ENERGY INFRASTRUCTURE | PERMIAN BASIN | TECHNOECONOMIC BRIEF

Powering the Permian

The Economics of Private Oilfield Microgrids for High-Density Shale Development

Jose Ignacio El Idd | Stanford MSx 2026 | May 2026

Abstract

Industry forecasts used by the Electric Reliability Council of Texas (ERCOT) indicate Permian Basin oil & gas electrification demand could grow from ~4.2 GW to ~17 GW by the early 2030s, while total Permian electricity demand may exceed ~25 GW over a similar timeframe. Today, most wellsite load is still served by diesel, the most expensive and carbon-intensive option available. This brief presents a technoeconomic assessment of an alternative: a centralized gas generation station paired with a private distribution network serving a standardized 250-well unconventional drilling campaign over five years. Built on a 20-year Discounted Cash Flow (DCF) model calibrated against Railroad Commission (RRC) well data, Homeland Infrastructure Foundation-Level Data (HIFLD), ERCOT wholesale prices, and Waha Hub gas pricing, the analysis evaluates 13 generation technologies and finds that reciprocating gas engines at $1/MMBtu deliver firm power at $37/MWh, well below ERCOT West wholesale at $42-55/MWh. The base case returns a 19.35% unlevered IRR (NPV of $46.3M at 12%) and a 23.0% equity IRR at 60% project debt; at $0/MMBtu Waha gas — a recurring basin reality — the same project delivers a 24.5% unlevered IRR and $83.5M NPV. Two variables dominate the outcome: well density (breakeven near ~3 wells/sq mi) and gas price (viable at ~$2.30/MMBtu). Nuclear Small Modular Reactors (SMR), evaluated alongside 12 other technologies, were disqualified on cost and load-following grounds. The result is a new infrastructure asset class, the private oilfield microgrid, most attractive to third-party developers partnering with top-tier operators in concentrated acreage positions.

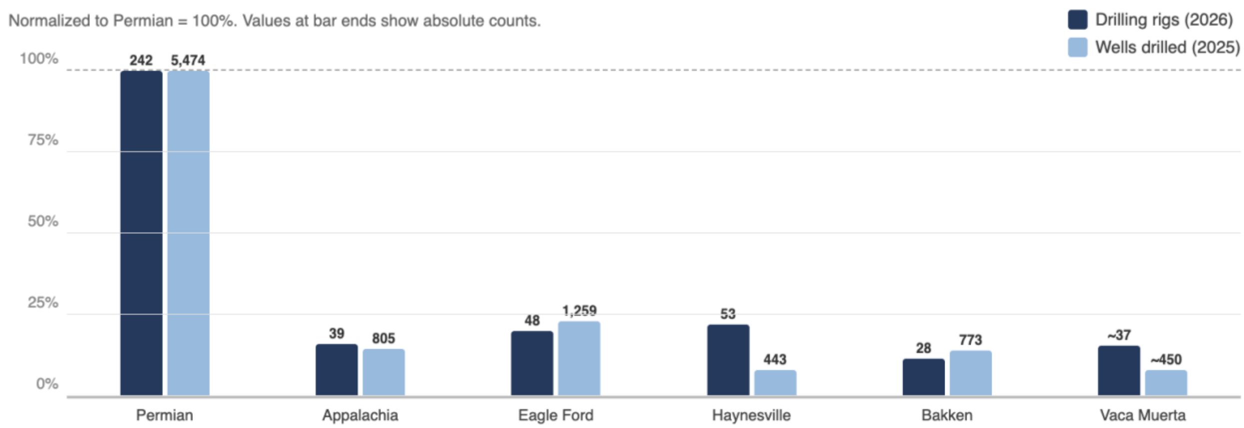
KEY TAKEAWAYS

- **>> Electrification economics win.** Centralized gas generation + private distribution beats diesel and the ERCOT grid for high-density Permian campaigns. 19.35% unlevered IRR and 23.01% equity IRR at base case.
- **>> Deployment speed is an advantage.** Reciprocating engines reach first power in 12-18 months versus 24-48 months for grid interconnection.
- **>> LCOE, modularity and relocatability select the technology.** Simple Cycle Gas Turbine (SCGT) is marginally cheaper per MWh, but 5 MW recip modules phase in with the campaign and redeploy to adjacent fields as it matures, matching the load profile.
- **>> Density is destiny.** Breakeven at ~3 wells/sq mi; base case requires 10. Geology and development style are the primary drivers.
- **>> Gas sourcing drives the upside.** Low-cost Waha gas works; co-located associated gas transforms the economics.
- **>> 13 technologies evaluated; only gas is viable today.** Nuclear, solar+storage, and hybrids fail on cost, deployment timeline, or load-following. Revisit post-2032.
- **>> This is a third-party asset, not an E&P balance-sheet project.** Energy as a Service (EaaS) / Power-Purchase-Agreements (PPA) structures with take-or-pay offtake match the return profile of infrastructure investors better than operator self-funding.

1. WHY THE PERMIAN, WHY NOW

The Permian Basin is the single largest concentration of electrifiable upstream oil & gas load on the planet. Unlike refining, unconventional upstream is uniquely diesel-intensive: rigs, frac spreads, and remote production equipment rely on mobile, off-grid power, producing some of the most expensive electricity in any industrial setting. This makes upstream the highest-leverage segment for electrification, where replacing diesel is a structural shift, not a marginal efficiency gain.

Figure 1 | Upstream Activity by Basin



Note: Frac spreads typically run at 1 per 2–3 drilling rigs, consistent across U.S. basins and Vaca Muerta.

Sources: Drilling rigs & wells (U.S.) — EIA STEO Table 10a, April 2026 (Q1 2026 avg. rigs; 2025 full-year wells). Vaca Muerta — NCS Multistage / EconoJournal rig survey (Dec. 2025); Secretaría de Energía / Economía & Energía est. (2025). "~" = estimated.

Three forces are colliding on the Permian grid at the same time. First, S&P Global projects oil & gas power demand alone will grow from ~4.2 GW in 2023 to ~17 GW by the early 2030s (Figure 2). ERCOT projects total Permian demand, including data centers, crypto mining, and industrial expansion, could exceed ~25 GW over a similar timeframe. Second, the basin's ~430 GW interconnection queue makes new grid-tied generation effectively unavailable for at least 24–48 months, even for operators willing to pay. Third, and most decisively, stranded associated gas at Waha has cleared at $0–$1/MMBtu for meaningful stretches of every year since 2020, and has been entirely negative through 2026 (Figure 3). Permian gas, burned in modern reciprocating engines deployable in 12–18 months, delivers power at a cost no grid in North America can match. The problem and its cheapest solution are in the same place.

