THE COLORADO DATA CENTER PLAYBOOK

Permitting, Generation, Incentives, Water & Risk Navigation

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Executive Summary

Colorado is emerging as a compelling yet uniquely complex market for hyperscale, artificial intelligence ("AI"), and other high-density compute infrastructure. The state offers meaningful strategic advantages, including a cool climate, robust fiber connectivity, a strong technical workforce, and geographic proximity to West Coast data traffic. But unlike jurisdictions where data centers operate within relatively predictable permitting and utility frameworks, Colorado requires developers to navigate an interdependent regulatory and resource environment. Projects that succeed here are those that recognize Colorado not as a typical industrial market, but as a tightly integrated permitting, land use, water, power, and community engagement system in which every major design decision influences regulatory outcomes.

Several realities define Colorado's development landscape heading into 2026. Interconnection timelines are now a critical constraint, with Xcel Energy and other utilities facing historic queue volumes. For large loads, interconnection studies and the process of securing transmission service can extend well beyond 18 to 24 months, particularly where transmission upgrades are required. Water availability has become one of the most significant gating factors, as evaporative-cooled loads face heightened scrutiny in a basin governed by the prior appropriation doctrine and the Colorado River Compact. Current conditions of prolonged drought, declining reservoir storage, and increasing competition among users have made water availability particularly challenging for new industrial loads. Air permitting has grown more complex with the addition of environmental justice ("EJ") narrative requirements, expanded modeling expectations, and longer review cycles for projects deploying gas reciprocating engines, combined heat and power systems, or substantial diesel backup fleets (*see* Section 2).

At the local level, county permitting under Colorado's Areas and Activities of State Interest law (H.B. 1041), referred to as "1041 permitting," has become one of the most determinative components of data center development in Colorado. Under this framework, numerous Colorado counties (including Adams, Arapahoe, Boulder, Clear Creek, Jefferson, Kiowa, Larimer, Pueblo, and Weld) designate certain categories of development (including major industrial and energy facilities, transmission lines, and developments with significant impacts on local infrastructure, the environment, or surrounding communities) as requiring special 1041 review and permitting. For data centers (particularly those with onsite generation, major transmission components, and/or meaningful water demand), this generally involves a comprehensive and discretionary permitting process that often operates in addition to other development approvals (*e.g.*, zoning, conditional/special uses), detailed analyses related to water use, environmental impacts, community effects (traffic, noise, economy), and EJ, and public hearings before planning commissions and boards of county commissioners. In many jurisdictions, 1041 approvals have become the primary venue through which communities evaluate data center impacts. In jurisdictions that have not enacted 1041 regulations, data center developments still require a primary "use" or "development" permit – generally in the form of a conditional or special use permit – which can present equally challenging processes.

Co-located power generation, where generating facilities are sited at or immediately adjacent to data centers, has emerged as a critical strategic option for developers seeking to navigate interconnection congestion and grid capacity constraints. The Federal Energy Regulatory Commission's ("FERC") December 18, 2025, order in Docket No. EL25-49-000, directing PJM to establish transparent rules for co-located loads (including multiple transmission service options), signals federal recognition of this trend. While the order is specific to PJM's mid-Atlantic footprint and not binding in Colorado, the framework it establishes provides influential precedent that may influence how Colorado utilities and the Colorado Public Utilities Commission ("PUC") address co-location arrangements; actual outcomes will depend on ongoing utility filings and PUC proceedings. Xcel Energy and Tri-State Generation and Transmission Association are developing large-load tariffs that address co-location arrangements, cost allocation, and transmission service options. Xcel Energy's tariff filing remains pending as of the date of this playbook. On January 26, 2026, Xcel Energy filed a Verified Petition for Variance in a new proceeding (No. 26V-0048E) requesting an extension of the filing deadline to April 2, 2026. Readers should check PUC Docket No. 24A-0442E (and the related variance proceeding) for any updates after publication of this playbook. Co-located generation in Colorado – whether natural gas, solar paired with battery energy storage systems ("BESS"), or future technologies – implicates overlapping regulatory requirements across air quality permitting, PUC jurisdiction, county 1041 (or equivalent) review, water rights, and other permitting requirements, making integrated planning essential.

As a result, successful Colorado projects integrate 1041 (or equivalent) strategy early with power planning, land acquisition and control, water and cooling selection, EJ posture, and site design, recognizing that county land use approvals often serve as the most comprehensive and important permitting process. A more comprehensive discussion of Colorado's 1041 framework (and similar non-1041 development approvals) appears later in this playbook.

Recent federal legislation, including the 2025 clean energy tax amendments (formally titled the One Big Beautiful Bill Act, enacted July 4, 2025), has significantly altered the Investment Tax Credit landscape for co-located generation, with accelerated phase-outs for solar (construction by July 4, 2026, in-service by December 31, 2027) but favorable treatment for battery energy storage systems through 2033. These federal tax dynamics now play a central role in structuring co-located power strategies. These incentives can be substantial, but they reward early modeling, disciplined sequencing, thoughtful stakeholder engagement, and alignment with permitting and power strategies. Parallel to these state and local dynamics, tribal sovereignty and federal nexus issues – including National Environmental Policy Act ("NEPA"), National Historic Preservation Act ("NHPA"), and Clean Water Act permitting – may materially influence timelines where cultural resources, rights-of-way ("ROW"), or federally-managed lands or waters are implicated.

Across these factors, a consistent pattern emerges: Colorado requires a multi-track, parallel development model rather than the sequential processes familiar in many other markets. Power strategy must be defined early because generator configuration, BESS sizing, and interconnection posture all shape air permitting, water strategy, and county land use outcomes. Cooling and water strategy likewise cannot be deferred; in Colorado, they drive political risk, EJ exposure, and community acceptance. Siting and land use determinations must be integrated with these technical decisions, as local approvals increasingly demand cohesive narratives regarding emissions, water use, traffic, resilience, and community benefits.

This playbook distills those realities into a practical guide for project developers, sponsors, investors, hyperscalers, utilities, and operators navigating Colorado's landscape – and beyond. The regulatory frameworks, integration strategies, and risk navigation principles outlined herein reflect Davis Graham's broader data center capabilities. While Colorado is among the most complex and instructive markets in which to develop this expertise, our capabilities extend to data center projects across the U.S. and to cross-border transactions involving international capital and sovereign investors.

To make the document most useful, we have structured it modularly: readers can jump directly to the section(s) most relevant to their current phase or challenge (*e.g.*, interconnection delays, water rights strategy, 1041 permitting risks, co-located generation options, or Tribal land considerations) without needing to read sequentially. Section 1 provides essential context on why an integrated, multi-track approach is non-negotiable in Colorado. The following sections then outline the Colorado-specific considerations for navigating each facet of this strategy, from the permitting environment to community and EJ expectations to tribal development frameworks. Although these sections are best consulted in their totality – given our view that an integrated approach is vital in Colorado – they are designed to serve as standalone primers for discrete topics or workstreams. Finally, the closing two sections offer a comparison of Colorado's strengths and weaknesses as a market compared to other states and an outline of existing data center projects in the state, which can serve as case studies for further consideration.

The through-line is straightforward: Colorado offers substantial long-term opportunity, but only for teams that align power, water, cooling, siting, tax strategy, stakeholder engagement, and tribal coordination from the outset. Developers that embrace this integrated model consistently obtain faster, smoother, and more durable approvals, and position themselves to capitalize on Colorado's growing role in the regional and national data center ecosystem. The integrated, multi-disciplinary approach we describe herein is equally applicable – and just as important – in other demanding markets across the U.S., where capital deployment at scale requires the same coordination of legal, regulatory, and transactional strategy that Colorado demands and which Davis Graham has mastered.

Section 1: Colorado's Development Landscape – Risks, Realities & the Need for Integrated Strategy

Colorado has emerged as one of the most sought-after yet structurally complex jurisdictions for hyperscale, AI, and high-density compute development. The state's natural cooling advantages, robust intermountain fiber connectivity, deep engineering and aerospace workforce, and geographic positioning between coastal load centers make it strategically attractive for the next generation of compute-intensive infrastructure. At the same time, Colorado imposes an unusually interdependent set of regulatory, environmental, and community-facing constraints that differentiate it sharply from more "plug-and-play" data center markets such as Arizona, Texas, Virginia, or Utah.

In Colorado, no single variable determines project viability. Success instead turns on how well developers understand and integrate the overlapping requirements governing water use, air emissions, interconnection, land use, environmental justice, fire code, noise, and long-lead procurement. These domains exert mutual influence: cooling strategy shapes air permit modeling; air permit decisions shape EJ narratives; EJ narratives influence county 1041 (or equivalent) outcomes; and 1041 determinations condition local political support, construction phasing, and development timelines. Likewise, interconnection delays alter generator sizing and emissions modeling; BESS configurations affect site layout, which in turn affects zoning and wildlife or wildfire designations; and water sourcing can determine whether a project faces a streamlined municipal approval or a multi-year Water Court adjudication involving senior rights holders and augmentation plan protests.

Colorado's regulatory agencies increasingly cross-reference filings, and local governments scrutinize consistency across air, water, 1041 (or equivalent), noise, traffic, and EJ materials. A single inconsistency across these domains can trigger additional rounds of review or create openings for organized opposition. For this reason, Colorado has become a systems-driven development environment, where power, cooling, water, permitting, and community alignment must be designed together rather than assembled sequentially. This insight – that integrated, multi-track strategy is the decisive variable in complex data center markets – applies with equal force to other markets where our clients deploy capital throughout the U.S. and beyond.

I. Colorado's Structural Constraints

Colorado's development environment poses several recurring challenges that developers must understand and plan for from project inception:

Water Scarcity & Water Court Exposure. Data centers proposing evaporative or water-intensive cooling solutions encounter heightened risk, particularly where augmentation is required to secure water rights. The prior appropriation doctrine (codified at Colorado Revised Statutes section 37-92-102 and enshrined in the Colorado Constitution) allocates water rights on a "first in time, first in right" basis, creating a hierarchy of users in which new appropriations are junior to existing rights often established decades ago. Water Court proceedings involve well-organized opposition from senior water rights holders, agricultural users, and municipalities protecting their supply portfolios. The Colorado Water Conservation Board's 2023 Water Plan update and the Colorado Climate Action Plan document ongoing drought conditions and increasing competition for limited supply, particularly on the South Platte and Arkansas River basins where most Front Range data center development is planned. Projects unable to secure municipal water contracts or unwilling to pursue augmentation plans to supplement junior water rights should evaluate dry or hybrid cooling from the outset, accepting the efficiency penalty in exchange for reduced regulatory and political risk.

Air Permitting Under Regulation 7 & Related Statutes. Colorado air quality permitting through the Department of Public Health and Environment ("CDPHE") has become more stringent, expensive, and time-consuming, particularly for projects deploying onsite generation. Regulation 7 (codified at 5 Colorado Code of Regulations section 1001-9) governs emissions of nitrogen oxides ("NOx"), carbon monoxide ("CO"), volatile organic compounds ("VOCs"), and particulate matter from stationary sources including gas reciprocating engines, turbines, and diesel generators. Air quality construction permits are subject to long permitting timelines and include stringent emission control requirements and, as of 2023, mandatory environmental justice narratives. These narratives must address demographic composition within two kilometers of the site, cumulative air quality impacts from other industrial sources, and community engagement efforts. Developers should engage air quality consultants during site selection to model emissions scenarios and assess permitting pathways before land acquisition.

Interconnection Queue Congestion & Utility Capacity Constraints. Interconnection timelines have become a critical constraint for Colorado data center development. These timelines reflect historic queue backlogs affecting both generation interconnection and transmission service requests. Xcel Energy and Tri-State Generation and Transmission Association face substantial queue pressures. Tri-State's proposed High-Impact Load Tariff (FERC Docket No. ER25-3316), designed for loads exceeding 45 megawatts, was rejected by FERC on October 27, 2025, on jurisdictional grounds related to retail service provisions. Black Hills Energy, municipal utilities, and smaller cooperatives have limited capacity to serve hyperscale loads without significant infrastructure upgrades, typically requiring developer-funded improvements. The Colorado PUC's late-2025 decision directing Xcel Energy to file a detailed large-load tariff proposal by January 31, 2026, (Proceeding No. 24A-0442E) reflects regulatory recognition that traditional utility frameworks inadequately address data center interconnection timing, cost allocation, and infrastructure investment risk; on January 26, 2026, Xcel Energy filed a Verified Petition for Variance in Proceeding No. 26V-0048E requesting an extension to April 2, 2026, and Xcel Energy's filing remains pending as of early February 2026 (*see* Section 3 for comprehensive treatment of interconnection processes, cost allocation, and co-located generation alternatives).

County 1041 Permitting as Determinative Approval. As noted in the Executive Summary, numerous Colorado counties have designated major electrical facilities, utility-scale energy infrastructure, or significant water use activities as Areas and Activities of State Interest requiring discretionary 1041 review under Colorado Revised Statutes section 24-65.1-101 to -601 (H.B. 1041). Counties including Adams, Arapahoe, Boulder, Clear Creek, Jefferson, Kiowa, Larimer, and Weld have adopted 1041 regulations that may apply to data centers, particularly those with onsite generation, substantial water demand, or transmission infrastructure. The 1041 process involves, among other elements: a formal and comprehensive application submittal, technical studies (*e.g.*, traffic, noise, visual impact, air quality, water supply, fiscal impact), public hearings before planning commissions and boards of county commissioners, and formal findings and conditions on approval. Unlike ministerial building permits, 1041 approvals are discretionary, meaning counties can deny applications or impose conditions that materially alter project economics or feasibility. Increasingly, counties are imposing comprehensive permit conditions and requiring payment of significant permit and development fees on projects pursuant to the 1041 process. Developers should review county 1041 regulations during site selection and engage planning staff early and often before formal application to understand county priorities, potential roadblocks, likely conditions, and stakeholder concerns. Importantly, for jurisdictions that have not enacted 1041 regulations, project developers still will need to obtain an equivalent development or use permit (such as a conditional or special use permit) which is an equally important and often burdensome process.

Environmental Justice Heightened Scrutiny. Colorado's 2021 Environmental Justice Act and subsequent CDPHE guidance require state agencies to consider cumulative impacts on disproportionately impacted communities when reviewing permits for industrial facilities. The U.S. Environmental Protection Agency's ("EPA") EJScreen tool (which maps demographic and environmental data including minority population percentages, low-income households, linguistic isolation, and proximity to pollution sources) is routinely used in Colorado permitting to identify potential EJ concerns. Projects sited in or near census tracts with high EJ scores face more detailed review, requirements for enhanced community engagement, and in some cases, permit denials or substantial mitigation conditions. Air permits, water discharge permits, and county land use approvals increasingly incorporate EJ analyses, and organized advocacy groups actively participate in permitting proceedings where EJ issues are identified. Developers should conduct EJ screening during site selection using EJScreen or similar tools and avoid sites with high cumulative impact scores unless prepared for potential extended permitting timelines and community opposition.

Fire Code Complexity for Battery Storage. Data centers deploying BESS for backup power, grid services, or co-located generation are typically governed by the National Fire Protection Association Standard 855 ("NFPA 855"), as adopted by the applicable local jurisdiction, together with the International Fire Code ("IFC"). The most recent edition of NFPA 855 is the 2026 edition (published in late 2025), and its adoption timeline varies by jurisdiction. In Colorado, adoption of the IFC (and any incorporation of NFPA 855) is primarily determined at the local level. Statewide, the Colorado Division of Fire Prevention and Control applies the IFC to state-regulated occupancies it oversees, but most data center projects will rely on local code adoptions and amendments. BESS installations require UL 9540A testing to characterize thermal runaway behavior, fire suppression systems, explosion venting, and minimum separation distances from occupied structures. Local fire marshals in Adams County, Douglas County, and other jurisdictions with data center activity have adopted requirements beyond model-code minimums, including fire department training, emergency response plans, and financial contributions to local fire services as conditions of approval. Given that local amendments can exceed model-code minimums, developers should engage fire protection engineers early and align BESS design with building officials and fire marshals to avoid costly redesigns during permit review.

II. Why Colorado Requires an Integrated Strategy

The interdependencies among Colorado's regulatory domains – that at times can be difficult to navigate – create a development environment in which sequential, discipline-by-discipline project planning consistently produces inferior outcomes compared to integrated, multi-track approaches.

Consider a hypothetical 100-megawatt hyperscale facility in Douglas County with evaporative cooling and onsite gas reciprocating engines for backup and supplemental power. If the developer pursues traditional sequential development (site acquisition, then civil engineering, then cooling design, then generator sizing, then permitting), that developer may run into a situation not too dissimilar from the following hypothetical:

> The civil engineer selects a site based on acreage, topography, and proximity to fiber, but does not evaluate 1041 (or equivalent) designation status, air quality dispersion modeling implications, or Water Court risk. When the cooling engineer later determines that evaporative cooling is most cost-effective and specifies water demand at 25 million gallons per year, the developer learns that the site lacks municipal water service and requires an augmentation plan, adding months of delay and substantial legal cost. When the mechanical engineer sizes gas recips at 40 megawatts to provide backup and grid services, the air quality consultant determines that potential NOx emissions exceed 250 tons per year, triggering PSD permitting with a long permitting timeline. The PSD application's air quality modeling identifies a nearby low-income census tract, triggering EJ narrative requirements and community opposition. The county, reviewing the 1041 (or equivalent) application, receives public comment objecting to fossil fuel generation in an EJ community and imposes conditions requiring the developer to reduce generator runtime, install additional emissions controls, and provide community benefits, altering project economics. The project now will suffer from significant development, permitting, and construction delays, and project costs will substantially increase, which ultimately could result in cancellation of the project.

In contrast, an integrated approach engages air, water, land use, utility, and other specialists during site selection and early project development. The team evaluates multiple sites using a matrix that considers: (1) 1041 (or equivalent) designation and county receptivity; (2) EJScreen scores and demographic context; (3) municipal water availability or augmentation feasibility; (4) utility interconnection capacity and timeline; (5) air quality dispersion modeling and proximity to Class I areas; (6) fiber availability and latency; and (7) workforce and transportation access. The cooling strategy is selected based on water availability and permitting risk, not solely on efficiency. Generator sizing is determined based on air permit thresholds, with synthetic minor source operational limits incorporated if PSD timelines are unacceptable. County engagement begins before site acquisition, with informal pre-application meetings to understand the 1041 (or equivalent) process and community and other stakeholder concerns. This integrated approach, while requiring greater upfront resources and investment in due diligence, consistently produces faster and more favorable approvals, lower risk of permit denial or costly conditions, and more accurate project budgets and timelines.

III. The Through-Line: Early Decisions Drive Outcomes

Across Colorado data center development, early decisions disproportionately influence outcomes. Site selection determines 1041 (or equivalent) exposure, EJ risk, water availability, and utility capacity. Cooling technology selection determines water permitting pathway, capital cost, and energy efficiency. Generator configuration determines air permitting timeline, operational flexibility, and community acceptance. These decisions, typically made in the early stages of project development, set the project on a trajectory that is difficult and expensive to alter later.

For this reason, Colorado rewards developers who invest in comprehensive due diligence before site acquisition and who engage multidisciplinary teams – including legal counsel experienced in Colorado energy, water, environmental, land use and data center operations law – from project inception. The following sections of this playbook provide detailed analysis of each regulatory domain and strategic decision point, with the goal of equipping developers to make informed early decisions that position projects for success in Colorado's complex but opportunity-rich market.

Section 2: Permitting Architecture – Navigating Colorado's Multi-Jurisdictional Framework

Permitting data center infrastructure in Colorado requires coordination across federal, state, and local (and potentially Tribal) agencies, each with distinct statutory authority, regulatory and technical requirements, and review timelines. Unlike other jurisdictions, Colorado's permitting architecture is distributed, with overlapping jurisdiction and limited coordination among agencies. Projects that succeed are those that understand which agencies have authority over which aspects of the development, what triggers their jurisdiction, and how to sequence applications to minimize delay and risk.

This section maps Colorado's permitting architecture, identifies key agencies and their roles, and provides strategic guidance on navigating the multi-jurisdictional framework. It covers state air quality permitting, county 1041 (or other) land use review, water rights adjudication, PUC interconnection oversight, fire code compliance, and federal environmental and cultural resource reviews where applicable. A recurring theme is the importance of early agency and other stakeholder engagement, consistency across applications, and alignment of technical narratives to avoid contradictory representations that can undermine approvals or create enforcement exposure.

I. State Air Quality Permitting: CDPHE's Air Pollution Control Division

The CDPHE's Air Pollution Control Division administers air quality permits for stationary sources under Regulation 7 (5 Colorado Code of Regulations section 1001-9) and related regulations. Data centers deploying onsite generation (gas reciprocating engines, turbines, combined heat and power systems, or diesel backup generators) require air permits unless emissions are de minimis or qualify for exemptions.

Permit Types & Thresholds. Colorado air permits fall into several categories based on a facility's potential to emit ("PTE") air pollutants. PTE is the maximum capacity to emit pollutants under worst-case operating conditions, before considering any operational limits or controls, and is expressed in tons per year for each criteria pollutant (NOx, CO, VOC, PM10, PM2.5, sulfur dioxide). The key thresholds are:

Major Source PSD Permit: Required if PTE equals or exceeds 250 tons per year of any criteria pollutant for most source categories, or 100 tons per year if the facility is within 10 kilometers of a Class I area (wilderness areas, national parks where visibility protection is paramount). PSD permitting is the most rigorous and time-consuming pathway, requiring: (1) a BACT analysis demonstrating use of the most effective emissions controls unless economically or technically infeasible; (2) air quality dispersion modeling using EPA's AERMOD model to demonstrate compliance with National Ambient Air Quality Standards and increment consumption limits; (3) additional impact analysis for Class I areas if applicable, including visibility impairment modeling; and (4) as of 2023, an environmental justice narrative addressing demographics, cumulative impacts, and community engagement. Projects triggering PSD also require Title V Operating Permits, which are comprehensive facility-wide permits with monitoring, recordkeeping, reporting, and annual compliance certification requirements.

Synthetic Minor Source Permit: If a facility's uncontrolled PTE would exceed major source thresholds, but the applicant accepts federally enforceable permit limits to reduce PTE below thresholds, the facility may obtain a synthetic minor source permit. For example, a data center with 50 megawatts of gas reciprocating engines might have uncontrolled NOx PTE of 300 tons per year (above the 250 ton PSD threshold), but by accepting a permit limit restricting operation to 6,500 hours per year and requiring continuous emissions monitoring or fuel usage tracking, that data center can reduce enforceable PTE to 240 tons per year, thereby avoiding PSD. Synthetic minor permits are less burdensome than PSD (no BACT analysis, no air quality modeling in most cases, and no EJ narrative). However, the operational limits are strictly enforceable, and violations can result in civil penalties, permit revocation, and citizen suits. Developers considering synthetic minor permits must carefully evaluate whether the operational restrictions are compatible with the data center's intended use profile, particularly if the facility may need to run generators during extended grid outages or peak demand periods.

Minor Source Registration: Facilities with PTE below 10 tons per year of any criteria pollutant may qualify for a streamlined registration process rather than a full permit. This is rare for data centers with substantial onsite generation but may apply to facilities with only small emergency backup generators (typically under 500 horsepower total) that operate fewer than 500 hours per year.

BACT & Emissions Controls. For major source PSD permits, BACT determinations are facility-specific and pollutant-specific, meaning CDPHE evaluates what controls are appropriate for the specific type of equipment, operating profile, and site conditions. For natural gas-fired reciprocating engines, typical BACT for NOx includes selective catalytic reduction achieving 90 to 95 percent reduction, low-NOx combustion technology, and good combustion practices. For CO and VOC, oxidation catalysts are standard BACT. Particulate matter controls may include filtration or limitation to pipeline-quality natural gas with low sulfur content. CDPHE maintains a BACT database and references EPA's RACT/BACT/LAER Clearinghouse, but ultimately makes case-by-case determinations based on technical and economic feasibility. Applicants should propose BACT in the initial application based on recent Colorado permits for similar sources, as proposing less stringent controls invites delays and public comment objections.

