

## Article

# Modeling and Simulation of Biomethane Injection in a Gas Distribution Network in Uzbekistan Towards a More Secure and Green Energy Supply

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## Abstract

This study assesses the potential of biomethane integration into a gas distribution network to improve supply reliability under constrained operating conditions. A steady-state, isothermal network model based on graph theory and a SIMPLE-type iterative algorithm was developed to simulate pressure distribution and mass flow in a real urban gas network in Margilan, Uzbekistan. The results show that under winter peak-demand conditions, only 30–35% of consumers satisfy the minimum pressure requirements, while under reduced summer demand, supply coverage remains limited to about 46%, indicating significant hydraulic constraints. Increasing the regulator pressures could theoretically improve supply coverage, but this is impractical due to operational limitations at the transmission level. As an alternative, biomethane injection into the medium-pressure network was investigated. A single-point injection strategy increases supply coverage to 94%, while a multi-point configuration achieves full network saturation within allowable pressure limits and with lower total injection. The novelty of this work lies in the quantitative evaluation of biomethane injection strategies in a real gas network and in the application of a SIMPLE-type iterative algorithm to a compressible gas flow simulation in complex distribution systems.

**Keywords:** biomethane injection; gas distribution network; gas network modeling; renewable gas integration; energy security; pressure distribution; urban gas infrastructure; SIMPLE algorithm; steady-state simulation



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## 1. Introduction

Uzbekistan has been carrying out fundamental reforms in recent years to develop and strengthen the energy sector. In the Development Strategy of Uzbekistan for 2022–2026, special attention is paid to the further development of “green” energy. Still, Uzbekistan is one of the key players in the field of natural gas in Central Asia. The country has a well-developed gas infrastructure due to its significant natural gas reserves. As of 2019, Uzbekistan’s proven natural gas reserves amounted to 2239.9 bcm [1]; however, natural gas production peaked in 2018–2019 at approximately 61.6–60.7 bcm and has since declined steadily, reaching 41.5 bcm in 2024, which indicates a persistent long-term reduction in

domestic gas output [2]. This amount of gas accounts for around 1.1% of the overall worldwide production of natural gas [3].

In the near future, the use of natural gas will still be a priority as natural gas contributes to the production of 84% of electricity in the country and to about 60% of total final consumption. Moreover, it represents 68% of total energy consumption in industry, 56% in transport, and 70% in residential sectors [4]. On the one hand, the country has a strong legacy, with natural gas being a primary national natural resource and a pillar of the whole economic and industrial system. On the other hand, natural gas is a major contributor to the greenhouse gas emissions of the country. A major focus on, and actions toward, decarbonization of the economy should consider innovation in this important energy sector.

From 2020 to 2021, there was a slight increase of 0.3% in energy-related carbon dioxide emissions in Uzbekistan. Additionally, there was a 0.4% increase in carbon dioxide equivalent emissions from energy, process emissions, methane, and flaring during the same period [1]. According to the New Uzbekistan development strategy, the ultimate goal is to reduce carbon dioxide emissions per unit of GDP by 35% by 2026 [5].

Despite the availability of substantial domestic natural gas resources, energy supply security remains a growing concern in Uzbekistan, largely due to an aging energy infrastructure and the high dependence on natural gas for both electricity generation, transport, and space heating. Gas-fired power plants, which account for the dominant share of electricity production, experience supply constraints during winter peak-demand periods, revealing infrastructural and operational limitations in meeting elevated loads [4].

Increasing population levels and rising industrial energy demand have further intensified pressure on the national gas and power systems, contributing to recurrent disruptions in electricity and natural gas supply. Declining domestic gas production, combined with climatic and weather variability, has exacerbated seasonal gas shortages. By 2019, the average number of power outages reached 1.9 events per month [6], indicating systemic stress within the electricity system.

To enhance energy security and ensure uninterrupted power supply, Uzbekistan has set a strategic objective to increase the share of renewable energy sources (RES) to 25% of total electricity generation by 2030, compared to the current level of approximately 10%, which is dominated by hydropower [4]. This transition underscores the need for diversification of energy sources and improved system flexibility [7], particularly through the integration of renewable and low-carbon energy carriers.

Uzbekistan has also initiated several policies and activities towards the production of hydrogen and biogas/biomethane [8]. The government adopted a number of resolutions to stimulate the construction of biogas plants at livestock and poultry factories. In Uzbekistan, biogas plants have been successfully installed in 45 livestock and poultry farms, with a combined annual production capacity of 1.1 million cubic meters of biogas [9]. According to available assessments, Uzbekistan's technical biogas potential is estimated at about 8–9 bcm per year, which corresponds to approximately 4–5 bcm of biomethane after upgrading [10].

Biogas is predominantly used for electricity and heat generation, as well as household applications. Once upgraded to biomethane, it can be injected into a gas grid or utilized as a transport fuel. In recent years, the development of biomethane production in Europe has accelerated significantly. According to the European Biogas Association, the number of biomethane plants increased from fewer than 100 facilities in 2011 to more than 1500 by 2024, reaching 1678 plants by early 2025 [11]. This rapid growth highlights the increasing role of biomethane as a key component of sustainable energy systems and demonstrates its technical feasibility for large-scale integration into existing gas infrastructure. Countries such as Sweden and Switzerland possess extensive experience in injecting biomethane into natural gas distribution networks and closed local networks, with their pioneering efforts

dating back to the 1990s [12]. Uzbekistan shall also benefit from the use of this experience in integrating biomethane into the network since it possesses the opportunity to utilize a variety of resources, including cotton stalks, by-products from different agricultural sectors, industrial and household refuse, and animal and cane waste, as sources like biomass for production of biogas.

Biomass resources derived from agriculture constitute the dominant feedstock base. In particular, cotton cultivation generates substantial residues: the annual gross energy potential of cotton stalks is estimated at approximately 2.3 million tons of oil equivalent (Mtoe), while the technically exploitable potential, considering realistic conversion efficiencies and competing uses, is assessed at around 0.3 Mtoe [4]. Livestock waste represents an additional and continuous source of organic material suitable for anaerobic digestion. Uzbekistan's agricultural sector includes more than nine million cattle and over 15 million sheep and goats, which together produce in excess of 100 million cubic meters of organic waste annually [4]. This volume provides a stable feedstock for decentralized biogas production, particularly in rural and peri-urban areas. Municipal solid waste further contributes to the country's biogas potential. Uzbekistan generates over 30 million cubic meters of solid household waste each year, with cumulative landfill volumes exceeding 100 million cubic meters. Due to limited waste separation and processing infrastructure, a large share of this waste undergoes uncontrolled biological decomposition, resulting in methane emissions that could otherwise be recovered through waste-to-biogas technologies.

Current utilization of biomass in Uzbekistan is predominantly focused on biogas production from agricultural and organic waste, enabling combined energy generation and biofertilizer production. This integrated approach provides both environmental benefits and local energy supply, particularly in off-grid or weakly connected rural regions. At present, biogas is mainly used for on-site heat and electricity generation, while the upgrading of biogas to biomethane remains limited. At present, Uzbekistan lacks a dedicated regulatory and technical framework for biomethane grid injection, as existing gas network regulations are designed exclusively for fossil natural gas, limiting biogas utilization to decentralized applications [4].

In this context, the absence of a dedicated regulatory and technical framework for biomethane grid injection in Uzbekistan contrasts with international research demonstrating the technical feasibility and economic viability of biomethane integration into existing gas networks. Although current regulations restrict biogas use to decentralized applications, numerous studies confirm that biomethane can be safely and efficiently injected into natural gas systems under appropriate conditions.

Recent research has increasingly addressed the technical and economic feasibility of integrating biomethane into existing natural gas infrastructures. Pasini et al. performed a techno-economic comparison between biomethane liquefaction and grid injection, demonstrating that direct injection into the gas grid is consistently the most cost-effective option when network connection costs remain sufficiently low. Their sensitivity analysis highlighted grid access costs as the dominant factor influencing the economic viability of biomethane deployment [13].

Mesthrige et al. [14] demonstrated that GIS-based approaches provide an effective framework for evaluating the spatial feasibility of biomethane injection into natural gas grids by jointly assessing biomass availability, optimal plant siting, and network-dependent injection constraints.

From a network operation perspective, steady-state gas network models have been widely applied to evaluate the impacts of renewable gas injection. Pellegrino et al. [15] developed a non-isothermal, steady-state model capable of representing pipeline networks with non-pipe elements, such as compressor and pressure reduction stations, as well as

looped configurations. Their simulations of distributed injection of substitute natural gas and hydrogen demonstrated that renewable gas integration affects pressure profiles, gas composition, Wobbe index, gas density, and higher heating value (HHV), underlining the necessity of network-wide modeling to ensure gas quality compliance. At the distribution level, the admissible share of biomethane or biogas injection has been shown to be primarily constrained by local network and demand conditions rather than by biomass availability alone. Stürmer [16] demonstrated that, despite substantial biogas potential from agricultural residues, only a limited fraction can be converted to biomethane and injected into the gas grid due to feed-in capacity thresholds, network availability, and technical–economic constraints. Complementarily, Cavana et al. [17] demonstrated, through a transient fluid-dynamic analysis, that admissible biogas injection levels strongly depend on regional demand patterns and temporal variations in gas composition, confirming that injection capacity cannot be defined independently of local consumption characteristics.

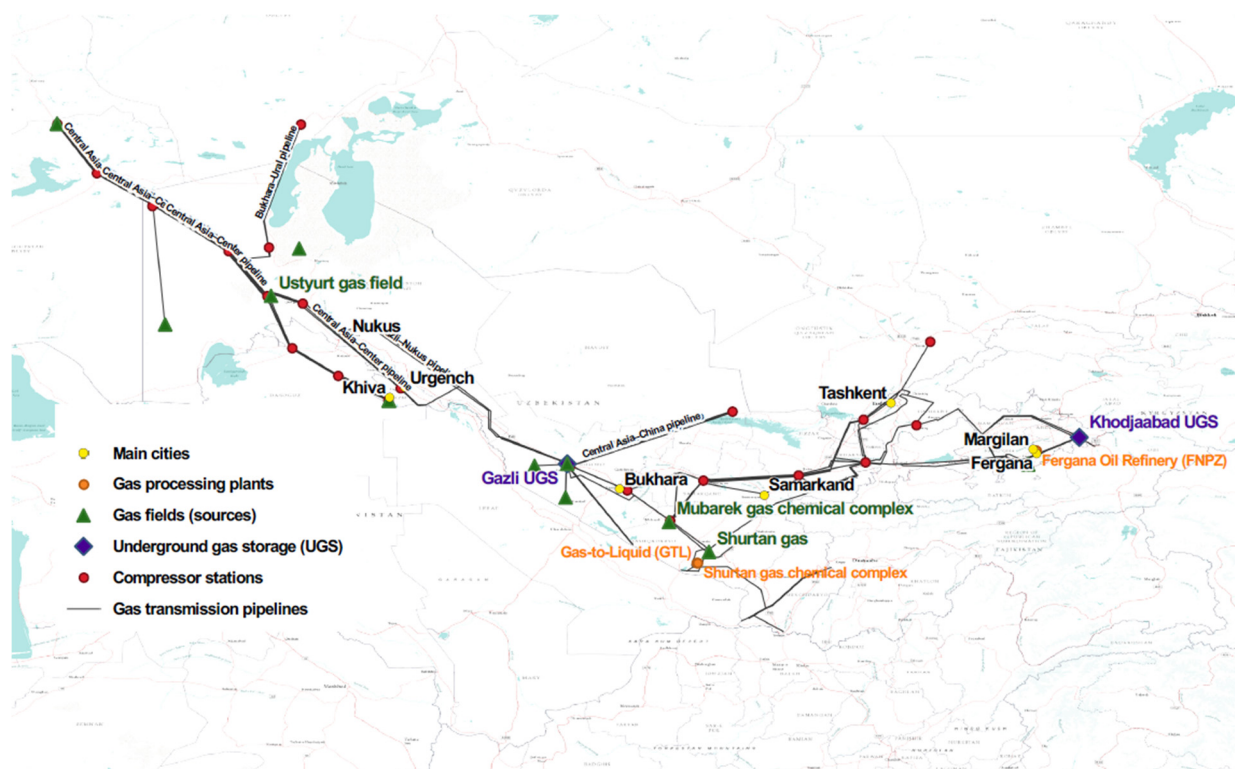
Supply-side flexibility has also been examined in the literature. Bekkering et al. [18] analyzed biomethane supply chains designed to respond to seasonal gas demand fluctuations by using measured data from a Dutch gas network to construct annual demand profiles. While their work provided valuable insights into system-level flexibility requirements, it did not explicitly model the hydraulic or compositional impacts of biomethane injection within the gas network itself. Several studies have focused specifically on low-pressure gas distribution networks. Abeysekera et al. [19] and Von Wald et al. [20] analyzed the injection of alternative gases, including biomethane and hydrogen, and observed that renewable gas distribution is inherently non-uniform, with concentrations highest near injection points. Their findings also indicated a local increase in network pressure around injection nodes and highlighted that, due to the lower HHV of biomethane compared to fossil natural gas, higher volumetric flow rates are required to deliver equivalent energy demand.

