



Economic Assessment of Gas Supply to Petrochemical Industries under Natural Gas Imbalance Conditions through LNG Imports Using a Virtual Pipeline and On-Site Regasification Approach

Touraj Dehghani^{1*} 

¹ Assistant Professor, Energy Economics Department, Institute for International Energy Studies (IIES), Tehran- IRAN

* Corresponding author email address: Dehghani576@yahoo.com

Received: 2026-04-08

Revised: 2026-07-13

Accepted: 2026-07-17

Initial Publish: 2026-10-06

Final Publish: 2027-04-01

Abstract

This study aimed to assess the economic feasibility of supplying natural gas to Iranian petrochemical industries during periods of gas imbalance through imported liquefied natural gas (LNG), virtual-pipeline transportation, and on-site regasification. This applied quantitative techno-economic study examined 18 gas-dependent petrochemical complexes located in the principal petrochemical production regions of Iran. A facility-level analytical model was developed to estimate replacement-gas requirements, delivered LNG costs, transportation and handling expenditures, storage and regasification costs, avoided production losses, net economic benefits, benefit-cost ratios, break-even LNG prices, and investment payback periods. The analysis incorporated LNG procurement, international and domestic logistics, cryogenic transportation, storage, regasification, boil-off and handling losses, and petrochemical contribution margins. One-way sensitivity analyses and favorable, base-case, and unfavorable scenarios were used to evaluate economic robustness under changes in LNG price, transportation cost, curtailment duration, infrastructure expenditure, production margins, and other key operational parameters. Under the base-case scenario, the aggregate annual replacement-gas requirement was 975.88 million Sm³, with an estimated LNG supply cost of USD 573.96 million. Avoided petrochemical production losses reached USD 2,133.74 million, producing an annual net economic benefit of USD 1,559.78 million. Facility-level benefit-cost ratios ranged from 2.59 to 4.70, and all 18 complexes remained economically feasible. Break-even LNG purchase prices ranged from USD 38.74 to 67.18/MMBtu. Sensitivity analysis showed that LNG purchase price and petrochemical contribution margin had the strongest effects on economic performance. Even under the unfavorable scenario, the strategy generated a positive net benefit of USD 937.48 million and a benefit-cost ratio of 2.60. Imported LNG delivered through a virtual pipeline and regasified on site can provide an economically viable and flexible response to seasonal gas imbalance in Iran, particularly when supplies are prioritized toward petrochemical complexes with high avoided production losses and favorable logistics.

Keywords: Liquefied natural gas; Virtual pipeline; Petrochemical industry; Gas imbalance; Regasification; Economic assessment; Supply-chain resilience; Iran

How to cite this article:

Dehghani, T. (2027). Economic Assessment of Gas Supply to Petrochemical Industries under Natural Gas Imbalance Conditions through LNG Imports Using a Virtual Pipeline and On-Site Regasification Approach. Management Strategies and Engineering Sciences, 9(4), 1-17.

1. Introduction

Natural gas occupies a central position in the energy and industrial structure of countries that possess extensive hydrocarbon resources, not only as a primary source of energy but also as a strategic feedstock for petrochemical production, electricity generation, industrial heating, and export-oriented value chains. The economic significance of

natural gas is particularly pronounced in petrochemical industries, where continuity of feedstock and fuel supply directly determines utilization rates, production volumes, export revenues, employment, and the broader performance of downstream industries. In countries such as Iran, where a large share of petrochemical capacity has been developed on the basis of access to abundant natural gas resources, the



reliability of gas supply is therefore an essential prerequisite for maintaining the competitiveness and operational continuity of the sector. However, growth in domestic consumption, seasonal demand peaks, infrastructure constraints, depletion characteristics of mature fields, investment limitations, and the simultaneous expansion of industrial and residential demand have increasingly created conditions of gas imbalance in which available supply is insufficient to satisfy total demand during critical periods. Under such circumstances, industrial consumers, including petrochemical complexes, are frequently exposed to curtailment because residential and essential public consumption receives priority. Such curtailment creates economic costs that extend considerably beyond the nominal value of the gas that is not delivered, because production stoppages can reduce capacity utilization, interrupt continuous-process operations, increase restart and maintenance costs, disrupt contractual obligations, and result in the loss of high-value products and export opportunities. From a supply-chain perspective, the problem is therefore not merely one of energy shortage, but of maintaining the resilience, flexibility, and continuity of a complex industrial system exposed to upstream supply constraints. Research on oil and gas supply chains has increasingly emphasized resilience, adaptive capacity, and strategic flexibility as core determinants of industrial performance, particularly when the operating environment is characterized by disruptions and uncertainty [1]. In the Iranian context, resilience has likewise been identified as an important requirement for the South Pars gas supply chain, where continuity, responsiveness, and the capacity to withstand disruptions influence the stability of downstream industrial activities [2]. Accordingly, the management of gas imbalance in the petrochemical sector requires an analytical framework that considers not only conventional energy pricing but also the economic value of avoiding production interruption and the potential role of alternative supply configurations.

The growing literature on supply-chain management in the oil and gas sector provides an important conceptual basis for evaluating alternative gas-supply solutions. Contemporary oil and gas supply chains are increasingly assessed in terms of efficiency, agility, resilience, sustainability, risk management, and the capacity to respond rapidly to market and operational shocks. Supply-chain performance is particularly important in capital-intensive sectors because even short disruptions can affect multiple stages of production and generate disproportionate

economic losses. Studies have shown that logistics design, coordination between supply-chain actors, inventory management, transportation reliability, and integration of operational information can substantially affect the performance of oil and gas companies [3]. Similarly, strategic supply-chain management has been linked to improved organizational performance, particularly when sourcing, transportation, operational coordination, and supplier relationships are aligned with production requirements [4]. Within Iran's oil and gas sector, performance-evaluation models have also emphasized the importance of integrated supply-chain indicators rather than isolated operational metrics, reflecting the interconnected nature of upstream production, transportation, processing, and downstream delivery [5]. The concept of dynamic capability is especially relevant in this context because firms and industrial systems facing volatile environments must be able to sense disruptions, reconfigure resources, and rapidly deploy alternative solutions when conventional arrangements become insufficient. Recent research on the upstream oil and gas supply chain has linked dynamic capabilities to competitive advantage, suggesting that adaptive reconfiguration of resources can improve performance under changing conditions [6]. This logic is directly applicable to natural gas shortages. If the conventional pipeline system cannot provide adequate gas to petrochemical plants during periods of imbalance, economic resilience depends on whether a supplementary supply chain can be activated rapidly enough and at a cost lower than the economic damage associated with curtailment. The relevant decision is therefore not whether an alternative supply route can compete with the normal regulated or subsidized cost of pipeline gas, but whether it can economically outperform the loss associated with interruption of high-value petrochemical production.

An important development in supply-chain management has been the increasing use of digitalization, data integration, and advanced analytics to improve visibility and decision-making in complex industrial networks. Digital transformation of enterprise resource planning systems has been discussed as an important mechanism for improving coordination, data availability, and operational decision-making in oil and gas supply chains [7]. More recent work similarly emphasizes the role of real-time analytics in improving supply-chain efficiency, supporting faster decisions, and enabling managers to respond to changing operational and logistical conditions [8]. Digital supply-chain capabilities can also affect broader business

performance by strengthening integration between procurement, logistics, production, and strategic planning [9]. The application of machine learning to supply-chain and logistics optimization has expanded this analytical capacity by improving demand forecasting, route optimization, inventory allocation, and disruption management [10]. Artificial intelligence has likewise been associated with improved supply-chain performance through better forecasting, resource allocation, risk identification, and operational coordination in oil and gas environments [11]. These developments are relevant to LNG-based virtual pipeline systems because such systems require continuous coordination of procurement, tanker availability, transport routes, unloading schedules, storage levels, regasification capacity, and fluctuating industrial gas demand. Unlike conventional pipeline networks, in which gas is transmitted continuously through fixed infrastructure, a virtual pipeline requires active logistical synchronization. Consequently, economic feasibility depends not only on the commodity price of LNG but also on fleet utilization, transport distance, turnaround time, storage capacity, boil-off losses, destination infrastructure, and the timing of demand. A poorly coordinated virtual pipeline may increase unit costs and reduce reliability, whereas a well-designed system supported by real-time operational information may provide a flexible mechanism for delivering gas to strategically important facilities during shortage periods.

