for the National Register of Historic Places, within the APE; and
3. Determine whether the undertaking has an adverse effect on those properties, including both physical damage and visual or auditory effects.

At each step of review, the agency must consult with affected parties, which can include the relevant SHPO, any affected THPOs, local governments, and, in certain cases, ACHP itself.

If an undertaking will have adverse effects on historic properties, the agency must consult with affected parties on how to prevent or mitigate them. Agencies have to work with consulting parties to negotiate a Memorandum of Agreement (MOA) that establishes a mitigation plan. Finalizing § 106 without an MOA is technically possible but practically infeasible, requiring a lengthy process to terminate consultation and request formal comment from ACHP.⁶³ In practice, if an undertaking has an adverse effect, sponsors and agencies must reach agreement with the consulting parties to complete the § 106 process.⁶⁴

⁶³ Circumventing the MOA process is rare but can happen in extreme cases. For example, [Cape Wind and Lava Ridge](#) could not reach an agreement with consulting parties despite large concessions by the developer and government.

⁶⁴ In the rare event that an agency circumvents the MOA, courts will view the resulting § 106 record as weak — courts are skeptical that an agency completed its obligation under § 106 if the consulting parties opposed the action. This introduces litigation risk.

Like NEPA, NHPA does not establish its own judicial review process, but courts allow legal challenges under the Administrative Procedure Act.

In July 2026, ACHP voted to move forward with a draft revision to the § 106 regulations, stripping many of the current regulatory requirements. This action by the executive branch has sparked opposition from [historic preservation](#) groups and [Tribes](#).

The problem: § 106 can be lengthy and burdensome, delaying infrastructure projects

Section 106, as expanded by ACHP's regulations, has become a costly process that stalls infrastructure projects, especially for long or tall infrastructure like [transmission lines and wind farms](#).

Visual-impacts analysis can be burdensome

NHPA § 106 review requires consideration of all properties that may be eligible for or are on the National Register of Historic Places. This requires federal agencies to survey and identify every potentially eligible property within the APE. For tall and long infrastructure projects with large visual effects APEs, like transmission lines and wind turbines, the identification process can require surveying [thousands](#) of square miles. Moreover, visual impacts can be nearly impossible to mitigate, leaving sponsors with little recourse.⁶⁵

ACHP's regulations create a lengthy process

NHPA § 106 requires agencies to review the potential effects of undertakings and give ACHP an opportunity to comment. But, through regulation, this modest statutory requirement has sprawled into a [lengthy](#) consultation process, introducing multiple stages of consultation, identification, and conflict resolution that the law does not specify.

Memoranda of agreement create a substantive requirement

ACHP's regulations create a de facto substantive obligation for agencies to agree to mitigation through MOAs. The regulatory requirement for agencies to reach agreement with consulting parties and sign MOAs comes from ACHP's [regulation](#); the statute does not mention or require it.

MOAs add costs, and mitigations are often unrelated to a project's adverse effects. For example, the MOA for Empire Wind required the developer to pay for a "[fitness lane](#)," which would not actually mitigate the "visual impact" of seeing wind turbines from the shore.

⁶⁵ For example, Lava Ridge Wind Farm in Idaho was [unable](#) to reach an MOA with historic groups even after agreeing to move the project seven miles farther away from a single historic site.

Judicial review

NHPA § 106 allows third parties to affect the agency's decision through consultation and MOAs. Because MOAs are in practice necessary for many projects, affected parties have leverage to force mitigations or project scope changes. As a result, almost all agency decisions move forward under § 106 with approval from the affected parties.⁶⁶ This explains why there is less litigation under NHPA than under NEPA — opponents extract costs from projects during the § 106 process, leaving few cases where opponents need to resort to litigation.

When NHPA litigation does occur, it is costly. The SunZia transmission line, which was completed and started delivering power to the grid in 2026 after 20 years of development, is still facing [litigation](#) under NHPA alleging the Department of the Interior (DOI) failed to consider the entire San Pedro Valley as a unified cultural property. The ongoing litigation could halt use of the line. Legal claims against § 106 reviews often hinge on subjective judgments: whether a visual effect is considered adverse is impossible to measure objectively, and judges differ in their decisions. Litigation risk drives federal agencies to be risk-averse, leading to delays and contributing to the pressure to sign MOAs.

BAAJA's solution: Require consultation in law, empower agency decision-making, and limit judicial review

Section 2301 comprehensively reforms NHPA § 106, codifying much of ACHP's existing regulatory process to protect consultation rights while also streamlining review, ensuring agencies are empowered to make decisions, and limiting judicial review.

Defining which actions trigger § 106 review

1. BAAJA redefines which actions trigger § 106 review, limiting the definition of a federal "undertaking" to projects, activities, and programs that require a federal permit or approval and are subject to "substantial Federal control and responsibility." The bill also explicitly states that funding alone is not sufficient for a project to become an "undertaking." The new definition of "undertaking" closely mirrors the definition of "major federal action" in NEPA.
2. BAAJA creates a set of explicit carve-outs for what does not count as an undertaking:
 - a. Segments of projects not subject to federal control: for a transmission line crossing a wetland, the "undertaking" would be only the portion built on the wetland (which requires a federal permit), not the rest of the project.

⁶⁶ MOAs only apply to undertakings where there is a finding of adverse effects on a historic property.

- b. Minor repairs and maintenance actions, surveys, public-safety alterations, special-use permit renewals with no changes, and the implementation of preservation agreements.⁶⁷
- c. Grid upgrades and pipeline work within existing rights-of-way and the reissuance of Clean Water Act Nationwide Permits.

3. BAAJA allows agencies to use existing programmatic agreements, which are similar to NEPA categorical exclusions and allow classes of low-disturbance undertakings to exit the § 106 process. It also directs agencies to develop new programmatic agreements covering routine and repetitive categories of actions.

Defining adverse effect and area of potential effects

BAAJA narrows the scope of what counts as an adverse effect to an effect that is “reasonably foreseeable” and “directly alters” the characteristics that make a property historic.⁶⁸ This new definition raises the bar for demonstrating that an effect harms a historic property, requiring parties to identify how the effect directly alters a core element that made the property eligible for the Register. Visual effects count as adverse effects only if they “significantly diminish” the characteristics of a property that make it historic.

