

ENERGY COMPLIANCE, INC. | *Field Reference for Large Loads and Data Centers*



LARGE LOAD & DATA CENTER SERIES • EC-WP-1003

The Data Center Owner's Playbook

Operating Inside Texas Senate Bill 6 and the New Large-Load Regime

A practical guide for data center owners and developers operating under Texas Senate Bill 6: the 75-megawatt interconnection trigger, the adopted study-fee, security and site-control rule, the curtailment bargain, behind-the-meter generation, the proposed move from 4CP to 12CP, and the choice between standalone and co-located configurations. Updated for the rules the PUCT adopted and proposed through October 2026.

Book Four of the Energy Compliance Large Load & Data Center Series

The Owner Layer

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This edition was first published in June 2026. Statements about Texas statute, PUCT rules, ERCOT revision requests, FERC proceedings and NERC registration were checked against the primary sources as they stood on October 17, 2026.

Where a matter is proposed but not yet final at the time of writing, it is described as such. Energy Compliance, Inc. does not represent that any proposed rule or pending order will be adopted in the form described, or at all.

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Foreword

This professional reference is one of a series Energy Compliance, Inc. publishes for registered entities and the people who run their compliance programs.

I have spent more than thirty years on every side of the bulk electric system. I have operated control centers as a Reliability Coordinator, Transmission Operator, and Power System Operator. I have audited grid facilities and signed off on findings as a senior compliance auditor. I have worked enforcement matters from inside the regulator's process. For the last several years I have advised registered entities directly through the firm I founded.

The entities that handle reliability well share a common habit. They take the standards seriously without confusing them with reliability itself. They know that a NERC Reliability Standard is a floor, not a ceiling. They know that compliance is what an auditor evaluates, but reliability is what the system either delivers or does not. They prepare for audits by building programs that survive real questions, not binders that look thick.

The data center owner who reads this book is in a different position than the owner who broke ground three years ago. The financial commitments are now written into a Commission rule. Curtailment is mandatory for new transmission-voltage load rather than negotiated, and co-location with an existing plant has moved from a private arrangement into a Commission approval proceeding. This fourth book in the series

translates those rules into the decisions an owner actually faces, from site selection through interconnection to day-to-day operation.

These references are written for the compliance manager who wants to understand the system, not just memorize requirements. For the legal counsel who has to brief a board honestly about what the next eighteen months of large-load regulation will require. And for the data center owner or engineering partner who has been told their facility may now be a registered entity, and wants to know what that actually means.

These references are not marketing material dressed as content. They are the product of three decades of doing this work and watching it succeed and fail. I have written them in the same voice I use in a control room or in front of a Regional Entity audit team: direct, grounded in evidence, and honest about what the rules do and do not require.

Energy Compliance, Inc. exists because most of the consulting offered to registered entities today is structured for billable hours rather than for outcomes. A senior practitioner with regulator-side experience oversees every engagement. We do not bring five people to a meeting that needs one. We automate what should be automated and apply senior judgment to what requires it. If that approach matches what you are looking for in a compliance partner, the back of this reference tells you how to reach us.

If not, the reference still belongs to you. Take what is useful. Apply it well. And remember the only test that ultimately matters: when the system needs to perform, does it?

Rob Smith

Founder and Principal, Energy Compliance, Inc.

Bloomington, Minnesota

How to Use This Reference

This whitepaper is the fourth of five books in the Energy Compliance Large Load and Data Center Series, plus an October 2026 update. The first three books built the institutional picture: the grid layer, the NERC response, and the registration question. This book turns to the owner's perspective and focuses on the most developed state regime in the country: Texas Senate Bill 6 and the implementing rules at the PUCT and ERCOT.

The grid layer (EC-WP-1000)

What the demand shock is, why the existing planning and interconnection frameworks cannot absorb it, and how the federal and state interconnection regimes are being rebuilt in response.

The standards layer (EC-WP-1001)

NERC's Large Loads Action Plan, the Level 2 and Level 3 Alerts, the technical white papers, the reliability guideline, and the mandatory standards under development.

The entity layer (EC-WP-1002)

The registration question as NERC first framed it in its April 2026 Computational Load Entity proposal, and what becoming a NERC-registered functional entity requires.

The owner layer (EC-WP-1003)

The data center owner's playbook under Texas Senate Bill 6: the interconnection trigger, the study-fee, security and site-control regime, the curtailment bargain, and the standalone-versus-co-located choice.

The operating layer (EC-WP-1004)

The compliance operating model for a registered computational load: internal controls, governance, evidence infrastructure, and the day-to-day disciplines that convert obligations into demonstrable compliance.

The October 2026 update (EC-WP-1005)

NERC's Board-approved Computational Load Owner and Computational Load Operator registry criteria and the CLO-001-1, CLO-002-1 and CLO-003-1 standards. Where any book in the series describes the Computational Load Entity proposal, EC-WP-1005 controls.

Every factual assertion in this reference is grounded in a primary source identified in the Sources and Authorities appendix. Where a regulatory matter was proposed or pending at the time of writing, it is described as such. Energy regulation in this area moves monthly. The status of a docket or a NERC project when you read this may differ from its status on the review date.

Executive Summary

In Texas, the rules for building a large data center changed in a single legislative session. Senate Bill 6, signed and effective June 20, 2025, rewrote how large loads interconnect to, pay for, and operate on the ERCOT grid. For a data center developer, it turned a set of long-held assumptions into a regulatory regime. Load was served on demand. Interconnection was a queue-and-build exercise. On-site generation was a private matter. None of that holds now. In its place are study fees, posted security, mandatory curtailability for new transmission-voltage load, and Commission approval of co-location with existing plants. This book is the owner's guide to that regime.

The earlier books in this series set out the wider picture: the grid-layer reliability problem and the federal interconnection framework (EC-WP-1000), NERC's Large Loads Action Plan (EC-WP-1001), and the registration question (EC-WP-1002, updated by EC-WP-1005). This book takes the owner's point of view inside the ERCOT market specifically, where the binding rules come not from FERC but from the Texas Legislature, the PUCT, and ERCOT. For anyone siting, financing, or building a large load in Texas, it is the most operational book in the series.

When this book was first published in June 2026, most of the implementing rules were still drafts. Several are now final. The PUCT adopted the large load forecasting rule (16 TAC §25.370) in February 2026 and the co-location net metering rule (16 TAC §25.205) in March 2026. It adopted the interconnection standards rule, 16 TAC §25.194, by order filed September 18, 2026, effective October 8, 2026. Two rules are proposed and not final: the demand management service (proposed §25.521, published for comment July 30, 2026) and the transmission cost recovery package in Project No. 58000, which would replace the four-coincident-peak method with a twelve-coincident-peak method and put large loads on a minimum billing demand.

Five findings frame the analysis

Interconnection now has a price of entry, and the price is set. SB 6 directs the PUCT to set interconnection standards for large loads at a 75-megawatt threshold. Adopted §25.194 requires a \$100,000 study fee, \$50,000 per MW of security before a load enters an ERCOT interconnection study, documented site control, disclosure of substantially similar requests by the customer and its affiliates, and an officer's attestation. A load that is allocated capacity and walks away gives up 20 percent of the associated security. One that neither withdraws nor signs the standard agreement forfeits all of it. The free option on a queue position is gone.

Curtailability is mandatory for new transmission-voltage load. For a transmission-voltage customer interconnected after December 31, 2025, the serving utility must have a protocol,

including any equipment installed before interconnection, that allows the load to be curtailed during firm load shed. The statute also lets ERCOT, after it has deployed available market services, direct a large load with qualifying on-site backup generation to run that generation or curtail. A separate, paid demand-management service is in rulemaking. A new Texas data center has to be built on the assumption that it can be told to reduce or disconnect.