Figure 2 | S&P Assessment: Permian Power Demand and Grid-Connect Targets

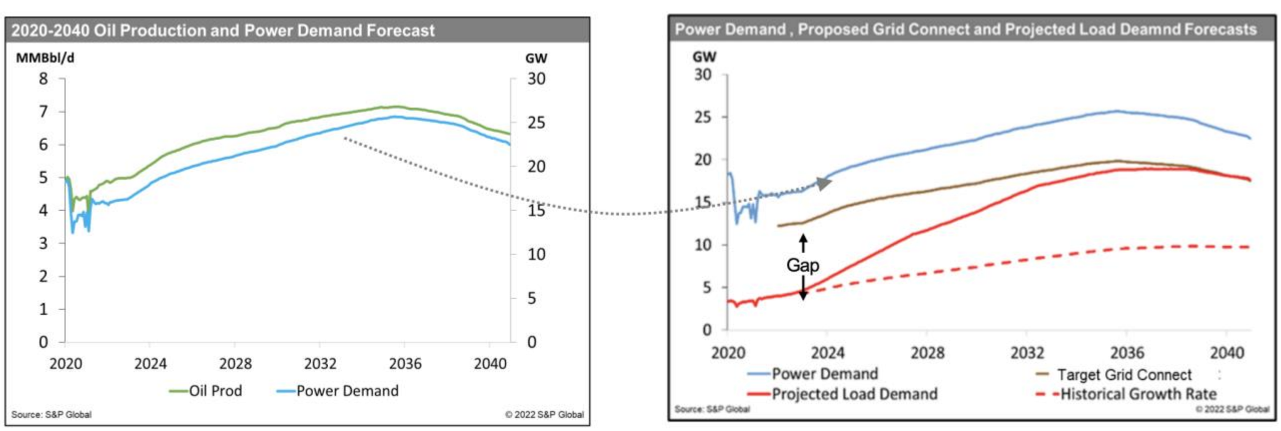
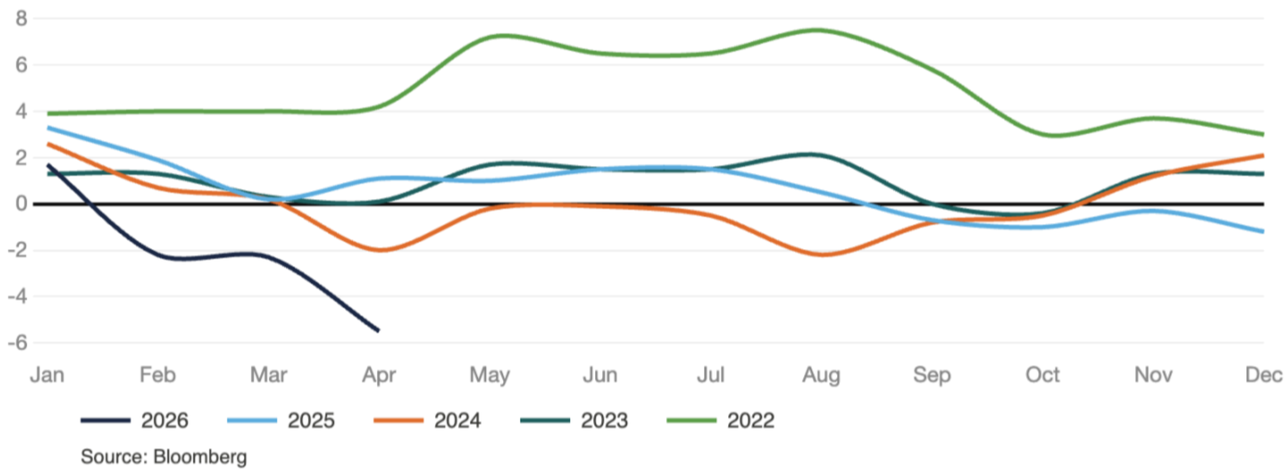


Figure 3 | Waha monthly average price $/MMBTU



THE ARBITRAGE

Waha gas at $0/MMBtu delivers roughly $27/MWh. Diesel-equivalent power ranges from $180-280/MWh. It is A 5-to-10x spread. The question is not whether to electrify; it is how, how fast, and who owns the asset.

2. THE OPERATOR'S QUESTION

To make the analysis concrete, this brief reframes the problem from an E&P Executive's perspective and builds the entire model around a single, standardized question:

> *"I have a planned 250-well drilling campaign over five years. Should I invest in centralized power generation and private distribution to electrify my drilling, completion, and production operations, instead of burning diesel?"*

Table 1 | The 250-Well Reference Campaign

Parameter	Value	Notes
Campaign duration	5 years	50 wells/year, phased in 5 blocks
Footprint	25 sq mi	10 wells/sq mi average density
Well pads	42 pads	6 wells per pad (multi-well cube)
Rigs / frac spreads	2 rigs, 1 spread	Continuous deployment
Peak electrical load	116 MW	Gas engines, phased commissioning
Distribution network	20 mi backbone + 62.5 mi feeders	69 kV trunk / 34.5 kV laterals
Reference operator archetype	Diamondback Energy (Martin/Midland)	722k acres, 463 wells drilled 2025

The diesel baseline that this system is designed to displace can be reduced to a savings formula, calibrated against observed well cost structures and OFS contractor rate data. You can check against your own AFEs:

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Annual D&C Opportunity Cost  =  Wells Drilled/Yr  x  $592,000/well

Annual Production Opportunity Cost  =  Production (BOE/d)  x  365  x  $0.85/BOE
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The $592,000/well figure combines drilling fuel displacement ($172,000) and completion/well fuel displacement ($420,000)[1]. On the production side, power and fuel represent approximately 15% of lease operating expenses (LOE), covering artificial lift (ESPs, rod pumps), gas compression, water handling, and facility operations. The $0.85/BOE factor captures this diesel-to-electric displacement on a per-barrel basis across the full production base.

Table 2 | Top 10 Permian Operators by Annual Diesel Displacement Potential: Opportunity Cost ($MM/yr)

Basin / Operator	Prod (MBOE/d)	Wells/Yr	Drilling ($M)	Completion ($M)	Prod ($M)	Total Opp. Cost ($M)
ExxonMobil (XOM)	~1250	~650	112	273	388	773
Chevron (CVX)	~450	~225	39	95	140	274
Occidental (OXY)	~550	~420	72	176	171	419
Diamondback (FANG)	~490	~400	69	168	152	389
ConocoPhillips (COP)	~350	~300	52	126	109	287
EOG Resources (EOG)	~320	~280	48	118	99	265
Devon Energy (DVN)	~275	~240	41	101	85	227
APA Corporation (APA)	~175	~160	28	67	54	149
Permian Resources (PR)	~165	~185	32	78	51	161
Coterra Energy (CTRA)	~140	~120	21	50	43	114
Top 10 Subtotal	~4165	~2980	514	1252	1292	3058

3. THIRTEEN TECHNOLOGIES, ONE CLEAR WINNER

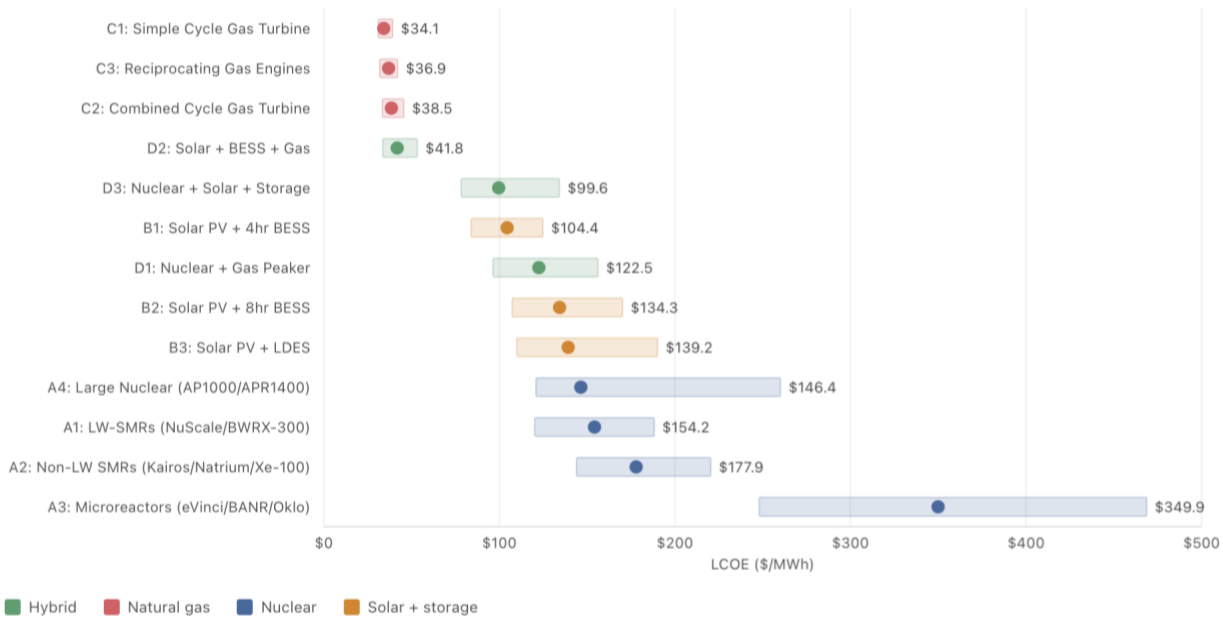
A centralized power source for unconventional well development must meet three non-negotiable requirements: (1) continuous, firm power delivery (24/7, not intermittent-only, though hybrid configurations are admissible); (2) load-following capability to track the sharp demand swings of frac operations (25-35 MW ramps within 6-15 minutes); and (3) deployment readiness within the Permian's 2026-2030 development window. Thirteen generation technologies across four categories were evaluated against four weighted criteria: Levelized Cost of Energy (LCOE - 40%), reliability/dispatchability (25%), deployment readiness (20%), and Permian-specific fit (15%).

