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Megawatts on Paper

From Requested Megawatts to Bankable Demand in Alberta's Data-Centre Power Boom

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Abstract

Alberta's electricity connection queue has become an important indicator of prospective data-centre development, but requested transmission capacity is not equivalent to expected consumption. As of 5 August 2026, the AESO connection list contained 39 non-cancelled Data Load entries totaling 20,525 MW of requested Demand Transmission Service capacity. Of this amount, 18,676 MW had an in-service date under review, while 1,200 MW was both included in AESO planning and modelled in connection studies. This paper reconstructs the public queue, classifies projects using observable development milestones, and presents illustrative scenarios for aggregate project load capacity in operation by 2030. The scenarios range from approximately 0.8 GW to 4.0 GW, with a central case of approximately 1.5 GW. Public disclosures concerning Meta's Sturgeon County campus and the Greenlight Electricity Centre show the customer, contractual, financing, equipment and regulatory evidence associated with an advanced project. The analysis suggests that Alberta can attract material data-centre load without realizing the full queue. For infrastructure investors, exposure is better protected where revenue is supported by binding contracts, staged deployment, termination protection and the ability to redeploy equipment if a project is delayed or cancelled.

Keywords: Alberta electricity, data centres, large loads, connection queues, demand forecasting, behind-the-meter generation, infrastructure investment.

Research cut-off: 13 August 2026. **AESO queue cut-off:** 5 August 2026.

This paper was prepared independently from public information and has not been commissioned, reviewed or endorsed by any company discussed.

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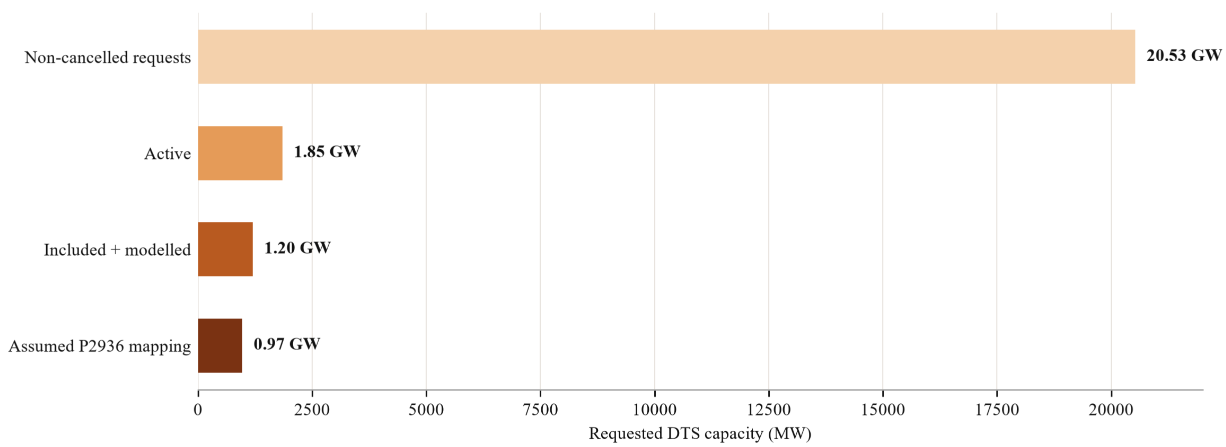
Executive Summary

On 5 August 2026, AESO listed 20,525 MW of non-cancelled data-centre connection requests. That amount is approximately 1.6 times Alberta's 2025 peak internal load, but it should not be interpreted as a forecast of additional consumption. Requested DTS capacity represents a maximum contractual request; it does not establish that a project will be financed, energized on its proposed date, or operate continuously at its requested capacity.[1][2][3]

The available evidence nevertheless supports a material increase in electricity demand. Global data-centre consumption grew rapidly in 2025, and both the IEA and LBNL project further growth through 2030. The uncertainty lies in the allocation of that demand among individual projects and regions. In Alberta, 91% of requested capacity had its in-service date under review at the research cut-off. Only 1.2 GW was both included in AESO planning and modelled in connection studies.[1][4][13][15]

This paper therefore estimates realized load from observable project milestones rather than applying a single percentage to the full queue. Its illustrative 2030 scenarios produce approximately 0.8 to 4.0 GW of aggregate project load capacity in operation, with a central case of approximately 1.5 GW. These cases are not AESO forecasts; they are intended to show how conclusions change with different assumptions about completion, timing, project size and utilization.

Figure 1. AESO data-load capacity by observed project status, August 2026



Source: Author analysis of AESO August 2026 Connection Project List and public commercial disclosures.[1][2][24][25][26] The 970 MW P2936 mapping is an explicit modelling assumption based on name, location, scale and timing; AESO does not publicly attribute the request to Meta.

Meta's July 2026 announcement and Greenlight's final investment decision establish a useful public benchmark. Meta disclosed a more than C$13 billion, 1 GW Sturgeon County campus. Greenlight disclosed a 932 MW dedicated combined-cycle plant, a long-term tolling agreement, project financing, AUC approval, fixed-price construction coverage and targeted service in the second half of 2030.[24][25][26][27] The package displays several characteristics associated with financeability and provides a standard against which less developed requests can be assessed.

For infrastructure investors, binding contracts, staged deployment, termination protection and redeployable equipment reduce exposure to delay or cancellation at an individual project.

1. Global demand outlook and Alberta's connection queue

1.1 Global demand outlook and project uncertainty

The IEA estimates that global data-centre electricity consumption grew 17% in 2025, while consumption at AI-focused facilities grew 50%. Its updated central projection rises from 485 TWh in 2025 to 950 TWh in 2030. It also observes that project pipelines are accelerating even though not all projects will come to fruition.[13]

LBNL's June 2026 bottom-up study reaches a similarly consequential but explicitly uncertain result for the United States: a 649 TWh reference case in 2030, with a compounded range of 521 to 843 TWh, or 9.5% to 15.3% of US electricity consumption.[15] Canada's Energy Regulator separately tests a high case with 12 GW of Canadian data-centre load by 2050 and 100 TWh of annual demand.[28]

Source	Period	Finding	Investment interpretation
IEA	2025-2030	485 to 950 TWh globally	Demand is real; bottlenecks limit near-term upside
LBNL	2030	521-843 TWh in the US	Wide range remains even in a bottom-up model
CER	2050 high case	12 GW / 100 TWh in Canada	Material national upside, not Alberta project proof
ERCOT	2022-2024 sites	49.8% peak use vs requested MW	Connection size can exceed realized early load

Sources: IEA, LBNL, CER and ERCOT.[13][15][28][16]

Rapid demand growth and overstated connection queues can coexist. ERCOT observed an average 180-day delay from original energization dates for projects due in 2022-2024 and reported average peak consumption equal to 49.8% of requested MW for the non-crypto data-centre sites it studied. ERCOT therefore produced an adjusted forecast rather than accepting customer schedules at face value.[16] The published result is used only as directional evidence: the paper does not document a sufficiently comparable sample for the 49.8% ratio to be transferred to Alberta.

