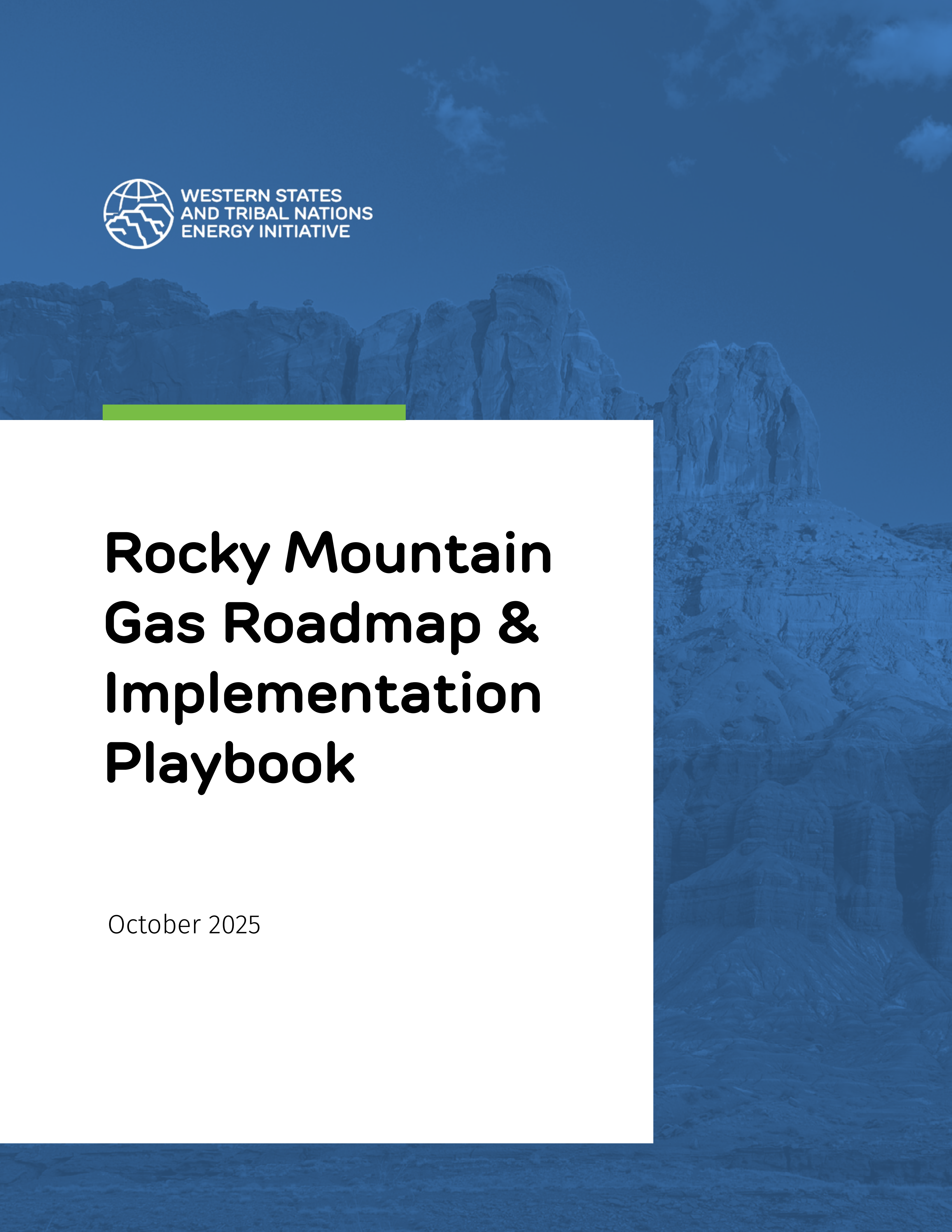


WESTERN STATES AND TRIBAL NATIONS ENERGY INITIATIVE

Rocky Mountain Gas Roadmap & Implementation Playbook

October 2025

Letter from WSTN President Andrew Browning

Abundant, affordable, and low-carbon resources are essential to meeting the accelerating demand for energy across domestic and international markets. Natural gas remains one of the few scalable solutions that satisfies each of these three criteria. With demand projected to rise significantly—driven by domestic load growth and global LNG export needs—gas supplied from the Rocky Mountain Basins is uniquely positioned to respond. Its extensive reserves, exceeding 277 TCF of recoverable gas, offer a reliable, cost-effective, and lower-emission supply capable of supporting everything from data center expansion in the Western U.S. to broad economic development across the Asia-Pacific region.

This report offers a strategic vision for developing the Rocky Mountain gas basins, including a clear, actionable roadmap for next steps to connect this cost-competitive, low-carbon reserve to growing centers of demand. In the near-term, the Rocky Mountain Basins can bolster a changing domestic energy system in the U.S., supporting grid reliability and resilience while helping to keep costs down for American rate payers. The expansion of infrastructure that will be needed to transport supply to key regional demand hubs in the Western U.S. can create synergies and enable new opportunities to export Rockies gas to rapidly expanding markets in the Asia-Pacific region while reducing unit costs and risks.

WSTN presents this roadmap as a bipartisan, trans-national initiative led by sovereign tribal nations and states focused on creating rural economic development, advancing tribal self-determination, and reducing global emissions. Our organization began as a bipartisan effort under former Colorado Gov. John Hickenlooper and former Utah Gov. Gary Herbert, and we remain committed to a bipartisan, common-sense approach to tackling some of the most pressing challenges impacting rural communities throughout the Western U.S.

This roadmap is a direct result of that spirit of collaboration among our member states and tribal nations who funded this important work. WSTN thanks the Wyoming Energy Authority, the State of New Mexico Economic Development Department, the State of New Mexico Energy, Minerals and Natural Resources Department, the Utah Governor's Office of Energy Development, the Southern Ute Growth Fund, the Jicarilla Apache Nation, and the Western Colorado counties of Garfield, Mesa, Moffat, and Rio Blanco for their contributions to make this roadmap a reality.

We believe that this roadmap for developing the Rocky Mountain Basins natural gas resources represents a crucial step towards meeting the growing demand for abundant, affordable, reliable, low-carbon energy in the Western U.S. and internationally. We present it as a tool to enable planning, decision-making, and above all, to look over the horizon to unlock new opportunities for our member states and tribal nations. The Rocky Mountain Basins have the supply to meet tomorrow's demand, and amidst a rapidly changing energy landscape, it will be a critical component in enabling sustainable long-term growth while strengthening U.S. energy security and the geopolitical power it confers.

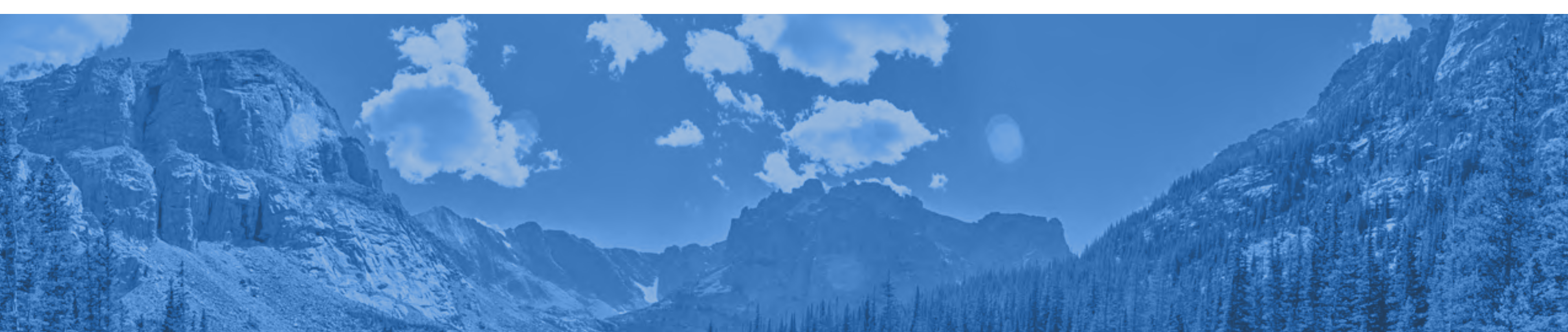
Andrew Browning

President, Western States and Tribal Nations Energy Initiative

Contents

List of Figures

List of Tables



List of Abbreviations

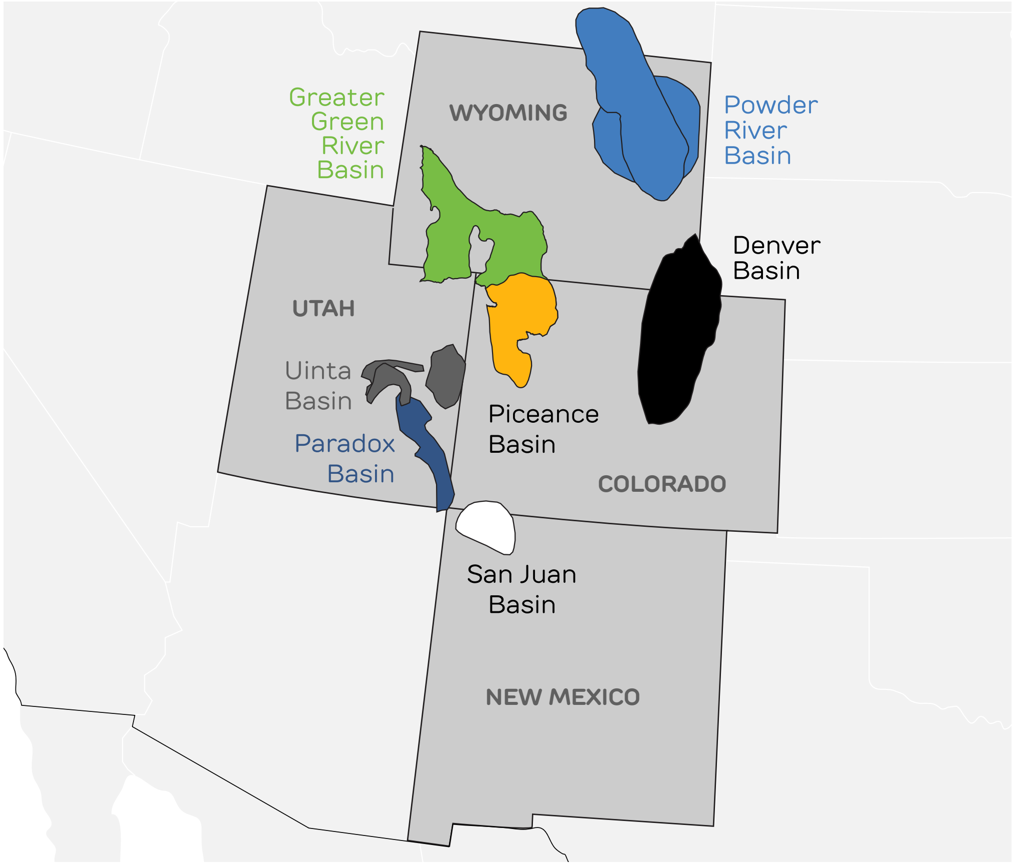
ACRONYM	MEANING
ANGEA	Asia Natural Gas & Energy Association
BCF/d	Billion cubic feet of natural gas per day
Btu	British thermal unit, measure of heat content of gas
CAPEX	Capital expenditure
ECA	Energía Costa Azul
EUR	Estimated ultimate recovery
GHG	Greenhouse gas
HP	Horsepower
JKM Price	Japan/Korea Marker
LNG	Liquefied natural gas
MTPA	Million tonnes per annum, measure of production capacity
OGMP	Oil and Gas Methane Partnership
OPEX	Operating expenditure
PNW	Pacific Northwest
Rockies	Rocky Mountain region
ROW	Right-of-way
SW	Southwest
TCF	Trillion cubic feet, measure of volume of gas
USGS	United States Geological Survey
WECC	Western Electricity Coordinating Council
WSTN	Western States and Tribal Nations

Executive Summary

Secure, long-term, low emission, competitive, and geographically diversified reserves of energy supply are paramount to meeting the growing energy demand being observed and forecasted,[1] both in the U.S. and across international markets. Natural gas supplied from the Rocky Mountain Basins (Rockies gas) can support this demand, providing a vast, low-cost, lower emission, and highly reliable source uniquely positioned to serve the Western U.S. and exports to the Asia-Pacific markets.

> **OVERARCHING FINDING:** ***The Rocky Mountain Basins present a significant development opportunity to meet growing demand with secure, affordable, abundant, low-carbon natural gas, providing a competitive advantage to alternative options for serving growing domestic load, supporting energy reliability, and supplying a diversified Asian LNG procurement strategy.***

Figure 1: Overview of Rocky Mountain Natural Gas Basins[2]



To capture the benefits that can be derived from the Rocky Mountain Basins, development initiatives must first manage distinct obstacles that have previously impeded the region's path to securing access to new markets. With some exceptions, the existing regional infrastructure is highly constrained and requires new investment to handle additional volumes. New pipelines require significant capital and are difficult to permit without strong local support, requiring large-scale demand and long-term contracts. Most scenarios for development will need to consider new large-scale infrastructure in their pathways, navigating through a difficult geography with mountainous terrain that has previously presented challenges to construction.

Rockies gas has historically been price-disadvantaged, consistently trading at a discount relative to the Henry Hub benchmark due to limited take-away capacity and distance from key markets. Despite the historical hurdles, the region possesses unique advantages that can be leveraged into attracting new domestic and export demand. Critically, the region is geographically proximate to key growing domestic markets like the Southwest, where incremental power demand is expected to continue rising. Gas supplied from the Rockies also represents the closest domestic supply source to the West Coast, offering a valuable shipping advantage to premium Asian LNG markets by avoiding Panama Canal congestion and Gulf Coast weather disruptions.

Dominated by dry natural gas resources, the region's production is not dependent on volatile oil prices, offering a stable and reliable supply source that can complement oil-driven associated gas from the Permian. Furthermore, regional producers have been early adopters of best practices to reduce the carbon intensity of the product that they deliver, a key differentiator for target markets that value low-carbon energy, including certified natural gas.

Overcoming the infrastructure and market-related challenges to achieve successful development requires an updated understanding and analysis of the Rockies gas resource. This involves creating unique, public-private partnerships to develop assets from wellhead to market, mitigating basis risk and offering partners sustainable development opportunities with reasonable returns. Analysis of the value proposition highlights a cost-competitive value chain and provides justification for offtakers in need of alternate supply options. With strong local support, a more favorable permitting environment for new infrastructure is achievable, potentially augmented by state-level assistance like low-cost financing connected to demonstrated economic benefits.

KEY MARKET DRIVERS & IMPLICATIONS FOR DEVELOPMENT

Future growth is heavily dependent on accessing two primary demand centers

Regional, High-Value Markets

In-basin power generation for data centers, onshoring of manufacturing, and accelerating load growth from electrification, particularly in the Desert Southwest and Pacific Northwest, are converging to create high-value, strategic markets. This represents a strong opportunity for regional low-carbon gas supply as it can help aggregate the demand needed to support new infrastructure.

International, High-Volume Markets

This includes LNG exports to Asian markets craving competitive, low-carbon, and reliable energy supply that can be achieved via shipments of LNG originating from the Pacific Coast—something Rockies gas can supply cheaper and faster than other available options.

TWO PREMIER OPPORTUNITIES

Leveraging existing rights of way, there are two attractive pathways for market development of Rockies gas.

Expanding gas supplies from the San Juan Hub to growing power generation needs in the Desert Southwest and Mexico, meeting growing industrial and power generation demand needs as well as international exports.

Transporting gas through Opal Hub to growing power generation in Utah, Idaho, and the Pacific Northwest (PNW), positioning for potential LNG export in the PNW as an alternate or additional route to growing Asian markets.

KEY FINDINGS

In assessing the economics of Rockies gas, the value proposition is built on three pillars.

Upstream Economics

The marginal cost of supply from basins like the San Juan, Piceance, and Greater Green River are highly competitive when producers can access West Coast U.S. markets and international demand. This access not only improves pricing dynamics but also creates better opportunities for partnership and alignment of interests—particularly in terms of vertical integration—where upstream and downstream players can collaborate more effectively across the value chain.

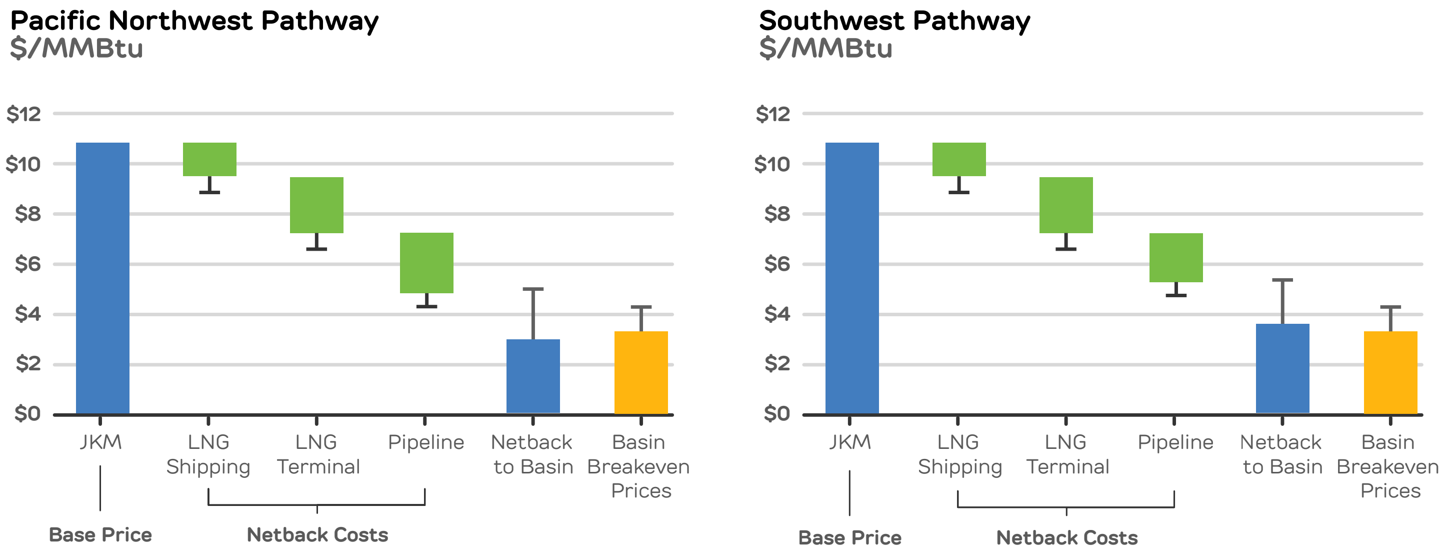
Leveraging Existing ROWs

Both the domestic and export pathways can leverage significant portions of existing pipeline infrastructure and rights-of-way, potentially reducing development timelines and capital costs and lowering environmental impacts. Midstream operators are already investing in westbound expansions to meet growing regional demand, demonstrating the viability of enhancing these energy corridors.