Table 3 | 13-Technology Integrated Ranking (Weighted Score)

Rank	Technology	LCOE ($/MWh)	Reliability	Deploy	Permian Fit	Weighted	Tier
1	Recip Gas Engines (C3)	36.9	4.2	5.0	4.8	4.73	Tier 1
2	Simple Cycle Gas Turb. (C1)	35.1	4.2	5.0	4.6	4.64	Tier 1
3	Combined Cycle Gas (C2)	41.6	4.0	4.2	3.6	4.38	Tier 1
4	Solar+BESS+Gas (D2)	41.9	4.0	4.5	3.8	4.36	Tier 1
5	Solar PV+4hr BESS (B1)	104.4	3.5	4.5	3.4	4.05	Tier 1
6	Solar PV+8hr BESS (B2)	134.3	3.2	4.2	3.4	3.74	Tier 1
7-8	Nuclear Hybrids (D1/D3)	99-122	4.0	2.8	3.0	~3.6	Tier 2
9	Large Nuclear (A4)	146.4	4.0	2.8	2.4	3.53	Tier 3
10	Light-Water SMRs (A1)	154.2	3.8	2.8	3.0	3.48	Tier 3
11	Solar+LDES (B3)	139.2	3.0	2.2	3.0	3.24	Tier 3
12	Non-LW SMRs (A2)	177.9	3.0	1.8	3.0	2.90	Tier 3
13	Microreactors (A3)	349.9	2.8	1.5	3.6	1.94	Tier 3

[1] Cross-referenced across pure Permian operators; weighted average D&C cost $7M–$8M/well, with fuel at ~8% of total drilling cost and fuel at ~10%-16% of total completion cost. Opportunity cost formula should be specifically calibrated to Operator's economics.

Figure 4 | LCOE Range Chart (Dot + Bar) at 12% Discount, 20-yr, Tech-Appropriate CF, $1/MMBTU gas[2]



The ranking is unambiguous: all three gas technologies occupy the top three positions, and only gas can deliver on all three requirements simultaneously. Solar+Battery Energy Storage System (BESS) combinations rank as viable supplementary layers (displacing 40-60% of daytime gas consumption) but cannot provide firm 24/7 power due to the 10+ hour nightly gap. Nuclear technologies, evaluated across 10 reactor designs from 8 vendors including NuScale, GE-Hitachi, X-energy, TerraPower, and Oklo, rank in Tiers 2-3: capital costs of $120-$220/MWh produce deeply negative NPVs (-$400M to -$600M), and no nuclear technology can deliver first power before 2032 in the Permian Basin.

A NOTE ON FUTURE BASELOAD CANDIDATES

Two technologies could complement or replace gas for baseload in the medium to long term. Nuclear SMRs, under reasonable cost reduction trajectories, with HALEU enrichment bottlenecks resolved and Nuclear Regulatory Commission licensing timelines compressed, could serve as baseload generation post-2032; their more natural near-term fit may be refineries, where steady load and high-capacity factors favor nuclear economics. Geothermal energy, though not assessed in this report, is an equally compelling future candidate. It offers clean, continuous baseload, and generates powerful synergies with unconventional operations: the drilling and completion expertise, equipment, and workforce already deployed in the Permian are directly transferable to geothermal well construction.

[2] LCOE methodology consistent with Lazard LCOE+ v18.0 (June 2025) @12% discount and 1$/MMBTU gas price

4. WITHIN GAS: WHY RECIPROCATING ENGINES

With gas established as the only viable generation category, the technology choice narrows to three candidates: Simple Cycle Gas Turbines (SCGT), Combined Cycle Gas Turbines (CCGT), and reciprocating gas engines. At Permian-specific gas prices, gas generation delivers power at $27-42/MWh across the three options, all below ERCOT West wholesale and dramatically below diesel. But the differences between them matter for a project of this scale and load profile.

Figure 5 | Gas Technology LCOE vs. Waha Gas Price

2025 USD, 12% real discount rate · 75% capacity factor · 20-yr life

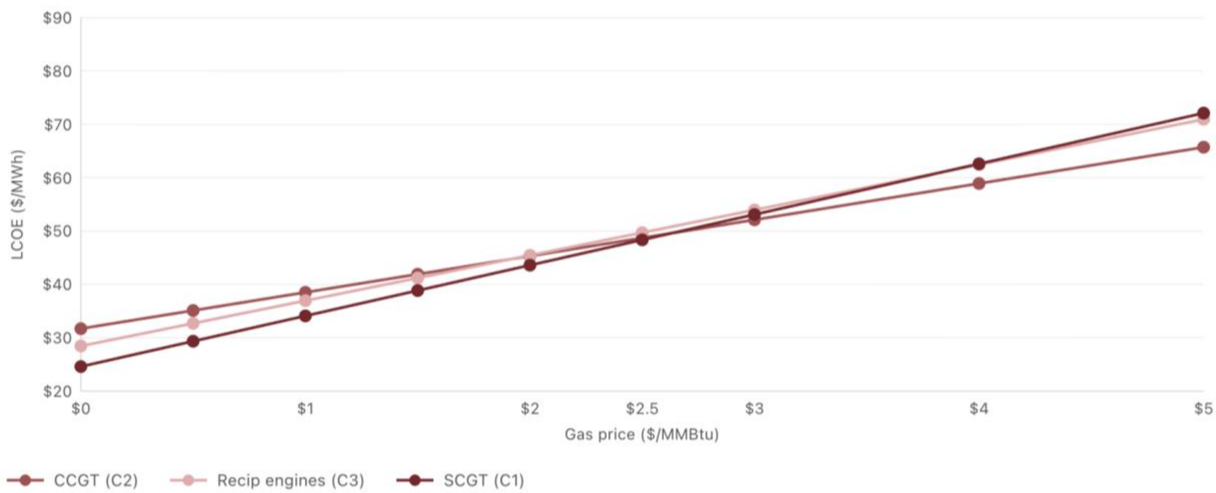


Table 4 | Natural Gas Technology Comparison Summary

Metric	SCGT (C1)	CCGT (C2)	Recip Engines (C3)
LCOE @ $1/MMBtu	$34.1/MWh	$38.5/MWh	$36.9/MWh
Project NPV @ 12% (base case)	$63.6M	$31.1M	$46.3M
Unlevered IRR (base case)	23.3%	15.8%	19.35%
Heat rate (BTU/kWh)	9,500	6,800	8,500
Part-load heat rate adj.	10,200 (+7-15%)	~7,500 (+10%)	~8,700 (<3%)
Ramp to full load	5-10 min	30-45 min	<2 min
Minimum module size	25 MW	200 MW	1-5 MW
Construction time	12-18 months	24-36 months	6-12 months
Water use (gal/MWh)	0-200	200-300	5-15
Relocatable?	Moderate	No	Excellent