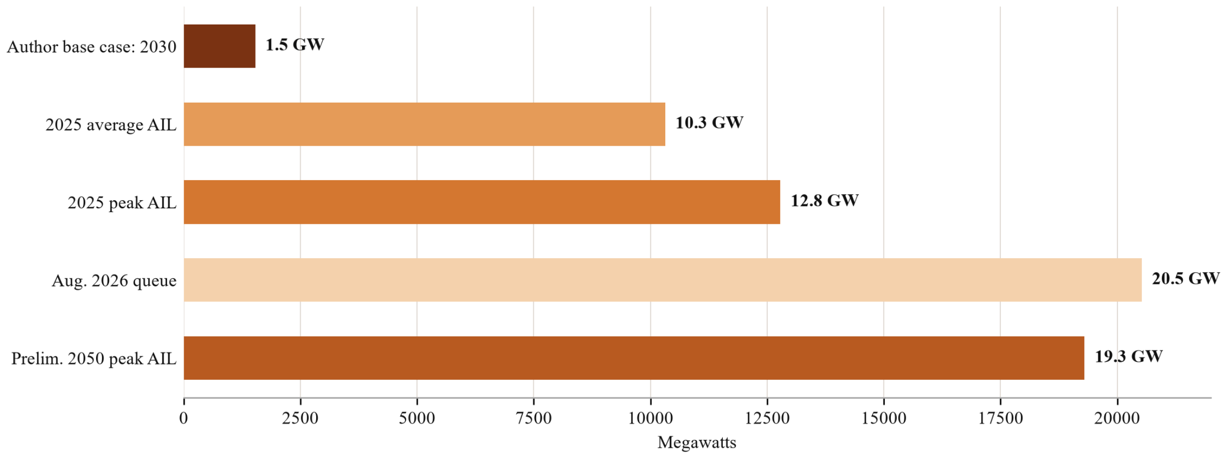
Regulators are reacting. FERC has highlighted contracts, security deposits and site control as objective milestones and warned that developers shopping the same project among utilities can create double counting and distorted investment signals.[17][18] Ofgem is consulting on commitment security and milestones covering credible end users, long-lead equipment and financial capability.[19]

The analysis therefore focuses on which Alberta projects may operate, their likely timing and utilization, and whether their electricity is supplied through the grid or customer-owned generation.

1.2 Scale relative to Alberta's electricity system

Alberta's 2025 average Alberta Internal Load (AIL) was 10,316 MW and its maximum was 12,785 MW. Total annual AIL was 90,371 GWh.[3] The 20,525 MW data-load queue equals 199% of average AIL and 161% of peak AIL. If every request operated at an 85% load factor, it would consume 152.8 TWh per year - 169% of Alberta's entire 2025 AIL. That is an illustration of scale, not a plausible central forecast.

Figure 2. Alberta data-load requests and electricity-system reference measures



Source: AESO 2025 Annual Market Statistics; AESO August 2026 Connection Project List; preliminary 2026 LTO Current Measures case; author scenario.[1][3][6] AIL and requested DTS are different measures; the comparison is illustrative.

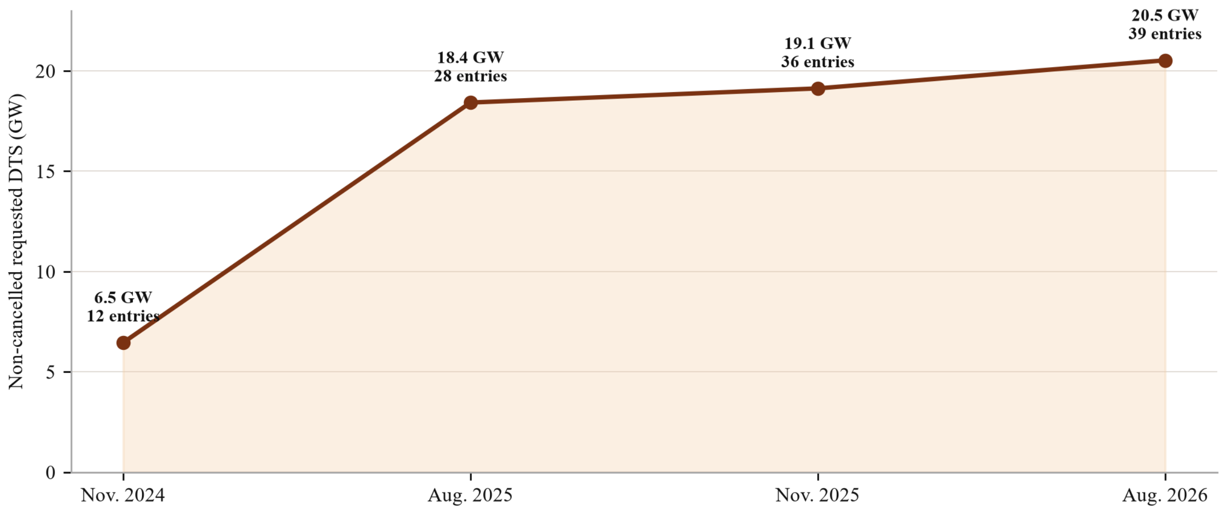
AESO's preliminary 2026 Current Measures case projects total peak AIL of approximately 14.7 GW in 2030 and 19.3 GW in 2050. It assigns data centres 11,593 GWh in 2035 and 15,144 GWh in 2050. The document describes the case as conservative and includes the existing 1,200 MW interim limit. The final 2026 Long-Term Outlook had not been released by the research cut-off.[6][7]

The queue therefore exceeds the preliminary forecast's entire 2050 Alberta peak. The two measures serve different purposes: the queue contains requests at varying stages of maturity, including separate project phases, competing locations, projects that may self-supply and projects whose timing remains unresolved.

