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Power-to-gas technologies in terms of the integration with gas networks

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Abstract

In a situation of surplus electricity production from fluctuating renewable energy sources, the optimal allocation, capacity and security of energy storage will play a pivotal role in the management of energy systems. In this context, highly flexible storage facilities providing access to stored energy at very short times are gaining in importance. Power-to-gas technologies combined with the injection of the produced gas to the natural gas network create the possibility of using the existing natural gas infrastructure to store large amounts of electricity converted into chemical energy of the fuel. This paper provides overview of selected demonstration projects carried out in this field. The literature review of the sensitivity of the elements of the gas value chain to the increased hydrogen concentrations is conducted. Next, the results of the simulation study of the effect of hydrogen injection on the hydraulic properties of a gas distribution network providing gas to 1167 customers are presented.

Keywords: Energy storage; Renewable gas; Hydrogen injection; Gas quality; Quality tracking; Simulation software

Nomenclature

D	–	pipe diameter, m
H	–	gas calorific value, MJ/m^3
p	–	pressure, Pa

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R	–	individual gas constant, J/(kg K)
T	–	gas temperature, K
$\dot{V}$	–	volumetric flow rate, m^3/s
Z	–	compressibility factor

Greek symbols

λ	–	Darcy friction factor
ρ	–	gas density, kg/m^3

Subscripts

in	–	inlet flow/pressure/gas calorific value
out	–	outlet flow/pressure/gas calorific value
i,j	–	node index
k	–	pipe index

Note: Flow rate $\dot{V}$ is shown in the standard conditions of 273.15 K, 101.325 kPa, gross calorific value, H, is shown in MJ/m^3 for the reference temperature of 25 °C.

1 Introduction

A range of scientific activities related to a decentralised energy systems with renewable energy sources can be observed in Polish research and development (R&D) institutions. Some examples are given in [1], where the transition to distributed energy generation is directly related to the development of smart grids. Smart grids enable easier connection of distributed sources to the energy system, reduce the grid load and minimize the risk of blackout. The term smart grid focuses primarily on electricity sector, while smart energy system concept suggests a more integrated approach, by assuming inclusion of more sectors and infrastructures in the transformation into future renewable and sustainable energy system (electricity, district heating and cooling, natural gas, transportation) [2]. Such holistic systems approach, as opposed to a single sector approach, has the potential to identify more efficient and affordable solutions, including energy storage technologies, e.g., thermal energy storage, power-to-gas, power-to-heat, vehicle-to-grid. The consequences arising from these recent trends in electricity sector for the natural gas sector have, however, received limited attention to date. To address this gap, we review power-to-gas technologies in terms of the integration with gas networks to explore potential technical barriers and impacts of their implementation on the existing natural gas transmission and distribution systems.

Power to gas is a process of conversion of surplus electrical power into hydrogen stream *via* water electrolysis. Hydrogen can be used as a fuel in well-established compressed natural gas/natural gas facilities or injected into the existing gas grid for long-term energy storage. The injection of hydrogen produced in power-to-gas installation to the gas network is an interesting option, since it enables integration of electricity and gas systems to store surplus electricity from renewable energy sources.

Several demonstration projects to study the viability of blending hydrogen from power-to-gas installation into the gas network are currently at the design or operation stage in Europe and in the rest of the world, among them, the installation in Falkenhagen, Germany [3]. Opened in 2013 and rated as the largest such installation in the world, the plant has a power input of 2 MW and produces 360 m^3/h of hydrogen injected into the regional transmission network.

While the injection of biomethane into the gas grid does not pose any risk, the injection of hydrogen can be problematic, because it raises a number of questions related to the sensitivity of the individual system components to elevated hydrogen concentrations in the natural gas mixture. The aim of this article is, first, to summarize the literature of the integration of power-to-gas technologies with natural gas grid, and second, to present in brief the results of the investigations designed to assess the effect of hydrogen injection on gas quality at the delivery nodes in a real-life local gas distribution network.

2 Characteristics of power-to-gas technology

Generally, three types of electrolysers can be potentially used in power-to-gas installations, namely alkaline, proton exchange membrane (PEM), and solid oxide (SO) electrolysers [4]. Alkaline electrolisers operate typically at pressure and temperature conditions of 3 MPa and 80 °C, respectively. Overall efficiencies range from 60% to 70%. Commercially available modules have the power output of up to 2.5 MW. In terms of technology development, this solution is the most advanced and the cheapest; therefore, among the planned and implemented demonstration projects listed in [5], 67% of installations use alkaline electrolysers, while the remaining installations are based on the PEM electrolysers. The SO electrolysers were not used in the projects reviewed in the above work. In the case of SO electroliser the problem is in the context of material degradation due to high temperature operation. Long-term stability limitations are also expected due to thermal stress in the ceramics, resulting from the high frequency of interruptions in the operation of the electroliser in power-to-gas application [6]. The advantage of PEM electrolysers is a simple design and high efficiency in the range of 65–83%. They are also designed for rapid load changes. The limitation of their application is the maximum capacity of a single module of 30 m^3/h. Short service life due to the stability of electrolyte or proton exchange membrane calls for the attention. They are also characterized by a higher cost due to the platinum used as the catalyst.