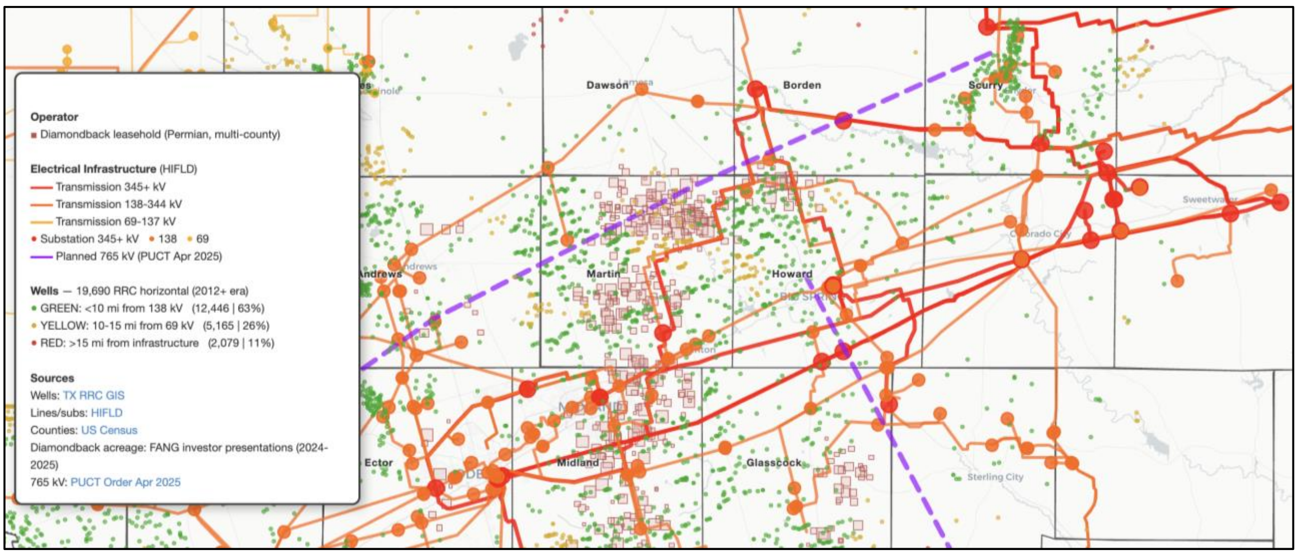
Reciprocating gas engines win on modularity and relocatability. SCGT is marginally cheaper per MWh and shows a higher modeled IRR under the base case, but the recip thesis is operational. First, modularity: 5 MW units can be phased as the campaign builds (60 MW Year 0, scaling to 116 MW by Year 5), whereas SCGT requires 25 MW minimum increments and CCGT a 200 MW commitment from Day 1. Second, relocatability: recip modules can be redeployed to adjacent campaigns as the anchor field matures, sustaining high fleet-weighted utilization across a multi-decade basin development that no fixed SCGT or CCGT plant can follow. Third, ramp rate: frac operations demand 25–35 MW swings in minutes; recip engines respond in seconds, while SCGT needs 5–10 minutes and CCGT 30–45. Fourth, construction and deployment: 6–12 months to first power for recip, versus 12–18 for SCGT and 24–36 for CCGT. These attributes — not a 1-2 percentage point LCOE gap — are what build the business.

5. DISTRIBUTION: THE PRIVATE GRID PLAYBOOK

Generation is half the system. The other half, moving electrons from a centralized plant to 42 well pads spread across 25 square miles, is where most operators overestimate the cost and omit the optionality. Thirteen distribution architectures were evaluated, from mobile diesel gensets through fully grid-tied options (Figure 6). The winning architecture is a two-tier private network: a 69 kV overhead backbone connecting the generation station to a handful of master pad substations, with 34.5 kV feeders radiating to individual well pads (Figure 10).

Architecture	CAPEX / mile[3]	Deploy Time
34.5 kV overhead feeders	$300-400K	6-9 months
69 kV backbone	$550-750K	9-14 months
138 kV private	$950K-1.2M	14-20 months
ERCOT grid interconnect	N/A (queue)	24-48+ months

Figure 6 | Permian Infrastructure-Activity Overlap Map



ERCOT's ~430 GW interconnection queue and the Texas Public Utility Commission's (PUC) 765 kV transmission build (construction 2028, online 2030-2031) mean that any operator who needs firm power in the next 24 months must self-provide. Four top-tier operators have already proven it: Devon Energy (800+ miles of private distribution[4]), Diamondback/Voltagrid[5], Coterra/PROPWR[6], and Riley Permian/Conduit Power[7].The pain point is real, the solution is buildable and the regulatory and right-of-way playbook exists.

> **THE STRATEGIC IMPLICATION**
>
> Operators who build private distribution now capture three options simultaneously: (1) immediate diesel displacement, (2) full electrification on their own timeline — sized and routed to the campaign, not to ERCOT's queue, and (3) the ability to sell power to the grid or adjacent operators when capacity allows. Waiting for the grid is the most expensive strategy on the board.

[3] MISO Transmission Cost Estimate @all-in utility-grade benchmark discounted by (i) zero right of way cost on E&P-controlled lease land, (ii) wood-pole construction acceptable (iii) exclusion of AFUDC, and (iv) lower contingency (~15%)

[4] Oil&Gas Journal: Devon CEO: We're looking at building 'essentially our own utilities' to help solve Delaware electricity supply issues

[5] Diamondback 2025 CSR, Voltagrid's 70MW of power and case-study

[6] PROPWR Secures Distributed Microgrid Contract With Coterra Energy and Adds 190 Megawatts in New Orders

[7] Riley Permian formed RPC Power LLC, a 50/50 JV with partner Conduit Power

6. DENSITY IS DESTINY

The economics of centralized infrastructure are fundamentally an amortization problem: fixed distribution costs divided by wells served. At 4 wells/sq mi the project clears the 12% hurdle at 15.8% IRR and $21.7M NPV, but the margin remains too thin for the risk. The investable range begins at 6 wells/sq mi (17.9% IRR, $35.3M NPV) and becomes robust above 10. Above 14 wells/sq mi, returns plateau — incremental density adds NPV but moves the IRR by less than 0.5 percentage points.

Figure 7 | IRR (%) and NPV ($M) vs. Well Density (Recip Base Case)