AIL includes load served by on-site generation and Medicine Hat. System load is the portion using the bulk transmission system plus losses and averaged 7,463 MW in 2025. Requested DTS represents maximum incremental grid contract capacity. Comparisons between these measures are useful for scale but cannot substitute for dispatch and consumption modelling.

1.3 Growth in outstanding connection requests

Figure 3. Alberta's outstanding data-load queue grew 3.18x from November 2024



Source: Author analysis of archived AESO connection lists using a consistent Data Load / non-cancelled filter.[1][2] Snapshot counts are entries, not necessarily unique customers; recently cancelled rows remain visible only temporarily.

Growth was front-loaded: requested capacity rose from 6.46 GW in November 2024 to 18.42 GW by August 2025 and reached 20.53 GW by August 2026. The current queue is also highly concentrated, with 24 entries of at least 400 MW accounting for 92.0% of requested capacity and the ten largest entries accounting for 59.8%. Separate project IDs may represent successive phases of the same campus, so the list measures connection requests rather than unique end users.[1][2]

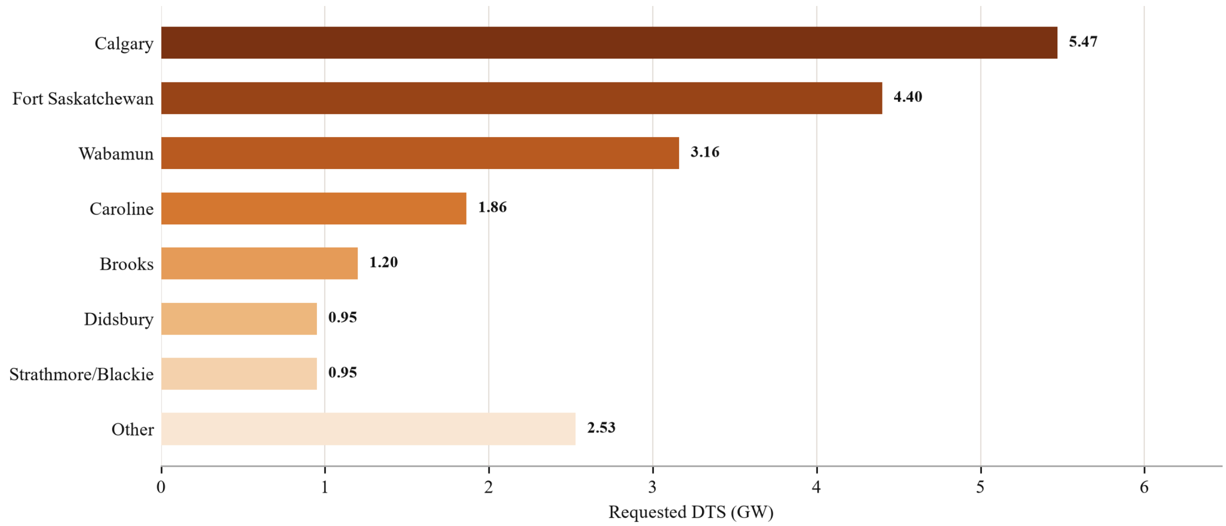
Sub-threshold request cluster

Eight active, non-included entries are exactly 74.9 MW, totaling 599.2 MW. Intent cannot be inferred from the public list. The pattern nevertheless matters because Alberta generally defines a large data centre at 75 MW, while the final regulation permits AESO to lower the threshold and aggregate affiliated or integrated facilities on the same or adjacent land.[1][8]

Sub-threshold project sizing should not be assumed to preserve lighter treatment because aggregation, affiliate ownership and future AESO threshold decisions can change a project's regulatory classification.

1.4 Geographic concentration

Figure 4. Requested capacity is concentrated around Calgary, Fort Saskatchewan and Wabamun



Source: Author analysis of AESO August 2026 Connection Project List.[1] Planning areas are not pricing nodes and do not, by themselves, establish deliverability.

Calgary represents 5.47 GW, Fort Saskatchewan 4.40 GW and Wabamun 3.16 GW - together 63.5% of the non-cancelled queue. The concentration creates both opportunity and risk. Existing industrial infrastructure, gas, fibre, land and power assets can accelerate development. At the same time, simultaneous projects can compete for transmission capability, turbines, switchgear, skilled labour and municipal approvals.

Alberta's Restructured Energy Market is intended to introduce locational marginal pricing for generators and eligible large customers, together with a new real-time ramping product and stronger scarcity signals.[12] A site with existing electrical headroom, dependable gas and a flexible operating agreement can therefore be worth more than an apparently cheaper site requiring major upgrades.

Location factor	Question for underwriting	Failure mode
Transmission	Is capacity firm, staged or interruptible?	Upgrade cost / delay
Gas	Is firm transport secured for peak burn?	Basis / curtailment risk
Fibre	Are diverse routes contractually secured?	Single-point outage
Water	Are cooling rights and permits complete?	Community / permit delay
Market node	What happens under local congestion pricing?	LMP volatility

2. Project-maturity framework and realized-demand scenarios

2.1 Project-realization methodology

ESIG recommends that large-load forecasts distinguish project realization, energization date, load realization, load ramp and load factor or shape.[20] Collapsing these into one queue haircut hides economically different outcomes. A cancelled 500 MW campus is different from a built 500 MW campus operating at 250 MW while servers are installed.

Project-maturity classification

Gate	Minimum public evidence	What it supports
G0 - Requested	Queue entry and stated site	Option value only
G1 - Advancing	Accepted request, site control, technical studies	Connection path
G2 - Permitted	Zoning, material permits, water, gas and fibre plans	Physical feasibility
G3 - Contracted	Named end user, binding power/offtake, financial security	Commercial demand
G4 - Financed	FID, debt/equity, EPC and major equipment orders	Bankable construction
G5 - Operating	Energized load and measured ramp	Observed demand

Scenario formula

Requested MW x probability of operation by year t x ultimate load-realization share x ramp factor in year t x load factor x 8,760 hours.

NERC's May 2026 guideline similarly points to interconnection agreements, security, site control, construction status, permits, land status and procured equipment as maturity evidence.[21] The guideline is recommended practice rather than an enforceable reliability standard.