These considerations highlight the need for system-level modeling to evaluate the operational implications of biomethane integration into existing gas distribution networks. Accordingly, this paper investigates the gas system of Uzbekistan from a technical and energy-system perspective, applying a data-driven modeling framework to analyze gas flows, pressure behavior, and operational constraints under current operating conditions, with a specific focus on renewable gas integration. The modeling approach enables the assessment of network reliability and operational performance, providing a basis for improved system planning, optimization, and compliance with technical limits. In this context, the paper further examines the potential impact of biomethane injection on the gas network and particularly on a distribution network of a medium-sized city located in the eastern part of the country, evaluating its role in enhancing system flexibility, stability, and resilience based on distributed and secure renewable gas supply. By quantifying hydraulic and operational effects, the analysis supports informed decision-making for future network development in line with Uzbekistan's energy transition and decarbonization objectives. Overall, based on the results of a single case study, this study aims to support a general finding about the role that integration of distributed renewable gas may have in the modernization of energy infrastructures, improving both security of supply and renewable energy integration, and providing decentralized routes for energy infrastructure expansion.

## 2. Gas Infrastructure in Uzbekistan

Uzbekistan operates an extensive gas transportation system covering all its internal regions and is interconnected with the gas networks of neighboring countries, providing access to the markets of China and Russia (as shown in Figure 1) [1,4]. Since the early 2000s, annual natural gas exports have ranged between 10 and 15 bcm, reaching 15 bcm in 2018,

including 8 bcm to China, 4.5 bcm to Russia, 2.5 bcm to Kazakhstan, and approximately 0.5–0.55 bcm to other Central Asian countries [21].



**Figure 1.** Map of Uzbekistan’s gas infrastructure.

The gas transmission system includes the Central Asia–Center pipeline, which transports gas from Turkmenistan to Russia via Uzbekistan and Kazakhstan. This system consists of several parallel branches (CAC-2 to CAC-5) with a total capacity of approximately 60 bcm per year. In addition, the Central Asia–China gas pipeline operates through Uzbekistan and is supported by compressor stations located in the Kashkadarya and Bukhara regions. Another key infrastructure element is the Uzbekistan South Pipeline, which connects the Bukhara gas fields to the Fergana Valley through Samarkand, Fergana, and Andijan, and consists of three parallel pipelines with a total length of about 1833 km and a combined capacity of approximately 55 bcm per year.

Uzbekistan operates two underground gas storage (UGS) facilities with a total working capacity of approximately 4.6 bcm [22]. The largest site, Gazli UGS, located in the Bukhara region, plays a key role in seasonal balancing of the transmission system, while Khodjaabad UGS supports supply to the Fergana Valley. In 2024, storage utilization reached 4.21 bcm, corresponding to more than 90% of installed capacity, which highlights the increasing reliance on UGS for system balancing under declining domestic throughput conditions [23].

The total length of the main gas transmission pipelines exceeds 13,600 km, supported by 20 compressor stations equipped with approximately 250 gas-pumping units, along with around 420 gas distribution stations operating within the national gas distribution system. The distribution network extends beyond 90,000 km, supplying more than 81,000 distribution points [23]. Gas delivery is organized across high-pressure (0.3–1.2 MPa), medium-pressure (0.005–0.3 MPa), and low-pressure (0.002–0.005 MPa) systems, with approximate pipeline lengths of 9000 km, 25,000 km, and 58,000 km, respectively [24].

These pressure ranges represent nominal values defined at the regulatory level for the design and operation of gas infrastructure in Uzbekistan. However, it is important to

distinguish these standard classifications from the actual operating pressures observed in real distribution systems. In the case of the Margilan network analyzed in this study, the medium-pressure network operates at approximately 1 bar at the outlet of the high-pressure reduction station (HPRS), while downstream pressures decrease to about 0.05 bar at medium-pressure reduction stations (MPRSs), which is significantly lower than nominal classification ranges.

This discrepancy highlights that real operating conditions in distribution networks may deviate substantially from nominal regulatory values due to hydraulic constraints, demand patterns, and network topology, and therefore require detailed modeling for accurate assessment.

### 3. Methodology

The modeling framework developed by Cavana et al. and presented in [25], originally formulated as a transient, multi-component fluid-dynamic model, is adapted in this study for the simulation of a gas distribution network. To reduce computational complexity and ensure applicability to large-scale highly meshed distribution systems, a steady-state and isothermal formulation is adopted while keeping high accuracy. The model structure allows consistent application to medium-pressure urban systems due to its network-oriented formulation.

Compared to several conventional approaches reported in the literature [26–29], which often rely on simplified gas representations or limited compositional treatment, the present framework adopts a steady-state formulation combined with a graph-based solution algorithm. The model assumes isothermal flow conditions and represents natural gas as a multi-component mixture of interacting chemical species rather than as a single-component fluid.

The modeling framework adopted in this study has been previously validated in the literature. In particular, similar steady-state gas network models have been shown to provide accurate predictions of pressure and flow distribution under typical operating conditions [25,28,30]. In addition, simplified modeling assumptions, such as neglecting minor losses and geometric singularities, are commonly employed in gas distribution analysis. Previous studies indicate that these simplifications have a limited impact on overall network-level results, while significantly reducing computational complexity [28,30].

In the simulations, nominal pressure levels defined in the infrastructure description are used as baseline operating conditions. Deviations from these values, including higher pressure levels, are introduced in the analysis as parametric scenarios to evaluate the sensitivity and structural limitations of the network.

#### 3.1. Governing Equations

##### 3.1.1. Basic Equations

The dynamic behavior of compressible gas flow in pipelines is governed by the conservation laws of mass, momentum, and energy. These equations are derived from the fundamental principles of fluid mechanics and are widely used in gas transmission and distribution modeling [28,31–33].

In one-dimensional form, the general conservation equation may be written as:

$$\frac{\partial}{\partial t}(A) + \frac{\partial}{\partial x}(B) = C \quad (1)$$

where  $A$ ,  $B$ , and  $C$  are functions of the dependent flow variables.

### 3.1.2. Conservation of Mass

The continuity equation expresses conservation of mass in a pipeline control volume:

$$\frac{\partial \rho}{\partial t} + \frac{\partial(\rho v)}{\partial x} = 0 \quad (2)$$

where  $\rho$  is the gas density, and  $v$  is the gas velocity.

Introducing the mass flow rate

$$(\dot{m}) = \rho A v \quad (3)$$

and considering the steady-state problem, the continuity equation becomes

$$\frac{1}{A} \frac{\partial(\dot{m})}{\partial x} = 0 \quad (4)$$

### 3.1.3. Equation of State

Natural gas is modeled as a compressible real gas. The thermodynamic relationship between pressure, density, and temperature is expressed as:

$$\frac{p}{\rho} = ZRT \quad (5)$$

where  $Z$  is the compressibility factor,  $R$  is the specific gas constant, and  $T$  is the absolute temperature.

For medium-pressure gas networks, the compressibility factor can be evaluated using empirical correlations. In the present work, the compressibility factor is evaluated using the Papay correlation [34], suitable for medium-pressure natural gas systems:

$$Z = 1 - 3.52 * \frac{p}{p_{cr}} * e^{-2.26 * \frac{T}{T_{cr}}} + 0.274 * \left( \frac{p}{p_{cr}} \right)^2 * e^{-1.878 * \frac{T}{T_{cr}}} \quad (6)$$

where  $p_{cr}$  and  $T_{cr}$  denote critical pressure and temperature. If a natural gas with a certain composition is considered, Papay correlation can still be used. In place of the critical pressure and temperature, the pseudo-critical pressure  $p_{pc}$  and temperature  $T_{pc}$  should be considered. They are calculated by means of Kay Mixing Rule [35]:

$$p_{pc} = \sum_{i=1}^{nc} y_i p_{cr_i} \quad T_{pc} = \sum_{i=1}^{nc} y_i T_{cr_i} \quad (7)$$

where  $nc$  is the number of components and  $y_i$  is the molar fraction of the  $i$ -th component.

Under isothermal conditions, Equation (5) can be rewritten as:

$$p = \rho c^2 \quad (8)$$

where

$$c^2 = ZRT \quad (9)$$

represents the squared isothermal speed of sound. This formulation is consistent with the pressure-squared approach widely used in gas network simulations [25,28].

### 3.1.4. Conservation of Momentum

The one-dimensional momentum equation for compressible flow in pipelines is given by:

$$\frac{\partial(\rho v)}{\partial t} + \frac{\partial(\rho v^2)}{\partial x} + \frac{\partial p}{\partial x} + \lambda \frac{\rho v |v|}{2D} + g \rho \sin \alpha = 0 \quad (10)$$

where  $\lambda$  is the Darcy–Weisbach friction factor,  $D$  is the pipe diameter,  $g$  is the gravitational acceleration, and  $\alpha$  is the pipe inclination angle.

The friction factor is evaluated using the Colebrook–White implicit correlation for turbulent flow [31]:

$$\frac{1}{\lambda} = -2 \log_{10} \left[ \frac{\varepsilon}{3.7D} + \frac{2.51}{Re \sqrt{\lambda}} \right] \quad (11)$$

where  $\varepsilon$  is pipe roughness and  $Re$  the Reynolds number [36]:

$$Re = \frac{4 \left| \dot{m} \right|}{\pi D \mu} \quad (12)$$

### 3.2. Reduced Steady-State Formulation

The full one-dimensional momentum equation (Equation (10)) is reduced under assumptions consistent with medium-pressure urban gas distribution systems. Similar reduction procedures are adopted in steady-state gas network modeling frameworks [28,30].

In this study, the analysis focuses on network-wide pressure distribution and supply adequacy under typical operating conditions, rather than transient dynamics. Therefore, a steady-state formulation is adopted as an appropriate simplification, providing a suitable balance between modeling accuracy and computational efficiency [37]. Steady-state analysis provides a snapshot of network operation and is widely used to determine nodal pressures and pipe flow rates for specified boundary conditions and gas demands [19,28,30]. These are commonly employed by network operators to perform hydraulic verifications of the network, such as in the case of peak consumptions and/or to evaluate possible network expansion and topology modifications, which are in line with the scope of this study. Dynamic phenomena, such as intraday demand fluctuations and linepack variation, and their role in shaving peak-consumption moments are not represented in the present formulation and are more appropriately analyzed using transient models. However, the role of a linepack buffer in distribution systems is very limited, as can be inferred from [38], and strongly depends on the difference between upper and lower operational pressure limits. For this reason, the steady-state approach is considered adequate for the current application.