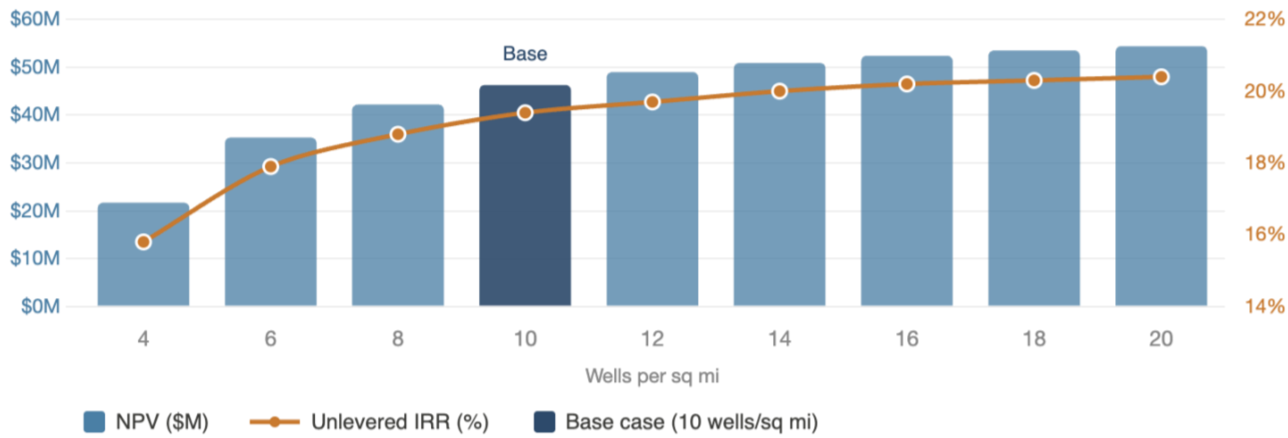


Figure 8 | Permian Well-Density Assessment

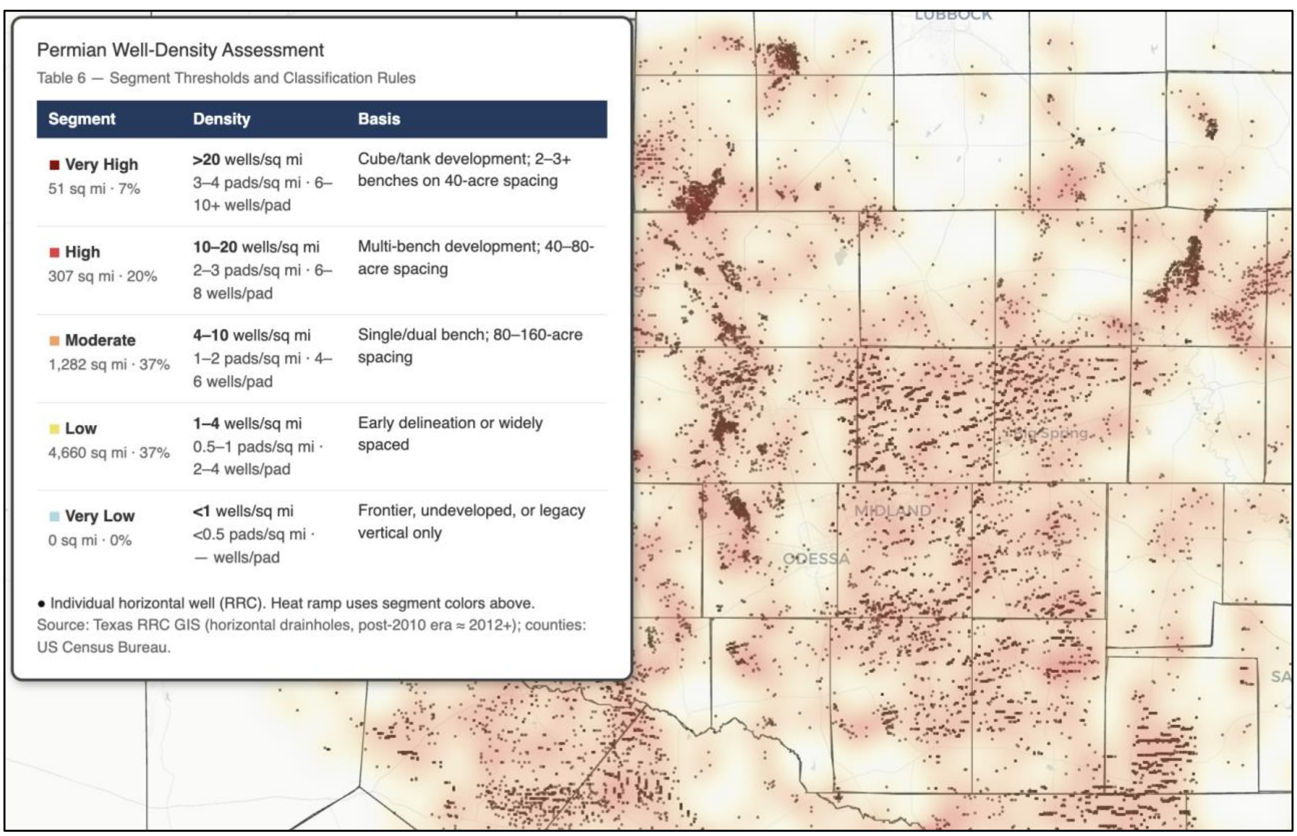

Permian Well-Density Assessment

Table 6 — Segment Thresholds and Classification Rules

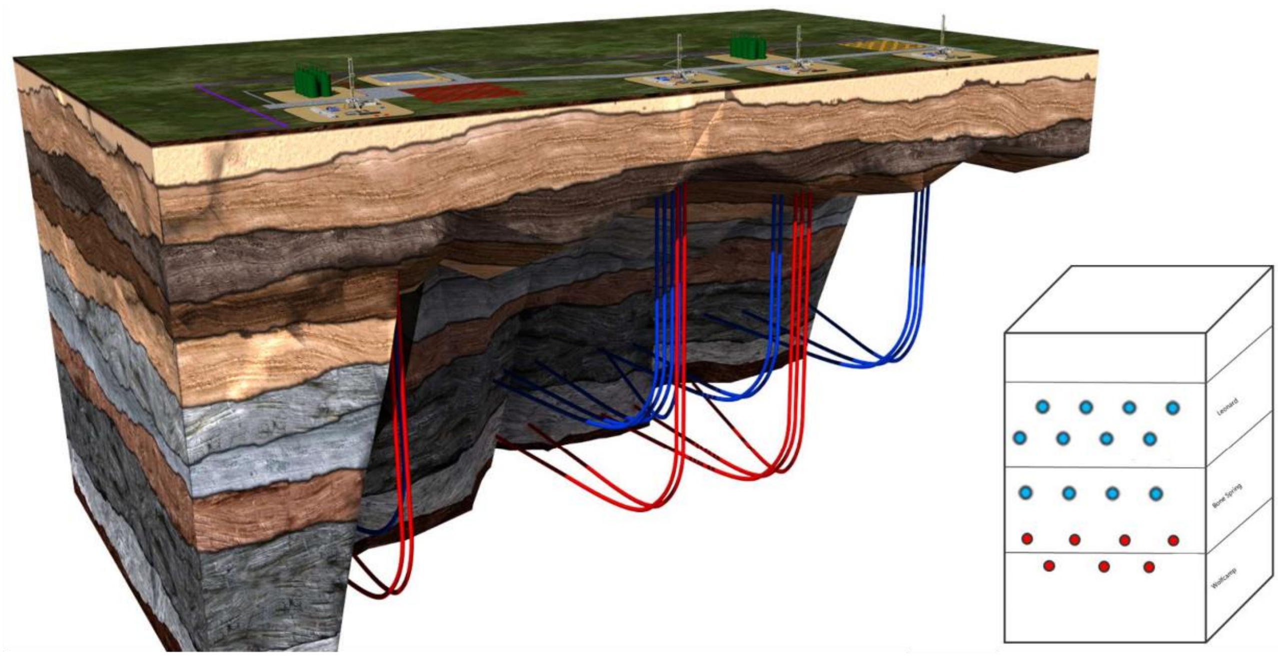
Segment	Density	Basis
Very High 51 sq mi · 7%	**>20** wells/sq mi 3–4 pads/sq mi · 6–10+ wells/pad	Cube/tank development; 2–3+ benches on 40-acre spacing
High 307 sq mi · 20%	**10–20** wells/sq mi 2–3 pads/sq mi · 6–8 wells/pad	Multi-bench development; 40–80-acre spacing
Moderate 1,282 sq mi · 37%	**4–10** wells/sq mi 1–2 pads/sq mi · 4–6 wells/pad	Single/dual bench; 80–160-acre spacing
Low 4,660 sq mi · 37%	**1–4** wells/sq mi 0.5–1 pads/sq mi · 2–4 wells/pad	Early delineation or widely spaced
Very Low 0 sq mi · 0%	**<1** wells/sq mi <0.5 pads/sq mi · — wells/pad	Frontier, undeveloped, or legacy vertical only

● Individual horizontal well (RRC). Heat ramp uses segment colors above.
Source: Texas RRC GIS (horizontal drainholes, post-2010 era ≈ 2012+); counties: US Census Bureau.

WHAT THIS MEANS FOR DEVELOPERS

The addressable market is not the whole Permian. Achieving the required density is primarily a function of three factors: subsurface geology (the number of commercially viable stacked formations — Wolfcamp A/B/C and Spraberry in the Midland Basin; Bone Spring and Wolfcamp in the Delaware), the operator's commitment to cube-style multi-bench co-development, and the capacity to structure a tightly clustered campaign across contiguous acreage. An operator with 5–6 stacked targets can reach 15–25 wells/sq mi; one with 2–3 tops out at 8–12. Geology and campaign design, not acreage alone, are the gatekeepers.