Geographic Proximity to Asia

The fundamental advantage of Rockies gas is its location. For LNG exports, the significantly shorter shipping times to Asia (~10-12 days versus ~25-30 days from the U.S. Gulf Coast) lead to lower transportation costs, reduced emissions, and greater insulation from Panama Canal congestion and fees. In addition to the cost savings, shorter transit times also offer greater certainty around delivery schedules and help avoid the uncertainty brought by potential congestion in the Panama Canal, which can disrupt timing and reliability.

Figure 2: Value Chain Economics for Export Pathways Utilizing Rockies Gas



A direct Pacific voyage represents an efficient shipping cost of approximately $1.10 to $1.60/MMBtu.[i]

Modern liquefaction facilities can be constructed and operated with tolling fees in the range of $2.40 to $2.80/MMBtu.[ii]

New pipeline capacity, built along existing rights-of-way, would require a transportation tariff between $1.50 and $2.40/MMBtu.[iii]

Average estimated breakeven production cost across the major Rockies gas basins is between $3.10 and 3.90/MMBtu.[iv]

Rockies gas offers a unique and compelling strategic fit for buyers on both sides of the Pacific, addressing distinct but complementary needs.

i Shipping costs based on Tacoma and Ensenada to Yokohama. Please see Appendix for detail.

ii LNG tolling fee cost is based on the full lifecycle cost of the liquefaction facility, including CAPEX & OPEX. Detailed methodology is provided in the Appendix.

iii Midstream pipeline costs are based on a cost-of-service model that recovers capital and operating expenses while providing an infrastructure like return.

iv Basins within the average include Green River, Uinta, Piceance, San Juan, and Denver; the values represent midpoint averages and high-end averages across those five basins; for details on calculation methodology, please reference the Appendix.

How to Read this Report

The Rocky Mountain Gas Roadmap & Implementation Playbook is structured around four key considerations underpinning the comparative advantage that gas supplied from the Rocky Mountain Basins can serve in targeted markets. These considerations include:

1. Availability of significant untapped reserves
2. A cost-competitive value proposition
3. Enablement of supply diversification
4. Access to a dispatchable, low-carbon fuel

Based on these key considerations, the report then concludes with an actionable set of next steps to inform an indicative roadmap for development. This roadmap synthesizes the core elements detailed throughout the report into a succinct and direct approach for development, taking into account all relevant stakeholders and the roles required for further action.

Detailed analysis and methodology from this market assessment can be found in the Appendix as reference.

The Growing Need for Natural Gas

Demand for natural gas is on the rise, both in the U.S. and around the world, driven by economic expansion, energy security concerns, and the need for flexible and affordable power generation. In 2024, global natural gas consumption reached a record 148 trillion cubic feet (TCF) and is projected to grow by another 2 TCF (1.4%) in 2025.[3] This growth is largely fueled by emerging markets in Asia—particularly China and India—where surging power needs, heatwaves, and expanding industrial activity are increasing reliance on gas.[4] Europe and North America also saw notable increases, with Europe's LNG imports rising sharply to meet seasonal and strategic storage needs.[5] Domestically, the industrial and power generation sectors account for the bulk of this demand, as natural gas continues to displace more carbon-intensive fuels.[6] Meanwhile, technological trends such as the rapid growth of AI and cloud computing combined with increased penetration of intermittent renewable energy supplies are straining electricity grids, further reinforcing the role of natural gas as a stabilizing energy source. Amidst these changes, ample supplies of natural gas in the U.S. continue to provide some of the most affordable and cost-effective energy options for consumers—both from power generation[7] as well as for residential heating needs.[8] Despite geopolitical uncertainties and the push for low carbon alternatives, natural gas remains a cornerstone of global energy needs.

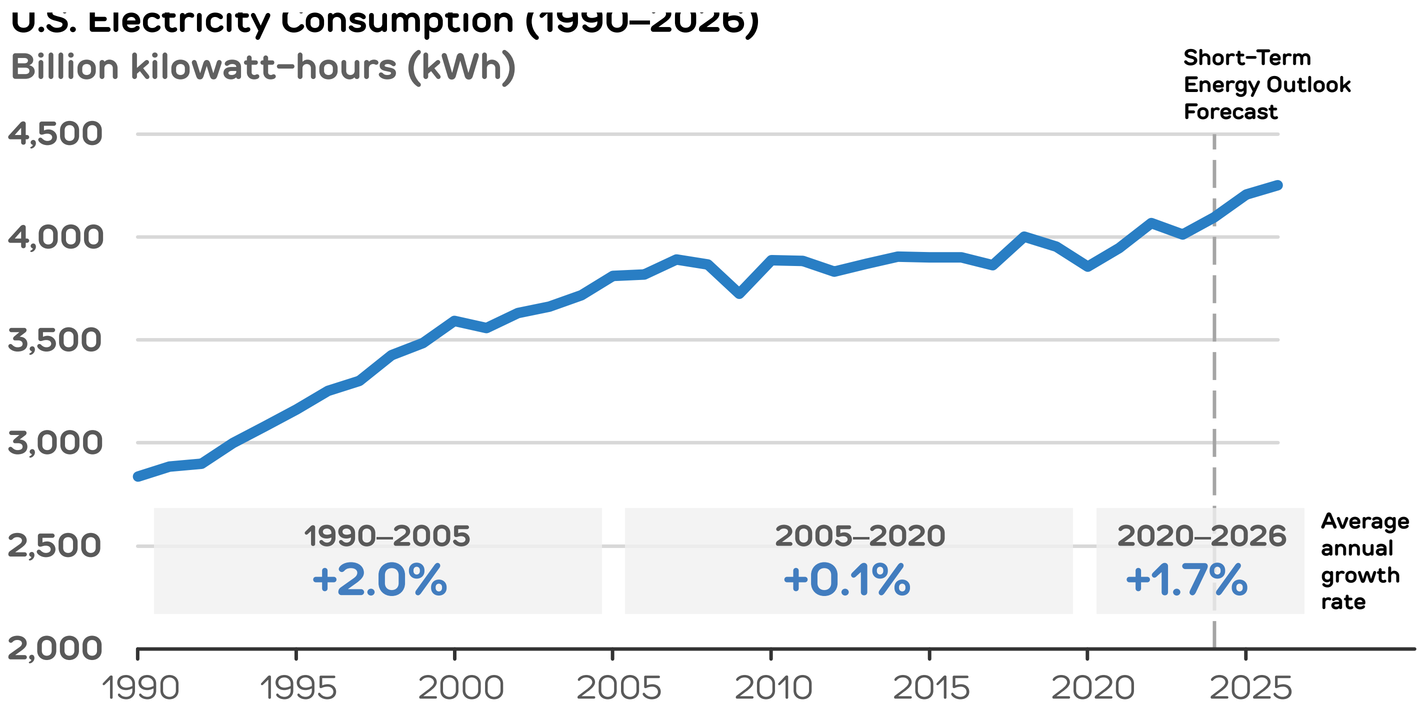
Meeting this growing demand requires an all-hands-on-deck approach to energy system planning and deployment of capital, without sacrificing cost, reliability, or environmental impact. When assessing the landscape of available energy resources, natural gas has repeatedly been recognized for its ability to serve a "fundamental role in achieving the United Nations Sustainable Development Goals, satisfying rising global energy needs and securing universal access to affordable, reliable, sustainable, and modern energy for all."[9]

Domestic Natural Gas Market

The U.S. is currently experiencing dramatic growth in natural gas demand, illustrated by an increase in demand of 21% over the past decade.[10] Concurrently, federal policy today recognizes the critical importance of having an abundant and secure supply of energy to meet the growth while shoring up domestic energy dominance and bolstering the reliability and stability of domestic energy systems. In 2024, U.S. natural gas consumption reached a record high of over 34 quadrillion Btu, second only to demand for petroleum among all primary energy sources.[11]

One of the primary drivers of recent demand growth for natural gas has come from the power sector. Since 2020, power demand in the U.S. has been growing at nearly 2% per year, a rate not seen in decades.[12] During the previous fifteen years spanning 2005 to 2020, growth in demand for electricity in the U.S. was virtually stagnant, climbing at an average rate of 0.1% annually for over a decade-long stretch.[13]

Figure 3: U.S. Electricity Consumption (1990-2026)[14]

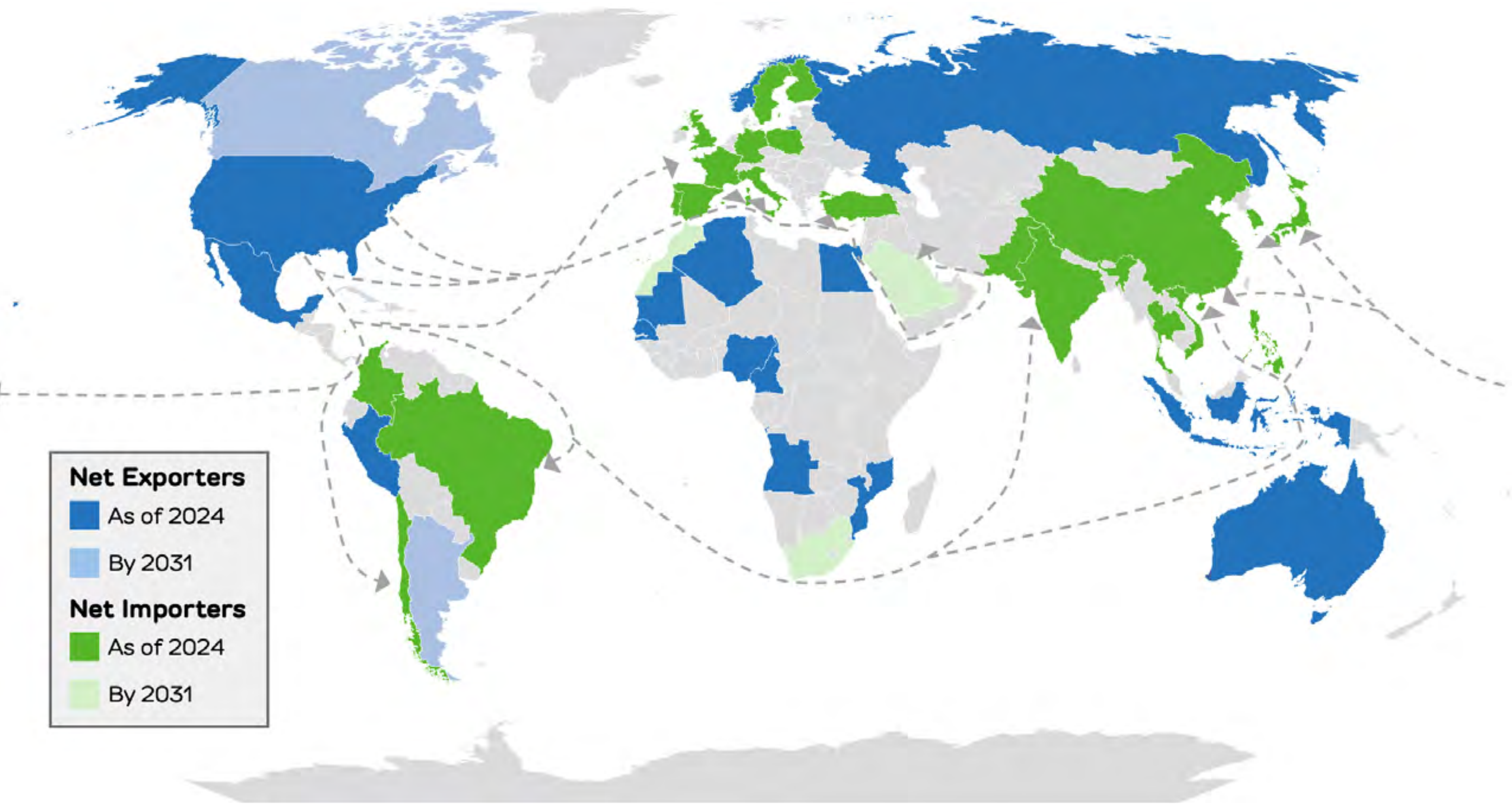


Global LNG Market Context

Globally, the demand for liquefied natural gas (LNG) is forecasted to double by 2050, growing from 400 MTPA (52 BCF/d) in 2023 up to 800 MTPA (105 BCF/d) by mid-century.[15] The vast majority of this demand growth is expected in the Asian Pacific market,[16] where a combination of rapid population growth, economic development, urban migration, industrialization, and increasing standards of living are driving a significant increase in demand for energy. While coal has been the primary source of energy to date in the region,[17] natural gas offers a lower carbon intensity alternative that can be traded globally via LNG shipments.

In 2024, the U.S. exported 11.9 BCF/d of LNG, more than any other nation.[18] Nearly all of the existing export capacity sits in the Gulf Coast region, requiring that shipments headed for the Asian Pacific market (of which nearly 4 BCF/d was exported to in 2024)[19] travel through the congested and constrained Panama Canal (LNG exports to the Asian Pacific market would likely be higher were it not for the Russian invasion of Ukraine in 2022 and subsequent premium placed by European nations on LNG sourced from outside Russia, notably the U.S.). This not only leads to increased shipping costs and less reliable shipping schedules, but it also presents a strategic risk that has led to more LNG shipments heading east to Asia via the Cape of Good Hope—a significantly longer journey.[20]

Figure 4: Global Shipments of Liquefied Natural Gas[21]



Rockies Gas, A Solution to Meet this Challenge

Meeting the growing demand for energy—both domestically and around the world—requires natural gas that is affordable, abundant, and low in carbon emissions. The Rocky Mountain Basins offer a compelling solution, with vast untapped reserves, a cost-effective value proposition, favorable environmental attributes, and the capacity to expand and diversify supply. These strengths position the Rockies as a proven resource to address this critical energy challenge.

#1 The Rockies Basins Include Significant Untapped Reserves

Sizing the Rockies Basins

The Potential Gas Committee (PGC) defines the Rockies basins as the region spanning from the Canadian border in Idaho, Montana, and North Dakota to the Mexican border in Arizona and New Mexico. In the 2022 Annual Report, PGC highlights this region as one containing some of the largest technically recoverable natural gas resources in the U.S., ahead of the Gulf Cost and Alaska regions;[i] however, the region's natural gas resources have remained relatively untapped due to a combination of challenging terrain, limited infrastructure, and stricter environmental regulations contributing to less favorable economic conditions compared to more developed energy producing regions like Texas and Appalachia.