Co-location with an existing plant is an approval proceeding. SB 6 requires ERCOT study and PUCT approval of net metering arrangements between a generation resource registered as stand-alone on September 1, 2025 and a new large load. Adopted §25.205 runs that process as a docketed application with a 120-day ERCOT study and a 60-day Commission decision. The narrow exemptions turn on how the plant was registered and who owned it on January 1, 2025.

Cost allocation is being rewritten, and the proposal is on the table. SB 6 directs the PUCT to reexamine the four-coincident-peak methodology, to consider what portion of transmission costs should be nonbypassable, and to amend its rules by December 31, 2026. In July 2026 the Commission proposed the answer: amendments to §25.192 and §25.193 and a new §25.252 that would allocate wholesale transmission costs on twelve monthly coincident peaks instead of four summer ones, and bill a large load on a minimum billing demand tied to its contracted peak demand, for no less than 20 years, whether or not it has energized. Nothing in that package is adopted yet. How it lands has direct consequences for the economics of a Texas large load.

These obligations sit on top of the federal and NERC layers. SB 6 governs interconnection, curtailment, co-location and cost allocation in ERCOT. It does not displace NERC reliability obligations. On October 8, 2026 the NERC Board approved registry criteria for Computational Load Owners and Operators, and the CLO standards passed their final ballot on October 14, 2026; NERC's implementation plans put the start of registration in 2027, pending FERC approval. A Texas owner will have to satisfy both layers.

The practical message: siting, financing, and structuring a large load in Texas are now regulatory decisions as much as commercial ones. The fee and security rules change the capital plan. Curtailment changes the operating model and the service levels a developer can promise tenants. The co-location rules change the build-versus-grid calculus. The cost allocation review changes the long-run economics. This book maps each decision so an owner can make it with the rules in view.

Chapter 1. The Owner's New Reality

Texas was the easy place to build. That was the point, and that is what changed. ERCOT's appeal to data center developers was speed and light-handed regulation: an energy-only market, no capacity obligation, and an interconnection path for load that was comparatively quick. The surge of demand that followed overwhelmed exactly those features, and Senate Bill 6 is the Legislature's response. The first thing an owner needs to understand is that the State's posture toward large load has shifted from accommodation to management.

1.1 The scale that forced the change

The numbers behind SB 6 are extraordinary. At its December 2025 meeting, ERCOT told its Board it was tracking about 226 GW of large loads seeking interconnection as of November 18, 2025, compared with 63 GW in December 2024, and that roughly 73 percent of it was data centers. By mid-2026 ERCOT put the figure at more than 438,000 MW, with nearly 90 percent of the requests coming from data centers. For scale, ERCOT's preliminary all-time demand record is 91,134 MW, set on July 22, 2026. A queue that large, dominated by one load type and inflated by speculative and duplicative requests, cannot be planned around with tools built for steady, organic growth. SB 6 is, at bottom, an attempt to impose discipline on that queue and reliability on the loads that come out of it.

Texas Senate Bill 6 is the most comprehensive large-load statute I have seen, and its scope is worth taking in whole. It addresses interconnection standards, study fees and financial commitment, site control, disclosure of parallel requests, backup-generation disclosure, curtailment protocols, ERCOT's emergency authority over loads with on-site generation, a voluntary demand-management service, co-location with existing generation, cost allocation, and the roles of the PUCT, ERCOT, and the utilities. An owner working inside the regime is working inside a coordinated set of provisions, not a single rule.

1.2 What SB 6 actually changed

Senate Bill 6 works by amending the Public Utility Regulatory Act (PURA) and directing the PUCT and ERCOT to implement the changes through rules and protocols. The amendments reach four areas an owner cares about directly:

- **Interconnection standards and cost.** New PURA §37.0561 and §35.004(c-1) set the price and process of getting connected.
- **Curtailment and demand management.** New PURA §39.170, together with §37.0561(e), sets the conditions under which a load can be reduced or disconnected.
- **Co-location and net metering.** New PURA §39.169 governs load sited with an existing generation resource.
- **Transmission cost allocation.** Section 6 of the bill orders the PUCT to reexamine who pays for the grid.

The statute took effect immediately on June 20, 2025, but its operative requirements arrive through PUCT rulemaking. The Commission opened an overarching implementation project, Project No. 58317, on June 30, 2025, and is carrying the work out through separate rulemaking projects on staggered timelines.

SB 6 provision	PUCT project	Status (October 17, 2026)
Large load forecasting criteria, PURA §37.0561(m)	No. 58480, 16 TAC §25.370	Adopted February 2026
Co-location net metering, PURA §39.169	No. 58479, 16 TAC §25.205	Adopted March 26, 2026; effective April 15, 2026
Interconnection standards, PURA §37.0561	No. 58481, 16 TAC §25.194	Adopted by order filed September 18, 2026; effective October 8, 2026
Demand management service and curtailment protocols, PURA §39.170	No. 58482, proposed §25.521	Proposed July 30, 2026; ERCOT expects a rule in November 2026
Transmission cost recovery, SB 6 Section 6	No. 58484 (evaluation); No. 58000 (rulemaking opened May 27, 2026), amending §25.192 and §25.193 and adding §25.252	Staff draft report May 2026; proposal approved for publication July 9, 2026, comments closed August 11, 2026; ERCOT expects a rule in December 2026

The direction is fixed by statute. The numbers that matter most to an owner, the fee, the security and the forfeiture terms, are now fixed by rule as well. Demand management and cost allocation are proposed, and the Commission can still change them before adoption.

The Legislature heard months of testimony before it acted, from ERCOT, the PUCT, transmission and distribution providers, large industrial customers, and the data center industry. The framing that came out of that record is consistent: the speed and scale of large-load interconnection had outpaced the legacy planning, cost allocation, and operating tools. SB 6 is not just a curtailment statute or a cost allocation statute. It resets the structural relationship between large loads and the system that serves them.

1.3 From customer to participant

The deepest change SB 6 works is one of posture. A large load in ERCOT is no longer just a customer that buys energy and expects service. It is a participant whose size has reliability consequences. It must pay to be studied, post security for its queue position, disclose parallel efforts, accept curtailment equipment if it takes transmission-voltage service, and get Commission approval to net against an existing plant. NERC is making the same shift through registration and reliability standards, as EC-WP-1005 describes. Reliability outcomes used to be the supply side's job. SB 6 puts large loads inside it: curtailment obligations, interconnection cost, study and security conditions, and planning and operating processes alongside generators and transmission providers. In my experience, owners who design their facilities, operating teams and commercial terms around the participant role operate far more comfortably here than owners who still see themselves as customers.

Chapter 2. The Interconnection Gauntlet

Getting connected now has a price, a process, and a paper trail. The foundational SB 6 rule, 16 TAC §25.194, sets the standards a large load must meet to interconnect in ERCOT. It imposes real financial commitment and disclosure obligations designed to separate committed projects from speculative ones, and to make the developer, rather than the broader ratepayer base, carry the cost and risk of connecting a large load. The rule took effect October 8, 2026.

2.1 The 75-megawatt trigger

PURA §37.0561(c) directs the PUCT to set a demand threshold of 75 megawatts at a single site unless it finds a lower threshold necessary. Adopted §25.194 keeps 75 MW. It applies to a large load customer that has not energized as of the rule's effective date and that seeks:

- a new interconnection at a single site of 75 MW or more;
- an expansion that takes a single site to 75 MW or more for the first time;
- an expansion of 75 MW or more at a site already above 75 MW; or
- to co-locate with a generation resource.

For an expansion, the rule applies to the incremental load. The threshold is measured on total expected non-coincident peak demand at a single site, whether served at transmission or distribution voltage.