Air Quality Modeling. PSD permits require AERMOD dispersion modeling to demonstrate that the facility's emissions, when combined with background air quality, will not cause or contribute to a violation of National Ambient Air Quality Standards or consume excessive amounts of the available air quality increment (the amount of additional pollution allowed in areas meeting standards). Modeling inputs include stack parameters (height, diameter, exit velocity, temperature), emission rates, building downwash effects, terrain elevation, and five years of meteorological data from representative weather stations. Modeling must evaluate impacts at nearby sensitive receptors (including residences, schools, and hospitals), and in some cases, demonstrate compliance with visibility protection requirements for Class I areas. Modeling deficiencies are a common source of permit delays, and applicants should engage experienced air quality consultants who have completed successful AERMOD analyses for CDPHE.

Environmental Justice Narratives. As of 2023, CDPHE requires PSD permit applicants to submit environmental justice narratives if the facility is located in or within two kilometers of a census tract identified as a disproportionately impacted community based on demographic and environmental indicators. The narrative must: (1) describe the demographic composition of nearby communities using EJScreen or similar tools, including percentages of minority population, low-income households, and linguistically isolated households; (2) identify other sources of air pollution within two kilometers and assess cumulative air quality impacts; (3) document community engagement efforts, including public meetings, notifications in multiple languages if appropriate, and responses to community concerns; and (4) describe measures to minimize impacts on disproportionately impacted communities, which may include enhanced emissions controls, operational restrictions, or community benefits such as funding for local air quality monitoring or public health programs. CDPHE reviews EJ narratives for completeness and may require revisions or additional community engagement before issuing a permit. Projects in Denver metro, Pueblo, and other urban areas with diverse populations should budget additional time and cost for EJ compliance.

Timing & Strategy. Air permit applications should be submitted as early as feasible in project development, ideally concurrent with or shortly after site acquisition, because air permitting is often the longest lead regulatory item. For PSD permits, applicants should engage CDPHE in pre-application meetings to discuss BACT proposals, modeling protocols, and EJ expectations. Some applicants pursue synthetic minor source permits initially, with the option to modify to higher emission levels later if operational needs change, though permit modifications to increase emissions are themselves time-consuming. Air permit approval is typically a condition precedent to county 1041 approval, building permits, and financing, so delays in air permitting cascade through project timelines.

II. County 1041 Permitting: Local Land Use Review as Gating Approval

Colorado's Areas and Activities of State Interest Act, codified at Colorado Revised Statutes sections 24-65.1-101 to -601 (H.B. 1041), authorizes counties to designate certain activities as having statewide interest and to impose permit requirements beyond traditional zoning. Designated activities commonly include major utility facilities, geologic hazards, natural resource areas, and large water or sewage treatment works. Numerous Colorado counties have designated major electrical facilities or energy infrastructure as 1041-regulated, creating a layer of discretionary land use review that operates independently from zoning, subdivision, and building permits.

Which Counties Regulate Data Centers Under 1041. Counties with 1041 regulations that may apply to data centers include Adams (regulating major electrical facilities over 50 megawatts), Boulder (energy resource development), Jefferson (major public or private utility facilities), Larimer (electrical generation and transmission), Weld (major electrical generation facilities), El Paso (public utilities and services), Arapahoe (major utility facilities), Clear Creek (utility transmission lines), Garfield (major energy facilities), and Pitkin (major utility facilities). Each county's regulations define thresholds, procedural requirements, and review criteria differently. Developers must obtain and review the specific county's 1041 regulations early in site selection and project development.

1041 Application & Review Process. The 1041 process typically begins with a pre-application conference where the applicant presents the project to county planning staff and receives guidance on application requirements, technical studies needed, and likely concerns from the public, other stakeholders, or county commissioners. Formal applications include site plans, building elevations, traffic studies, noise analyses, visual impact assessments, fiscal impact analyses (estimating tax revenue and public service costs), water supply verification, environmental assessments addressing wildlife habitat and wetlands, air quality impact summaries, and environmental justice demographic analyses. Some counties require applicants to prepare draft findings for the county commissioners, articulating how the project meets the county's 1041 review criteria (typically focusing on minimizing adverse impacts on the environment, public health and safety, and community character).

After application submittal and completeness determination, counties circulate the application to referral agencies including fire districts, school districts, water providers, and state (and potentially federal) agencies for comment. The application is then scheduled for a public hearing before the county planning commission or department, which makes a recommendation to the board of county commissioners. The board of county commissioners holds its own public hearing and issues a final decision, which may be approval, approval with conditions, or denial.

Conditions of Approval & Negotiation. Unlike ministerial permits, 1041 approvals are discretionary, meaning the county has broad authority to impose conditions. Common conditions for data center 1041 approvals include: (1) limits on water use or requirements to use non-potable water sources; (2) noise limits stricter than state standards, with continuous monitoring; (3) requirements for landscaping, berms, or architectural treatments to minimize visual impacts; (4) traffic mitigation measures such as road improvements or contributions to intersection upgrades; (5) restrictions on hours of operation for delivery trucks or shift changes to minimize neighborhood disruption; (6) wildlife mitigation such as raptor-safe design for power lines or avoidance of certain construction periods during nesting seasons; (7) contributions to local fire protection, schools, or parks; (8) ongoing reporting to the county on water use, energy consumption, or employment; (9) phased development approvals where initial approvals are for a portion of the planned buildout, with subsequent phases requiring additional 1041 review; and (10) payment of significant permit, development, or impact fees. Developers should anticipate conditions and propose mitigation measures proactively in the initial application and throughout the permitting process, rather than waiting for the county to impose requirements, as this demonstrates responsiveness to regulator and community concerns and improves the likelihood of approval.

Community Engagement & Opposition. Public hearings in 1041 proceedings often draw significant attendance from nearby residents, environmental advocacy groups, and other stakeholders. Common concerns voiced by the public include water use (particularly in drought-conscious areas), truck traffic and noise, visual impacts, potential environmental contamination or other degradation, and property value impacts. Organized opposition from groups such as the Sierra Club, local watershed coalitions, or neighborhood associations can materially delay or derail 1041 approvals if the county perceives that the project lacks community and stakeholder support. Developers should conduct proactive community outreach well before the formal public hearings, including neighborhood meetings, one-on-one discussions with adjacent property owners, presentations to homeowner associations, and engagement with county commissioners and planning commissioners in informal settings. Transparency about project details, responsiveness to concerns, and willingness to incorporate community feedback into project design are consistently the most effective strategies for obtaining 1041 approvals in contested cases.

Strategic Considerations. Because 1041 approval is discretionary and subject to political considerations, developers should evaluate county receptivity during site selection. Counties with prior data center approvals, pro-business reputations, and transparent 1041 processes are lower-risk than counties without data center precedent or with histories of denying or imposing onerous conditions and fees on industrial projects. Early engagement with county planning staff and elected officials (before site acquisition, if possible) provides critical intelligence on whether the county is expected to support the project and what concerns must be addressed. In some cases, developers may negotiate development agreements with counties in parallel with 1041 applications, providing certainty on tax revenue, public improvements, and other benefits in exchange for the county's commitment to process the application expeditiously and approve subject only to specified conditions.

III. Water Rights & the Colorado Water Court System

Colorado's prior appropriation doctrine, a constitutional and statutory framework that allocates water based on seniority of use rather than land ownership, governs water rights used to supply data center cooling and onsite generation. Unlike riparian systems in eastern states where landowners have rights to use water adjacent to their property, the scopes of Colorado water rights are defined by priority date, rate of diversion, and decreed use, and are administered strictly during times of shortage. For data centers requiring significant water – whether for evaporative cooling towers, adiabatic cooling, or onsite power generation – water supply is often the most complex and time-consuming permitting element.

Prior Appropriation Basics. Colorado's water law is codified primarily at Colorado Revised Statutes sections 37-92-101 through 37-92-602, with the foundational principle of "first in time, first in right." A water right's priority date determines its place in the administration hierarchy. During times of insufficient supply – which is the norm rather than the exception in Colorado's semi-arid climate– junior water rights are curtailed before senior rights. A data center seeking to appropriate new water from a stream would receive a priority date junior to virtually all existing agricultural, municipal, and industrial uses, many of which have priority dates from the 1800s or early 1900s. This means the new appropriation would be curtailed during dry years, rendering it unreliable for data center operations that cannot tolerate even minor supply interruptions.

Augmentation Plans as the Path for New Out-of-Priority Depletions. Rather than appropriating new water directly from streams (which would be junior, unreliable, and likely require a substitute supply), most data centers pursue water supply through one of two pathways: (1) purchasing water from a municipal water utility under a long-term service contract, or (2) obtaining a new water right, whether groundwater or surface water, along with an augmentation plan from the Water Court. An augmentation plan is a court-decreed arrangement that allows out-of-priority depletions (uses that would otherwise injure senior water rights) in exchange for providing replacement water to the stream system to offset the depletions, ensuring no injury to other water rights. For example, a data center might pump groundwater from wells (which would deplete streamflow and injure downstream senior surface water rights) but simultaneously release stored reservoir water or treated effluent into the stream to replace the depletions on a day-for-day, or in some cases, an acre-foot-for-acre-foot basis.

Augmentation plans are filed in the Water Court for the division where the depletions occur (Colorado has seven Water Court divisions corresponding to major river basins). The application must quantify the depletions using hydrologic models, identify sources of replacement water (which must themselves be legally decreed or purchased), and demonstrate that no injury will occur to any senior water rights. The application is published in local newspapers, and any interested party (including municipalities, ditch companies, agricultural users, environmental groups, and the Colorado Water Conservation Board) may file statements of opposition. If oppositions are filed, the matter proceeds to a hearing before a Water Court referee or judge, with expert witnesses testifying on hydrology, return flows, replacement water adequacy, and injury. Developers should engage water lawyers and hydrologists during feasibility analysis to assess augmentation plan viability before committing to a site.

Municipal Water as an Alternative. Purchasing water from a municipal utility (such as Denver Water, Aurora Water, Colorado Springs Utilities, or smaller municipal systems) avoids the need for augmentation plans and Water Court proceedings. Municipalities hold large, senior water rights portfolios and have the legal authority to provide water service within their service territories. However, municipalities face their own supply constraints. Data centers seeking municipal water must negotiate service agreements that address: (1) whether the municipality has available capacity to serve the data center's demand (which may be 10 to 30 million gallons per year for a hyperscale facility with evaporative cooling); (2) what happens during drought conditions (will the data center face curtailment?); (3) what rates apply (municipal rates may be higher than agricultural or raw water rates); and (4) whether the data center must contribute to water supply infrastructure costs (new wells, treatment plants, pipelines). Not all municipalities are willing to serve large industrial users, particularly where the municipality is facing growth-driven demand from residential and commercial customers. Early discussions with municipal water providers are essential.

Reuse Water as an Emerging Strategy. Colorado Revised Statutes section 37-60-126 authorizes municipal wastewater treatment districts to provide treated effluent (reuse water) for non-potable industrial uses, including data center cooling. Reuse water has several advantages: (1) it is a relatively secure supply not subject to priority administration because it is treated effluent that has completed its use cycle; (2) it is typically less expensive than potable water; (3) it can be available in significant quantities near urban areas where wastewater treatment capacity is substantial; and (4) it avoids the environmental and political concerns associated with new stream appropriations or groundwater depletions. The Metro Wastewater Reclamation District, which serves the Denver metro area, operates a water reuse program providing Class A reuse water for industrial customers. Developers should evaluate reuse water availability early, though some sites may require pipeline construction to access reuse water, which can add cost, permitting complexity, and delay.

Strategic Water Planning. Water supply strategy should be determined during site selection, not after. Sites without municipal water service and requiring augmentation plans carry materially higher risk and timeline than sites with municipal service or access to reuse water. If evaporative cooling is essential to project economics, water supply is determinative of site feasibility. If augmentation plans are required, developers should engage experienced water counsel and hydrologists at the feasibility stage to assess the likelihood of obtaining a decree, identify potential opponents, and estimate timelines and costs. In some cases, the best water strategy is to design the facility for dry or hybrid cooling from the outset, accepting a modest efficiency penalty in exchange for eliminating water rights risk entirely.

IV. Public Utilities Commission Oversight and Interconnection

The Colorado Public Utilities Commission regulates investor-owned retail electric utilities (Public Service Company of Colorado, a subsidiary of Xcel Energy, and Black Hills Energy) with jurisdiction over utility construction of facilities, rates, service terms, resource planning, and interconnection. The PUC has limited jurisdiction over municipal electric utilities and certain cooperative electric associations. The PUC has jurisdiction over electric resource planning for generation and transmission cooperative electric associations that provide wholesale electric service directly to cooperative electric associations. While there is no PUC permitting requirement for data center construction itself, PUC proceedings involving investor-owned retail electric utilities determine power availability, authorization for construction of new transmission facilities (where required), cost allocation for transmission upgrades, and utility service terms that materially affect project feasibility.

Interconnection Queue & Study Process. Data centers requiring grid-supplied power typically trigger a formal interconnection or large-load study process with the retail serving utility (or the transmission provider if transmission upgrades are needed). For retail distribution service, projects are evaluated under the serving utility's large-load procedures (with study requirements generally scaling with size). Projects seeking to interconnect generation (*e.g.*, co-located or backup) follow generator-specific rules: Colorado PUC Small Generator Interconnection Procedures (Rules 3850–3859) apply to the interconnection of retail renewable or other distributed energy resources that operate in parallel with and are connected to one of the investor-owned utilities when such interconnections are not subject to the jurisdiction of FERC. Electric cooperative tariffs also typically have small generator interconnection procedures and guidelines such as Poudre Valley REA's guidelines for small generating facilities less than 10 MW. Otherwise, the transmission provider's FERC Tariff Small Generator Interconnection Procedures or Large Generator Interconnection Procedures apply such as Xcel Energy's Schedule GIP for Large Generator Interconnection Procedures for facilities exceeding 20 MW at transmission voltage. The study process for large loads or generation generally includes three sequential phases: feasibility study, system impact study, and facilities study. Upon completion, developers must execute an interconnection or service agreement specifying cost responsibility, construction timelines, and operational requirements. Queue backlogs documented in Xcel Energy's 2024 Just Transition Solicitation (PUC Proceeding No. 24A-0442E) have prompted requirements for upfront security deposits to ensure project commitment before utilities commit study resources.

Large Load Tariffs Cost Allocation. In November 2025, the Colorado PUC adopted guiding principles for service to large-load customers and directed Xcel Energy to file a more detailed large-load tariff proposal by January 31, 2026 as part of Xcel Energy's Electric Resource Plan proceeding (Proceeding No. 24A-0442E). On January 26, 2026, Xcel Energy filed a Verified Petition for Variance in a new proceeding (No. 26V-0048E) requesting an extension of that deadline to April 2, 2026. These guiding principles reflect regulatory recognition of the unique cost allocation and reliability challenges presented by large loads such as data centers and include: upfront fees and security deposits; minimum 15-year service contracts; minimum bill requirements for reserved capacity; and early exit fees if service terminates before the contract term.

Xcel Energy's forthcoming large-load tariff proposal is expected to address how co-located generation affects cost allocation and could inform approaches by other Colorado utilities and cooperatives, though structural and governance differences among utilities may limit direct applicability.

Section 3: Power Strategy and Interconnection – Grid Service, Onsite Generation & Emerging Frameworks

Power strategy is foundational in Colorado, where interconnection constraints, clean-energy mandates, and co-location opportunities intersect. Developers must balance traditional utility service (via evolving large-load tariffs), co-located/on-site generation, renewables + BESS, power purchase agreements ("PPAs"), and 24/7 carbon-free matching. Early decisions here shape air permitting, water strategy, land use, EJ positioning, and project economics. Xcel Energy's pending large-load tariff filing (originally due January 31, 2026, in PUC Proceeding No. 24A-0442E, with Xcel Energy having requested an extension to April 2, 2026, via a variance petition filed January 26, 2026, in Proceeding No. 26V-0048E) and related PUC proceedings will clarify cost allocation and co-location pathways.

This section addresses both traditional utility service through Xcel Energy, Tri-State Generation and Transmission Association, Black Hills Energy, municipal utilities, and electric cooperatives, as well as co-located generation strategies where generating facilities are sited at or immediately adjacent to data centers. It examines interconnection processes, queue timelines, emerging large-load tariff structures, and the regulatory pathways and strategic considerations for co-located power generation models that have become increasingly viable in Colorado.

I. Colorado's Utility Landscape &Service Territories

Colorado's electric utility industry comprises investor-owned retail utilities subject to PUC regulation, municipal electric utilities owned and operated by cities, and cooperative electric associations primarily served by Tri-State Generation and Transmission Association, a wholesale generation and transmission cooperative. Understanding which utility serves a prospective site is the starting point for power strategy, as each utility type has different interconnection procedures, cost structures, regulatory oversight, and capacity to serve large loads.

Xcel Energy (Public Service Company of Colorado). Xcel Energy (d/b/a Public Service Company of Colorado) is Colorado's largest investor-owned retail electric utility, serving approximately 1.6 million customers in the Denver-Boulder metropolitan area and across much of the Front Range as well as in mountain communities including Vail and Aspen. Xcel Energy operates under PUC jurisdiction for rates, service terms, resource planning, and generation interconnections for certain distributed generation operating in parallel with and connected to its system. The utility's generation portfolio includes natural gas, coal (with the last plant scheduled for retirement in 2031 to meet statutory greenhouse gas reduction and clean energy requirements), wind, solar, and hydroelectric resources. Xcel Energy is also a provider of FERC-jurisdictional transmission service. Xcel Energy's transmission system is robust in urban corridors but constrained in some suburban and exurban areas, particularly where residential growth has outpaced infrastructure investment. Data centers seeking Xcel Energy service should evaluate transmission capacity early, as many sites may require substation upgrades, new transmission lines, or other network improvements that can add significant costs and delay. Xcel Energy's FERC Large Generator Interconnection Procedures (OATT Attachment N) govern generating facilities exceeding 20 megawatts interconnecting at transmission voltage. Smaller generation interconnections are subject to Xcel Energy's Small Generator Interconnection Procedures or Colorado PUC Rules 3850–3859 (for interconnections not subject to FERC jurisdiction).

Tri-State Generation & Transmission Association. Tri-State is a wholesale power provider serving 42 electric distribution cooperatives and public power districts across Colorado, Nebraska, New Mexico, and Wyoming. In Colorado, Tri-State serves 15 cooperatives – including United Power, Poudre Valley REA, San Isabel Electric, and others – covering rural and suburban areas outside Xcel Energy's service territory. Tri-State operates its own generation fleet (natural gas, renewable energy, and coal plants transitioning to retirement) and transmission system, with FERC jurisdiction over wholesale rates and transmission service. Data centers in Tri-State member cooperative territories must work with both the local distribution cooperative (which provides retail distribution service) and Tri-State (which provides generation and transmission). In August 2025, Tri-State proposed a High-Impact Load Tariff ("HIL tariff") at FERC (Docket No. ER25-3316) designed specifically for loads exceeding 45 megawatts. The proposed tariff included provisions for expedited interconnection studies, flexible service options (firm versus non-firm), and cost allocation frameworks addressing network upgrade responsibility. On October 27, 2025, FERC rejected the HIL tariff filing on jurisdictional grounds, determining that provisions requiring utility members' retail customers to execute Member-Customer High-Impact Load Agreements and related security deposit requirements based on retail service terms exceeded FERC's jurisdiction over wholesale transactions under sections 205 and 206 of the Federal Power Act. Developers considering sites in Tri-State territories should engage early with both the distribution cooperative and Tri-State to understand capacity availability and study timelines, and should monitor whether Tri-State files a revised HIL tariff addressing FERC's jurisdictional concerns.

Black Hills Energy. Black Hills Energy serves approximately 100,000 electric customers in Pueblo and southern Colorado, operating under Colorado PUC jurisdiction. Black Hills has more limited generation and transmission capacity than Xcel Energy and is generally less able to accommodate hyperscale loads without significant infrastructure investment. However, for smaller data center developments (typically under 20 megawatts, depending on site-specific transmission needs), Black Hills may offer faster interconnection and more flexible service terms than larger utilities facing queue congestion.

Municipal Utilities. Cities including Colorado Springs, Fort Collins, Longmont, and Loveland operate municipal electric utilities with autonomy over rates and service terms, not subject to Colorado PUC regulation (though still subject to federal oversight for wholesale transactions and transmission). Municipal utilities typically prioritize serving residential and commercial customers within city limits and may be unwilling to serve large industrial loads, particularly if doing so would require the municipality to purchase additional wholesale power or build new infrastructure. However, some municipal utilities view data centers as desirable customers providing stable revenue and tax base, and may offer competitive rates and expedited service. Colorado Springs Utilities, for example, has served data center developments and has generation capacity (including the Drake and Nixon coal plants – though both are scheduled for retirement in coming years – as well as renewable generation additions). Developers considering sites in municipal utility territories should engage utility leadership early to gauge interest and assess capacity.

Electric Cooperatives. Rural electric cooperatives such as Poudre Valley REA, United Power, Highline Electric, and others serve lower-density areas and generally obtain wholesale power from Tri-State or generate locally. Cooperatives vary widely in capacity and sophistication. Some cooperatives have served small data centers and telecommunications facilities successfully, while others lack the infrastructure to accommodate loads exceeding a few megawatts. Developers considering cooperative-served sites should conduct thorough due diligence on the specific cooperative's capacity, interconnection experience, and governance structure (cooperatives are member-owned, and large load service decisions may require board approval and member input).

II. Interconnection Process for Grid-Supplied Power

Regardless of which utility serves the site, interconnection for large data center loads follows a structured study process designed to identify system impacts and necessary upgrades before committing to service. The process is time-consuming, expensive, and subject to queue position (earlier-queued projects are studied first, and later projects must wait).

Small Generator Interconnection Procedures (Under 10 MW). The Colorado PUC's Electric Utility Interconnection Standards govern small, distributed generation resources from 10 kilowatts up to 10 megawatts. These procedures provide three interconnection levels: Level 1 for inverter-based systems up to 25 kilowatts with minimal study requirements; Level 2 for systems from 25 kilowatts to two megawatts with expedited review; and Level 3 for systems from two megawatts to 10 megawatts requiring supplemental review. Data centers under 10 megawatts (relatively rare in the hyperscale context but applicable to edge computing facilities) may use these streamlined procedures, which provide faster timelines and lower study costs than large generator procedures. However, even under small generator procedures, the utility may require system upgrades if the interconnection affects distribution system reliability, power quality, or protection schemes.

Large Generator Interconnection Procedures (Generally >10–20 MW). For larger projects, Xcel Energy applies its Large Generator Interconnection Procedures (Schedule GIP), which reference FERC Large Generator Interconnection Procedures for facilities exceeding 20 MW at transmission voltage. FERC Small Generator Interconnection Procedures ("SGIP") may also apply in appropriate cases for generation components ≤20 MW. The process includes:

Application & Queue Position. The developer submits an interconnection request providing technical details on the facility's electrical characteristics, desired interconnection point, and proposed in-service date. The request is placed in the interconnection queue based on the date the application is deemed complete (including required deposit). Queue position determines study order. Xcel Energy currently has dozens of projects in queue, many of which are renewable energy generators seeking to interconnect under Colorado's renewable energy mandates, creating competition for study resources and network capacity.

Feasibility Study. The first study phase assesses whether interconnection is technically feasible, identifies the general location for interconnection (substation or transmission line), and provides preliminary cost estimates for utility-side interconnection facilities and any network upgrades. If the study identifies significant network upgrade needs, such as a new substation, transmission line reconductoring, or protection system upgrades, the developer must decide whether to proceed to the next study phase.