Most power-to-gas projects assume that hydrogen produced in electrolysers is then stored in pressurized tanks. The operating pressure of storage tanks is very wide and ranges from 0.4 MPa to 70 MPa. For example, in the case of refuelling stations high hydrogen pressure of up to 70 MPa is required for fuel dispensers. High operating pressures allow for space-saving installation of storage tanks, however, increase the investment costs, due to the necessity of using hydrogen boosters. In order to reduce compression costs the buffer tanks are used and the refuelling is performed indirectly, as in the case of fillig stations of compressed natural gas (CNG). Another way to reduce the cost of compression is to use the high-pressure electrolysis. There are applications with operating pressure in the range of 1.2–3.0 MPa. The overall efficiency of the high-pressure electrolysis is about 5% higher compared to the low pressure electrolysis, however, due to higher investment and maintenance costs, it is advisable to use low-pressure electrolysers integrated with hydrogen compressors. The analysis of electrolyser pressure levels in power-to-gas plants shows that optimal pressure profile is dependent on the configuration of the plant [7].

Several authors reviewed various aspects of power-to-gas technologies [4,5,8–12]. A detailed review of the power-to-gas pilot plants is presented in [5]. Most of the projects were carried out in Germany (7), United States (6), Canada (5), Spain (4), and the United Kingdom (4). Generally, 95% of projects were implemented in Europe and North America. In the work [10], fifteen power-to-gas projects with hydrogen injection into the gas networks (including 11 locations in Germany) were reported.

There are limitations associated with the allowable hydrogen concentrations in the natural gas networks. Therefore hydrogen to methane conversion using the external CO or CO_2 source via methanation is a highly researched aspect of power-to-gas technology. Since methane is a main component of the natural gas mixture, this process leads to a grid compatible gas known as substitute natural gas (SNG). An example of power-to-gas installation integrated with SNG refuelling station is the Audi e-gas plant in the city of Werlte in Germany, comissioned in 2013 and considered as worlds' largest power-to-gas working plant by hydrogen production capacity. The electrolysers have a power input of 6.3 MW, hydrogen and SNG capacity of 1300 m^3/h and 300 m^3/h, respectively, and the average efficiency of 54%. The hydrogen is converted to substitute natural gas (methane) for fuelling the fleet of CNG cars.

The main drawbacks of power to gas are relatively low efficiency and high costs. According to [13], the overall efficiencies of power-to-gas conversion chains with and without methanisation are 56.1% and 69.9%, respectively. It is therefore of interest to inject hydrogen directly into the gas grid and devise procedures to control the hydrogen-natural gas mixture properties by gas transmission/distribution system operators.

3 Admissible hydrogen concentrations in natural gas systems

It must be emphasised that the hydrogen tolerance in the gas transmission and distribution systems should specifically be assessed per case based on location (network structure), gas composition, gas flow rate, end-user appliances, etc. The allowed hydrogen content in the gas network specified by the national regulator for work-related health and safety in Great Britain is currently $\leq 0.1\%$ (molar) [14]. The specified range for gas transmission grid by the Dutch Transmission System Operator is 2% by volume [10], while the respective figure for German market specified in DVGW Technical Rule G 262 (Utilisation of gases from renewable sources in the public gas supply) is 5% [15]. It remains an open question whether current natural gas infrastructure is ready to act as renewable energy storage with higher concentrations of hydrogen.

The sensitivity of the gas value chain to the hydrogen addition to natural gas mixture was studied in [16]. Five functional areas, namely gas transport, gas storage, regulation and metering, gas distribution, and utilisation, were identified, that span 30 core business processes. The amount of hydrogen that is technically allowable per process was reported with three thresholds, wherein: (i) mixing of hydrogen is harmless, (ii) technological and regulatory adaption is required, and (iii) research and development is still needed.

Figure 1 shows the results of the study with respect to the processes related to gas transport. The volume fraction of hydrogen in the natural gas mixture considered as a 'noncritical' varied from 50% for the material of the pipeline to 10% for the gas turbine operation in mechanical drive application (pipeline compressor). The limitation imposed on the operation of the compressor was 20%. Despite concerns about hydrogen embrittlement, natural gas transmission pipelines can cope well with hydrogen addition of up to 30% with no adverse effects. Dry low NOx burners in currently used gas turbines in compressor drive applications are tuned for optimum operation given current fuel specifications. Turbine manufactures place limits on hydrogen volume fractions in natural gas usually below 5%, but sometimes set it as low as 1%. A case by case approach is required, and, after tuning and/or modifications, much of the installed gas turbines may be capable of tolerating 5% to 10% volume hydrogen admixture [17]. As an example, Solar Turbines Inc. and Siemens AG declare the maximum allowable hydrogen content in a natural gas fuel of 4% vol. and 15% vol., respectively. Hydrogen admixture up to 20% is not critical in case of gas compressors, but higher hydrogen concentartions may cause problems related to the need of compensating for low energy content of hydrogen-natural gas mixture compared to natural gas (by volume) with higher flowrates necessary to maintain the same energy delivery.