Under steady-state conditions, the transient inertia term  $\partial(\rho v)/\partial t$  is neglected by assuming a steady-state operation. This assumption is justified for distribution networks operating under quasi-stationary demand conditions, where characteristic hydraulic time scales are significantly shorter than load variation time scales. In transient calculations, the convective inertia term  $\partial(\rho v^2)/\partial x$  plays a significant role, particularly when sudden openings, closings, or valve failures occur in the network [39]. However, in steady-state conditions, its impact is relatively minor [30]. The hydrostatic term  $g \rho \sin \alpha$  is neglected by assuming horizontal pipelines ( $\sin \alpha \approx 0$ ). In urban distribution systems, elevation differences are typically small compared to friction-induced pressure gradients [40]. Previous studies have reported that elevation effects have only a limited influence on hydraulic behavior in medium-pressure gas distribution networks, whereas they become significant mainly in low-pressure systems where available pressure drops are small [41]. What is more, when the distribution networks are located in a relatively flat area, the elevation differences are so small that this simplification is justified. In addition, as commonly adopted

in the literature [19,28,30,41] and by commercial applications, the simulation model considers only distributed friction losses along pipe sections, while local hydraulic losses associated with valves, fittings, bends, tees, reducers, and other geometric singularities are neglected. In fact, these losses can, in principle, be considered as the equivalent length to be added to the geometrical length of the pipelines, and in the natural gas field they are on the order of a few meters. Considering the sizes of the municipal distribution networks, the simplification errors introduced are generally lower than 10%.

Thermal effects are neglected by assuming isothermal flow. Buried pipelines experience strong thermal buffering from surrounding soil, resulting in limited temperature variations under steady operating conditions. Isothermal modeling is therefore widely adopted in steady-state gas network simulations [25].

Under the above assumptions, the momentum equation reduces to:

$$\frac{\partial p}{\partial x} + \lambda \frac{\rho v |v|}{2D} = 0 \quad (13)$$

By using Equations (3) and (8), the governing equation can be rewritten in terms of mass flow rate as

$$\frac{\partial p}{\partial x} + \lambda \frac{c^2(\dot{m}) \left| \dot{m} \right|}{2DA^2p} = 0 \quad (14)$$

Integration along a pipeline segment of length  $L$ , assuming uniform pipe parameters, yields the classical steady-state pressure–flow relation

$$p_1^2 - p_2^2 = \frac{16\lambda c^2 L}{\pi^2 D^5} (\dot{m}) \left| \dot{m} \right| \quad (15)$$

Equation (15) represents the nonlinear hydraulic relationship between nodal pressures and branch mass flow rates and forms the basis of the network model. The associated hydraulic resistance coefficient is defined as

$$R(\dot{m}) = \frac{16\lambda c^2 L}{\pi^2 D^5} \quad (16)$$

where the nonlinearity arises from the Reynolds-number dependence of the friction factor and from the pressure-dependent compressibility factor embedded in  $c^2 = ZRT$ .

### 3.3. Network Model and Numerical Solution

#### 3.3.1. Network Representation

The urban gas distribution system is represented as a directed graph composed of  $n$  nodes and  $b$  pipelines. The network topology is described by the incidence matrix  $\mathbf{A} \in \mathbb{R}^{n \times b}$ , whose elements are defined as

$$a_{ij} = \begin{cases} -1, & \text{if pipe } j \text{ enters node } i \\ +1, & \text{if pipe } j \text{ leaves node } i \\ 0, & \text{otherwise} \end{cases}$$

Mass flow rates  $(\dot{m})_j$  are associated with pipelines (edges), while pressures  $(p_i)$  are defined at nodes.

To account for gas compressibility, squared pressures are introduced:

$$P_i = p_i^2 \quad (17)$$

This pressure-squared formulation preserves the algebraic structure of incompressible network equations while accounting for density–pressure coupling.

### 3.3.2. Nodal Mass Balance

Applying the steady-state continuity equation to each node yields:

$$\sum_{j=1}^b a_{ij}(\dot{\mathbf{m}})_j + (\dot{\mathbf{m}})_{ext,i} = 0 \quad (18)$$

where  $(\dot{\mathbf{m}})_{ext,i}$  represents the external mass injection or withdrawal at node  $i$ .

In matrix form:

$$\mathbf{A}(\dot{\mathbf{m}}) + (\dot{\mathbf{m}})_{ext} = 0 \quad (19)$$

Equation (19) enforces global mass conservation and provides  $n$  algebraic constraints.

### 3.3.3. Pipeline Momentum Equation

Under steady-state and isothermal assumptions, the integrated pressure–flow relation for each pipeline is written in pressure-squared form as

$$P_{in} - P_{out} = R_F \dot{m} |\dot{m}| \quad (20)$$

where the hydraulic resistance coefficient is defined as

$$R_F = \frac{16 \lambda c^2 L}{\pi^2 D^5} \quad (21)$$

For the entire network, the pipeline equations can be expressed in matrix form as

$$\mathbf{A}^T \mathbf{P} = \mathbf{R}_F (\dot{\mathbf{m}} \circ |\dot{\mathbf{m}}|) \quad (22)$$

where  $\circ$  denotes element-wise multiplication and  $\mathbf{R}_F$  is a diagonal matrix containing the hydraulic resistance of each pipeline.

### 3.3.4. Nonlinear Algebraic System

The nodal mass balance equation is given by Equation (19), while the pipeline momentum relation is expressed by Equation (22).

Combining Equations (19) and (22) yields the coupled nonlinear algebraic system governing the steady-state network behavior.

The nonlinearity arises from the quadratic dependence on mass flow rate, the Reynolds-number dependence of the friction factor, and the pressure dependence of density through the equation of state.

### 3.3.5. Numerical Solution: SIMPLE-Based Algorithm

The nonlinear algebraic system defined by Equations (19) and (22) is solved using a pressure–velocity coupled SIMPLE-type iterative scheme. The method relies on a pseudo-linear reformulation of the nonlinear momentum equation and a pressure-correction strategy to enforce global mass conservation.

In the following formulation, bold symbols denote vectors and matrices, while non-bold symbols represent scalar quantities and individual components.

An initial estimate of the nodal squared pressure vector  $\mathbf{P}^*$  is assumed. Based on this tentative pressure field, the nonlinear momentum equation is rearranged in pseudo-linear form as

$$\dot{\mathbf{m}} = \mathbf{Y} \mathbf{A}^T \mathbf{P} \quad (23)$$

where

$$Y = R_F^{-1} \quad (24)$$

is the pseudo-conductance matrix.

Using the guessed pressure field  $P^*$ , the corresponding tentative mass flow vector  $\dot{m}^*$  is obtained as

$$\dot{m}^* = Y^* A^T P^* \quad (25)$$

To enforce the continuity equation, corrections to pressure and mass flow are introduced:

$$P' = P - P^* \quad (26)$$

$$\dot{m}' = \dot{m} - \dot{m}^* \quad (27)$$

Assuming that variations of the pseudo-conductance matrix between successive iterations are small ( $Y \approx Y^*$ ), the mass-flow correction can be approximated as

$$\dot{m}' = Y^* A^T P' \quad (28)$$

Substituting Equation (27) into Equation (18) yields

$$A \dot{m}' = -A \dot{m}^* - \dot{m}_{ext} \quad (29)$$

Combining Equation (28) with Equation (29) leads to the pressure-correction equation:

$$H P' = \gamma \quad (30)$$

with

$$H = A Y^* A^T \quad (31)$$

$$\gamma = -A \dot{m}^* - \dot{m}_{ext} \quad (32)$$

Equation (29) constitutes the core of the SIMPLE procedure, as it links pressure corrections to mass imbalance at nodes.

Once  $P'$  is obtained, the solution is updated using under-relaxation:

$$P_{new} = P^* - \omega_p P' \quad (33)$$

$$\dot{m}_{new} = \dot{m}^* - \omega_m \dot{m}' \quad (34)$$

where  $\omega_p$  and  $\omega_m \in (0, 1]$  are under-relaxation factors introduced to enhance numerical stability.

The convergence of the iterative procedure is assessed by evaluating the residuals of the momentum and continuity equations:

$$Res_{mom} = A^T P - R_F(\dot{m} \circ |\dot{m}|) \quad (35)$$

$$Res_{cont} = A \dot{m} + \dot{m}_{ext} \quad (36)$$

The solution is considered converged when

$$\max(\|Res_{mom}\|, \|Res_{cont}\|) \leq tolerance \quad (37)$$

If the convergence criterion is not satisfied, the updated pressure and mass flow fields replace the previous estimates and the procedure is repeated until the residual norms fall below the prescribed tolerance.

## 4. Case Study: Urban Gas Distribution Network

### 4.1. Network Topology and Structural Characteristics

The mathematical framework outlined in Section 3 was applied to a real urban gas distribution infrastructure in the city of Margilan, which has a population of approximately 250,000 and is located in the Fergana region in eastern Uzbekistan [42]. The case study aims to assess the hydraulic behavior of the existing medium-pressure network under realistic operational conditions using the SIMPLE-based steady-state formulation.

The analyzed system represents a passive gas distribution network without compressor stations. Gas flow is driven exclusively by pressure differences imposed at the HPRS, which acts as the single supply node of the network within the analyzed network configuration. Such a topology introduces a structural limitation in terms of system reliability and resilience, particularly given that the network supplies approximately 250,000 inhabitants. The reliance on a single injection point creates a potential bottleneck, as any disturbance, capacity limitation, or operational issue at this node may affect the performance of the entire network.

### 4.2. Boundary Conditions and Operating Parameters

The network topology was reconstructed within this work based on publicly available data and technical assumptions. The layout was processed using Autodesk AutoCAD 2021 (Autodesk, San Rafael, CA, USA) to extract node coordinates and pipe connectivity, yielding an operational topology of 1043 nodes and 1053 pipeline segments forming a connected branched structure. For visualization purposes, the original AutoCAD coordinates were converted from millimeters to kilometers. The coordinate origin was defined for modeling convenience and does not represent a geographic reference system.

The system operates across three pressure levels, high (HP), medium (MP), and low (LP), with a single HPRS serving as the sole supply node (Figure 2). The network analysis focused exclusively on the high- and medium-pressure levels, as detailed data for the low-pressure infrastructure was not available. Low-pressure reduction stations (LPRSs) are located at the terminal points, and end-user demand is aggregated at these nodes. In total, 26 medium-pressure reduction stations (MPRSs) were identified. All terminal (degree-1) nodes are classified as LPRSs, where the aggregated demand is applied as the withdrawal boundary condition. The hydraulic incidence matrix was automatically generated from node–edge connectivity, with each branch defined by its end nodes, length, diameter, material, and pressure classification.

Gas pressure at the inlet of the HPRS varies from approximately 18 bar in summer to about 1 bar during winter. These values reflect local operating conditions at the city gate rather than nominal upstream transmission pressures.