System Impact Study. The second phase provides detailed analysis of how the interconnection affects power flows, voltage stability, short circuit duty, and system protection on the transmission and distribution system. The study models the interconnection under various system conditions (peak load, light load, contingencies) and identifies all required network upgrades with more refined cost estimates. At this stage, developers often learn that network upgrade costs will be substantial, prompting reconsideration of the site or exploration of alternative interconnection points.

Facilities Study. The final study phase provides engineering designs and firm cost estimates for all required interconnection facilities and network upgrades, including equipment specifications, construction schedules, and cost allocation between the developer and the utility. Upon completion, the developer and utility negotiate an interconnection agreement specifying construction responsibilities, cost-sharing, operational protocols, and in-service dates.

III. Network Upgrade Costs & Allocation

One of the most significant financial considerations in Colorado interconnection is the allocation of network upgrade costs. When a new large load interconnects, it may trigger the need for transmission line upgrades, substation expansions, new protection equipment, or other system improvements to maintain reliability and accommodate the new demand. These costs can range from negligible (if the interconnection point has ample capacity) to significant (if a new substation or multi-mile transmission line is required).

Current Cost Allocation Framework. Under traditional utility ratemaking, network upgrades benefiting the entire system are typically recovered through utility rates paid by all customers, while upgrades benefiting only the interconnecting customer (such as the service drop from the utility system to the customer's meter) are paid by the customer. However, data centers blur this distinction: network upgrades may be necessary only because of the data center's load, but once built, the upgrades benefit the overall system. Colorado utilities, concerned about non-data center ratepayers bearing costs for infrastructure serving data centers, have sought PUC approval for interconnection agreements requiring developers to fund network upgrades directly, either through upfront payment or through higher rates over the service contract term.

Colorado Large-Load Tariff Developments. In November 2025, the Colorado PUC adopted guiding principles for service to large-load customers and directed Xcel Energy to file a more detailed large-load tariff proposal by January 31, 2026 as part of its Electric Resource Plan proceeding (Proceeding No. 24A-0442E). The PUC-adopted guiding principles include:

Developer-Funded Upgrades. Data centers may be required to pay upfront for network upgrades, with potential credits or reimbursements if other customers subsequently benefit from the upgrades. This contrasts with traditional generator interconnection, where the utility funds network upgrades and recovers costs through rates.

Minimum Bill & Reserved Capacity Charges. Data centers may be required to pay for reserved transmission and distribution capacity even if actual usage is lower, ensuring that the utility recovers infrastructure costs regardless of data center utilization. This protects ratepayers from the risk that a data center underperforms, cancels, or curtails load after the utility has built costly infrastructure.

Security Deposits & Early Exit Fees. Developers may be required to post security deposits at interconnection application to demonstrate financial commitment. If the developer withdraws from the project or fails to reach commercial operation, the utility retains the deposit to offset costs incurred in design and permitting of upgrades. Similarly, if the developer terminates service before the contract term, early exit fees (liquidated damages) compensate the utility for unrecovered infrastructure investments.

Xcel Energy's forthcoming tariff proposal is anticipated to address co-located generation's impact on cost allocation, potentially with differentiated transmission charges based on actual grid usage (rather than full nameplate capacity) and minimum charges for backup service. This could influence approaches by other Colorado utilities and cooperatives, though structural and governance differences may limit direct applicability.

IV. Co-Located Power Generation: Models and Regulatory Frameworks

Given the challenges of traditional utility interconnection (long timelines, cost uncertainty, and limited control over power supply characteristics), co-located power generation has emerged as a critical strategic option for developers seeking to navigate interconnection congestion and grid capacity constraints. Co-location involves generating facilities sited at or immediately adjacent to data centers, providing some or all of the facility's electrical load either behind the meter or through networked interconnection arrangements.

On December 18, 2025, FERC ordered PJM Interconnection to revise its tariff to provide greater clarity and options for co-located loads at generating facilities (stemming from arrangements such as data centers co-located with nuclear plants). The order applies to PJM's footprint and is not directly applicable in Colorado, but it may influence how Colorado utilities and the PUC address co-location arrangements, such as in Xcel Energy's upcoming tariff proposal. FERC directed PJM to propose revisions offering four transmission service options (including firm and non-firm service, with options for partial load service and acceptance of curtailment risk) and mechanisms such as minimum monthly charges for grid reliability and backup capability.

Models of Co-Located Generation

Co-located generation encompasses several distinct operational and regulatory models, each with different interconnection requirements, cost allocation structures, and reliability implications.

Behind-the-Meter Generation. In a pure behind-the-meter ("BTM") model, the generating facility serves the data center load directly without delivering power through the transmission or distribution system, except during outages or maintenance when the data center draws from the grid. The generator and load are on the customer side of the utility revenue meter. BTM generation may avoid full PUC jurisdiction if not selling power into wholesale markets, though interconnection agreements with the serving utility are still required for backup grid service. Air quality permitting under CDPHE Regulation 7 applies to combustion sources, and county 1041 review treats BTM generation as a major electrical facility in many jurisdictions. Water rights are also required if evaporative cooling is used for generation. Utility concerns about cost-shifting and infrastructure under-recovery are prominent in BTM discussions, as utilities argue that BTM loads benefit from grid availability during outages or maintenance without paying proportionate infrastructure costs.

Networked Co-Located Load. Under this model, the data center receives power from both the co-located generator and the grid, with the utility providing various transmission service options for the portion of load not served by the co-located generator. FERC's December 18, 2025, order addresses this configuration in PJM, directing revisions to ensure co-located loads pay for transmission service commensurate with their reliance on the grid, including mechanisms to prevent co-location from shifting transmission costs to other customers. In Colorado, similar approaches may emerge through Xcel Energy's forthcoming large-load tariff proposal, which is expected to address co-located generation's impact on cost allocation – potentially with differentiated charges based on actual grid usage (rather than full nameplate capacity) and minimum charges for backup service. Networked co-location offers operational flexibility (the data center can draw from both the generator and grid based on economics or reliability needs, including through options accepting curtailment risk), but requires careful coordination with the serving utility on transmission service, cost allocation, and operational protocols.

Hybrid Models with Battery Energy Storage Systems. Many co-located projects integrate BESS to smooth generator output, provide spinning reserve, and enable participation in wholesale energy markets or utility demand response programs. BESS paired with renewable generation (solar, wind) addresses intermittency, allowing the data center to maintain stable power supply during low renewable output periods. BESS paired with natural gas reciprocating engines or combustion turbines can reduce engine run-time, lowering air emissions and fuel consumption while maintaining reliability. Colorado's regulatory framework for BESS is maturing, with the PUC addressing BESS interconnection, ownership structures (utility-owned versus customer-owned), and market participation rules in recent proceedings.

V. Co-Located Generation Technologies in Colorado

Natural Gas Reciprocating Engines. Reciprocating internal combustion engines burning natural gas are the most common co-located generation technology for data centers nationally and increasingly in Colorado. Engines offer high electrical efficiency, modular scalability (units typically range from 1 to 20 megawatts, allowing phased build-out), fast start capability, and compatibility with existing natural gas distribution infrastructure along Colorado's Front Range. Air permitting under CDPHE Regulation 7 is required, with emissions limits for nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter. Engines equipped with selective catalytic reduction (SCR) and oxidation catalysts can achieve low emission rates suitable for attainment areas, though projects in nonattainment areas or near environmental justice communities face heightened scrutiny. Noise is a significant consideration, as reciprocating engines generate substantial operational noise requiring acoustic enclosures, setbacks, and noise modeling to demonstrate compliance with county standards and minimize community impact. Water cooling (either evaporative or recirculating with dry coolers) is typically required, implicating water rights and cooling tower permitting.

Combustion Turbines & Combined-Cycle Systems. Combustion turbines (gas turbines) burning natural gas offer higher capacity per unit and potentially lower NOx emissions than reciprocating engines, making them suitable for large data center campuses. Simple-cycle turbines have lower capital costs but also lower electrical efficiency. Combined-cycle configurations, which recover turbine exhaust heat to generate steam and drive a steam turbine, achieve higher efficiency but require larger footprints and higher capital investment. Air permitting is similar to reciprocating engines but with different emission profiles (combustion turbines typically emit less CO and VOCs but may require additional NOx controls). Turbines require high-quality fuel and may need gas treatment facilities. Water demand for turbine cooling can be substantial, particularly in combined-cycle configurations.

Solar Photovoltaic Paired with BESS. Solar generation paired with BESS offers emissions-free operation, alignment with corporate sustainability goals, and eligibility for federal Investment Tax Credit ("ITC") under the Inflation Reduction Act (as amended). However, the 2025 clean energy tax amendments accelerated ITC phase-outs: solar projects must begin construction by July 4, 2026, and achieve commercial operation by December 31, 2027, to qualify for the 30 percent ITC, with steep reductions thereafter. BESS, by contrast, retains favorable ITC treatment through 2033, making solar-plus-storage projects highly time-sensitive. Solar-plus-BESS co-location requires substantial land area (five to seven acres per megawatt of solar capacity, depending on panel efficiency and site constraints), which may be impractical for urban or constrained sites. Interconnection with the grid is typically required to provide power during extended low-sun periods or BESS depletion. Air permitting is not required (no combustion), simplifying the regulatory pathway, though 1041 review, visual impact assessments, and glare studies may be required by counties.

Wind Generation Paired with BESS. Colorado's eastern plains and some mountain corridor areas have strong wind resources suitable for utility-scale wind generation. However, co-located wind for data centers faces challenges: wind turbines require substantial setbacks from structures and property lines (often 1,500 feet or more), limiting siting flexibility; turbine noise and shadow flicker can trigger community opposition; and wildlife impacts (avian and bat mortality) require extensive pre-construction surveys and operational mitigation. Wind-plus-BESS may be viable for large campus developments on expansive sites but is less practical than solar-plus-BESS for typical data center footprints.

Emerging Technologies (Small Modular Reactors, Hydrogen Fuel Cells, Geothermal). Small modular reactors ("SMRs"), advanced hydrogen fuel cells, and enhanced geothermal systems represent longer-term co-location options under active development nationally. As of 2026, none are commercially deployed at scale for data centers in Colorado, though pilot projects and feasibility studies are underway in other states. SMRs face Nuclear Regulatory Commission licensing (multi-year process), spent fuel management, and community acceptance challenges. Hydrogen fuel cells require hydrogen supply infrastructure (which is largely absent in Colorado outside of limited industrial uses) and economic viability relative to natural gas. Enhanced geothermal systems may become viable in Colorado's western slope or mountain regions but may require significant upfront geological assessment and drilling risk.

VI. Colorado Permitting Requirements for Co-Located Generation

Co-locating generation in Colorado triggers overlapping regulatory requirements across air quality, water rights, PUC jurisdiction, and local 1041 permitting.

Air Quality Permitting (CDPHE Regulation 7). All combustion-based generation requires air permitting. Projects emitting below *de minimis* thresholds may qualify for permit-by-rule or general permits with streamlined review. Larger projects require individual construction permits specifying emission limits, monitoring requirements, and compliance demonstration protocols. Air permit applications must include: (1) emissions calculations based on manufacturer data and operational profiles; (2) dispersion modeling demonstrating compliance with National Ambient Air Quality Standards and Colorado standards; (3) environmental justice narratives addressing impacts on disproportionately impacted communities (if applicable); (4) and BACT analysis for projects in PSD areas.

Water Rights (Prior Appropriation Doctrine). Evaporative cooling for co-located generation requires water rights procured under Colorado's prior appropriation system. Developers must either: acquire existing water rights through purchase or lease (subject to Water Court approval of the change in use, place of use, point of diversion, and sometimes change of use); obtain new appropriations (extremely difficult in over-appropriated basins like the South Platte); or secure treated municipal water supply through contracts with municipalities or special districts (if the municipality has surplus capacity and is willing to serve industrial loads). Augmentation plans (to offset out-of-priority depletions) may be required for certain water sources, adding complexity and cost.

PUC Jurisdiction (Qualifying Facility Status & Utility Regulation). Under the Public Utility Regulatory Policies Act (PURPA), small power production facilities (cogeneration facilities or facilities using renewable energy) under 80 megawatts that meet PURPA criteria are "qualifying facilities" exempt from certain state utility regulation. Qualifying facilities must file self-certification with FERC. Non-qualifying generation facilities may be subject to PUC jurisdiction as public utilities if they sell electricity to third parties or provide service to the public. Developers structuring co-located generation for a single data center load (not selling to others) generally avoid PUC utility regulation, but interconnection agreements with the serving utility are required and may be subject to PUC review. The Colorado PUC's evolving treatment of BTM and networked co-located loads are expected to be clarified through the pending Xcel Energy large-load tariff proceeding discussed earlier.

County 1041 Permitting. Co-located generation, particularly natural gas generation or large-scale solar arrays, typically triggers county 1041 review as a major electrical generating facility or major industrial development. The 1041 process requires: a detailed project description including generation technology, capacity, operational profile, and interconnection configuration; environmental impact assessments covering air emissions, water use, noise, traffic, visual impacts, and cumulative effects; an environmental justice analysis addressing whether the project disproportionately affects low-income or minority communities; public hearings before planning commissions and boards of county commissioners; and conditions of approval that may include emissions monitoring, noise limits, water use reporting, community benefit commitments, and payment of significant fees.

VII. Strategic Considerations for Co-Located Generation in Colorado

Co-located generation offers potential advantages – faster deployment, avoidance of interconnection queue delays, operational resilience, predictable long-term energy costs, and alignment with sustainability commitments – but introduces complexity and risk that must be carefully evaluated.

When Co-Location Advances Project Objectives:

- Interconnection queue delays exceed project timeline requirements
- Grid capacity at preferred sites is constrained or unavailable
- Long-term operational cost control justifies upfront capital investment in generation
- Corporate sustainability mandates require renewable energy that cannot be satisfied through utility green tariffs
- Operational resilience requirements favor dedicated on-site generation independent of grid reliability
- Wholesale market participation or demand response revenue streams are viable and economically attractive

When Traditional Utility Service May Be Preferable:

- Utility capacity is available with reasonable interconnection timelines
- Developer prefers to minimize permitting complexity and operational responsibility for generation
- Air permitting pathways for combustion generation face significant opposition or EJ concerns
- Water rights for evaporative cooling are unavailable or prohibitively expensive
- Site constraints (urban location, limited acreage, noise-sensitive surroundings) preclude viable generation configurations
- Utility rates are competitive and long-term rate trajectory is favorable

Hybrid Approaches. Many successful Colorado projects employ hybrid models combining utility service with co-located generation. For example, a data center might rely on utility service for base load with co-located natural gas engines providing peaking capacity and resilience, or might deploy solar-plus-BESS to offset a portion of load while maintaining full utility grid connection for reliability. Hybrid approaches require careful coordination with the utility on interconnection, cost allocation, and operational protocols, but offer flexibility and risk diversification.

VIII. Power Strategy Decision Framework

Developers should evaluate power strategy using a structured decision framework that considers:

Site-Specific Utility Capacity. Does the serving utility have generation and transmission capacity to serve the anticipated load without multi-year delays or prohibitive upgrade costs? If not, can alternative interconnection points be identified within reasonable distance? Is co-located generation technically and economically viable at the site?

Interconnection Timeline Constraints. Does the project's investor return model, customer commitments, or competitive positioning require faster deployment than traditional interconnection allows? Can co-located generation be permitted, constructed, and commissioned on a compressed timeline?

Cost Structure Preferences. Does the developer prefer utility service with predictable rates and the utility bearing supply risk, or is the developer willing to invest capital in onsite generation to achieve long-term operational cost savings and control? What are the comparative lifecycle costs of utility service versus co-located generation over 15 to 20 years?

Regulatory Risk Tolerance. Is the project able to navigate multi-jurisdictional permitting for onsite generation (air quality, water, 1041, PUC) or does the developer prefer to minimize permitting complexity by relying solely on utility service? What is the risk profile for air permits, water rights adjudication, and 1041 approval?

Sustainability & Carbon Goals. Do corporate sustainability commitments, investor ESG requirements, or customer preferences favor renewable energy generation? If so, can the utility provide renewable energy through green tariffs or power purchase agreements, or is onsite solar or wind generation necessary? What is the economic impact of federal tax credits (ITC for solar and BESS, with accelerated phase-outs under the 2025 clean energy tax amendments)?

Operational & Resilience Considerations. Does the data center require higher reliability than grid service provides (*e.g.*, five-nines uptime for critical applications)? Can co-located generation with BESS and backup utility service provide superior reliability? What are the operational risks of managing generation assets versus relying on utility service?

These questions do not have universal answers. Each project's optimal power strategy depends on site characteristics, financial structure, timeline requirements, and risk tolerance. The key is to ask these questions early (during initial site screening) rather than after land acquisition, when flexibility is reduced and costs to pivot are higher. Successful Colorado data center projects are those that design power strategy, cooling systems, air permitting, water sourcing, and site selection as an integrated whole, recognizing that power decisions cascade through every other project element.

Section 4: Water & Cooling Strategy – Navigating Colorado's Prior Appropriation Regime

Water availability and cooling technology selection are among the most determinative factors in Colorado data center development. Unlike jurisdictions where municipal water service is abundant and cooling technology choices are driven purely by efficiency and cost, Colorado requires developers to navigate a constitutional and statutory water allocation system that prioritizes existing uses over new demands, subjects new appropriations to multi-year court proceedings, and operates under conditions of sustained drought and interstate compact obligations. For data centers proposing evaporative cooling (which can consume 10 to 30 million gallons per year for a hyperscale facility), water strategy is often the difference between project viability and infeasibility.

This section explains Colorado's prior appropriation doctrine, Water Court adjudication processes, augmentation plan requirements, and alternative water sources including municipal supply and reuse water. It addresses cooling technology options (evaporative, air-cooled, hybrid, and liquid cooling) and their respective water demands, efficiency trade-offs, and regulatory implications. The through-line is that water strategy must be determined early, integrated with cooling design and air permitting, and supported by experienced water law counsel capable of navigating Colorado's unique legal framework.

I. Colorado's Prior Appropriation Doctrine

Colorado water law is governed by the doctrine of prior appropriation, codified primarily at Colorado Revised Statutes sections 37-92-101 through 37-92-602 and enshrined in Article XVI, Section 6 of the Colorado Constitution. The foundational principle is "first in time, first in right": water rights are ranked by priority date, and during times of insufficient supply, junior rights are curtailed before senior rights to ensure that senior appropriators receive their full decreed amounts.

Priority Dates & Administration. A water right's priority date is established by the date of the initial appropriation (either by decree from Water Court or by historical beneficial use predating the court adjudication system). In Colorado's major river basins (the South Platte, Arkansas, Colorado, Rio Grande, and others), many agricultural, municipal, and industrial water rights have priority dates from the 1800s or early 1900s, reflecting Colorado's history of mining, agriculture, and early settlement. A data center seeking to appropriate new water directly from a stream in 2026 would receive a priority date of 2026, making it junior to virtually all existing uses. During dry years, which are increasingly common due to multi-decade drought conditions documented in the Colorado Climate Action Plan and the Colorado Water Conservation Board's Colorado Water Plan, junior rights are "called out" (curtailed) by senior rights holders through the state's water administration system. This means a new 2026 appropriation would be unreliable, potentially receiving zero water during critical summer months when data center cooling demand is highest.

Beneficial Use & Non-Speculation. Colorado water law requires that appropriations be for beneficial use and prohibits speculative appropriations (securing water rights without intent to put water to use within a reasonable time). Data centers constitute beneficial industrial use, but applicants must demonstrate reasonable demand projections, facility plans, and timelines for putting water to use. Water Court judges scrutinize appropriation applications for speculation, and opponents frequently challenge applications on grounds that the applicant lacks firm development plans or is seeking more water than can be beneficially used.

Interstate Compacts & Federal Constraints. Colorado's water is further constrained by interstate compacts, most significantly the Colorado River Compact (allocating flows among seven western states) and the Arkansas River Compact with Kansas. These compacts impose delivery obligations on Colorado, limiting the amount of water available for new in-state uses. In the Colorado River Basin (western Colorado), the Colorado River Compact's allocation to Colorado is fully appropriated, meaning new uses can only be satisfied by purchasing existing rights or through storage and reuse. On the South Platte and Arkansas rivers (Front Range and southeastern Colorado), interstate compact obligations require Colorado to ensure adequate flows reach downstream states during specified periods. Data center water use on these systems must account for such obligations, which can complicate augmentation plan approvals.

II. Water Court & Augmentation Plans

Given the impracticality of obtaining new, reliable surface water appropriations with junior priority dates, most Colorado data centers pursue water supply through one of two pathways: purchasing water from a municipal utility, or obtaining an augmentation plan from Water Court allowing out-of-priority depletions in exchange for replacement water.

Water Court System. Colorado has seven Water Court divisions corresponding to its major river basins, each with a Water Judge and Water Referee who adjudicate water rights applications and disputes. Applications for new appropriations, changes of water rights, augmentation plans, and other water matters are filed in the division where the water is located or where the use will occur. The application is published in a resume (legal notice) in local newspapers, and any party with a potentially affected water right may file a statement of opposition. If no oppositions are filed, the application may be granted on an uncontested basis after consultation with the Division Engineer and the Colorado Water Conservation Board (which represents the state's interest in preserving stream flows and protecting the environment). If oppositions are filed, the matter proceeds to a hearing before the Water Referee, with both parties presenting expert testimony on hydrology, return flows, injury to other water rights, and other technical issues. The Water Referee issues findings and a ruling, which may be appealed to the Water Judge.

Augmentation Plans Explained. An augmentation plan is a court-decreed arrangement allowing a water user to make depletions that would otherwise be out-of-priority and injurious to senior rights, provided the user supplies replacement water to the stream system sufficient to prevent injury. For example, a data center might pump groundwater from wells for cooling tower makeup water. Pumping groundwater depletes the aquifer, which may be hydrologically connected to nearby streams, reducing streamflow and injuring downstream senior surface water rights. Assuming hydrologically connected to the surface water, to lawfully make these depletions, the data center obtains an augmentation plan decreeing that it will release stored reservoir water, treated effluent, or other replacement supplies into the stream on a timing and quantity basis sufficient to offset the depletions and prevent injury to senior rights.

The augmentation plan application must include: (1) hydrologic modeling quantifying the depletions (how much streamflow is reduced due to the data center's groundwater pumping, on what timeline, and at what locations); (2) identification of sources of replacement water (which must be legally available and are typically purchased reservoir storage rights, shares in ditch companies, or treated effluent from a wastewater treatment plant); (3) a plan of augmentation specifying how much replacement water will be released, when, and where, to offset the depletions; and (4) demonstration that the plan prevents injury to all senior water rights and complies with interstate compact obligations. The Division Engineer reviews the application for technical adequacy, and the Colorado Water Conservation Board reviews for consistency with state water policy and instream flow protection.

Opposition & Litigation Risk. Augmentation plan applications frequently draw opposition from: (1) senior ditch companies and irrigation districts concerned about injury to their members' agricultural water rights; (2) municipalities protecting their water supply portfolios; (3) environmental organizations advocating for instream flows and aquatic habitat; and (4) the Colorado Water Conservation Board if the plan is deemed inconsistent with state water policy. Oppositions raise issues such as: inadequate replacement water (claiming the applicant's proposed releases do not fully offset depletions); improper timing of releases (replacement water released in winter when depletions occur in summer); injury to vested rights (downstream users will experience reduced flows despite claimed augmentation); and environmental harm (depletions harm stream ecosystems or wetlands). Developers must be prepared to defend augmentation plans with robust hydrologic modeling, demonstrate legal availability of replacement water sources, and negotiate with opponents to resolve concerns. In some cases, augmentation plan litigation extends to trial, with dueling expert witnesses and appeals, adding years to project timelines.