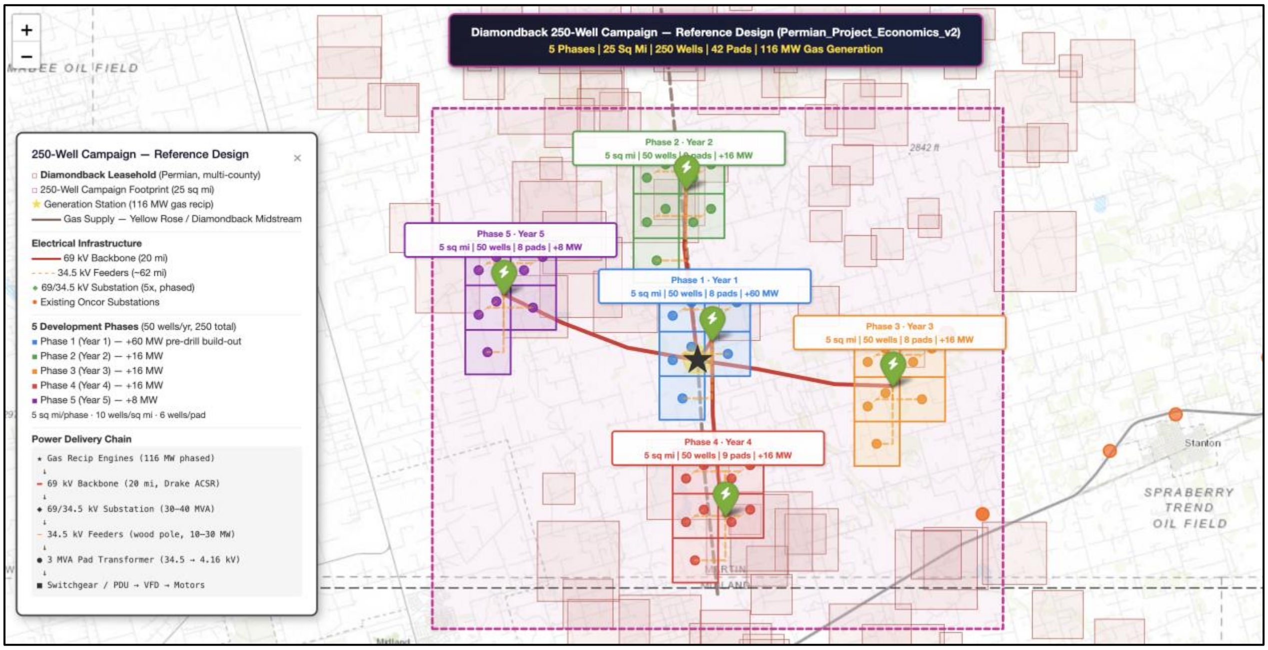
Figure 9 | Cube Development Animation



7. THE 250-WELL REFERENCE CASE & ECONOMICS

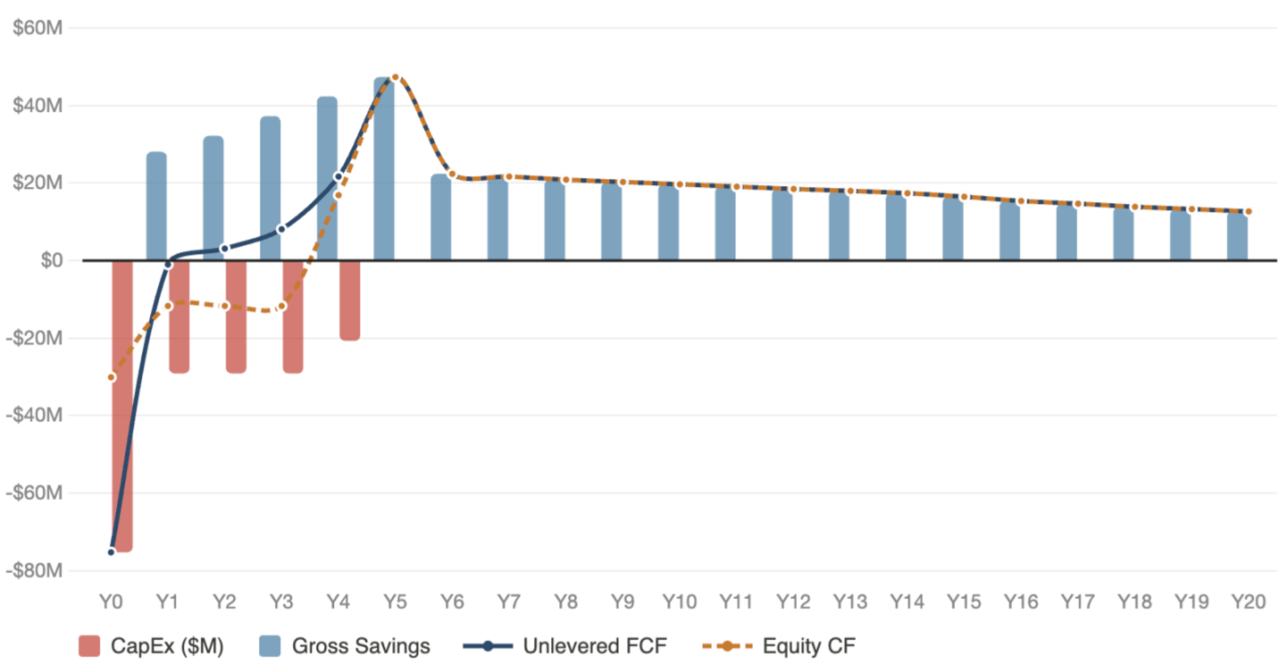
The reference case is anchored on Diamondback Energy's Martin/Midland County footprint: the most density-concentrated top-tier position in the basin. Diamondback holds 722,000+ Midland Basin acres, drilled 463 wells in 2025, and operates through the Rattler midstream affiliate, which owns the gas gathering infrastructure supplying the generation station. The campaign map overlays the full 250-well development across 25 sq mi and 42 pads, with a 116 MW generation station, 20 miles of 69 kV backbone, and 5 phased substations stepping down to 34.5 kV feeders at each pad cluster. Existing Oncor 138 and 345+ kV lines cross the footprint, preserved as a future grid interconnection point.

Figure 10 | 250-Well Campaign Reference Design — Diamondback Martin/Midland



The 20-year DCF model is structured as a third-party infrastructure vehicle: the project entity builds, owns, and operates the generation and distribution assets, and sells firm power to the E&P operator under a tolling or Energy-as-a-Service contract. Revenue is a blended $/MWh tariff indexed to avoided diesel cost; costs are dominated by gas fuel (variable), O&M (semi-fixed), and debt service during the amortization period.

Figure 11 | 20-Year Unlevered Free Cash Flow Waterfall (Recip Base Case: $1/MMBTU, 10 wells/sqmi and 12% discount)



Once peak load is reached around Year 5 and the campaign transitions primarily to production power, part of the reciprocating engine fleet can be redeployed to adjacent drilling campaigns. This modularity allows the first project to partially finance the next one, improving fleet utilization and strengthening long-term platform economics beyond the standalone DCF.

Table 5 | Project Metrics Summary

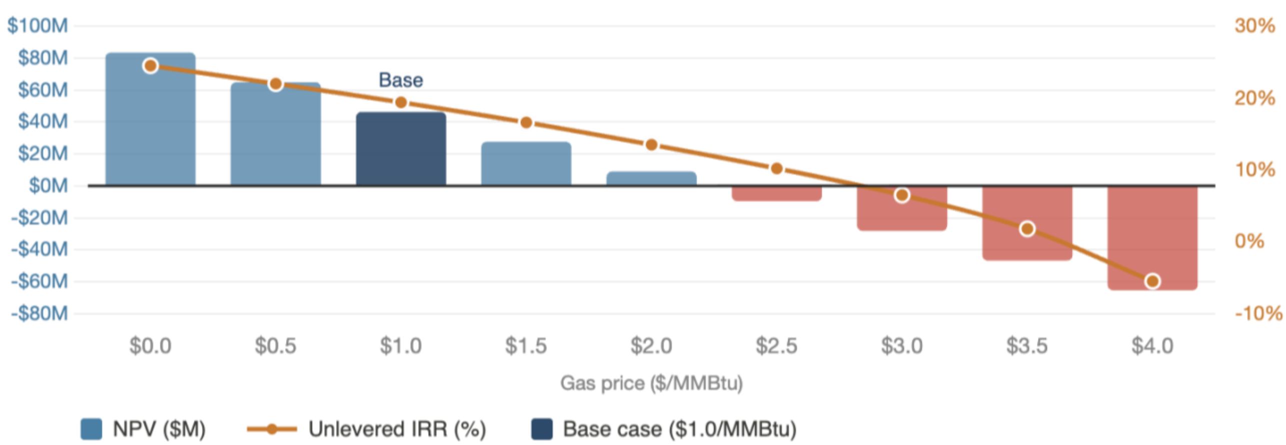
Metric	Base Case (Recip)
Total CAPEX	$183.5M
Generation	$121.8M (recip @ $1,050/kW)
Distribution (incl. 20% Engineering & Contingency)	$61.7M
Installed capacity	116 MW (phased 60/16/16/16/8)
Heat rate	8,500 BTU/kWh
Unlevered IRR	19.35%
Unlevered NPV @ 12%[8]	$46.3M[9]
Equity IRR (60% debt)	23.01%
Debt repayment year	Year 5
Net CO2 displaced (20 yr)	~1.7 million tonnes
Gas price assumption	$1/MMBtu (Waha base)
Delivered power cost	~$37/MWh
Upside IRR ($0/MMBtu gas)	24.5% / $83.5M NPV
Tax treatment	SPV; MACRS (15-yr GDS gen + 20-yr GDS T&D); NOL carryforward

These economics capture drilling, completion, and production power. They do not capture gas gathering, gas processing and other field facilities that are diesel-dependent and all serviceable by the same private grid. S&P Global puts current grid connectivity for these operations at 3–63%, with top-operator targets of 75–97% by 2040. Every incremental load improves utilization and lowers delivered $/MWh.