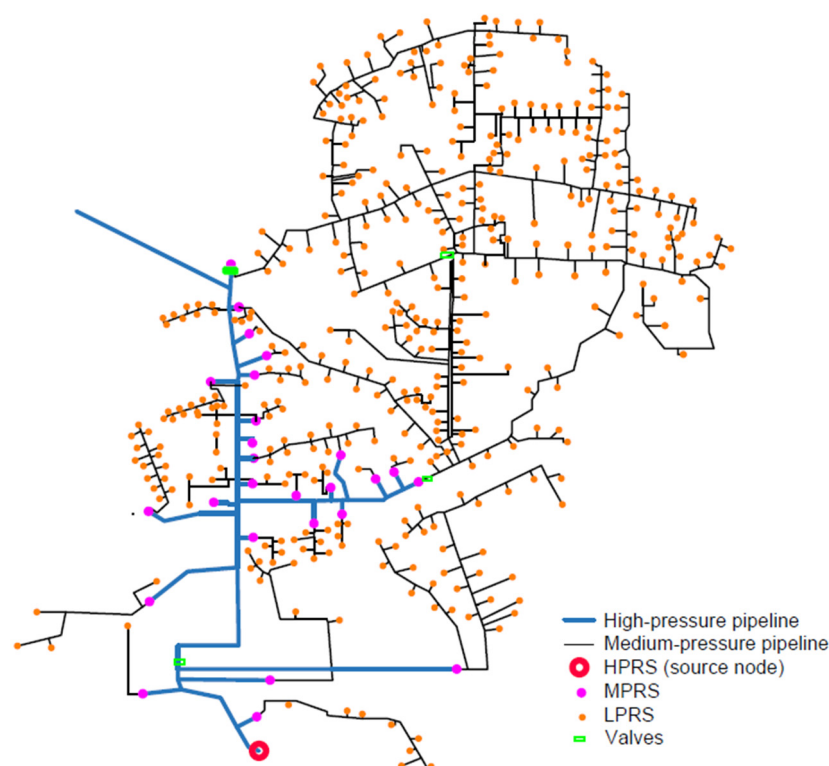
At the HPRS, the pressure is reduced to around 1 bar for the medium-pressure distribution network. When the inlet pressure drops below 1 bar(g), a bypass system is used to maintain stable operation.

The outlet pressure at the MPRS can decrease to 0.05 bar, corresponding to the minimum permissible pressure in the network.

### 4.3. Demand Modeling and Consumer Aggregation

All end users are connected to the low-pressure network. On average, each LPRS serves between 15 and 50 consumers. For modeling purposes, a value of 15 consumers per station was adopted, based on information provided by the local distribution system operator (DSO) and in line with typical configurations of low-pressure gas distribution networks. Each household is assumed to use natural gas for cooking and domestic hot water, with additional use for space heating during the winter, thus accounting for all major

household gas uses. In summer, gas consumption is limited to cooking and domestic hot water (DHW). Reported data indicate that DHW demand is approximately  $0.4 \text{ m}^3/\text{day}$ , while total household consumption during summer typically ranges from about  $0.9$  to  $1.9 \text{ m}^3/\text{day}$  [43]. Based on these figures, a representative consumption level of  $2 \text{ m}^3/\text{day}$  per consumer is adopted. During the winter season, gas consumption is dominated by space-heating demand. Measured data show that daily consumption increases significantly, reaching approximately  $8.6\text{--}10.2 \text{ m}^3/\text{day}$  during the coldest months, with typical values ranging from  $9$  to  $12 \text{ m}^3/\text{day}$  [44]. Accordingly, a representative value of  $10 \text{ m}^3/\text{day}$  per consumer is adopted.



**Figure 2.** Topology of the analyzed urban gas distribution network.

These values are consistent with residential gas consumption patterns reported in the literature for regions with comparable climatic conditions, including European regions [45], and are consistent with observed consumption patterns in Central Asian distribution networks, as confirmed by operational data provided by the DSO.

The adopted demand distribution represents a simplified and spatially uniform loading condition for network-scale hydraulic analysis. In the reality, the number of consumers connected to individual LPRSs and their gas consumption may vary depending on local conditions and specific downstream connections that are not known to the author. The nodal pressure field is representative of this underlying assumption and may slightly vary if more heterogeneous distribution is considered. However, the low-pressure level of the network is mildly meshed, and thus pressure balancing may be observed. Furthermore, the overall consideration in terms of hydraulic behavior of the network would not be dramatically changed.

#### 4.4. Pipeline Physical Properties

Once the node map is established, the pipeline network is characterized by its physical properties. Each branch is defined by its geometric characteristics, such as diameter and total length, as well as the material used in construction (Table 1). The absolute roughness

was selected based on standard hydraulic references for commercial steel pipelines. According to Crane TP-410 and Idelchik [43,46], the equivalent roughness of steel pipes typically ranges from 0.015 to 0.045 mm depending on surface condition and operational aging. In the absence of detailed information on pipe material and age, a representative value of  $\varepsilon = 0.02$  mm was adopted for all pipelines. This value lies within the commonly reported range and corresponds to typical operating conditions, ensuring a realistic estimation of friction losses without overestimating hydraulic resistance [30]. The direct assessment of pipeline roughness for an operating network is not possible. DSOs who carry out network modeling and simulation activities usually calibrate the roughness on the basis of the comparison between simulation results and on-field pressure measurements, but this was not the case as the network was not digitalized and the measurements were not available.

**Table 1.** Technical characteristics of the modeled pipelines.

| Pressure Level       | Material | Roughness $\varepsilon$ [ $\mu\text{m}$ ] | Diameter [mm] |
|----------------------|----------|-------------------------------------------|---------------|
| High pressure (HP)   | Steel    | 20                                        | 519           |
| Medium pressure (MP) | Steel    | 20                                        | 100           |

Some pipes are laid above ground, while others are buried underground. This is a common construction habit for the gas network in Uzbekistan. This may cause local differences in gas temperature, a consequence of pipeline exposure to open-air conditions. This level of detail could not be considered for two reasons: (1) the model only allows one temperature set point, common for all the infrastructure, and (2) the authors do not have the knowledge of which specific pipelines are buried and which are not.

It should be noted that the present model does not explicitly account for losses associated with diameter changes or pipe curvature. However, such simplifications are commonly adopted in steady-state gas network modeling and have a limited impact on overall system behavior, as discussed in Section 3.

The seasonal boundary conditions and the main model input parameters adopted in the simulations are summarized in Table 2.

**Table 2.** Seasonal boundary conditions and model input parameters. Temperature data source: National Centers for Environmental Information [37]. Temperature data correspond to winter 2022–2023 and summer 2023 conditions.

| Parameter                            | Unit                    | Summer Case | Winter Case |
|--------------------------------------|-------------------------|-------------|-------------|
| Nominal pressure at the HPRS inlet   | bar                     | 18          | 1           |
| Nominal pressure at the HPRS outlet  | bar                     | 1           | 1           |
| Nominal pressure at the MPRS outlet  | bar                     | 0.05        | 0.05        |
| Nominal pressure at the LPRS outlet  | bar                     | 0.02        | 0.02        |
| Average gas consumption per end node | $\text{m}^3/\text{day}$ | 2           | 10          |
| Ambient temperature (average)        | $^{\circ}\text{C}$      | 32          | 2           |
| Ambient temperature (minimum)        | $^{\circ}\text{C}$      | 12          | −14         |
| Ambient temperature (maximum)        | $^{\circ}\text{C}$      | 42          | 17          |

#### 4.5. Gas Composition and Thermodynamic Properties

Natural gas mainly contains methane and other hydrocarbons—though in smaller amounts—including ethane, propane, n-butane, i-butane, n-pentane, i-pentane, hexane, and heavier compounds at very low concentrations. The exact composition can vary depending on the production field and treatment process.

The composition adopted in this study was determined from laboratory analysis of a sample collected on 30 May 2022 within the distribution system (Tables 3 and 4).

The measured H<sub>2</sub>S concentration remains below regulatory limits, confirming adequate upstream desulfurization.

Mercaptans detected in the sample originate from odorization. In the Margilan network, ethyl mercaptan (C<sub>2</sub>H<sub>5</sub>SH) is injected at the HPRS at a dosage of 36 g per 1000 m<sup>3</sup> in accordance with safety standards [47], indicating that the sample was taken downstream of the odorization stage. The measured calorific value and relative density are consistent with medium-calorific natural gas. The experimentally determined composition was used to evaluate thermodynamic properties through the adopted equation of state for subsequent hydraulic modeling.

**Table 3.** Natural gas composition (volumetric fractions). Typical ranges based on operational data were provided by Uztransgaz. Source: Laboratory analysis report (Conclusion No. 880), Uztransgaz, Fergana Department, May) [48].

| Volumetric Fraction of Mixture Components | Unit | Acceptability Ranges | Measured Value |
|-------------------------------------------|------|----------------------|----------------|
| CH <sub>4</sub>                           | %    | 85.9–98.75           | 92.65          |
| C <sub>2</sub> H <sub>6</sub>             | %    | 0.15–5.0             | 4.6            |
| C <sub>3</sub> H <sub>8</sub>             | %    | 0.06–1.5             | 0.6            |
| iC <sub>4</sub> H <sub>10</sub>           | %    | -                    | 0.08           |
| n-C <sub>4</sub> H <sub>10</sub>          | %    | 0.02–0.1             | 0.04           |
| CO <sub>2</sub>                           | %    | 0.08–3.5             | 1.0            |
| N <sub>2</sub>                            | %    | -                    | 0.74           |
| Ar + O <sub>2</sub>                       | %    | -                    | 0.29           |

**Table 4.** Measured gas quality parameters. Source: Laboratory analysis report (Conclusion No. 880), Uztransgaz, Fergana Department, May 2022 [48].

| Parameter                                   | Unit                | Typical Value/Limit | Measured Value |
|---------------------------------------------|---------------------|---------------------|----------------|
| Lower heating value                         | kcal/m <sup>3</sup> | 8200 ± 100          | 8180.5         |
|                                             | MJ/m <sup>3</sup>   | 34.3 ± 0.4          | 34.2           |
| Solid particles content                     | g/m <sup>3</sup>    | ≤0.001              | 0.0011         |
| Hydrogen sulfide (H <sub>2</sub> S) content | g/m <sup>3</sup>    | ≤0.02               | 0.016          |
| Mercaptan sulfur content                    | g/m <sup>3</sup>    | ≤0.036              | 0.033          |
| Density                                     | kg/m <sup>3</sup>   | 0.55–0.75           | 0.72           |

## 5. Results and Discussion

The network solver was implemented using a steady-state and isothermal formulation, with natural gas modeled as a mixture of gaseous hydrocarbons. The network topology was derived from the CAD layout, enabling automatic identification of nodes and branches, as well as branch subdivision and node numbering. Simulations were performed under different operating scenarios by varying key input parameters, including ambient temperature and outlet pressures at the HPRS and MPRS.

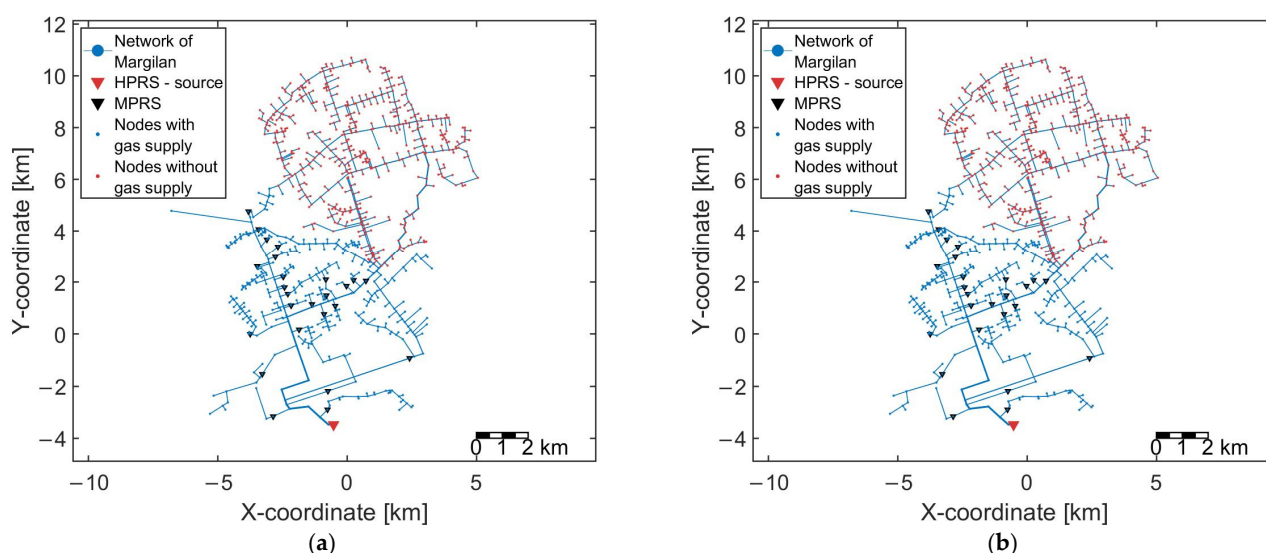
### 5.1. Seasonal Operation: Winter and Summer Scenarios

The winter operating scenario, characterized by high gas demand and low ambient temperatures, poses significant challenges for the operation of the gas distribution network and increases the risk of supply shortages. During cold periods, residential demand rises substantially due to increased space-heating requirements, leading to higher gas consumption needed to maintain indoor thermal comfort.