Smaller loads are not free of obligations. ERCOT's large-load revisions (NPRR1234 and PGRR115, approved by the PUCT on May 15, 2025) set modeling standards for loads of 25 MW or greater. A 30 MW facility sits below the §25.194 threshold but above the modeling threshold: it is still visible to the planning function and still carries data and modeling obligations, without the §25.194 financial commitments. Owners of facilities between 25 and 75 MW should plan for that dual-threshold structure.

Project No. 58481 is where the rule was written, and it drew 219 filings before adoption. The rule leaves a good deal to ERCOT protocols: the study process itself, an optional additional ERCOT study fee, what counts as a material change, and how notices flow. Owners with Texas projects should track the protocol revisions that follow §25.194 as closely as the rule itself.

ERCOT's revision requests are the operational counterpart to the PUCT rules. NPRR1234 and PGRR115 were the first round. PGRR145, the Batch Zero process for large load interconnections, was approved by the PUCT on June 18, 2026. ERCOT's September 2026 Board materials show further revision requests planned for filing in November 2026 to move from Batch Zero to an ongoing batch study within a Comprehensive Transmission Planning framework. Owners with active or planned facilities should treat ERCOT's stakeholder process as a venue for substantive engagement, comparable in importance to the PUCT projects.

2.2 Study fees and financial security

The statute set a floor: a flat study fee of at least \$100,000 for initial transmission screening studies, with any unused portion credited toward later obligations at the same site. Adopted §25.194 builds the financial structure on top of that floor, in two stages.

Before the study. The customer signs and funds an intermediate agreement with the interconnecting distribution service provider (DSP) and, if different, the interconnecting transmission service provider (TSP). It pays the \$100,000 study fee, and ERCOT protocols may add a flat fee of their own. Any unused study amount comes back within 60 days after the study concludes. The customer also posts security of \$50,000 per MW of requested peak demand, or per MW of the increment for an expansion. Security can take only three forms: segregated interest-bearing cash, a guaranty from a guarantor rated at least BBB- or Baa3, or a letter of credit from a bank rated at least A- or A3. Where equipment with a lead time of 18 months or more must be ordered before the standard agreement is signed, the customer posts additional security to cover it, and direct interconnection costs are paid as nonrefundable contribution in aid of construction (CIAC).

After allocation. Within 60 days after ERCOT issues a study report that allocates capacity, the customer must sign and fund a standard large load interconnection agreement (SLLIA). SLLIA security is the greater of \$50,000 per MW of contracted peak demand or the system upgrade costs allocated to the customer. All direct interconnection costs are paid as CIAC in cash, with no allowance to offset them, trued up to actual cost and not refundable.

The forfeiture terms are where the rule bites:

Event	Consequence under §25.194
Withdraw before ERCOT begins the study, or allocated zero MW and withdraw before the SLLIA deadline	Security returned after outstanding amounts owed are paid
Allocated some capacity, withdraw before the SLLIA deadline	20% of the security tied to the allocated capacity is kept
Neither withdraw nor sign the SLLIA by the deadline	All intermediate security forfeited
Withdraw contracted demand after signing the SLLIA	20% of the security tied to the withdrawn demand is kept
Miss the phased energization schedule by 24 months	Security drawn for amounts owed; 20% tied to the non-utilized capacity kept
Energize	20% of remaining security returned at energization, the rest in 20% steps as minimum billing demand milestones are met

The \$50,000 figures and the study fee adjust for inflation every five years starting in 2032. The rule's own stated purpose, in the adoption order, is to require commitment before a load is studied. For an owner, the consequence is concrete: capital is committed earlier and put

genuinely at risk, which changes both the financing and the care with which a developer approaches the queue.

A \$100,000 study fee is a routine cost for a serious project. The security is not. At \$50,000 per MW, a 300 MW request means \$15 million posted before the load is studied. That is the design. Security tied to study milestones converts a nominal commitment into a capital commitment, and the queue inflation of the past two years happened because there was no equivalent discipline.

2.3 Site control and disclosure

Beyond money, the rule requires proof of commitment and transparency. At the intermediate agreement stage, the customer must show site control through one of three legally binding interests: a lease of at least five years measured from the date the load is expected to reach requested peak demand, a deed, or a signed option to buy or lease (with an option to lease obligating at least a five-year term). At the SLLIA stage the options narrow to a lease of at least five years, a deed, or a signed purchase and sale agreement. If an affiliate holds the interest, the customer must show a legally binding connection linking itself, the affiliate and the site.

The customer must also disclose whether it, an affiliate, or the end-use customer it has contracted to host is pursuing a substantially similar interconnection request in Texas, directly or through a third-party developer, that would cause it to materially change, delay or withdraw. The rule defines material change: a delay of a year or more, a change of 20 percent or more in requested peak demand, or a change in the point of interconnection. "Affiliate" reaches anyone holding 5 percent of the voting securities, up and down the ownership chain. The disclosure must give the ERCOT serial number, location and load zone, requested demand, timing and utilities for the parallel request. Competitively sensitive details may be anonymized, and the utility may share the information only with the PUCT and ERCOT.

The rest of the disclosure list is longer than many owners expect: development schedule and progress on site studies, state and local permits and approvals, a phased energization schedule in MW, power factor and MVAR, water volume, source, supplier and cooling technology, power procurement plans and any on-site generation that can synchronize to ERCOT, and whether the load will register as a controllable load resource. An officer with binding authority must attest to all of it, and everything is subject to audit by ERCOT and PUCT staff. Failing that audit can mean administrative penalties or loss of allocated capacity.

The site-control rule answers a problem the pre-rule process surfaced repeatedly: phantom queue positions. A developer with weak site control could file at several sites and hold positions in several study queues with no intent or capacity to build at most of them. The result was queue inflation, planning distortion, and wasted study resources. Section 25.194 closes that gap by requiring a binding property interest before a load is studied and again before the SLLIA. The duplicate-disclosure requirement backs it up by forcing the applicant to reveal its other pending requests and those of its affiliates.

These obligations reach further than they appear on first reading. The duplicate-disclosure rule turns queue strategy from a parallel-applications race into a single, accountable commitment. For developers whose financing models depended on holding several queue positions while

negotiations played out, that is a material change in working capital and risk allocation. Under SB 6, site selection, financing and queue strategy are one problem, not the separate workstreams a looser regime used to allow.

2.4 Backup generation disclosure

PURA §37.0561(e) requires an interconnected large load to disclose its on-site backup generating facilities, defined in the statute as generation that cannot export to the ERCOT grid and that, in the aggregate, can serve at least 50 percent of on-site demand. The utility passes that information to ERCOT. Adopted §25.194 goes further: the customer must disclose any backup generating facilities, and any on-site backup generating facilities, with nameplate capacity, fuel source, run-hour and fuel-storage limits under existing permits, and how fast each can reach full output. Material changes must be disclosed as they occur.

This disclosure feeds the curtailment regime in Chapter 3, because a load with qualifying on-site backup generation is one ERCOT may, in an emergency, direct to run that generation or curtail. It also feeds the co-location analysis in Chapter 4. On-site generation is no longer an invisible resilience measure. It is a disclosed, regulated feature of the facility that shapes its obligations.

Owners underestimate this one. Making the disclosure is easy. The consequence is not: once the facility meets the statutory definition, it falls within ERCOT's emergency directive authority whether or not the backup is ever dispatched commercially. An owner who planned emergency-only diesel should assume the disclosure brings operational obligations with it.

2.5 ERCOT's batch study process

On the operational side, ERCOT has rebuilt how it studies the flood of requests. Studying projects one at a time produced repeated restudies, because each new large project could change or invalidate the studies of projects further along. ERCOT's answer is a batch process that studies eligible projects together and allocates transmission capacity based on what the grid can support. PGRR145 set up the first round, called Batch Zero. ERCOT's Board adopted it on June 2, 2026, the PUCT approved it on June 18, 2026, and most of it took effect July 11, 2026. Developers had to submit required studies and data by July 10, 2026 to participate, and ERCOT was to classify each project as base load, studied load or excluded load in August 2026. Adopted §25.194 includes transition terms for Batch Zero loads.