Next, BAAJA defines the effects agencies must consider as those that are “reasonably foreseeable” and “proximately caused” by the project.⁶⁹ The APE is limited to the area where adverse effects may be caused by the undertaking. Effects of the project that are considered indirect or cumulative are excluded from review. The bill also limits what may count as a property of traditional cultural importance to geographically identifiable places where an event of cultural or religious significance occurred.

BAAJA also provides that properties listed on or nominated to the National Register of Historic Places after the review begins do not require the agency to reopen its review.⁷⁰

⁶⁷ 54 U.S.C. § 306108(a)(7)(B) (as proposed). The financial assistance exclusion does not apply to historic preservation funding. Other exclusions cover surveys, safety improvements that maintain the historical integrity of a property, nondiscretionary actions, special-use permit renewals and transfers without substantive change, and operation and maintenance of a previously approved project. A later decision to materially modify an approved project is considered a new undertaking, however, and not excluded.

⁶⁸ BAAJA codifies six out of seven of the “aspects of integrity” for historic places. The bill codifies location, design, setting, materials, workmanship, and association but drops “feeling” as a criterion.

⁶⁹ 54 U.S.C. § 306108(a)(1)(A), (a)(4) (as proposed). An effect is “reasonably foreseeable” if it “shares a reasonably close causal relationship to, and is proximately caused by, the undertaking,” and is not “speculative or attenuated.”

⁷⁰ Id. § 306108(d).

Codifying a new § 106 process

BAAJA also establishes deadlines, ownership, and clear endpoints that the NHPA process currently lacks:

1. **Lead agency:** When more than one agency is involved, the NEPA lead agency presumptively leads § 106 review.⁷¹
2. **Initiating review (30 days):** The lead agency has 30 days to decide whether a project is an undertaking, and therefore requires review under § 106.
3. **Period for input (30 days):** If the lead agency determines § 106 is required, the agency “shall” seek input from consulting parties on defining the APE and identifying eligible properties.⁷² If information is submitted after 30 days, the lead agency does not have to consider it.
4. **Adverse effects report (60 days):** Once the agency determines § 106 is required, it has 60 days to prepare a report identifying the historic properties and potential effects, and, if there are any adverse effects, prudent and feasible measures to avoid, minimize, or mitigate them. This analysis can be done concurrently with and in the same document as the environmental review under NEPA.⁷³ Once the report is complete, consulting parties have 30-day windows to respond; once the parties respond, the lead agency must answer substantive objections within 30 days.
5. **Agreement or agency decision (90 days):** Within 90 days of issuing the report, the agency must either reach an agreement with the consulting parties or decide to move forward without agreement.⁷⁴ BAAJA allows agencies to determine that other priorities are more important and move forward with or without mitigation.
6. **Continued consultation (60 days):** If agreement fails and the agency does not choose to move forward without agreement, the parties must continue negotiations for 60 days. The agency may still choose the off-ramp of moving forward without agreement.
7. **ACHP formal comments (45 days):** If, after 60 days, the parties have not reached agreement and the lead agency has still not chosen to move forward without

⁷¹ 54 U.S.C. § 306108(c)(4) (as proposed). If agencies do not designate a lead within 15 days, an applicant may ask the Secretary of the Interior to do so.

⁷² BAAJA limits consulting parties to affected SHPOs, THPOs, Tribes and Native Hawaiian organizations, local governments, the applicant, and ACHP in certain circumstances. It does not codify inclusion of other historic preservation organizations, landowners, or members of the public.

⁷³ Id. § 306108(c)(2)(A), (c)(2)(D)(iii), (c)(6). The agency may follow an applicable program alternative under ACHP's regulations. Id. § 306108(c)(2)(C). If the agency finds that there are no adverse effects or no historic properties present, it has no further obligations, as under the current regulations. Id. § 306108(c)(2)(D)(ii).

⁷⁴ Id. § 306108(c)(3)(A), (c)(5)(C). NHPA obligations are satisfied if the agency determines that adverse effects would not make the property ineligible for the National Register, or that other considerations outweigh historic preservation. A party that does not respond within 30 days forfeits its right to participate, and the agency may consult with ACHP in its place.

agreement, the lead agency shall request formal comments from ACHP, which is given 45 days to produce the comments.

8. **Final decision (30 days):** The agency must make a final decision within 30 days of receiving ACHP's formal comments.⁷⁵

If a consulting party does not respond by the defined deadlines, the agency shall move forward. If the party re-enters the process later, the agency "shall not be required to reconsider" earlier steps. If a consulting party is absent for the purposes of reaching an agreement under step 5, ACHP may stand in for the party and sign an agreement with the lead agency.

Limits on mitigation

BAAJA also tightens the scope of mitigation. Any mitigation must relate to the affected properties, addressing the current practice of funding unrelated benefits like fitness lanes. Furthermore, mitigation must stay within the review area, unless the applicant requests otherwise.⁷⁶

Deadline enforcement

Separately, BAAJA requires that § 106 consultation be completed by the time a project's EA or EIS is published. The Secretary of the Interior can extend this deadline and must cite extraordinary circumstances. If this deadline is missed, BAAJA requires the relevant officials in each SHPO, THPO, and agency involved to spend at least half of their work week to remedy the issue. If the § 106 process is not complete in time, the project applicant may sue the lead agency for failure to comply with the deadline.

Codifying Tribal involvement

BAAJA protects Tribal and Native Hawaiian organization involvement in the § 106 process:

- BAAJA preserves Tribal consultation rights in Section 101, which requires consultation with Tribes that attach religious and cultural significance to a property.
- BAAJA maintains Tribes' authority to operate their own Tribal Historic Preservation Offices and names Tribes as explicit participants at each stage of the statutory process, enshrining in statute what is just a regulatory requirement today.

⁷⁵ Id. § 306108(c)(3)(B) (60 days of further consultation, then ACHP formal comments within 45 days and a final agency determination within 30 days).