To evaluate these effects, simulations were performed for extreme seasonal conditions corresponding to the minimum winter temperature and maximum summer temperature, using the input data summarized in Table 2.

A pressure threshold of 0.02 bar (gauge) was adopted as a reference value corresponding to the nominal operating conditions of domestic gas appliances. According to the GOST 33998-2016 gas appliance standard, adopted within the interstate standardization framework including Uzbekistan, gas appliances operate within defined pressure ranges, with a nominal supply pressure of approximately 2.0 kPa (20 mbar) for natural gas [49,50]. Nodes with pressures below this threshold are indicated by red markers and represent areas with an insufficient gas supply. Line thickness represents gas flow rates in the network.

The results show that, under winter conditions (Figure 3b), a significant portion of the network operates below the required pressure level due to increased demand and the resulting hydraulic losses. Consequently, gas availability is insufficient for a substantial share of consumers, with only approximately 35% of end users meeting the minimum pressure requirement. This highlights the strong impact of seasonal demand on network performance.



**Figure 3.** Gas supply adequacy in the Margilan distribution network under seasonal operating conditions: (a) summer ( $T_{amb} = +42\text{ }^{\circ}\text{C}$ , demand =  $2\text{ m}^3/\text{day}$ ), (b) winter ( $T_{amb} = -14\text{ }^{\circ}\text{C}$ , demand =  $10\text{ m}^3/\text{day}$ ). The axes represent the pipeline layout coordinates in kilometers (km). Nodes are classified based on a minimum pressure threshold of 0.02 bar (gauge); blue markers indicate sufficient supply, while red markers indicate insufficient supply.

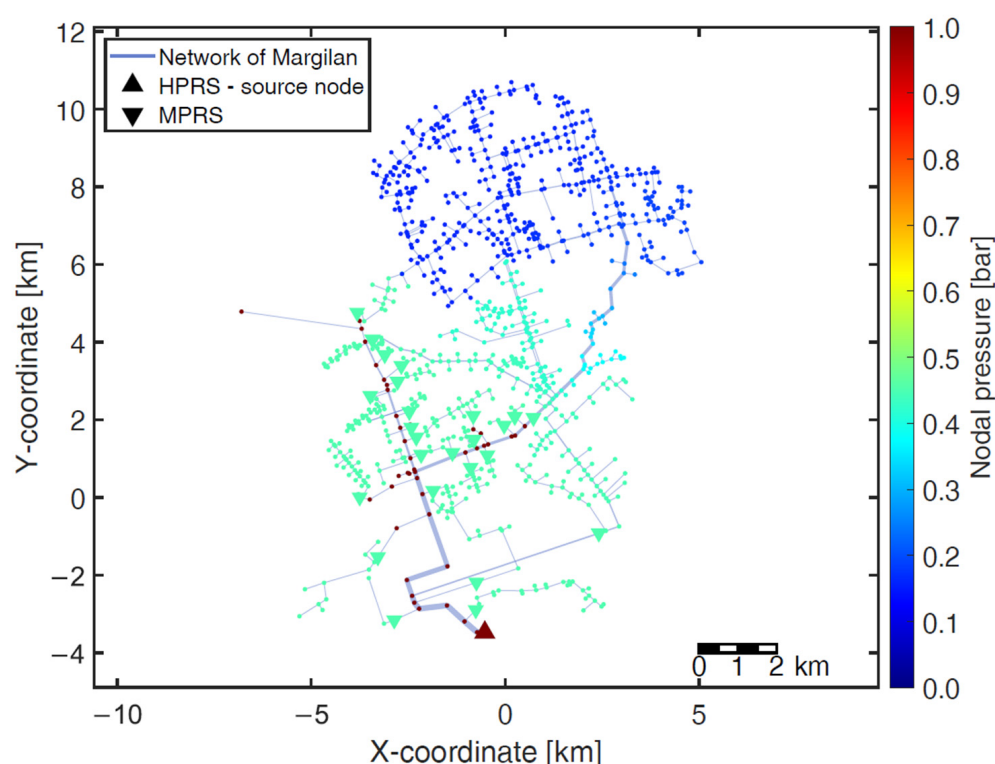
In contrast, the summer scenario (Figure 3a) demonstrates improved hydraulic behavior, as reduced demand leads to lower flow rates and smaller pressure losses throughout the network. However, even under these conditions, certain nodes remain below the required pressure threshold due to cumulative losses along the pipelines. As a result, only approximately 46% of consumers are adequately supplied with gas.

It should be noted that, although natural gas enters the city network at high pressure levels (up to 18 bar), the pressure is reduced at the HPRS to approximately 1 bar before entering the distribution network. Therefore, all simulations are conducted at distribution-level pressures, based on operational data provided by the local gas distribution system operator (DSO).

### 5.2. Pressure Sensitivity Analysis

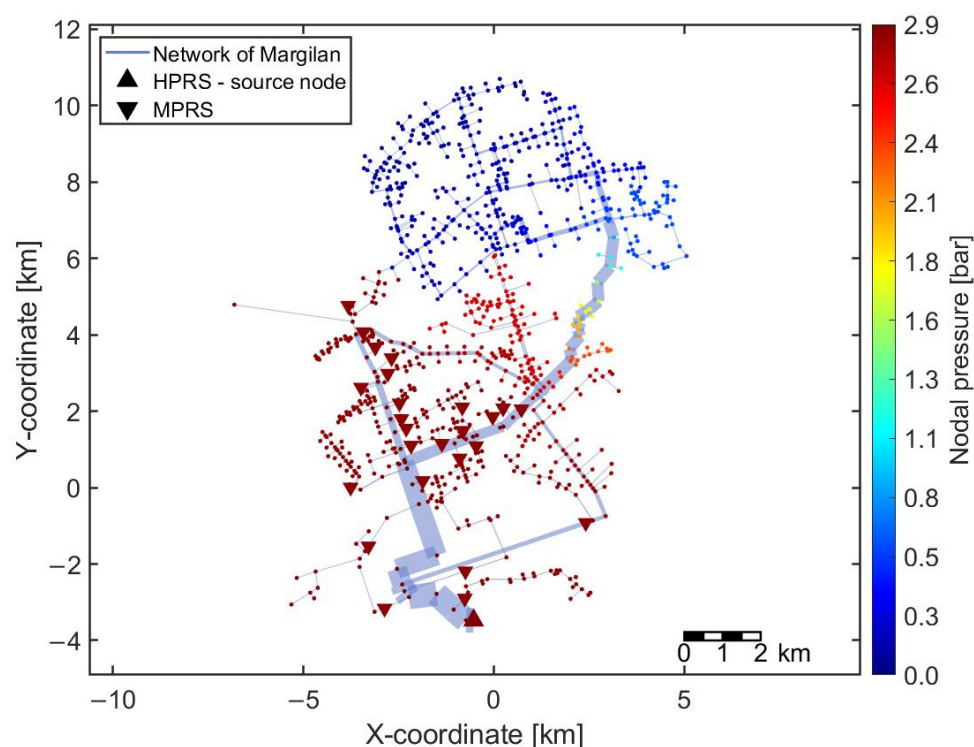
Under the nominal outlet pressure specified by the DSO for the MPRS (0.05 bar), the gas supply requirement cannot be satisfied due to insufficient downstream pressure levels. To assess the conditions necessary for full network serviceability, the outlet pressures of the reduction stations were treated as adjustable parameters.

For the summer scenario ( $T_{\text{amb}} = +42\text{ }^{\circ}\text{C}$ ; household demand =  $2\text{ m}^3/\text{day}$ ), increasing the MPRS outlet pressure from 0.05 bar to 0.452 bar, while maintaining the HPRS outlet pressure at 1 bar, is sufficient to ensure full network serviceability (Figure 4). This adjustment restores adequate pressure levels across all terminal nodes. In the winter scenario ( $T_{\text{amb}} = -14\text{ }^{\circ}\text{C}$ , household demand =  $10\text{ m}^3/\text{day}$ ), increased mass flow rates lead to significantly higher hydraulic losses across the network. The model indicates that achieving full pressure compliance at all terminal nodes would require outlet pressures of approximately 2.9 bar at the HPRS and 2.86 bar at the MPRS (Figure 5).



**Figure 4.** Pressure distribution in the Margilan gas distribution network under summer operating conditions ( $T_{\text{amb}} = 42\text{ }^{\circ}\text{C}$ , PHPRS = 1 bar, PLPRS = 0.452 bar). The axes represent the pipeline layout coordinates in kilometers (km), and the color scale indicates nodal pressure (bar).

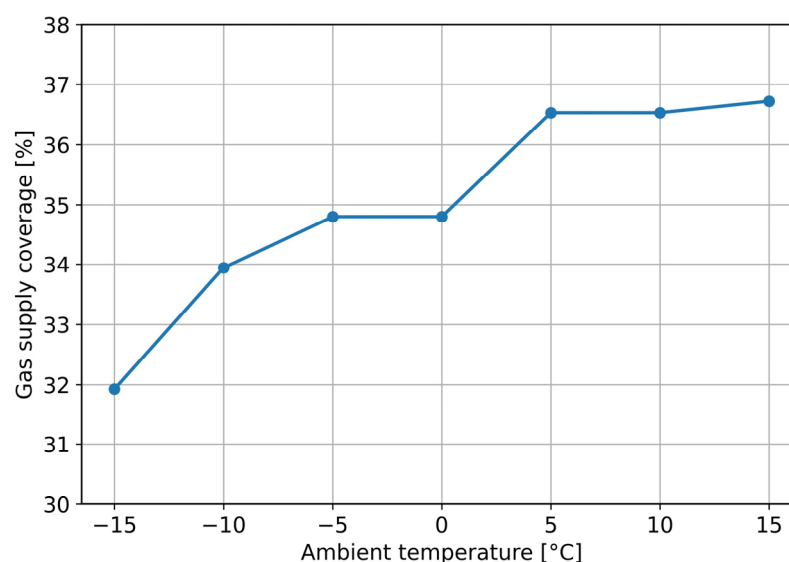
However, these values should be interpreted as theoretical requirements rather than feasible operating conditions. In practice, the outlet pressure of the HPRS is limited to approximately 1 bar due to regulatory and operational constraints, as specified by the distribution system operator. Therefore, increasing the pressure to the required levels is not realistic. This result indicates that the existing network configuration is unable to ensure an adequate gas supply under peak winter-demand conditions. Consequently, the observed pressure deficits should be interpreted as a structural limitation of the network rather than an operational issue that can be resolved by pressure adjustment alone.



**Figure 5.** Pressure distribution in the Margilan gas distribution network under winter operating conditions ( $T_{\text{amb}} = -14\text{ }^{\circ}\text{C}$ , PHPRS = 2.9 bar, PLPRS = 2.857 bar). The axes represent the pipeline layout coordinates in kilometers (km), and the color scale indicates nodal pressure (bar).