III. Municipal Water Supply as an Alternative

Purchasing water service from a municipal utility (such as Denver Water, Aurora Water, Colorado Springs Utilities, South Metro Water Supply Authority, or smaller municipal systems) avoids the need for Water Court proceedings and augmentation plans. Municipalities hold large, senior water rights portfolios developed over decades through appropriations, reservoir construction, and purchases from agricultural users. Municipal utilities may have legal authority to provide water service within their jurisdictions and to customers outside city limits through special service agreements.

Capacity & Availability. The primary question when pursuing municipal water is whether the utility has available capacity to serve the data center's demand. Municipalities prioritize domestic, commercial, and fire protection uses for their residents and businesses. Industrial users, including data centers, are lower priority during drought conditions and may face curtailment or surcharges when supplies are constrained. Developers should engage municipal water providers early in site selection to discuss: (1) whether the utility has surplus capacity beyond projected growth in domestic and commercial demand; (2) what happens during drought – will the data center face mandatory reductions or cutoffs?; (3) what rates apply (municipal industrial rates may be higher than agricultural or raw water rates, and some utilities impose demand charges based on peak usage); and (4) whether the data center must contribute to water supply infrastructure costs (new wells, pipelines, treatment plant expansions, etc.). Not all municipalities are willing to serve large industrial users, particularly where population growth is consuming available supply. Denver Water, for example, serves a growing metro area and has limited surplus capacity for new large industrial loads. Smaller municipal utilities in slower-growth areas, by comparison, may have more willingness and capacity to serve data centers.

Service Agreement Terms. Municipal water service agreements for data centers should address: (1) contract term (15 to 30 years typical to align with data center lifespan); (2) reserved capacity (maximum daily and annual usage the utility commits to provide); (3) rate structure (volumetric charges, demand charges, connection fees); (4) drought curtailment protocols (at what stage of drought restrictions does the data center face mandatory reductions, and by what percentage?); (5) treatment standards (potable versus raw water; some utilities will provide non-potable water at lower cost for industrial cooling); (6) infrastructure improvements (if the utility must extend water mains or upsize treatment facilities to serve the data center, who pays?); and (7) termination provisions (what happens if the data center closes or demand is significantly lower than projected?). Municipalities are generally risk-averse and prefer to avoid long-term commitments that could constrain their ability to serve future residential growth, so negotiations can be lengthy and may require data center concessions such as subordination to residential uses during severe drought.

IV. Reuse Water: An Emerging Solution

Colorado Revised Statutes section 37-60-126 authorizes municipalities and wastewater treatment districts to provide treated effluent (reuse water) for non-potable industrial uses, including data center cooling. Reuse water has emerged as one of the most promising strategies for data centers seeking to avoid augmentation plans while securing reliable, cost-effective supply.

Legal Framework. Under Colorado law, once water is diverted, used, and returned to a wastewater treatment system, the treated effluent is considered "fully consumed" for purposes of the original water right and can be reused without further diminution of the original right holder's entitlement. This means municipalities can treat wastewater to high standards (Class A reuse water, suitable for irrigation and industrial use with minimal human contact) and sell or provide it to industrial users without needing new water rights or augmentation plans. The reuse water is not subject to priority administration because it represents water that has completed its use cycle. However, reuse water use is subject to permitting by the CDPHE's Water Quality Control Division to ensure that reuse does not cause public health risks or water quality violations.

Availability in Colorado. The Metro Wastewater Reclamation District, serving the Denver metro area, operates a water reuse program providing Class A reuse water through dedicated pipelines to industrial and irrigation customers. Other municipal wastewater treatment plants throughout Colorado (including Aurora, Colorado Springs, Fort Collins, and others) have capacity to provide reuse water, though infrastructure (pipelines from treatment plant to data center site) may need to be constructed. Reuse water pricing is typically lower than potable municipal water (reflecting the lower treatment costs for non-potable use) and provides a drought-resilient supply because wastewater generation continues even during drought (people continue to use water for indoor domestic purposes, generating sewage that is treated and available for reuse). For data centers requiring 10 to 30 million gallons per year, reuse water can provide the majority or entirety of cooling water needs, particularly if combined with efficient cooling tower operation and blowdown minimization.

Strategic Considerations. Reuse water is most attractive when: (1) the data center site is within reasonable distance (typically within 10 miles) of a wastewater treatment plant with available reuse water capacity; (2) the municipality or district is willing to enter into long-term reuse water agreements (some are, others prefer short-term contracts); (3) the data center's cooling system is designed to handle reuse water quality (which may have higher total dissolved solids or other constituents than potable water, requiring more frequent blowdown or treatment); and (4) the pipeline infrastructure costs to deliver reuse water to the site are economically justified by avoiding augmentation plan costs and timelines. Developers should evaluate reuse water availability during site screening and engage utilities early to negotiate terms.

V. Cooling Technology Options & Water Demand Implications

Cooling system selection determines water demand, energy efficiency, capital cost, and air permitting implications. The primary options are evaporative cooling, air-cooled (dry cooling), hybrid cooling, and liquid cooling.

Evaporative Cooling. Traditional evaporative cooling – using cooling towers where water is evaporated to reject heat from the data center's chilled water loop – is the most energy-efficient option, typically achieving Power Usage Effectiveness ("PUE") of 1.2 to 1.3 (meaning the facility uses 1.2 to 1.3 watts of total power for every watt of IT load, with the 0.2 to 0.3 overhead attributable to cooling and other infrastructure). Evaporative cooling is well-understood, cost-effective from a capital perspective, and widely deployed. However, it consumes significant water: approximately 25 to 35 gallons per megawatt-hour of IT load, translating to 10 to 30 million gallons per year for a 50-megawatt facility operating at 80 percent utilization. In Colorado, evaporative cooling triggers the water rights challenges discussed above: municipal supply negotiations, augmentation plans, or reuse water procurement. It also generates blowdown (concentrated mineral-laden water discharged from cooling towers) that requires disposal, typically through sanitary sewer discharge with pretreatment to meet municipal wastewater acceptance standards.

Air-Cooled (Dry Cooling). Air-cooled chillers or direct air cooling (using outside air to cool servers when ambient temperatures are low enough, and transitioning to mechanical cooling during warmer periods) eliminates or dramatically reduces water consumption. Colorado's climate, with significant diurnal temperature swings, low humidity, and cool nights even during summer, makes air cooling more viable than in hot, humid climates. However, air cooling imposes energy efficiency penalties: PUE typically increases to 1.4 to 1.6 (a 15 to 30 percent increase in total energy consumption compared to evaporative cooling), because mechanical chillers must work harder to reject heat to warm ambient air rather than relying on evaporative cooling's efficiency. This energy penalty translates to higher operating costs (electricity consumption) and higher greenhouse gas emissions if electricity is sourced from fossil fuel generation. The trade-off is elimination of water rights risk, augmentation plan costs and timelines, and community concerns about water use in a drought-prone state. For projects where water supply is infeasible or prohibitively expensive, air cooling is the fallback option despite the efficiency penalty.

Hybrid Cooling. Hybrid systems combine evaporative and air-cooled components, using air cooling during cooler months and limited evaporative cooling during peak summer temperatures. This approach reduces water consumption by 50 to 70 percent compared to full evaporative cooling while maintaining better efficiency than pure air cooling (PUE of 1.3 to 1.4). Hybrid cooling offers a middle ground, though it involves higher capital cost (deploying both cooling tower and air-cooled chiller infrastructure) and more complex controls. Hybrid systems are increasingly common in Colorado as developers seek to balance water constraints with efficiency goals.

Liquid Cooling. Direct-to-chip liquid cooling and immersion cooling technologies, where servers are cooled by liquid in direct contact with processors or submerged in dielectric fluid, are emerging solutions for high-density AI and machine learning workloads. These technologies dramatically reduce or eliminate the need for facility-level chilled water systems, as heat is captured at the chip level and rejected through closed-loop heat exchangers. Liquid cooling can reduce data center PUE to 1.1 or lower and may require minimal water (only for rejecting heat from the closed-loop heat exchanger, which can be done via air-cooled heat exchangers). However, liquid cooling is more expensive (in terms of both capital and operational complexity), not yet proven at hyperscale, and applicable primarily to high-density computing rather than traditional server rack configurations. As AI workloads grow, liquid cooling may become more prevalent, offering water-efficient pathways for future developments.

VI. Strategic Water & Cooling Planning Framework

Water and cooling strategy should be determined during site selection using the following framework:

Site Screening for Water Availability. Evaluate whether the site has: (1) access to municipal water service with available capacity (contact utility directly to confirm); (2) proximity to reuse water sources (within 10 miles of wastewater treatment plant with reuse program); and (3) a feasible augmentation plan scenario (groundwater availability, proximity to streams for replacement water, absence of highly-contested senior rights). Sites lacking all three options should be deprioritized or designed for dry/hybrid cooling from the outset.

Cooling Technology Decision. If evaporative cooling is essential to project economics (due to efficiency requirements, investor return expectations, or operational cost targets), water supply must be secured before site acquisition through municipal service agreements, reuse water contracts, or commitments to pursue augmentation plans with the applicable Water Court. If water supply is uncertain or augmentation plans face likely opposition, design for air-cooled or hybrid cooling from the beginning, incorporating the efficiency penalty into financial models and interconnection capacity planning (air cooling increases total facility load, affecting utility interconnection requirements).

Integrate with Air Permitting. If co-located generation is contemplated (*see* Section 3), generator cooling water compounds data center cooling water demand. For a 100-megawatt data center with 50 megawatts of co-located gas recips, total evaporative cooling water demand could reach 40 to 60 million gallons per year, significantly increasing augmentation plan complexity and costs. Dry or hybrid cooling for co-located generation may be necessary to keep total water demand within manageable limits.

Section 5: Siting Strategy – Balancing Technical Requirements, Regulatory Constraints & Community Acceptance

Site selection is the most consequential early decision in Colorado data center development, setting the trajectory for entitlement and permitting timelines, community acceptance, infrastructure costs, and ultimate project feasibility. Colorado's variable regulatory overlay (1041 or equivalent, EJ, water availability, utility capacity, wildfire/wildlife considerations) demands multi-factor evaluation from the outset.

This section provides a framework for evaluating prospective sites against Colorado-specific criteria, identifying common site selection pitfalls, and structuring due diligence to surface risks before land acquisition. It addresses fiber infrastructure, utility capacity, environmental constraints (wildlife habitat, wetlands, floodplains), wildfire risk, transportation access, workforce availability, and political considerations. The overarching message is that Colorado rewards comprehensive site screening (evaluating 10 to 20 sites against a detailed matrix of technical and regulatory criteria) over opportunistic site acquisition based on availability and price alone.

I. Technical Requirements: The Non-Negotiables

Certain technical requirements are absolute prerequisites for data center viability, and sites lacking these characteristics should be eliminated from consideration immediately regardless of other attributes.

Fiber Connectivity & Latency. Data centers require redundant, diverse fiber optic connectivity with low latency to major internet exchange points and cloud regions. In Colorado, primary fiber routes follow Interstate 25 (Denver north to Fort Collins and Cheyenne, south to Colorado Springs and Pueblo) and Interstate 70 (Denver west to the mountains and Utah, east to Kansas). Sites within five miles of these corridors typically have access to multiple fiber providers including Zayo, Level 3 (now Lumen), Comcast Business, and others. Sites in rural areas distant from major fiber routes may require construction of lateral fiber connections, which can add significant costs to the project and involve permitting constraints for rights-of-way across private property, county roads, and potentially state or federal lands. Latency to major cloud regions – AWS US-West (Oregon), Google Cloud US-Central (Iowa), Azure West US (Washington) – should be evaluated for sites serving latency-sensitive applications. Denver metro sites typically achieve sub-20 millisecond latency to US-West regions, which is acceptable for most applications. Edge computing facilities serving real-time applications (gaming, autonomous vehicles, AR/VR) may require more restrictive latency thresholds.

Electric Utility Service & Capacity. As addressed in Section 3, sites must have access to an electric utility with sufficient generation and transmission capacity to serve the anticipated load. For hyperscale facilities (50 to 200 megawatts), this typically limits viable sites to: (1) Xcel Energy territory along the Front Range with proximity to existing transmission lines (115 kV or 230 kV); (2) Tri-State member cooperative territories with available substation capacity; or (3) municipal utility territories where the utility has expressed willingness to serve large loads. Rural cooperative territories distant from transmission infrastructure are generally infeasible for hyperscale development without developer-funded transmission construction. During site screening, developers should obtain preliminary capacity assessments from utilities (available informally in some cases, or through formal pre-application meetings) to confirm that the utility can serve the load within the project's timeline and budget constraints for network upgrades.

Seismic & Geotechnical Stability. Colorado's Front Range is generally low seismic risk (USGS Seismic Hazard Maps show Peak Ground Acceleration of less than 0.1g for most areas, corresponding to minimal earthquake risk), but certain areas have geotechnical challenges including expansive soils (bentonite clays that swell when wet, causing foundation movement), collapsible soils, shallow groundwater, and historical mining subsidence in mountain communities. Geotechnical investigations (soil borings, laboratory testing, and foundation design recommendations) are thus essential during due diligence. Sites with expansive soils may require deep foundations (piers or caissons extending to stable strata) or soil stabilization (lime treatment or moisture barriers), increasing foundation costs by 20 to 50 percent. Historical mining areas (particularly in mountain counties with gold, silver, or coal mining history) pose subsidence risk and should generally be avoided unless detailed mine maps and stability assessments confirm safety.

Water Availability. As discussed in Section 4, sites must have a viable pathway to water supply (whether municipal service, reuse water access, or feasible augmentation plan scenarios) if evaporative or hybrid cooling is intended. During site screening, confirm that the site is within the service area of a municipal water utility, or within reasonable distance (10 miles or less) of reuse water sources, or has groundwater availability with proximity to streams for augmentation. Sites in isolated rural areas distant from municipal infrastructure and lacking viable groundwater may be limited to air-cooled designs.

II. Regulatory & Environmental Constraints

Beyond technical requirements, Colorado sites must be evaluated for regulatory and environmental constraints that can delay, increase costs of, or prohibit development.

County 1041 Regulations & Permitting. As discussed in Section 2, numerous Colorado counties have 1041 regulations designating major electrical facilities, energy infrastructure, or significant water uses as requiring special review. During site screening, developers should obtain a copy of the county's 1041 regulations and determine whether data centers are designated activities. If so, developers must then evaluate the county's 1041 review criteria, procedural requirements (public hearings, technical studies, timeline), and track record with industrial projects. Counties with transparent 1041 processes, a history of approving energy or technology projects, and a pro-business political climate present lower risk than counties without 1041 precedent or with histories of denying industrial development. Adams County and Weld County have approved multiple data center and technology projects and have relatively predictable 1041 processes. Boulder County and some mountain counties, by comparison, have more restrictive land use policies and higher bars for approval of industrial development.

Environmental Justice Demographics. Using EPA's EJScreen tool, evaluate whether the site is located in or within two kilometers of census tracts with high environmental justice scores. EJScreen provides composite indices reflecting minority population percentage, low-income population, linguistic isolation, and proximity to pollution sources. Sites with EJScreen scores in the 80th percentile or above (nationally) for multiple indicators face heightened air permitting scrutiny, 1041 review complexity, and community opposition. Urban areas including north Denver, Commerce City, Pueblo, and parts of Colorado Springs have census tracts with high EJ scores. Suburban and rural areas generally have lower scores, though specific tracts should be evaluated. If the site is in a high-EJ area, developers should either select an alternative site or be prepared for extended permitting timelines, enhanced community engagement requirements, and the potential for organized opposition.

Wildlife Habitat & Threatened Species. The U.S. Fish and Wildlife Service's Information for Planning and Consultation ("IPac") website offers a planning tool for developers to identify species of concern, including species listed as threatened and endangered under the Endangered Species Act. The Colorado Wildlife Action Plan prioritizes conservation areas for sensitive species. Key species of concern in data center development areas include:

Preble's Meadow Jumping Mouse. Listed as threatened under the Endangered Species Act, this species occurs in riparian areas along the Front Range from Fort Collins to Colorado Springs. Sites within or near the species' habitat face federal consultation requirements under Section 7 of the Endangered Species Act (if federal permits or funding are involved) or conservation measures to avoid prohibited "take" under Section 9 of the Endangered Species Act. Sites near designated "critical habitat" in certain riparian areas may face heightened Section 7 consultation and mitigation requirements. Mitigation may include habitat buffers, seasonal construction restrictions, or conservation easements.

Burrowing Owl. Though not federally listed, this species of concern occupies prairie and grassland habitats throughout eastern Colorado. Occupied burrows must be avoided during nesting season (March through August), potentially delaying construction. Pre-construction surveys are recommended.

Raptors (Ferruginous Hawk, Bald Eagle, Golden Eagle). Nesting raptors are protected under the Migratory Bird Treaty Act, Bald and Golden Eagle Protection Act, and Colorado's nest protection statutes. Active nests within or near project sites require seasonal buffers (typically 0.5 to one mile depending on species and activity level) during nesting season. Transmission lines and tall structures must be designed to minimize electrocution and collision risk (raptor-safe pole designs, bird flight diverters, etc.).

During site screening, developers should conduct desktop habitat assessments using Colorado Parks & Wildlife data and aerial imagery to identify potential habitat. Sites with obvious riparian corridors, prairie dog colonies (which attract prey), or known raptor nesting areas should be flagged for field surveys. Early engagement with Colorado Parks & Wildlife biologists can provide guidance on whether surveys and seasonal buffers will be required, informing timeline and cost assumptions.

Wetlands & Waters of the U.S. and/or the State of Colorado. Sites containing wetlands or streams that constitute "Waters of the United States" ("WOTUS") are subject to Clean Water Act Section 404 jurisdiction, requiring permits from the U.S. Army Corps of Engineers ("USACE") for dredge or fill activities. Mitigation may include on-site wetland preservation, off-site mitigation bank credits, or wetland restoration. Sites with visible wetlands (vegetation, standing water, topographic depressions) should undergo early desktop wetland screening using National Wetlands Inventory maps and soil survey data. If wetlands are present and avoidance is not feasible, developers will need to factor Corps permitting into project timeline and budget.

In addition, Colorado recently enacted a program that supplements Section 404 of the Clean Water Act by regulating discharges of dredged or fill material into state waters that are not subject to federal jurisdiction. The program is administered by CDPHE's Water Quality Control Division. As of January 1, 2025, any person seeking authorization to discharge dredged or fill material into state waters not subject to federal jurisdiction must apply for a Temporary Authorization from the Division.

Floodplains. Development in 100-year floodplains (as mapped by FEMA in its Flood Insurance Rate Maps) generally is restricted by county floodplain regulations, typically requiring elevation of structures above base flood elevation or floodproofing. Data centers, with their significant electrical infrastructure, generators, and BESS equipment, are particularly vulnerable to flood damage and should generally avoid floodplain locations. If a site includes floodplain areas, confirm that developable portions are outside the floodplain or that the county allows fill and elevation mitigation.

Wildfire Risk. Colorado's increasing wildfire activity poses a risk to data centers in wildland-urban interface areas, particularly in mountain communities and foothills. Sites in high or very high wildfire hazard areas face: (1) higher insurance premiums or limited insurance availability; (2) county development restrictions (defensible space requirements, fire-resistant construction, limited densities); and (3) operational risk (wildfires can cause power outages, road closures preventing employee access, and smoke affecting air quality and cooling system intakes). For sites in moderate to high wildfire zones, evaluate wildfire mitigation measures, including defensible space (vegetation clearing within 100 feet of structures), fire-resistant building materials, on-site water storage for fire suppression, and redundant transportation access in case primary routes are blocked by fire. Sites in very high hazard areas (mountain corridors or heavily forested areas) are generally unsuitable for data centers unless extraordinary wildfire mitigation is implemented.

III. Infrastructure & Accessibility

Beyond the site itself, surrounding infrastructure determines construction cost, operational efficiency, and community impact.

Transportation Access. Data centers require truck access for construction (delivery of generators, chillers, electrical switchgear, building materials) and ongoing operations (equipment replacement, fuel delivery if on-site generation, employee commuting). Sites should have direct access to arterial roads or highways capable of handling 40-foot and 53-foot semi-trailers without requiring specialized permits or route surveys. County road departments should be consulted regarding weight restrictions, seasonal load limits (some counties restrict heavy trucks on rural roads during spring thaw), and road maintenance responsibility. If the site requires road improvements (widening, paving gravel roads, intersection upgrades) to accommodate construction traffic, these costs must be budgeted, and CDOT or county public works approvals must be factored into timeline.

Proximity to Workforce. Data centers require operational staff including facility managers, electrical and mechanical technicians, network engineers, and security personnel. While staffing levels are modest compared to manufacturing (typically 50 to 150 employees for a hyperscale facility), sites should have reasonable commute times (under 45 minutes) to population centers where a technical workforce resides. The Denver metro area, Colorado Springs, Fort Collins, and Boulder all provide strong pools of technical talent due to the strong presence of technology companies, the aerospace industry, and universities. Rural sites distant from such workforce centers face challenges recruiting and retaining staff, potentially requiring premium wages or employer-provided transportation.

Community Context & Political Climate. While not a technical requirement, community receptivity materially affects permitting success and timeline. Counties and municipalities with a history of supporting technology, energy, or industrial development are lower-risk than jurisdictions with strong environmental advocacy presence, anti-growth political movements, or records of denying industrial projects. Informal engagement with county commissioners, planning staff, and economic development offices during site screening may provide insight on whether the jurisdiction views data centers favorably and what concerns are likely to arise. Some counties actively market themselves to data center developers, offering expedited permitting, reduced fees, or economic development incentives. Others view data centers skeptically due to concerns about water use, energy consumption, or other localized impacts.

IV. Site Due Diligence & Risk Assessment

Once candidate sites are identified through initial screening, formal due diligence should confirm technical feasibility and quantify regulatory risks.

Phase I Environmental Site Assessment. Standard Phase I ESAs (ASTM E1527-21) identify recognized environmental conditions, including historical contamination, underground storage tanks, hazardous materials, and regulatory compliance issues. Colorado-specific considerations include historical oil and gas operations (abandoned wells, production pits), mining activity (tailings, subsidence), and agricultural chemical use (pesticides, fertilizers). Sites with recognized environmental conditions may require Phase II investigations (soil and groundwater sampling) and remediation, increasing costs and timeline.

Title & Survey. Confirm fee simple ownership or the availability of a long-term ground lease, the absence of deed restrictions prohibiting data center use and other covenants, conditions or restrictions affecting development, and the availability of necessary easements for access, utilities, and drainage. Surveys should identify property boundaries, encroachments, topography, and floodplain limits and meet the requirements for obtaining title insurance.

Utility Commitment Letters. Obtain written commitments from electric, water, gas (if applicable), and telecommunications utilities confirming their ability to serve the project, preliminary cost estimates for extensions or upgrades, and estimated timelines. For electric service, request a preliminary interconnection study or capacity assessment from the utility.

Preliminary Permitting Assessment. Engage environmental consultants to prepare preliminary air quality dispersion modeling (if onsite generation is contemplated), wetland reconnaissance, and habitat assessment. Engage water law counsel for preliminary analysis of water supply options (municipal service, augmentation plan feasibility, reuse water availability). Engage land use counsel for analysis of zoning, 1041 applicability, and county permit requirements.

Community & Stakeholder Interviews. Conduct confidential interviews with county planning staff, economic development officials, fire marshals, and utility representatives to gauge receptivity and identify concerns. If feasible without disclosing the specific site, discuss the project concept and solicit feedback on likely permitting pathway and timeline.