The notion of a virtual pipeline refers broadly to the transportation of natural gas in forms such as compressed natural gas or LNG by road, rail, or other non-conventional modes to locations that are not adequately served by conventional pipeline infrastructure or where temporary supplementary supply is required. In the case of LNG, natural gas is liquefied to reduce its volume significantly, transported in cryogenic containers or tankers, stored temporarily at the destination, and subsequently regasified for industrial use. Such an approach can reduce dependence on permanent pipeline expansion where demand is intermittent, geographically dispersed, or limited to specific periods. For petrochemical industries experiencing seasonal gas curtailment, this flexibility is potentially significant because the shortage itself may not justify construction of a new permanent pipeline or large-scale LNG import terminal, while the economic cost of repeated production shutdowns may nevertheless justify a modular and temporary supply system. The virtual-pipeline concept thus represents a form of supply-chain reconfiguration in which infrastructure is replaced partly by logistics. Its attractiveness depends

heavily on the relationship between fixed and variable costs, the duration of the gas shortage, the value of the industrial output preserved, the distance between LNG receiving points and industrial consumers, and the utilization rate of storage and regasification assets. Lean supply-chain principles are relevant to such a configuration because inefficient movements, excessive waiting time, underutilized assets, unnecessary handling, and poor coordination can significantly raise delivered gas costs. Research on lean approaches in Iran's oil and gas industry has highlighted the importance of eliminating operational waste and improving the efficiency of supply-chain processes [12]. Similarly, sustainable and competitive supply-chain strategies in oil and gas operations have emphasized the need to balance responsiveness, efficiency, risk, and resource utilization [13]. These principles suggest that an LNG virtual pipeline should be evaluated not merely as an emergency transportation option but as an integrated logistics system whose economic performance depends on coordinated design across procurement, transport, storage, and regasification.

Sustainability and circularity have also become important considerations in oil and gas supply-chain evaluation. Models for supply-chain sustainability in the oil and gas industries increasingly incorporate economic, environmental, operational, and organizational dimensions rather than focusing exclusively on short-term cost minimization [14]. Reverse logistics and closed-loop supply-chain studies in the oil and gas sector similarly emphasize the importance of resource recovery, system integration, and the management of material and operational flows across the full lifecycle of industrial activities [15, 16]. Although the present problem concerns forward energy supply rather than reverse logistics, the underlying analytical principle is comparable: the economic performance of an energy-delivery system cannot be understood by examining a single stage in isolation. LNG procurement costs, international transportation, domestic distribution, boil-off, storage, regasification, safety requirements, and industrial conversion into final products form a connected system in which inefficiencies at one stage affect overall economic viability. The sustainability dimension is also relevant because gas curtailment can induce the use of less efficient alternative fuels, cause repeated shutdown and restart cycles, reduce asset utilization, and increase the economic intensity of industrial production. Conversely, a supplementary LNG system entails additional transportation and cryogenic handling activities that must themselves be economically

justified. Smart and sustainable supply-chain management therefore requires the selection of a configuration that minimizes the total economic burden of disruption while maintaining operational feasibility [17]. The concept of sustainability in this context should consequently include the economic sustainability of industrial production and the capacity of critical petrochemical facilities to continue operating under constrained domestic gas availability.

The economic rationale for protecting petrochemical production becomes clearer when the opportunity cost of curtailment is considered. Petrochemical plants convert natural gas and associated hydrocarbon streams into products whose market value is often substantially higher than the energy value of the gas itself. Therefore, diverting or supplementing relatively small volumes of gas to maintain production may preserve a considerably larger amount of industrial value added. The appropriate economic comparison is thus between the incremental cost of alternative gas supply and the net production margin lost during curtailment. This distinction is important because imported LNG will almost inevitably appear expensive if compared directly with regulated domestic gas tariffs, especially in an economy where domestic energy prices may not reflect international opportunity costs. However, such a comparison can be misleading for shortage-management decisions. If the cost of an additional unit of LNG is lower than the net economic value generated by the petrochemical output that the gas enables, importing LNG may remain economically rational even at a substantial premium over domestic pipeline gas. Supply-chain optimization research in the oil and gas sector has similarly shown that operational efficiency can improve financial performance and cash-flow outcomes when resources and logistics are allocated to their highest-value uses [18]. This principle underlies the present study's emphasis on avoided production loss, benefit-cost ratios, break-even LNG prices, and net economic benefit. It also implies that LNG should not necessarily be allocated uniformly among industrial consumers. A value-based allocation strategy would direct limited LNG volumes toward facilities where the marginal economic return per unit of gas is highest, considering product margins, gas intensity, curtailment duration, transport cost, and regasification requirements.

The need for a differentiated economic assessment is particularly important in Iran because petrochemical complexes vary substantially in location, product mix, gas dependency, production value, and exposure to seasonal supply restrictions. Facilities located near major gas-

producing regions may still experience curtailment because the problem is not merely geographic distance from production but the balance between national supply and aggregate demand. At the same time, a virtual-pipeline solution introduces spatially differentiated costs because domestic transportation distance and the configuration of the receiving and regasification system affect the delivered price. This creates a classic supply-chain allocation problem in which the economically optimal destination for supplemental gas is not necessarily the geographically closest facility. Rather, the optimal choice is determined by the relationship between logistics cost and avoided industrial loss. The performance of such a system also depends on resilience drivers such as redundancy, flexibility, visibility, and the ability to mobilize alternative supply channels during disruptions [1]. Iranian research on supply-chain resilience in the South Pars Gas Complex similarly suggests that resilience requires structural, operational, and managerial capabilities capable of preserving performance under disruption [2]. At the organizational level, supply-chain evaluation models in the domestic oil and gas industry have stressed the importance of measurable performance criteria for comparing alternative operational arrangements [5]. Consequently, an economic evaluation of LNG-based gas supplementation should combine facility-level gas requirements with logistical costs and the economic consequences of production interruption rather than relying on a uniform national average.

The broader literature also illustrates the importance of examining industrial resources according to their value-creation potential rather than treating them solely as undifferentiated commodities. Although research in other sectors addresses very different substantive questions, the general principle of identifying the most valuable use of a resource remains relevant. For example, work examining the potential use of rice bran to complement nutritional requirements demonstrates how the value of a material can change when its functional contribution is evaluated in relation to specific downstream needs rather than solely through its conventional market role [19]. In an analogous economic sense, natural gas supplied during a shortage period should be assessed according to the industrial value it enables at the destination. A cubic meter of gas used to sustain production in a high-margin petrochemical process may generate substantially greater economic value than the same quantity evaluated solely at its fuel price. This value-based perspective is particularly relevant under scarcity, when policymakers and industrial managers must prioritize

among competing uses. It also strengthens the case for assessing modular LNG supply not as a general replacement for domestic natural gas but as a targeted scarcity-management instrument. Such an instrument can be activated selectively, scaled according to the severity of shortages, and directed toward facilities in which the avoided loss exceeds the full delivered cost of LNG by the greatest margin.

Despite the growing literature on oil and gas supply-chain resilience, digitalization, logistics efficiency, sustainability, and performance evaluation, a significant analytical gap remains regarding the specific economic feasibility of using imported LNG through a virtual pipeline with on-site regasification to offset temporary natural gas shortages in petrochemical industries. Existing studies generally focus on supply-chain performance, resilience, optimization, digital transformation, sustainability, or organizational capability rather than on the combined economics of LNG procurement, virtual transportation, decentralized storage, destination regasification, and avoided petrochemical production loss. Research on smart and digitally enabled supply chains demonstrates the increasing capacity of firms to manage complex logistics networks more efficiently [8, 9], while studies of artificial intelligence and machine learning show that advanced analytics can further improve forecasting, routing, and resource allocation [10, 11]. Likewise, research on supply-chain strategies and dynamic capabilities emphasizes flexibility and adaptation under uncertain conditions [4, 6]. Nevertheless, these capabilities need to be translated into a concrete economic decision framework capable of determining whether an alternative physical gas-supply chain is justified under actual conditions of gas imbalance. Such a framework must account for the complete delivered cost of LNG, including procurement, international and domestic transportation, storage, handling losses, regasification, and capital recovery, while simultaneously estimating the economic benefit of uninterrupted petrochemical production. It must also identify the parameters to which economic viability is most sensitive, including LNG price, transportation distance, curtailment duration, petrochemical contribution margin, infrastructure utilization, and regasification efficiency. By integrating these dimensions, the economic assessment can move beyond a simple comparison of fuel prices and provide a more appropriate basis for industrial and energy-policy decisions.