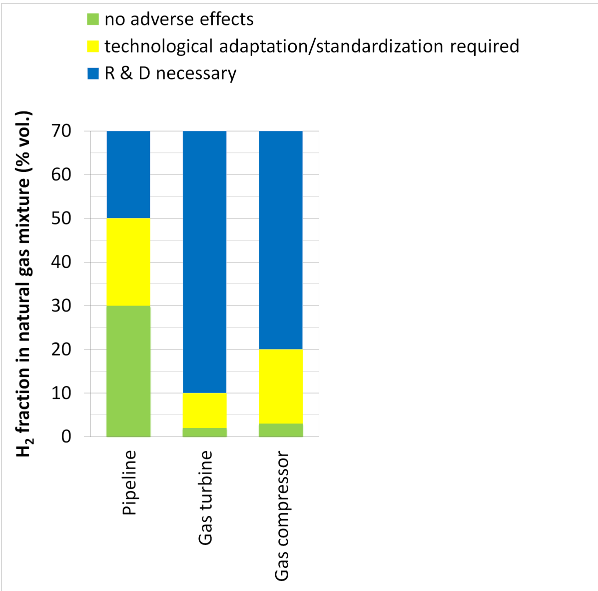

Figure 1: Sensitivity of transmission system infrastructure to the increased hydrogen concentrations [14].

As shown in Fig. 2 hydrogen fraction in natural gas mixture of around 50%vol. does not pose any difficulty for gas storage in salt caverns or tanks (pipeline linepack) except from aqufiers. In case of aquifers (possibly oil/gas depleted fields as well) serious problems associated with bacterial growth were identified, i.e., hydrogen metabolism during growth of sulfidogenic bacteria resulting in the production of H_2S. Further research is needed to explore this issue as there is no possiblity at the moment to define a limit value for the maximum acceptable hydrogen admixture for natural gas storage sites in saline aquifers.

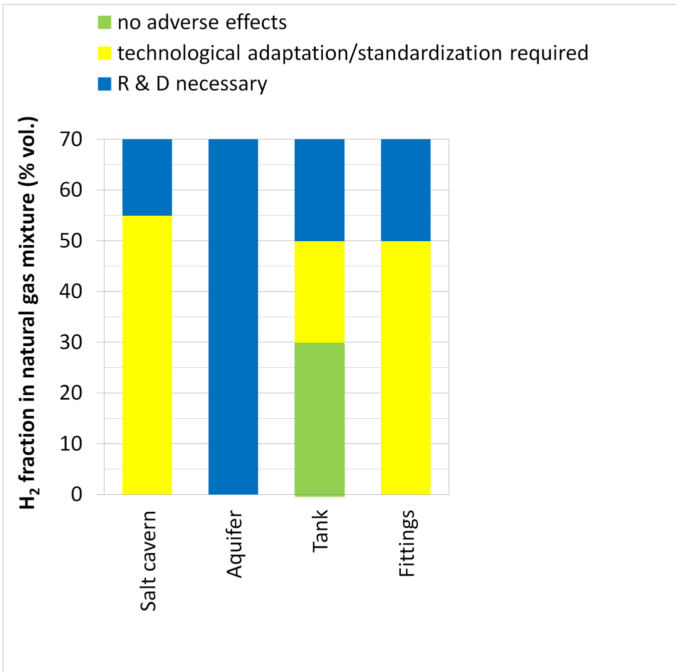

Figure 2: Sensitivity of gas storage infrastructure to the increased hydrogen concentrations [14].

Compared to the transport and storage elements of the gas value chain, distribution presents the least technically challenging component (Fig. 3). Gas distribution and in-house pipework systems, where leakage was shown to be negligible, should cause no problems. Presumably special attention will have to be drawn to leak detection devices and ATEX zoning. However, since hydrogen-natural gas mixture has a lower calorific value compared to natural gas, customers located downstream of the injection plant might be undersupplied relative to others in terms of chemical energy rate (power nominations). For example, a binary mixture of methane and hydrogen at proportions by volume/molar percent of 85% and 15%, respectively, requires 1.7 times higher flow velocity compared to the flow rate of pure methane in order to maintain constant energy delivery in the distribution networks of low and medium pressure (gauge pressure of 10 kPa and 0.4 MPa, respectively). Higher flow velocities of the hydrogen-natural gas mixture may have an impact on the operation of excess flow valves at service lines.

In case of gas metering and regulating systems, as represented in Fig. 4, attention should be given to flow computers equipped with volume corectors