Section 6: Critical Infrastructure, Fire Code Compliance & Cybersecurity

Data centers are critical infrastructure, essential to commerce, communications, financial systems, and, increasingly, government operations and national security. This classification brings heightened regulatory scrutiny, operational standards, and design requirements beyond those applicable to typical commercial or industrial facilities. Colorado data centers must comply with stringent fire codes addressing battery energy storage systems, emergency backup generation, and fire suppression; implement comprehensive cybersecurity controls protecting sensitive data and operations from threats; and coordinate with local emergency services to ensure appropriate response capabilities.

This section addresses fire code requirements under NFPA 855 and related standards, building code and electrical code implications for high-density computing equipment, cybersecurity frameworks including CIRCIA reporting obligations and NIST standards, and operational security considerations. The through-line is that data centers face elevated compliance obligations reflecting their role as critical infrastructure, requiring early engagement with fire marshals, building officials, and cybersecurity regulators.

I. Fire Code Requirements for Battery Energy Storage Systems

Battery energy storage systems – whether deployed for backup power, utility grid services, or co-located generation – present unique fire safety challenges due to the potential for thermal runaway, a cascading exothermic reaction that can lead to fire, explosion, and toxic gas release. Multiple high-profile BESS fires nationally, including incidents in Arizona (2019) and California (2022), have driven increased regulatory attention and the development of NFPA 855.

NFPA 855 (2026 Edition). The National Fire Protection Association issued NFPA 855, *Standard for the Installation of Stationary Energy Storage Systems*, with the 2026 edition released in fall 2025 (adoption timing varies by jurisdiction). In Colorado, adoption of the IFC occurs at the local level and by the Colorado Division of Fire Prevention and Control for state-regulated occupancies. Many jurisdictions have adopted or are adopting the 2024 IFC, which incorporates NFPA 855. NFPA 855 imposes comprehensive requirements for BESS installations including:

Fire Testing (UL 9540A). BESS installations are generally required to undergo UL 9540A testing, a standardized fire test method characterizing the thermal runaway behavior of specific battery cell, module, and unit configurations. The test measures heat release rate, time to thermal runaway propagation, off-gassing composition, and explosion potential. Test results inform system design, including fire suppression agent selection, ventilation requirements, and separation distances. Developers must confirm that proposed BESS products have completed UL 9540A testing and that installation design complies with test-based spacing and protection requirements.

Fire Suppression Systems. NFPA 855 requires automatic fire suppression systems for indoor BESS installations and certain outdoor installations. Acceptable suppression agents include water (sprinklers or water mist systems), clean agents (FM-200, Novec 1230), or aerosol systems, with selection based on UL 9540A test data demonstrating suppression effectiveness for the specific battery chemistry. Water-based systems are often most cost-effective but require drainage systems to manage suppression water runoff, which may be contaminated with battery electrolyte. Clean agent systems avoid water damage but are more expensive and may require larger agent storage volumes for large BESS installations.

Deflagration Venting. BESS enclosures must include deflagration venting (explosion relief panels) sized to relieve pressure if thermal runaway generates rapid gas expansion. Venting must be directed away from personnel areas, building openings, and property lines.

Separation Distances. NFPA 855 specifies minimum separation distances between BESS units and between BESS and occupied structures, based on battery energy capacity and chemistry. Applicable distances depend on technology, capacity, listing, and whether prescriptive tables or UL 9540A-based alternatives are used. Reduced distances may be permitted with approved fire-resistance-rated barriers or as otherwise authorized by the local authorities. Separation from occupied buildings ranges from 10 to 100 feet depending on BESS size. Lithium-ion installations typically require 10 to 20 feet separation between BESS containers and three feet between individual battery racks within containers.

Ventilation. Indoor BESS rooms require mechanical ventilation to exhaust off-gas during thermal runaway events, preventing accumulation of flammable or toxic gases. Outdoor BESS containers may require passive or active ventilation depending on configuration.

Emergency Response Plan. NFPA 855 requires site-specific emergency response plans addressing BESS fire scenarios, including coordination with local fire departments, evacuation procedures, and hazard communication. Plans should be coordinated with the local authorities. Fire departments must be trained on BESS fire response tactics (which differ from traditional structural firefighting) and provided with site layout information, battery chemistry data, and pre-incident plans.

Local Fire Marshal Variations. While NFPA 855 provides the baseline, local fire marshals in Colorado jurisdictions (including Adams County, Douglas County, and others) have issued supplemental guidance imposing requirements beyond NFPA minimums. Common local requirements include: (1) increased separation distances (*e.g.*, 50 feet from property lines); (2) mandatory thermal imaging systems to detect hot spots indicating potential thermal runaway; (3) fire department access roads surrounding BESS installations to enable apparatus positioning; (4) on-site water supply for fire suppression (hydrants or storage tanks); and (5) financial commitments to local fire departments for training and equipment (thermal imaging cameras, gas monitors, specialized personal protective equipment). Developers should engage local fire marshals early in design to understand jurisdiction-specific requirements and incorporate them into site layout and BESS equipment selection.

II. Building & Electrical Code Considerations

Data centers are classified as Group B (Business) occupancies under the International Building Code as adopted in Colorado, but their electrical loads, cooling systems, and equipment densities create design challenges requiring careful code analysis.

High Electrical Loads & Emergency Power. Data centers' electrical loads (measured in watts per square foot) far exceed typical commercial buildings. Server halls may have electrical densities of 200 to 500 watts per square foot, compared to 20 to 50 watts per square foot for office buildings. The National Electrical Code (as adopted in Colorado, with local amendments) requires that electrical systems be sized for actual load, with appropriate conductor sizes, overcurrent protection, and grounding. Emergency and standby power systems must comply with Articles 700, 701, and 702 of the National Electric Code, with distinctions between life safety systems (egress lighting, fire alarms), legally required standby systems (HVAC for smoke control), and optional standby systems (IT equipment). Data centers typically deploy uninterruptible power supplies ("UPS") providing instantaneous backup for IT loads (batteries carrying load for 10 to 15 minutes while diesel or gas generators start) and generators providing extended runtime. Generator fuel storage (diesel above-ground or underground storage tanks) must comply with applicable fire codes, environmental regulations (spill prevention, secondary containment), and local zoning.

Structural Loads. Server racks, BESS containers, and cooling equipment impose significant floor loads, often 250 to 500 pounds per square foot for raised-floor data halls. Structural design must account for these loads, particularly for adaptive reuse projects converting warehouses or other structures not originally designed for data center loads. Foundation and floor slab reinforcement, or structural framing upgrades, may be required, increasing construction costs.

Fire-Resistance-Rated Construction. While Group B occupancies generally require one to two hour fire-resistance ratings for structural elements depending on building height and area, data centers may voluntarily increase fire ratings (*e.g.*, three-hour concrete construction) to provide additional protection for high-value equipment and to satisfy insurance underwriters. Fire-resistance-rated separations between data halls, mechanical rooms, and administrative areas limit fire spread and allow continued operation of unaffected portions if fire occurs in one area.

III. Cybersecurity Frameworks & CIRCIA Compliance

Data centers handling sensitive information (financial data, healthcare records, government information, critical infrastructure control systems) are subject to cybersecurity obligations at federal and state levels, primarily based on the nature of the data processed, the industries served, and applicable contractual or regulatory frameworks.

Cyber Incident Reporting for Critical Infrastructure Act ("CIRCIA"). Enacted in 2022, CIRCIA requires covered entities – including certain operators and service providers within designated critical infrastructure sectors, which may include some data center providers serving certain sectors – to report substantial cyber incidents to the Cybersecurity and Infrastructure Security Agency ("CISA") within 72 hours and to report ransomware payments within 24 hours. CISA's proposed implementing regulations (expected final rule in Q1-Q2 2026) will define covered entities, incident thresholds, and reporting procedures. Data centers that support critical infrastructure customers should monitor CIRCIA rulemaking and implement incident detection and reporting capabilities to ensure compliance when those regulations become effective.

NIST Cybersecurity Framework. The National Institute of Standards and Technology's ("NIST") Cybersecurity Framework (NIST CSF 2.0, released February 2024) provides voluntary guidance for managing cybersecurity risk through six core functions: Govern, Identify, Protect, Detect, Respond, Recover. While voluntary for the private sector, NIST CSF has become the *de facto* standard, and many data center customers contractually require service providers to demonstrate NIST alignment. Colorado's Information Security Act (Colorado Revised Statutes sections 24-37.5-401 to -407) requires state agencies and third-party IT service providers supporting those agencies to implement security controls consistent with NIST standards, creating compliance obligations for data centers serving government clients.

FERC / NERC Critical Infrastructure Protection (CIP) Standards. The North American Electric Reliability Corporation's ("NERC") CIP Reliability Standards, which are approved and enforced through FERC, apply to registered entities responsible for the reliable operation of the bulk electric system ("BES") and to their applicable BES Cyber Systems. Data center operators are not categorically subject to CIP requirements; however, compliance obligations may arise where a data center is itself a registered entity, hosts or operates BES Cyber Systems on behalf of a registered entity, or provides facilities or services that fall within a registered entity's CIP compliance boundary, typically through contractual flow-down obligations. In FERC Order No. 907 (issued June 2025), FERC approved NERC CIP-015-1, which requires registered entities to implement internal network security monitoring for high- and medium-impact BES Cyber Systems. These requirements focus on internal network visibility, anomaly detection, logging, alert review, incident response integration, and evidence retention to identify and respond to malicious activity within protected environments. Data center operators supporting electric utilities or grid-related infrastructure should work with legal counsel to assess whether their interconnection architecture, hosted systems, or managed services place them within the scope of NERC CIP requirements or related contractual compliance obligations.

Physical Security & Access Control. Beyond cyber threats, data centers face physical security risks, including unauthorized access, theft, vandalism, and insider threats. Industry best practices include: (1) perimeter fencing and gate access control (card readers, biometric authentication); (2) video surveillance covering all entrances, data halls, and equipment areas; (3) man-trap entries (two-door vestibules requiring authentication at each door, preventing tailgating); (4) visitor escort policies; (5) background checks for employees and contractors with data hall access; and (6) audit logging of all access events. Some data center customers (government agencies, financial institutions) require third-party security audits or certifications such as SOC 2 Type II reports issued under SSAE 18 or comparable assurance frameworks, as a condition of service.

Section 7: Tax Structuring, Incentive Optimization & Financial Modeling

Colorado data center developers face a tax and incentive landscape that differs materially from competing jurisdictions. Unlike Virginia, Texas, Arizona, and Utah – all of which offer broad sales and use tax exemptions for data center equipment and energy purchases – Colorado provides limited statewide tax relief for data centers. The failure of comprehensive data center tax incentive legislation in 2025 (S.B. 25-280 postponed indefinitely) has given way to competing 2026 proposals: H.B. 26-1030 (Data Center & Utility Modernization) would create a certification program for 20-year 100% state sales and use tax exemption on qualified infrastructure for projects meeting investment ($250M+), job creation, and utility verification thresholds (no unreasonable ratepayer impacts); S.B. 26-102 (Large-Load Data Centers) emphasizes 100% hourly renewable matching starting 2031, full cost recovery for grid investments, water efficiency, no economic development rate discounts, and enhanced public engagement/EJ protections, without tax incentives. Both bills are active in early session; outcomes remain pending. Developers therefore rely on federal incentives (ITC/BESS favorable post-OBBBA), county-level property tax abatements, Enterprise Zone credits, Job Growth Incentive Tax Credits, and, for projects on Tribal lands, tax-equivalency agreements negotiated with Tribal governments. This patchwork requires sophisticated tax planning, early engagement with economic development officials, and integration of tax strategy with entity structuring, financing, and operational planning.

This section addresses the available federal and state tax incentives, county economic development tools, Enterprise Zone program mechanics, Job Growth Incentive Tax Credit qualification, property tax abatement strategies, and Tribal tax considerations. It also examines how tax strategy interacts with entity selection (C corporation, partnership, REIT), financing structures (debt, equity, tax equity for renewable generation), and exit planning.

I. Federal Tax Incentives

Federal incentives provide the most substantial tax benefits available to Colorado data centers, particularly those deploying renewable energy or co-located generation.

Investment Tax Credit (ITC). Section 48E, added by the Inflation Reduction Act, provides a technology-neutral clean electricity investment credit for zero-emission generation facilities placed in service after 2024, with base credit rates of six percent (increasing to 30 percent if prevailing wage and apprenticeship requirements are met). Additional 10 percentage point increases are available for projects located in energy communities (generally defined as brownfield sites, communities with significant employment or tax revenue from fossil fuel industries, or areas with closed coal mines or retired coal-fired power plants) or meeting domestic content requirements, potentially raising the credit to 50 percent in some cases. However, the 2025 clean energy tax amendments dramatically altered the credit's availability timeline, creating a bifurcated regime for solar versus battery energy storage systems:

Solar Projects: The Section 48E credit is subject to termination under the 2025 clean energy tax amendments, establishing the following timelines:

- *Projects beginning construction before January 1, 2025*: These projects remain eligible for the Section 48E credit without regard to when placed in service, provided all other requirements are satisfied.
- *Projects beginning construction between January 1, 2025, and July 4, 2026*: These projects qualify for the full 30 percent credit only if placed in service by December 31, 2027.
- *Projects beginning construction after July 4, 2026*: These projects do not qualify for the Section 48E credit regardless of when placed in service.

This compressed timeline requires immediate action for developers planning co-located solar generation.

Battery Energy Storage Systems (BESS): BESS projects are not subject to the accelerated solar phase-out and remain eligible for the Section 48E credit at full value (30% with prevailing wage and apprenticeship) for projects beginning construction through 2033. The credit phases down beginning in 2034 (75% of full credit), 2035 (50%), and is eliminated for projects beginning construction in 2036 or later. This favorable treatment reflects recognition of BESS's critical role in grid reliability and AI data center power demand.

FEOC Restrictions: All projects beginning construction after December 31, 2025, must comply with restrictions on material assistance that limit components from prohibited foreign entities of concern (China, Russia, North Korea, Iran). Projects must demonstrate that at least 55% of total project costs in 2026 (escalating to 60% in 2027, 65% in 2028, 70% in 2029, and 75% in 2030 and thereafter) are sourced from non-prohibited sources. Compliance requires robust supply chain documentation and certifications, increasing administrative complexity.

Example: A data center deploying a $100 million BESS project (without solar) beginning construction in 2026 generates $30 million in tax credits (30 percent of capital cost with prevailing wage/apprenticeship compliance), reducing the net project cost to $70 million, provided FEOC requirements are satisfied. A similar $50 million solar project beginning construction in early 2026 could generate $15 million in credits, but only if placed in service by December 31, 2027, and FEOC-compliant.

However, the ITC can only be utilized against federal tax liability. Developers without sufficient taxable income must monetize the credit by selling the credit to a third party or through tax equity partnerships (see financing discussion below).

Accelerated Depreciation. Data center equipment (including servers, storage, networking equipment, cooling systems, electrical distribution, backup generators) qualifies for Modified Accelerated Cost Recovery System (MACRS) depreciation. Most equipment is classified as five-year or seven-year property, allowing accelerated cost recovery compared to the 39-year recovery period for commercial building structures.

Section 168(k) bonus depreciation, which provides 100 percent first-year expensing for property acquired and placed in service after January 19, 2025, can provide a substantial cash flow benefit by reducing the income tax liability of the developer. Developers should model the cash flow impact of immediate expensing under different entity structures (C corporations benefit from depreciation shields against corporate income; partnerships pass depreciation through to partners who may have varying ability to utilize losses).

Research & Development (R&D) Expenses. Data centers developing proprietary software, AI/machine learning models, or novel cooling/power efficiency technologies in the United States may qualify for federal R&D tax credits under Internal Revenue Code Section 41, providing a credit equal to 20 percent of qualified research expenses (wages, supplies, contract research) and for the immediate expensing of R&D costs. The credit is particularly valuable for hyperscalers operating their own facilities and developing in-house technologies, though traditional co-location providers are less likely to have qualifying activities. R&D credit planning requires contemporaneous documentation of research activities, the technical uncertainties being addressed, and the business components being developed.

Section 174A allows an immediate deduction for any domestic R&D expenditures paid or incurred by the taxpayer during the taxable year. Taxpayers may use the Section 41 R&D credit alongside the Section 174A domestic R&D deduction to reduce their tax burden. However, any deduction under Section 174A must be reduced by any R&D credit taken under Section 41, unless the taxpayer elects to reduce the R&D credit.

Energy Efficient Commercial Buildings. Section 179D provides a deduction available for energy efficient commercial buildings, including data centers, that can exceed $5 per square foot. The deduction specifically applies to certain energy-related components like interior lighting, HVAC, and a building's envelope (*e.g.*, insulation, windows, roofing). For a building to qualify, it must meet certain energy efficiency requirements and be certified by a properly credentialed energy professional. The 2025 clean energy tax amendments accelerated the termination date of Section 179D to June 30, 2026, for property that has not begun construction on or before such date.

II. Colorado State Tax Incentives

Colorado provides limited state-level tax benefits for data centers, but the programs that exist can generate meaningful value if structured properly.

Sales & Use Tax Exemptions (Limited). Colorado Revised Statutes section 39-26-709 provides sales and use tax exemptions for certain types of equipment, but the exemptions are narrow and generally do not apply to data center equipment in the way they do in competitor states. Exemptions exist for manufacturing equipment, agricultural equipment, and certain renewable energy components, but data center servers, cooling equipment, and power distribution systems do not qualify for broad exemptions. Developers should work with Colorado tax counsel to identify any available exemptions (*e.g.*, components of co-located renewable generation may qualify for renewable energy equipment exemptions), but should not assume Virginia-style or Texas-style broad exemptions are available. The failure of SB 25-280, which would have provided comprehensive sales and use tax exemptions for qualifying data centers making minimum capital investments, means Colorado remains at a competitive disadvantage relative to states with broad data center tax incentives.

Enterprise Zone Tax Credits. Colorado's Enterprise Zone program, administered by the Colorado Office of Economic Development and International Trade (OEDIT) under Colorado Revised Statutes section 39-30-106, provides tax credits for businesses making investments and creating jobs in designated economically distressed areas. Colorado has approximately 16 designated Enterprise Zones covering rural areas and certain urban neighborhoods, with enhanced credits available in Enhanced Rural Enterprise Zones. Key credits include:

Investment Tax Credit: Three percent of qualified investment in business equipment and facilities (including land), capped at $750,000 per taxpayer per year. For a data center investing $200 million in a qualified Enterprise Zone, this generates $6 million in credits, though the annual cap means the credits are claimed over multiple years (eight years to fully utilize $6 million at $750,000 per year).

Job Training Credit: 10 percent of training costs for new employees, capped at $1,000 per employee per year.

Employer-Sponsored Health Insurance Credit: 20 percent of employer contributions to health insurance premiums for employees working at least 30 hours per week in the Enterprise Zone, capped at $1,000 per employee per year.

New Business Facility Employee Credit: $1,100 per new employee (or $2,200 in Enhanced Rural Enterprise Zones) in the first year of operation for new Colorado businesses (those with no prior Colorado employees). This credit is particularly valuable for greenfield data center projects creating 50 to 150 jobs, generating $55,000 to $330,000 in credits.

Enterprise Zone credits are refundable if the taxpayer's Colorado tax liability is insufficient to fully utilize the credits, though refundability is subject to annual state budget appropriations. Developers should engage with OEDIT early to confirm Enterprise Zone boundaries (which can be adjusted through administrative processes if a site is near but not within a current zone), understand certification requirements (businesses must obtain an Enterprise Zone Contribution Certificate from the local Enterprise Zone Administrator before claiming credits), and model credit utilization over the project lifecycle.

Job Growth Incentive Tax Credit ("JGITC"). Colorado Revised Statutes section 39-22-551 authorizes the Colorado Economic Development Commission to award performance-based tax credits to businesses creating net new jobs in Colorado. The JGITC provides a credit equal to 50 percent of the state income tax withholding from net new jobs over a performance period of up to eight years, with the credit percentage negotiable based on project size, wages, and county economic conditions. For data centers creating high-wage jobs (the program requires wages to be at least 100 percent of the county average, which data center technical positions typically exceed), the JGITC can provide substantial value: 100 new jobs at $80,000 average salary generate approximately $400,000 in annual state income tax withholding; 50 percent JGITC equals $200,000 per year in credits, or $1.6 million over an eight-year performance period.

JGITC awards are discretionary and competitive, requiring application to the Economic Development Commission with demonstration of project benefits (job creation, capital investment, wages), "but for" causation (the credits are necessary to the project occurring in Colorado), and absence of alternative higher-value uses for the state's limited credit allocation. The Economic Development Commission meets quarterly and reviews applications against criteria including job quality, industry sector (technology and advanced industries are priorities), county unemployment rates, and strategic fit with state economic development goals. Developers should engage with OEDIT staff early to assess JGITC eligibility and begin the pre-application process, as the Economic Development Commission's annual allocation of credits is limited and awarded on a first-come, best-qualified basis.

III. County Economic Development Tools

County-level economic development incentives, negotiated directly with boards of county commissioners, often provide more material tax benefits than state programs and are increasingly essential to Colorado data center feasibility.

Property Tax Abatements & PILOTs. Colorado counties have broad authority under Colorado Revised Statutes sections 39-1-102 and 39-4-101 to abate property taxes or enter into payments-in-lieu-of-taxes agreements for economic development purposes. Property tax abatements reduce assessed value of improvements (typically not land) by a negotiated percentage over a negotiated term, with abatements of 50 to 75 percent over 10 to 20 years common for data center projects. PILOTs substitute negotiated fixed payments for traditional property taxes, providing the developer with predictability (fixed payments unaffected by assessed value increases or mill levy changes) and the county with guaranteed revenue (PILOT payments structured to equal or exceed current property tax revenue from the site). For a $200 million data center project in a county with a combined mill levy of 100 mills (ten percent of assessed value), annual property taxes would be approximately $5.8 million (based on Colorado's 27.9 percent assessment rate for commercial property). A 50 percent abatement over 15 years saves approximately $43 million in present value, materially improving project economics.

Counties structure abatements and PILOTs to balance attracting development (which creates construction jobs, operational jobs, and eventual property tax revenue after abatement expires) against protecting current tax revenue supporting schools, fire districts, libraries, and county services. Negotiations focus on: (1) abatement percentage and duration; (2) job creation and wage commitments; (3) capital investment minimums; (4) local hiring and procurement preferences; (5) community benefits (contributions to affordable housing, infrastructure, schools); and (6) clawback provisions (if the developer fails to meet job or investment commitments, abatement is reduced or recaptured). Douglas County, Adams County, and Weld County have approved property tax incentives for data center and technology projects and have established frameworks and precedents for negotiations. Developers should engage county economic development offices during site selection to understand appetite for incentives and negotiate terms in parallel with site acquisition.

Development Agreements. In addition to property tax incentives, counties may enter into development agreements under Colorado Revised Statutes section 29-20-101 that provide other benefits, including: (1) expedited permitting (dedicated planning staff, concurrent reviews, guaranteed timelines); (2) fee reductions or waivers (building permit fees, plan review fees, impact fees); (3) infrastructure commitments (county investment in road improvements, water/sewer extensions, broadband); and (4) zoning certainty (vested rights to develop under current zoning for a specified term, protecting against future downzonings or regulatory changes). Development agreements are particularly valuable in counties with lengthy or unpredictable permitting processes, as they create enforceable commitments from the county to process applications within specified timeframes and according to agreed-upon standards.

IV. Tribal Tax Considerations

For data centers on Tribal trust lands (*see* Section 9), tax structures differ fundamentally from off-reservation developments due to Tribal sovereignty and Federal-Tribal-State jurisdictional complexities.