2.2 Case study: Meta and the Greenlight Electricity Centre

Meta announced a new 1 GW Sturgeon County data centre representing more than C$13 billion of investment. Pembina, Morgan Stanley Infrastructure Partners and Kineticor reached FID on a 932 MW combined-cycle plant dedicated to the campus under a long-term electrical energy supply agreement. Pembina confirmed Greenlight will power Meta's project.[24][25][26]

Pembina's public disclosures describe a tolling structure that combines capacity payments with reimbursement of usage-based fuel and operations-and-maintenance costs. Approximately 85% of project cost is covered by fixed-price turbine and EPC agreements, while the planned capital structure consists of approximately 60% asset-level debt and 40% equity. The project has received key regulatory approvals, identified Siemens as the turbine supplier and an Aecon / Tecnicas Reunidas consortium as EPC contractor, and secured long-term transportation capacity for an estimated 150 MMcf/d of natural gas. Pembina projects approximately C$310 million of annual run-rate adjusted EBITDA attributable to its 47.5% interest.[24][27]

AESO's P2936 GLDC Phase 1.1 is a 970 MW Fort Saskatchewan-area request with an executed load contract and staged DTS entries. The name, location, scale and timing strongly align with the Greenlight/Meta development, but no single primary document reviewed explicitly states that P2936 is Meta. This paper uses the 970 MW block as a commercial proxy and labels the linkage as an inference.[1][4][24][25][26][27]

Construction, schedule, counterparty and carbon risks remain, but the project's public disclosures provide substantially more evidence of financeability than a queue entry alone.

2.3 Case study: Keephills

AESO allocated 230 MW to Keephills Phase 1 and states that the project executed a load contract.[4] TransAlta later announced an MOU with CPP Investments and Brookfield that contemplates an initial long-term power purchase agreement for approximately 230 MW and potential expansion to as much as 1 GW.[22]

TransAlta's own project page is appropriately cautious: municipal planning changes permit potential data-centre development but do not approve a specific project, and the MOU does not mean construction is underway. The project remains in an early planning stage and depends on commercial, technical and regulatory conditions.[23]

Keephills benefits from existing transmission, natural-gas, water and on-site generation infrastructure at a former coal-generation complex, as well as a large zoned land position. Its relative development credibility is further supported by the involvement of TransAlta, CPP Investments and Brookfield, together with a 230 MW Phase I AESO allocation and executed load contract.[4][22][23]

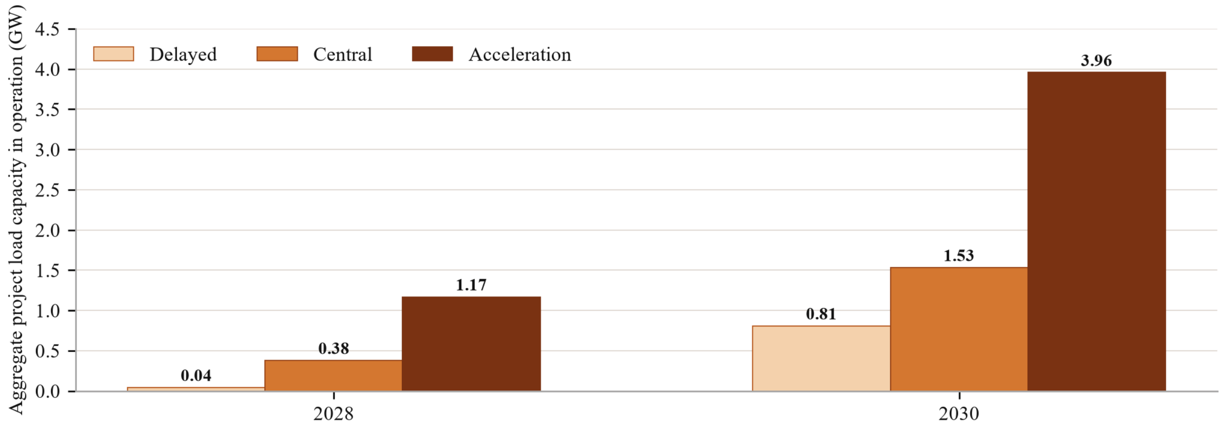
Important commercial evidence was not public at the research cut-off. The disclosed materials did not identify an end user or definitive binding agreements replacing the MOU, and no final investment decision, committed financing, project-specific development approval, EPC scope or major equipment order had been announced.[22][23]

Proof point	Meta / Greenlight	Keephills
AESO allocation / load contract	970 MW proxy; executed	230 MW; executed
Named end user	Meta	Not publicly named
Power arrangement	932 MW dedicated CCGT	Contemplated PPA / existing assets
Binding offtake	Long-term EESA / tolling	MOU framework
FID and financing	Yes	Not announced
Major permits	AUC approval obtained	Planning framework only
Classification	FID-stage; construction risk remains	Advanced option; commercial proof incomplete

2.4 Illustrative realized-load scenarios

The scenario analysis groups the 20.5 GW queue into four maturity cohorts: the assumed P2936 mapping, Keephills, other active requests, and requests whose in-service dates are under review. It varies the share of each cohort operating by 2030 rather than applying one queue-wide realization rate. The resulting cases are illustrative and are not probabilistic forecasts. Excluding the inferred P2936-to-Meta mapping would reduce the central 2030 result from 1.53 GW to approximately 0.61 GW, demonstrating the model's sensitivity to that assumption.

Figure 5. Illustrative scenarios for aggregate project load capacity in operation



Source: Author analysis of AESO queue status, scheduled increments and public project milestones.[1][4][5][20][24][25][26] Values are underwriting scenarios, not AESO forecasts.