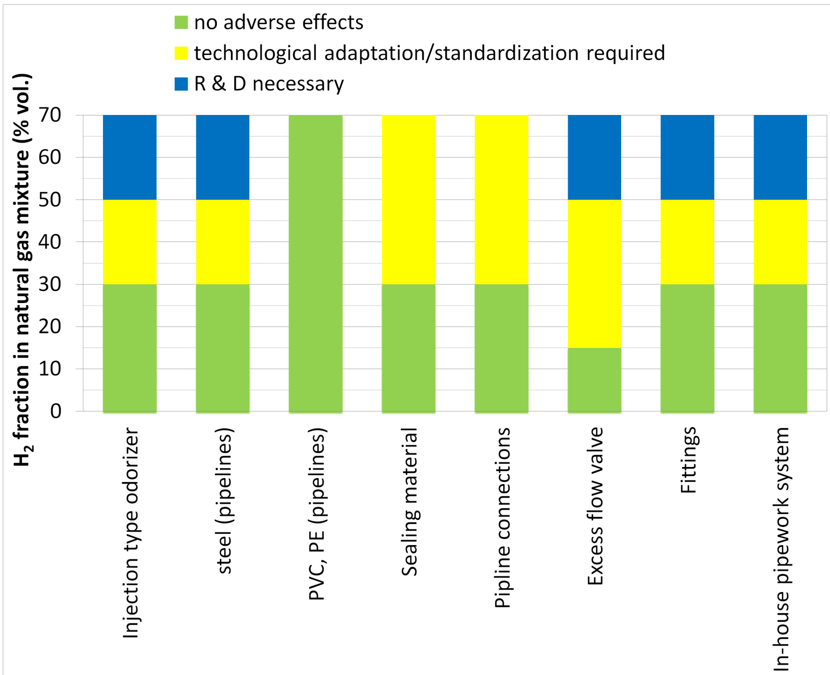

Figure 3: Sensitivity of distribution system infrastructure to the increased hydrogen concentrations [14].

implementing algorithm for the solution of GERG-88 equation of state. Current industry standards require the uncertainty of compressibility factor introduced by equation of state to be below ±0.1% for custody or fiscal transfer. GERG-88 provides this level of uncertainity with hydrogen content in natural gas mixture not exceeding 10% mol. Newer real gas models for hydrocarbon mixtures, namely GERG-2004 and GERG-2008, are for wider range of natural gases and other mixtures, therefore fulfill this requirement for higher concentrations of hydrogen. For example, under typical pipeline gas pressure-temperature conditions the uncertainity of density calculations from GERG-2004 equation of state for a binary mixture of methane-hydrogen with H_2 fraction in a range of 15–75% mol. is ±(0.07–0.1)%.

Another problem comes with existing process gas chromatographs, which use helium as the carrier gas and are unable to detect hydrogen. The problem can be solved by providing additional separation column for hydrogen detection with argon as carrier gas, on a retrofitt basis, or by replacing the existing gas chromatographs with the new ones licenced for hydrogen metering [17].

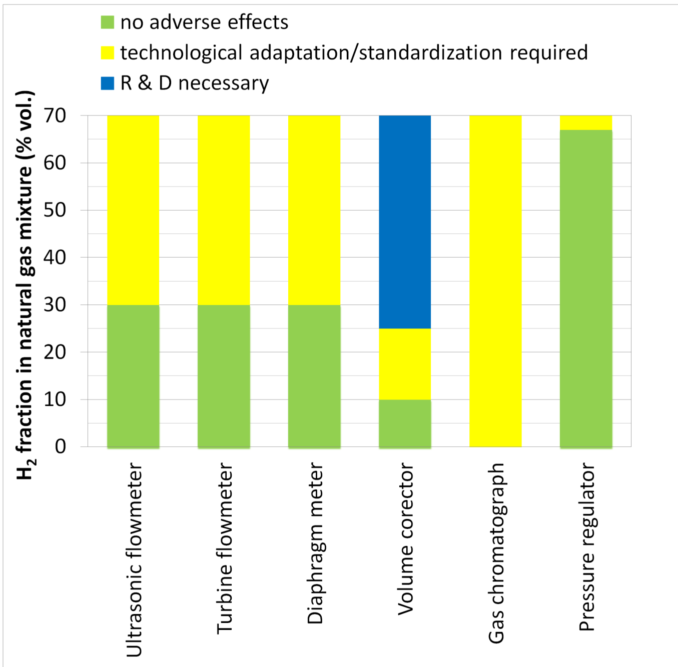

Figure 4: Sensitivity of gas metering and regulating systems to the increased hydrogen concentrations [14].

Figure 5 shows the sensitivity of end-user gas appliances to the increased hydrogen concentrations in natural gas mixture. The most severe problems are reported for steel CNG vehicle tanks. The negative effects of hydrogen on the mechanical properties of steel have been known for many years and a restriction on the maximum hydrogen admixture in CNG vehicle fuel of 2% vol. has been placed by DIN and ISO standards [18,19]. Hydrogen is an active deleterious agent when present in contact with steel. It has been shown that steel becomes permeable to hydrogen under high pressure. Simultaneously, embrittlement of the material occurs even at room temperature. The effects are aggravated by stresses and by the simultaneous presence of nitrogen, ammonia, and hydrogen sulfide. Steel can be made more resistant to hydrogen by lowering the carbon content in solid solution and by binding the remaining carbon into stable, dispersed carbides [20]. Quenched and tempered steel 34CrMo4 is employed exclusively for CNG tanks in Europe owing to its compatiblity with hydrogen, provided that the tensile strength of the steel is less than 950 MPa, and that the inner surfaces of the cylinder have been inspected for allowable defects [17].