⁷⁶ 54 U.S.C. § 306108(c)(2)(D)(iii)(ee), (gg) (as proposed).

- Section 2301(c) exempts Tribes from the new standing requirements, ensuring that Tribes who raised a concern in writing during consultation can bring a lawsuit after the decision.⁷⁷
- BAAJA directs significant resources to two of the major problems Tribal Historic Preservation Officers have faced. Section 2302 of BAAJA authorizes \$200 million a year for the Historic Preservation Fund for ten years and \$20 million a year to develop databases of properties significant to Tribes (kept from public disclosure to protect the sites).⁷⁸ BAAJA also directs DOI, together with Tribes, to develop clear qualification standards for Tribal preservation.⁷⁹

Despite these protections, at least one part of BAAJA could reasonably be understood to reduce Tribal involvement in NHPA: if a THPO does not meet the new timelines, that THPO's Historic Preservation Fund grants and agreements are suspended and, after two years, the Tribal Office's duties are assumed by DOI.⁸⁰

Limits on judicial review

Critically, BAAJA changes how § 106 lawsuits are resolved, mirroring the bill's reforms to NEPA:

- Lawsuits must be filed within 150 days and generally only by parties that will suffer direct harm and that raised the issue during any public comment period, if there was one.⁸¹
- Instead of beginning at the district court level, cases go directly to the federal courts of appeals, and courts must give the agency's judgment "substantial deference."⁸²

⁷⁷ 54 U.S.C. § 306108(c)(2)(B)(iii)–(iv), (c)(2)(D)(iii), (c)(3)(A)–(B) (as proposed) (identification, report, determination, agreement, and further consultation); id. § 306108(c)(9)(D)(ii) (standing and comment requirements do not apply to a Tribe, Tribal Historic Preservation Officer, or Native Hawaiian organization that "provided detailed notice in writing during the consultation process").

⁷⁸ BAAJA § 2302(a)–(c) (authorizing \$200 million a year for fiscal years 2027 through 2036 and \$20 million a year for fiscal years 2027 through 2030). Current law provides \$150 million a year in deposits through fiscal year 2026. 54 U.S.C. § 303102.

⁷⁹ BAAJA § 2302(c) (adding 54 U.S.C. § 302703(b)) (grants to Tribal Historic Preservation Officers for databases of properties of traditional religious and cultural importance, with protection against public disclosure); 54 U.S.C. § 306108(c)(8) (as proposed).

⁸⁰ BAAJA § 2301(b) (amending 54 U.S.C. § 302302 and adding § 302707). A program is not considered consistent with NHPA if its officer "does not regularly comply with timelines for consultation." Programs found inconsistent face suspension of agreements and Historic Preservation Fund grants and, after two years, assumption of their functions by the Secretary of the Interior. Fiscal audits are required at least every four years.

⁸¹ 54 U.S.C. § 306108(c)(9)(D) (as proposed). The 150-day period runs from the later of public notice of the final agency action and notice to the State or Tribal Historic Preservation Officer.

⁸² Id. § 306108(c)(9)(B), (E) (courts "may not substitute the judgment of the court for the judgment of the agency"; original and exclusive jurisdiction in the courts of appeals, except for applicants' deadline suits).

- If a court finds an NHPA violation, it sends the matter back to the agency to fix within 180 days rather than nullifying the permit (“vacatur”) or halting the project, and an NHPA violation alone can no longer support a preliminary injunction.⁸³
- Parties can no longer challenge individual steps in carrying out a preservation agreement years after a project is approved; parties that did not sign an agreement cannot challenge its implementation, and implementing an agreement under NHPA is not considered a reviewable “undertaking.”⁸⁴

These limits apply to § 106 review and mitigation;⁸⁵ decisions that are separately arbitrary and capricious on the merits, or that violate other substantive laws, remain subject to the full range of judicial remedies, including vacatur and injunction.⁸⁶

6. Geothermal

Geothermal power is a rapidly expanding source of American energy that combines firm power generation with zero emissions. However, geothermal faces unique federal permitting challenges because the best locations for geothermal development are on federal lands, and the industry’s innovative technologies are unfamiliar to regulators.

BAAJA creates new NEPA exemptions for geothermal projects, gives geothermal regulatory parity with oil and gas, creates a new geothermal ombudsman, clarifies when drilling permits are required, requires annual geothermal lease sales, and fixes a geothermal royalty rate issue.

Background and Problem: Geothermal faces disparate regulatory burdens

Technological innovations have made geothermal energy more competitive across a wider range of locations. Frontier companies are currently developing next-generation techniques, including advanced closed-loop systems, superhot-rock drilling, and systems that fracture the subsurface to create surface area for heat transfer. These techniques

⁸³ Id. § 306108(c)(9)(C). A preliminary injunction is available only on a substantial likelihood that the action violates a federal law other than NHPA or NEPA. A supplemental findings document prepared on remand may be challenged only as to new information. Id. § 306108(c)(9)(D)(iii). Likewise, a preliminary injunction in a NEPA case may not rest on an NHPA violation. BAAJA § 1110 (adding NEPA § 111(c)(5)(B)).

⁸⁴ 54 U.S.C. § 306108(a)(7)(B)(viii), (c)(10) (as proposed). See *Tohono O’odham Nation v. U.S. Dep’t of the Interior*, 138 F.4th 1189 (9th Cir. 2025) (treating post-decision notices to proceed under a programmatic agreement as reviewable final agency actions).

⁸⁵ The limits may also apply to NHPA § 110(f) — the text of BAAJA says “requirements of this division”.

⁸⁶ Ordinary review under 5 U.S.C. § 706(2)(A), and remedies under substantive statutes such as the Endangered Species Act and Clean Water Act, are unaffected. Section 110(f) of NHPA, which requires agencies to minimize harm to National Historic Landmarks, is also unchanged. 54 U.S.C. § 306107.

promise to increase efficiency, lower the cost of the electricity produced, and expand the geological map where the technology can be deployed.