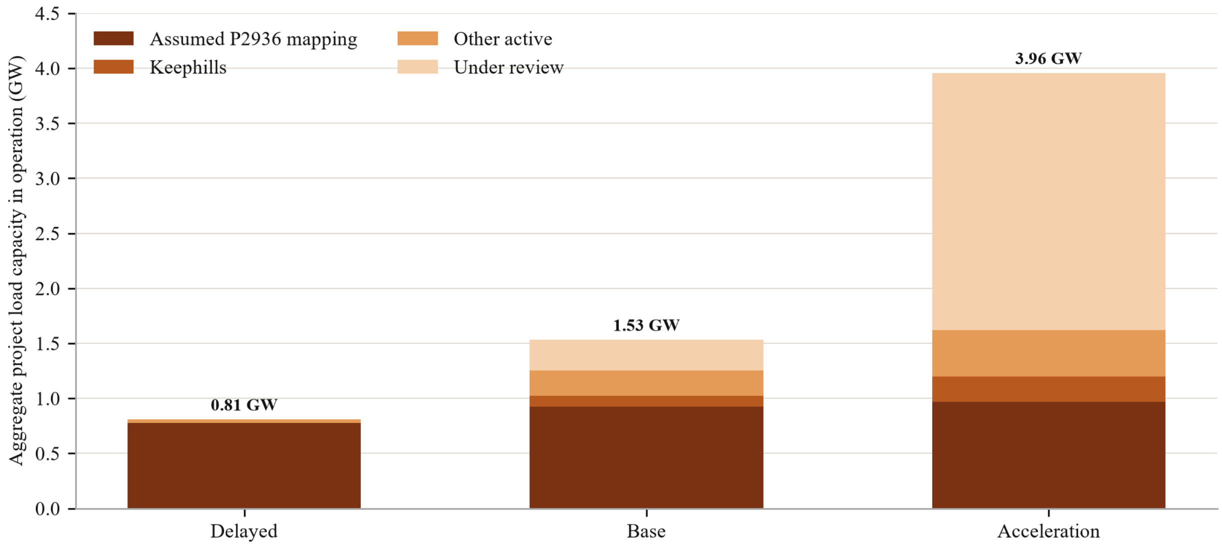
2030 group	Queue MW	Delayed	Base	Acceleration
Assumed P2936 mapping	970	80%	95%	100%
Keephills	230	0%	45%	100%
Other active	649	5%	35%	65%
ISD under review	18,676	0%	1.5%	12.5%
Aggregate capacity in operation	20,525	808 MW	1,532 MW	3,957 MW

Note: percentages combine completion, timing and ultimate size by 2030. They are not historical Alberta transition probabilities.

At an illustrative 85% load factor, the 2030 cases imply 6.0 TWh, 11.4 TWh and 29.5 TWh of annualized run-rate demand. Those amounts equal 6.7%, 12.6% and 32.6% of 2025 AIL. Calendar-year consumption could be lower because projects energize and ramp during the year.

For order-of-magnitude context, the base case's 11.4 TWh annualized run rate in 2030 is similar to AESO's preliminary Current Measures data-centre component of 11.6 TWh in 2035. The dates and methods differ, so this comparison is not evidence of validation; both measures are nevertheless far below the 152.8 TWh implied by the full queue at an 85% load factor.[6]

Figure 6. The high case requires meaningful conversion from projects under review



Source: Author scenarios. The P2936-to-Meta mapping is an inference, not a public AESO customer attribution; the acceleration case assumes 12.5% of under-review capacity operates by 2030.

The model should be updated only when observable evidence changes. Relevant evidence includes a named creditworthy end user and binding campus commitment; an executed power contract addressing capacity, fuel, curtailment and termination; final investment decision, committed debt and equity, and a fixed-price EPC package; major equipment orders with delivery slots; firm gas and fibre capacity; project-specific approvals; and visible construction progress. Once a site is energized, measured load and monthly ramp data should replace development-stage assumptions. Deferred projects should remain in a post-2030 demand category rather than be treated as cancelled.[20][21]

The model does not estimate hourly coincidence, gross versus net grid draw, redundant generation capacity, distribution-connected facilities, duplicate customers across sites or projects absent from the AESO Data Load classification. It should therefore be used to frame investment exposure, not to plan system dispatch.

3. Power-system and policy implications

3.1 System integration requirements

AESO describes Alberta as a comparatively small and lightly interconnected system, with average internal demand near 10.2 GW, two limited AC interties and periods of low inertia. A large electronic load can therefore affect frequency, voltage, interties and system balance when it trips, ramps or reconnects.[11]

AESO's guidance states that no single credible event should produce an unacceptable loss of net load and that voltage and frequency ride-through must be designed and demonstrated. It identifies 300 MW over 30 minutes, or 10 MW per minute, as a ramp generally manageable in normal operations, subject to project-specific mitigation. Large reconnection blocks may require real-time telemetry, reactive-power support and detailed operating procedures. Behind-the-fence generation and batteries can reduce ramp and disturbance risk, but they also increase control, integration and compliance requirements.[11]

These obligations increase the importance of switchgear, transformers, substations, uninterruptible power systems, batteries, protection, controls, telemetry, commissioning and recurring maintenance.

3.2 Regulation and project prioritization

Alberta's Data Centre Regulation, effective June 2026, generally defines a large data centre at 75 MW, permits aggregation, and allows projects to tether new, expanded or qualifying underutilized generation or storage to their load. AESO must prioritize tethered requests over non-tethered large data centres. It may require evidence relating to site control, zoning, financing, permits and water licences.[8]

Tethered supply must be reliable and predictable and, at an AESO-determined rate, at least equal to maximum data-centre demand. A bridge can allow service before tethered supply is ready, but generally for no more than three years. Bridged load is reduced before other market participants when supply is inadequate; large data centres are reduced before ordinary load during mandatory shedding.

Proposed Phase 2A implementation

AESO's Phase 2A detail remained a proposal at the research cut-off. The published design contemplates a C$15,000/MW refundable commitment fee, readiness evidence, initial eligibility for gas-fired thermal technologies, a proposed 1,600 MW bridging pool and staged interruptible access as generation advances.[10] These details should not be described as final until AESO implements them.

Feature	Final regulation	Published Phase 2A proposal
Threshold	Generally 75 MW; can be lowered	At least 75 MW; aggregation
Tethered resources	Generation or storage	Initial gas-fired thermal intake
Readiness	AESO may require site, zoning, finance, permits	Checklist incl. equipment, credit, gas, fibre
Bridge	Up to 3 years; priority curtailment	1,600 MW pool; staged 20% / 30% / 40%
Financial security	Authority to set criteria	C$15,000/MW commitment fee

3.3 On-site generation configurations

The IEA estimates that reliable on-site gas supply for critical and variable data-centre load can require 30% to 70% more installed capacity than site demand. It also notes that turbine constraints mean on-site generation may not be faster at scale, even though 15 to 27 GW of on-site gas could serve data centres by 2030, primarily in the United States.[13]

Configuration	Strength	Principal underwriting risk	Best fit
Grid-only	Lower operating complexity	Connection delay, congestion, cost allocation	Smaller / unconstrained sites
Modular gas bridge	Fast staging and redeployment	Fuel, emissions, OEM availability	Time-to-power gap
Dedicated CCGT	Efficient firm power at scale	Large fixed capital and project concentration	Contracted hyperscale campus
Gas + storage + grid	Ride-through, ramp control and redundancy	Controls integration and multi-asset economics	Grid-interactive campus