Tribal Taxes & Tax-Equivalency Agreements. Federally-recognized Tribal governments are not subject to federal income tax and have sovereign authority to impose taxes on economic activities within the boundaries of their reservations (this applies to both commercial and non-commercial activities conducted directly by the Tribe). However, Tribes often negotiate tax-equivalency agreements with developers, structuring payments to the Tribe in amounts comparable to state and local taxes that would apply off-reservation, while potentially offering favorable treatment relative to off-reservation effective tax rates. For example, a Tribe might structure a payments-to-Tribe agreement at 80 percent of the combined state/county property tax rate, providing the developer with a 20 percent effective discount while generating revenue for the Tribe. These agreements are negotiated case-by-case based on project economics, Tribal priorities, and competitive positioning relative to off-reservation alternatives.

State Tax Exemptions on Trust Lands. In general, states cannot tax Tribal Nations or Tribal citizens on their reservation due to federal preemption and Tribal sovereignty, though the legal boundaries are complex and fact-specific. Thus, sales occurring on-reservation to Tribal members or Tribal entities may be exempt from Colorado sales tax. Tribal trust lands are also not subject to state or county property taxes (as the land is held in trust by the federal government), though improvements may be subject to taxation or tax-equivalent payments depending on agreements. Income earned by non-Tribal entities operating on Tribal lands may be subject to Colorado income tax, though allocation and sourcing rules are complex. Developers considering Tribal sites should engage tax counsel with federal Indian law expertise to structure transactions in a tax-efficient manner while complying with federal, Tribal, and state tax law.

Federal Incentives on Tribal Lands. Federal tax credits (*e.g.*, ITC, R&D credits, accelerated depreciation) apply to projects on Tribal lands in the same manner as off-reservation projects.[1] Additionally, Tribal projects may qualify for certain federal grant programs and incentives specifically available to Tribal governments and Tribal enterprises, including those under the Department of Energy's Office of Indian Energy (*e.g.*, Tribal energy development grants), the Department of Interior's Bureau of Indian Affairs ("BIA") economic development programs, and the Department of Commerce's Economic Development Administration (*e.g.*, grants for Tribal infrastructure). Note that while some Inflation Reduction Act benefits for Tribes were rescinded under the One Big Beautiful Bill Act of 2025, these base programs remain active, subject to annual appropriations and eligibility criteria. These programs, while often smaller in dollar value than tax credits, can provide grant funding for feasibility studies, infrastructure, and workforce development, reducing developer out-of-pocket costs.

V. Entity Structuring & Tax Planning

Tax incentive utilization depends critically on entity structure, ownership, and financing, requiring coordination between tax, corporate, and project finance counsel from inception.

C Corporation vs. Partnership Structures. C corporations directly utilize tax credits and deductions against corporate income, but face double taxation (corporate income tax plus shareholder dividend tax). Partnerships (including LLCs taxed as partnerships) pass income, credits, and deductions through to partners, who utilize them against their individual or corporate tax liabilities, but partners must have sufficient tax liability to capitalize on the benefits. For data centers with substantial tax credits (Section 48E ITC from co-located BESS or solar (noting the 2025 clean energy tax amendments' accelerated solar phase-out), Enterprise Zone credits, JGITC), partnership structures allow credits to be passed through to tax equity investors or other partners with tax liability, maximizing credit utilization. However, partnership structures involve complexity in drafting operating agreements, allocating tax items, and managing partner relationships.

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1 Notably, until the Inflation Reduction Act of 2022, Tribes were unable to access federal tax credits since they are tax exempt. The IRA amended a number of energy tax credits to allow for "direct pay" to Tribes, allowing them to receive the subsidy in the form of a direct payment once the project is placed into service. The One Big Beautiful Act maintained the direct-pay mechanism for clean energy.

REIT Structures. Real estate investment trusts ("REITs") are often used for data center ownership due to their tax-advantaged treatment (no entity-level taxation if 90 percent of income is distributed to shareholders). However, due to this lack of entity-level taxation, REITs are generally unable to utilize tax credits such as the ITC. Due to transferability of certain credits implemented by the IRA, however, REITs are able to monetize these credits by selling them to third parties for cash. The generation and sale of credits will not violate any of the various asset or income tests for satisfying the REIT qualification requirements.

Tax Equity for Co-Located Renewable Generation. As discussed in Section 3, battery energy storage systems and, for projects beginning construction by July 4, 2026, solar co-located generation can generate substantial Section 48E investment tax credits, though solar credit eligibility is now severely time-constrained under the 2025 clean energy tax amendments. Developers unable to efficiently use credits (due to insufficient tax liability, REIT structure, or foreign ownership) can monetize credits through tax equity financing, where a third-party investor with tax liability contributes a percentage (*e.g.*, 30 to 50 percent) of project capital in exchange for 99 percent of tax attributes (ITC and depreciation) during an initial period (typically five to seven years), with economic benefits "flipping" to the developer after the tax investor achieves its target return. Tax equity structures are complex and require specialized legal counsel, but they provide an option for developers to effectively convert non-usable tax credits into upfront cash (through the tax equity investor's capital contribution), improving project returns. Although the transferability of tax credits has reduced the need for tax equity financing, developers remain incentivized to pursue tax equity investments to monetize tax depreciation benefits that are not included in tax credit transfer scenarios. In addition, tax equity investors are able participate in a traditional tax equity structure and subsequently transfer the credits in a separate transaction.

VI. Financial Modeling & Strategic Tax Planning

Tax strategy should be modeled quantitatively at the feasibility stage, using detailed cash flow projections that incorporate:

Credit Availability and Timing. Model when tax credits are generated (*e.g.*, upon placed-in-service dates for ITC, annually for Enterprise Zone and JGITC credits) and when they can be utilized (immediately if sufficient tax liability exists or the credits are sold; deferred and carried forward if liability is insufficient). For transferable credits, consider the timing and value of potential sales. The sales price for tax credits generally varies based on the seller's creditworthiness, project size, credit type and amount, and existence of tax insurance.

Abatement Structures & Escalation. Model property tax abatements over the abatement term, accounting for assessed value growth (as property values may increase over time) and potential mill levy changes. Compare scenarios with varying abatement structures (*e.g.*, 75 percent abatement for 10 years versus 50 percent abatement for 20 years) to identify optimal structures.

Entity Cascading & Allocations. For partnership structures with multiple investors or tax equity partners, model the allocation of income, losses, credits, and cash distributions under the operating agreement terms, ensuring that allocations will be respected and that after-tax returns to each partner meet their return thresholds.

Exit Tax Consequences. Model the tax consequences of exit scenarios (sale, refinancing, liquidation), including depreciation recapture, capital gains, and credit recapture (if projects are sold before required holding periods).

Tax planning is not a back-end exercise; it is a front-end driver of structure, site selection, and financing. Projects that integrate tax counsel early consistently achieve better after-tax returns than projects that treat tax as a compliance function rather than a strategic value driver.

Section 8: Deal Structuring, Procurement Models & Delivery Strategies

Data center development in Colorado requires careful selection of procurement and delivery strategies that align technical requirements, risk allocation, schedule constraints, and financing structures. Unlike traditional commercial real estate where design-bid-build is standard, data centers – with their unique technical complexity, mission-critical reliability requirements, and rapid technology evolution – often benefit from alternative delivery methods, including design-build, construction manager/general contractor, and integrated project delivery. This section addresses procurement model selection, contract risk allocation, construction management considerations, and equipment procurement strategies for long-lead items, including generators, chillers, electrical switchgear, and battery energy storage systems.

I. Procurement & Delivery Models

There are multiple construction contracting approaches available for data center projects, each offering distinct advantages and disadvantages.

Design-Bid-Build. In the design-bid-build model, the owner directly engages an architect to complete the design. Following completion of the design, the project is customarily put out via a competitive bid process to general contractors for the construction work, resulting in the award of the fixed-price construction contract to the successful bidder. This model provides price certainty (lump-sum bids or a guaranteed maximum price bid based on the completed design) and a clear allocation between design responsibility (architect) and construction responsibility (general contractor). However, design-bid-build is inherently sequential (generally, the design must be at a sufficient level complete before bidding, and construction generally cannot start until the full contract is awarded), creating longer overall timelines. For data centers with compressed schedules driven by customer commitments or competitive pressures, design-bid-build's sequential nature is often a constraint. While there are options to execute a limited notice to proceed to commence procurement or to perform a limited scope of work before the design is complete or the full contract is negotiated, such limited notices to proceed can create contractual and commercial tension with the subsequent full construction contract. Additionally, separating design and construction creates the risk of constructability issues (design not optimized for efficient construction), change orders (unforeseen field conditions or design errors requiring additional work), and disputes between designer and contractor when problems arise.

Design-Build. Design-build contracts engage a single entity (often a joint venture between a design firm and a construction contractor, or a contractor with in-house design capabilities) to provide both design and construction services under a single contract. Design-build allows overlapping design and construction (early site work and long-lead procurement can begin while later design elements are finalized). Compared to design-bid-build, the overall project schedule in a design-build contract often achieves faster timelines and greater flexibility as the project evolves. Single-point responsibility minimizes many design-construction interface disputes, and early contractor involvement in design improves constructability and value engineering. Trade-offs include less owner control over design details (the design-build team makes many design decisions within performance specifications set by the owner) and potentially higher pricing, reflecting the design-build team's assumption of schedule and performance risk. Design-build is increasingly common for data center projects where schedule is critical and owners are comfortable delegating design responsibility to experienced design-build teams.

Construction Manager/General Contractor ("CM/GC"). CM/GC is a hybrid model where the owner engages a construction manager early in design to provide preconstruction services (cost estimating, scheduling, constructability review, value engineering) while the design is being completed. CM/GC provides schedule advantages (the construction manager can order long-lead-time items and begin site work before execution of the full construction contract) while preserving owner control over design. However, CM/GC involves negotiation risk (if the construction manager's proposal exceeds the owner's budget, the owner may need to re-bid or value-engineer design) and less pricing certainty than lump-sum competitive bidding. Although the owner typically retains the right to terminate the construction manager's engagement if the proposed pricing exceeds the owner's budget, exercising that right is often difficult in practice because significant design and pre-construction work is usually already underway by the time the construction manager submits its proposed price. Still, CM/GC can be appropriate for complex data center projects where early contractor input is valuable and the owner has sophisticated project management capabilities to manage the design process and later negotiate the full construction contract when the design reaches an appropriate level of completion.

Integrated Project Delivery ("IPD"). IPD involves early engagement of the project team under a collaborative contractual framework with shared risk and reward. IPD contracts aim to align incentives by providing cost-savings bonuses if the project comes in under target cost, and by sharing cost overruns if the project exceeds target cost. IPD accelerates schedules and promotes innovative problem-solving but requires alignment among team members, sophisticated contract administration, and a willingness to share financial information among the parties. IPD remains relatively rare in commercial construction but is gaining traction in data centers where complexity and collaboration drive value and faster project delivery.

II. Contract Risk Allocation & Key Terms

Regardless of delivery model, data center construction and design contracts must address several critical risk allocation and technical performance issues.

Performance Specifications & Acceptance Criteria. Data center design contracts should consider specifying technical performance requirements, including: (1) Power Usage Effectiveness targets (*e.g.*, design PUE of 1.25, measured PUE not to exceed 1.30); (2) cooling capacity and redundancy (*e.g.*, N+1 redundant cooling with each unit capable of meeting full design load); (3) electrical system reliability (*e.g.*, 99.95 percent availability, meaning less than five hours of downtime per year); (4) generator runtime and load acceptance (*e.g.*, diesel generators must start and accept full load within 10 seconds of utility power loss); and (5) battery energy storage system capacity and discharge duration (*e.g.*, lithium-ion BESS providing four-hour discharge at rated capacity). Such performance specifications should include testing and commissioning protocols verifying that installed systems meet requirements before final acceptance and payment.

Uptime Institute Tier Certification (If Applicable). Some data center projects pursue Uptime Institute Tier certification, which evaluates the resiliency of a facility's infrastructure design and construction (Tier I through Tier IV, with Tier IV representing the highest redundancy and fault tolerance). If Tier certification is a project requirement, the construction contract should allocate responsibility for achieving certification (typically joint responsibility of design and construction teams) and specify remedies if certification is not achieved (re-work at contractor's cost, liquidated damages, termination rights).

Liquidated Damages for Delay. Given data centers' revenue generation potential and customer contract commitments, construction schedule and timely completion is a key consideration for data center projects. Construction contracts typically include liquidated damages for delays beyond contractual completion milestones to compensate the owner for late delivery. Contractors often seek caps on liquidated damages and carve-outs for delays caused by matters beyond the contractor's reasonable control (*e.g.*, owner-caused changes, force majeure, and permitting delays). Owners should carefully evaluate proposed caps on liquidated damages and seek to structure liquidated damages provisions so that the agreed amounts represent, at a minimum, a reasonable estimate of the owner's anticipated damages attributable to late completion of the project.

Equipment Performance Guarantees. Long-lead equipment purchases (generators, chillers, UPS systems, BESS) should include manufacturer warranties issued in the name of the owner. Contracts should require the contractor to ensure proper and timely procurement, installation, startup, and coordination of such equipment and to provide for manufacturer warranties to be issued in the name of, or assigned directly to, the owner.

Change Order Procedures. Data center projects frequently encounter changes due to evolving technology (*e.g.*, a client decides to deploy higher-density servers requiring additional cooling), unforeseen site conditions (*e.g.*, encountering groundwater or unsuitable soils requiring foundation redesign), or permit-driven changes (*e.g.*, county imposes landscape or noise mitigation conditions of approval). Construction contracts should establish clear change order procedures, including: (1) notice requirements (prompt written notice of potential cost or schedule change impacts); (2) pricing mechanisms (time and materials, negotiated lump sum, or other agreed-upon methods of calculating change order value); (3) approval authority (delegated limits for project manager versus executive approval for changes exceeding thresholds); and (4) schedule impact analysis (identification and evaluation of impacts to the project cost or schedule prior to approval).

III. Equipment Procurement & Long-Lead Items

Data center construction schedules are often driven by equipment lead times rather than building construction duration. Key equipment with long lead times includes:

Diesel & Gas Generators. Backup generators (diesel or natural gas reciprocating engines or turbines) have long lead times from order to delivery, depending on size, emissions controls, and manufacturer backlog. Generators should be specified and ordered during early design (at or before 30 percent design completion) to ensure delivery aligns with construction schedule. Generator specifications should address fuel type, power output and voltage, emissions controls (if required by air permits; *see* Section 2), noise attenuation (acoustic enclosures to meet county noise ordinances), and compliance with EPA Tier 4 emissions standards (if applicable based on size and application).

Chillers & Cooling Systems. Large centrifugal or screw chillers for data center cooling have similarly long lead times. Early selection of cooling technology (evaporative versus air-cooled, chiller versus direct evaporative, traditional versus liquid cooling; *see* Section 4) is essential to allow equipment procurement in parallel with building construction. Cooling system specifications should address capacity, efficiency (kW per ton), redundancy configuration (N+1, N+2, 2N), and refrigerant type (consideration of environmental regulations phasing down high-global-warming-potential refrigerants).

Electrical Switchgear & Transformers. Medium-voltage switchgear (13.2 kV or 34.5 kV typical for utility interconnection) and transformers have similarly long lead times due to custom manufacturing and testing requirements. Utility coordination is essential to ensure that utility-side equipment (substation transformers, protective relays) is compatible with owner-side equipment. Electrical specifications should address fault current ratings, arc flash protection, relay protection schemes, and integration with building management systems.

Battery Energy Storage Systems. Lithium-ion BESS installations (Section 6) have similarly long lead times for battery modules, power conversion systems, and fire suppression equipment. BESS procurement should be coordinated with UL 9540A testing requirements, NFPA 855 compliance, and local fire marshal approvals. Battery chemistry (lithium nickel manganese cobalt oxide, lithium iron phosphate, etc.) should be selected based on performance requirements, safety characteristics, and cost. Contracts should address battery degradation (capacity loss over time), warranty coverage, and end-of-life disposal or recycling.

Uninterruptible Power Supplies. UPS systems (batteries or flywheels providing instantaneous backup power while generators start) have similarly long lead times. UPS sizing should account for IT load growth over the data center's initial build-out phase, with modular designs allowing capacity additions as demand increases.

IV. Procurement Strategy & Vendor Management

Direct Owner Procurement vs. Contractor Procurement. Owners may choose to procure certain long-lead equipment directly (owner-furnished, contractor-installed) to: (1) compress schedule (owner can order equipment before construction contract execution); (2) reduce cost (avoiding contractor markup on equipment); and (3) maintain vendor relationships (owners developing multiple data centers benefit from volume pricing and preferred support from manufacturers). Trade-offs include owner assumption of equipment risk (if equipment is late or defective, the contractor may claim excusable delay) and coordination complexity (contractor must integrate owner-furnished equipment into construction schedule and warranty). For mission-critical equipment (generators, UPS, BESS), direct owner procurement is common. For commodity equipment (electrical distribution, HVAC for administrative areas), contractor procurement is often more efficient.

Multiple Vendor Qualification & Redundancy. To mitigate supply chain risk, sophisticated owners qualify multiple manufacturers for critical equipment categories, avoiding single-source dependencies. If one vendor faces production delays, the owner can pivot to alternate vendors without redesigning systems. However, multi-vendor qualification requires engineering effort to develop standards allowing equipment from different manufacturers to be interchangeable.

Section 9: Tribal Overlay & Sovereign Partnerships

Development on Tribal lands in Colorado introduces legal, regulatory, and business considerations that differ fundamentally from off-reservation projects. Tribal sovereignty – recognized in federal law, treaties, and Supreme Court decisions – means that Tribal governments have inherent governmental authority over their territories, which they can exercise in a variety of ways, including by enacting and enforcing their own laws, operating their own courts, and consulting with federal and state governments on a government-to-government basis. For data center developers, Tribal lands offer potential advantages, including access to energy resources, favorable tax structures, and community support when the project is aligned with Tribal economic development priorities. However, projects on Tribal trust lands requires federal approvals (which trigger environmental and cultural resource reviews), compliance with Tribal law and governance processes, and consistent, patient, and culturally respectful engagement efforts over what can be extended timelines.

This section expands on the co-located generation discussion in Section 3 by providing a comprehensive analysis of the legal, regulatory, and strategic considerations for data center development on Colorado's Tribal lands, which fall under the Tribal jurisdiction of either the Southern Ute Indian Tribe or the Ute Mountain Ute Tribe. Specifically, it addresses the relevant federal regulatory frameworks (*e.g.*, BIA involvement/approvals, compliance with NEPA and NHPA), Tribal governance and approval processes, environmental permitting under Tribal authority, and business structures for partnerships. The goal is to equip developers with a realistic understanding of development pathways for projects sited on Tribal lands so they can make an informed decision as to whether the use of Tribal lands aligns with project objectives and timelines.

I. Southern Ute & Ute Mountain Ute: Distinct Sovereigns with Different Contexts

Colorado's two federally recognized Tribes – the Southern Ute Indian Tribe (Ignacio) and the Ute Mountain Ute Tribe (Towaoc) – are distinct sovereign nations with separate governments, laws, territories, and economic development strategies. Developers must not conflate the two or assume that approaches successful with one Tribe will translate to the other.[2]

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2 A phrase often quoted by Indian law practitioners emphasizes the need to recognize the immense diversity among Native nations: "If you've met one Tribe, you've only met one Tribe."

Southern Ute Indian Tribe. The Southern Ute Reservation encompasses approximately 1,100 square miles in La Plata and Archuleta Counties in southwestern Colorado, with Tribal headquarters in Ignacio. The Tribe has approximately 1,400 enrolled members. The Southern Ute economy is heavily based on energy development, particularly oil and natural gas extraction from the San Juan Basin's prolific coalbed methane and conventional gas reserves and associated infrastructure. The Tribe is also a sophisticated and experienced business owner, operating several distinct energy companies, including the Tribe's wholly owned exploration and production arm, Red Willow Production Company ("Red Willow"). Red Willow was founded in 1992 and operates both on-reservation and in Texas (Delaware Basin), Wyoming (Green River Basin), and the Gulf of Mexico. The Tribe also owns two midstream companies – Aka Energy Group, which is also wholly owned by the Tribe, and Red Cedar Gathering, which is a joint venture between Kinder Morgan (49%) and the Tribe (51% via Aka Energy) – and operates its own utility company, the Southern Ute Utilities Division. The success of these Tribal businesses has made the Southern Ute Tribe one of the most sophisticated Tribal energy developers in the United States, generated substantial revenue for the Tribe, funded government services, fueled economic diversification, and enabled the establishment of the Southern Ute Permanent Fund and Growth Fund, which are respectively tasked with maintaining and growing the Tribe's revenue for future generations. Notably, the Tribe's energy companies and wealth funds operate independently from the Tribal government, reducing the risks associated with staff turnover and policy instability. The Tribe's financial strength (with credit ratings comparable to investment-grade corporations) and experience with complex energy transactions, federal permitting, and commercial partnerships are a testament to this approach, positioning the Southern Ute as a capable partner for data center development involving co-located natural gas generation.

The Southern Ute Tribal Council exercises governmental authority for the Tribe and is composed of seven members, including a chairman, all of whom are elected on an at-large basis for three-year staggered terms. However, as noted, the Tribe's business enterprises and investments (in energy, real estate, and private equity) are separately managed via the Southern Ute Growth Fund. And the Southern Ute Indian Tribe Department of Energy, which functions similarly to the US Department of Energy, is responsible for managing the Tribe's energy resources for maximum Tribal benefit, overseeing environmental oversight and regulatory compliance, and providing technical assistance. The Tribe has established processes for reviewing major economic development projects, conducting environmental and cultural resource assessments (through the Southern Ute DOE, Environmental Programs Division, and Tribal Historic Preservation Office), and negotiating development agreements. Developers engaging with the Southern Ute should expect a professional, business-oriented dialogue, though respect for Tribal sovereignty, cultural values, and community benefits remains essential.

Ute Mountain Ute Tribe. The Ute Mountain Ute Reservation encompasses approximately 553,000 acres in Montezuma and La Plata Counties in Colorado as well as San Juan County in New Mexico, and includes the White Mesa community in San Juan County, Utah. The Tribe has approximately 2,000 enrolled members, with the majority residing in or near Towaoc (the Tribe's capital in Colorado) or White Mesa. Unlike the Southern Ute, the Ute Mountain Ute economy has historically been based on ranching (the Tribe maintains a cattle herd of approximately 2,000 head), gaming (Ute Mountain Casino and associated hospitality facilities), and tourism (Ute Mountain Tribal Park is adjacent to Mesa Verde National Park). Oil and gas resources on the Ute Mountain Ute Reservation are limited compared to Southern Ute lands, and the Tribe has thus focused its energy development efforts on renewable resources, including the Towaoc Community Solar Project (one megawatt, 3,600 PV panels commissioned in March 2020) and the White Mesa Solar Initiative (under development in Utah). Accordingly, solar paired with BESS co-located generation aligns with the Tribe's renewable energy priorities and climate-adaptation commitments. However, water constraints are more acute than on Southern Ute lands, as the reservation has limited surface water (the Mancos River is seasonal and often dry September through November) so dry or hybrid cooling for data centers is key.

The Ute Mountain Ute Tribal Council exercises governmental authority for the Tribe and is composed of seven members who serve three-year staggered terms. One council member represents White Mesa, and the other members are elected at-large. The elected council then selects a chairman, vice-chairman, treasurer and secretary-custodian from its membership. The Tribe's economic development and environmental management capacity is less extensive than the Southern Ute's (reflecting the Ute Mountain Ute's smaller revenue base and different development history), but the Tribe has successfully partnered with federal agencies (DOE, BIA, EPA) and private entities on renewable-energy, environmental-restoration, and cultural-resource-preservation projects. The Tribe has less capital and experience with large-scale energy projects compared to the Southern Ute, so external financing or partnership structures would likely be required. As with the Southern Utes, developers engaging with the Ute Mountain Ute Tribe should also expect a consultative process focused on aligning projects with Tribal priorities (*i.e.*, renewable energy, climate adaptation, job creation, and community benefits) and respect cultural values and traditional lands.