8. SENSITIVITIES, RISK MITIGATION AND TRADE-OFFS

Two variables drive more than 80% of the outcome variance: gas price and well density. Everything else (CAPEX, debt share, tariff, uptime) matters at the margin. Gas cost, however, can be assessed through two lenses: as an external commodity indexed to Waha prices (results in Figure 12), or as an internal fuel stream sourced directly from production batteries.

Figure 12 | Gas Price Sensitivity — Unlevered IRR (%) & NPV ($M) @ 10 Wells/sq mi

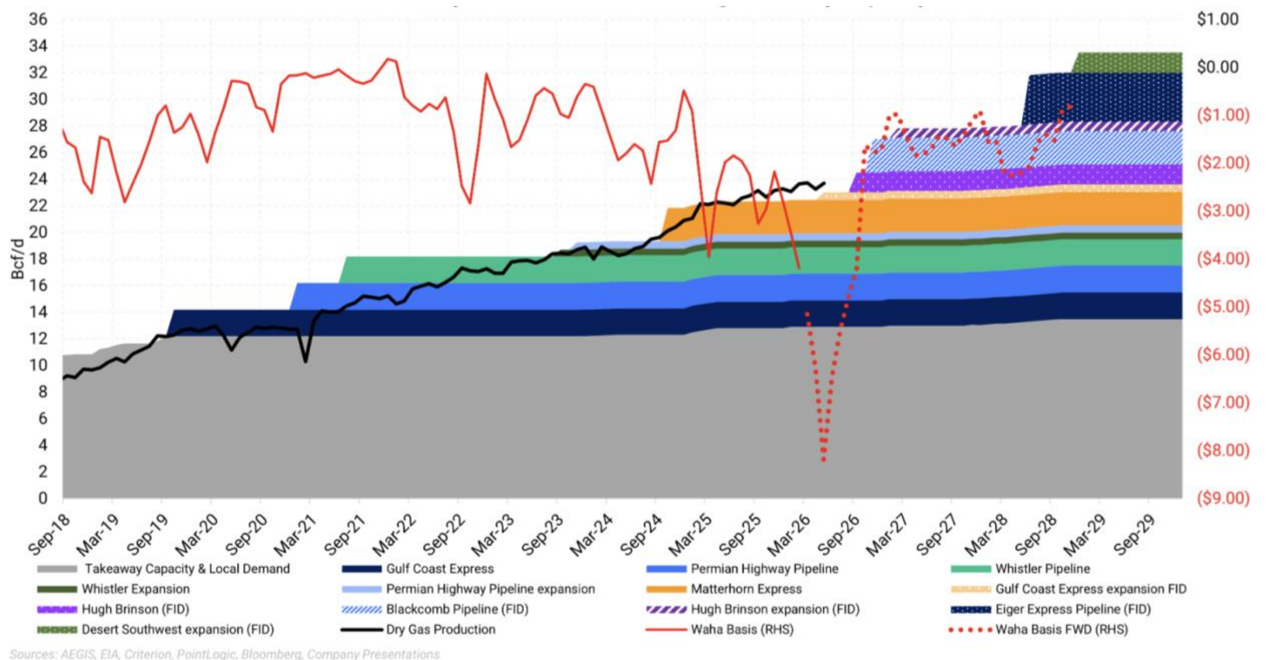


[8] Consistent with Lazard LCOE+ (2025), which applies 12% cost of equity and 40/60 equity-debt to natural gas generation projects.
[9] The model assumes zero terminal value despite clear residual utility-scale optionality. Taxes are computed at the SPV level under MACRS accelerated depreciation (componentized 15-/20-year GDS), with NOL carryforward; bonus depreciation and clean-energy credits are excluded (conservative).

When considered as an external source, negative or low gas price is conditioned by pipeline takeaway capacity. Permian gas production has outgrown long-haul pipeline takeaway capacity by 4–6 Bcf/d since 2022. When pipelines are full, gas clears locally at whatever price the market will bear; zero or below for extended stretches of 2024, 2025, and 2026 (Figure 3).

That bottleneck is being resolved. Figure 13 maps Permian dry gas production against cumulative takeaway capacity additions through 2029. Three sanctioned projects — Blackcomb (2.5 Bcf/d, late 2026), Hugh Brinson Phase I (1.5 Bcf/d, late 2026), and subsequent expansions — add approximately 7 Bcf/d of new egress against only 2 Bcf/d of incremental supply growth over the same period. The forward curve has already priced this: Waha basis tightens from −$3.52/MMBtu in 2026 to −$1.28 in 2027 and −$1.50 to −$2.00 by 2028, implying a Waha absolute price of $1.50–$2.00/MMBtu once Henry Hub is factored in.

Figure 13 | Permian Gas Production, Takeaway Capacity, and Waha Basis (Vs Henry Hub) Outlook[10]



The Structural Mitigation: Generation at the Battery

The most effective response to Waha normalization is not a hedging contract, but an architectural decision made at project inception. Locating the reciprocating engine plant at or immediately adjacent to the production battery reframes the gas cost question entirely.

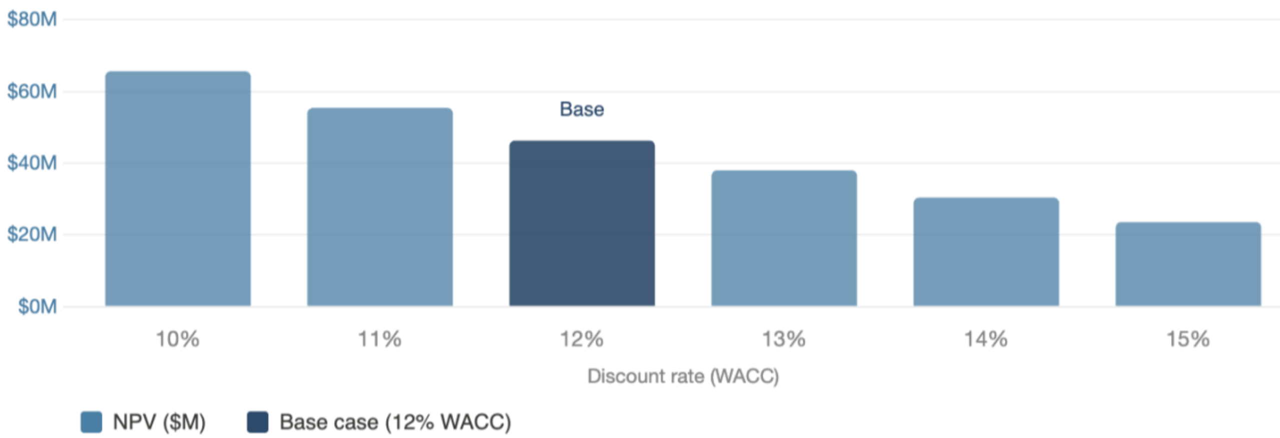
When gas travels from the wellbore separator to an engine skid two hundred feet away, the following costs are eliminated in full: gathering tariff, processing fee, fuel retained by gatherer, volume shrink and long-haul pipeline tariff. The total cost stack avoided is $1.25–$1.75/Mcf. At 22.7 MMcfd required for 116 MW of continuous generation, that is $28,000–$40,000 per day in friction costs eliminated. Additionally, co-location also generates a second layer of synergies, that go from engineering, construction and O&M costs.