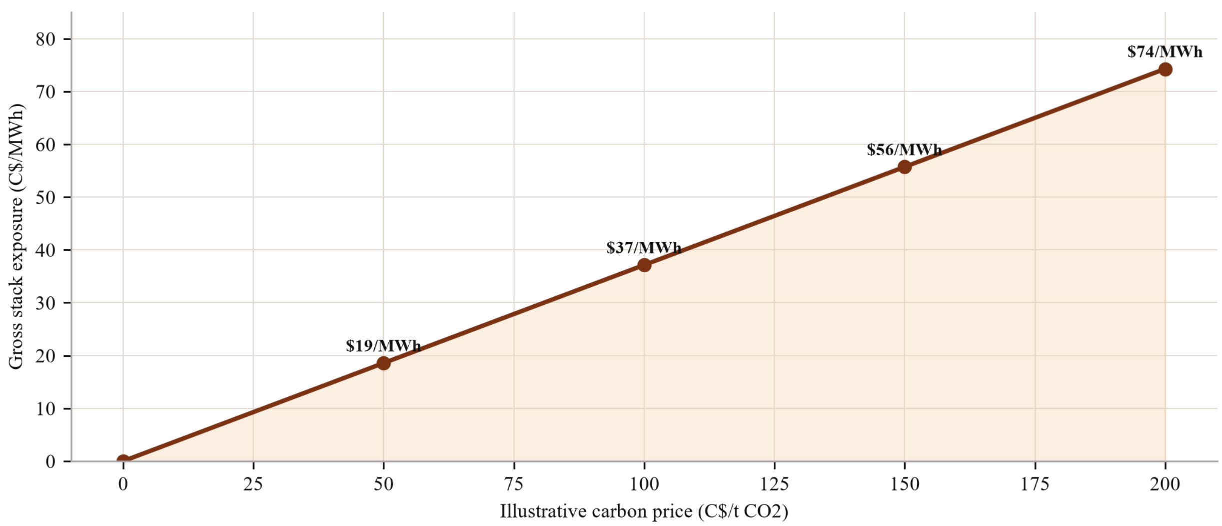
Configuration	Strength	Principal underwriting risk	Best fit
Fully islanded	Avoids bulk-grid dependence	Redundancy, outage and stranded-asset exposure	Exceptional constrained sites

Greenlight expects its 932 MW first phase to require approximately 150 MMcf/d of natural gas, implying roughly 161 MMcf/d per GW at that project configuration. It secured long-term transportation capacity and uses a tolling contract under which the provider receives a capacity return and fuel and operating costs are reimbursed by the customer. Fixed-price EPC and turbine agreements reduce construction-cost exposure, although the public disclosure does not eliminate schedule, performance or residual-value risk.[24]

3.4 Emissions and compliance implications

Using an illustrative efficient combined-cycle heat rate of 7.0 MMBtu/MWh and a natural-gas combustion factor of 53.06 kg CO2/MMBtu produces gross stack emissions of approximately 0.371 t CO2/MWh.[30][31] A 1 GW plant operating at an 85% capacity factor would emit approximately 2.77 million tonnes of CO2 per year before capture.

Figure 7. Illustrative gross carbon-price exposure for efficient gas generation



Source: Author calculation using EIA heat-rate and natural-gas emissions factors.[30][31] This is not a forecast of Alberta TIER compliance cost; benchmarks, credits, capture, contract pass-through and actual heat rate can materially change net exposure.

A credible emissions strategy should measure hourly physical supply and emissions rather than rely on annual matching claims alone. Site and interconnection designs can preserve future options for batteries, lower-carbon fuels or carbon capture where economic, while contracts should allocate carbon costs, performance degradation and compliance obligations explicitly. Heat recovery, efficient equipment and flexible operation may be recognized when their performance is demonstrable, but unproven abatement should not be included in the base case.

3.5 Market design and load flexibility

AESO's Restructured Energy Market is intended to add locational marginal pricing, a new real-time ramping product, stronger scarcity pricing and broader participation in operating reserves. Eligible large consumers would have a one-time option to settle at local prices.[12]

Lever	Value creation	Proof required
Load shaping	Avoid local peaks and congestion	Hourly workload and cooling flexibility
Demand response	Payments / avoided scarcity exposure	Contracted MW, telemetry and performance
Battery dispatch	Ride-through, ramp control, reserves	State of charge and cycle economics
On-site generation	Firm supply and potential market support	Fuel, availability and grid controls
Locational choice	Lower upgrade and congestion cost	Node study, not province-wide averages

Limits to compute flexibility

The IEA notes that AI-focused data centres are exceptionally capital-intensive, making curtailment expensive even when spare server capacity exists.[14] Workload shifting, thermal storage, batteries and backup generation each have different duration and recovery limits. A demand-response forecast therefore requires explicit assumptions for call frequency, notice, duration, rebound load and penalties.

AESO's **Ramp30** guidepost describes data-centre load movement over 30 minutes, whereas the REM's **R30** is a market product that compensates flexible supply; the two measures are analytically distinct.

4. Infrastructure investment implications

4.1 Investment resilience

Exposure	Queue attrition resilience	Preferred economics	Primary risk
Modular BTM generation	High if redeployable	Capacity / take-or-pay; fuel pass-through	OEM, gas, carbon
Switchgear / substations / EPC	High-medium	Deposits, progress billing, cancellation protection	Working capital
Controls / analytics / demand response	Medium-high	Recurring software + performance fees	Uptime / integration
Rental / lease power	High	Utilization floors + service	Fleet utilization
Batteries / UPS / ride-through	High-medium	Integration + maintenance / software	Commoditization
Gas transport / conditioning	Medium-high if contracted	Firm transport / availability	Carbon / concentration
Dedicated CCGT	High only after G3-G4	Investment-grade tolling	Construction / stranded capacity
Merchant generation	Low	Power-price upside	Phantom demand / congestion
Campus land speculation	Low	Option value	No customer / power / permits

Downside analysis should quantify returns under a two-year project delay, operation at half of requested capacity, and cancellation of the proposed data centre.

Where acceptable returns depend on full and timely campus delivery, the investment remains exposed to concentrated development risk. Contracted payments, staged capital deployment and redeployment value can reduce dependence on a single project's completion.