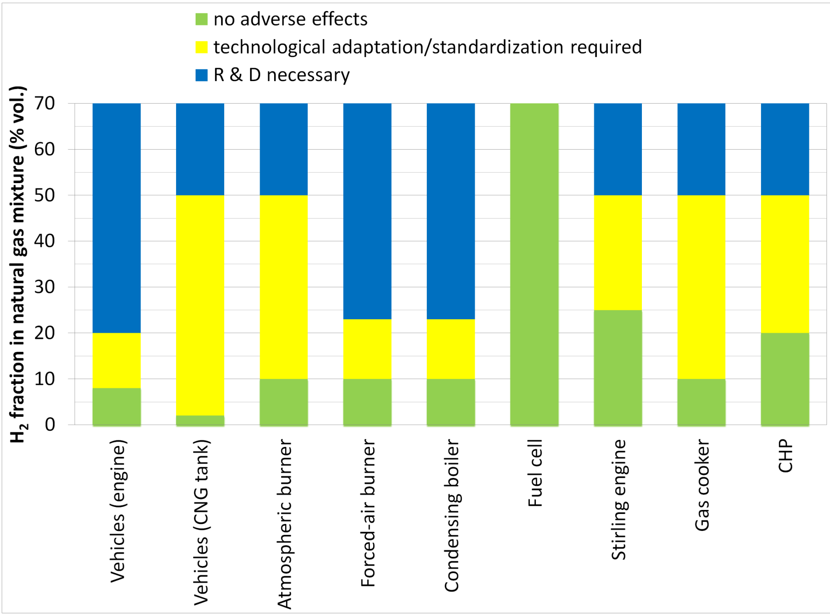

Figure 5: Sensitivity of gas appliances to the increased hydrogen concentrations [14].

Gas engines are widely used in combined heat and power (CHP) installations and in CNG vehicles. The effect of hydrogen on NOx emissions and knock resistance due to increased in-cylinder peak pressures and combustion temperatures need to be examined in the above applications. The engines need to be readjusted and/or modified from case to case, given the decrease in methane number of the resultant blend used as a fuel.

Laminar and turbulent flame speeds are important combustion parameters for atmospheric burners of the gas boilers and for combustion chambers in the gas turbines, respectively. For a binary hydrogen/methane mixture with 20%/80% concentration, about 5% increase in the laminar flame speed was observed in [21]. With regard to gas turbines, the effect of hydrogen on turbulent flame speeds is stronger, and the increase reported in [22] was about 25% for the same admixture level of 20%.

4 Gas quality tracking with software simulation tools

Hydrogen addition reduces the calorific value of the gas mixture measured by volume. This effect may lead to higher gas flow rates in pipes and significant underpressures, which have serious impact on the reliability of the pipeline transport. In order to get a fundamental understanding of how power-to-gas equipment impacts the pressure and flow of gas in the network, computer simulations must be performed, that demonstrate basic hydraulic properties of the network and scenarios of new operating conditions that dispatchers must respond to.

The flow model of hydrogen-natural gas mixture under steady-state conditions in a single pipeline has been investigated in [23,24]. The studies assume isothermal flow condition and horizontal layout of a pipeline. The effect of hydrogen injection to the tree-shaped gas network was also studied in [25]. More recent studies concerning hydrogen-natural gas mixture flows in looped network are reported in [26,27]. The former is devoted to small scale gas distribution network without non-pipe units, the latter to the transmission network, wherein non-pipe units (compressor stations) are also present. The Newton-nodal method was used for the solution of the set of nodal equations describing the gas network in the above research studies, which precludes their application to a large scale system due to poor convergence characteristics and method's sensitivity to initial conditions [28].

In the present study the Newton loop-node method [28] is used for the solution of hydraulic and mass transport (gas quality tracking) model in a larger-scale gas distribution network with complex structure, two pressure levels and twelve non-pipe elements (pressure regulator stations).

We consider a network with N nodes, M pipes, and IU units. There are N nodal flow, $\dot{V}$, balancing equations (Kirchhoff's first circuit law)

$$\sum_{k \in C_i} a_{ik} \dot{V}_k = S_i \;, \tag{1}$$

where C_i is the set of all pipes connected to node i, $a_{ik} = \pm 1$, whether pipe k begins (+1) or ends (-1) at node i, and S_i is the flow entering node i.

There are M pressure drop equations expressed by nodal pressures p,

$$p_i^2 - p_j^2 = c \frac{\lambda_k L_k \rho Z R T}{D_k^5} \dot{V}_k \left| \dot{V}_k \right| \;, \tag{2}$$

where $p_i - p_j$ is the pressure drop over pipe k with begin node i and end node j, λ_k is the Darcy friction factor of pipe k, L_k is the length of pipe k, ρ is the gas density, Z is the compressibility factor, R is the gas constant, T is the gas temperature, D_k is the internal diameter of pipe k, and c is the constant in the pressure drop equation. The pressure drop equations use the volumetric flow rate and density at standard conditions.

Nodal balance equations are rewritten in matrix form by means of $N \times M$ node-branch incidence matrix. The network simulation begins with an initial estimate of flows in each pipe that may not necessarily satisfy flow continuity. At each iteration, new nodal pressures are found by solving the matrix equation

$$\mathbf{Jp} = \mathbf{f} \ , \tag{3}$$

where $\mathbf{J}$ is the Jacobian matrix, dim $\mathbf{J} = (N \times N)$, $\mathbf{p}$ is the vector of unknown nodal pressures, dim $\mathbf{p} = (N \times 1)$, and $\mathbf{f}$ is the vector of right hand side terms, dim $\mathbf{f} = (N \times 1)$. Each right hand side term consists of the net flow imbalance at a node.