For an owner, interconnection timing is now tied to a batch cadence rather than to the moment an individual application is filed. That rewards readiness: site control, security, and disclosures in order when a window opens. ERCOT's September 2026 Board materials describe the move from Batch Zero to an ongoing batch study inside a single Comprehensive Transmission Planning framework, with revision requests expected in November 2026 and Board consideration planned for April 2027.

Batching has consequences beyond timing. The batch a request enters, the composition of that batch, and the interactions among the projects in it all shape the study outcome and the upgrade costs allocated to each project. An individual study would not have produced the same answer. Owners should know which batch their project sits in and who else is in it.

Application strategy matters in a queue this large. An applicant whose timing, site work and disclosures are ready when a batch window opens moves faster than one whose application straddles a study boundary. My advice is to talk with ERCOT and experienced counsel before filing. Developers who file when their internal schedule demands it tend to learn the queue dynamics after the application is already in.

The revision requests will keep coming, and each is open to stakeholder comment. The stakeholders most engaged in that process shape the result. Owners with active or planned facilities benefit from participating, directly or through a trade association with credible representation. It costs staff time and technical analysis. The alternative is operating under protocols written to other participants' preferences.

Chapter 3. The Curtailment Bargain

The price of fast, large-scale power in Texas is the obligation to give it back when the grid needs it. SB 6's reliability core is its treatment of curtailment and demand management. It converts large loads from must-serve demand into a controllable resource, sometimes voluntarily and for pay, sometimes by mandate. This is the provision that most directly reshapes the operating model and the commitments an owner can make to tenants.

3.1 Mandatory curtailment for new load

PURA §39.170(a) directs the PUCT to require ERCOT to ensure that each electric cooperative, transmission and distribution utility, and municipally owned utility serving a transmission-voltage customer develops a protocol, including installation of any necessary equipment or technology before the customer is interconnected, that allows the load to be curtailed during firm load shed. The utility must confer with the customer, where feasible, so load is shed in a coordinated way. The requirement applies only to load interconnected after December 31, 2025, and excludes critical load industrial customers and designated critical natural gas facilities. Proposed §25.521(a) restates the same directive.

Two things stand out. The trigger is transmission-voltage service, not the 75 MW threshold. And the date is the line that matters: a transmission-voltage load energizing after the end of 2025 is built into this regime from day one. An owner planning a Texas facility must design for remote curtailability as a baseline requirement and account for it in the service commitments it makes.

Firm load shed is the most consequential operating condition in ERCOT's emergency response. It is the controlled disconnection of firm load ERCOT orders when supply can no longer meet demand, to prevent an uncontrolled collapse. Historically, utilities have carried it out by rotating outages across distribution customers. SB 6 puts new transmission-voltage load into that response with equipment installed before energization, and gives ERCOT a separate tool, covered next, for loads with qualifying backup generation. The largest loads on the system become an early line of demand-side response rather than the last.

The curtailment equipment itself gets little attention and deserves more. A transmission-voltage load interconnected after December 31, 2025 takes on, with its interconnection, the equipment and protocol its utility develops under §39.170(a), installed before it connects. The statute leaves the technical specifics to the utility and ERCOT, so get the specification in writing early and build the design around it. The obligation runs as long as the load is connected. Plan the operations and maintenance program on the assumption that the equipment will be tested, examined, and on rare occasions actually used, every year the facility runs.

3.2 ERCOT's authority over on-site backup generation

SB 6 reaches on-site generation as well as grid draw. Under PURA §37.0561(e), ERCOT must establish a threshold, before or during an energy emergency alert, at which it may give

reasonable notice that large loads with on-site backup generating facilities may be directed to run that generation or curtail. After ERCOT has deployed all available market services except frequency-responsive services, it may direct the serving utility to require the customer to do one or the other. ERCOT counts such a deployment as firm load shed for pricing purposes. The subsection does not authorize violating emissions limits or other environmental rules, and it does not bar the load from the voluntary service in Section 3.3.

The conditions are layered on purpose. ERCOT gains a reliability lever over large configurations with substantial non-exporting generation, but only as a late-stage emergency measure. For an owner with on-site generation, the configuration decides the exposure: generation that cannot export and can serve at least half the load brings the facility inside this authority.

The authority is also, in part, an authority to see. ERCOT cannot manage what it cannot model, and on-site generation that is invisible to the planning models distorts everything downstream, from resource adequacy projections to transmission sequencing to reserve targets. The disclosure obligations do two jobs at once. They support an operational emergency tool, and they give the planning function the visibility it needs to assess the system's actual exposure. An owner who treats them as paperwork misreads them.

3.3 The voluntary demand-management service

Alongside the mandate, PURA §39.170(b) directs ERCOT to develop a reliability service that competitively procures demand reductions from large loads of at least 75 MW, to be deployed in the event of an anticipated emergency condition. The statute requires at least 24 hours' notice, requires a deployed load to stay curtailed for the duration of the energy emergency alert or until it can be safely recalled, and bars any load that curtails in response to wholesale prices or takes part in another reliability or ancillary service.

This is the carrot to the mandate's stick. A large load that can reduce on request can be paid to stand ready. For an owner whose workloads have genuine flexibility, computing that can pause, shift, or run on backup, the service turns curtailability into a revenue line rather than a pure constraint.

The PUCT published proposed §25.521, the Large Load Demand Management Service (LLDMS), on July 30, 2026. As proposed, and subject to change on adoption:

- ERCOT may procure LLDMS to help prevent or relieve an energy emergency alert caused by extreme weather, through requests for proposal driven by monthly probabilistic modeling, weekly forecasts, or an anticipated or actual alert.
- A participant must prequalify at least annually, offer at least 1 MW of reduction and pass a price-responsiveness test.
- Offers are in dollars per MWh through a qualified scheduling entity, and ERCOT must reject offers above \$5,000 per MWh.
- Payment uses a single clearing price: 25 percent for a resource held available but not deployed, 100 percent for deployed capacity.
- Annual procurement spending is capped at \$54 million, and costs are charged to load serving entities by load ratio share.

- The ineligible list is long, including ancillary services, other ERCOT curtailment programs, price-responsive demand response, and a \$39.169 net metering arrangement that already carries a curtailment obligation.

The structure rewards owners who can make credible offers, which means facilities that can show, through telemetry and operating records, that the reductions they offer will be delivered. Owners without that infrastructure can still participate, but their offers will be more conservative and their revenue smaller.

Participating in LLDMS as proposed means working through a qualified scheduling entity, prequalifying every year, designating operating personnel who will execute deployments, and keeping telemetry good enough to prove the reduction happened. The operating discipline is closer to a resource's than a passive customer's. Facilities entering the service should plan for the staffing and process changes that come with it.

The voluntary service also belongs in the financial model earlier than most developers put it. The mandatory regime is a cost. The voluntary service, once adopted, is a revenue stream: a facility that can credibly offer reductions ahead of extreme-weather emergencies is selling flexibility back to a market that values it, on its own commercial terms, which beats waiting to be curtailed in firm load shed. Carry a realistic LLDMS revenue case alongside the mandatory-curtailment compliance cost, and check it against the rule as adopted. The proposed \$54 million annual cap and the eligibility exclusions limit how much any one facility can expect.