However, geothermal faces regulatory barriers that slow the industry's ability to innovate and deploy. In addition to facing the same regulatory challenges as other energy generation — such as interconnection queues, federal NEPA and NHPA permitting challenges, and state and local permitting requirements — geothermal is subject to disproportionate restrictions in federal regulation compared to other drilling industries. For example, the Energy Policy Act of 2005 created a categorical exclusion under NEPA for certain oil and gas drilling sites but left out geothermal.⁸⁷ The Bureau of Land Management (BLM) finally updated its categorical exclusions to include geothermal exploration in 2024.

Next-generation geothermal also suffers from risk-averse bureaucracy. Administrators processing regulatory compliance prefer to see established science and clear legal precedent to approve projects. But first-of-a-kind projects inherently lack clear precedent and require agency staff to evaluate unfamiliar science. And most of the best sites for geothermal development are on federal lands in the American West, so geothermal companies have little choice but to wade through the costly federal permitting process.

BAAJA's solution: Streamline geothermal regulation

BAAJA proposes many interventions across several categories to ease the regulatory process for geothermal projects.

New exclusions from NEPA

1. Section 2221 of BAAJA requires DOI and the Department of Agriculture (USDA) to create a categorical exclusion for "geothermal observation test projects," covering test, monitoring, and calibration wells that disturb no more than ten acres, do not create permanent roads, finish within one year, and are carried out on leased land. Sites must also be restored after use.

However, the proposed categorical exclusion is largely redundant: Section 1102 of BAAJA already exempts geothermal test projects from NEPA.

2. Section 2229 converts the existing categorical exclusions under Section 390 of the Energy Policy Act of 2005 into full exemptions from NEPA, and adds geothermal to the list of exempted categories. Geothermal, oil, and gas activities qualify if they involve small surface disturbances — under five acres each, on a lease whose total disturbance is no more than 150 acres, where site-specific NEPA review has already been completed — or

⁸⁷ The Section 390 categorical exclusions apply to certain oil and gas exploration and production activities that use less than five acres of land.

if they involve drilling at a pad used within the past five years, or drilling on land where a NEPA document already analyzed drilling within the past five years. Drilling permits are still required but carry no NEPA requirements.

The new exemptions also cover transmission lines that connect geothermal plants. To qualify, lines must be no longer than 20 miles and located within corridors approved within the past ten years. Pipelines also qualify for exemption if they are located within corridors approved within the past ten years, up from five.

Clarifying leasing and permitting requirements

3. Section 2225 exempts geothermal projects from federal drilling permits if the project is located on non-federal land and the federal government owns less than 50% of the geothermal resource the project taps. This allows geothermal projects on state or private land to avoid a federal drilling permit even if their underground reservoirs extend partly into federally owned resources.

4. Section 2223 requires geothermal lease sales to be held at least once a year in every state where there is a pending nomination for a lease. The section also sets a 30-day deadline for agencies to confirm a drilling permit application is complete. Within 30 days of that notice, the agency must issue the permit if the relevant environmental reviews are complete, or defer the decision and set a timeline with milestones for action.

5. Section 2227 grants BLM authority to charge applicants and lessees for inspection and processing costs through 2033.

6. Section 2222 extends lower royalty rates to new geothermal plants on existing leases. For the first ten years of production, geothermal royalties are set at 1.75% of gross proceeds from electricity sales. After ten years, the royalties increase to 3.5%. However, under current law, building a new plant on the same lease as an existing plant does not reset the clock for the new development — a new geothermal plant on a lease that has already been producing for over ten years would have to pay 3.5% on the new plant's sales. Section 2222 fixes this, resetting the clock for each geothermal plant.

Other interventions to enable geothermal

7. Section 2224 creates a new official, the geothermal ombudsman, to resolve disputes between BLM field offices and geothermal applicants. The ombudsman will lead a permitting task force that can borrow staff from across different field offices.

8. Section 2228 directs DOI to identify geothermal procedures and add them to BLM's field manual for drilling operations.

9. Section 2226 requires BLM to continue processing applications under existing leases, such as drilling permits and rights-of-way, despite pending lawsuits. BLM must make a decision on a pending application within 60 days of completing all required federal reviews, unless a federal court vacates or enjoins the authorization.

7. Mining

Reinvigorating domestic production of critical minerals is necessary for national security and domestic manufacturing of advanced goods such as [semiconductors](#) and [electric vehicles](#). But the Ninth Circuit's 2022 [Rosemont decision](#) has undercut mining by establishing an unworkable policy for approving ancillary facilities under the General Mining Act of 1872.

BAAJA proposes to fix this problem by adding a new definition of "mill site" to allow ancillary facilities, like crushing mills and waste-rock disposal, to be built next to mines. BAAJA would also expand authority for hardrock mine leases on acquired lands, and use the proceeds from the new mill sites and mining leases to fund abandoned mine cleanup.

Background and Problem: Mines cannot build supporting facilities or lease government-purchased land

Ancillary facilities

In order to produce and sell useful metals, mining companies need both a mine from which to extract mineral-rich ore and "ancillary facilities" such as a nearby mill to process the ore, a disposal site to dump extra rock, and accompanying infrastructure like transmission lines, electrical substations, access roads, water lines, and railroads to transport resources. Building these facilities close to the mine is essential to the project's economic viability. Waste-rock disposal sites in particular need to be located close to the extraction site — waste rock is heavy and expensive to move, so placing the disposal site even a few miles farther away or several hundred feet higher up can significantly raise production costs and undercut a mine's viability.⁸⁸

Under the General Mining Act, ancillary sites on federal land are difficult to get approved. The problem stems from a drafting flaw. The law establishes two distinct tests for claims to develop mining sites and ancillary facilities: to develop a mine, the claimant must show that the location is a "valuable mineral deposit" (i.e., that it is economically valuable to develop), a high bar; to make a claim for an ancillary facility, the developer must show the

⁸⁸ See, CRS "[The U.S. Mining Industry and the Rosemont Decision](#)." 2024.

land to be “non-mineral in character,” a much lower threshold.⁸⁹ Some parcels fail both tests, leaving some land not sufficiently economically viable for mining but too rich in mineral contents for ancillary facilities.