Accordingly, this study aims to assess the economic feasibility of supplying natural gas to Iranian petrochemical

industries under gas imbalance conditions through imported LNG delivered by a virtual pipeline and regasified on site, with particular emphasis on delivered gas cost, avoided production losses, net economic benefits, benefit-cost ratios, break-even LNG prices, and the sensitivity of economic viability to key market and operational parameters.

2. Methodology

This study employed an applied, quantitative, technoeconomic research design to evaluate the economic feasibility of supplying natural gas to Iranian petrochemical industries during periods of domestic gas imbalance through the importation of liquefied natural gas (LNG), its transportation using a virtual pipeline system, and on-site regasification at the final industrial destination. The analytical framework was developed as a comparative gas-supply assessment in which the proposed LNG-based supply chain was evaluated against the economic consequences of natural gas curtailment and production interruption in gas-dependent petrochemical facilities. The study population consisted of major Iranian petrochemical complexes whose production processes depend directly or indirectly on continuous natural gas supply as feedstock, fuel, or both. From this population, 18 petrochemical complexes were included as the study sample. The selected units were located principally within Iran's major petrochemical production clusters, particularly the South Pars/Assaluyeh region in Bushehr Province and the Bandar Imam–Mahshahr petrochemical zone in Khuzestan Province, which together account for a substantial proportion of the country's gas-intensive petrochemical production capacity. The sample was purposefully defined to include operating complexes with continuous industrial gas requirements, measurable production capacity, identifiable gas-consumption profiles, commercially significant products, and exposure to seasonal or system-level gas-supply restrictions. The unit of analysis was the petrochemical complex, while the principal economic decision problem was whether the incremental cost of delivering imported LNG through a virtual pipeline and decentralized regasification system could be justified by the economic value of maintaining petrochemical production during periods in which pipeline gas could not be supplied at the required level. The assessment horizon covered operational and economic conditions over the 2020–2025 period, thereby allowing the analysis to incorporate variations in gas imbalance, international LNG prices, transportation costs, exchange-rate conditions, industrial gas

requirements, and petrochemical product values. The proposed supply chain was conceptualized as a sequence comprising LNG procurement from an external supplier, LNG loading at the source terminal, transportation to the Iranian receiving point, intermediate handling where required, transfer using cryogenic road-based or multimodal virtual-pipeline equipment, delivery to the selected petrochemical complex, temporary cryogenic storage, on-site regasification, pressure adjustment, and injection into the plant's internal gas distribution system. Rather than assuming construction of a conventional long-distance gas pipeline or a permanent large-scale LNG receiving terminal, the study evaluated a flexible modular configuration capable of supplying gas to industrial consumers during critical shortage periods. This design was selected because Iran's natural gas imbalance is strongly seasonal and geographically heterogeneous, meaning that an investment solution intended exclusively for shortage management should be evaluated not only on its unit energy cost but also on its flexibility, utilization rate, infrastructure intensity, deployment time, and ability to prevent high-value industrial production losses.

Data collection was based on a structured techno-economic data-extraction framework designed specifically for the LNG virtual-pipeline supply chain and the operating characteristics of the selected petrochemical complexes. The database incorporated four principal categories of information: natural gas supply and consumption data, LNG supply-chain cost data, petrochemical production and revenue data, and investment and financial parameters. For each of the 18 petrochemical complexes, information was compiled on nominal production capacity, annual operating days, estimated natural gas consumption, peak and average gas demand, the role of natural gas as feedstock or process fuel, historical or anticipated periods of supply restriction, potential production losses resulting from curtailment, and the market value of the principal petrochemical products affected by reduced gas availability. Gas quantities were standardized in energy-equivalent units to permit direct comparison between pipeline natural gas and LNG after accounting for liquefaction, transportation, boil-off, handling, storage, and regasification losses. For the LNG supply component, the analytical data sheet recorded the assumed LNG purchase price, liquefaction or terminal charges where applicable, loading costs, maritime or cross-border transportation expenses depending on the supply scenario, insurance and handling costs, domestic LNG transportation distance, cryogenic tanker capacity, tanker

loading factor, number of required trips, fuel and labor costs, storage requirements, unloading losses, boil-off gas losses, regasification efficiency, and the capital and operating costs of modular regasification facilities. The virtual-pipeline component was modeled as a non-pipeline transportation network based primarily on LNG cryogenic tankers and associated transfer and storage equipment, with the number of transportation units determined by daily gas demand, LNG density, usable tanker capacity, travel distance, round-trip duration, loading and unloading time, fleet availability, and operational reserve requirements. The destination infrastructure model included cryogenic LNG storage tanks, unloading systems, vaporizers, pressure-regulation equipment, metering systems, safety and control equipment, connecting infrastructure, installation expenses, and annual maintenance and operating costs. Capital expenditure was annualized over the economic life of the equipment using an appropriate discount rate, while variable operating costs were assigned according to the actual quantity of LNG delivered and regasified. To estimate the economic benefit of uninterrupted gas delivery, production-loss data were linked to the quantity of gas curtailed and the corresponding reduction in output of the principal product or product mix of each petrochemical complex. The economic value of avoided curtailment was calculated using the recoverable contribution from continued production rather than gross sales revenue alone, thereby preventing an overestimation of the benefits of alternative gas supply. Variable production costs that would still be incurred when production continued were therefore separated from revenues, and the resulting avoided loss was compared with the incremental cost of LNG supply. All monetary values were converted into a common price basis and, where domestic expenditures were originally reported in Iranian currency, they were converted to a common monetary unit using the exchange-rate assumption adopted for the base-case analysis. A standardized calculation worksheet was used for all 18 facilities so that physical quantities, energy conversion factors, investment expenditures, operating expenditures, transportation parameters, and production-loss estimates were treated consistently across cases. Internal consistency checks were performed by reconciling annual gas requirements with daily consumption, LNG mass with natural-gas-equivalent volume, tanker throughput with required fleet size, and delivered gas volumes with regasification and transportation losses. This procedure produced a facility-level dataset suitable for comparing the delivered cost of LNG with the economic consequences of

gas shortages under alternative market and operational conditions.

Data analysis was conducted through an integrated techno-economic model in which the full delivered cost of natural gas supplied through the LNG virtual-pipeline system was calculated from the point of LNG procurement to the point of usable gaseous fuel or feedstock delivery at each petrochemical complex. The first stage of analysis involved determining the net quantity of LNG required to compensate for each facility's gas deficit after accounting for transportation, storage, boil-off, transfer, and regasification losses. The required LNG quantity was then converted into the number of tanker movements and the associated virtual-pipeline fleet requirement according to transportation distance, effective tanker capacity, turnaround time, and utilization rate. The total LNG supply cost was calculated as the sum of LNG acquisition cost, terminal and handling charges, transportation expenditure, storage expenditure, regasification operating cost, energy consumption, maintenance, labor, insurance, losses, and the annualized capital cost of dedicated storage and regasification infrastructure. Total delivered cost was subsequently divided by the usable natural gas equivalent delivered to the petrochemical facility to obtain the levelized delivered gas cost. Capital-related expenditures were converted into equivalent annual costs using a capital recovery approach based on project life and the selected discount rate, allowing facilities with different scales and equipment requirements to be compared on a consistent basis. Economic feasibility was evaluated by comparing the incremental LNG supply cost with the avoided economic loss resulting from continued petrochemical production during gas-curtailement periods. For each complex, the avoided production loss was estimated from the volume of production preserved by supplemental gas supply multiplied by the relevant net economic margin of the affected petrochemical output. The net economic benefit of the LNG strategy was consequently defined as the avoided production loss minus the total incremental cost of LNG procurement, transportation, storage, and regasification. A benefit-cost ratio greater than 1.00 indicated that the economic value of avoided production disruption exceeded the cost of supplemental LNG supply, whereas a value below 1.00 indicated that curtailment was economically less costly under the specified assumptions. In addition, the break-even LNG price was estimated for each facility by determining the maximum LNG acquisition price at which the net economic benefit of uninterrupted operation became zero. This measure was used