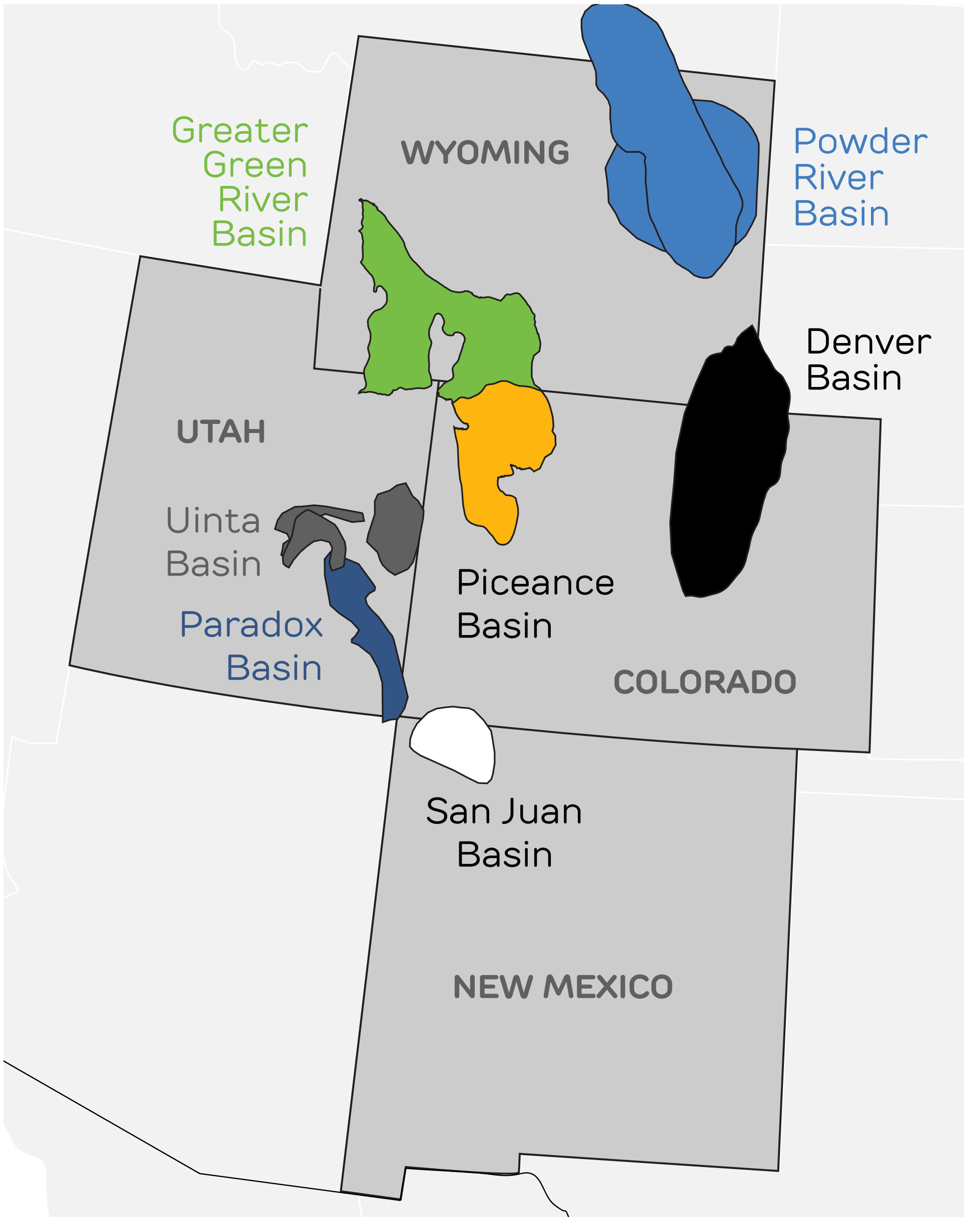


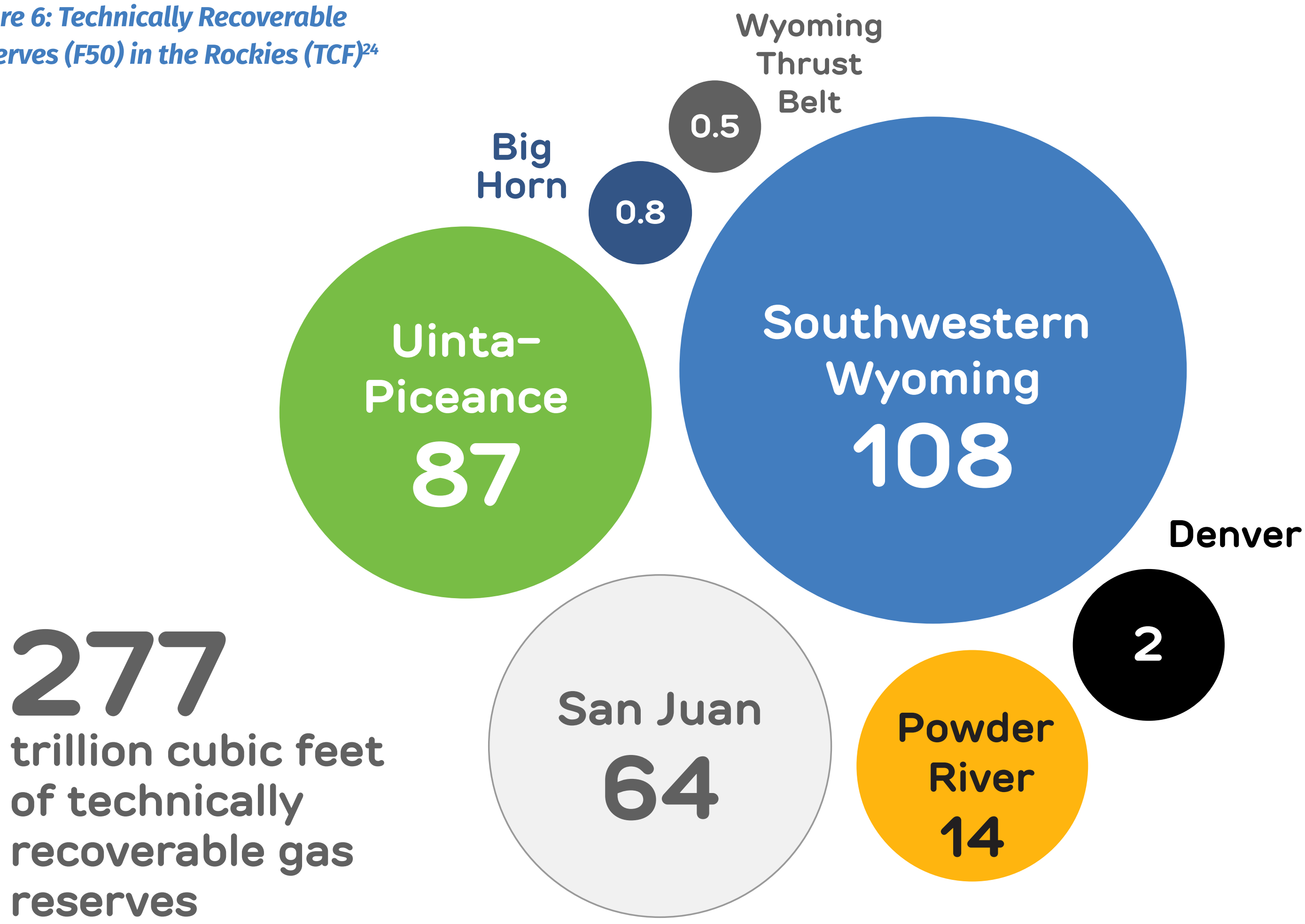
Figure 5: Overview of Rocky Mountain Natural Gas Basins[22]

i Technically recoverable resource estimates are the amount of gas that can be extracted using current technology. This amount has increased significantly over time as production technology has improved.

Wyoming, Colorado, New Mexico, and Utah own most of the Rockies natural gas resources, with the most prominent and productive natural gas areas concentrated in the Denver, Uinta-Piceance, South-western Wyoming, Powder River, San Juan, Wyoming Thrust Belt, and Bighorn regions. These regions are defined based on the United States Geological Survey (USGS) assessment units,[23] encompassing areas with significant natural gas reserves.

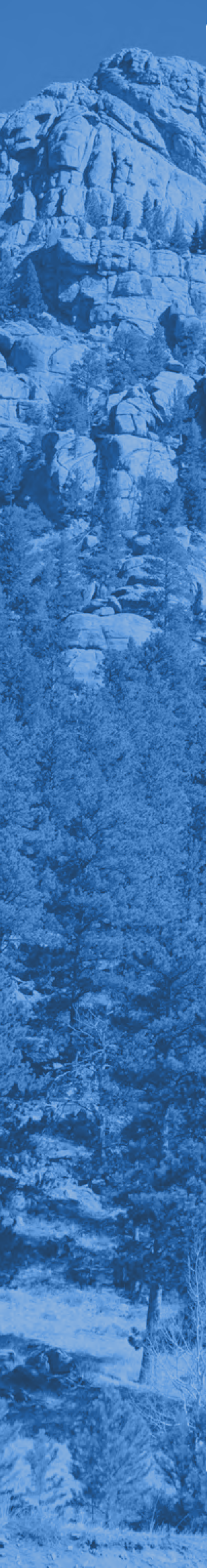
USGS national gas assessments from the past two decades demonstrate the substantial untapped reserves in the region, totaling 277 TCF of gas,[i] which is sufficient to support over 50,000 TWh of gas-fired electricity generation.[ii] The Uinta-Piceance, Southwestern Wyoming, and San Juan basins have the largest reserve quantities, each independently holding sufficient reserves to ensure long-term gas supply. The significant quantity of technically recoverable reserves across basins demonstrates the long-term viability of Rockies gas.

Figure 6: Technically Recoverable Reserves (F50) in the Rockies (TCF)[24]



i This data represents the total F50 value from USGS continuous assessments from 2000–2024. It does not account for production between 2000–2025 or any reserves in assessment units not covered by USGS.

ii Assuming an energy content of 1037 btu/cubic foot of gas and 60% efficiency.



Unlocking the Rockies Gas Resource

The Rockies basins are currently interconnected, enabling gas delivery from North to South, but are limited by capacity constraints. Although the existing infrastructure is sufficient in the short-term, the development of additional intra-basin connectivity will increase offtake potential and provide the scale and flexibility for Rockies gas to compete for large dynamic loads from international markets.

#2 The Rockies Basins as a Cost-Competitive Source of Supply

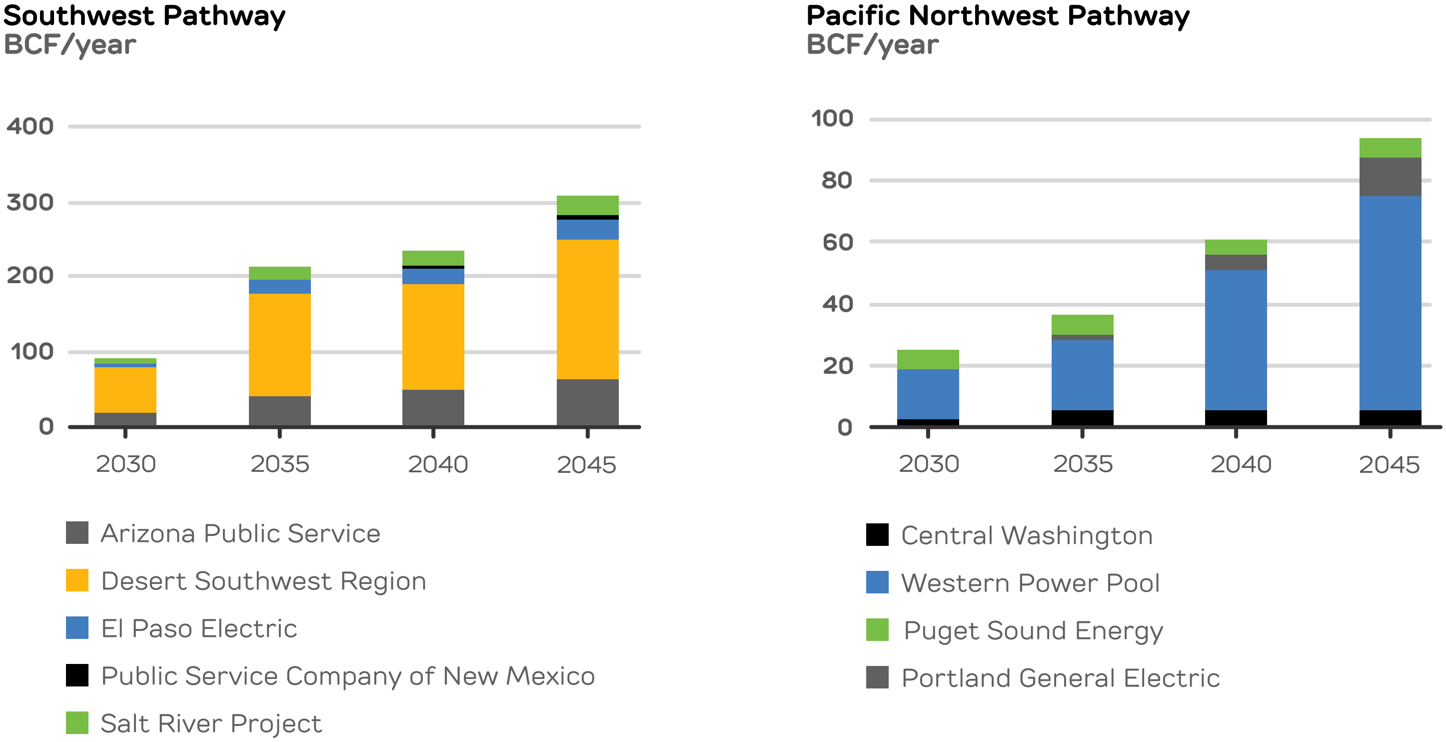
A landmark opportunity exists to unlock the vast natural gas resources of the Rocky Mountain Basins, establishing the region as a cost-competitive source of supply for both domestic and international markets. A strong business case for new infrastructure and production growth is underpinned by historic growth in domestic energy demand. This foundational demand creates commercially viable pathways to the West Coast either through the Pacific Northwest or Mexico that not only enhance U.S. energy reliability but can also be extended to serve high value liquefied natural gas export markets in Asia. A full value chain assessment confirms that these dual-purpose markets are profitable, investable, and strategically vital.

Domestic Demand: The Foundation for Growth

Historically, the expansion of production from the Rocky Mountain Basins has been constrained by a lack of infrastructure to move gas to key markets. That dynamic is changing. The U.S. is experiencing significant growth in domestic energy demand, driven by the onshoring of manufacturing, the rapid expansion of data centers, and the continued need for baseload power generation to support energy reliability. This presents a significant opportunity for the Rockies to expand beyond its historical role as a swing supplier.

The Mountain West and Southwest are expected to see particularly strong growth, creating a greater opportunity for the Rockies to supply neighboring centers of load growth. The projected incremental natural gas demand for power generation in the Western Electricity Coordinating Council (WECC) region over the next decade indicates a significant and sustained increase, with forecasts showing a 20% rise in annual demand by 2045. Meanwhile, forward settlement prices for natural gas are expected to remain relatively stable, fluctuating between $3.50 and $4.50 per MMBtu between 2026 and 2030.[25] This rising domestic demand, combined with stable forward pricing for natural gas, creates the strategic and commercial anchor needed to support the development of new energy corridors to the West Coast.

Figure 7: Incremental Natural Gas Demand for Power Generation by Utility Region[26]



While the utility-level demand illustrated in Figure 7 is substantial, it represents a conservative baseline. A key variable—rapid data center expansion—introduces significant upside potential that is not yet fully captured in traditional utility-scale demand forecasts. Additionally, many of these new, large-scale facilities are deploying behind-the-meter (BTM) natural gas generators operating independently of the local utility grid. As a result, their gas consumption falls outside conventional utility demand projections.

Forecasts suggest that data center energy demand could reach between 325 and 580 TWh by 2028, with natural gas expected to be the predominant source of new generation capacity for these facilities.[27,28] In the Northwest, energy use from data centers and chip fabrication facilities will grow from 4.4 million MWh in 2024 to 34.8 million MWh by 2029 under a mid-case scenario.[29] Assuming gas-fired power plants provide at least half of generation, with a 50/50 mix of single-cycle and combined-cycle, an additional 17.5 million MWh would require approximately 160 Bcf of natural gas.[i]

i Gas requirement assumes a heat rate of 9.0 MMBtu/MWh.

The Pacific Coast Advantage: De-Risked Pathways to Market

This foundational domestic demand growth supports two distinct yet complementary pathways to the Pacific. The commercial viability of these pathways was assessed by analyzing the entire value chain and determining whether producers could profitably supply LNG at the projected price levels. These routes are not speculative; rather, they represent logical extensions of existing commercial activity and infrastructure currently under development to serve U.S. consumers. This alignment significantly reduces development risk and positions LNG as a highly strategic and valuable addition.

The first option is a Southwest Pathway that leverages the advanced progress of export facilities in Mexico. This route is fundamentally anchored by strong domestic energy demand growth in the Southwestern U.S. and northern Mexico. Pipeline expansions in this corridor are primarily designed to serve the electricity sector, which has driven most of the region's incremental gas demand in recent years. This foundational domestic need underpins the development of new pipeline capacity to the Southwest, making LNG export a logical and highly valuable extension. This pathway offers a faster speed to market by capitalizing on the Energía Costa Azul (ECA) facility that is already over 94% complete and nearing an early 2026 operational start date for Phase 1. The commercial momentum is clear, as midstream operators are looking to develop new natural gas pipeline infrastructure to serve new southwestern domestic loads and Mexican LNG facilities.[30]

The second option is a Pacific Northwest Pathway, which represents a direct, U.S.-based route with long-term supply security. Similar to the Southwest Pathway, the business case for this pathway can initially build upon domestic demand. The growth in domestic power demand is driving the need for additional pipeline capacity to serve consumers in the Pacific Northwest region. This existing and growing domestic load provides a secure foundation for infrastructure investment. Midstream operators are already planning to invest in federally regulated, westbound pipeline expansions to meet this growing regional and West Coast demand, demonstrating the viability of the route and reducing the execution risk for a larger-scale buildout that could support an LNG export facility.[31] Both options present a more predictable and manageable investment environment than higher-risk, technically complex alternatives in other parts of North America.