### 5.3. Gas Supply Coverage as a Function of Temperature

The primary objective of this analysis is to quantify the extent to which gas demand can be satisfied under varying climatic conditions. Figure 6 presents the relationship between gas supply coverage (expressed as the percentage of supplied end nodes) and ambient temperature during winter operation.



**Figure 6.** Gas supply coverage as a function of ambient temperature during winter operation.

Domestic gas consumption is temperature-dependent. As reported by Tso and Yau [51], residential gas demand is primarily driven by cooking, domestic hot water (DHW), and space heating. Cooking demand remains approximately constant throughout the year, whereas DHW demand shows moderate seasonal variation. In contrast, space heating

exhibits a strong inverse correlation with ambient temperature and represents the dominant component during winter periods. Accordingly, in the present study, the average daily gas consumption per household is modeled as a linear function of temperature [52]:

$$q(T) = A + BT \quad (38)$$

where  $q(T)$  is the daily gas consumption ( $\text{m}^3/\text{day}$ ),  $T$  is ambient temperature ( $^{\circ}\text{C}$ ),  $A$  represents the base load (cooking and hot water demand), and  $B < 0$  accounts for the reduction in heating demand as temperature increases. The coefficients were calibrated using the minimum and maximum observed winter daily gas consumption values (approximately  $2\text{--}20 \text{ m}^3/\text{day}$  per household). Since nodal demand directly determines mass flow rates in the network, temperature-induced variations in consumption affect pressure distribution and, consequently, the percentage of supplied nodes. The results indicate that, at  $-15^{\circ}\text{C}$ , approximately 32% of the population satisfies the minimum pressure requirement, whereas at  $+15^{\circ}\text{C}$ , this value increases only slightly to about 36.6%.

This limited improvement suggests that the network performance is primarily constrained by structural and hydraulic limitations rather than demand variations alone. Therefore, even under more favorable temperature conditions, a significant portion of consumers remains undersupplied. These findings highlight the need for infrastructure upgrades or alternative supply strategies to ensure reliable gas delivery under varying operating conditions.

#### 5.4. Hydraulic Response of the Distribution Network to Regulator Pressure Variation

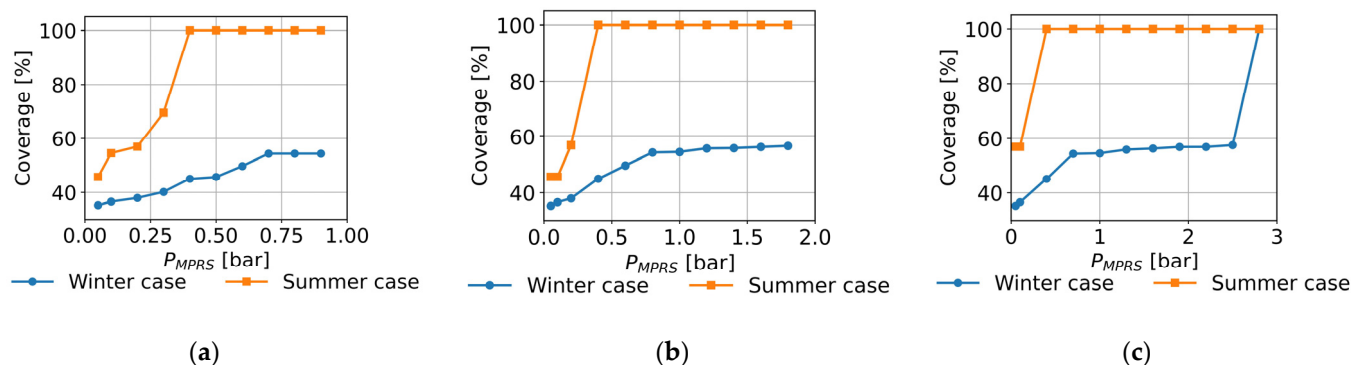
Gas supply coverage is strongly influenced by the coordinated regulation of outlet pressures at the HPRS and MPRS. Unlike the analysis presented in Section 5.2, which aimed to determine the minimum pressure levels required to achieve full network serviceability, the present section evaluates the sensitivity of network performance to variations in regulator outlet pressures.

To this end, three scenarios were analyzed with the HPRS outlet pressures of 1, 2, and 3 bar at the inlet of the medium-pressure network. For each pressure level, both winter and summer operating conditions were considered using the seasonal temperatures and consumption values reported in Table 2.

It should be noted that the considered pressure levels include both realistic operating conditions (approximately 1 bar at the HPRS outlet) and hypothetical scenarios exceeding typical regulatory limits. These extended scenarios are intentionally examined to assess the intrinsic hydraulic limitations of the network and to evaluate how pressure variations influence system performance. Therefore, the analysis is intended as a parametric sensitivity study rather than a representation of actual operating setpoints.

The results indicate that summer operation is less constrained due to reduced demand and lower hydraulic losses. In contrast, winter conditions lead to significantly higher flow rates and pressure drops, limiting the ability of the network to maintain adequate pressure at terminal nodes. Although increasing the HPRS outlet pressure improves gas supply coverage in both scenarios, full network serviceability (100% supply coverage) is achieved only at elevated pressure levels (Figure 7).

Given that such pressure increases are not feasible under normal operating and regulatory constraints, the results demonstrate that pressure regulation alone is insufficient to ensure a reliable gas supply during peak-demand conditions. Instead, the findings point to the need for infrastructure-related improvements, such as pipeline reinforcement, network reconfiguration, or the introduction of additional supply points, in order to enhance overall system performance.



**Figure 7.** Gas supply coverage as a function of MPRS outlet pressure under seasonal operating conditions for different HPRS pressure levels: (a) PHPRS = 1 bar, (b) PHPRS = 2 bar, (c) PHPRS = 3 bar.

## 6. Biomethane Integration into the Distribution Network

In the analyzed distribution network in Margilan, gas supply limitations are primarily associated with insufficient pressure levels at the HPRS, MPRS, and along the transmission pipeline. These constraints result in an inability to deliver adequate pressure to all consumers, particularly under peak-demand conditions.

As a potential mitigation strategy, the integration of biomethane into the medium-pressure network is considered. In contrast to upstream supply reinforcement, distributed biomethane injection enables localized support of pressure-deficient areas by supplying gas directly to critical nodes within the network [15,19].

The design and operation of biomethane injection facilities depend on the local operating conditions of the gas network, including pressure levels, gas composition, pipeline configuration [12,53] and, to some extent, the national incentive scheme. According to [54], the average size of operating biomethane plants in Europe is 483 m<sup>3</sup>/h, with most plants ranging from 450 to 650 m<sup>3</sup>/h. Nevertheless, there is wide variability among the European states: A French average plant is 212 m<sup>3</sup>/h, while a Danish one is 1528 m<sup>3</sup>/h.

Since pressure and flow regulation in distribution systems are controlled through metering and regulation equipment, a predefined biomethane flow rate can be introduced in a controlled manner.

Several injection configurations were analyzed by considering different connection points and injection flow rates within the medium-pressure network. Given that the network operates within a pressure range of 0.05–3 bar, biomethane injection must comply with these hydraulic limits, ensuring that the maximum allowable network pressure is not exceeded under any operating condition [34].

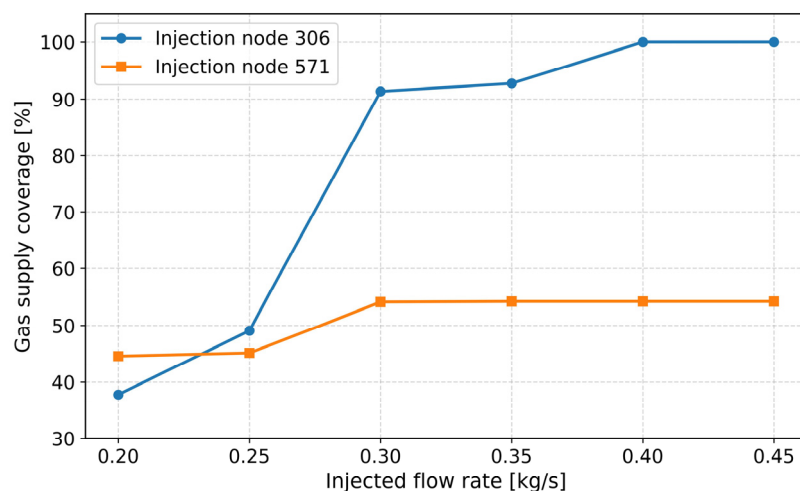
Following the network studies, a short discussion on biomethane production potential of the Fergana region is given.

### 6.1. Single-Point Injection Performance

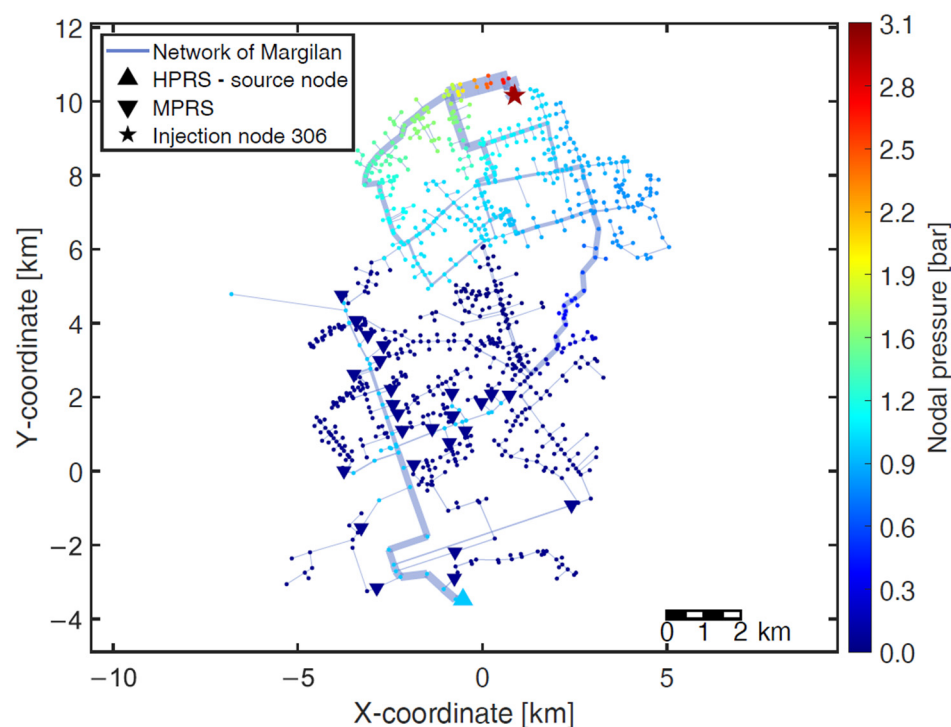
Biomethane injection simulations were performed for different injection nodes and flow rates. Figure 8 presents a comparative analysis of biomethane injection at Nodes 306 and 571. In the first scenario, Node 306 was selected as the injection point, as it represents a hydraulically critical location within the network where pressure deficits are most pronounced.

To get a full network saturation (i.e., 100% demand coverage), an injection rate of 0.39 kg/s (approximately 2000 m<sup>3</sup>/h) was applied. This high-capacity test has been chosen to evaluate the upper performance limits of the network in terms of pressure levels. However, the corresponding local pressure increased to 3.04 bar, slightly exceeding the maximum allowable operating pressure for the medium-pressure network. To satisfy the

regulatory pressure constraint of 3 bar, the injection rate was reduced to 0.387 kg/s. Under this condition (Figure 9), the maximum pressure remained within permissible limits, while the network supply coverage decreased to 94%.



**Figure 8.** Comparative analysis of gas supply coverage for biomethane injection at Nodes 306 and 571.



**Figure 9.** Pressure distribution in the Margilan gas network for biomethane injection at Node 306 with an injection rate of 0.387 kg/s. The axes represent the pipeline layout coordinates in kilometers (km), and the color scale indicates nodal pressure (bar).