3.4 What curtailability means for the business model

Taken together, the curtailment provisions force an owner to answer a question that used to be optional: how flexible is this facility, really? A site serving latency-sensitive, must-run workloads with strict uptime commitments will feel the mandatory regime as a hard constraint and a risk to disclose to tenants. A site serving interruptible or shiftable work, some AI training and batch processing among it, can treat the same regime as manageable and offer into the voluntary service. The rules do not dictate the business model. They price it. Flexibility is rewarded and rigidity is penalized, and that calculus belongs in the development decision from the start.

Mandatory and voluntary curtailment together produce a hybrid that resembles how generation has operated for decades in organized markets. Generators carry obligations the system operator can invoke, alongside voluntary market participation they manage on their own commercial terms. SB 6 applies a similar architecture to the load side: the mandatory protocol and ERCOT's emergency directive play the role of the obligation, and LLDMS plays the role of market participation. Owners who see the parallel will find the structure familiar even where the substance is new.

Curtailment protocols need to be in place before the equipment is energized. They describe how an instruction from ERCOT or the serving utility is received, who is authorized to execute it, how execution is documented, and how the result is reported back. Facilities that write protocols during commissioning and drill them before live operation execute cleanly when called. Facilities that wait until after energization end up writing protocols under pressure when the first instruction arrives, which is the worst time to design them.

Curtailment compliance also produces an operating record that will be examined later. ERCOT, the PUCT, and counterparties in any contract dispute will look back at how the facility responded to specific instructions, whether the response met the requirements, and whether the contemporaneous records support the facility's account. Keep those records as you go: instructions received, actions taken, telemetry confirming the response, post-event reports. Facilities that rely on reconstructed records are set up for an uncomfortable conversation with the regulator.

Chapter 4. The Co-Location Decision

The fastest path to power is now the most regulated one. For a developer racing the interconnection queue, co-locating a data center with an existing power plant has been the shortcut: draw from generation that is already connected and skip years of waiting. SB 6 did not ban that route, but it ended its status as a private commercial arrangement. Netting a new large load against an existing stand-alone plant is now a decision the Commission approves, and the analysis behind it is one of the most consequential an owner makes.

4.1 Net metering now requires approval

Under PURA §39.169, a power generation company, municipally owned utility or electric cooperative must notify ERCOT before implementing a net metering arrangement between a facility registered with ERCOT as a stand-alone generation resource as of September 1, 2025 and a new large load at the 75 MW threshold. The serving utility may object for reasonable cause. ERCOT studies the system impacts and must file results and recommendations with the PUCT within 120 days after it has all required information. The Commission then has 60 days to approve, deny, or impose reasonable conditions, and an arrangement it does not act on in time is deemed approved. Parties are limited to the Commission, ERCOT, the serving utility and the parties to the arrangement.

The conditions have teeth. A plant that made dispatchable capacity available to ERCOT before the arrangement must keep at least that much available afterward, at ERCOT's direction ahead of an anticipated emergency. The Commission may also require the load to reduce during certain events, require the plant to make capacity available, or require that other customers be held harmless for stranded or underutilized transmission. Open-ended conditions are reviewed at least every five years.

The PUCT implemented §39.169 in 16 TAC §25.205, adopted March 26, 2026 and effective April 15, 2026. The rule makes Commission approval a precondition to implementation, extends coverage to stand-alone energy storage resources registered as of September 1, 2025, and requires the applicants to file a docketed application. That application must include testimony, a completed large load interconnection study under ERCOT protocols, identification of the interconnecting TSP and DSP, and a copy of the ERCOT notice. A material change in the load's physical characteristics or configuration that requires restudy restarts the clock. ERCOT's study must cover resource adequacy, including the load's curtailment capability and on-site backup, along with transmission security and stranded or underutilized transmission assets. The effect is a reliability review inserted between the developer and the structure it would otherwise have signed privately.

4.2 The exemptions and timing

PURA §39.169(b) and §25.205(a) carve out two exemptions. The approval requirement does not apply to a generation or storage resource whose registration included a co-located large load at the time of energization, even if the load energized later. Nor does it apply where a majority interest in the resource was owned, directly or indirectly, on January 1, 2025, by a parent company of the large load in the new arrangement. In practice, the second exemption covers load and generation that were already under common ownership before the statute was written.

Timing matters at the margins too. The rule covers only resources registered as stand-alone on September 1, 2025, and only large loads that were not already modeled as part of a generation or storage private use network on that date. For an owner weighing co-location, the plant's registration history and its ownership on January 1, 2025 are threshold questions. They decide whether the approval process applies at all.

Disclosure has a long tail. Once on-site resources are disclosed and modeled, they stay visible to the planning function, and their assumed role becomes part of the planning case. Backup generation an owner intended for emergency-only operation may, in my view, come to be counted on more broadly once the planning case depends on it.

4.3 Behind-the-meter versus grid-connected

The co-location decision comes down to a choice between two postures toward the grid. A behind-the-meter or private-network configuration, with load drawing from co-located generation and minimizing measured grid draw, offers speed and potential cost advantages. If it nets against an existing stand-alone resource, it now triggers the §25.205 approval process and the conditions that can come with it. If on-site generation cannot export and can serve at least half the load, it also brings ERCOT's emergency authority. A grid-connected posture, taking service through the normal interconnection and paying for transmission, avoids the co-location approval but exposes the load to the full §25.194 process and to transmission cost allocation. Note that §25.194 now applies to a large load seeking to co-locate with a generation resource as well. Neither path is categorically better. The right answer turns on the project's timeline, its generation options, its tolerance for regulatory process, and the cost allocation outcome in Chapter 5.

Co-location questions reach beyond the obvious case of an existing plant adding a data center behind its meter. New generation developed jointly with a new data center, a data center contracting for a nearby plant's output, and on-site resources serving part of facility load each sit differently under §39.169, §25.205 and §25.194. The definitions in the rules decide where each lands. Engage counsel early on any configuration near a boundary, because getting it wrong can mean an arrangement implemented without a required approval.

4.4 The multi-market contrast

Developers working beyond Texas should read the co-location decision against the federal backdrop the first book examined. On December 18, 2025, FERC found PJM's tariff unjust and unreasonable for lacking clear rates, terms and conditions for co-located load (193 FERC ¶ 61,217). It directed new transmission service options for co-located load and revised behind-

the-meter generation rules, and on June 18, 2026 it issued its order on rehearing, clarification and compliance (195 FERC ¶ 61,209). On the same day, instead of issuing the nationwide rule the Secretary of Energy's October 2025 advance notice in Docket No. RM26-4-000 had proposed, FERC instituted Section 206 show-cause proceedings against each of the six RTOs and ISOs it regulates (PJM, Docket No. EL26-67, 195 FERC ¶ 61,211; SPP, EL26-68; NYISO, EL26-69; MISO, EL26-70; CAISO, EL26-71; ISO New England, EL26-72). Each order directs the grid operator and its transmission owners, within 60 days, to show cause why the tariff is just and reasonable without provisions on the study process for large loads, cost transparency and a cost recovery agreement, transmission services for flexible large loads, and interconnection customers serving co-located or electrically proximate load, or to propose tariff revisions. The June 18 orders did not terminate the ANOPR docket, and FERC's August 2026 regulatory agenda still lists RM26-4-000 with its next action undetermined. ERCOT is not among those proceedings.

The instruments differ. Texas acts by statute and PUCT rule, the FERC world by tariff order. The direction runs parallel: both are pulling co-location into the open and subjecting it to explicit reliability and cost rules. A developer choosing between a Texas site and a PJM site is choosing between two procedural paths to the same regulated destination, and that comparison belongs in the siting analysis.

Cost exposure varies with the site as much as the regime. A facility in a transmission-constrained area will see different allocated upgrade costs from one in an unconstrained area. A facility with on-site generation is treated differently from one without, and so is a facility built for firm service versus one built to be interrupted. Owners evaluating several candidate sites should model the cost outcome at each.