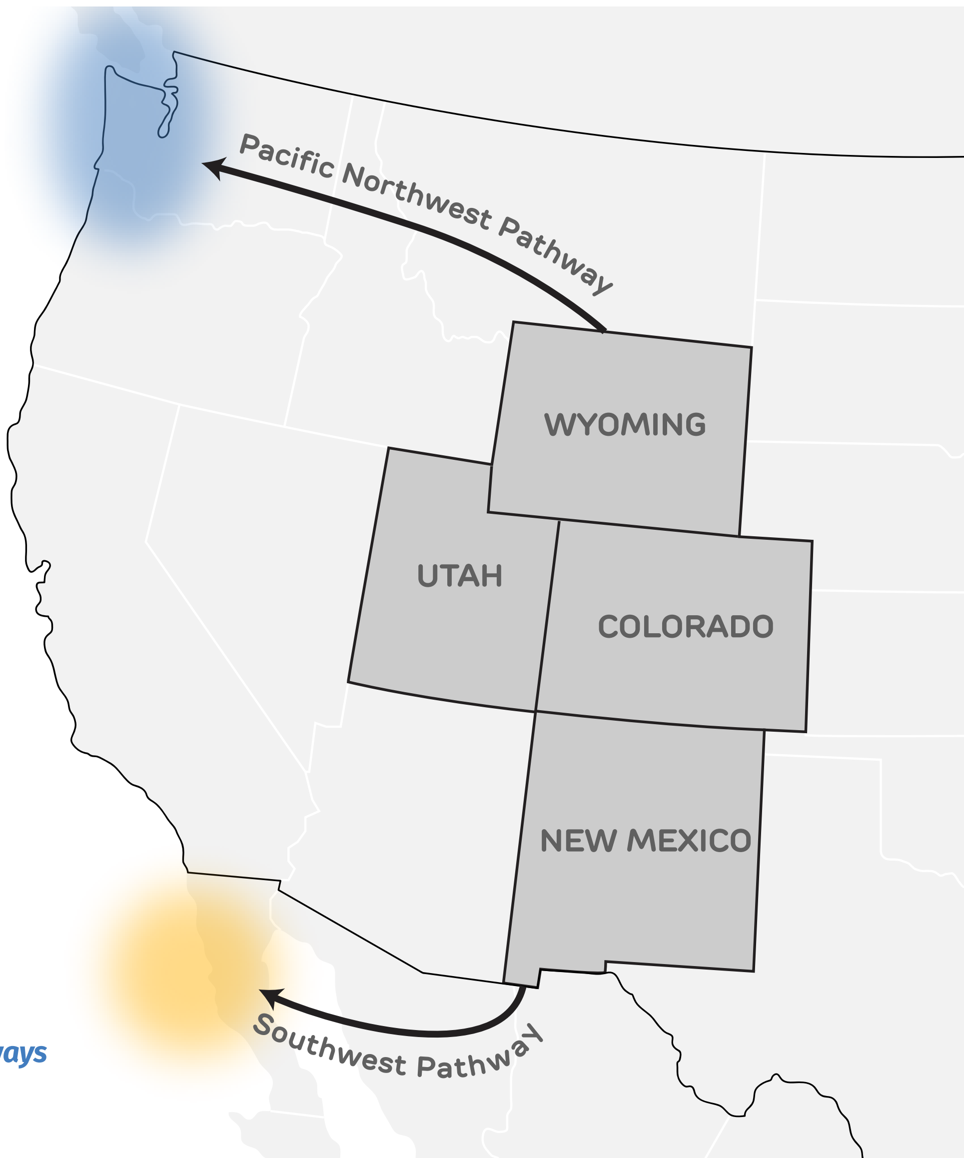
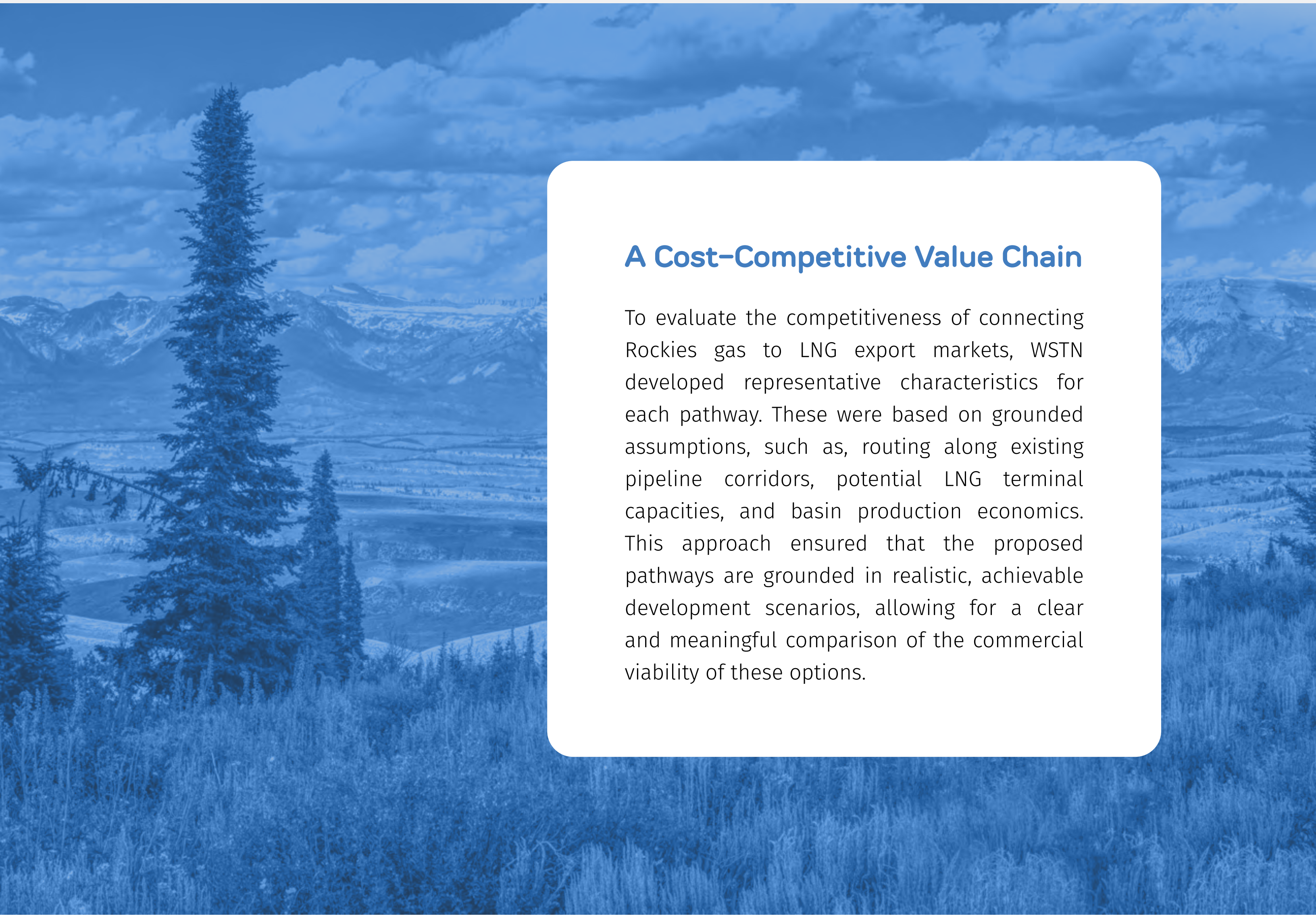


Figure 8: Representative Development Pathways



A Cost-Competitive Value Chain

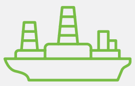
To evaluate the competitiveness of connecting Rockies gas to LNG export markets, WSTN developed representative characteristics for each pathway. These were based on grounded assumptions, such as, routing along existing pipeline corridors, potential LNG terminal capacities, and basin production economics. This approach ensured that the proposed pathways are grounded in realistic, achievable development scenarios, allowing for a clear and meaningful comparison of the commercial viability of these options.

Table 1: Overview of Key Pathway Attributes

VARIABLE	UNITS	SW PATHWAY	PNW PATHWAY
Size of LNG Terminal	Bcf/d	2.4	2
Length of New Pipeline	miles	775	825
Pipeline Construction Cost[i]	$mm/mile for 48" diameter	$7.0	$8.8
Supply Basins		All Rockies	
CAPEX per well	$mm	6.3–19	
Average EUR per well	Bcf	2.2–10	
Shipping Distance	nautical miles	5,100	4,300

i SW pipeline costs are due to ~50% of pipeline length being constructed in Mexico, where labor, land, and permitting costs are significantly less.

The representative economics across the value chain for these pathways confirm a profitable and investable business case for Rockies gas. While cost components can be dynamic, the analysis demonstrates that a clear commercial opportunity exists. With landed LNG prices in Asia at approximately $10.50/MMBtu,[i] there is a direct and profitable business case.



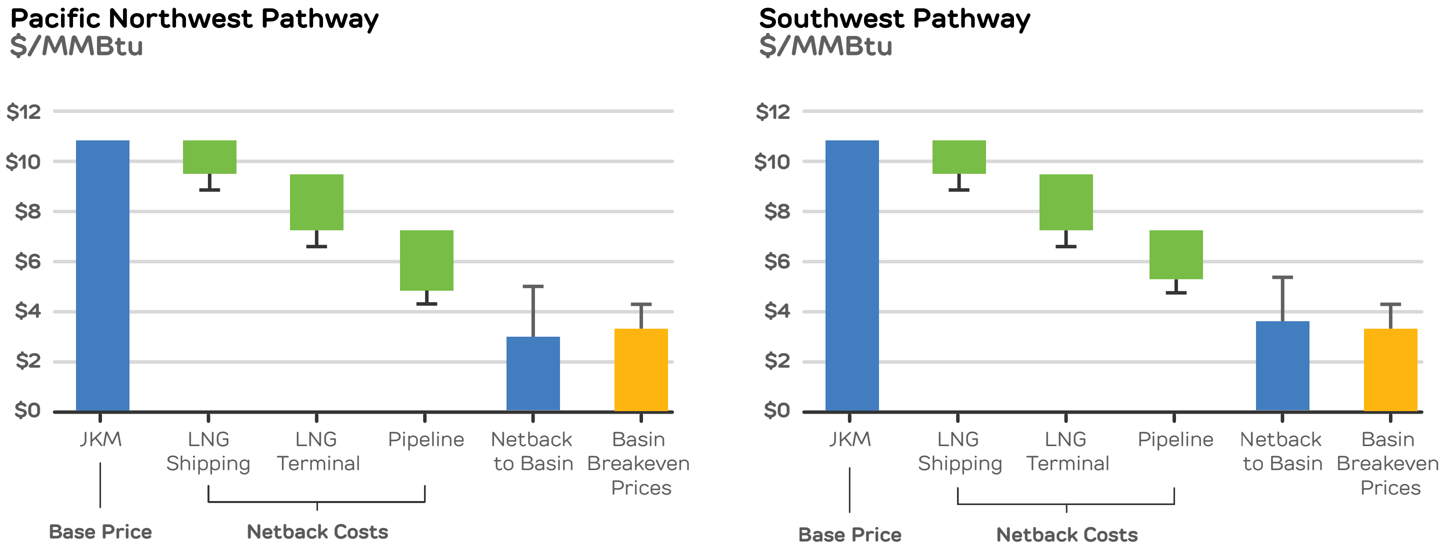
A direct Pacific voyage represents an efficient shipping cost of approximately $1.10 to $1.60/MMBtu.[ii]

Modern liquefaction facilities can be constructed and operated with tolling fees in the range of $2.40 to $2.80/MMBtu.[iii]

New pipeline capacity, built along existing rights-of-way, would require a transportation tariff between $1.50 and $2.40/MMBtu.[iv]

Average estimated breakeven production cost across the major Rockies gas basins is between $3.10 and 3.90/MMBtu.[v]

Figure 9: Value Chain Economics for Export Pathways Utilizing Rockies Gas



i The JKM price represents an average based on historical data for 2024 and 2025 and forecasted values for 2026. Detailed methodology and calculation steps are provided in the Appendix.

ii Shipping costs based on Tacoma and Ensenada to Yokohama. Please see Appendix for detail.

iii LNG tolling fee cost is based on the full lifecycle cost of the liquefaction facility, including CAPEX & OPEX. Detailed methodology is provided in the Appendix.

iv Midstream pipeline costs are based on a cost-of-service model that recovers capital and operating expenses while providing an infrastructure like return.

v Basins within the average include Green River, Uinta, Piceance, San Juan, and Denver; the values represent midpoint averages and high-end averages across those five basins; for details on calculation methodology, please reference the Appendix.

Strategic Fit for Domestic and International Buyers

A West Coast supply strategy offers a strategic fit for buyers on both sides of the Pacific Ocean. For the U.S. West Coast, increased access to Rockies gas is a critical tool for ensuring grid reliability and resilience. As states integrate larger shares of intermittent renewable energy, the electric grid becomes more dependent on dispatchable, gas-fired generation to prevent reliability events, especially during extreme weather. A robust gas supply from the Rockies helps manage the costs and risks of this transition, ensuring dependable energy for homes and businesses.

For international buyers in Asia, Rockies-sourced LNG offers a powerful tool for portfolio diversification and long-term energy security. Asian nations, whose LNG demand is projected to nearly double by 2050, are actively seeking to reduce their dependence on any single supply point. Rockies gas provides a stable source not reliant on oil market pricing and greater contractual flexibility than many non-U.S. suppliers. This new stream of supply is crucial for the region's energy transition, enabling countries to switch from higher-emitting fuels to natural gas, thereby reducing air pollution and making tangible progress on climate targets. As stated by the Asia Natural Gas & Energy Association (ANGEA), a reliable supply of U.S. LNG is considered "critical" to meeting future energy demand and supporting decarbonization efforts across the Asia-Pacific.[32]

#3 The Rockies Basins Enable Supply Diversification

Increasing Offtaker Optionality

The Rockies basins can serve as a key additional resource to enable greater supply diversification and increase supply optionality for offtakers. Integrating additional Rockies gas supply sources would significantly strengthen the energy resilience of large domestic markets, particularly against disruptions, such as those caused by severe weather events like Winter Storm Uri, which have caused substantial infrastructure and economic damage for both electric and gas customers.

Gas supplied from the Permian Basin continues to be considered for additional supply to the Desert Southwest region. The basin currently supports a robust delivery capacity of 25 Bcf/d, with an additional 10 Bcf/d in projected demand from new and upcoming pipeline projects. Pipeline operators have also announced projects totaling another 7 Bcf/d in capacity, aimed at transporting Permian gas to demand centers in Mexico and along the Texas Gulf Coast.[33] The Permian Basin's total demand—factoring in current inventory, upcoming projects, and planned expansions—will reach a remarkable 42 Bcf/d, placing a tremendous amount of domestic supply risk upon a single resource and its infrastructure. Furthermore, the Permian Basin supplies associated gas, making production susceptible to the volatility in oil prices. Broadening regional supply to include gas sourced from the Rocky Mountain Basins is a key step in curtailing this risk by introducing greater diversity of supply into growing markets.

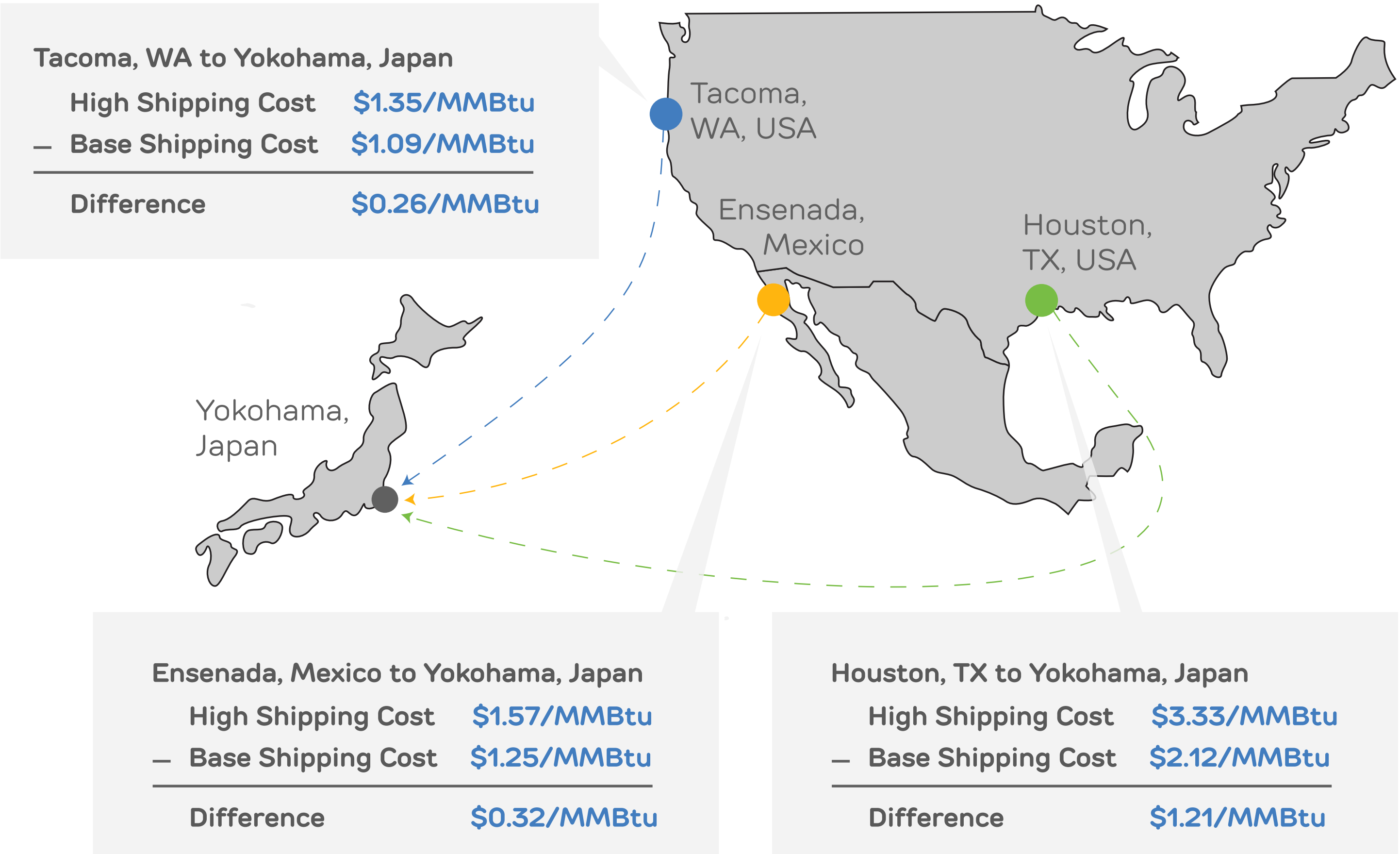
The Pacific Northwest also suffers from a lack of gas supply diversity, with approximately two-thirds of the region's gas consumption being supplied from Canada.[34] Additionally, pipeline transportation capacity is consistently high, with the Northwest Gas Association reporting that "average utilization of the region's interstate pipeline system exceeded 95% over the last five years."[35] This has increased the risks associated with demand exceeding supply and transportation capacity, particularly during the winter and extreme weather events.

On the international stage, the U.S. remains the global leader in LNG exports;[36] however, current export capacity is heavily centralized and predominantly located in the Gulf Coast region. Exports from the Gulf Coast have recently had to navigate challenges and delays associated with congestion in the Panama Canal, forcing more shipments east to reach Asian Pacific markets. For example, in late 2024 and early 2025, LNG carriers without reservations faced wait times of over 22 days, compared to the usual 1–2 days, due to drought-induced slot reductions from 32 to 18 ships per day.[37] Comparatively, shipments of LNG from the U.S. West Coast can cut shipping times in half, offer greater reliability by not being vulnerable to delays at the Panama Canal, save costs, and reduce total emissions associated with the transport of LNG.