After new pressures are computed by solving the set of Eq. (3), new flows are found from pressure drop equations. The system of equations must be solved using a sparse matrix methods based on node reordering. Reordering of the nodes allows us to minimize the amount of fill-in for matrix $\mathbf{J}$. Furthermore, a symbolic factorization is carried out so that only the nonzero elements of $\mathbf{J}$ need to be stored and operated on in memory [28]. The presence of non-pipe units introduces extra unknown variables and hence additional equations are needed for the solution. In our case a general equation is introduced of the form

$$m_1 p_{in} + m_2 p_{out} + m_3 \dot{V} = f \ , \tag{4}$$

where p_{in} is the unit inlet pressure, p_{out} is the unit outlet pressure and $\dot{V}$ is the flow through the non-pipe unit, while m_1, m_2, m_3, and f are coefficients whose values depend on the controlling constraint of the non-pipe unit.

At a node a perfect mixture of all entering gases is assumed. As a result all gases leaving a node have the same quality (the nodal quality, e.g., gas calorific value). Denoting the nodal quality at node i by H_i, the energy balancing equation is

$$\sum H_{\text{in}} \dot{V}_{\text{in}} = \sum H_{\text{out}} \dot{V}_{\text{out}} = H_i \sum \dot{V}_{\text{out}} \ . \tag{5}$$

Substitution of volumetric balance equation $\sum \dot{V}_{\text{in}} = \sum \dot{V}_{\text{out}}$ yields

$$H_i = \frac{\sum H_{\text{in}} \dot{V}_{\text{in}}}{\sum \dot{V}_{\text{in}}} \ . \tag{6}$$

This mixing rule is valid for each property that can be represented by a linear relation in the components.

Once the distribution of the flows in a network is determined, the gas qualities in the nodes can be calculated. The set of equations arranged in a matrix form is

$$\mathbf{Gh} = \mathbf{b} \ , \tag{7}$$

where **G** is the coefficient matrix consisting of the flows, dim $\mathbf{G} = (N \times N)$, $\mathbf{h}$ is the vector with nodal qualities, dim $\mathbf{h} = (N \times 1)$, and $\mathbf{b}$ is the right hand side vector containig the sums of products of quality and flow of the supplies, dim $\mathbf{b} = (N \times 1)$. If there are branches with zero flow, solvability of the system of quality equations needs to be maintained.

Gas quality tracking problem is described by the following procedure:

(i) give all the nodes an initial quality;

(ii) calculate the nodal pressures and pipe flow rates in the network using Eqs. (3) and (2), respectively;

(iii) repeat:
- recalculate the quality at each node using Eq. (7);
- recalculate the pressures and flow rates in the network, step (ii),

until the change in quality is negligible.

Tests have shown that above iterative procedure in conjunction with Newton loop-node method is very robust.

5 Case study

Simulation tests were carried out for the gas network in the city of Chełmno in Poland [29]. The network consists of 390 nodes, 416 pipelines and 1167 service pipes. Figure 6 shows the structure of the dual pressure level network, i.e., 0.4 MPa grid marked with grey lines and 10 kPa grid marked with black lines. The 0.4 MPa grid is fed from an upstream high pressure gas transmission pipeline through a single pressure regulator station with a nominal capacity of 9000 m^3/h (marked with square symbol in the upper part of Fig. 6). The low pressure grid is supplied through a total of 18 entry points, including 4 pressure regulator stations delivering gas to municipal areas with the capacity of, respectively, 2000 m^3/h, 3500 m^3/h, 600 m^3/h, and 1600 m^3/h, one pressure regulator station with the capacity of 60 m^3/h servicing domestic users, and 14 pressure regulator stations delivering gas to industrial users. Currently they all provide gas of the same quality (Tab. 1). The total length of the pipelines is 41.2 km, while the length of service pipes is 19.5 km. A brief description of the network pipe data is provided in Tab. 2. A characteristic feature of the network is its non planarity, due to large differences in terrain height resulting in considerable changes in node elevations