4.5 The energy-first model

Some developers have built their strategy around co-location: the "energy-first" approach of siting computing where generation already exists, on the theory that it needs less new transmission and catalyzes new generation. SB 6 does not foreclose that model, but it changes how it is executed. The arrangement has to survive the §25.205 review and its conditions, fit within or around the exemptions, and account for ERCOT's emergency authority over qualifying on-site generation. An energy-first developer in Texas must engineer the structure with the approval process in view from the outset, not treat regulatory clearance as a formality after the deal is struck.

Plan the legal budget accordingly. Counsel on a Texas large-load project now advises on PUCT rule participation, ERCOT revision requests, intermediate agreements and SLLIAs with substantial regulatory content, curtailment posture, and the financing disclosures the regime triggers. Owners who underestimate that work end up spending more on disputes than they would have spent on preparation.

Chapter 5. Cost Allocation and the Long Game

Who pays for the grid that serves a data center will move the economics more than any single fee in §25.194. SB 6 did not settle transmission cost allocation. It ordered a reexamination of it, and in July 2026 the PUCT published its proposed answer. The proposal is not adopted, and the Commission can change it before the statutory deadline. That makes cost allocation the variable still most in motion, and a planning factor in its own right.

5.1 The four-coincident-peak question

Under 16 TAC §25.192, ERCOT wholesale transmission charges are allocated to distribution service providers using the four-coincident-peak (4CP) method: each provider's demand in the four intervals coincident with the ERCOT system peak in June, July, August and September. Section 6 of SB 6 directs the PUCT to evaluate whether that method still assigns transmission costs appropriately; whether it ensures all loads contribute appropriately; whether alternatives such as multiple seasonal peaks, different daily intervals or peak energy intervals would assign costs better; and what portion of transmission costs should be nonbypassable. The Commission had to begin within 90 days of the effective date and must amend its rules by December 31, 2026.

The concern behind the review is specific. A large load that can shape its consumption to avoid the coincident-peak intervals, through curtailment, on-site generation or operational flexibility, can cut its transmission charges while still relying on the system the rest of the year. That shifts cost onto other ratepayers.

5.2 What the PUCT has proposed

The Commission ran the evaluation in Project No. 58484, where staff filed a draft report in May 2026, and then opened Project No. 58000 to write the rules. On July 9, 2026 it approved for publication amendments to §25.192 and §25.193 and a new §25.252, with comments due August 11, 2026. As proposed, and subject to change on adoption:

- Wholesale transmission costs would be allocated on a twelve-coincident-peak (12CP) basis: the 30-minute interval of ERCOT system peak in each of the 12 months from October through the following September, replacing the four summer intervals.
- A large load customer subject to §25.194 would be billed on a minimum billing demand equal to the greatest of its contracted peak demand under the SLLIA, its highest non-coincident peak demand in the past year, or its 12CP demand. Billing would start when service is available, whether or not the load has energized or is using the capacity, and would run for no less than 20 years.

- Study fees and forfeited security collected under §25.194 would offset the transmission service provider's revenue requirement rather than stay with the utility.
- Block load transfers would pay transmission costs, non-opt-in DSPs would give ERCOT settlement-quality meter data for each large load, and new §25.252 would set terms for the tariffs that govern service to large loads.

The proposal does not adopt a separately labeled nonbypassable charge. It reaches the same concern a different way: a 20-year minimum billing demand pegged to contracted capacity is a charge a load cannot avoid by reshaping its measured demand. For an owner, the consequence cuts both ways. A load built around flexibility and on-site generation to minimize peak-based charges would find that advantage blunted, and the same flexibility that earns money in the demand management service would stop working as a cost-avoidance tool. Twelve monthly peaks also mean a winter morning counts as much as an August afternoon, which changes what "avoiding the peak" even means.

5.3 Planning under a proposal

The planning posture I recommend is to treat the July 2026 proposal as the base case and the current 4CP method as the alternative, not the other way around. An owner modeling a Texas large load should run the project under 12CP with a minimum billing demand at contracted peak for 20 years, then test how much the economics improve if the Commission softens the minimum billing demand in adoption. The owners who fare best will be those whose projects pencil out across that range, not those whose economics depend on continuing to shape around four summer intervals.

The standalone-versus-co-located decision in 2026 is no longer simply a build-cost or queue-position question. It is a regulatory-exposure question. A standalone facility lives inside §25.194, the curtailment bargain and the cost allocation rule. A co-located facility lives there too, plus §25.205 and the on-site generation disclosures, and, if part of the portfolio sits in an RTO, the federal co-location framework taking shape in the PJM proceeding and the June 2026 Section 206 proceedings. The exposure profiles differ, and the choice deserves analysis that looks past capital cost and queue position to the obligations each configuration carries forward.

This is the long game of SB 6. The interconnection and curtailment rules shape a project's entry and operation. Cost allocation shapes its lifetime economics, and the statutory deadline for the Commission to act is December 31, 2026.

Chapter 6. Siting and Structuring Decisions

Regulation has become a design input. Once interconnection, curtailment, co-location and cost allocation all carry regulatory weight, the decisions a developer used to make on land, fiber and power availability pick up a regulatory dimension. This chapter pulls the threads into the choices an owner actually faces: where to site, how to structure, and how to sequence, with the rules treated as variables rather than afterthoughts.

6.1 Texas versus the FERC-jurisdictional markets

The most basic siting choice, Texas or elsewhere, is now partly a regulatory one. ERCOT still offers an energy-only market and, historically, speed. SB 6 has layered on study fees, posted security, mandatory curtailability for new transmission-voltage load, co-location approval, and a proposed shift to twelve-coincident-peak cost allocation with a 20-year minimum billing demand. The FERC-jurisdictional markets offer a different mix: RTO-by-RTO Section 206 proceedings on large-load interconnection, the PJM co-location framework, and capacity constructs that price reliability differently. A developer comparing sites should compare these regimes head to head: the cost and risk of interconnection, curtailment exposure, the treatment of on-site generation, and the direction of cost allocation. The regime can now swing project economics as much as land and power prices.

6.2 Structuring the project

Within a chosen market, structure follows from the rules. The ownership of any co-located generation on January 1, 2025 decides whether the §39.169 exemption applies. The size of on-site generation relative to load, and whether it can export, decides ERCOT's emergency reach. Taking transmission-voltage service after December 31, 2025 decides whether the mandatory curtailment protocol attaches. The flexibility of the workloads decides whether curtailability is a constraint or a revenue opportunity. None of these is a detail to sort out after closing. Each is a structuring decision to make deliberately, with the regulatory consequences modeled, because reconfiguring generation, renegotiating tenant commitments or refile for approvals after the fact costs far more than getting it right up front.

6.3 The municipal and cooperative wrinkle

One structural point deserves attention. PURA §37.0561(l) bars the PUCT from limiting the authority of a municipally owned utility or electric cooperative to impose service requirements on large loads beyond the statewide standards, and §25.194(a) repeats it. A developer siting in a municipal or cooperative territory may face requirements beyond the baseline PUCT rule and cannot assume that meeting the statewide standard is enough. A cooperative or municipal utility that has not adopted customer choice must also pass the reasonable costs of interconnection

through to the large load, in a manner it decides, under PURA §35.004(c-2). The identity of the serving utility belongs in the siting analysis.

6.4 The registration overlay

Every Texas siting and structuring decision also sits under the NERC reliability layer. This book's first edition described the proposed Computational Load Entity registration. That proposal is now history. On October 8, 2026, the NERC Board approved Rules of Procedure revisions creating two functional entities, the Computational Load Owner and the Computational Load Operator. The revised criteria, as NERC posted them in August 2026, capture a site that primarily contains IT infrastructure, with total connected load of at least 50 MW supplied at 100 kV or above from one or more points of connection. The companion standards, CLO-001-1, CLO-002-1 and CLO-003-1, passed their final ballot on October 14, 2026, and go to the NERC Board for adoption. FERC's July 16, 2026 order in Docket No. RD26-7-000 requires NERC to file the standards by December 31, 2026, and NERC says it will file the registry criteria by the same date. NERC's implementation plans put the start of registration in 2027. None of it is in effect yet. EC-WP-1005 covers the current framework in full.