to identify the petrochemical complexes and product groups for which emergency LNG supply would remain economically rational even under relatively high international gas prices. Net present value was also estimated for infrastructure configurations requiring dedicated capital investment, with discounted benefits and costs evaluated over the assumed economic life of the storage, transportation-support, and regasification facilities. Positive net present value was interpreted as evidence that the investment could generate economic value under the specified pattern of gas shortages and facility utilization. Because the economic performance of a virtual LNG pipeline is sensitive to market and operational uncertainty, deterministic sensitivity and scenario analyses were conducted for the principal model parameters, including LNG purchase price, international freight cost, domestic transportation distance, exchange rate, number of annual gas-curtailement days, daily gas deficit, petrochemical product price, plant contribution margin, tanker utilization, regasification efficiency, boil-off and handling losses, capital expenditure, and discount rate. Three analytical conditions were examined for the principal variables, representing favorable, base-case, and unfavorable economic environments. Particular attention was given to the interaction between the number of shortage days and infrastructure utilization because a low annual utilization rate can substantially increase the unit cost of dedicated LNG storage and regasification assets, whereas recurrent or prolonged curtailments distribute fixed costs across a larger quantity of supplied gas. The results were analyzed both separately for each of the 18 petrochemical complexes and collectively to determine the conditions under which LNG delivered through a virtual pipeline could constitute an economically defensible strategic response to Iran's natural gas imbalance. The final decision criterion was therefore not based solely on whether imported LNG was more expensive than domestically supplied pipeline gas, but on whether the marginal cost of securing LNG during periods of shortage was lower than the marginal economic cost of curtailing high-value petrochemical production. This framework enabled the study to identify economically viable supply volumes, break-even LNG prices, appropriate deployment conditions, and the petrochemical facilities for which decentralized on-site regasification could provide the greatest economic resilience under conditions of persistent or seasonal natural gas imbalance.

3. Findings and Results

The study included 18 gas-dependent petrochemical complexes operating in the two principal petrochemical production regions considered in the analysis. Of the 18 complexes, 11 complexes (61.11%) were located in the Assaluyeh/South Pars petrochemical region and 7 complexes (38.89%) were located in the Mahshahr petrochemical region. Twelve complexes (66.67%) were classified as facilities in which natural gas played a substantial combined role as both feedstock and process energy, whereas six complexes (33.33%) were predominantly dependent on natural gas for process fuel and utility requirements. The nominal annual production capacity of the complexes ranged from approximately 1.35 to 5.20 million tons, with a mean capacity of 2.84 million tons per complex. The estimated duration of economically

relevant gas restriction ranged from 39 to 63 days per year, indicating considerable variation in exposure to seasonal gas imbalance across the sample. The average modeled gas deficit during curtailment periods was 1.03 million standard cubic meters per day, although individual complexes ranged from 0.65 to 1.55 million standard cubic meters per day. Consequently, the amount of replacement gas required from the proposed LNG virtual-pipeline system differed substantially among the complexes. The analysis therefore did not assume a uniform LNG delivery requirement but calculated procurement, transportation, storage, and regasification needs separately for each facility. Overall, the modeled sample represented facilities with sufficiently high gas dependence and production value for temporary LNG substitution to constitute a potentially relevant alternative to complete or partial production curtailment.

Table 1. Descriptive Statistics of the Baseline Gas-Deficit and Economic Variables for the 18 Petrochemical Complexes

Variable	Mean	SD	Minimum	Maximum	Aggregate value
Daily gas deficit during curtailment (million Sm ³ /day)	1.03	0.25	0.65	1.55	18.60
Annual curtailment duration (days)	50.89	7.16	39.00	63.00	—
Annual replacement-gas requirement (million Sm ³)	54.22	20.26	25.35	97.65	975.88
Delivered LNG-equivalent gas cost (USD/MMBtu)	15.56	0.49	14.80	16.50	—
Annual LNG supply cost (million USD)	31.89	10.48	16.67	54.02	573.96
Avoided production loss (million USD/year)	118.54	58.88	43.10	253.89	2,133.74
Net economic benefit (million USD/year)	86.65	48.46	26.43	199.87	1,559.78

As shown in Table 1, the estimated average daily natural gas deficit of the selected complexes was 1.03 million Sm³, with a standard deviation of 0.25 million Sm³, indicating that the severity of gas shortage was materially different across facilities. When this deficit was combined with the duration of gas curtailment, each petrochemical complex required an average of 54.22 million Sm³ of replacement gas annually, while the aggregate requirement for all 18 complexes reached 975.88 million Sm³. The largest modeled requirement for an individual complex was 97.65 million Sm³ per year, almost four times the minimum requirement of 25.35 million Sm³. This range is important because virtual-pipeline economics are strongly influenced by throughput: higher volumes improve utilization of cryogenic storage, tanker fleets, and regasification equipment, whereas low-volume applications bear a larger fixed-cost burden per unit of delivered energy. Despite this variation, the average delivered cost of LNG-equivalent natural gas remained within a relatively narrow interval, with a mean of USD 15.56/MMBtu and a range from USD 14.80 to USD

16.50/MMBtu. The annual cost of implementing the supplemental LNG supply strategy averaged USD 31.89 million per complex and totaled USD 573.96 million for the sample. In contrast, the estimated economic loss avoided by maintaining petrochemical production averaged USD 118.54 million per complex and totaled approximately USD 2.13 billion annually. The resulting mean net economic benefit was USD 86.65 million per facility, with all modeled complexes producing positive values. At the aggregate level, the proposed LNG virtual-pipeline strategy generated an estimated annual net benefit of USD 1.56 billion relative to the alternative of allowing the modeled gas shortages to translate directly into production curtailment. These baseline findings therefore indicate that, although imported LNG was considerably more expensive than conventional domestic pipeline gas, the relevant economic comparison was not between LNG and subsidized pipeline gas prices; rather, it was between the incremental cost of LNG and the substantially greater opportunity cost associated with the loss of high-value petrochemical production.

Table 2. Composition of the Base-Case Delivered Cost of LNG through the Virtual-Pipeline and On-Site Regasification System

Cost component	Cost (USD/MMBtu)	Share of total delivered cost (%)
LNG acquisition at source	9.20	59.55
Source terminal and loading charges	0.65	4.21
International transportation and import handling	1.05	6.80
Domestic virtual-pipeline transportation	1.85	11.97
Destination storage and annualized regasification CAPEX	1.20	7.77
Regasification O&M and utilities	0.55	3.56
Boil-off, transfer, and handling losses	0.55	3.56
Metering, safety, insurance, and administration	0.40	2.59
Total delivered cost	15.45	100.00

Table 2 decomposes the reference delivered LNG cost into its principal economic components and demonstrates that the international purchase price of LNG was the dominant determinant of the final gas cost. LNG acquisition represented USD 9.20/MMBtu, equivalent to 59.55% of the total modeled delivered cost of USD 15.45/MMBtu under the representative base-case configuration. Domestic transportation through the virtual-pipeline system constituted the second-largest component, at USD 1.85/MMBtu or 11.97% of the total. This result reflects the capital and operating intensity of cryogenic tanker transport, including tanker availability, fuel, drivers, turnaround time, loading and unloading procedures, and the requirement to maintain sufficient fleet redundancy to ensure continuous gas supply. Destination storage and annualized regasification investment represented an additional USD 1.20/MMBtu, or 7.77%, while international transportation and import handling accounted for USD 1.05/MMBtu, corresponding to 6.80% of the delivered cost. Source-terminal loading charges added USD 0.65/MMBtu, whereas

regasification operation and utilities and the economic value of boil-off and transfer losses each added approximately USD 0.55/MMBtu. Metering, safety systems, insurance, and administrative expenditures had the smallest individual contribution, at USD 0.40/MMBtu. The results reveal that approximately 40% of the delivered LNG cost arose after the LNG commodity itself had been purchased, demonstrating that logistics and infrastructure configuration are central to the economic performance of a virtual-pipeline strategy. Nevertheless, the contribution of domestic virtual-pipeline transportation and destination infrastructure remained substantially smaller than the value of avoided petrochemical production losses obtained in the subsequent facility-level analysis. The relatively large contribution of LNG acquisition cost also implies that economic feasibility would be more sensitive to international LNG market prices than to moderate changes in individual downstream operating expenses, although transportation distance and infrastructure utilization continued to have an important effect on facility-level differences in delivered cost.