II. Regulatory Framework for Development on Tribal Trust Lands

Tribal trust lands are owned by the U.S. in trust for the benefit of Tribes or are restricted fee interests owned by individual Tribal members, with title held by the federal government. This trust relationship means that certain transactions and activities on trust lands require federal approval, triggering federal environmental and cultural resource review.

Tribal law applies to activities on Tribal lands within reservation boundaries. Both the Southern Ute and Ute Mountain Ute Tribes have Tribal Councils, environmental codes, business licensing requirements, and Tribal Employment Rights Ordinances ("TEROs") (which mandate that all employers engaged in operating a business on the reservation give preference to qualified Tribal members in all aspects of employment, contracting, and other business activities) that project proponents must comply with. State law generally does not apply to activities on Tribal trust lands due to tribal sovereignty, though off-reservation impacts (*e.g.*, transmission lines crossing state land, road improvements) remain subject to state jurisdiction.

Bureau of Indian Affairs Approval. The BIA (within the Department of the Interior) administers the federal government's trust responsibilities on behalf of Tribe and generally must approve leases, rights-of-way, and certain other agreements affecting trust lands.

Leases (25 U.S.C. § 415 *et seq*. (Indian Long-Term Leasing Act ("ILTA") and Helping Expedite and Advance Responsible Tribal Homeownership ("HEARTH") Act); 25 U.S.C. § 396a *et seq*. (Indian Mineral Leasing Act ("IMLA")), 25 C.F.R. Part 162 (leases and permits)):[3] If a developer intends to lease trust land to construct and operate a data center, the lease must generally be approved by the BIA, and the term of the lease may be limited by regulation. However, a number of Tribes – including the Southern Ute (but not the Ute Mountain Ute) – are permitted to lease their Tribal lands without BIA approval under the HEARTH Act. In either instance, lease terms are negotiated between the Tribe and developer, but in the case of leases requiring BIA approval, the BIA reviews leases for compliance with federal regulations, adequacy of compensation to the Tribe, environmental compliance, and protection of trust resources. In the case of leases with HEARTH Act Tribes,

3 It is important to note that certain provisions of the ILTA and IMLA apply to specific Tribes – and additional statutory and regulatory provisions may be applicable if leasing of Tribal oil or gas is contemplated – so consultation with counsel experienced in Indian energy law and a close examination of the relevant statute and regulations is essential to assess the applicability of specific requirements.

lease reviews and approvals are conducted by the Tribe in compliance with the Tribe's DOI-approved Leasing Ordinance.

Rights-of-Way (25 C.F.R. Part 169): If the project requires rights-of-way across Tribal trust lands for transmission lines, water pipelines, access roads, or fiber optic cables, BIA approval is required. Rights-of-way are distinct from leases (they grant use of a specific corridor rather than a defined parcel) and are often required for infrastructure connecting the data center to utility systems, water sources, or fiber networks off-reservation.[4] The BIA will typically grant, approve, or deny a ROW, although a Tribe with an approved Tribal Energy Resource Agreement ("TERA") may grant a ROW over Tribal lands related to energy resources development. As of the date of this writing, the Southern Ute Tribe is awaiting Interior approval of its final proposed TERA. If approved, they would be the first Tribe with an approved TERA.[5]

Energy Development Agreements: Under the Indian Mineral Development Act ("IMDA"), 25 U.S.C. §§ 2101–2108, Tribes can enter into agreements (rather than traditional leases) for the exploration, extraction, processing, or other development of mineral resources. These agreements provide the Tribe with greater control and flexibility in the development of their resources. IMDA agreements allow Tribes to participate as equity partners, joint venturers, or in any other development arrangements beyond a landlord-tenant relationship. For co-located generation projects, IMDA agreements may be preferable to leases, as they allow the Tribe to share in project economics and exercise greater operational oversight. IMDA agreements still generally require BIA approval but are subject to less prescriptive regulations than traditional leases, giving the Tribe and developer more flexibility in structuring terms.

National Environmental Policy Act (40 U.S.C. § 4331 *et seq.*). BIA approval of leases, rights-of-way, or IMDA agreements is a federal action triggering NEPA review (42 U.S.C. §§ 4321 *et seq.*) (though it is separate but concurrent process from the actual

4 Note that service lines (i.e., lines used to connect a main line, transmission line, or distribution line to a business, house, or other structure to supply telephone, water, electricity, gas, internet, or other utilities) are subject to a separate process.
5 The Red Lake Band of Chippewa Indians was the first Tribe to have an approved Tribal Energy Development Organization ("TEDO"). Both TERAs and TEDOs strengthen Tribal sovereignty and improve the efficiency of energy development by removing the barrier of Interior approval for individual leases, business agreements, and ROWs for energy projects on Tribal lands. However, a TEDO is a business organization in which the Tribe owns a majority interest. When a Tribe has a TEDO, it can forgo Interior approval for leases, agreements, and ROWs with the TEDO. In contrast, a TERA allows a Tribe to manage leasing, business agreements, and ROWs with any third party.

lease review). NEPA requires federal agencies to analyze the environmental impacts of certain proposed federal actions, consider alternatives, and provide an opportunity for public comment. For data center projects, the BIA will prepare either an Environmental Assessment ("EA"), up to 75 pages long analyzing impacts and determining whether the action will have significant environmental effects, or an Environmental Impact Statement ("EIS"), a more detailed document required if significant impacts are likely typically up to 150 pages long with extensive alternatives analysis.

NEPA documents analyze impacts to air quality, water resources, wildlife and habitat, cultural resources, socioeconomics, and transportation, among other resources. For data centers with co-located generation (particularly fossil fuel generation with air emissions), the air quality analysis will be detailed and may drive design decisions or project scope. The NEPA water resource analysis will address water supply source, impacts to groundwater or surface water, and adequacy of supply.

Consultation with other federal agencies (*e.g.*, EPA, Fish & Wildlife Service, Forest Service if nearby federal lands are affected) and public engagement are components of NEPA. Accordingly, federal agencies, Tribes with cultural or treaty interests in the area, citizen groups, and adjacent landowners may comment and raise concerns on proposed actions.

National Historic Preservation Act Section 106. (54 U.S.C. § 306108; 36 C.F.R. Part 800). NHPA Section 106 requires federal agencies to consider the effects of actions they carry out, license, or financially assist (undertakings) on historic properties,[6] including archaeological sites, traditional cultural properties, historic buildings, and cultural landscapes. With regard to Tribes, the NHPA's implementing regulations require that, in carrying out its responsibilities under the Section 106 review process, a federal agency consult with any Tribe that attaches religious and cultural significance to historic properties that may be affected by the agency's undertaking. NHPA Section 106 involves four main steps:

1. *Initiation of the Section 106 Process / Tribal Consultation*: BIA initiates consultation by notifying the appropriate consulting parties. Consultation for projects on Tribal lands is typically between the federal agency, the Tribal Historic Preservation Officer ("THPO"), and other consulting

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6 Historic properties are any prehistoric or historic districts, sites, buildings, structures, or objects that are eligible for or already listed in the National Register of Historic Places. Also included are any artifacts, records, and remains (surface or subsurface) that are related to and located within historic properties and any properties of traditional religious and cultural importance to Tribes or Native Hawaiian Organizations.

parties, including but not limited to project applicants, local governments, and members of the general public with an economic, social or cultural interest in the project.

2. *Identification of Historic Properties and Determination of Significance*: BIA, in consultation with the THPO, will identify historic properties (*e.g.*, sites, artifacts, traditional use areas, and other places of cultural or spiritual significance) through archaeological and cultural resource surveys of the project area. Both the Southern Ute and Ute Mountain Ute Tribes have active THPO offices with professional archaeologists and cultural advisors. Surveys typically involve pedestrian walkovers, shovel-test excavations, consultation with Tribal elders and cultural practitioners, and/or the review of ethnographic and historical records. If cultural resources are identified, the THPO and the BIA determine whether they are eligible for the National Register of Historic Places (based on age, integrity, and cultural importance).

3. *Assessment of Adverse Effects*: In consultation with the THPO, the BIA will determine whether the project has the potential to adversely affect the identified historic properties (*e.g.*, through physical disturbance, visual impacts, noise, or changes to the cultural landscape).

4. *Resolution of Adverse Effects (Mitigation and Treatment)*: If potential adverse effects are identified, the THPO, the BIA, and the developer will "develop and evaluate alternatives or modifications to the undertaking that could avoid, minimize, or mitigate adverse effects." Mitigation may include: (1) avoidance (*e.g.*, redesigning the project to avoid disturbing the site); (2) data recovery (*e.g.*, archaeological excavation and documentation before disturbance); (3) monitoring (*e.g.*, having Tribal monitors present during construction to ensure no inadvertent disturbances); or (4) cultural landscape preservation (*e.g.*, protecting viewsheds, limiting noise during ceremonial periods). And increasingly, Tribes and developers are negotiating creative mitigation measures (*e.g.*, public education/exhibit programs, construction of interpretive centers, building internal Tribal cultural resource capacity). However, for particularly significant sites, such as ancestral Puebloan villages, petroglyphs, or places used for traditional ceremonies, the consultation process may yield a preference for avoidance and alternative site selection.

NHPA Section 106 process typically runs parallel to NEPA process but can extend beyond NEPA if mitigation planning is complex.

Additional Federal Laws Requiring Tribal Consultation. The federal government's obligation to consult Tribes is not limited to NHPA. Depending on the nature of the activity and effects, Tribal consent may be required for certain other archeological and cultural-resource matters. Specifically, the Archaeological Resources Protection Act of 1979 (16 U.S.C. §§ 470aa-mm) requires Tribal consent for archeological excavation or artifact removal on Tribal lands. And the Native American Graves Protection and Repatriation Act of 1990 ("NAGPRA") (25 U.S.C. §§ 3001 *et seq.*; 43 C.F.R. Part 10) requires federal land-managing agencies to consult with federally recognized Indian Tribes prior the intentional removal or excavation of Native American human remains and other cultural items (as defined in NAGPRA) from federal lands. On Tribal lands, planned excavation requires the consent of the appropriate Tribe. In instances where a proposed project that is funded or licensed by a federal agency may cross federal or Tribal lands, it is the federal land managing agency that is responsible for compliance with NAGPRA.

III. Tribal Governance & Approval Processes

In addition to federal approvals, Tribal government approval is required for all major projects on Tribal lands. The Tribal approval process varies by Tribe but typically involves:

Tribal Council Authorization. Both the Southern Ute and Ute Mountain Ute Tribal Councils must approve leases, development agreements, and major contracts. Councils meet regularly (monthly or more frequently) but schedule agenda items based on readiness, completeness of proposals, and council priorities. Developers should expect multiple council presentations: (1) initial concept briefing to gauge interest; (2) detailed proposal presentation with project plans, economic terms, and community benefits; and (3) formal vote on agreement approval. Councils may request revisions, additional community engagement, or specific conditions (*e.g.*, Tribal employment preferences, revenue sharing structures, environmental commitments) before approval. Engaging Tribal leadership (*i.e.*, Chairman, Vice Chairman, Council members) and the Tribal community early and maintaining ongoing communication is essential. As with any elected body, Tribal councils are accountable to their voters (*i.e.*, Tribal members) and there may be rival factions within the Tribe or Tribal leadership (*i.e.*, pro-development versus anti-development). However, council members generally will not approve projects perceived as contrary to Tribal interests or lacking community support. Thus, engagement beyond Tribal leadership into the community can also be helpful in gauging interest and support for projects.

Tribal Regulatory Compliance. Both Tribes have enacted environmental, business, and cultural resource protection laws that apply to on-reservation activities. Southern Ute and Ute Mountain Ute environmental codes address air quality, water quality, solid waste management, and hazardous materials, with standards often as stringent as federal and state regulations. Developers must often obtain Tribal environmental permits (separate from EPA permits) and comply with Tribal monitoring and reporting requirements. Tribal business licensing and taxation requirements also apply (*see* Section 7.IV). TEROs require employers operating a business on the reservation to give preference for Tribal members in all aspects of employment, contracting, and other business activities, with penalties (often fees or contract cancellation) for non-compliance. Developers should engage Tribal regulatory departments early to understand requirements and build compliance into project planning and budgets.

IV. Environmental Permitting on Tribal Lands

Environmental permitting on Tribal lands involves a combination of Tribal, EPA, and (in limited circumstances) state authority.

EPA Air Quality Permitting. Several federal environmental laws, including the Clean Air Act ("CAA"), authorize EPA to treat federally recognized Indian tribes as a state ("TAS") when certain requirements are met. However, neither the Southern Ute nor the Ute Mountain Ute has obtained CAA TAS status. Accordingly, EPA Region 8 (not the CDPHE) is the permitting authority for air quality on the Tribal trust lands within Colorado. For data centers with co-located fossil fuel generation (natural gas recips, turbines, or diesel generators exceeding emergency backup thresholds), the EPA issues Prevention of Significant Deterioration permits, synthetic minor permits, or minor source registrations under essentially the same standards as the CDPHE applies off-reservation (*see* Section 2.I). However, EPA processes may differ procedurally (different application forms, review procedures, and timelines) and may involve Tribal consultation and coordination obligations that are not required for off-reservation permits. Developers should engage EPA Region 8 Air Program early to understand permitting pathway and timelines. Importantly, solar and BESS installations avoid combustion-related air permitting.

Tribal Water Quality Permitting & Federal CWA Oversight. Water quality on Tribal lands is governed by the CWA. As with the CAA, Tribes may obtain TAS status under the CWA, namely under Section 303(c)/401 (water quality standards), Section 319 (non-point source management program), Section 402 (discharge permits), and Section 404 (dredge and fill permits). If a Tribe has obtained TAS status, Tribal water quality agencies – rather than EPA – issue the relevant permits and enforce the applicable standards. If the Tribe has not obtained TAS, the EPA retains permitting authority. Neither the Southern Ute Tribe nor the Ute Mountain Ute Tribe has obtained TAS status under Section 319, 402, or 404, but both have obtained TAS status under Section 303(c)/401. Data centers typically have minimal direct wastewater discharges (sanitary waste goes to septic systems or is trucked off-site; process water from cooling towers is discharged to sanitary sewer if municipal service is available or to on-site treatment and disposal systems if not). However, stormwater discharges during construction and from impervious surfaces (parking lots, building roofs) and projects affecting waters of the United States may require permits from the EPA or the Tribe. Developers should confirm TAS status and permitting authority during due diligence.

V. Strategic Considerations for Tribal Land Development

When Tribal Lands Advance Project Objectives. Tribal lands are appropriate for data center development when: (1) the developer seeks a long-term partnership; (2) the project aligns with Tribal energy priorities (*i.e.*, Southern Ute: natural gas co-located generation; Ute Mountain Ute: solar/BESS); (3) tax advantages or other economic benefits (*e.g.*, access to federal grants, Tribal tax structures) materially improve project economics; and (4) the developer has patience for federal approval timelines.

When Tribal Lands Present Prohibitive Challenges. Tribal lands should be avoided when: (1) project timelines are tight and cannot accommodate longer permitting timelines to accommodate federal approval processes; (2) the developer is uncomfortable with Tribal governance, NEPA complexity, or Tribal sovereign immunity (as sovereigns, Tribes – like states and the federal government – enjoy sovereign immunity; thus, they are immune to lawsuits in Tribal, federal, and state courts in the absence of express waiver by the Tribe or an abrogation by Congress, though in reality Tribes often negotiate limited waivers in contract with non-Tribal businesses that frequently provide for arbitration); (3) project financing is constrained (lenders may be uncomfortable with trust land status, BIA approval contingencies, or sovereign immunity, requiring the developer to secure non-recourse project finance or negotiate lender comfort measures); (4) cultural resource concerns make development prohibitive (*e.g.*, if sites have a high probability of significant archaeological or cultural resources, NHPA Section 106 may require costly mitigation or avoidance measures, which can effectively halt the project); or (5) the project does not align with Tribal priorities (Tribes will not approve projects inconsistent with their economic development strategies, cultural values, or community vision).

Best Practices for Successful Tribal Partnerships. Developers who successfully develop on Tribal lands consistently follow these practices:

Early & Continuous Engagement. Initial discussions with Tribal leadership (Chairman, Tribal Council) and the Tribal community should occur during site selection, well before land options or detailed planning – so that project proponents still have the flexibility to respond to Tribal feedback in a meaningful way (such as by modifying proposed siting in response to cultural resource concerns). Maintaining regular communication with the Tribe throughout development by providing updates, soliciting ongoing input, and addressing concerns proactively is essential.

Respect for Tribal Sovereignty. Approach the Tribe as a sovereign government, not a landlord. While formal government-to-government consultation protocols are only binding on the federal government, project proponents can – and should – support the consultation process. Project proponents should also respect Tribal authority and decision-making processes, recognize that Tribes may be facing certain capacity challenges (*e.g.*, insufficient funding, limited staff knowledge, administrative burdens, and inconsistent federal practices), and avoid attempting to bypass the Tribal government through direct negotiations with either the federal government or individual Tribal members or officials.

Alignment of Benefits. Structure agreements to provide meaningful benefits to the Tribe: direct revenue (lease payments, royalties, profit-sharing, equity stake), employment (commit to hiring Tribal members for construction and operations with training programs if necessary), capacity building (support Tribal education, workforce development, or infrastructure), and environmental stewardship (demonstrate commitment to protecting Tribal resources and minimizing impacts).

Cultural Competency and Respect. Invest in understanding Tribal history, culture, and values. Retain consultants or advisors with experience in Tribal communities. Avoid cultural insensitivity (*e.g.*, scheduling meetings during Tribal ceremonies, failing to respect sacred sites, using terminology or symbols without permission). Cultural missteps can irreparably damage relationships.

Patience & Long-Term Perspective. Tribal approval processes take time. Federal NEPA and NHPA Section 106 reviews are not optional or negotiable. Developers who approach Tribal projects with realistic timelines and commitment to a thorough process consistently achieve better outcomes than those attempting to pressure Tribes or federal agencies to accelerate reviews.

Tribal lands offer unique opportunities for data center developers willing to embrace different regulatory, cultural, and business frameworks. Projects that succeed on Tribal lands are those where developers genuinely partner with Tribes, align projects with Tribal priorities, and commit to long-term, mutually beneficial relationships. Those approaching development on Tribal lands opportunistically or without respect for Tribal sovereignty will encounter obstacles, delays, and frequently, project denial.

Section 10: AI Workloads, Edge Computing & Distributed Infrastructure

Data center development in Colorado increasingly involves facilities designed for artificial intelligence and machine learning workloads, edge computing serving latency-sensitive applications, and distributed infrastructure models that depart from traditional centralized hyperscale designs. Requirements evolve rapidly with compute density, latency demands, and sustainability commitments. This section addresses workload-specific design considerations, power and cooling implications, edge deployment strategies, and associated regulatory overlays.

I. AI & High-Density Computing: Power & Cooling Implications

Electrical Density & Infrastructure Requirements. Traditional enterprise data centers deploy servers with power densities of five to 10 kilowatts per rack. AI workloads utilizing graphics processing units ("GPUs") or tensor processing units ("TPUs") for parallel processing generate power densities of 30 to 80 kilowatts per rack, with some next-generation AI accelerators exceeding 100 kilowatts per rack. These densities create challenges for electrical distribution (busway and power distribution units must be sized for higher amperages), cooling (traditional raised-floor air cooling cannot remove heat from racks exceeding approximately 20 kilowatts per rack), and utility interconnection (a 50,000-square-foot AI training facility may require 50 to 100 megawatts of power, comparable to a traditional hyperscale facility 10 times larger).

For developers pursuing AI-focused facilities in Colorado, these density implications mean: (1) utility interconnection capacity becomes even more critical, as sites requiring 100-plus megawatts of firm power are rare and expensive to serve; (2) cooling strategy must shift toward liquid cooling technologies (direct-to-chip cold plates, immersion cooling) rather than traditional air cooling, which has implications for water use (liquid-cooled systems still require heat rejection to ambient, though water consumption can be lower than air-cooled chillers if dry heat rejection is used); and (3) co-located generation becomes more attractive, as dedicating utility capacity for AI workloads that may operate at 90-plus percent utilization (compared to 50 to 70 percent for traditional enterprise workloads) creates cost allocation and reliability concerns for utilities serving other customers.

Colorado PUC Regulatory Considerations. The Colorado Public Utilities Commission's emerging large-load tariff frameworks (Section 3) were developed in part to address AI and high-density computing loads that continuously draw massive power. Xcel Energy's tariff filing is expected to include specific provisions addressing AI facilities, potentially including differentiated rate structures (higher capacity charges to reflect the cost of dedicating transmission and generation resources to loads that rarely curtail), minimum utilization requirements (ensuring AI facilities do not reserve capacity speculatively), and coordinated planning processes (requiring AI developers to provide long-term load forecasts and coordinate with Xcel Energy's resource planning to ensure adequate generation is available).

Developers planning AI facilities should engage Xcel Energy, Tri-State, or other serving utilities early (ideally before site selection) to discuss load profiles, timing, and whether the utility's generation and transmission resources can accommodate the load. In some cases, utilities may decline to serve AI loads exceeding certain thresholds without developer participation in funding new generation resources, creating *de facto* co-located generation requirements.

II. Edge Computing: Siting & Latency Optimization

Edge vs. Hyperscale Siting Criteria. Edge computing facilities serve latency-sensitive applications requiring sub-ten millisecond (or even sub-five millisecond) round-trip times to end users. Unlike hyperscale facilities that can be sited in low-cost rural areas with fiber backbone connectivity, edge facilities must be located within metropolitan areas, close to concentrations of end users. In Colorado, this means edge facilities are typically sited within the Denver-Boulder metropolitan areas, Colorado Springs, or Fort Collins; urban and suburban environments with different regulatory and community contexts than rural or exurban hyperscale sites.

Urban edge facilities face: (1) higher land costs (urban infill sites or commercial/industrial zones within city limits); (2) more restrictive zoning (data centers may not be permitted in all zones, requiring conditional use permits or rezoning); (3) greater community scrutiny (neighbors, business associations, and city councils are more engaged in urban development decisions); (4) limited space for outdoor equipment (diesel generators, cooling towers, and BESS containers must all be carefully sited to minimize noise and visual impacts on adjacent properties); and (5) environmental justice considerations (urban areas often have high EJ scores; *see* Section 5.II).

However, urban edge facilities also benefit from: (1) better utility infrastructure (urban substations have more capacity and shorter interconnection timelines than rural sites); (2) municipal water availability (cities have water supply infrastructure without the need for augmentation plans); (3) workforce proximity (technical staff can live nearby, reducing commute times and improving recruitment); and (4) existing telecommunications infrastructure (fiber is ubiquitous in urban areas in Colorado).

Smaller Scale, Distributed Models. Edge facilities are typically smaller than hyperscale facilities (one to 10 megawatts rather than 50 to 200 megawatts), which positions them below some regulatory thresholds. For example, a five-megawatt edge facility with backup diesel generators may have air emissions below PSD major source thresholds (depending on generator size and operating hours), qualifying for simpler synthetic minor source permits or even registrations (Section 2.I). County 1041 review may not apply if the facility does not meet size thresholds (*e.g.*, counties designating "major electrical facilities over 50 megawatts" would not capture a five-megawatt edge facility). However, municipal zoning and building permits apply regardless of size, and urban environmental justice concerns may be heightened even for smaller facilities if sited in sensitive locations.

III. Distributed Energy Resources & Grid Integration

DER Interconnection & Virtual Power Plants. Data centers increasingly participate in utility demand response programs, curtailing non-critical loads during grid stress events in exchange for payments or rate reductions. Data centers with onsite generation, BESS, or flexible cooling systems can operate as distributed energy resources ("DERs"), providing grid services that include frequency regulation, voltage support, peak shaving, and emergency backup. Colorado utilities (particularly Xcel Energy) are developing programs to aggregate DERs into "virtual power plants" that collectively provide capacity and ancillary services.