This test creates two problems for ancillary facilities. First, attempting to prove a site is “non-mineral” is difficult because it requires proving a negative.⁹⁰ Second, ancillary sites must be close to the mine to keep the project profitable, but land close to heavily mineralized deposits is likely to contain minerals in greater quantities, meaning almost all of the most practical locations cannot clear the “non-mineral” requirement.

This definitional problem is a flaw in the General Mining Act’s text, but until the *Rosemont* decision, the government could avoid its consequences. Prior to the ruling, federal agencies allowed ancillary facilities to ride along with mining claims. The government would move forward with a project’s permits and approvals without ever taking an explicit position on the validity of the mining site claim, effectively allowing the ancillary sites to ride along with the mining claim. But, in a decision on the Rosemont Mine, the Ninth Circuit ruled that under the APA, the government must affirmatively make a ruling on the validity of a mining claim — meaning the government must review the described activities against the law’s explicit requirements.⁹¹

Rosemont closed the loophole that the government had used to work around the broken underlying legal definitions. Ancillary facilities cannot pass the test for mining site claims because those require showing a parcel contains economically valuable minerals, which dump sites do not.⁹² This forces ancillary claims to stand on their own and be evaluated under the paradoxes created by the General Mining Act’s “non-mineral” definition, a test that the facilities cannot practically pass.

Alternative methods for siting ancillary sites are possible, but come with high costs:

- Under the Federal Land Policy and Management Act (FLPMA), ancillary sites can be sited within rights-of-way, but use comes at agency discretion and requires its own NEPA review. In addition, to let mining companies use a right-of-way, the relevant agency is required to evaluate the use against other potential uses, often resulting in a denial.

⁸⁹ Courts eventually settled on the interpretation that “valuable mineral deposit” means a deposit that is economically valuable enough to spend time and money developing. See *Castle v. Womble* (1894) and *United States v. Coleman*, 390 U.S. 599 (1968).

⁹⁰ Proving that a site is non-mineral is challenging: it requires definitively evaluating the subsurface of the entirety of a very large plot needed for waste-rock disposal, and demonstrating that it does not include minerals.

⁹¹ *Center for Biological Diversity v. U.S. Fish and Wildlife Service* (2022).

⁹² It is economically impractical and undesirable to locate dump sites on valuable mineral deposits because mineral deposits are rare, dump sites require large amounts of surface area compared to mine sites themselves, and dump sites prevent future development of mineral deposits.

- Land swaps, where a developer agrees to swap a private parcel of land in exchange for a parcel of federal land, are possible, but the process is extremely slow and contested.
- In some cases, private land is available near the mine site, allowing mines to avoid federal approval of ancillary facilities altogether. But this option is rare and rules out many of the most promising ore deposits on federal lands.

Leasing hardrock mines on acquired land

Federal laws do not give hardrock mining clear authorization on land the federal government acquires.⁹³

Mining claims on eligible public lands are a finders-keepers process: anyone who finds a valuable source of minerals may stake a claim and develop the resource. Under current law, mining claims are only available on lands in the “public domain.” However, “acquired land” — land that the federal government has purchased — is legally distinct and therefore not eligible for mining claims. Mining is possible on acquired lands via a lease, a discretionary contract the government issues. However, leasing is only available in certain regions authorized by a patchwork of laws and regulations.

BAAJA's solution: A new category for ancillary facilities and new authority for hardrock mining on acquired lands

BAAJA addresses the *Rosemont* issue by establishing a new kind of mill site. It also expands authority for hardrock mining leases on acquired land and funds cleanup for abandoned hardrock mines.

1. Section 2215(a) adds a new type of “mill site” to the General Mining Act. The new definition covers waste-rock disposal and other facilities “reasonably necessary” to support a mine. These new mill sites can be located on any land open to mining claims regardless of whether the mineral content is known. Each mill site is capped at five acres, but developers may stake as many mill sites as are “reasonably necessary.” Mill sites must be included in a mining plan of operations. The bill allows claim holders to stake mill sites on top of their existing mining claims. Section 2215(b) sets the annual fee for new mill sites at \$400 but leaves fees on existing claims and old-style mill sites at \$200.
2. Section 2215(c) expands statutory authority under the Mineral Leasing Act for Acquired Lands of 1947 to allow hardrock mineral leasing on acquired lands. Under BAAJA, BLM would issue the leases, with the consent of federal agencies that manage the land, such

⁹³ Hardrock includes metal ore and minerals, distinct from other materials such as oil and gas, phosphate, or gravel.

as the Forest Service. Existing exclusions from leasing — such as parks, monuments, and towns — remain off-limits.

3. Section 2215(d) places the fees from new mill sites and mining leases on acquired lands into a new fund, not subject to appropriations, to clean up abandoned hardrock mines.

8. The Endangered Species Act

BAAJA proposes a change to the Endangered Species Act (ESA) to allow the US Fish and Wildlife Service to delegate authority for ESA Section 7 consultation to states. The bill defines “best scientific and commercial data available,” directing the objective application of the best available evidence without defaulting to worst-case scenarios. BAAJA also shortens the timeline for § 7 consultations, requires state data to be incorporated into listing and delisting decisions, and establishes a 150-day statute of limitations for claims challenging biological opinions.

Background and Problem: ESA § 7 consultation is lengthy

The Endangered Species Act forbids killing or harming (known as a “take”) endangered species, and requires federal agencies to avoid actions that jeopardize them. Section 7 of ESA requires federal agencies to consult on any federal action that may affect listed species and determine whether the action is “likely to jeopardize” a listed species or “destroy or adversely modify its critical habitat.”⁹⁴

Section 7 review is akin to NEPA review in that it is a procedural obligation on federal agencies, but differs in that the review imposes a substantive duty, through consultation, to avoid jeopardizing listed species or adversely modifying their critical habitat. And unlike NEPA, the lead agency — known in ESA as the “action agency” — for a project does not conduct the ESA § 7 review on its own. Instead, the action agency, either for itself or on behalf of a private developer, engages with “the Services” — either the US Fish and Wildlife Service (FWS) for land and freshwater species, or the National Marine Fisheries Service (NMFS) for marine species — which provide information and, if necessary, issue a biological opinion determining whether the action triggers a jeopardy finding or destroys or adversely modifies critical habitat.