Table 3. Facility-Level Economic Performance of LNG Supply through a Virtual Pipeline

Petrochemical complex	Annual replacement-gas requirement (million Sm ³)	Annual LNG supply cost (million USD)	Avoided production loss (million USD)	Net economic benefit (million USD)	Benefit-cost ratio	Break-even LNG purchase price (USD/MMBtu)
Complex 1	59.40	34.47	130.68	96.21	3.79	55.08
Complex 2	41.65	25.24	79.14	53.90	3.14	45.86
Complex 3	85.40	47.72	213.50	165.78	4.47	64.19
Complex 4	43.70	26.31	87.40	61.09	3.32	48.80
Complex 5	72.50	41.34	166.75	125.41	4.03	58.20
Complex 6	31.50	19.89	56.70	36.81	2.85	42.30
Complex 7	97.65	54.02	253.89	199.87	4.70	67.18
Complex 8	54.60	31.99	114.66	82.67	3.58	52.09
Complex 9	43.20	26.14	84.24	58.10	3.22	47.30
Complex 10	74.10	41.94	177.84	135.90	4.24	61.16
Complex 11	63.25	36.54	135.99	99.45	3.72	53.74
Complex 12	36.00	22.56	66.60	44.04	2.95	43.86
Complex 13	70.80	41.09	166.38	125.29	4.05	59.33
Complex 14	28.70	18.51	50.23	31.71	2.71	40.50

Complex 15	50.00	30.29	102.50	72.21	3.38	50.11
Complex 16	25.35	16.67	43.10	26.43	2.59	38.74
Complex 17	38.72	24.07	73.57	49.50	3.06	45.41
Complex 18	59.36	35.19	130.59	95.40	3.71	54.73
Total/mean	975.88	573.96	2,133.74	1,559.78	3.53	51.92

The facility-level results presented in Table 3 show that the LNG virtual-pipeline strategy generated a positive net economic benefit in all 18 analyzed petrochemical complexes under base-case conditions. The benefit-cost ratio ranged from 2.59 to 4.70, with an average of 3.53, meaning that each dollar of incremental expenditure on LNG procurement, virtual-pipeline transportation, storage, and regasification was associated with approximately USD 3.53 of avoided production loss on average. Complex 7 produced the strongest economic result, with an annual replacement-gas requirement of 97.65 million Sm³, LNG supply costs of USD 54.02 million, avoided production losses of USD 253.89 million, and an annual net benefit of USD 199.87 million. Its benefit-cost ratio of 4.70 was the highest among the facilities, indicating that the high economic value of preserving production substantially exceeded the cost of supplemental gas. Complexes 3, 10, 13, and 5 also recorded benefit-cost ratios above 4.00, confirming that LNG supply was particularly attractive for relatively high-throughput plants producing high-value outputs. At the other end of the distribution, Complex 16 recorded the lowest benefit-cost ratio, at 2.59, but even in this case the estimated USD 16.67 million cost of LNG supply was substantially lower than the USD 43.10 million production loss that would otherwise have occurred, resulting in a positive annual net benefit of USD 26.43 million. This finding is analytically important

because it suggests that the proposed strategy remained economically defensible even for the least favorable facility included in the baseline sample. The break-even LNG purchase price provides an additional indication of this economic resilience. While the assumed base-case LNG purchase price was USD 9.20/MMBtu, the estimated facility-specific break-even prices ranged from USD 38.74 to USD 67.18/MMBtu, with a sample mean of approximately USD 51.92/MMBtu. These values represent the LNG acquisition prices at which the total economic advantage of avoiding production curtailment would theoretically be exhausted, assuming that other cost components and petrochemical margins remained unchanged. The substantial gap between the assumed purchase price and the break-even thresholds indicates a relatively wide economic margin for the LNG strategy, particularly for complexes with high contribution margins and substantial production losses during gas interruption. The results therefore demonstrate that facility selection should be based not solely on gas consumption but on the economic value generated by each unit of gas supplied. Prioritizing LNG allocation to plants with the highest avoided-loss-to-gas-consumption ratios would produce greater national economic value than distributing scarce imported LNG proportionally across all gas-consuming facilities.

Table 4. One-Way Sensitivity Analysis of the Economic Performance of the LNG Virtual-Pipeline Strategy

Sensitivity variable	Change from base case	Total annual LNG supply cost (million USD)	Total net economic benefit (million USD)	Aggregate benefit-cost ratio	Interpretation
Base case	—	573.96	1,559.78	3.72	Reference condition
LNG purchase price	−20%	446.90	1,686.84	4.77	Strong improvement
LNG purchase price	+20%	701.02	1,432.72	3.04	Economically feasible
International freight cost	+25%	591.10	1,542.64	3.61	Limited deterioration
Domestic transport cost	+25%	604.41	1,529.33	3.53	Moderate deterioration
Regasification CAPEX	+25%	593.73	1,540.01	3.59	Limited deterioration
Total handling and boil-off losses	+50%	592.85	1,540.89	3.60	Limited deterioration
Petrochemical contribution margin	−20%	573.96	1,133.03	2.97	Feasible but less attractive
Petrochemical contribution margin	+20%	573.96	1,986.53	4.46	Strong improvement
Curtailement duration	−25%	498.41	1,101.90	3.21	Lower infrastructure utilization
Curtailement duration	+25%	649.52	2,017.66	4.11	Improved asset utilization

Domestic transport distance	+50%	665.28	1,468.46	3.21	Feasible with higher logistics burden
Discount rate	+4 percentage points	593.41	1,540.33	3.60	Minor effect on annual economics

The sensitivity results in Table 4 indicate that the economic viability of the virtual-pipeline approach remained positive across all modeled variations, although the magnitude of the economic advantage differed substantially among the parameters. The LNG purchase price was one of the most influential cost-side variables. A 20% reduction in LNG acquisition price lowered the aggregate annual supply cost from USD 573.96 million to USD 446.90 million and increased the benefit-cost ratio to 4.77, whereas a 20% increase raised total annual cost to USD 701.02 million and reduced the ratio to 3.04. Even at the higher LNG price, however, the strategy retained a substantial positive annual net economic benefit of USD 1.43 billion. Petrochemical contribution margin exerted an equally important influence from the benefit side. A 20% reduction in product contribution margins reduced the aggregate net benefit to approximately USD 1.13 billion and the benefit-cost ratio to 2.97, whereas a 20% increase in margins raised the net benefit to nearly USD 1.99 billion and the benefit-cost ratio to 4.46. These findings indicate that the economic justification for LNG supply is fundamentally connected to the opportunity cost of industrial production interruption. In contrast, changes in international freight, destination regasification capital costs, and boil-off losses had considerably smaller effects. A 25% increase in international freight cost reduced the benefit-cost ratio only from the reference level to 3.61, while a 25% increase in

regasification capital expenditure resulted in a ratio of 3.59. Similarly, a 50% increase in handling and boil-off losses did not eliminate economic viability. Domestic transportation was somewhat more important because of the characteristics of the virtual-pipeline model. Increasing domestic transport costs by 25% reduced the aggregate ratio to 3.53, while increasing average transportation distance by 50% reduced it to 3.21. The duration of gas curtailment produced a more complex effect because it simultaneously determined replacement-gas requirements and utilization of fixed LNG infrastructure. When curtailment duration decreased by 25%, annual net economic benefit remained positive but the benefit-cost ratio fell to 3.21 because fixed infrastructure costs were spread across a smaller volume of LNG. Conversely, extending the shortage period by 25% increased the economic utilization of the virtual-pipeline and regasification system and raised the aggregate benefit-cost ratio to 4.11. The modest effect of an increase in the discount rate further showed that the proposed configuration was driven primarily by avoided short-term production losses rather than by highly distant cash flows. Overall, the sensitivity analysis confirms that international LNG prices, petrochemical product margins, shortage duration, and inland transportation requirements were the parameters requiring the greatest attention in commercial decision-making.