[10] AEGIS hedging: Permian Basin Gas Price and Fundamentals

REPRICING ASSOCIATED GAS AGAINST DIESEL

The key economic insight is that associated gas should not be valued only as a commodity sold at Waha. If available, its relevant benchmark is diesel displacement. Gas that might otherwise be flared, stranded, or sold into a local market can instead be converted into field power, where each MMcf/d avoids roughly $10,400–$11,700 per day of diesel cost. Selling that same volume at a normalized 2028 Waha price would generate only $1,575–$2,100 per day. At full capacity, the project requires ~22.7 MMcf/d, or roughly 4% of the ~500 MMcf/d currently flared across the Permian. Avoiding flaring penalties, RRC/EPA methane-rule exposure, and regulatory tightening are meaningful secondary benefits. But the primary arbitrage is not compliance. It is the conversion of low-value associated gas into a direct substitute for high-cost diesel.

Figure 14 | Discount Rate VS NPV Sensitivity



Beyond the financial sensitivities, the centralized model introduces operational trade-offs that the executive team must weigh before committing capital.

Table 6 | Centralization: Strategic Pros and Cons

	Centralized Private Microgrid	Current Diesel Status Quo
Rigs & frac spreads	Electric: less maintenance, more HP, faster	Diesel: proven, mobile, flexible
Flaring avoidance	Uses produced associated gas; avoids flaring penalties and waste	No impact on flaring
Campaign flexibility	Locked to infrastructure footprint; changes costly	Any location, any time
Single point of failure	Generation station outage can halt operations[11]	Each unit independent
Coordination	Power must arrive before rigs; precise sequencing	Rigs deploy autonomously
Personnel	New skills for microgrid O&M (power engineers)	Existing contractor crews
Grid delivery to frac	Requires electrical specialists to manage power swings to frac spreads[12]	OFS crew handles own fuel/power
Equipment availability	Requires electric rigs and e-frac spreads[13]	Diesel equipment abundant
Post-campaign value	Sell power to grid, operators, or data centers	Zero residual value
Emissions	~26% net CO2 reduction per MWh	Highest emission intensity

[11] Shoutout to operations: Redundancies must be added
[12] SPE-220763-MS, JPT Plug and Frac: Grid-Powered Pressure Pumping and Halliburton press release
[13] Oilfield Service (OFS) rates due to switch to e-equipment should be part of the analysis

9. COMMERCIAL STRUCTURE AND EMISSIONS

A 19.35% unlevered IRR is an excellent infrastructure return and a mediocre upstream return. That asymmetry is the key commercial factor in this study. An E&P operator evaluating the same project on its balance sheet, against a portfolio of new wells at 25-35% IRRs, will always pass. A third-party infrastructure developer, evaluating the same project against regulated utilities and renewable PPAs at 12-14% IRRs, will always bid. The deal structure has to match the capital.

Table 7 | Commercial Structure Comparison

Dimension	E&P Self-Fund	JV (50/50)	Third-Party EaaS / PPA
Capital source	Operator balance sheet	Shared equity	Infra investor + project debt
IRR hurdle	25-35% (upstream)	15-20% (blended)	10-16% (infra)
Operator cash impact	Full CAPEX up front	50% CAPEX	Zero CAPEX, opex line
Balance sheet	On-book asset	Equity investment	Off-balance-sheet
Operator upside	Full savings retained	Shared 50/50	Contracted savings share
Best fit	Rare (top quartile only)	Situational	Default recommendation

The commercial structure that resolves the asymmetry is a take-or-pay offtake contract paired with project-finance debt. Under take-or-pay, the E&P operator commits to a minimum monthly capacity payment regardless of actual dispatch, which converts merchant exposure into a contracted cash flow stream. That contracted stream is exactly what infrastructure debt requires: at 60% leverage and investment-grade pricing, equity IRR lifts from the 19.35% unlevered return to 23.01% — inside the band that generalist infrastructure funds, pension capital, and dedicated energy-transition vehicles will underwrite. The operator gets firm power with no CAPEX and no operational burden; the developer gets a bankable contract; the lender gets a senior position against a diversified, long-lived asset. Every party is at the right place on the risk-return curve, which is why the self-fund alternative almost never clears internal hurdles, and the third-party structure almost always does.

Emissions: A Cost Story That Happens to Decarbonize

The 250-well campaign displaces approximately 1.7 million tonnes of net CO_2 over 20 years[14]: the difference between diesel combustion (10.21 kg CO_2/gallon, EPA factor) and centralized gas generation at an 8,500 BTU/kWh heat rate (~0.45 t CO_2/MWh). That is a ~26% net reduction per MWh switched. The emissions outcome is not the reason to build this project, but it is a material side effect that aligns with operator Scope 1 commitments and with methane/CO_2-linked tariff discounts that several midstream counterparties have begun to price in.

> **WHY THIS MATTERS FOR ESG-CONSCIOUS CAPITAL**
>
> 1.7 Mt CO_2 is not a rounding error. At $30/ton internal carbon pricing, it adds ~$50M of present-value benefit that does not show up in the DCF. Infrastructure funds with shadow carbon prices should be running this math already.

[14] This estimate reflects operational combustion emissions and excludes upstream methane leakage and embodied construction emissions.

10. THE 10X SCENARIO: MAKING THE PROBLEM BIGGER

"Whenever I run into a problem I can't solve, I always make it bigger."

— Dwight D. Eisenhower

The 250-well reference case was designed as the minimum viable assessment unit: the smallest campaign that justifies centralized infrastructure. But the Permian does not operate at minimum scale. Diamondback drills 463 wells per year. ExxonMobil runs 33-35 rigs simultaneously. The four operators best positioned to anchor a 10x deployment are Diamondback Energy (400 wells/yr, 722K+ acres), ExxonMobil (650+ wells/yr, 856K+ acres), Occidental (420+ wells/yr, 200K+ Midland acres), and Chevron (225+ wells/yr, multi-basin position). If the 250-well project generates a 19.35% IRR and $46.3M NPV, what happens when the problem is made 10x bigger?

Table 8 | The 10x Scenario: 2,500 Wells Over 5-10 Years

Parameter	250-Well Base Case	2,500-Well (10x) Scenario
Wells	250 (50/yr x 5 yr)	2,500 (500/yr x 5 yr)
Anchor operators	1 (single anchor)	Diamondback, ExxonMobil, Oxy, Chevron
Rigs / frac spreads	2 rigs, 1 spread	20 rigs, 7 spreads (3:1 ratio)
Footprint	25 sq mi	~250 sq mi
Generation capacity	116 MW (recip)	900 MW (600 MW CCGT + 300 MW Recip, two hubs)
Distribution network	20 mi backbone + 62.5 mi	55 mi 138 kV backbone + 476 mi feeders (69 kV + 34.5 kV)
Total CAPEX (est.)	$183.5M	~$1.75B (~$1.04B gen + ~$711M T&D)
CAPEX per well	~$734K	~$698K
Est. unlevered IRR	19.35%	25.3%
Est. NPV @ 12%	$46.3M	$703.3M
D&C diesel displaced (5 yr)	$148M	$1.48B
Post-campaign asset	Local microgrid	Regional utility-scale platform

The economics improve at 10x scale through three channels. First, generation efficiency. At ~900 MW of installed capacity (600 MW CCGT + 300 MW Reciprocating across two regional hubs), 300 MW CCGT blocks become the dominant baseload technology, with heat rates of 6,500 BTU/kWh versus 8,500 BTU/kWh for modular recip engines that handle D&C peaking. That ~$2/MWh fuel-cost advantage, compounded over 20 years against a production fleet building to 2,500 wells, is the single largest contributor to the IRR lift from 19.35% to 25.3%. Second, financing and offtaker scale. Four investment-grade anchors and a ~$1.14B project finance facility (65% LTV at 5.25%) unlock institutional debt markets at 50–100 bps tighter spreads than the base case could command; the 250-well project is too small for capital markets, the 2,500-well project is exactly the ticket size infrastructure funds actively seek. Third, and most importantly, the post-campaign residual value transforms from a local asset to a regional platform: 900 MW of generation across two hubs and ~530 miles of private distribution constitute a utility-scale system that can serve adjacent operators, sell into ERCOT, or anchor a data center corridor.

THE REAL INSIGHT

The 250-well case proves the concept. The 2,500-well case proves the business. At 10x scale, the private oilfield microgrid is no longer an infrastructure project. It is a regional power company built on the most active drilling basin on Earth. Diamondback, ExxonMobil, Occidental, and Chevron are the natural anchor tenants: they control the acreage, produce the gas, and run the rigs. The infrastructure investors who move first will own the platform.