Section 7 review proceeds along one of two tracks: informal consultation for actions unlikely to harm listed species, and formal consultation for actions likely to cause them harm. To start, the action agency gathers basic information about listed species and the effects of the project. Then, the action agency makes a determination, finding either “no effect,” which ends the agency’s obligation under ESA § 7; “not likely to adversely affect,”

⁹⁴ [See 16 U.S. Code § 1536 - Interagency cooperation](#) and [50 C.F.R. § 402.02](#).

which triggers informal consultation; or “likely to adversely affect,” which leads to formal consultation.

Informal consultation is the process of determining, together with the Service(s), whether the action will adversely affect listed species. The process ends if the Service issues a letter of concurrence, agreeing with the action agency that the action is unlikely to adversely affect listed species. If the Service does not concur with the action agency, the review must go to formal consultation.

Formal consultation requires the action agency to submit a written request for consultation with the Service(s) that includes (1) a description of the project, the project area, the affected species, and any proposed mitigations, and (2) a biological assessment identifying listed species, known effects of the project on species, and known critical habitat.⁹⁵ A complete request starts the statutory timeline — 90 days for consultation, 45 more for the Service(s) to issue a biological opinion.⁹⁶ To complete consultation, the Service(s) must evaluate effects of the project on listed species using the best scientific and commercial data available.

The final report is the biological opinion, which states the Service’s opinion of whether the project jeopardizes listed species or destroys or adversely modifies critical habitat. If the project does not jeopardize species or damage their habitat, then the opinion sets binding terms for the agency to minimize harm to listed species. The Service’s terms authorize take below the limit stated in the opinion, shielding the action agency and developer from liability under Section 9 of the ESA, which forbids taking of listed species.⁹⁷ Once the opinion is issued, formal consultation ends and the action agency may proceed to its decision on a final agency action.

If the opinion finds either jeopardy or destruction or adverse modification of a critical habitat, the Service identifies alternatives and presents them to the action agency. Typically, the agency chooses one of the alternatives and proceeds. If the action agency ignores the proposed alternatives, the action agency and developer are no longer shielded from liability under Section 9 and the decision invites near-certain litigation.

Unlike NEPA and NHPA, ESA has its own right of action. Claims alleging that the Service(s) erred — for example, by issuing a flawed biological opinion — are filed under the APA. Claims that an action agency violated ESA § 7 — whether by failing to properly consult, wrongly skipping formal consultation, or jeopardizing listed species — are generally

⁹⁵ [50 C.F.R. § 402.14\(c\)](#).

⁹⁶ [16 U.S.C. § 1536\(b\)\(1\)](#).

⁹⁷ See, [16 U.S. Code § 1538 - Prohibited acts](#). Also note: the authorization for take of listed species below the Service’s stated limit is contingent on the action agency and developer following the prudent measures (mitigations) set by the Service in the opinion.

brought as citizen suits under the ESA. Both litigation paths have a statute of limitations of six years.

BAAJA's solution: Define best available scientific evidence; let states take on ESA § 7 duties

BAAJA proposes several adjustments to the ESA, primarily related to Section 7 but also touching on Sections 3 (the definitions section) and 4 (the process for listing and delisting endangered species).

1. BAAJA would require data on endangered species collected by states to be incorporated into decisions to list or delist species under Section 4 of the ESA. This change would not require the Services to prioritize state data over federal data.
2. The bill would partially codify the DC Circuit's decision in *Maine Lobstermen*, which rejected NMFS's practice of deferring to worst-case scenarios when deciding whether to issue a jeopardy finding. Section 1301 of BAAJA adds a new definition of "best scientific and commercial data available," in ESA § 3, specifying that the data must be "relevant and objective" and "impartially gathered and objectively applied without presumptions or policy prescriptions that bias the application."⁹⁸ Under the new language, the Services could no longer default to using the worst-case scenarios when making a jeopardy or critical habitat determination.
3. The bill would create the option for states to assume primary responsibility for ESA § 7 consultation, similar to how state transportation departments can take over NEPA responsibilities.⁹⁹ Under BAAJA, the Secretary of the Interior would approve qualifying state wildlife agencies to take on the role of FWS; NMFS's duties may not be assumed. Delegation would last up to ten years and be renewable. To be delegated authority, the state must show legal and financial capability as well as current and future staff capacity to handle the responsibilities under ESA § 7. State authority would be limited to projects within the state, and applicants would have the option to opt out and request review from FWS instead. To be allowed to assume ESA § 7 responsibilities, states would have to waive sovereign immunity, making themselves liable under federal law as the Services are today.
4. BAAJA establishes a 150-day statute of limitations for claims against biological opinions and sends them to the DC Circuit. BAAJA also establishes a 150-day statute of limitations for claims against all energy, mining, carbon capture, wildfire projects that require an EA or EIS under NEPA.

⁹⁸ Section 1301 of BAAJA. ESA § 3(2)(B)(iii)

⁹⁹ See 23 U.S.C. § 327.

5. BAAJA Section 1302 shortens the timeline for ESA § 7 consultations from 90 days to 60. The Services can extend the deadline to 100 days provided they explain the delay to the applicant in writing. If the applicant consents, the timeline can be extended beyond 100 days. However, if consultation runs past 145 days and the applicant did not consent to the extension, the applicant may sue to compel action. Separately, where a project requires an EA or EIS, BAAJA imposes a requirement for agencies to finish consultation by the time a NEPA document is published.¹⁰⁰

6. Section 1303 exempts activities within a pre-established highway or transit right-of-way from ESA § 7.¹⁰¹

7. Section 1307 authorizes \$150 million per year through 2031 to expand ESA § 7 consultation capacity and state programs.