Table 5. Comparative Economic Results under Favorable, Base-Case, and Unfavorable Scenarios

Indicator	Favorable scenario	Base-case scenario	Unfavorable scenario
LNG purchase price (USD/MMBtu)	7.50	9.20	12.50
Average delivered gas cost (USD/MMBtu)	13.32	15.56	19.71
Average annual gas-curtailment duration (days)	58.00	50.89	42.00
Aggregate replacement-gas requirement (million Sm ³ /year)	1,112.40	975.88	803.70
Aggregate LNG supply cost (million USD/year)	566.84	573.96	587.32
Avoided petrochemical production loss (million USD/year)	2,568.20	2,133.74	1,524.80
Net economic benefit (million USD/year)	2,001.36	1,559.78	937.48
Benefit-cost ratio	4.53	3.72	2.60
Facilities with BCR > 1	18 of 18	18 of 18	18 of 18
Facilities with BCR > 3	18 of 18	14 of 18	5 of 18
Estimated average payback period for dedicated destination infrastructure (years)	0.74	1.08	1.86
Economic decision	Strongly favorable	Favorable	Favorable with selective prioritization

Table 5 presents the combined effects of multiple simultaneous changes in the key model parameters and provides a more conservative assessment of economic robustness than the one-way sensitivity analysis. Under the favorable scenario, characterized principally by a lower LNG acquisition price, greater shortage duration, higher infrastructure utilization, and stronger petrochemical margins, the average delivered gas cost declined to USD 13.32/MMBtu. The aggregate replacement-gas requirement increased to 1,112.40 million Sm³ because LNG was assumed to be used during a larger number of gas-shortage days, yet the annual LNG supply cost remained limited to USD 566.84 million because of the lower procurement cost and improved utilization of logistics and destination assets. Avoided petrochemical production losses reached approximately USD 2.57 billion, generating a net annual economic benefit of approximately USD 2.00 billion and a benefit-cost ratio of 4.53. All 18 facilities achieved benefit-cost ratios above 3.00 in this scenario, suggesting that widespread deployment would be economically defensible where LNG could be procured under favorable contractual conditions. In the base-case scenario, the delivered cost increased to USD 15.56/MMBtu, but the strategy continued to generate a net benefit of USD 1.56 billion and an aggregate benefit-cost ratio of approximately 3.72. Fourteen of the 18 facilities recorded benefit-cost ratios greater than 3.00, and all remained above the minimum economic threshold of 1.00. The unfavorable scenario simultaneously assumed an LNG price of USD 12.50/MMBtu, higher transportation and operating costs, a shorter annual shortage period, weaker petrochemical margins, and reduced utilization of dedicated infrastructure. These conditions raised the average delivered cost to USD 19.71/MMBtu while reducing the economic value of avoided production losses to USD 1.52 billion. Nevertheless, aggregate LNG supply costs of USD 587.32 million remained substantially below the estimated curtailment losses, producing a positive annual net benefit of USD 937.48 million and a benefit-cost ratio of 2.60. All facilities continued to exceed the minimum benefit-cost threshold of 1.00, although only five retained ratios above 3.00, indicating that allocation should become considerably more selective when LNG markets and petrochemical margins are unfavorable. The modeled payback period for dedicated destination infrastructure also increased from approximately 0.74 years in the favorable case to 1.08 years in the base case and 1.86 years under unfavorable conditions. These results show that the economic case for LNG-based emergency gas supply did not

depend on an exceptionally favorable set of assumptions; rather, the strategy remained economically positive across a comparatively wide parameter range, although the intensity and geographical scope of deployment should be adjusted in response to LNG prices, plant margins, transport distances, and the anticipated duration of the gas imbalance.

Taken together, the findings demonstrate a clear economic distinction between the accounting cost of imported LNG and its economic value as a mechanism for preventing industrial production losses. Under the base-case assumptions, supplying approximately 975.88 million Sm³ of natural-gas equivalent through imported LNG, virtual-pipeline transportation, and decentralized regasification required approximately USD 573.96 million annually, while the production value preserved by this intervention was estimated at approximately USD 2.13 billion. The resulting annual net economic benefit of approximately USD 1.56 billion shows that the higher unit price of LNG relative to domestic pipeline gas does not, by itself, constitute a sufficient reason to reject supplemental LNG supply. The relevant decision criterion is the marginal value of the petrochemical output that can be maintained with each additional unit of gas. The facility-level results further indicate that the optimal strategy is not indiscriminate LNG substitution across the petrochemical sector but a prioritized allocation mechanism in which limited LNG volumes are directed first toward complexes with high contribution margins, substantial gas-related production exposure, favorable logistics, high regasification utilization, and high avoided production losses per unit of replacement gas. The sensitivity and scenario analyses reinforce this conclusion by showing that the economic advantage remained positive even when LNG prices, inland transportation costs, infrastructure expenditure, losses, and product margins shifted adversely. Accordingly, the empirical pattern of the modeled findings supports the use of LNG imports combined with virtual-pipeline delivery and on-site regasification as a flexible shortage-management instrument rather than as a permanent substitute for Iran's conventional pipeline-based natural gas system.

4. Discussion and Conclusion

The findings of this study indicate that supplying gas-deficient petrochemical complexes in Iran through imported LNG, virtual-pipeline transportation, and on-site regasification can be economically justified under conditions in which the value of avoided production losses

exceeds the incremental cost of LNG delivery. Under the base-case scenario, the 18 petrochemical complexes required an aggregate replacement-gas volume of approximately 975.88 million Sm³ per year, while the total annual LNG supply cost was estimated at USD 573.96 million. This expenditure was substantially lower than the approximately USD 2.13 billion in avoided petrochemical production losses, generating an aggregate annual net economic benefit of approximately USD 1.56 billion. The result is significant because it demonstrates that the economic assessment of imported LNG during periods of domestic gas imbalance should not be based on a direct comparison between imported LNG prices and regulated domestic pipeline-gas prices. Rather, the appropriate comparison is between the marginal cost of supplying additional gas and the opportunity cost of interrupting high-value petrochemical production. The average benefit-cost ratio exceeded 3.00, and all facilities remained economically viable under the base-case assumptions. This pattern is consistent with the broader supply-chain literature emphasizing that resilience-oriented decisions should be evaluated according to their contribution to continuity, avoided disruption costs, and preservation of system value rather than solely according to direct procurement costs [1]. It is also consistent with research on gas-sector resilience in Iran, which has highlighted the importance of maintaining continuity and adaptive capability in systems exposed to operational and supply disruptions [2]. The present results extend this logic by demonstrating that resilience can be given a measurable economic value through the comparison of supplemental gas-supply costs with avoided industrial losses.

The facility-level findings further revealed substantial heterogeneity in economic performance, with benefit-cost ratios ranging from 2.59 to 4.70 and break-even LNG purchase prices differing considerably among petrochemical complexes. This indicates that the economic attractiveness of LNG-based virtual pipelines is strongly facility-specific and depends on the interaction between gas requirement, production margin, product value, curtailment intensity, and logistics cost. Complexes characterized by larger production losses per unit of gas shortage generated the highest economic returns from supplemental LNG supply. This finding is consistent with supply-chain strategy research emphasizing that resources should be allocated to activities and nodes that generate the greatest strategic and economic value rather than distributed uniformly across a network [4]. Similarly, performance-evaluation research in the Iranian oil

and gas sector has stressed the need for multi-dimensional assessment rather than reliance on single cost indicators [5]. The implication is that emergency LNG allocation should be prioritized according to avoided economic loss per unit of gas, not merely according to the absolute size of the gas deficit. Such a prioritization mechanism would allow scarce imported LNG to be directed toward facilities where its marginal economic productivity is highest. This result also corresponds with the concept of dynamic supply-chain capability, according to which organizations facing volatile environments should continuously reconfigure resources in response to changing risks and opportunities [6]. In the context of Iran's petrochemical sector, the ability to redirect imported LNG toward different destinations according to changing shortage conditions is one of the principal advantages of a virtual-pipeline system over fixed infrastructure.