Others have recognized this problem and have begun looking to develop LNG export facilities along the West Coast of North America as an alternate pathway. Today, the only operational West Coast facilities are located in Canada and Mexico. In June, LNG Canada became the first large-scale operational Canadian LNG export facility, sending its first LNG cargo to Japan.[38] In Mexico, ECA Phase 1, which will export approximately 0.5 Bcf/d when it achieves commercial operations in Spring 2026, is about 94% complete and is set to begin commissioning.[39] In the U.S., there is one domestic project under development, located in Alaska, that aims to export 3.5 BCF/d.[40]

Figure 10 provides a high-level comparison of shipping estimates between Gulf routes and the proposed alternatives examined in this study. While the average Panama Canal crossing fee for a 174,000 m³ LNG carrier is approximately $650,000 USD, this cost can escalate significantly, reaching between $2.5 million and $4 million during periods of high congestion. While typical unplanned waiting times range from 2 to 4 days, congestion can extend delays to 8–18 days. These conditions introduce not only elevated shipping costs but also potential disruptions to gas supply reliability at the destination. Comparatively, LNG shipped from the West Coast provides a $1-$2/MMBtu cost advantage, representing a significant savings over current Gulf routing options.

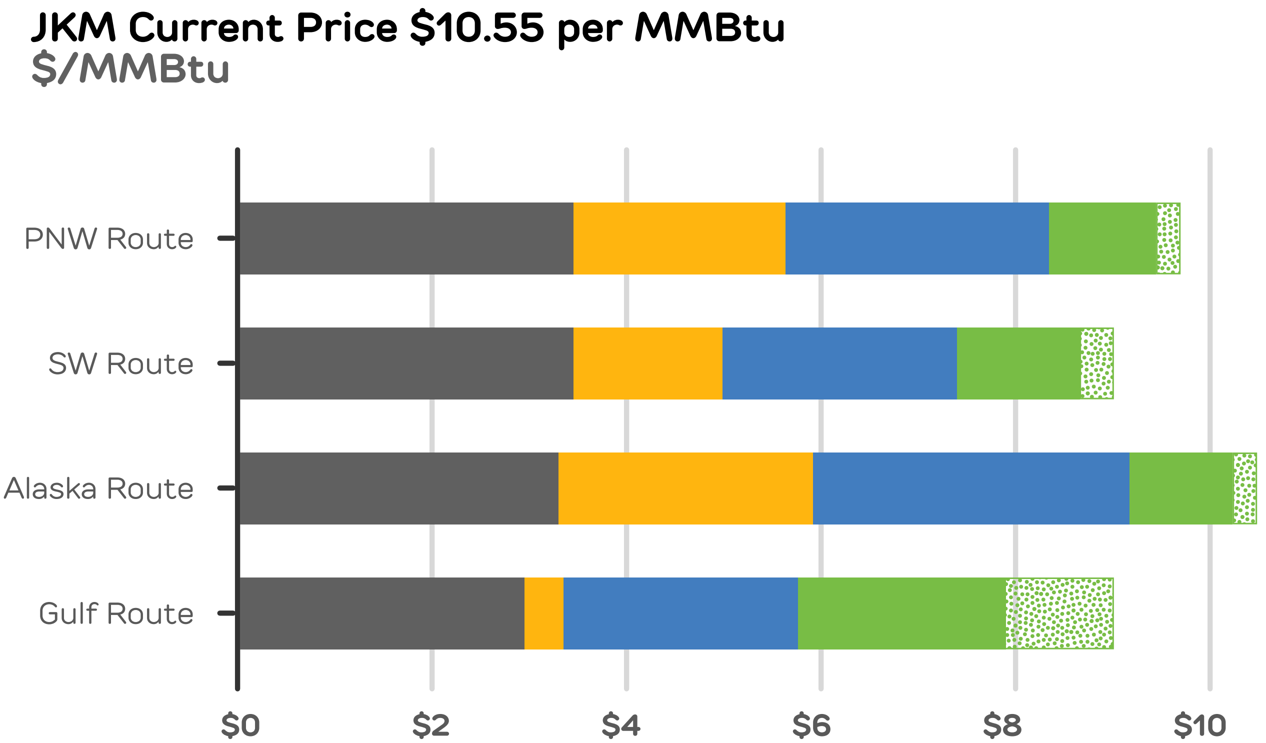
Figure 10: Comparison of Shipping Cost Estimates[41]



Despite the ongoing development of new LNG export facilities along the North American West Coast, offtaker optionality remains limited. Low market rivalry between LNG exporters exists for international buyers looking to purchase LNG from the West Coast. Abundant, affordable, and low-carbon supply from the Rockies basins can introduce new competition to the market, taking advantage of existing infrastructure and rights-of-way to easily transport gas to the coast for export to Asian Pacific markets.

Figure 11 illustrates the cumulative midpoint price of delivering natural gas from U.S. production basins to Asia, based on key cost components. Historically, Rockies gas has been price disadvantaged when compared to the initial costs of gas shipped from the Gulf Coast, which typically average $7.8/MMBtu compared to estimates of $8.6 to $9.4/MMBtu for Rockies gas shipped from the Pacific Coast; however, the Gulf route has recently become subject to greater volatility and risk in shipping costs, leading to a wide range in final costs. These factors enhance the competitiveness of the West Coast pathway, making it a more viable alternative under current market conditions. It is worth noting that preliminary estimates suggest the full-cycle LNG cost from Alaska to Asia could also range between $10.20 and $13.70 per MMBtu.[42]

Figure 11: Cumulative Price Comparison[i]



ROUTE	PRICE AT BASIN/HUB	PIPELINE COST	LNG TERMINAL COST	BASE SHIPPING COST	HIGH SHIPPING COST
PNW	$3.50	$2.15	$2.70	$1.10	$0.25
SW	$3.50	$1.50	$2.40	$1.25	$0.35
Alaska	$3.25	$2.60	$3.25	$1.05	$0.25
Gulf	$2.90	$0.40	$2.40	$2.10	$1.20

i For this study, we assume $3.25/MMBtu as Alaska's benchmark production cost. Prudhoe Bay production costs range $2.50–$4.00/MMBtu; Cook Inlet historically $3.3–$15.5/MMBtu. Current Alaska industrial gas averages $6.12/MMBtu vs. Texas $3.39/MMBtu (ratio 1.81). Alaska pathway CAPEX is ≥$40B for 3.3 Bcf/d—about 20% higher than PNW ($20B for 2 Bcf/d).

#4 The Rockies Basins as a Low-Carbon Alternative

Low Methane Intensity Resource Can Reduce Environmental Impact

The producers in the Rocky Mountain region are committed to reducing the environmental impact of their gas production. Flaring, a contributor to nearly 20% of emissions during gas production and refining, has been significantly reduced in the region.[43] In 2020, Colorado became the first state to ban routine flaring,[44] leading to a 25% decrease in gas flared from 2021 to 2023 and one of the lowest flaring rates amongst states.[45] In New Mexico, flaring is only permitted during emergencies and operators are required to achieve a 98% gas capture rate by 2026.[46] In the portion of the Permian Basin in New Mexico, these regulations have resulted in half as many major leaks per unit of production compared to Texas, a state that does not have strict flaring limitations.[47]

These regulations have encouraged producers to limit flaring practices and install improved methane leakage systems to lower emissions. Two of the largest producers in Wyoming—Jonah Energy and PureWest—have significantly lower GHG intensities than their competitors, ranking 38th and 71st for greenhouse gas intensity on a per-unit production basis.[48] In addition, they are continuing to make strides to achieve lower carbon intensities by improving monitoring and leakage practices, created certified gas programs, and joining reporting standards such as the UN's Oil and Gas Methane Partnership (OGMP) 2.0. Through these commitments, Jonah Energy has managed to reduce methane emissions per unit of natural gas by 68% over the past three years,[49] while PureWest has achieved a methane intensity rate of 0.05%.[50] Along with strong regulations, these actions highlight how Rockies producers are setting a precedent for low emission natural gas production and are reinforcing the region's potential in a low carbon environment.

CASE STUDY

Jonah Energy's Path to Lowering Methane Emissions[51]

Jonah Energy has taken significant steps to reduce its carbon emissions through its certified gas program, the Responsibly Produced Gas (RPG) initiative. Over the past decade, the company has implemented advanced technologies to monitor and reduce methane emissions, achieving a 68% reduction in methane emissions per unit of natural gas produced in just three years. This includes deploying LongPath laser-based detection systems, drones, and optical gas imaging cameras to identify and repair methane leaks more efficiently. Additionally, the company partnered with Context Labs to adopt a Decarbonization-as-a-Service (DaaS) platform, enabling real-time, measurement-based emissions data and verification, further enhancing transparency and accountability in its operations. These efforts have earned Jonah Energy the Gold Standard rating from the United Nations' Oil and Gas Methane Partnership (OGMP) 2.0, marking it as a leader in low-emissions natural gas production.

International Interest in Low-Carbon Solutions

To global offtakers, such as Asian LNG buyers, a low-carbon product is essential to achieving decarbonization objectives, as indicated by JERA and Korean Gas Corporation's "CLEAN" initiative to encourage LNG producers to reduce methane emissions across the value chain.[52] Notably, natural gas, as a low carbon yet dispatchable fuel, is an attractive option for these international buyers relative to other fuels. A natural gas power plant emits less than half the amount of carbon dioxide per kilowatt relative to a coal power plant, while remaining readily dispatchable to provide load during peak events.[53] Moreover, Rockies gas has a fundamental advantage in attracting these markets because of the targeted actions to lower GHG emissions in the region. As buyers increasingly prioritize environmental impact, Rockies gas can be positioned as the cleaner alternative.

LNG produced from Rockies gas presents the strategic advantage of direct shipment from the West Coast. Deliveries to Asian markets via this route circumvent the Panama Canal and benefit from reduced transportation distances, resulting in significantly lower greenhouse gas emissions and yielding a product with a smaller carbon footprint compared to other domestic LNG export options.

Producers and regulators in the Rockies are setting a precedent for low-carbon gas production. These developments highlight the Rockies region's role in producing lower-emission natural gas that supports both domestic energy reliability and international decarbonization efforts.

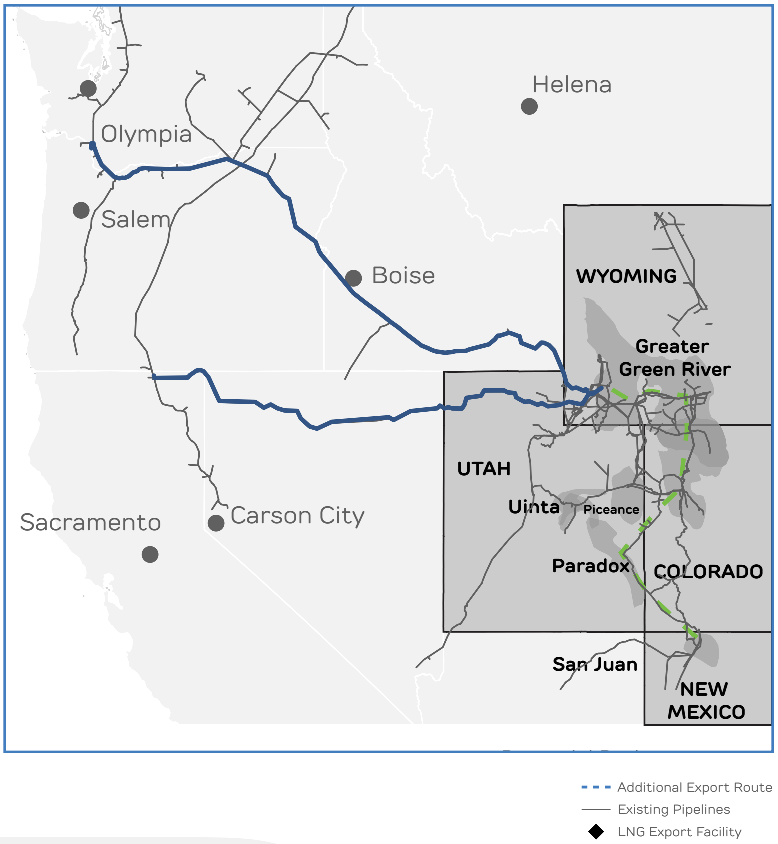
Low-Carbon Gas for Energy Resilience

Natural gas is needed now more than ever to help address immediate load growth and ensure energy resilience and resource adequacy, especially as domestic power generation, driven by clean electricity targets and renewable portfolio standards, shifts towards lower-carbon alternatives. The ability of natural gas to provide firm generation is critical in providing reliability as renewable generation increases. Even under scenarios with high renewable penetration, studies from the Pacific Northwest confirm that natural gas remains essential to maintaining reliability when variable generation falls short.[54] During low renewable generation or high demand periods, such as extreme weather events, natural gas proves to be the most cost-effective and reliable energy source.[55] These assessments highlight the role of natural gas as an integral part of a low-carbon energy strategy, especially to complement renewable buildout to ensure firm generation and grid stability.

IN FOCUS:
The Pacific Northwest Opportunity

The Northwest Pathway takes advantage of increasing energy demand from data centers, industrial onshoring, and electrification in the Pacific Northwest, as well as along the energy corridor to the Pacific Northwest, to unlock a market for Rockies gas.

In addition to the growing demand, the region is increasingly challenged with energy supply constraints, including the ability to source new gas supplies from existing fully subscribed infrastructure. Existing pipelines (such as the Northwest Pipeline) operate near full capacity, particularly during peak winter demand. A study conducted by the Northwest Gas Association found that "there is currently almost no margin to accommodate unexpected outages on the system," with the region's pipeline system having exceeded 95% average utilization over the past five years.[56]



Key Statistics

ESTIMATED DEMAND
Additional 35 BCF/yr by 2035 from incremental gas-fired generation.

DISTANCE TO MARKET
900–1100 mi

LOAD TO SERVE
New power generation, data centers, and manufacturing loads in the Pacific Northwest.

Potential to capture market share from Canadian suppliers, who may opt to prioritize their supply for Canadian opportunities over the U.S. market.

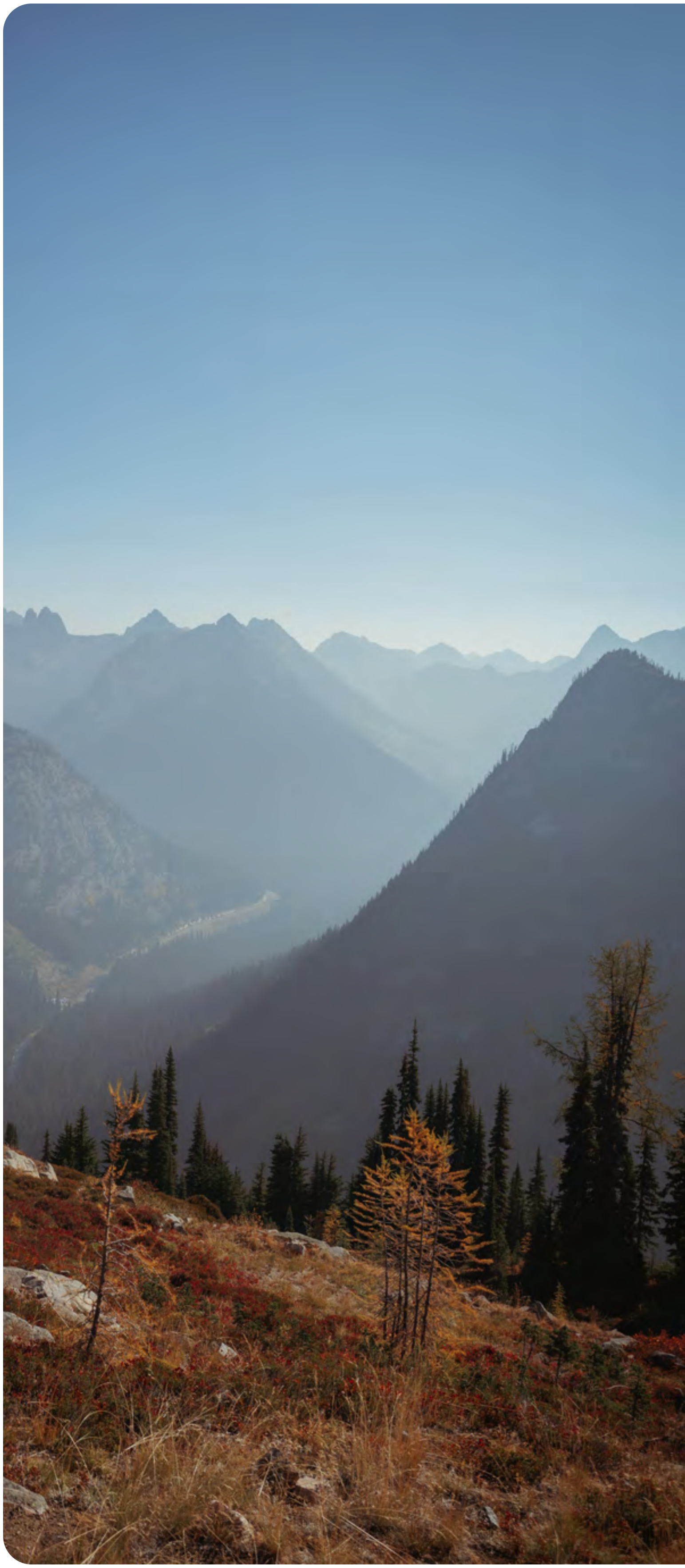
Routing Options

The vision for serving the Pacific Northwest market starts from the Southwestern Wyoming basin, or the Northwest-most point of the Rockies gas resource. This basin offers 108 TCF of technically recoverable reserves (F50), adequate to support the contemplated demand in the Pacific Northwest. As demand grows, it may be necessary to develop additional intra-regional connectivity through local pipeline development throughout the Rockies basins, to ensure adequacy of supply.

There are multiple options to deliver Rockies gas to the growing Pacific Northwest market, each of which limit greenfield development by leveraging existing rights-of-way and underutilized infrastructure. The following are the pathways contemplated to serve the Pacific Northwest market:

- Developing a new pipeline following the existing right-of-way of the Northwest Pipeline, passing through Idaho towards the Oregon-Washington border. This option would mitigate the need for new energy corridors and support growing demand in Washington and Oregon, as well as surging gas demand in Idaho (Idaho Power, the state's largest utility, forecasts in its 2025 Integrated Resource Plan adding 550MW of new gas resources plus 611MW of converted coal-to-gas demand over the coming two decades).[57]
- Taking advantage of available capacity on the existing Ruby pipeline (average utilization rate of 16%)[58] that travels directly West towards Malin, Oregon. This option contemplates access to potential large load project development across northern Utah and Nevada directly connected to the pipeline, while still serving growing demand in Washington and Oregon.