8. Section 1308 authorizes a \$50-million-a-year National Fish and Wildlife Foundation grant fund for coastal states.

9. Hydropower

BAAJA makes tweaks to ease hydroelectric development. The bill proposes to exempt maintenance and temporary operating changes from FERC approval, directing FERC to issue a rule defining what counts as “substantial alterations.” The bill also addresses mandatory conditions, requiring agencies to only set conditions reasonably related to the project’s effects. Finally, the bill requires a report on the barriers to hydropower and requires FERC to set up a new licensing program for small hydrokinetic projects.

Background and Problem: Hydro licensing takes too long and comes with burdensome conditions

Under the Federal Power Act, non-federal hydroelectric facilities are licensed by FERC for terms of up to 50 years. Applying for a new license or relicense requires, among other things, NEPA review, CWA § 401 certification, and ESA consultation if listed species are affected. The licensing process [takes](#) five years on average, and relicensing takes 7.6 years. The time to relicense is especially concerning because many hydroelectric dams are nearing the end of their current terms — licenses for [12,324 MW](#) of hydroelectric capacity are set to expire between 2026 and 2036.¹⁰²

¹⁰⁰ See Section 1302 of BAAJA.

¹⁰¹ Specifically, this excludes actions within corridors covered by MAP-21’s categorical exclusions for operation within right-of-way from ESA § 7(a)(2)–(4).

¹⁰² See, DOE/NREL [“An Examination of the Hydropower Licensing and Federal Authorization Process”](#) 2022.

When FERC issues or renews a license for a hydroelectric project, federal agencies that control the affected federal reservation (areas of federal land) may issue mandatory conditions to protect the reservation under Section 4(e) of the Federal Power Act. These agencies include the Bureau of Land Management for federal lands, the Forest Service for national forests, the Bureau of Indian Affairs for Tribal land, and the Fish and Wildlife Service for national wildlife refuges. Because mandatory conditions may not be altered by FERC, federal agencies can impose conditions unrelated to the project's effects, such as remedying an issue that predates the project or mitigating unrelated, ongoing harms.

In practice, hydroelectric projects are required to get FERC approval for minor changes to existing infrastructure. Current law does not clearly specify what counts as a "substantial" alteration requiring FERC approval. Emerging technologies, like hydrokinetic projects that generate small amounts of electricity from currents without dams, must use the FERC licensing program intended to review dam projects.

BAAJA's solution: Limit mandatory conditions; allow routine maintenance; create a licensing program for small projects

1. Section 2232 of BAAJA requires that conditions set by federal agencies on hydroelectric facilities under Section 4(e) of the Federal Power Act be "reasonably related to the effects of the project."¹⁰³ Conditions to repair preexisting environmental issues would likely be barred.¹⁰⁴ This new requirement on conditions could be enforced by court challenge by project proponents.

2. Section 2233 allows license holders to carry out routine maintenance or temporary operating changes caused by factors beyond their control, such as the weather changing water levels, without FERC approval. The bill directs FERC to issue a rule specifying the distinction between "substantial alterations," "non-substantial alterations," and "routine maintenance." FERC must propose the rule within 90 days of enactment and finalize it within 180 days of proposing it.

3. Section 2234 creates a licensing program for micro hydrokinetic facilities with a capacity of 5 MW or less. The license will cover hydroelectric projects that do not require dams, such as those that generate electricity from waves, tides, or free-flowing water in rivers or streams. Licenses would be valid for between 10 and 20 years, and applicants for relicensing would need to apply at least one year before expiry. FERC must decide whether to license a hydrokinetic facility within one year of its application. BAAJA requires FERC to issue regulations implementing the new licensing program within 180 days of enactment. Separately, FERC would also need to issue a report to Congress

¹⁰³ BAAJA, Section 2232.

¹⁰⁴ It is unclear how "reasonably related to the effects of the project" will be adjudicated in court.

covering licensed projects' impacts on the environment, the economy, and the affordability and reliability of electricity.

4. Section 2231 directs FERC, in consultation with DOE, to issue a report to Congress within 270 days on the market barriers to hydropower. This report must investigate what the hydroelectric industry believes is a structural undervaluation of hydropower and pumped-storage capacity.

BAAJA's reforms target roadblocks for the maintenance and growth of the hydroelectric industry. By tying conditions to the effects of the project, the law reduces federal agencies' ability to require projects to mitigate unrelated issues. Improved licensing processes and an investigation of hydroelectric power's market viability can further ease development.

10. Protecting ratepayers from data centers

The AI-driven race to build data centers has contributed to soaring electricity demand. At the same time, much of the US grid requires maintenance or replacement, driving up costs that are ultimately passed on to electricity ratepayers. Rising costs have created political backlash: public opinion of data centers has [soured](#), and politicians are increasingly critical of data centers and utilities alike.

BAAJA proposes aggressive policies to protect ratepayers, including forcing data centers to pay for all the costs they impose, establishing a federal floor for costs data centers must cover, and allowing states to go even further.

Background and Problem: Data centers can increase costs for ratepayers

American demand for electricity is skyrocketing. Utilities forecast that peak demand will rise by 166 GW by 2030, a [20%](#) increase over five years.¹⁰⁵ The rise in demand is a shock to America's system for building grid infrastructure — for decades, electricity demand had been mostly flat. Between 2010 and 2019, demand grew at only 0.2% annually.

Data centers account for [55%](#) of forecast demand growth through 2030. The rapid buildout of data centers across the country has sparked controversy about rising electricity prices. Data centers do raise costs in certain circumstances, but those costs largely stem from our inability to expand the grid due to sclerotic regulatory processes.

¹⁰⁵ See, Wilson, John, et. al. "[Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers](#)." Grid Strategies. November 2025.

Electricity prices are a function of the cost to generate power and the cost to transmit and manage it on the grid. A monthly electricity bill reflects the cost of both generation and system maintenance. Increased demand is only partially responsible for price growth — in a functioning market, new loads are matched by new generation to bring the price back to equilibrium.