The cost decomposition analysis showed that LNG acquisition accounted for the largest share of the total delivered cost, representing close to 60% of the base-case value, while domestic virtual-pipeline transportation represented the second-largest cost component. This finding confirms that both international market exposure and domestic logistics efficiency are decisive for economic feasibility. While the commodity price of LNG cannot be fully controlled by domestic operators, logistics-related costs are potentially manageable through improved routing, tanker utilization, storage planning, scheduling, and coordination between supply-chain actors. This result aligns with research showing that logistics optimization is a central determinant of efficiency in oil and gas supply chains [3]. It also corresponds with studies that associate supply-chain optimization with improved operational performance and cash flow in the oil and gas sector [18]. From this perspective, the economic viability of LNG supplementation depends not only on procurement strategy but also on the operational design of the domestic distribution system. The importance of lean supply-chain principles is particularly evident because underutilized transport assets, excessive waiting times, repeated handling, inefficient inventory levels, and poorly coordinated unloading and regasification schedules can increase unit costs substantially. Research in the Iranian oil and gas sector has similarly emphasized the role of lean supply-chain management in reducing waste and improving resource efficiency [12]. The present findings therefore support the argument that a virtual-pipeline system should be treated as an integrated logistics network rather than merely as a transportation arrangement.

The sensitivity analysis showed that LNG purchase price and petrochemical contribution margin were the two most influential economic variables, whereas moderate changes in regasification capital expenditure, boil-off losses, freight cost, and discount rate had more limited effects on the overall feasibility of the strategy. This result is economically intuitive because the two largest determinants of value are the cost of the imported energy commodity and the industrial margin preserved by maintaining production. Even with a 20% increase in LNG price or a 20% reduction in petrochemical contribution margins, the modeled system remained economically viable at the aggregate level. This indicates a substantial margin of resilience under the tested assumptions. The result is compatible with studies emphasizing that robust supply chains are those capable of preserving performance across a range of disruptive conditions rather than only under optimal operating environments [1]. It also supports the sustainability-oriented perspective in oil and gas supply-chain management, according to which operational strategies should be assessed across multiple economic and risk scenarios rather than by static cost minimization alone [13]. The finding that the system retained positive net benefits under unfavorable conditions is particularly important for policy because it suggests that LNG supplementation may remain defensible even when global LNG prices rise, provided the avoided petrochemical production losses remain sufficiently high. In practice, however, the margin of safety would differ between complexes, reinforcing the need for facility-specific rather than sector-wide decisions.

Another important result was the effect of shortage duration and infrastructure utilization on economic performance. Longer curtailment periods increased total LNG demand but also improved the utilization of fixed storage and regasification assets, thereby spreading capital costs over a larger volume of supplied gas. Conversely, shorter shortage periods reduced aggregate supply costs but also weakened utilization and increased the relative burden of fixed infrastructure. This demonstrates an important distinction between permanent infrastructure investment and modular shortage-management systems. A large-scale fixed LNG terminal may be difficult to justify when shortages are intermittent, while modular destination-based storage and regasification can be scaled according to actual need. This logic corresponds with the broader concept of supply-chain flexibility, which seeks to match infrastructure and operational resources to uncertain demand conditions. The finding also aligns with research emphasizing sustainability

and structural adaptability in oil and gas supply chains [14]. A virtual-pipeline configuration provides an additional advantage because transportation capacity can be reallocated geographically and temporally, unlike a fixed pipeline whose economic viability depends on sustained throughput. Therefore, the modeled results suggest that the strongest case for LNG virtual pipelines exists in circumstances where shortages are recurrent but not necessarily permanent, and where the cost of building additional conventional transmission infrastructure would be difficult to justify.

The role of digitalization and advanced analytics is also relevant to the interpretation of the findings. The calculated economics depend on variables such as LNG procurement timing, fleet size, transportation distance, tanker turnaround time, destination storage capacity, daily gas deficit, and plant-specific production value. Efficient management of these variables requires high-quality operational data and dynamic decision support. Previous research has shown that digital transformation of ERP and supply-chain systems can improve visibility, integration, and real-time decision-making in oil and gas operations [7, 8]. Digital supply-chain capability has likewise been associated with improved business performance through better coordination and responsiveness [9]. Machine-learning methods have been proposed for optimizing logistics, forecasting demand, and allocating resources in oil and gas supply chains [10], while artificial intelligence has been linked to improvements in supply-chain performance through enhanced prediction, optimization, and operational decision support [11]. These studies provide strong conceptual support for the present findings because the economic viability of a virtual LNG system can be enhanced when fleet allocation, procurement timing, storage management, and plant prioritization are continuously optimized. In other words, the physical flexibility of a virtual pipeline becomes more valuable when combined with digital decision-making capability.

The findings also reinforce the importance of viewing the petrochemical supply problem through a full supply-chain lens. LNG importation, domestic transport, temporary storage, regasification, and industrial use are interdependent stages, and inefficiencies at any point can affect the final delivered cost. This system-wide perspective is consistent with research on closed-loop and integrated supply chains in the oil and gas sector, which emphasizes that individual activities should not be assessed independently from the broader network in which they operate [15, 16]. Although the current study concerns forward supply rather than reverse logistics, the underlying analytical principle is the

same: network performance depends on coordination among connected processes. The same reasoning applies to sustainability-oriented supply-chain design, where economic, operational, and risk criteria must be considered simultaneously [14]. Accordingly, LNG procurement contracts, transport logistics, destination storage capacity, and plant dispatch priorities should be designed jointly rather than through separate organizational decisions. Fragmented decision-making could result in excessive storage, insufficient tanker capacity, poorly timed deliveries, or LNG procurement volumes that do not correspond with actual industrial demand.

The favorable performance of the modeled strategy can also be interpreted through the concept of industrial value creation. Natural gas in petrochemical industries is not merely an energy input but an enabling input for products whose value may considerably exceed the commodity value of the gas consumed. Therefore, the economic return on an additional unit of gas depends on the value of the output it preserves. This result is consistent with the general principle that the economic value of a resource depends on its functional contribution to downstream outcomes rather than only on its initial market price. Although originating from a different field, the work of Alves et al. illustrates this broader concept by showing how the value of a material can be reassessed according to its potential contribution to specific downstream needs [19]. Applied to the present study, LNG should therefore be evaluated according to the industrial value it preserves at the destination. This explains why imported LNG can remain economically attractive even when its unit price is substantially higher than the domestic regulated gas price. The relevant opportunity cost is the production that would otherwise be lost.

The scenario analysis further demonstrated that the LNG strategy remained economically positive even under unfavorable conditions, although the number of facilities with very high benefit-cost ratios declined. This supports a selective rather than universal deployment strategy. Under favorable conditions, all facilities could be supplied with strong economic justification, whereas under unfavorable conditions the most efficient policy would be to prioritize facilities with the largest avoided losses per unit of gas. This finding is consistent with smart supply-chain management approaches that emphasize prioritization, adaptive allocation, and optimization under constraints [17]. It also aligns with the broader literature indicating that supply-chain performance improves when operational resources are aligned with strategic priorities and changing external

conditions [4]. Therefore, the results should not be interpreted as suggesting that imported LNG should systematically replace domestic gas. Rather, LNG should function as a targeted resilience mechanism deployed during periods of imbalance and allocated according to economic value.

The findings have several broader implications for Iran's energy and petrochemical policy. First, industrial gas curtailment should be evaluated using explicit opportunity-cost calculations rather than merely through physical allocation rules. Second, LNG imports can be economically justified even when their nominal energy cost is high, provided that the protected industrial output generates sufficient contribution margin. Third, decentralized regasification and virtual pipelines can offer a flexible alternative where constructing permanent LNG or pipeline infrastructure is not economically justified. Fourth, supply-chain resilience, logistics efficiency, digital coordination, and economic prioritization should be integrated into gas-allocation planning. These conclusions are consistent with studies emphasizing resilience, dynamic capabilities, digitalization, and operational efficiency in oil and gas supply chains [3, 6, 18]. Overall, the present study adds a specific techno-economic dimension to this literature by quantifying the economic conditions under which a flexible LNG-based supply chain can preserve industrial value during periods of gas imbalance.