NERC's authority runs across the ERCOT Interconnection independent of state law. A Texas data center that meets the NERC criteria will be registered regardless of how it resolves its SB 6 obligations. Note the different tests: §25.194 turns on 75 MW of non-coincident peak demand at any voltage, while the NERC criteria turn on 50 MW of connected load at 100 kV or above. A site can fall under one and not the other. Satisfying the PUCT is necessary but not sufficient, and the two layers must be planned together. ERCOT's own ride-through requirements for Large Computational Loads (NOGRR282 and NPRR1308, approved by the PUCT on July 9, 2026 and effective August 1, 2026) add a third layer for some owners.

6.5 Run it as a program, not a project

Define the metrics for your SB 6 compliance posture and write them down: curtailment equipment status, response time to instructions, completeness of telemetry delivery, timeliness of required disclosures and updates to the utility, and participation in the rulemakings and stakeholder process. Give each a target, a reporting cadence and an owner. Programs that run against defined metrics hold their performance. Programs without them hold it only until the person who tracked it informally leaves.

Continuous improvement disciplines carry over directly. Periodic operating reviews, root-cause analysis of compliance events, lessons captured from drills, and procedure updates based on those lessons produce a program that gets better over time. Generators in the same market and long-registered entities already run this way. Owners who treat the SB 6 regime as a long-term operating discipline rather than a one-time project build these habits early and benefit from them for the life of the facility.

Chapter 7. The Owner's Action Plan

Some of the rules have hardened and some are still moving. That combination is exactly why now is the time to act. The interconnection, co-location and forecasting rules are final. The demand management rule and the cost allocation package are proposed, and the cost allocation rules are due by year-end. An owner who waits for every proceeding to finish before planning will be making capital and design decisions under rules others helped shape.

7.1 Model the project across the open questions

First, build the project's economics against the range of plausible outcomes, not the most favorable one. The study fee, security and forfeiture terms are now fixed in §25.194. The curtailment protocol is fixed for post-2025 transmission-voltage load. The demand management service and the cost allocation method are proposed, not adopted. A disciplined owner stress-tests the project against the proposed 12CP method with a 20-year minimum billing demand at contracted peak, against the existing 4CP approach, and against realistic curtailment exposure, so the decision to proceed does not rest on assumptions a rule change could overturn.

Project economics under §25.194 are not the economics of the pre-rule process. The study fee, the per-MW security, site-control costs, nonrefundable CIAC and the minimum billing demand obligation all combine into a front-loaded cost profile that must be modeled before site selection is final. Sophisticated developers keep a project cost model that tracks each variable across candidate sites and updates as PUCT and ERCOT decisions settle open parameters. Less sophisticated developers find the front-loaded costs after financing is committed, which is exactly what the rule was designed to prevent.

An SB 6 financial model differs from the model the same facility would have run before the statute in specific ways. The study fee and \$50,000 per MW of security are due before the load is studied. Site control has to be secured, not optioned loosely. Direct interconnection costs are paid as nonrefundable CIAC. Twenty percent of security is at risk on withdrawal after allocation, and all of it if the SLLIA deadline is missed. Curtailment equipment is a capital cost with a maintenance and testing program attached. LLDMS revenue may offset part of the curtailment cost, within the limits of the final rule. The proposed 12CP method and minimum billing demand could raise transmission charges against the 4CP baseline, and would bill contracted capacity before the load uses it. Co-location with an existing plant is slower and conditioned. A complete model carries each of these, not as afterthoughts but as line items.

Lenders and equity sponsors evaluating Texas large-load projects increasingly ask for an SB 6 compliance plan in diligence, in my experience. A plan that addresses each obligation with actions, milestones and cost estimates gives them what they need to underwrite. A vague plan, or one that assumes favorable readings of unsettled provisions, creates friction it did not need to. Prepare the compliance plan with the same rigor as the financial model and the construction plan.

7.2 Decide structure deliberately

Second, settle the structuring questions early: who owned any co-located generation on January 1, 2025 and whether an exemption applies; the size and export capability of on-site generation; whether the load takes transmission-voltage service after December 31, 2025; and how flexible the workloads really are. These decisions interact, and they are far cheaper to make at design time than to retrofit. Where co-location with an existing plant is contemplated, treat the §25.205 application, with its 120-day study and 60-day decision, as a gating item in the schedule, not a closing formality.

Vendor selection picks up new dimensions. Curtailment equipment has to meet whatever specification the serving utility sets under its §39.170 protocol. Telemetry and instrumentation vendors have to support the data ERCOT and the utility require. Engineering firms preparing interconnection studies need to know the batch process and the §25.194 disclosure set. Integrators tying the facility to ERCOT systems need to satisfy commissioning requirements. Judge vendors on their knowledge of the Texas regime as well as their technical capability, because work from a vendor who does not know it will need independent validation.

7.3 Engage the rulemakings

Third, participate. The interconnection, co-location and forecasting rules are adopted, but the demand management rule (Project No. 58482) and the transmission cost recovery rules (Project No. 58000) are proposed and not final, and ERCOT will file further batch study revision requests. Large-load developers have a direct path to influence LLDMS eligibility and compensation, the cost allocation method, and the protocols that implement §25.194. The cost of filing comments is trivial against the lifetime cost of unfavorable rules. An owner with material projects in Texas should be at the table.

This book translates the standards and entity-level obligations into the decisions an owner makes during development and operation. EC-WP-1004 covers how the day-to-day compliance program for a registered computational load is built and run, and EC-WP-1005 brings the NERC registration framework current as of October 2026. Read together, the series describes the regulatory environment large computational loads will operate in for the foreseeable future.

Texas is a preview of where other markets may land. I expect other states with concentrated data center growth to look hard at what Texas built, and owners with multi-state portfolios should expect SB 6-like obligations elsewhere, shaped by each state's own traditions. The disciplines built under SB 6 will transfer, which is one more reason to treat the Texas build-out as an investment in operating capability rather than a one-time cost.

7.4 The bridge to operations

This book has mapped the owner's decisions under Texas law: interconnection, curtailment, co-location, cost allocation, and the siting and structuring choices that follow. It does not cover the operational compliance program a registered computational load must build and defend once it is interconnected and registered. That is the subject of EC-WP-1004, the operating layer, which takes the facility from built and registered to compliant and audit-ready, and EC-WP-1005 sets out the registration criteria and CLO standards that program will answer to. The decisions analyzed here determine what gets built; the rest of the series covers how it is operated.

Glossary of Terms

The following terms are used throughout this whitepaper. Definitions are summarized for convenience. The operative definitions are those in the governing statute, PUCT rules, ERCOT protocols and NERC documents.