Both options support growing demand for gas in the greater Northwest region, as each route creates opportunities to provide energy supply to key centers of demand along the energy corridor.



Why the Pacific Northwest?

By 2045, regional power demand could double, growing from an average of 22,000 MW annually to upwards of 44,000 MW, according to the Northwest Power and Conservation Council.[59] For natural gas specifically, forecasts indicate that an approximate 35 BCF/yr of incremental gas-fired power demand by 2035 is expected for the Northwest of the U.S.[60] Much of this forecasted demand can be attributed to electrification trends in the residential, commercial, and transportation sectors, along with greater buildout of data centers and other industrial processes.[61]

As noted, this growth is already being highlighted among key utilities in the region, including Idaho Power, which now anticipates an additional gigawatt of thermal power from gas needed in order meet the heightened load forecasts in the region.[62] Resource availability is also impacting gas demand projections. Idaho relied on hydropower for nearly 80% of its electricity generation in 2009, but now due to drought and other changes across the energy system, hydro provides less than half of the total power generated, placing further pressure on the need for readily available, affordable, and low-carbon gas supplied from the Rockies basins.[63]

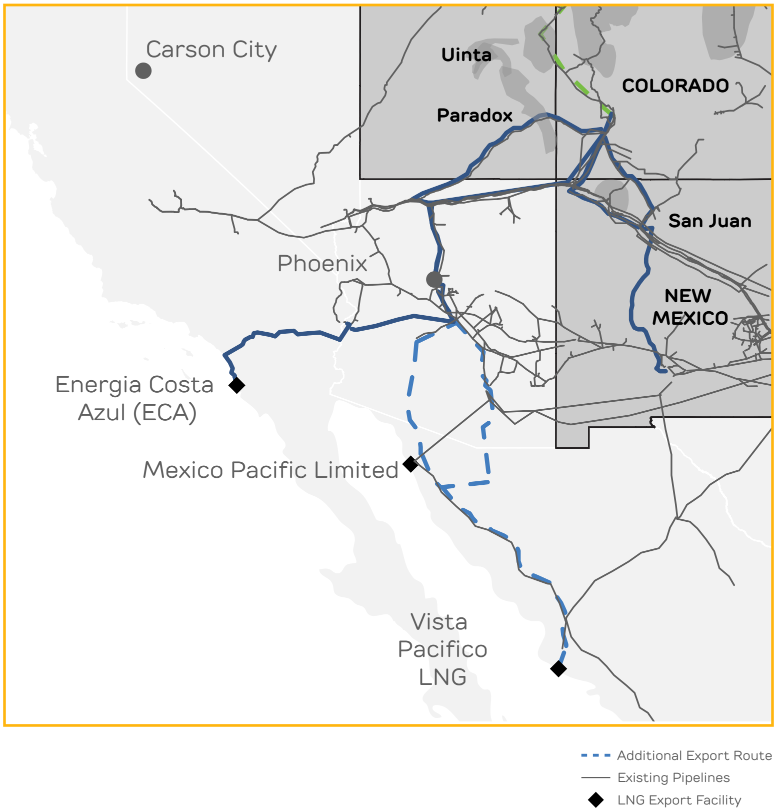
In addition to the forecasted ramp-up in demand, the region is already struggling with supply availability and pipeline constraints. Approximately two-thirds of gas consumed in the Northwest region today is supplied from Canada.[64] With Western Canada experiencing similar growth in natural gas demand, including large LNG projects such as LNG Canada commencing operations[65] and Cedar LNG among others expected soon,[66] Canadian gas supplies are anticipated to first be targeted to Canadian opportunities and may not make it to the Northwest U.S. market. Regional pipeline capacity remains constrained and has been exceeding 95% utilization for several years.[67] All together, these market forces create a strategic opening for new pipeline development from the Rockies to the Pacific Northwest, delivering economic benefits across the Western U.S., improving energy reliability to keep the lights on for all, and shoring up domestic energy security.

Furthermore, the commercial development opportunity available to Tribal Nations in the region presents a significant economic benefit to the communities that this development could serve. Key partnerships can be made amongst Tribal Nations situated near the Rocky Mountain Basins and others along a Pacific Northwest development pathway—including the Ute Indian Tribe, Northern Arapahoe Tribe, and Eastern Shoshone Tribe—that could benefit both sides in transporting and selling Rockies gas to key centers of demand throughout the region.

IN FOCUS:
The Southwest Opportunity

The Southwest Pathway captures increasing demand from a growing gas-fired generation market in the Phoenix region while also opening the door for international LNG exports from the Mexican Coast.

The Southwest Power Pool has been identified as a leader in the gas-generation market due to its attractive future electricity prices, low startup costs, and abundant resources.[68] Serving incremental market growth in this region can enable infrastructure build towards a Mexican LNG export opportunity, connecting Rockies gas to key international markets through existing LNG terminals on Mexico's Pacific Coast while avoiding Panama Canal congestion.



Key Statistics

ESTIMATED DEMAND — Additional 205 BCF/yr by 2035 from incremental gas-fired generation,[69] as well as 2 BCF/day for a LNG facility with a 12 MTPA export capacity.

DISTANCE TO MARKET — 600–900 mi

LOAD TO SERVE — New power generation, data centers, and industrial loads in Arizona and New Mexico.

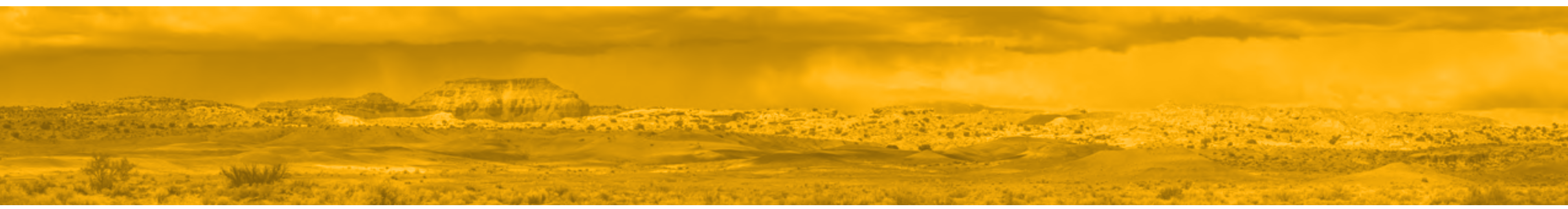
Asian LNG buyers through planned LNG facilities on the Mexican coast.

Routing Options

There are multiple options to deliver Rockies gas to the growing Southwest market, all of which create access to LNG facilities on Mexico's Pacific Coast while utilizing existing corridors:

1. Leveraging the Southern Trails pipeline right-of-way for a new pipeline to Phoenix.
2. Building a new pipeline along the El Paso Natural Gas (EPNG) right-of-way towards Phoenix.
3. Paralleling the existing ROWs of Energy Transfer's Transwestern Pipeline and Public Service of New Mexico to send gas south towards Albuquerque and continue further south to El Paso, TX via existing or proposed pipelines (Energy Transfer's recently announced Desert Southwest Pipeline or EPNG's Southern Leg Expansion and the proposed Copper State pipeline) to get to the Phoenix market.

These pathways vary in commercial and Tribal partnership opportunities, all while accessing markets in New Mexico and Arizona. From Phoenix, a new build pipeline following an existing ROW would be required to transport gas towards ECA. There is additional optionality to send gas towards two LNG export facilities in Mexico, Mexico Pacific Limited (MPL) and Vista Pacifico, which are at various stages of development. These export facilities would be particularly advantageous for routes that go south towards El Paso, while ECA can best support the westward routes.



Why the Southwest?

Forecasts estimate an approximate 205 BCF/yr of incremental gas-fired generation by 2032 for the Southwest Corridor, largely driven by data centers and new industrial loads.[70] For example, as of August 2025 Arizona Public Service (APS) had 10 GW of pending interconnection requests from data centers, notably larger than its peak demand record of 8.5 GW.[71] Increasing demand in the region paired with constrained infrastructure, which has already demonstrated an inability to reliably meet current load, creates the need for new energy supply. The Southwestern pathway envisions new-build pipeline infrastructure to support this demand and take advantage of potential collaboration with tribal nations, such as the Navajo Nation, the Jicarilla Apache Nation, and the Southern Ute Indian Tribe to take more direct routes to key markets or for development of upstream resources while creating economic opportunities for these Tribal nations.

Heading south from Arizona and New Mexico, there is an opportunity to serve the Mexican West Coast for power generation and LNG export, with Sempra's ECA Phase 1 as the most immediate option. ECA Phase 1 is fully contracted for 3.25 MTPA (0.4 BCF/d) and is already under construction targeting commercial operations in the Spring 2026, making it the fastest route to West Coast LNG export. ECA Phase 2 is expected to add up to 12 MTPA of additional capacity (1.6 BCF/d) and target commercial operations in the next 5-7 years.[72] In addition to ECA, several other LNG facilities in Mexico, such as Mexico Pacific Limited (MPL) and Vista Pacífico, are at various stages of development. MPL and Vista Pacífico would primarily drive a Southern Route out of the San Juan Basin, while ECA is better served from the more western corridor. This presents a strategic opportunity for Rockies gas to access an LNG facility already under construction, enabling fast and direct connection to key international markets where LNG demand is projected to double by 2050.

Indicative Roadmap for Development

Summary of Findings

Growing demand for natural gas in the U.S. and internationally will require opening up access to readily available supply that offers a cost-competitive value proposition. Rockies gas has the unique opportunity to take advantage of this competitive global market while supporting key domestic development and regional energy supply needs. To the Pacific Northwest, Rockies gas can address increased demand from the development of new data centers and manufacturing loads paired with the retirement of baseload power plants. To the Southwest, Rockies gas can address incremental demand for power generation, especially in the Phoenix area, while bolstering development in Tribal Nations.

Actionable Next Steps to Unlock Rockies Gas

Unlocking the substantial Rockies gas resource requires alignment across the ecosystem, including the states and producers in the Rocky Mountains, the federal government, commercial developers, Tribal Nations, and potential offtakers. The actions must be coordinated to ensure that resource development is streamlined. Critical actions to support the development of the Rockies gas resources include:

Engage Directly with Major Offtakers, Domestically & in the Asian-Pacific

Long-term offtake commitments for Rockies gas are the first crucial step in building the infrastructure to unlock the Rockies gas resource. To build the long-term market demand signals necessary for these projects, state trade representatives and Tribal leaders can drive the development of the Rockies gas resource by securing commitments with Asian nations and other major sources of demand for gas offtake. The objective is to directly connect Rockies producers with potential buyers—including utilities, industrial end-users, and national energy ministries—to develop tailored supply agreements. This includes exploring opportunities for co-investment in U.S. infrastructure and structuring deals that can help Asian nations address the U.S. trade imbalance.

Pursue Low-Cost International Financing

To ensure projects are cost-competitive on a global scale, stakeholders should coordinate their efforts to secure financing from institutions that offer low-cost, long-term debt. This involves proactively engaging with the key public and private financial institutions and export credit agencies of partner nations, such as Japan's JBIC and Korea's KEXIM. Securing this type of financing for the full value chain is critical to lowering the final delivered cost of LNG.

Streamline Permitting Process Across Local, State, and Federal Governments

To reduce the significant hurdles to market access, relevant federal, state, and tribal regulatory bodies need to better coordinate their review processes. Examples of this type of streamlining could include:

- Establishing a more unified permitting schedule,
- Working to eliminate duplicative environmental reviews, and
- Creating a more centralized point of contact for project developers.

By better coordinating the various federal and state requirements, such as the National Environmental Policy Act (NEPA) process and FERC applications, project timelines and regulatory uncertainty can be significantly reduced.

Secure Tribal and Local Support Through Community Investment

To ensure local backing and an equitable distribution of benefits, a standardized framework for community and Tribal Nation cooperation must be developed for any new infrastructure projects. These agreements, negotiated at the outset of a project, ensure local communities and Tribal Nations directly benefit from development and play a leading role in all discussions to support local economies and social priorities. Tangible provisions should include commitments to local hiring and apprenticeships, direct funding for community infrastructure improvements, and long-term revenue-sharing mechanisms with counties and tribal governments along the project route.

Explore Government Co-Investment to De-Risk Projects

To improve project economics and attract private capital, governments should explore innovative financial models, including direct co-investment in foundational infrastructure. This could involve creating a multi-state, quasi-public entity capitalized by producing states that could act as an anchor investor or provide loan guarantees. By taking a strategic equity stake or de-risking the debt, such an initiative would lower the overall cost of capital and help build projects at the required scale.

This could include evaluating innovative Public-Private Partnership (PPP) models to attract specialized expertise and private capital. A model such as the Design-Build-Finance-Operate-Maintain (DBFOM) framework could be particularly effective for pipeline infrastructure. Under this model, a private consortium would finance and operate the asset under a long-term service contract, with ownership eventually transferring to a public or tribal entity, accelerating project delivery and optimizing life-cycle costs.

Support the Regions Independent Producers

To overcome the credit concerns associated with the region's independent producers, public economic development agencies could develop programs that offer financial support. Many international offtakers require their suppliers to have investment-grade credit ratings, which can be a barrier for smaller producers. Public loan guarantees or a revolving credit facility could backstop long-term supply agreements, providing the financial assurance that international buyers and infrastructure developers require and enabling the region's diverse producer ecosystem to participate in global markets.

Formalize Interstate Energy Partnerships

To anchor new infrastructure with domestic demand, producing states should initiate formal agreements with key consuming states on the West Coast. These Interstate Energy Reliability Compacts would codify the role of Rockies gas in ensuring West Coast grid stability, particularly as a backup for intermittent renewable energy sources. By creating a mutually beneficial framework where West Coast states support the infrastructure development needed for their own energy security, these compacts would provide the foundational domestic offtake that de-risks the larger-scale pipeline buildout required for an export component.

Continue to Lead on Methane Emissions Reductions and Certified Gas

To create a durable competitive advantage and meet the demands of discerning buyers, stakeholders should build on the region's leadership in low emissions-intensity energy production. Producers should continue to implement best practices to further reduce upstream methane emissions, such as deploying comprehensive leak detection and repair (LDAR) programs and investing in continuous monitoring technology. This operational excellence should be captured and validated by spearheading the development of a standardized and transparent framework for certified gas or responsibly sourced gas. This involves collaborating with producers, Tribal Nations, and independent third-party certifiers to create a credible, measurement-based standard for the region based on robust quantification, monitoring, reporting, and verification (QMRV) protocols. State and Tribal leaders should then engage directly with international offtakers and global trading houses to create a market that recognizes and values this certification.

Appendix

Introduction

WSTN engaged Guidehouse to conduct a commercial feasibility analysis evaluating representative pathways for transporting Rocky Mountain natural gas supply to both domestic and Asia Pacific LNG markets. These pathways were selected to reflect distinct, yet commercially feasible, archetypes for connecting Rockies supply with demand centers. Guidehouse collaborated closely with WSTN members—including policymakers, midstream operators, Tribal Nations, and independent producers—to assess infrastructure feasibility, basin production economics, and other critical technical and commercial considerations. The analysis aims to provide an early-stage assessment of the commercial feasibility of infrastructure initiatives that unlock economic development opportunities across the Rockies.

Guidehouse applied a consistent netback analysis methodology to evaluate each conceptualized pathway, modeling the full value chain from the landed market in Asia to the supply basin. The objective of this analysis was to provide an early-stage assessment for commercial feasibility.

The analysis included:

1. **Basin Production Economics:** Defining the production capacity and breakeven economics of the source basins.
2. **Midstream Infrastructure:** Assessing the new required pipeline capacity and infrastructure to transport the gas from the Rockies basins to the LNG export terminal, including estimating transportation tariffs.
3. **LNG Export Terminal Costs:** Evaluating estimated liquefaction CAPEX and operating costs of a new build LNG plant.
4. **Shipping Costs:** Cost to ship an LNG cargo from the export terminal to Asia.
5. **Commercial Summary:** Synthesizing these components into a cost stack-up to estimate the final delivered price of LNG in Asia and assessing the commercial viability of the pathway based on netback prices.

The specific inputs for each pathway differ reflecting their unique geographical, logistical, and commercial characteristics when applying the methodology.

Approach to Pathway Definition

The two representative pathways were determined via a collaborative and iterative process that ensured that all potential pathways for Rockies gas were considered. Existing and planned pipeline infrastructure and ROW, as well as new routes, were identified based on potential demand pockets across the continental United States. These pathways were evaluated against each other considering market size, policy and regulatory environment, and technoeconomic potential. The two pathways with the strongest potential were towards the Southwest, from the San Juan Basin through Phoenix and ultimately towards Mexico for LNG export, and the Northwest, from Opal Hub towards the Pacific Northwest.