A principal limitation of this study is that the economic analysis was based on modeled facility-level assumptions and standardized cost structures rather than confidential operational and contractual data from each petrochemical complex. Although the assumptions were designed to reflect realistic industrial conditions, actual LNG procurement prices, tanker costs, insurance charges, regasification expenditures, plant-specific gas intensity, and production margins may differ across facilities and over time. The analysis also focused primarily on direct economic effects and did not fully quantify environmental externalities, emissions associated with LNG liquefaction and transportation, potential congestion in road-based LNG logistics, security risks, financing constraints, sanctions-related transaction costs, or the operational consequences of prolonged disruptions in international LNG supply. In addition, the study assumed that LNG volumes could be procured and transported when required and that destination infrastructure could be installed and operated without major regulatory or technical delays. These assumptions may not always hold under real-world conditions.

Future research should therefore develop more detailed facility-specific models using actual hourly or daily gas-consumption profiles, plant-level contribution margins, specific product portfolios, and geographically precise transport routes. Further studies could compare road-based LNG virtual pipelines with alternative options such as compressed natural gas, small-scale pipeline expansion, underground storage, fuel switching, electricity substitution, or demand-response arrangements. Multi-objective optimization models could also be used to determine the optimal allocation of limited LNG volumes across multiple petrochemical complexes under simultaneous constraints related to tanker availability, storage capacity, shortage duration, and budget. Future studies should additionally incorporate environmental and life-cycle indicators, stochastic LNG price scenarios, geopolitical supply risks, emissions costs, and probabilistic assessments of shortage severity. A further extension would be the development of a real-time digital decision-support platform integrating demand forecasts, LNG procurement prices, plant economics, transport conditions, and destination storage levels.

From a practical perspective, policymakers and petrochemical operators should treat LNG-based virtual pipelines as a strategic contingency instrument rather than a permanent substitute for domestic pipeline gas. Priority should be given to facilities with high production value, high avoided-loss-to-gas ratios, favorable logistics, and strong economic margins. Modular storage and regasification systems should be preferred where shortage duration is uncertain, because they provide greater flexibility and reduce the risk of underutilized fixed infrastructure. Procurement contracts should be structured to allow flexible LNG volumes and seasonal deliveries, while tanker fleets should be optimized according to route length, turnaround time, and plant-specific requirements. A centralized coordination mechanism could further improve performance by ranking petrochemical facilities according to marginal economic benefit and directing available LNG to the locations where each unit of gas generates the greatest avoided industrial loss. Integration of real-time monitoring, digital scheduling, and operational analytics would further strengthen the reliability and economic efficiency of the system.

Authors' Contributions

Authors equally contributed to this article.

Acknowledgments

Authors thank all participants who participate in this study.

Declaration of Interest

The authors report no conflict of interest.

Funding

According to the authors, this article has no financial support.

Ethical Considerations

All procedures performed in this study were under the ethical standards.

References

- [1] S. Piya, A. Shamsuzzoha, and M. Khadem, "Analysis of supply chain resilience drivers in oil and gas industries during the COVID-19 pandemic using an integrated approach," *Applied Soft Computing*, vol. 121, p. 108756, 2022, doi: 10.1016/j.asoc.2022.108756.
- [2] J. Soheili, "Designing a Supply Chain Resilience Model in the South Pars Gas Complex," *Scientific Journal of New Research Approaches in Management and Accounting*, vol. 5, no. 18, pp. 32-48, 2021. [Online]. Available: <https://majournal.ir/index.php/ma/article/view/1000>.
- [3] S. A. S. A. Jaradi and D. N. Ayadi, "Improving Logistics and Supply Chain Efficiency in the Oil and Gas Sector: A Literature Review," *IJRDO - Journal of Business Management*, 2025, doi: 10.53555/bm.v11i1.6323.
- [4] C. A. Ogbaini, "Supply Chain Management Strategies on Oil and Gas Companies Performance in Nigeria," *INCOME: Innovation of Economics and Management*, 2025, doi: 10.32764/income.v4i3.5668.
- [5] E. Mehri Babadi, S. Iranzadeh, and K. Fathi Hafshjani, "Providing a Model for Performance Evaluation of Large-Scale Supply Chain in the Oil and Gas Industry (Case Study: National Iranian South Oil Company)," *Iranian Management Sciences Association Quarterly Journal*, vol. 17, no. 65, pp. 83-121, 2022. [Online]. Available: https://journal.iams.ir/article_369.html.
- [6] M. Behi Far, M. Razavi, and P. Jafari, "Dynamic capability of the upstream oil and gas supply chain for achieving competitive advantage," *Supply Chain Management*, vol. 27, no. 89, pp. 1-26, 2025, doi: 10.47176/scmj.2026.1620.
- [7] D. Pentyala, "Enhancing Supply Chain Management in the Oil and Gas Industry Through Digital Transformation of ERP Systems," *Research and Analysis Journal*, 2022, doi: 10.18535/raj.v5i1.278.
- [8] S. K. C. Tulli, "Enhancing Supply Chain Efficiency in the Oil and Gas Industry: The Role of Digital Transformation in ERP Systems for Real-Time Analytics and Decision-Making," *Research and Analysis Journal*, 2024, doi: 10.18535/raj.v7i03.394.
- [9] A. Jusoh, "Digital Supply Chain and Business Performance: The Case of the Oil and Gas Industry," *Information*

- Management and Business Review*, 2024, doi: 10.22610/imbr.v16i3(i)s.3998.
- [10] A. C. Odimarha, S. A. Ayodeji, and E. A. Abaku, "Machine learning's influence on supply chain and logistics optimization in the oil and gas sector: a comprehensive analysis," *Computer Science & IT Research Journal*, vol. 5, no. 3, pp. 725-740, 2024, doi: 10.51594/csitrj.v5i3.976.
- [11] A. V. Orajaka and C. V. Orajaka, "The Role of Artificial Intelligence in Enhancing Supply Chain Performance within Nigeria's Oil and Gas Sector," *International Journal of Research and Innovation in Applied Science*, 2025, doi: 10.51584/ijrias.2025.1005000110.
- [12] A. Etemadi and A. Kasraei, "Leaning the Supply Chain in the Oil and Gas Industry: A Case Study of Iran Marine Industrial Company," *Industrial Management Journal*, no. 30, pp. 36-44, 2024.
- [13] A. Hosseinzadeh, M. E. Mohammadpourzarandi, and M. A. Afshar Kazemi, "Evaluating Competitive Strategies of LARG Supply Chain Management with a Sustainability Approach: A Case Study of an Oil and Gas Operating Company," *Strategic Studies in the Oil and Energy Industry*, vol. 14, no. 55, 2022.
- [14] A. Keyghobadi, "Presenting a Model for Evaluating Supply Chain Sustainability in the Oil and Gas Industries Based on Structural Equation Modeling," *Quarterly Journal of Human Capital Empowerment*, vol. 4, no. 2, pp. 129-146, 2021.
- [15] A. K. Ghazifard and K. Rasouli, "Study of Influential Variables on Reverse Logistics and Closed-Loop Supply Chain in the Oil and Gas Industry of Gachsaran Using Hierarchical Methods," in *Seventh International Conference on Management and Accounting Sciences*, 2021. [Online]. Available: <https://civilica.com/doc/1257747/>.
- [16] A. K. Qazi Far and K. Rasouli, "Study of influential variables on reverse logistics and closed-loop supply chain in the oil and gas industry of Gachsaran using hierarchical methods," in *Seventh International Conference on Management and Accounting Sciences*, Tehran, 2021. [Online]. Available: <https://civilica.com/doc/1257747/>.
- [17] A. Kumar, "Challenges and Opportunities to Conduct a Smart Supply Chain Management in Oil and Gas Industry With a Sustainable Strategies," 2023, doi: 10.52783/jier.v3i2.171.
- [18] V. Roshan, "Enhancing Operational Efficiency and Cash Flow through Supply Chain Optimization in the Oil and Gas Sector," *International Journal of Business and Management*, 2024, doi: 10.5539/ijbm.v19n3p91.
- [19] J. B. Alves, M. H. P. Rodrigues, F. A. Duarte, E. B. Furlong, and A. Christ-Ribeiro, "Rice Bran and Its Potential To Complement the Nutritional Needs of Children and Elderly," *Plant Foods for Human Nutrition*, vol. 78, no. 1, pp. 86-92, 2023/03/01 2023, doi: 10.1007/s11130-022-01014-w.