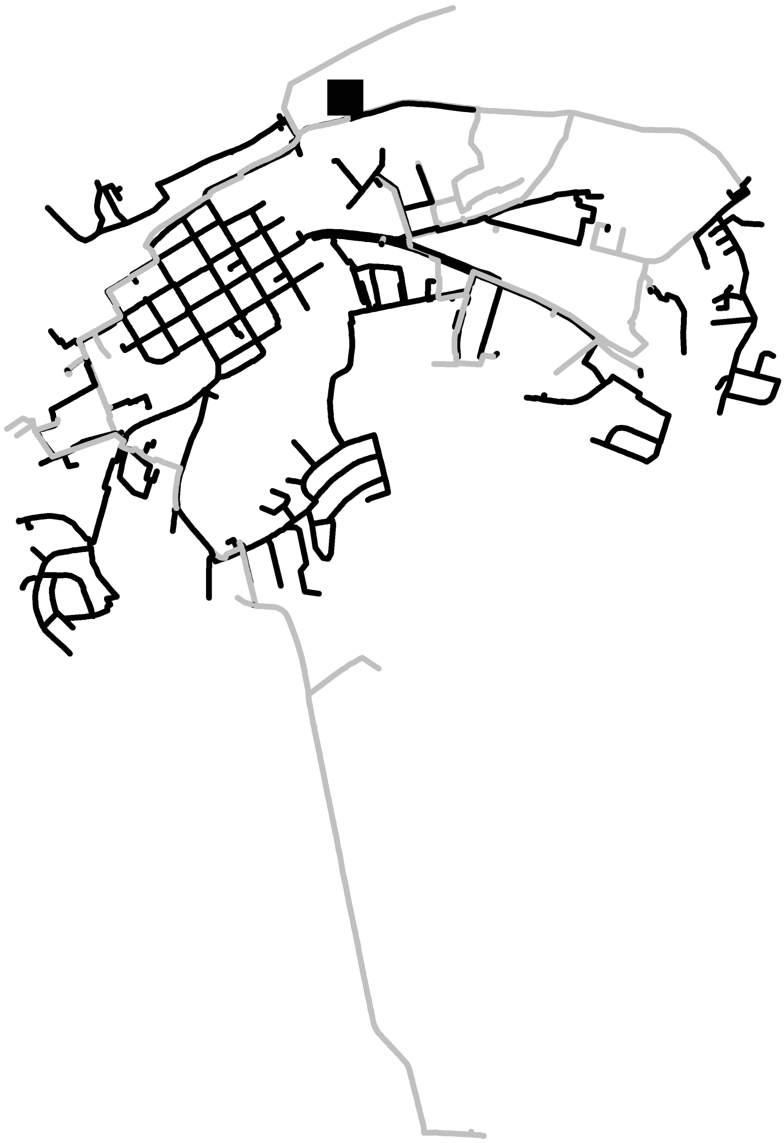

Figure 6: Structure of the gas distribution network in Chełmno, grey lines – medium pressure pipes, black lines – low presurre pipes [27].

ranging from 24.7 m to 86.4 m. Tests have shown that it has a significant impact on the gauge pressures in the 10 kPa grid.

Table 1: Gas composition data.

Components	Unit	Value
C1	mole fraction (%)	96.64
C2	mole fraction (%)	1.24
C3	mole fraction (%)	0.30
C4	mole fraction (%)	0.15
C5	mole fraction (%)	0.05
C6	mole fraction (%)	0.40
N_2	mole fraction (%)	1.88
CO_2	mole fraction (%)	0.34
Density	kg/m^3	0.749
Relative deisty (to air)	–	0.579
Gross calorific value	MJ/m^3	39.745
Net calorific value	MJ/m^3	35.842
Wobbe index	–	52.23

Table 2: Basic network data.

Pressure level	middle	low
Total pipe length (km)	13.4	27.8
Total service pipe length (km)	3	16.5
Number of end-user connections	119	1124
Diameter range	DN50-DN450	DN63-DN250

The simulations were performed for the peak winter demand condition with the use of the in-house developed software code [30,31]. The predictions of the minimal delivery pressures in medium and low pressure grids were 203.4 kPa and 2.0 kPa, respectively. The results also helped to identify 8 pipeline sections with relatively high gas flow velocities. The highest value of 11.7 m/s has been received, which clearly showed that this branch was a network bottleneck. The pipeline was an element of the low pressure grid in the Old Town area, located in north-west part of the city with the characteristic taxicab gemetry.

For the purpose of this study, the potential location of a new renewable gas source from power-to-gas plant in the western part of the low-pressure grid was considered. The hydrogen injection point has been marked with a black square on the maps in Figs. 7 and 8. The analysis was aimed at identifying the range of the network impacted by the new source, and at assesing its effect on the gas quality at the delivery nodes. The simulations were carried out with the assumption that hydrogen is to be injected at a selected medium pressure regulator station with two scenarios corresponding to hydrogen admixture of 2 %vol and 10 %vol of the current capacity of the station, respectively. The results of the calculations for the above scenarios in the form of thematic geographic information system (GIS) maps showing the distribution of gross calorific value of the natural gas-hydrogen mixture in the network are shown in Figs. 7 and 8.