4.2 Contract structure and downside protection

Term	Purpose	Investor question
Capacity payment	Pays for availability before full utilization	Is it fixed, indexed and credit-supported?
Fuel / O&M; pass-through	Separates commodity cost from infrastructure return	Who bears heat-rate and basis risk?
Minimum utilization	Protects fleet economics	What happens during server ramp?
Termination payment	Covers unamortized capital and demobilization	Is it enforceable after customer default?
Milestone deposits	Screens readiness and funds procurement	Are deposits refundable?
Step-in rights	Protects the asset if project parties fail	Can lenders operate or sell the facility?
Redeployment rights	Creates a second use for modular equipment	Who pays transport and reconfiguration?
Carbon allocation	Prevents policy cost from eroding return	Benchmark, credit and capture treatment?

Greenlight's disclosed structure combines a long-term capacity-and-usage toll, fuel and O&M; reimbursement, investment-grade counterparty, project debt, fixed-price EPC and turbine agreements, and secured gas transportation.[24] That package does not eliminate risk; it converts open-ended merchant exposure into identifiable construction and performance risks.

For modular power and electrical-infrastructure providers, deposits, mobilization fees, minimum payments, customer security and redeployment rights can protect returns during delay or cancellation. Equipment that can serve another campus, industrial site or remote market retains greater residual value than site-specific infrastructure.

4.3 Examples of enabling infrastructure

Publicly announced investments illustrate how businesses outside the data-centre campus can participate in electricity-demand growth. VoltaGrid's 1.5 GW INNIO equipment order is an example of modular generation capacity being positioned for AI-related power demand, while Arcus Power's forecasting platform addresses load, peak and power-price management.[28][29] These examples do not establish project-level returns; they illustrate how customer credit, contract terms, staged deployment and redeployment value can reduce exposure to delays at an individual campus.

4.4 Acquisition due diligence

Dimension	Questions	Red flag
End user	Named? Investment-grade? Binding commitment?	Developer-only demand
Power contract	Capacity term? Fuel pass-through? Curtailment?	Merchant exposure hidden in toll
Capital	FID? Debt? Equity? Security?	Unfunded development plan
Site	Land, zoning, water, gas, fibre and grid?	One critical utility missing
Equipment	Fixed price? Delivery slot? Warranty?	Indicative OEM quote only
Schedule	Critical path and liquidated damages?	Connection date treated as COD
Redeployment	Alternative customers and residual value?	Site-specific stranded asset
Carbon	Who pays compliance and future retrofit?	Uncapped owner exposure
Reliability	Ride-through, ramp, redundancy, telemetry?	Generic load model
Returns	Case under delay, half-load and cancellation?	IRR depends on full queue

At minimum, an investment case should compare the contracted customer schedule with a two-year delay that produces carrying costs but no revenue, half-load operation after testing minimum-payment protection, and customer cancellation after accounting for termination proceeds and redeployment expense. Separate sensitivities should test higher gas and carbon costs, local congestion, delayed OEM delivery and the need to substitute equipment.

5. Sensitivities and monitoring indicators

5.1 Sensitivities and falsifiers

Higher realization would be supported if multiple queue projects disclose the same observable evidence as Meta/Greenlight: named investment-grade customers, binding power agreements, final investment decisions, financing, equipment orders and visible construction. Tethered generation and coordinated regulatory implementation could also shorten time-to-power.

Observation	Implication	Model response
Several multi-GW projects reach G4	Queue quality improving rapidly	Raise under-review conversion
AESO implements multi-GW Phase 2 bridge	Timing constraint easing	Pull demand forward
Operating sites use near requested MW	ERCOT sensitivity too low	Raise load realization
On-site gas equipment arrives on time	BYOG bottleneck weaker	Reduce schedule delay
Compute proves reliably flexible	Grid capacity need can fall	Lower firm requirement; add services
Carbon / gas costs overwhelm tolls	Dedicated gas economics weaken	Shift to grid / storage / alternatives

Risks to infrastructure exposures

These infrastructure exposures retain meaningful downside risks. Simultaneous project failures could strand modular equipment, while fixed-price electrical contractors could incur losses if procurement, labour or change-order risk is mispriced. Software providers may struggle to achieve expected economics if customers restrict operational control or data access. Fuel-cost pass-through does not protect against unavailable transportation or physical curtailment, and even a strong counterparty leaves construction, cyber, community and policy risks with the project.

5.2 Monitoring framework

Indicator	Current reference	Evidence for higher realization	Evidence for lower realization
Non-cancelled queue	20.53 GW	Growth with higher G3-G4 share	More MW under review / cancelled
Included + modelled	1.20 GW	Multiple new inclusions	Flat despite queue growth
Named customer + FID	Meta / Greenlight benchmark	Replication at other sites	MOU-only pipeline
Phase 2A	Proposal at cut-off	Final rules + credible intake	Delay / weak screening
Equipment	Tight turbine / transformer supply	Firm delivery slots	Lead-time extension
Construction	Greenlight H2 2030 target	On-budget milestones	EPC slippage
Actual utilization	No Alberta sample yet	Measured ramp near contract	Persistent under-use
Market / carbon	REM implementation from 2027	Flexible revenues offset cost	Congestion / carbon erosion

Near-term evidence will include AESO's final Phase 2A BYOG rules and first intake; any definitive Keephills agreement, named customer, final investment decision or project-development application; construction and equipment milestones at Meta / Greenlight; AUC decisions concerning Beacon Indus, Beacon Heartland and Synapse; the final 2026 AESO Long-Term Outlook; and the first observed operating-load data from Alberta campuses.[6][7][9][22][23][24][25][26][27][32][33]

Conclusion

Alberta has attracted credible data-centre interest, but the public connection queue does not support a 20.5 GW demand forecast. Most requested capacity remains subject to schedule review, and the public record provides uneven evidence concerning customers, financing, equipment, permits and construction. The illustrative scenario framework produces approximately 0.8 to 4.0 GW of aggregate project load capacity in operation by 2030, materially below the queue total.

Meta's announced campus and the Greenlight Electricity Centre provide the clearest public evidence of an advanced Alberta project. The disclosed package includes a named end user, final investment decision, dedicated generation, project financing, equipment arrangements and a long-term power agreement. Keephills has meaningful site and grid advantages, but its commercial agreements and construction decision remained conditional at the research cut-off. These cases show why project milestones provide more information than queue status alone.

For infrastructure investors, the relevant distinction is not between belief and disbelief in data-centre demand. It is between assets whose returns depend on the full requested capacity being realized and assets protected by contracted payments, staged capital deployment, termination provisions or redeployment value. Alberta may support substantial data-centre development even if a large share of the present queue is delayed, resized, supplied behind the meter or never built.