Data centers participating in DER programs must comply with Colorado PUC interconnection standards for distributed generation and energy storage, including technical requirements for inverter controls, protective relays, and communication systems enabling utility dispatch. The PUC's Proceeding No. 21A-0141E addresses Xcel Energy's Transportation Electrification Plan and distributed energy resource integration, with regulatory frameworks emerging for compensating DERs for grid services. Developers considering DER participation should engage Xcel Energy's distributed energy resources team to understand program availability, technical requirements, and compensation mechanisms.

Microgrids & Resilience. Some data centers operate as microgrids: self-contained electrical systems capable of disconnecting from the utility grid and operating autonomously using onsite generation and storage. Microgrids provide resilience during extended utility outages (Colorado experiences periodic outages due to wildfire, severe weather, or transmission failures) and enable critical services during regional emergencies.

Colorado's Microgrid Roadmap (released January 2, 2025) identifies priorities for microgrid deployment statewide and recommends regulatory reforms to facilitate microgrid interconnection, including streamlined PUC approval and clarification of microgrid operator responsibilities. Data center microgrids face regulatory questions, including: (1) whether operating a microgrid serving only the data center triggers PUC jurisdiction as a public utility; (2) how microgrid disconnection and reconnection is coordinated with the utility; (3) and whether microgrid generation must participate in utility resource planning or capacity markets. Developers considering microgrid configurations should engage legal counsel to assess PUC jurisdictional issues and structure operations to avoid unintended utility regulation (*see* Section 3 for comprehensive discussion of co-located generation and Section 6 for critical infrastructure considerations).

IV. Interplay with Colorado's Grid Modernization & Clean Energy Transition

Renewable Energy Integration & 24/7 Carbon-Free Commitments. Colorado's clean energy mandates (80 percent carbon-free electricity by 2030 for investor-owned utilities, 100 percent by 2050) create both opportunities and constraints for data centers. Utilities are aggressively adding wind and solar generation, which provides low-cost renewable energy but creates grid integration challenges due to variability. Data centers with flexible loads or BESS can provide valuable grid services by absorbing excess renewable energy during oversupply periods and curtailing during undersupply periods.

Some hyperscale operators (Google, Microsoft, Amazon) have adopted "24/7 carbon-free" commitments, requiring that data centers match every hour of electricity consumption with carbon-free generation, not just annual renewable energy purchases. Achieving 24/7 carbon-free in Colorado requires either co-located generation combining solar, wind, BESS, and clean firm resources (geothermal, nuclear, hydrogen) to provide around-the-clock carbon-free power, or power purchase agreements with portfolios of renewable and storage resources shaped to match hourly load profiles. Developers pursuing 24/7 carbon-free should engage early with utilities, renewable developers, and regulators to structure viable pathways.

Impact on Utility Resource Planning. Large data center loads materially influence utility resource planning. Xcel Energy's 2024 Just Transition Solicitation (Proceeding No. 24A-0442E) includes data center load growth projections and discusses how data centers affect generation capacity needs, transmission planning, and renewable energy integration. The PUC reviews utility resource plans periodically and may require utilities to demonstrate that data center load growth is accommodated without undermining clean energy goals or imposing costs on other customers. Developers with projects exceeding 50 megawatts should consider participating in PUC resource planning proceedings to advocate for supportive policies (*see* Section 3 for comprehensive discussion of power strategies, renewable energy integration, and co-located generation pathways).

Section 11: Benchmarking Colorado Against Competing Markets

Colorado competes with multiple western and intermountain states for data center development, each offering different combinations of incentives, regulatory environments, climate, and infrastructure. Understanding Colorado's competitive positioning (its strengths and weaknesses relative to alternatives) informs strategic decisions about when to pursue Colorado sites versus when alternative markets offer superior economics or timelines. Our practice is not limited to advising on Colorado. We regularly counsel clients – including domestic and international investors, sovereign wealth funds, hyperscalers, and institutional lenders – on site selection, structuring, permitting, and financing across all major U.S. data center markets. The Colorado market analysis that follows reflects the type of rigorous, jurisdiction-specific intelligence we bring to every market in which our clients operate.

This section provides a comparative analysis of Colorado's key competitors, including Utah, Arizona, Texas, Nevada, Idaho, and New Mexico, examining tax and incentive structures, permitting timelines, utility costs and capacity, water availability, and workforce. The goal is not to disparage Colorado but to provide developers with a realistic assessment of where Colorado excels and where it faces headwinds, enabling informed market selection.

I. Tax & Incentive Comparison

Virginia (Northern Virginia). Virginia is a leading destination for data centers, particularly in Northern Virginia, due to a combination of robust fiber infrastructure, proximity to major metropolitan areas, and a favorable tax environment. The state offers a sales and use tax exemption for data center equipment and software, contingent on meeting investment and job creation thresholds (*e.g.*, $150 million in capital investment and 50 high-wage jobs, or 25 jobs in certain localities), with the exemption currently extended through June 30, 2035. Localities like Loudoun County provide accelerated depreciation schedules for business tangible personal property tax on computer equipment, but tangible personal property taxes remain a significant ongoing cost, with no abatement for most data centers. Virginia imposes a corporate income tax that includes property and payroll in its apportionment formula, potentially increasing tax exposure for capital-intensive businesses. Electricity costs are relatively low and grid reliability is strong, but the rapid growth of data centers is straining power infrastructure, prompting concerns about future capacity and environmental impacts. The regulatory environment is generally supportive, but local opposition and permitting challenges can arise, especially near sensitive sites. Overall, Virginia's combination of tax incentives, infrastructure, and business environment makes it highly competitive, though property tax and power constraints are notable challenges. Virginia offers substantial sales tax exemptions for data center equipment and has a mature data center market, though its incentives face increasing scrutiny due to environmental and local opposition.

Texas. Texas provides a competitive environment for data centers, with a state sales tax exemption on data center equipment for qualifying projects, and a more generous local sales tax exemption for large data centers that meet high thresholds (*e.g.*, $500 million investment, 20 MW capacity, 40 new jobs). Property tax abatements are commonly negotiated at the local level, and the state does not levy a personal income tax, but it does impose a gross receipts-based franchise tax (the "margin tax"), which can affect large operators. Electricity costs are generally low, and the state's deregulated power market offers flexibility, but grid reliability has been a concern in recent years due to extreme weather events and high demand. The permitting and regulatory environment is business-friendly, with streamlined processes and strong support for economic development. Texas's large land availability and pro-business policies are attractive, but the need for reliable power and the complexity of local tax negotiations are important considerations. Texas provides significant sales tax exemptions for large data center projects with high investment and job creation thresholds, but its requirements for single-occupant use and strict certification may limit flexibility.

Utah. Utah offers a favorable tax environment for data centers, including a sales and use tax exemption on data center equipment and electricity for qualifying projects that meet investment and job creation requirements. Property tax abatements are available through local economic development agreements, and the state corporate income tax is relatively low and apportioned primarily on sales, reducing the impact of in-state property and payroll. Utah benefits from low electricity costs and a reliable grid, with a climate that reduces cooling expenses. The regulatory and permitting environment is efficient and supportive of new development, with relatively few barriers to entry. Utah's central location and growing tech sector further enhance its appeal, though the state's smaller labor pool and water availability may be limiting factors for very large projects.

Arizona. Arizona provides a strong incentive package for data centers, including a sales and use tax exemption for equipment and electricity for qualifying facilities, with no state-level tangible personal property tax. Local governments may offer property tax abatements or reductions, and the state corporate income tax is moderate and based on sales apportionment, minimizing the impact of in-state assets. Electricity costs are competitive, and the grid is generally reliable, though water availability for cooling can be a concern in some areas. The permitting and regulatory environment is streamlined, with state and local agencies actively supporting data center development. Arizona's dry climate is advantageous for equipment longevity, and the state's proximity to major western markets is a further benefit. However, competition for power and water resources may pose future challenges as the sector grows.

Nevada (Reno/Northern Nevada). Nevada offers a highly competitive environment for data centers, with broad sales and use tax exemptions for equipment and electricity, and the possibility of significant property tax abatements through state and local economic development programs. The state does not levy a corporate income tax, but it does impose a gross receipts-based commerce tax, which is generally less burdensome for capital-intensive businesses. Electricity costs are low, and the grid is reliable, with increasing investment in renewable energy sources. The regulatory and permitting environment is business-friendly, with expedited processes for large projects. Nevada's dry climate and low risk of natural disasters are additional advantages. However, the state's smaller labor market and water scarcity in some regions may limit the scale of future data center expansion. Nevada offers partial sales tax abatements for eligible data center equipment, but these are time-limited and require approval, whereas Colorado's incentives may be more straightforward and less administratively burdensome for qualifying data centers.

Colorado's Competitive Position. Colorado does not lead on tax incentives (it lags Virginia, Texas, and Utah) but offers several other competitive advantages, including: (1) a natural cooling climate (free air-side economization much of the year, reducing PUE); (2) central U.S. geography (latency to both coasts, strategic positioning for disaster recovery and redundancy); (3) a strong technical workforce (Colorado's aerospace, telecommunications, and technology sectors provide a deeper talent pool); (4) established fiber infrastructure (Zayo, Level 3/Lumen, Comcast, others provide redundant connectivity); (5) political stability and a pro-business environment (at least compared to California's regulatory complexity or Washington's tax structures); and (6) renewable energy leadership (Colorado's clean energy mandates drive renewable generation growth, supporting corporate sustainability commitments). Colorado's weaknesses include water scarcity, increasing 1041 (or equivalent) permitting complexity, utility interconnection delays, and the lack of statewide tax incentives. Colorado is most competitive for: (i) workloads requiring central U.S. positioning; (ii) developers prioritizing sustainability and renewable energy alignment; (iii) projects where cooling efficiency drives economics (free cooling advantage); and (iv) operators valuing regulatory predictability and workforce quality over lowest absolute cost.

II. Utility Cost & Capacity Comparison

Energy Costs. Colorado's blended commercial/industrial electricity rates competitive with Utah, Idaho, and Nevada, but higher than Texas ERCOT rates and Pacific Northwest hydropower-served areas. Xcel Energy's rates are regulated by the Colorado PUC, with costs driven by generation mix (natural gas, wind, solar, coal retirements). As Colorado adds renewable generation to meet clean energy mandates, rate trajectories depend on natural gas prices, renewable capital costs, and transmission investments. Developers should model energy costs over 15- to 20-year horizons, not just current rates, and evaluate whether co-located generation (Section 3) provides long-term cost stability.

Transmission Capacity & Interconnection Timelines. Colorado's interconnection timelines are longer than Texas ERCOT, similar to Utah, and shorter than California CAISO. Colorado's transmission system is robust along the Front Range but constrained in rural and mountain areas. Competitors with better interconnection access include Texas (competitive market encourages rapid interconnection), the Pacific Northwest (Bonneville Power Administration provides ample hydropower capacity), and parts of the Southeast (TVA and Duke Energy have available capacity in some territories). Colorado's interconnection challenges are being addressed through PUC large-load tariff reforms and utility resource planning, but developers should expect longer timelines than in some competitor markets.

III. Workforce & Operational Considerations

Colorado's Technical Workforce. Colorado benefits from strong concentrations of aerospace (Lockheed Martin, Ball Aerospace, Northrop Grumman), telecommunications (Comcast, Charter, Zayo headquarters in metro Denver), technology (Google Boulder, Amazon Denver Tech Hub, Microsoft, Salesforce), and federal agencies (NOAA, NIST, USGS), providing a deep pool of electrical engineers, network engineers, mechanical engineers, and data center operations professionals. Colorado also has strong university programs (Colorado School of Mines, University of Colorado Boulder, Colorado State University) producing engineering graduates. Competitors with comparable or stronger workforces include Texas (Austin tech hub, Dallas-Fort Worth corporate concentration), Washington (Seattle-area technology workforce), and Northern Virginia (D.C. metro professional services and technology workforce). Colorado's workforce is stronger than Utah's (smaller population base), Nevada's (Reno and Las Vegas have growing but smaller technical communities), and most intermountain competitors.

Quality of Life & Retention: Colorado's outdoor recreation, cultural amenities, and quality of life support workforce recruitment and retention. Data center operators consistently cite workforce stability as a differentiator for Colorado versus some lower-cost states with fewer amenities. This advantage becomes more important as data centers scale operations requiring larger local staff.

IV. Strategic Market Selection Framework

Developers should select Colorado when: (1) workloads require central U.S. positioning for latency or redundancy; (2) sustainability commitments favor renewable energy-rich markets; (3) workforce quality and retention are priorities; (4) cooling efficiency materially affects economics (Colorado's climate provides advantage); (5) the developer has sophisticated regulatory and project management capabilities to navigate permitting complexity; and (6) the project timeline can accommodate comparatively longer development cycles. Developers should select competitor states when: (1) tax incentives materially determine project viability (in that case, favor Virginia, Texas, or Utah); (2) speed to market is paramount (in that case, again favor Texas, Utah, or Nevada); (3) energy cost is the dominant economic driver and sustainability is secondary (in that case, favor Texas or the Pacific Northwest); or (4) water-intensive evaporative cooling is essential and water availability is constrained in Colorado (in that case, consider alternatives with more secure water, though most western competitors also face water challenges).

Section 12: Case Studies & Precedent Projects

While many data center projects in Colorado are not publicly disclosed (proprietary developments by hyperscalers or private co-location providers protecting competitive intelligence), several publicly known projects offer instructive precedents. These demonstrate successful navigation of Colorado's permitting environment, innovative site selection strategies, and effective community engagement.

I. Urban Infill Co-Location Facility (Denver Metro Area)

A multi-tenant co-location data center in the Denver metro area serves enterprise, cloud, and network customers. The facility is strategically positioned with connectivity to existing campus infrastructure and major fiber routes. The developer navigated Denver's urban permitting environment, including building permits, fire code compliance (NFPA standards for multi-tenant facilities), and utility coordination with the primary local provider. This project exemplifies successful urban infill development for data centers, capturing latency-sensitive workloads that require proximity to the Denver metro area while avoiding the regulatory complexities of greenfield rural sites (such as 1041 reviews and augmentation plans). The approach—leveraging existing infrastructure, municipal water and power, and established utility relationships—serves as a model for incremental expansion in urban markets.

II. Suburban Expansion in Douglas County (Parker Area)

A co-location and cloud-focused data center expansion occurred in the Parker area of Douglas County. The project successfully navigated the county's permitting process through effective engagement with planning staff and community stakeholders. Douglas County's development review requires detailed applications addressing water supply, energy efficiency, traffic impacts, and fiscal considerations. The developer's application included commitments to energy-efficient cooling (achieving below-market PUE targets), reliance on municipal water (avoiding augmentation plan requirements), construction-phase traffic management, and coordination with local fire services. Approval followed public hearings before the Planning Commission and Board of County Commissioners, with conditions related to landscaping, noise limits, and ongoing reporting on energy and water use. This experience illustrates that Douglas County maintains established review processes and can approve data center projects when developers demonstrate responsiveness to county priorities and community concerns.

III. Metro Campus Development (Aurora-Denver Area)

A large-scale data center campus in the Aurora-Denver metro area was initially launched over a decade ago, with subsequent expansions. The developer navigated municipal permitting (building permits, site plan approvals), utility interconnection with the primary provider, and community engagement addressing concerns about energy use and economic impacts. The project highlights the advantages of selecting sites in municipalities with pro-business reputations and established utility infrastructure. The jurisdiction actively recruits technology companies and offers streamlined permitting for data centers that meet energy efficiency and design standards. The approach included early engagement with economic development officials, securing property tax incentives, and commitments to local hiring and workforce development partnerships. Success in this receptive municipality (contrasted with challenges in more restrictive jurisdictions) underscores the critical role of municipal alignment in site selection.

IV. Lessons from Colorado Precedents

Successful Colorado data center projects share common characteristics:

(1) Early engagement with regulatory authorities (utilities, county planning departments, fire marshals, and relevant state divisions such as air quality) before formal applications;

(2) Selection of sites with favorable regulatory contexts (municipalities or counties with pro-business reputations, existing utility capacity, water availability, and low environmental justice scores);

(3) Proactive community and stakeholder engagement (neighborhood meetings, transparent communication about project details, and responsiveness to concerns);

(4) Demonstration of alignment with state and local priorities (energy efficiency, renewable energy use, job creation, and economic benefits); and

(5) Retention of experienced Colorado-based legal, engineering, and public affairs professionals and firms familiar with the state's unique regulatory and political environment.

Projects that encounter delays, cost overruns, or denials typically fail in one or more of these areas: selecting adversarial jurisdictions, delaying regulatory engagement until after site acquisition, underestimating community opposition, or lacking local counsel familiar with Colorado processes.

Section 13: Conclusion

Colorado presents compelling opportunities for data center developers willing to navigate its complex but ultimately manageable regulatory environment. The state's central U.S. geography, natural cooling climate, strong technical workforce, established fiber infrastructure, and renewable energy leadership position it as a strategic location for hyperscale, AI, edge, and hybrid workloads. At the same time, Colorado's water constraints, multi-jurisdictional permitting framework, utility interconnection challenges, and community engagement expectations require developers to approach projects with sophistication, patience, and integration across technical, regulatory, and business domains.

The data center industry is evolving rapidly. AI workloads, co-located generation, 24/7 carbon-free commitments, and distributed edge architectures are reshaping infrastructure requirements and regulatory frameworks. Colorado's regulatory and utility sectors are adapting through large-load tariff development, co-location frameworks informed by FERC precedent, microgrid roadmaps, and renewable energy integration, but these adaptations are ongoing, not complete. Developers entering Colorado in 2026 and beyond will encounter a dynamic regulatory environment where active engagement, advocacy, and innovation in project structuring materially influence outcomes.

This playbook has provided a roadmap; not a simple checklist, but a framework for strategic decision-making across site selection, permitting, power strategy, water supply, siting, tax optimization, deal structuring, Tribal partnerships, competitive positioning, and integrated project execution. Colorado rewards developers who embrace this complexity, invest in local relationships and expertise, and align projects with the state's values and priorities. The same is true of every market where the stakes are high and the regulatory terrain is complex. Davis Graham brings this same integrated approach to data center projects across the U.S., serving developers, lenders, and capital partners who require legal counsel that understands not only the documents but the underlying markets, regulatory systems, and deal dynamics that determine project success.

How Davis Graham Can Help

Data center development in Colorado requires integrated legal strategy across permitting, power, water, tax, transaction, and (where applicable) Tribal and federal regulatory domains. Our multidisciplinary teams work in parallel to advance projects through Colorado's interconnected approval environment, ensuring that cooling decisions inform air permitting, power strategies align with utility coordination, site selection accounts for 1041 (or equivalent) exposure, and tax structuring maximizes available incentives while preserving flexibility for financing and exit.

Our data center infrastructure practice extends well beyond Colorado and the Rocky Mountain West. We advise developers, investors, lenders, and capital partners on the full lifecycle of data center projects – from site selection and regulatory strategy to deal structuring, tax optimization, and financing – across all major U.S. markets and in connection with cross-border transactions. Whether you are deploying capital into a hyperscale campus in Virginia or Texas, evaluating portfolio acquisitions spanning multiple jurisdictions, structuring a joint venture with a U.S. partner, or seeking counsel on the U.S. regulatory and tax environment from outside the country, we bring the same integrated, multidisciplinary approach that Colorado demands and which Davis Graham has mastered.

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This playbook is provided for informational purposes and does not constitute legal advice. Developers should retain experienced legal counsel for project-specific guidance.

Section 14: References and Resources

This section provides a comprehensive bibliography of authorities, regulations, agency guidance, case law, and other sources cited throughout this playbook. Citations are organized by section and formatted according to The Bluebook: A Uniform System of Citation (21st ed. 2020).

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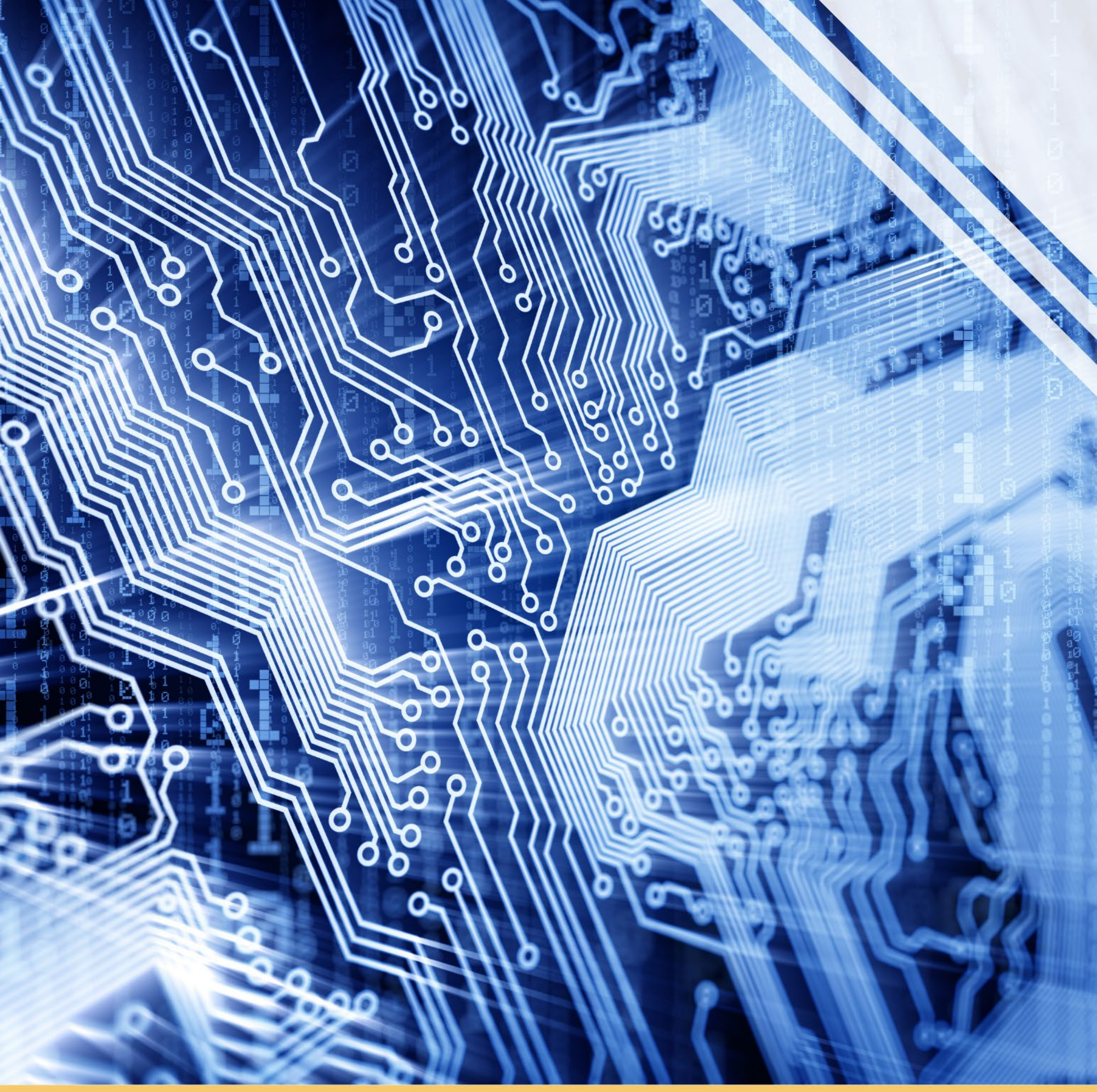
Publication Date: February 27, 2026



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