Electricity costs are compounded by a few factors:

1. America's grid is aging, many transmission lines need repairs or replacements just to maintain existing capacity, and utilities pass the costs of upgrades and maintenance to ratepayers. Grid replacement costs are incurred independently of data centers and are exacerbated by utilities' incentives favoring expensive local projects over cost-efficient regional or interregional transmission.¹⁰⁶
2. It can take years to interconnect new generation to the grid, driving competition over scarce electricity in the meantime.
3. Once enough new load is added, grid operators must invest in new capacity and other infrastructure to maintain reliability. These secondary costs are not paid by the added generation or load but instead by the utility, which again passes the investment costs to ratepayers. This means data centers pass on part of their costs to other ratepayers.

While data centers contribute to one of these sources of electricity costs, in some circumstances they can also lower costs for other ratepayers. Data centers can lower other customers' share of the grid's fixed costs — for example, replacements and maintenance needed to preserve the aging grid can be offset by adding new load to spread the costs among a broader base. Studies have shown that states with faster load growth have seen rates fall because the costs have been offset by the added buyers of electricity.¹⁰⁷

But data centers can raise costs for ratepayers when the data center and the generation needed to match it require grid expansion projects beyond interconnection. So far, load growth has tended to lower prices, but that effect likely only holds true while new load fills existing headroom, the spare capacity that the grid can manage without adding upgrades. Once new load increases enough to require upgrades, it is likely that new data centers will pass on costs to ratepayers.

Data centers also pose an uncertainty risk to ratepayers. Buildouts may trigger expensive upgrades and new generation. But if the data center boom collapses or recedes, ratepayers may be left to pay for needless grid investments.

¹⁰⁶ See the section on inefficient utility investment.

¹⁰⁷ See, Berkeley Lab "[Factors influencing recent trends in retail electricity prices in the United States.](#)" Note, the study tracks prices in inflation-adjusted terms.

BAAJA's solution: Make data centers pay for every cost they create

To shield ratepayers from increased costs, Section 2107 of BAAJA would require utilities to charge data centers for every cost they create. BAAJA sets a federal floor on data center costs while granting states authority to exceed those minimum requirements.

1. Section 2107(a) of BAAJA directs FERC to issue regulations requiring utilities to charge data centers, which the bill calls "computational load," for both embedded and incremental costs. Embedded costs are prices customers pay for their share of the transmission system. Incremental costs cover hookup costs, capacity and reliability upgrades, and new generation required to serve the load. The bill also requires utilities to offer cheaper rates to data centers that agree to non-firm service, requiring them to power down when requested. Utilities would be required to revise their rates to reflect FERC's new regulations.

2. Section 2107(b) of BAAJA establishes a federal floor for costs to data centers of 20 MW or more, requiring utilities to charge data centers for their incremental costs *at minimum*, and allowing states to charge more. Utilities may not shift a data center's "incremental cost" to other customers. Furthermore, utilities must design rates to cover the full incremental cost even if the data center terminates its contracts or stops buying power early, and must require financial assurances from the developer up front.

3. BAAJA also permits states to set further requirements on data centers of 20 MW or more, including charging data centers more than incremental costs and crediting the surplus to other consumers. States may also run open seasons for data center connection, holding a competitive solicitation and awarding connection to projects that offer the greatest benefit to other consumers. States may require data centers to bring their own power, meaning they must build or contract for enough new generation to serve their load. States may also require data centers to accept limited service, such as forcing them to power down during peak times to maintain grid headroom.

4. BAAJA allows states to treat data centers as a distinct consumer class and impose less favorable terms on them than on other industrial customers, such as factories. BAAJA's federal floor and state powers only apply to data centers that connect after the bill's enactment.

5. Section 2114 of BAAJA requires EIA to track electricity use by data centers, including any demand associated with cryptocurrency mining.

BAAJA's data center provisions dovetail with its transmission reforms, addressing the interplay of demand growth and expansion challenges.

11. Federal lands, leasing, and rights-of-way

BAAJA also includes several provisions related to federal lands, leasing, and rights-of-way:

Streamlines rights-of-way for renewables on federal lands

Section 2213 of BAAJA establishes deadlines for agencies to process rights-of-way for clean energy projects on BLM and Forest Service land. The section also directs DOI and USDA to define new categorical exclusions for small solar projects and low-disturbance activities within 180 days of enactment. Section 2213 also classifies energy storage as an “eligible project” for the purposes of leasing and right-of-way applications.

Exempts oil and gas on mostly private land from drilling permits

Section 2211 specifies that federal drilling permits are not required when a project sits on non-federal land and the federal government owns less than 50% of the oil and gas minerals in the drilling unit. This fixes the issue where drilling on private land that affected a small amount of federal minerals would trigger federal review. However, production of federal oil and gas is still subject to royalties. Tribal lands are excluded from this reform.

Expands Tribal authority to grant rights-of-way

Section 2212 lets Tribes grant rights-of-way across their land without any federal environmental review or DOI's approval, provided they establish Tribal rules, approved by DOI, to implement their own environmental review and public comment process. DOI is required to approve or reject Tribal rules within 180 days of submission. Other federal permits would still apply, and the ESA's prohibition on harming listed species would remain in effect.

Expands authority for offshore leasing and transmission

Section 2251 amends the Outer Continental Shelf Lands Act to allow reasonable interference with other uses of offshore lands — DOI may allow offshore wind developers to interrupt fishing activities provided the disruption is reasonable. The section also allows DOI to grant rights-of-way for electricity transmission through marine sanctuaries, relaxing the outright prohibition in current law.

Section 2252 designates DOI as the lead agency for offshore transmission lines, directs DOI and DOE to periodically identify preferred routes for offshore transmission, and allows DOI to issue rights-of-way without competitive bidding.

12. Judicial review for energy and mining projects

Section 2201 sets a global statute of limitations for claims against covered energy and mining projects. Rather than applying to claims against a specific permit or law, Section 2201 applies to project types, including energy production; transmission and storage; CO₂ capture, transport or storage; mining and mineral processing; and wildfire fuel-reduction work. For any project of this nature that requires an EA or EIS, Section 2201 sets a 150-day statute of limitations to challenge a decision to grant or deny any federal "authorization." This uniform standard creates additional certainty.