Appendix A. Methodology and definitions

Queue calculation

Filter AESO's August 2026 spreadsheet for MW Type = Data Load. For each entry, sum EN1 DTS MW, EN2 DTS MW and EN3 DTS MW because each field represents an incremental change in load contract capacity. Exclude Status = Recently Cancelled from the outstanding queue. Do not include STS MW, which is generation capacity.

Classification	Entries	Requested DTS MW	Share
Active	13	1,849.19	9.01%
ISD under review	26	18,676.00	90.99%
Non-cancelled total	39	20,525.19	100.00%
Recently cancelled	3	840.00	n/a

Key definitions

Alberta Internal Load (AIL) includes demand served by on-site generation and the City of Medicine Hat. Demand Transmission Service (DTS) is the principal tariff service for customers drawing load from the transmission system, while Supply Transmission Service (STS) applies to generation supplying it. An in-service date (ISD) is the scheduled date for connection service and is not necessarily the customer's commercial-operation date. In AESO's connection list, CA Modelled indicates inclusion in connection-assessment base cases, while Inclusion indicates that a project has entered system planning and long-term adequacy forecasts after meeting AESO criteria.[1][2][3]

Scenario calculation

The 2030 cases apply realized operating shares to four maturity groups. The shares combine completion by 2030, ultimate realized size and ramp. They are judgement-based cases informed by public milestones and external evidence, not statistical Alberta probabilities. Annualized energy equals operating peak MW x 85% load factor x 8,760 hours.

Limitations

Public information is incomplete. Queue entries can represent phases rather than unique campuses. Customer identities may be confidential. DTS is maximum grid service, not metered consumption. Behind-the-meter supply, redundancy and hourly coincidence are not fully observable. The work should be updated when the final AESO 2026 LTO and Phase 2A process are released.

Appendix B. Active data-load entries

Accepted connection requests remain development projects; staged dates are not firm commercial-operation forecasts.

AESO project	Area	Stage	DTS MW	Included	Staged connection dates
P2936 GLDC Load Phase 1.1	Fort Saskatchewan	2	970.00	Yes	60 MW - May 2027; 910 MW - Sep 2030
P3083 Keephills Data Centre Phase 1.1	Wabamun	2	230.00	Yes	115 MW - Jan 2027; 115 MW - Mar 2028
P2952 North Calgary One Data Centre MPC Load	Calgary	1	74.90	No	74.9 MW - Mar 2027
P3077 Calgary Enterprise A.I. Load	Calgary	2	74.90	No	74.9 MW - Jan 2029
P2953 North Calgary Two Data Centre MPC Load	Calgary	2	74.90	No	74.9 MW - Mar 2027
P3174 Sovereign Cloud Data Load	Edmonton	2	74.90	No	74.9 MW - Dec 2029
P3078 Calgary A.I. Centre Load	Calgary	2	74.90	No	74.9 MW - Jan 2029
P3079 Captus Load	Glenwood	2	74.90	No	74.9 MW - Sep 2027
P3114 Banshee Data MPC Load	Hinton/Edson	2	74.90	No	74.9 MW - Nov 2027
P3157 Clearwater Technology Park Data Load	Calgary	2	74.90	No	74.9 MW - Nov 2028
P3075 Balzac Area Load	Calgary	2	45.00	No	30 MW - Aug 2026; 15 MW - Aug 2028
P3126 Sollair Load	Airdrie	2	4.99	No	4.99 MW - Dec 2027
P3141 Opal Data Load	Fox Creek	1	0.00	No	No DTS populated

Source: AESO August 2026 Connection Project List.[1][2] EN2 and later dates can be outside dates rather than target dates.[5]

Appendix C. Data-load entries with timing under review

This group contains 18.68 GW, or 91.0% of non-cancelled requested capacity.

AESO project	Area	Stage	DTS MW	Included	Status
P3066 Leedale Data Load	Caroline	2	1,864	No	ISD under review
P3198 Lynx Data Load	Fort Saskatchewan	1	1,800	No	ISD under review
P2970 Beacon Langdon A.I. Hub 2 Load	Calgary	1	1,400	No	ISD under review
P3108 Wild Rose Power Hub Load	Calgary	2	1,300	No	ISD under review
P3109 Newell Data Center MPC Load	Brooks	2	1,200	No	ISD under review
P2942 Genesee Data Center 1 MPC Load	Wabamun	2	1,000	No	ISD under review
P3101 Carstairs Technology Park MPC Load	Didsbury	2	950	No	ISD under review
P3102 Goldfinch Technology Park MPC Load	Strathmore/Blackie	2	950	No	ISD under review
P3151 GLDC Load Phase 1.2	Fort Saskatchewan	2	830	No	ISD under review
P3116 Rocky View Data Center MPC Load	Calgary	2	800	No	ISD under review
P3137 Sheerness Data MPC Load	Sheerness	1	800	No	ISD under review
P2946 Genesee Data Center 2 MPC Load	Wabamun	2	500	No	ISD under review
P3095 Keephills Data Centre Phase 2	Wabamun	2	466	No	ISD under review

Appendix C. Data-load entries with timing under review (continued)

AESO project	Area	Stage	DTS MW	Included	Status
P3112 North Calgary Three Data Centre MPC Load	Calgary	1	450	No	ISD under review
P3136 Sundance Data MPC Load	Wabamun	1	401	No	ISD under review
P2926 Beacon Foothills A.I. Hub Load	High River	2	400	No	ISD under review
P2935 Beacon Saunders Lake A.I. Hub Load	Edmonton	2	400	No	ISD under review
P2927 Beacon Harry Smith A.I. Hub Load	Wabamun	2	400	No	ISD under review
P2934 Beacon Heartland A.I. Hub Load	Fort Saskatchewan	2	400	No	ISD under review
P2928 Beacon Langdon A.I. Hub Load	Calgary	2	400	No	ISD under review
P3106 Alberta South A.I. Load	Lethbridge	1	400	No	ISD under review
P3107 Chestermere Enterprise A.I. Load	Calgary	1	400	No	ISD under review
P3175 Beacon Heartland Data Load	Fort Saskatchewan	1	400	No	ISD under review
P3110 Mihta Askiy Data Load	Peace River	1	300	No	ISD under review
P3156 High Plains East Industrial Park	Calgary	1	300	No	ISD under review
P3152 Keephills Data Centre Phase 1.2	Wabamun	1	165	No	ISD under review

Source: AESO August 2026 Connection Project List.[1][2] ISD under review establishes timing uncertainty; it does not establish cancellation.

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