Netback Analysis Approach

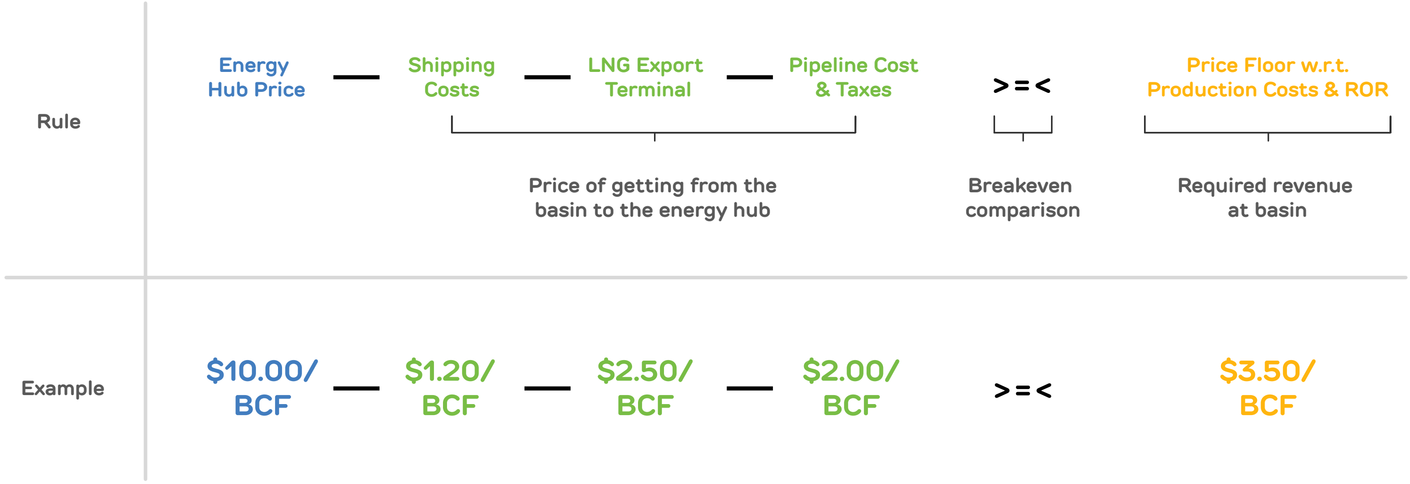
The netback analysis begins with the market price at the energy hub in Asia, which represents the revenue potential for LNG delivered to that destination. From this price, a series of cost components are sequentially subtracted to determine the value that can be realized at the production basin (the Rocky Mountains). These components include:

- **Shipping Costs:** The cost of transporting LNG from the export terminal to the Asian hub, incorporating charter rates, fuel, port fees, insurance, and any additional charges such as Panama Canal fees, as applicable.
- **LNG Export Terminal Costs:** Expenses associated with liquefying, storing, and loading LNG at the export facility.
- **Pipeline Costs:** The cost of moving natural gas from the production basin to the LNG export terminal, including pipeline tariffs and applicable taxes.
- **Breakeven Price at the Basin:** The minimum price needed at the production basin to cover production costs and achieve a target rate of return (ROR).

The process results in a breakeven comparison, where the netback price at the basin is compared to the production costs. If the netback price meets or exceeds the required revenue at the basin, the supply chain is economically viable.

This structured approach ensures that all major cost elements are accounted for, enabling robust breakeven and sensitivity analyses. By adjusting each component, such as shipping costs or LNG terminal fees, we can quantify how market or operational changes impact the overall project economics and competitiveness of LNG exports sourced from the Rockies to Asia.

Figure 12: Netback Analysis Structure



Upstream Calculations

This section outlines the methodology for estimating the breakeven price of natural gas from wellhead to processing plant, expressed in U.S. dollars per MMBtu—the minimum price at which discounted revenues equal discounted costs (NPV = 0). Guidehouse validated basin-level estimates through engagement with Rockies producers and external sources.

The breakeven analysis aggregates CAPEX, OPEX, post-processing, mid-life reinvestments, and fiscal obligations into a discounted cash flow model. CAPEX is based on well depth, lateral length, and EUR, while reinvestments (e.g., re-fracturing, workovers) are modeled as a percentage of initial CAPEX. OPEX and processing costs scale with EUR and annual production. All cost streams are discounted at the required rate of return, and taxes and royalties applied to gross revenues raise the price threshold. Using hyperbolic decline profiles and basin-level production targets, the model solves for the breakeven gas price that ensures capital recovery and investor returns.

The flowchart below summarizes the steps:

Figure 13: Flow Diagram for Calculating Breakeven Price

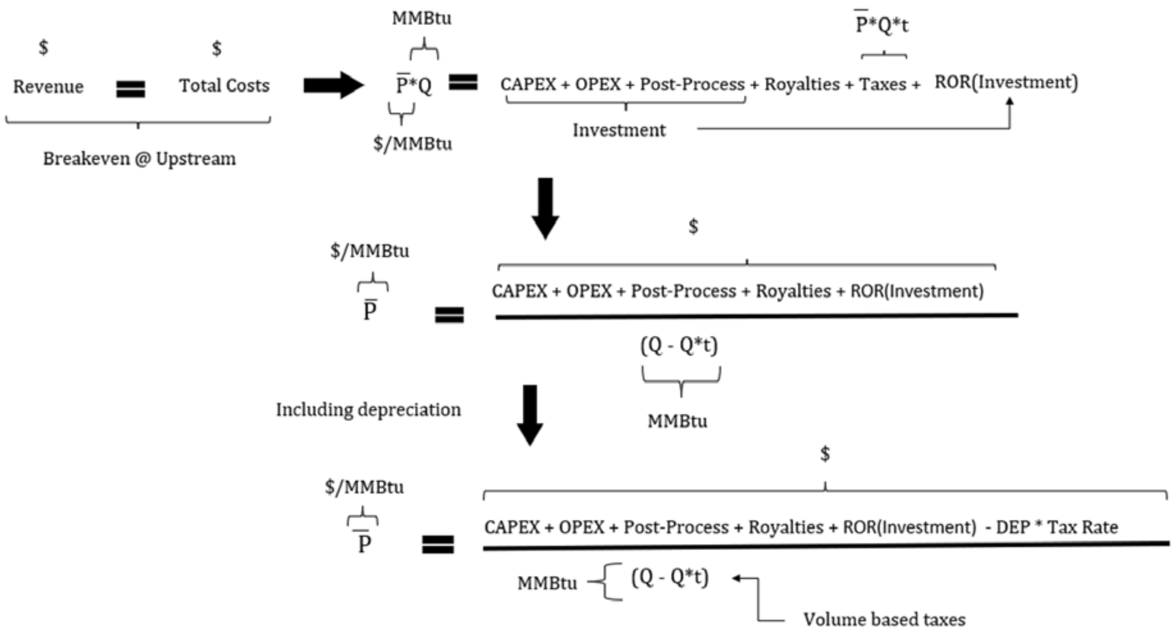


Table 2: Production Cost Modeling Key Inputs

PRODUCTION PARAMETERS	FINANCIAL & GENERAL ASSUMPTIONS
Daily production requirement	Linear deprecation
Estimated ultimate recovery (EUR)	Discount rate/ROR (12%)
Initial decline rate	Tax rate (8%)[73]
Economic life of project	Royalty rate (12.5%~17%)[74]
Well depth	Project lifetime (35 years)
Lateral length	Heat conversation factor (1,038 MMBtu/MMcf)
Well lifecycle	Production ramp up period (5 years)[75]

Per-Well Production Profile

By calibrating the parameters of the production function and setting the Estimated Ultimate Recovery (EUR) for each well type, we can estimate the initial production rate (q_0) as follows, using the definite integral of the Arps decline model:[76]

$$\mathrm{EUR} = \int_0^T \left[\frac{q_0}{1+bDt^{1/b}}\right] dt$$

Solving the integral gives the formula for EUR under hyperbolic decline with finite well life T:

$$\mathrm{EUR} = [q_0 / (1 - b)] \times [1/D \times (1 - \frac{q_0}{1+bDt^{(b-1/b)}})]$$

Solving for q_0:

$$q_0 = \mathrm{EUR} \times (1 - b) / [\ (1/D) \times (1 - \frac{q_0}{1+bDt^{(b-1/b)}})\ ]$$

- EUR: Estimated Ultimate Recovery (same time units as $q_0 \times T$)
- D: nominal decline rate per year
- b: hyperbolic decline exponent
- T: well life in years (can be converted to days by simply multiplying by 365)

Typically, production peaks in the first year and then declines exponentially. Using the average lifespan of a typical well in each basin, along with its declining production profile, we derive the annual production output over the well's lifetime.

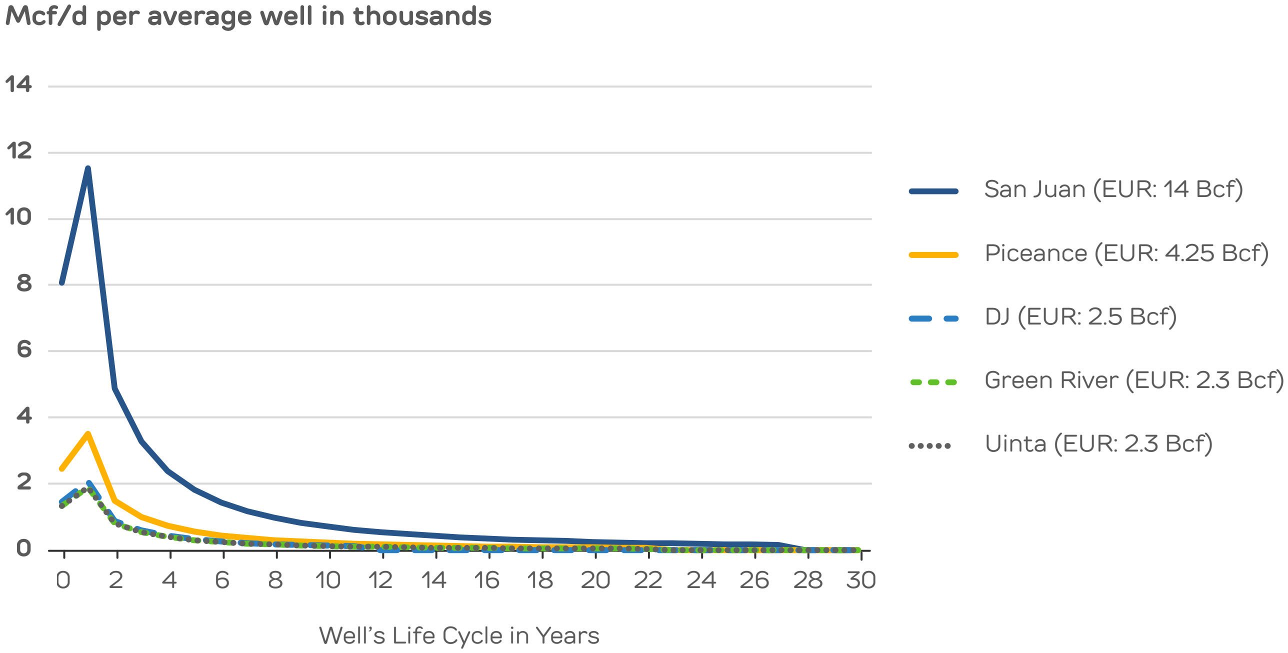
$$q_t = \frac{q_0}{1 + bDt^{1/b}}$$

Where:

- q_0: Initial production rate (MMcf/day)
- D: Nominal decline rate
- b: Hyperbolic decline factor
- t: Time (in months or years)

The next step involves determining the target production for each year. Based on this target, we calculate the number of wells that need to be drilled annually. This calculation must account for wells drilled in previous years that are still producing, depending on their lifespan. Consequently, we can estimate the number of new wells required each year to meet the production level.

Figure 14: Production Profile Simulation for Each Basin Based on Well Type Life Cycle[i]



Capital Expenditures (CAPEX)

Linear Cost Function (CAPEX):

Total CAPEX = α1 × Depth + α2 × Lateral + α3 × EUR + Fixed Costs

The following simplified CAPEX categories represent a practical way to model gas well development costs in the Rocky Mountain basins. The percentages reflect typical industry averages and allow for scalable, linear modeling.

Table 3: CAPEX Cost Breakdown by Component

COMPONENT	INCLUDES	VALUE	BASIS
Drilling, completion, and facilities[77]	Rig day rate, casing, mud, bit, logging, perforation, hydraulic frac, plugs	\$150-\$580	Vertical depth (\$/ft)
Drilling, completion, and facilities	Rig day rate, casing, mud, bit, logging, perforation, hydraulic frac, plugs	\$650-\$1050	Horizontal length (\$/ft)
Infrastructure and site preparation[78]	Road, pad, and pipeline construction	5%-12.5%	Percentage of subtotal
Permitting, contingency, and overhead[79]	Legal, survey, engineering, contingency	5%	Percentage of subtotal

i Guidehouse initial estimate, using the Arps decline model where the hyperbolic parameter set to 0.57, and the initial decline rate for the first year set to be 70%. Using the initial production formulation (q_0), and having the average EUR for each basin, we calculated the initial production, and derive the production each year (q_t) until the end of well type life cycle.

Operating Expenditures (OPEX)

Linear Cost Function (OPEX-Post-Processing):

Total OPEX/Post-Processing = $\beta 1 \times$ EUR + $\beta 2 \times$ Annual Fixed Cost + $\beta 3 \times$ Annual Production

OPEX represents recurring annual costs during the production life of the well. These simplified categories allow for scalable modeling based on EUR, production rates, or fixed per-well assumptions.

Table 4: OPEX Cost Breakdown by Component

COMPONENT	BASIS	INCLUDES	VALUES
Field operations and maintenance[80]	Per $/MMBtu	Labor, inspections, equipment maintenance	$0.50-$1.10
Administration and overhead[81]	Fixed or percentage of total	Field general and administrative (G&A), insurance, and other overhead costs	10%-12.5%
Pre-processing[82]	Per $/MMBtu	Gas sweetening, dehydration, compression, other conditioning, and fuel use	$0.20-$1.00

Mid-life Investment (Semi-CAPEX) Costs

To simplify modeling of mid-life reinvestments, these costs can be estimated as a percentage of the initial CAPEX. For gas wells in the Rocky Mountain Basins, reinvestment costs typically range between 15% and 25% of initial CAPEX over the life of the well. This approach enables scalable and linear modeling in financial analysis.

We used the following formulation to scale reinvestment costs relative to initial CAPEX:

Semi_CAPEX = Reinvestment_Ratio × Initial_CAPEX

This value can be distributed across planned reinvestment years and levelized annually.

Table 5: Semi-CAPEX Cost Components

COMPONENT	NOTE	VALUES
Re-fracturing[83]	Enhances reservoir contact; boosts production	5%-10%
Workover operation	Tubing, pump repair, wellbore integrity	1%-5%
Artificial lift upgrade	Gas lift, ESP, or rod pump replacement	1%-5%

Total Production Cost Summary

The table below summarizes the results for the five primary basins studied, including low/high sensitivities for drilling costs.

Table 6: Key Comparison Metrics Across Basins

		SAN JUAN			DJ			GREEN RIVER[ii]			UINTA			PICEANCE		
Metric	**Unit**	**Low[i]**	**Base**	**High[i]**	**Low[i]**	**Base**	**High[i]**	**Low[i]**	**Base**	**High[i]**	**Low[i]**	**Base**	**High[i]**	**Low[i]**	**Base**	**High[i]**
Breakeven gas price	$/MMBtu	3.25	3.45	3.65	3.0	3.5	4.1	3.1	3.5	3.8	3.3	3.8	4.2	3.0	3.3	3.6
CAPEX per well	$ mm	15.1	18.9	22.7	7.0	8.7	10.5	5.1	6.3	7.6	6.5	8.1	9.7	7.9	9.9	11.9
Well type EUR	BCF		14			2.5			2.3			2.2			4.25	
Well depth	ft		7,000			7,250			14,675			7,000			8,000	
Well lateral	ft		12,000			9,000			-			4,000			10,000	

i Low and high costs are based on changing drilling costs by 20%, while holding well's characteristics constant (such as EUR, depth, and lateral).
ii Only for vertical wells, does not include re-investment during the well's life cycle.

Midstream & Logistics

This section outlines the methodology used to estimate CAPEX and OPEX associated with the development and construction of a new natural gas transportation pipeline. The model is designed to translate technical and economic inputs into a tolling fee to transport natural gas over the pipeline.

To determine the midstream tolling fee for transporting natural gas via pipeline and compressor stations, we begin by estimating the CAPEX and OPEX associated with the infrastructure. The pipeline spans approximately 800 miles, with a 48-inch diameter, and is designed to operate at a maximum allowable pressure of 1,050 psia. The base construction cost is estimated at $8.3 million per mile, which is then adjusted using a regional multiplier to reflect local labor, material, and regulatory conditions. This yields the adjusted pipeline cost, which forms the foundation of the CAPEX.

To maintain flow and pressure over the long distance, compressor stations are placed every 100 miles, resulting in 8 stations. Each station is designed to handle ~60,000 HP, with inlet and outlet pressures of 950 psia and 1100 psia, respectively. The total horsepower required is calculated based on flow rate, pressure differential, and pipeline characteristics. The base compression cost is derived from standard industry benchmarks per unit of horsepower and similarly adjusted using regional multipliers.

Annual OPEX is estimated at 3% of total CAPEX, covering labor and benefits, maintenance, utilities, administration, and insurance. These recurring costs are essential for reliable operation and are factored into the transportation fee. Additionally, the infrastructure is depreciated linearly over 30 years, which spreads the capital recovery evenly across the asset's life. This depreciation schedule is used to calculate the annualized capital recovery component of the toll.

The tolling fee is ultimately derived by summing the annualized CAPEX (via depreciation and discount rate) and OPEX, then dividing by the annual throughput (in this case, 2 BCF/d or ~730 BCF/year). This tolling fee will be added to the netback analysis that serves as a benchmark for evaluating project viability and competitiveness of moving Rockies gas to market.