In the second scenario (Figure 8), Node 571 was selected as the biomethane injection point to evaluate the influence of injection location on network performance. In contrast to Node 306, this node is located in a less hydraulically critical area of the network.

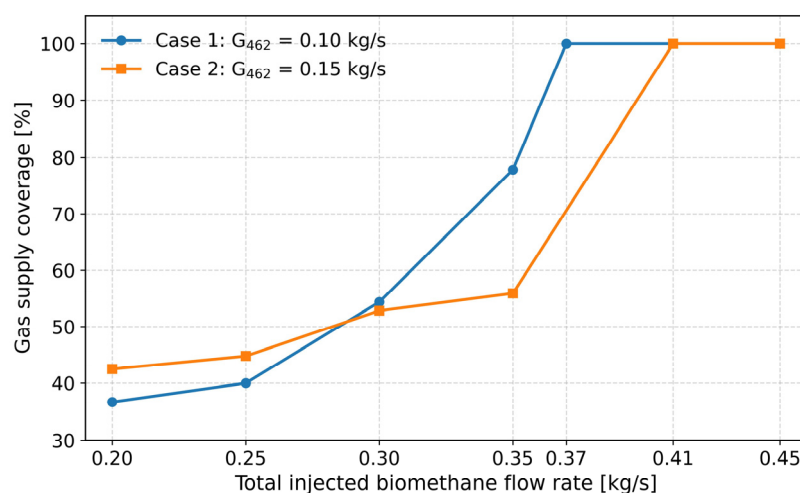
Compared to the first case, the effectiveness of injection at this location was significantly lower. For the same injection rates, the achieved network supply coverage was substantially reduced. Although the injection rate could be increased up to 0.466 kg/s while still complying with the maximum allowable pressure constraint, the resulting supply

coverage remained limited. Even at this elevated injection rate, only 54% of the population satisfied the minimum service pressure criterion.

### 6.2. Multi-Point Injection Optimization

To improve spatial uniformity of gas supply, simultaneous biomethane injections at two nodes were investigated. Based on the single-injection analysis, Node 306 demonstrated the highest hydraulic effectiveness and was therefore selected as the primary injection point. A second node (Node 462) was chosen from a previously identified critical region with persistent pressure deficiency.

Initially, equal injection rates were applied at both nodes ( $G_{306} = G_{462} = 0.1$  kg/s). The results (Figure 10) indicated only partial network saturation, suggesting that symmetric distribution of injection does not optimally exploit the hydraulic structure of the network.



**Figure 10.** Percentage of gas supply with biomethane injection at 2 nodes 1)  $G_{462} = 0.1$  kg/s 2)  $G_{462} = 0.15$  kg/s.

Subsequent simulations revealed that Node 306 exerts a significantly stronger influence on overall pressure propagation. Therefore, the injection rate at Node 462 was fixed at 0.1 kg/s, while the injection at Node 306 was increased. Complete network saturation (100% supply coverage) was achieved for  $G_{306} = 0.27$  kg/s and  $G_{462} = 0.10$  kg/s; total injection = 0.37 kg/s. Under these conditions (Figure 11), the maximum pressure in the network reached 1.66–1.67 bar, well below the 3-bar operational limit.

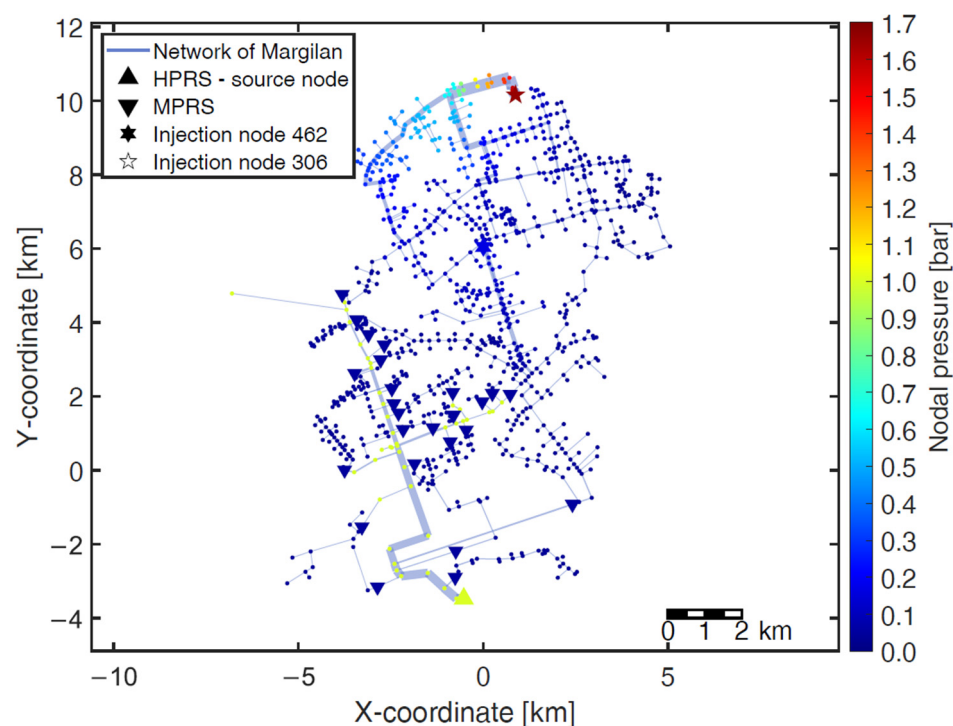
In a further scenario, the injection at Node 462 was increased to 0.15 kg/s, while adjusting the injection at Node 306 accordingly. In this configuration, full network saturation required a higher total injection rate of 0.41 kg/s, compared to 0.37 kg/s in Case 2. The maximum pressure remained moderate (approximately 1.58 bar).

### 6.3. Network-Wide Injection Sensitivity Analysis

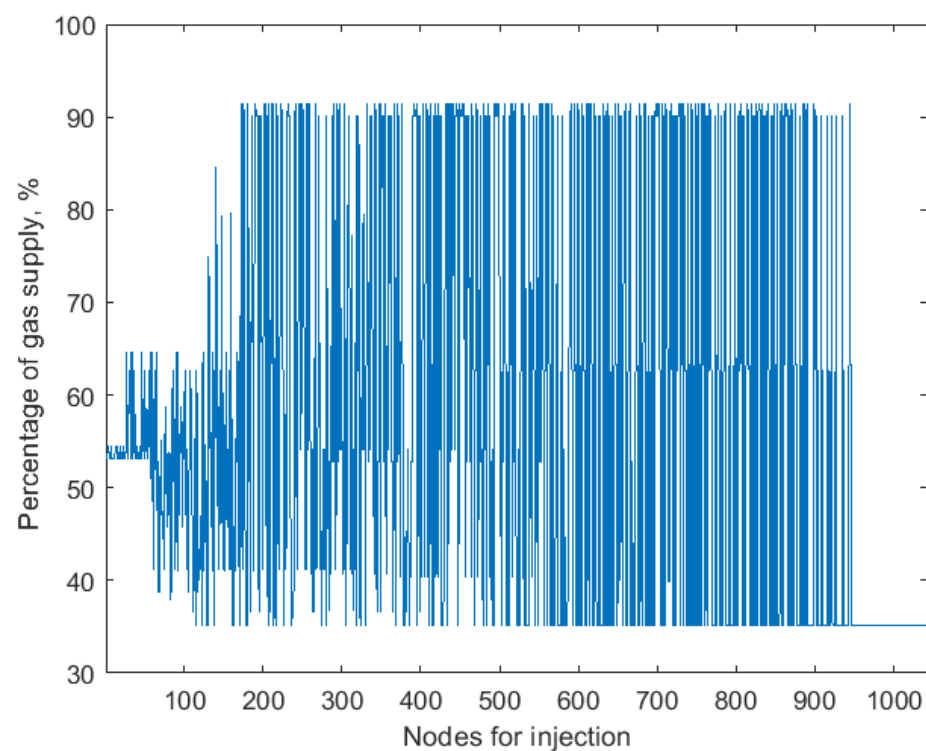
In this section, all possible single-injection scenarios are presented. Following the injection of a fixed amount of biomethane at all potential injection points, a comprehensive analysis was conducted to identify the most suitable points for biomethane injection. This analysis also determined the possible maximum saturation of the gas network under the given conditions.

Figure 12 presents the percentage of gas supply provided by biomethane injection at various nodes (source node and MPRS nodes are not included) within the network, assuming a constant injection rate of 0.3 kg/s. Under the specified injection conditions, the network saturation levels range from a minimum of 35.86% to a maximum of 91.37%.

This variation indicates that different areas of the network experience varying degrees of biomethane penetration.

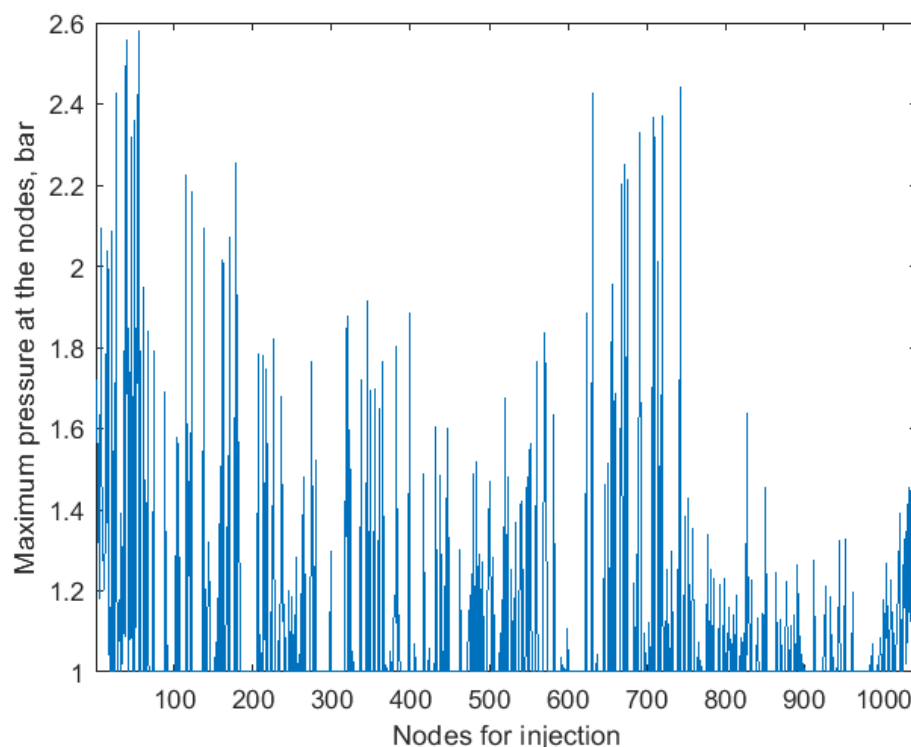


**Figure 11.** Pressure distribution in the Margilan gas network for two-point biomethane injection:  $G_{306} = 0.27$  kg/s (injection node 1) and  $G_{462} = 0.1$  kg/s (injection node 3). The axes represent scaled spatial coordinates of the network nodes, and the color scale indicates nodal pressure (bar).



**Figure 12.** Percentage of gas supply with single biomethane injection to the different nodes.  $G = 0.3$  kg/s,  $T = -14$  °C, consumption =  $10 \text{ m}^3/\text{day}$ , consumers = 15.

Furthermore, the analysis reveals that injecting biomethane at a specific point in the network results in a maximum pressure of 2.58 bar (Figure 13). This observation highlights the importance of carefully selecting injection points and managing injection rates to maintain network stability and prevent overpressurization.