Term	Meaning in this paper
4CP (Four Coincident Peak)	The method under 16 TAC §25.192 for allocating ERCOT wholesale transmission costs, based on demand in the four intervals coincident with the ERCOT system peak in June through September. SB 6 Section 6 directs the PUCT to reevaluate it and amend its rules by December 31, 2026. The PUCT's July 2026 proposal in Project No. 58000 would replace it with 12CP.
12CP (Twelve Coincident Peak)	The proposed replacement for 4CP: the 30-minute interval of ERCOT system peak in each of the 12 months from October through the following September, as proposed in amendments to §25.192 (Project No. 58000, July 2026). Not adopted as of the review date.
Backup generating facilities	Under §25.194, generation or storage that cannot operate in parallel with, and cannot export to, the ERCOT system. Large loads must disclose them.
Batch Zero	The first group of large loads studied together, rather than one at a time, under ERCOT's batch process established by PGRR145 (PUCT approved June 18, 2026).
Behind-the-meter / private use network (BTM/PUN)	Configurations in which generation and load connect on the customer side of the meter or within a private network, reducing measured grid draw.
CIAC (contribution in aid of construction)	A cash payment toward utility facilities. Under §25.194, a large load pays all direct interconnection costs as nonrefundable CIAC.
Co-location	Siting a large load with a generation resource so the load draws from it directly. Netting a new large load against a resource registered as stand-alone on September 1, 2025 requires PUCT approval under PURA §39.169 and 16 TAC §25.205.
Computational Load Owner / Computational Load Operator	The NERC functional entities created by Rules of Procedure revisions the NERC Board approved on October 8, 2026, replacing the proposed Computational Load Entity. See EC-WP-1005.
Curtailment	A directed reduction or interruption of load. PURA §39.170(a) requires a curtailment protocol, with equipment installed before interconnection, for transmission-voltage load interconnected after December 31, 2025.
ERCOT	The Electric Reliability Council of Texas, the independent organization certified under PURA §39.151, which implements SB 6 through protocols under PUCT oversight.

Term	Meaning in this paper
Firm load shed	The controlled disconnection of firm load to preserve overall system reliability during an emergency.
Intermediate agreement	The agreement under §25.194 that a large load signs and funds, with the study fee, disclosures and \$50,000 per MW of security, before it is included in an ERCOT interconnection study.
Large load customer	Under §25.194, an entity requesting a new or expanded interconnection where total expected non-coincident peak demand at a single site is 75 MW or more, at transmission or distribution voltage. ERCOT modeling standards under NPRR1234 and PGRR115 reach loads of 25 MW or greater.
Large Load Demand Management Service (LLDMS)	The reliability service PURA §39.170(b) directs ERCOT to develop to competitively procure demand reductions from loads of at least 75 MW for anticipated emergencies. Proposed as 16 TAC §25.521 on July 30, 2026.
Net metering arrangement	Under §25.205, an arrangement in which an existing generation resource and a large load net the resource's output against the load for settlement, using an ERCOT-approved metering scheme.
Large load minimum billing demand	As proposed in §25.193 (Project No. 58000): the greatest of contracted peak demand under the SLLIA, the highest non-coincident peak in the past year, or 12CP demand, billed from the time service is available for at least 20 years. Not adopted as of the review date.
Nonbypassable charge	A charge a load cannot avoid by reshaping its measured demand. SB 6 Section 6 directs the PUCT to decide what portion of transmission costs should be nonbypassable.
On-site backup generating facilities	Under PURA §37.0561(e) and §25.194, generation that cannot export to the ERCOT system and that, in aggregate, can serve at least 50 percent of on-site demand. Such facilities bring a large load within ERCOT's emergency directive authority.
PUCT	The Public Utility Commission of Texas, which implements SB 6 through rulemaking in Project No. 58317 and the related rule projects.
PURA	The Public Utility Regulatory Act, Title 2 of the Texas Utilities Code, which SB 6 amends.
Senate Bill 6 (SB 6)	The 2025 Texas statute (89th Legislature, Regular Session) on the planning for, interconnection and operation of, and costs of serving large loads in ERCOT. Signed and effective June 20, 2025.
Site control	A legally binding property interest in the load location (five-year lease, deed, option, or purchase and sale agreement, depending on stage) that §25.194 requires before study and again at the SLLIA.
SLLIA (standard large load interconnection agreement)	The Commission-approved pro forma agreement a large load must sign and fund within 60 days after ERCOT allocates transmission capacity.

How Energy Compliance Can Help

The decisions in this book are regulatory decisions with engineering and financial consequences, and most owners are making them for the first time. Energy Compliance, Inc. works on exactly this seam. Three services fit a Texas large load directly.

Registration and applicability analysis. Whether a site falls under §25.194, §25.205, ERCOT's 25 MW modeling standards, the Large Computational Load ride-through requirements, and the NERC Computational Load Owner and Operator criteria is a set of separate tests with different thresholds. We run them against the actual configuration and give you a written position you can hand to counsel, lenders and the utility.

Compliance program management. The curtailment protocol, the disclosure and attestation obligations, the LLDMS prequalification and the NERC CLO standards each produce evidence that a regulator will one day ask for. We design the program, write the procedures, and build the evidence set so the first audit or data request is answered from records, not from memory.

Data request strategy and audit defense. When ERCOT or PUCT staff exercise the audit rights in §25.194, or a Regional Entity opens a monitoring engagement under the NERC layer, we map the request, tighten the scope, and manage the response.

Two platforms support that work. WattOps Compliance is EC's NERC compliance evidence platform (wattopscompliance.com). For a new client, EC will run one standard at one facility through WattOps at no cost, CIP standards excluded, so you can see how the evidence is organized before committing. RenewOps is EC's renewable operations monitoring and analytics platform, with a Data Center module for the operating data, curtailment records and telemetry a Texas large load will be asked to produce.

If you are siting, financing or building a large load in Texas, call before the intermediate agreement is signed, not after. The rules in this book reward the owner who had the plan first.

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About the Author

Rob Smith is the Founder and Principal of Energy Compliance, Inc., with more than thirty years in the industry on every side of the system. He began in control-room operations as a Reliability Coordinator, Transmission Operator, and Power System Operator across RTO/ISO and utility control centers. On the regulator side, he was a senior compliance auditor and subject matter expert for NERC Reliability Standards. He audited grid facilities, evaluated mitigation adequacy, participated in risk-based oversight of utility mitigation activities, and supported the development of violation notifications and settlements in FERC-directed enforcement actions. He conducted a regulatory audit in the Sultanate of Oman against the Sultanate's Sector Law and Grid Code.

He founded Energy Compliance, Inc. to deliver senior regulator-side compliance authority without the layered staffing and billable-hour overhead of larger firms.

Education:

- MBA, Energy Management, University of Mary
- MSL, Compliance Law, Fordham Law University
- BAS, Energy Management, Bismarck State College
- BAS, Mechanical Engineering, Metallurgy minor, University of Florida
- BAS, Criminology, St. Petersburg College (State Law Enforcement Certification)
- AAS, Power Plant Technology, Bismarck State College
- AAS, Electrical Transmission System Technology, Bismarck State College

Certifications: NERC Lead Auditor training; previously NERC-certified at the Reliability Coordinator level; 1st Class A Boiler Engineer License, Minnesota.

The views expressed in this publication are the author's and do not represent the views of NERC, FERC, ERCOT, the PUCT, or any Regional Entity.

About Energy Compliance, Inc.

Energy Compliance, Inc. is a multidisciplinary regulatory compliance firm serving the energy industry across NERC, Texas PUCT, ERCOT and adjacent regulatory frameworks. The firm helps registered entities, large-load developers, and prospective registrants through the full compliance lifecycle, from interconnection and registration through program design, evidence development, RSAW production, mitigation, and audit defense.

The firm's approach is built on a research-analyst-first discipline. Every conclusion is tied to an authoritative source. Every narrative is backed by evidence. Every deliverable is built to stand up to regulator scrutiny. Our work also includes legal and engineering services in the energy regulatory space, industry-specific education through the EC-WP whitepaper library and custom NERC training, and two platforms: WattOps Compliance, EC's NERC compliance evidence platform (wattopscompliance.com), and RenewOps, EC's renewable operations monitoring and analytics platform, which includes a Data Center module.

To learn more, or to assess how Texas Senate Bill 6 and the new NERC computational load framework apply to a specific project, contact us.

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