Table 7: Pipeline CAPEX Components

COMPONENT	EXPLANATION
Pipeline diameter[84]	The width of the pipeline in inch, which affects the volume of material it can transport
Pipeline length	The total distance the pipeline covers in miles, impacting overall material and labor costs
Cost per mile[85]	The expense incurred for constructing one mile of the 48-inch pipeline, including materials and labor
Regional multiplier	A factor that adjusts costs based on regional variations in labor, materials, and regulations
Total HP required for compressor[86]	Represents the total horsepower needed to compress the gas to the desired pressure
Number of compressor stations	Determines how many stations are required based on pipeline length and pressure requirements

Table 8: OPEX Breakdown Components (as Percent of CAPEX)

COMPONENT	DESCRIPTION	VALUE
Labor and benefits	Covers salaries, wages, and employee benefits for operational staff; percentage of subtotal	35%
Maintenance and repairs	Includes routine upkeep and unexpected repairs of equipment and infrastructure	30%
Utilities	Costs for electricity, water, and other essential services required for operations	15%
Administrative	General administrative expenses such as office supplies, management, and support services	10%
Insurance	Premiums for insuring assets, operations, and liability coverage	10%

Below are the key parameters to develop the cost components of the pipeline along with the compressor stations, in calculating the tolling fee per $/MMBtu:

Table 9: Key Parameters for the Pipeline/Compressor Stations Calculations

PARAMETER	VALUE
Max allowable operating pressure[87]	1050 psia
Minimum inlet pressure	775 psia
Pipeline length	770~830 miles
Cost per mile for 48-inch pipeline[88]	$7~$8.8 million
Regional multiplier	0.74~0.94
Compressor inlet pressure (P1)[89]	950 psia
Compressor outlet pressure (P2)	1,100 psia
Horsepower per station	59,000 ~ 63,000 HP
Distance between compressor stations	100 miles
Operating expenses (OPEX)[90]	3% of CAPEX
Depreciation method	Linear over project life cycle
Project life cycle	30 years
Rate of return on asset	10%

Export Terminal Analysis

To derive the tolling fee for the LNG facility over the project lifetime, we begin by estimating the total CAPEX and OPEX based on the facility's components. The LNG facility was sized to receive 2 BCF/d of natural gas, which is converted into LNG measured in million tonnes per annum (MTPA). A facility processing 2 BCF/d of natural gas would produce roughly 14 MTPA of LNG. This conversion aligns input volumes with output capacity and is essential for calculating the tolling fee on a per MMBtu basis.

The tolling fee, expressed in $/MMBtu, is calculated by annualizing the CAPEX using straight-line depreciation over the project's lifetime, adding annual OPEX, and incorporating contingency costs. These total annual costs are then divided by the annual energy throughput, derived from the 2 BCF/d input, to yield a unit cost. Discount rate, tax rate, and tolling fee escalation are applied to model the fee over time and ensure financial viability.

This methodology ensures that the tolling fee reflects the full lifecycle cost of the LNG facility, adjusted for economic and operational parameters, and provides a transparent basis for LNG export facility cost for the netback analysis.

Table 10: LNG Facility CAPEX Components

COMPONENT	DESCRIPTION	VALUE	UNIT
Number of trains	The total number of liquefaction units in the LNG facility, each capable of processing a portion of the gas	2	Trains
Capacity per train	The maximum annual output of LNG per train	7	Million tonnes per annum (MTPA)
Plant performance	The percentage of time the plant is expected to operate at full capacity under normal conditions	99%	Percent steady-state availability
EPC costs[91,92]	Base cost of EPC $/TPA, there is a cost difference between the U.S. and Mexico	$760~$880	$/TPA
Project life cycle	Duration of the operation without major re-investment	25	Years
Rate of return	Owner's annual cost of investment	10	%
Escalation rate	Maintenance escalation rate	2.5	%

Table 11: OPEX Breakdown Components

COMPONENT	DESCRIPTION	VALUE	UNIT
Fuel[93]	Energy required to power compressors, turbines, and other equipment during LNG processing	$4	$/MMBtu
Maintenance	Annual routine and corrective upkeep of mechanical, electrical, and instrumentation systems	0.4	% of total CAPEX
Labor cost	Plant operators, control rooms, engineers and technicians, admin and security, safety and management	$40	Million
Other fixed costs	Additional recurring expenses not tied to production volume, including: insurance, consumables and catalysts	$21	Million

Shipping Fees and Sensitivities

LNG Shipping Cost Estimation Methodology

To estimate the shipping cost of LNG from the U.S. West Coast (e.g., Tacoma, WA or Ensenada, Baja California) to Japan, we begin by identifying the key cost components involved in maritime transport. These include the charter rate (fuel included), voyage distance, vessel speed, cargo energy content, port fees, insurance, and loading/unloading time. The base formula is a one-factor model where the charter day rate is the primary driver of cost volatility, expressed as:

$C(\$/MMBtu) = (R \times D) / E$

Where:

- R = Spot charter rate ($/day)
- D = Voyage days (distance / speed)
- E = Cargo energy content (MMBtu per cargo)

This formula provides a simplified way to assess shipping costs under varying market conditions, especially when charter rates fluctuate significantly.

To ensure our shipping cost estimates more accurately reflect observed market values, we have included a correction factor into our formulation, to account for discrepancies between calculated and real-world costs. This adjustment helped bridge gaps identified in our research, where calculated shipping costs were consistently lower than published benchmarks. In addition to this correction, we have considered other relevant fixed costs such as port fees (noting that Japan has waived certain entry fees for LNG and dual-fuel ships in Tokyo Bay) and insurance and agent fees, which are typically modest compared to the total cargo value.

Table 12: Key Parameters to Estimate LNG Shipping Costs from West Coast to Japan[94,95]

COMPONENT	DESCRIPTION	VALUE	UNIT
Charter rate (fuel included)[96,97]	Daily cost of leasing the LNG vessel, including fuel expenses	$25k ~ $52k	$/day
Distance (Tacoma)	Distance from Tacoma, WA to Japan	~4,300	Nautical miles (nm)
Distance (Ensenada)	Distance from Ensenada, Mexico to Japan	~5,100	Nautical miles (nm)
Speed	Vessel cruising speed; affects total voyage duration	13~17	Knots
Cargo energy[98]	Total energy content of the LNG cargo (based on 174,000 cubic meter capacity)	4 mm	MMBtu
Loading/unloading time	Time spent at port for loading and unloading LNG	3	Days
Port fees and insurance[99]	Charges incurred at ports and insurance per unit of energy	$0.15	$/MMBtu
Charter rate max	Maximum expected charter rate under market volatility	~$500k	$/day
Probability to hit the max rate	Likelihood of encountering the max charter rate during the project period	2.5	%

Gulf Coast Comparison via Panama Canal

For shipments originating from the U.S. Gulf Coast, the route to Japan typically involves transiting the Panama Canal, which introduces additional cost and risk factors. These include canal crossing fees, waiting time due to congestion, extra charges from fee surges, and distance-related fuel and time costs. These components are outlined in Table 13 and are added to the base shipping cost to reflect the full economic impact of canal transit.

The Gulf Coast route is longer in nautical miles compared to the West Coast route, and the Panama Canal introduces variability in both cost and schedule. While the Gulf Coast may benefit from proximity to major LNG export terminals, the added complexity of canal transit can offset these advantages, especially during periods of high congestion or fee escalation.

Table 13: Panama Canal Crossing Fee Components

COMPONENT	DESCRIPTION	VALUE	UNIT
LNG carrier size[100]	Standard cargo capacity of the LNG vessel	174,000	Cubic meters (m^3)
Average canal queue time	Estimated waiting time before canal transit	3	days
Distance (Houston to Yokohama)	Total voyage distance via Panama Canal	~10,800	Nautical miles (nm)
Crossing fee per MMBtu[101]	Base fee charged for canal transit per unit of energy	$0.16	$/MMBtu
Crossing congestion factor	Adjustment factor for congestion-related delays	6	
Crossing waiting factor	Multiplier for waiting time due to traffic or scheduling	3	
Extra waiting day due to congestion	Additional delay caused by canal congestion	9	Days
Extra charges due to surge in canal fee	Unexpected cost increase due to fee surges	~$3.3	Million
Extra crossing fee per MMBtu	Additional fee per unit of energy due to surge or congestion	$0.82	$/MMBtu

Sensitivity Analysis and Risk Adjustment

To conduct our sensitivity analysis, we employed a simple two-scenario Bernoulli shock model. This approach considered both the midpoint and high-end cost estimates, each assigned a corresponding probability, to calculate the upper bound. We applied this method not only to estimate the high end of shipping costs, but also to assess the potential upper bounds for pipeline and LNG facility tolling fees in previous sections.

To account for the uncertainty and volatility associated with canal congestion, fee surges, and charter rate fluctuations, we apply a sensitivity analysis framework. This framework allows us to model how changes in key variables—such as charter day rates and voyage duration—impact the delivered cost per MMBtu.

In particular, the Panama Canal congestion factor and extra waiting days are treated as probabilistic risks. By assigning likelihoods to these events and quantifying their monetary impact, we can incorporate a risk-adjusted cost premium into the Gulf Coast shipping estimate. This approach ensures that the final cost comparison between West Coast and Gulf Coast routes reflects not only base economics but also operational and market risks.

References

1 International Energy Agency, “Global electricity demand to keep growing robustly through 2026 despite economic headwinds”, 2025

2 Guidehouse analysis

3 International Energy Agency, “Gas Market Report, Q3 2025”, 2025

4 International Energy Agency, “Gas Market Report, Q2-2025”, 2025

5 International Energy Agency, “Gas Market Report, Q3 2025”, 2025

6 U.S. Energy Information Administration, “Short-Term Energy Outlook”, 2025

7 U.S. Energy Information Administration, “U.S. wholesale electricity prices were lower and less volatile in 2024”, 2025

8 American Gas Association, “DOE announces natural gas is 3.3 times more affordable than electricity - American Gas Association”, 2023

9 United Nations Economic and Social Council, “Report on the Group of Experts on Gas”, 2024

10 U.S. Energy Information Administration, “Total Energy”, 2025

11 U.S. Energy Information Administration, “Total Energy”, 2025

12 U.S. Energy Information Administration, “After more than a decade of little change, U.S. electricity consumption is rising again”, 2025

13 U.S. Energy Information Administration, “After more than a decade of little change, U.S. electricity consumption is rising again”, 2025

14 U.S. Energy Information Administration, “After more than a decade of little change, U.S. electricity consumption is rising again”, 2025

15 Gas Exporting Countries Forum, “GECF Global Gas Outlook 2050”, 2025

16 Gas Exporting Countries Forum, “GECF Global Gas Outlook 2050”, 2025

17 International Energy Agency, “Asia Pacific”, 2025

18 U.S. Energy Information Administration, “The United States remained the world’s largest liquefied natural gas exporter in 2024”, 2025

19 U.S. Energy Information Administration, “The United States remained the world’s largest liquefied natural gas exporter in 2024”, 2025

20 S&P Global, “US LNG cargoes to Asia set record via Cape of Good Hope as Panama Canal stagnates in July”, 2024

21 S&P, Global LNG Imports, Exports and Shipping Routes, 2024

22 Figure developed by Guidehouse

23 U.S. Geological Survey, “United States Assessments of Undiscovered Oil and Gas Resources”, 2024

24 U.S. Geological Survey, “United States Assessments of Undiscovered Oil and Gas Resources”, 2024

25 S&P Global, “Natural Gas Price Assessments”

26 Guidehouse power market modeling results for the US reference case

27 Rystad Energy, “Data centers reshape US power sector”, 2025

28 U.S. Department of Energy, “DOE Releases New Report Evaluating Increase in Electricity Demand from Data Centers”, 2024

29 Northwest Power and Conservation Council, “Pacific Northwest Power Supply Adequacy Assessment for 2029”, 2024

30 Business Wire, “Energy Transfer Announces Natural Gas Pipeline Project to Serve Growing Southwestern U.S. Markets”, 2025

31 Natural Gas Intelligence, “Northwest Pipeline Mapping Natural Gas Expansion to Gain Western Demand Advantage”

32 Asia Natural Gas & Energy Association, “ANGEA DOE submission: US LNG is ‘critical’ to Asia’s future”, 2025

33 U.S. Energy Information Administration, “Natural gas pipeline capacity from the Permian Basin is set to increase”, 2024

34 Northwest Gas Association, “NWGA Releases 2024 Pacific Northwest Natural Gas Market Outlook”, 2024

35 Northwest Gas Association, "NWGA Releases 2024 Pacific Northwest Natural Gas Market Outlook", 2024

36 U.S. Energy Information Administration, "The United States remained the world's largest liquefied natural gas exporter in 2024", 2025

37 Freight Waves, "No reservation at Panama Canal? Prepare for a long wait", 2023

38 LNG Canada, "First Cargo Puts Canada on the Map of LNG Exporting Nations", 2025

39 Natural Gas Intelligence, "Sempra Moves to Realign Mexico Natural Gas Assets as ECA LNG Nears Completion", 2025

40 Alaska LNG, "Project Overview"

41 Guidehouse analysis

42 Wood Mackenzie, "Economic viability assessment and economic value of Alaska LNG project - Phase 1, 2024

43 American Institute of Chemical Engineers, "Minimize Flaring in Oil and Gas Facilities", 2023

44 U.S. Department of Energy, "Colorado Natural Gas Flaring and Venting Regulations", 2022

45 Gas Outlook, "Colorado natural gas flaring occurs out of public view", 2024

46 U.S. Department of Energy, New Mexico Natural Gas Flaring and Venting Regulations", 2022

47 EnergyWire, "Texas emits far more methane than New Mexico — analysis", 2023

48 ERM, "Benchmarking Methane and Other Greenhouse Gas Emissions", 2024

49 Jonah Energy, "Responsibly Produced Gas"

50 PureWest Energy, "PureWest Energy and Proman Sign Agreement to Reduce Scope 3 Methanol Footprint Through Digital Tokens", 2023

51 Jonah Energy, "Responsibly Produced Gas"

52 JERA, "Launch of the methane emission reduction initiative (CLEAN) by KOGAS and JERA", 2023

53 U.S. Energy Information Administration, "Electric power sector CO2 emissions drop as generation mix shifts from coal to natural gas", 2021

54 Energy and Environment Economics, "Resource Adequacy in the Pacific Northwest", 2019

55 Energy and Environment Economics, "Resource Adequacy in the Pacific Northwest", 2019

56 Northwest Gas Association, "NWGA Releases 2024 Pacific Northwest Natural Gas Market Outlook", 2024

57 Idaho Power, "2025 Integrated Resource Plan", 2025

58 S&P Capital IQ

59 Northwest Power and Conservation Council, "Council releases initial 20-year forecast for Pacific Northwest electricity demand", 2025

60 Guidehouse Power Markets Reference Case Forecast

61 Northwest Power and Conservation Council, "Council releases initial 20-year forecast for Pacific Northwest electricity demand", 2025

62 Idaho Power, "2025 Integrated Resource Plan", 2025

63 Idaho Capital Sun, "Idaho doesn't produce energy like it used to. How drought, renewables are changing our landscape.", 2024

64 Northwest Gas Association, "NWGA Releases 2024 Pacific Northwest Natural Gas Market Outlook", 2024

65 LNG Canada, "First Cargo Puts Canada on the Map of LNG Exporting Nations", 2025

66 Cedar LNG, "Project Overview", 2025

67 Northwest Gas Association, "NWGA Releases 2024 Pacific Northwest Natural Gas Market Outlook", 2024

68 POWER Magazine, "Hundreds of New Gas-Fired Power Units Planned as U.S. Gas Output Soars", 2024

69 Guidehouse Power Markets Reference Case Forecast

70 Guidehouse Power Markets Reference Case Forecast

71 Power Engineering, "Arizona utilities lock in fuel supply for gas plants to power data center boom", 2025

72 Sempra, "ECA LNG ", 2020

73 New Mexico Tax Research Institute, "Oil and Natural Gas Taxing", 2010

74 Bureau of Land Management, "General Oil and Gas Leasing Instructions"

75 SPE Journal, "Field-Development Optimization of the In-Situ Upgrading Process Including the Ramp-Up Phase", 2021

76 SPE International, "Analysis of Decline Curves", 1945

77 Civitas, "Civitas Resources Reports Second Quarter 2025 Results and Reinstates Capital Return Program", 2025

78 U.S. Army Corps of Engineers, "Civil Works Cost Engineering", 2016

79 U.S. Department of Energy, Cost Estimating Guide, 2018

80 U.S. Energy Information Administration, "Trends in U.S. Oil and Natural Gas Upstream Costs", 2016

81 Council of Petroleum Accountants Societies, "Economic Factors", 2025

82 American Biogas Council, "H2S Removal for Biogas Project", 2019

83 American Association of Drilling Engineers, "Refracturing Activities in the United States - How Much Do We Know So Far?", 2023

84 PennState Extension, "Understanding Natural Gas Compressor Stations", 2015

85 U.S. Department of Transportation, "Safety of Gas Transmission Pipelines Rule Fact Sheet", 2024

86 National Energy Technology Laboratory, "Natural Gas Compressors and Processors - Overview and Potential Impact on Power System Reliability", 2017

87 U.S. Department of Transportation, "Safety of Gas Transmission Pipelines Rule Fact Sheet", 2024

88 Federal Energy Regulatory Commission, "Cost of Service Rates Manual", 1999

89 PetroSkills, "Onshore Natural Gas Pipeline Transportation Alternatives", 2013

90 Great Plains Institute, Improved Hydrocarbon Recovery LLC, Kansas Geologicacl Survey, "Economics for CO2 Capture, Compression, and Transportation in the Mid-Continent", 2018

91 Pipeline & Gas Journal, "Venture Global Raises Plaqueminse LNG Cost Estimate by $2 Billion", 2025

92 IOP Conference Series, "Global LNG Market: Supply-Demand and Economic Analysis", 2022

93 Thunder Said Energy, "How do LNG costs vary with plant size?"

94 Journal of Natural Gas Science and Engineering, "A techno-economic study of shipping LNG to the Asia-Pacific from Western Canada by LNG carrier," 2016

95 Canadian Energy Centre, "Canada's LNG Opportunity in the Asia-Pacific Natural Gas Market", 2021

96 Spark, "LNG Freight Platform", 2025

97 The Oxford Institute for Energy Studies, "LNG Shipping Forecast: costs rebounding, outlook uncertain", 2018

98 U.S. Energy Information Adminsitration, "Energy conversion calculators", 2025

99 Gobierno de Mexico, "Piloting Rates"

100 Spark, "LNG Freight Methodology", 2025

101 Canal de Panama, "Maritime Tariff List," 2025

Western States and Tribal Nations 2025

Contacts

Andrew Browning,
WSTN President,
Andrew@westernnaturalgas.org

For media, please contact,
Bryson Hull,
Bryson@westernnaturalgas.org

WESTERN STATES AND TRIBAL NATIONS ENERGY INITIATIVE