**Figure 13.** Maximum pressure at the nodes with single biomethane injection to the different nodes.  $G = 0.3 \text{ kg/s}$ ,  $T = -14 \text{ }^{\circ}\text{C}$ , consumption =  $10 \text{ m}^3/\text{day}$ , consumers = 15.

#### 6.4. Calorific Differences Between Natural Gas and Biomethane

The present study focuses on hydraulic impact of distributed biomethane injection as the employed network simulator does not perform different gas mixing and composition tracing. In fact, biomethane is considered fully interchangeable with natural gas. In Table 5 the main calorific parameters of natural gas (following the composition of Table 4) and biomethane are compared and benchmarked with Uzbek gas regulation limits.

**Table 5.** Comparison between locally distributed natural gas and biomethane.

| Parameter            | Unit              | Natural Gas | Biomethane <sup>1</sup> | Difference | Uzbek Gas Regulation Limits <sup>2</sup> |
|----------------------|-------------------|-------------|-------------------------|------------|------------------------------------------|
| Lower heating value  | MJ/m <sup>3</sup> | 34.2        | 32.9                    | −4.1%      | >31.8                                    |
| Higher heating value | MJ/m <sup>3</sup> | 38.7        | 37.0                    | −4.5%      | Not standardized                         |
| Relative Density     | [-]               | 0.598       | 0.573                   | −4.2%      | Not standardized                         |
| Wobbe Index          | MJ/m <sup>3</sup> | 50.0        | 48.8                    | −2.4%      | 41.2–54.5                                |

<sup>1</sup> Network quality upgraded biomethane composition is considered: 98% CH<sub>4</sub> and 2% CO<sub>2</sub> for calorific values assessments. <sup>2</sup> GOST 5542-2014—values from Table 1—physico-chemical parameters of natural gas for industrial, municipal, and domestic purposes.

Biomethane is compliant with the calorific values prescription set by the regulation. However, the lower calorific value is about 4% less than the locally distributed one, while

the Wobbe Index difference is only 2.4% less. These differences are not considered critical under the hydraulic assessment point of view. However, under network management and billing purposes, the issue of gas quality tracing may rise as a further challenge for DSOs, especially at local level with distributed renewable gas injection.

#### 6.5. Regional Biomethane Theoretical Production Potential

While the overall national biomethane potential has been estimated to be approximately 4–5 bcm of biomethane, regional estimations would be needed as biomass is a local resource. However, regional assessment of biogas and biomethane potential for lower administrative levels (i.e., regions—viloyatlar) are lacking in the literature. To frame the biomethane injection scenarios in the broader context of local resource availability, an estimation of the biomethane potential is provided at regional level, starting from available statistics on biomass resources.

The Fergana region (where Margilan is located) possesses substantial biomass resources suitable for biomethane production. According to regional agricultural statistics, the region contains approximately 1.02 million cattle and 8.06 million poultry, together with an annual production of approximately 1.02 million tons of grain crops, 265 thousand tons of raw cotton, and 128 thousand tons of maize [42]. These resources provide considerable quantities of livestock manure and agricultural residues suitable for anaerobic digestion and biomethane production.

In addition to livestock manure, the Fergana region generates considerable quantities of agricultural residues suitable for biomethane production, including cotton residues, wheat straw, and corn stover.

The theoretical methane production potential of these agricultural residues was estimated using regional crop production statistics together with literature data on residue-to-product ratios, total solids (TS), volatile solids (VS), and specific methane yields. The estimated annual methane potential was calculated by multiplying the annual crop production by the corresponding residue-to-product ratio, total solids (TS), volatile solids (VS), and the average specific methane yield reported in the literature for each feedstock.

Tables 6 and 7 present the estimated methane potential from livestock manure and agricultural residues, respectively. The annual methane potential is approximately  $2.57 \times 10^8 \text{ m}^3/\text{year}$  for livestock manure and  $2.92 \times 10^8 \text{ m}^3/\text{year}$  for agricultural residues, resulting in a combined regional methane potential exceeding  $5.4 \times 10^8 \text{ m}^3/\text{year}$ .

**Table 6.** Preliminary estimation of the theoretical biogas and methane production potential from livestock manure in the Fergana region.

| Parameter                                       | Unit                               | Cattle             | Poultry            |
|-------------------------------------------------|------------------------------------|--------------------|--------------------|
| Livestock population <sup>1</sup>               | heads                              | 1,022,600          | 8,059,800          |
| Fresh manure production <sup>2</sup>            | kg/(animal·day)                    | 25                 | 0.036              |
| Annual manure production                        | t/year                             | $9.33 \times 10^6$ | $1.06 \times 10^5$ |
| Biogas yield <sup>3</sup>                       | $\text{m}^3/\text{t}$ fresh manure | 40–50              | 70–90              |
| Methane content in biogas <sup>3</sup>          | %                                  | 60                 | 60                 |
| Estimated annual biogas potential <sup>4</sup>  | $\text{m}^3/\text{year}$           | $4.20 \times 10^8$ | $8.47 \times 10^6$ |
| Estimated annual methane potential <sup>4</sup> | $\text{m}^3/\text{year}$           | $2.52 \times 10^8$ | $5.08 \times 10^6$ |

<sup>1</sup> Livestock population data were obtained from Ref. [42]. <sup>2</sup> Fresh manure production values were adopted from Ref. [55]. <sup>3</sup> Biogas yield and methane content were adopted from Ref. [56]. <sup>4</sup> Annual manure quantities and theoretical biogas and methane potentials were calculated by the authors using the regional livestock statistics and literature values reported in Refs. [55,56].

**Table 7.** Preliminary estimation of the theoretical methane production potential from agricultural residues in the Fergana region.

| Parameter                                       | Unit                     | Cotton Residues        | Wheat Straw            | Corn Stover            |
|-------------------------------------------------|--------------------------|------------------------|------------------------|------------------------|
| Annual crop production <sup>1</sup>             | t/year                   | 265,000                | 1,020,000              | 128,000                |
| Residue-to-product ratio <sup>2</sup>           | –                        | 1.0                    | 1.3                    | 1.0                    |
| Estimated residue production <sup>3</sup>       | t/year                   | 265,000                | 1,326,000              | 128,000                |
| Total solids (TS) <sup>4</sup>                  | %                        | 92.28                  | 96.63                  | 92.33                  |
| Volatile solids (VS) <sup>4</sup>               | %                        | 85.82                  | 82.34                  | 84.71                  |
| Specific methane yield <sup>5</sup>             | L CH <sub>4</sub> /kg VS | 62                     | 242                    | 229                    |
| Estimated annual methane potential <sup>6</sup> | m <sup>3</sup> /year     | 1.30 × 10 <sup>7</sup> | 2.56 × 10 <sup>8</sup> | 2.29 × 10 <sup>7</sup> |

<sup>1</sup> Annual crop production based on national agricultural statistics for Uzbekistan [42]. <sup>2</sup> Residue-to-product ratio (RPR) adopted from the published literature to estimate residue generation [57]. <sup>3</sup> Estimated residue production was calculated as the product of annual crop production and the residue-to-product ratio. <sup>4</sup> Total solids (TS) and volatile solids (VS) were adopted from experimental studies on untreated feedstocks. For cotton residues, TS and VS were adopted from Sołowski et al. [58]; for wheat straw from Gao et al. [59]; and for corn stover from Chen et al. [60]. <sup>5</sup> Specific methane yield values represent untreated substrates reported in the literature. For cotton residues, the average methane yield (62 L CH<sub>4</sub>/kg VS) was obtained from the reported range for untreated cotton stalks [61]. For wheat straw, the average methane yield (242 L CH<sub>4</sub>/kg VS) was calculated from the range reported for different crop maturity stages [62]. For corn stover, the methane yield of untreated corn stover (229 L CH<sub>4</sub>/kg VS) was adopted from Chen et al. [60]. <sup>6</sup> Estimated annual methane potentials were calculated by the authors using the regional agricultural production statistics and literature data reported in Refs. [57–62].

This demonstrates that the available biomass resources are sufficient to support the biomethane injection scenarios investigated in this study.

## 7. Conclusions

This study examined the gas infrastructure system of Uzbekistan, focusing on the distribution of gas in a medium-sized city's local network with the goal of studying enhanced security of gas supply through distributed renewable gas integration. Mathematical modeling was employed to identify the root causes of gas disruptions, particularly during winter.

One proposed solution to ensure a reliable gas supply is to increase the pressure in the main network and regulate it at gas distribution stations. Simulations revealed that raising the pressure at high-pressure and medium-pressure stations to 2.9 bar and 2.857 bar, respectively, could help resolve gas supply issues in winter. However, due to low pressure in the main transmission line, this approach may not be fully effective.

An alternative solution explored in this study is the injection of biomethane into the medium-pressure network. By carefully selecting the injection point, the network can be saturated with sufficient gas. By analyzing the distribution of biomethane injection, operators can identify areas with the highest potential for renewable energy utilization and optimize the allocation of biomethane resources to meet local demand. Simulations showed that injecting 0.387 kg/s of biomethane at a single point during winter can meet up to 94% of the population's gas demand.

Due to pressure limitations in the medium-pressure network (0.05–3 bar), providing gas to the entire population through a single injection point is not feasible. To overcome this challenge, the study explored the use of multi-point biomethane injection.

Simulations revealed that strategically selecting two injection points can effectively meet the population's gas demand while adhering to pressure limits. By injecting 0.1 kg/s and 0.27 kg/s of biomethane at specific points, the network can be saturated to cover 100% of the demand.

This approach not only provides a reliable gas supply but also reduces the total amount of biomethane injected compared to the single-point injection scenario. By understanding the saturation and pressure profiles of the network, operators can optimize biomethane injection strategies to maximize renewable energy utilization while ensuring safe and reliable operation.

The findings of this study also highlight the important role of mathematical modeling in supporting decision-making for gas distribution system operators. By providing a detailed representation of network behavior under varying operating conditions, the developed model enables the identification of critical bottlenecks and the evaluation of alternative supply strategies. Improvements and verification of the results may be obtained by calibrating some of the key model parameters, such as pipeline roughness and boundary pressure conditions, with on-field data. This, however, calls for the need for specific collaborations with distribution system operators. In general, the use of transparent and transferable modeling approaches facilitates knowledge transfer to distribution system operators (DSOs), allowing them to apply similar methodologies for planning and operational optimization. In this context, the adoption of open-source modeling frameworks and information exchange based on empirical know-how can further enhance accessibility, reproducibility, and practical implementation of such tools in real-world gas network management. For future works, efforts on the quality tracing of different gas qualities may help to focus on the issue of gas quality management in a local distribution network with multiple gas injections, eventually also leading to subject of hydrogen injection and blending.

The present study focuses exclusively on the hydraulic feasibility of biomethane integration into the gas distribution network. Therefore, techno-economic analysis, including biomethane production costs, grid connection costs, and greenhouse gas emission reduction assessment, was beyond the scope of the present work. The biogas and biomethane sector is still at a very early stage in Uzbekistan and other Central Asian countries; thus, literature is lacking about the production potentials and the perspective costs. Systematic reviews, statistical reporting activities, and further research should be conducted to advance all bioenergy and renewable gas topics from all the multifaceted aspects of the subject: system-level estimation of production potential (with adequate spatial resolution), and country-specific techno-economic studies and environmental impact assessment—as well as its integration with the natural gas infrastructure—focusing on the potential and criticalities of the existing infrastructure. This study aimed to cover a small portion of the latter.

The role of the gas infrastructure is fundamental for a coordinated exploitation and planning of biomethane. Network modeling and simulations may empower DSOs with tools for more advanced network analysis. Furthermore, as demonstrated in this work, the infrastructure itself may benefit from distributed injection of renewable gases (especially biomethane), strengthening the security of the supply of gas to peripheral regions in Uzbekistan where the transmission system may fail or may not be adequate under certain conditions.

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