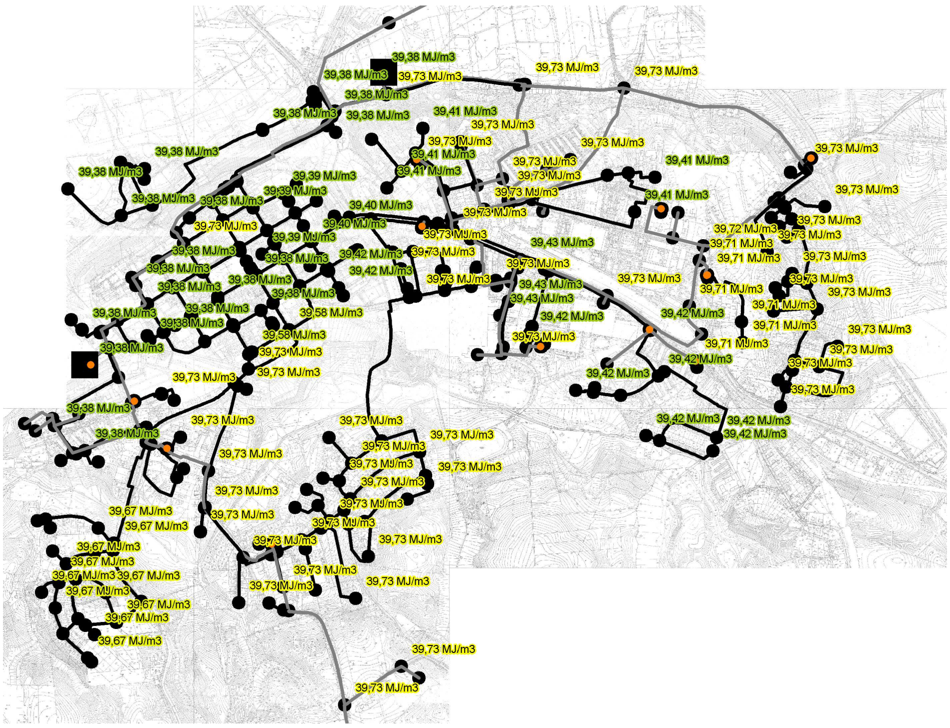

Figure 7: Gross calorific value distribution for the first scenario (natural gas–hydrogen mixture with volume concentrations 98%/2%).

The results show that the minimum gross calorific value in the network was 39.383 MJ/m^3 in the first scenario and 37.936 MJ/m^3 in the second scenario. It should be noted that the minimum gross calorific value of the group E high methane gas admitted to trading on the Commodity Market in Poland is 38.000 MJ/m^3, which leads to the conclusion that given the composition of the currently transported gas, the proposed location of the new renewable gas source prevents hydrogen

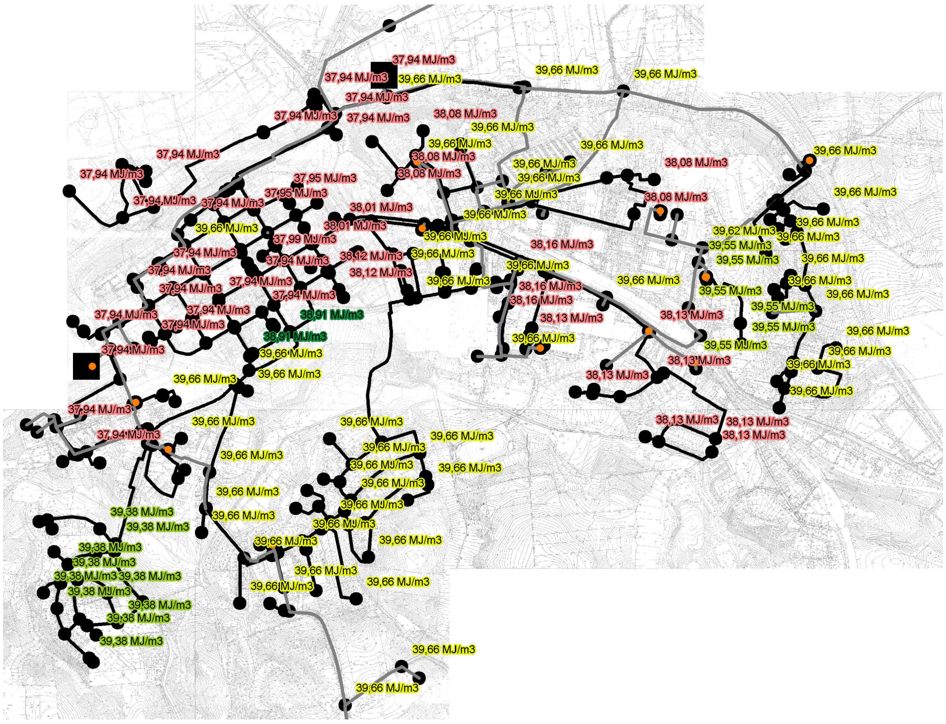

Figure 8: Gross calorific value distribution for the second scenario (natural gas–hydrogen mixture with volume concentrations 90%/10%).

injection at a rate of 10 %vol as assumed for the second scenario. Selected node labels in Fig. 8 indicate the gross calorific value of the gas below the required level (a critically low level of 38.170 MJ/m^3 has been adopted for creating the thematic GIS map).

6 Conclusions

The amount of hydrogen that can be safely added to natural gas strongly depends on the composition of the natural gas at the injection point and the appliances downstream to the injection point. With certain restrictions, admixture of up to 10% vol. as proposed here is not critical for the pipeline infrastructure, however may violate quality constraints related to group E high methane gas specifications.

The integrated natural gas/hydrogen networks are considered as an important element of the future smart energy supply infrastructure. In summary, developing an integrated natural gas-hydrogen-network of appropriate capacity may present a considerable logistical challenge requiring guidance and planning based on simulation and analysis of hydraulic properties of network elements.

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