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# Analysis of Delta In-Out of natural gas distribution networks

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**Abstract:** In recent years, the estimation of Unaccounted for Gas in natural gas networks has been a very debated topic in the scientific literature and within regulatory authorities. In fact, this issue has broad implications since it can affect the cost of supplying gas, the safety of the service and the environmental impact. Unfortunately, although this issue has been widely focused in transmission networks, large and generalized literature studies for the distribution sector are still lacking. In this paper, a theoretical study of the causes of Delta In-Out in natural gas distribution networks, of the related applied analysis methodologies have been presented, together with an in-depth analysis of the Delta In-Out in Italian distribution networks. To this aim, Delta In-Out of 2904 natural gas distribution networks in Italy in the period 2013-2017 have been analysed aimed at focusing the relevant aspects of the phenomenon and at identifying appropriate reduction strategies. A national average value of Delta In-Out approximately equal to +1% was found, whereas the standard deviation significantly varies depending on the size of the network (i.e. from about 2% for large networks to 10% in small networks) and on the climatic zone (i.e. from about 3% for networks in center-north Italy to 11% in the southern ones).

**Keywords:** Natural Gas, Unaccounted for Gas (UAG), Delta In-Out, distribution network

## 1. Introduction

Despite the continuous technological and managerial progress in the natural gas sector, the mass and energy balances on the distribution and transportation networks are characterized by unavoidable differences between the input and output quantities, leading to the so-called Unaccounted for Gas (UAG). In the natural gas distribution sector, this difference is generally called 'Delta In-Out' (hereinafter *deltaIO*).

In recent years, the *deltaIO* issue has attracted the attention of both the scientific community [1-3] and of the regulatory authorities [4-7]. In fact, the *deltaIO* issue has broad implications for regulatory practices as it can affect the cost of supplying gas, the safety of the service [8] and the environmental impact. Unfortunately, although this issue is widely known and debated, a generalized study of *deltaIO* in gas distribution networks, especially the distribution ones, is still lacking. In particular, historical data on the actual values of the *deltaIO* are still lacking, often available from unofficial and

39 heterogeneous sources (e.g. percentages/absolute, aggregate and disaggregated data with the transport  
40 network, annual/multi-year time base). The main challenge is to identify a methodology for the  
41 evaluation of the *delta IO* which considers the peculiarity of the distribution network. In fact, due to  
42 the specific operating conditions and infrastructural characteristics, the differences in the *deltaIO*  
43 within different Distribution System Operators (DSO) can be extremely significant.

44 The lack of standardization of recognized evaluation methods and of punctual statistical studies  
45 makes it particularly difficult and complex to establish benchmark targets for the network  
46 performance and consequently to establish/update policies by regulatory authorities. In particular  
47 among the main difficulties in defining a *deltaIO* evaluation model, the following have been identified  
48 [3]: i) the different definition of the *deltaIO* (which makes comparative data analysis difficult); ii) the  
49 difficulty of measuring the effects of the various influencing factors with reasonable accuracy; iii) the  
50 number of influencing factors themselves; iv) the high annual variability of the *deltaIO* (which would  
51 therefore lead to the need for a complete analysis basing on periods of several years); v) the presence  
52 of unique and difficult to replicate determinants (e.g. age and materials of the infrastructures such as  
53 pipelines, gas meters and pressure regulators); vi) different control and management procedures by  
54 DSO (e.g. loss and theft control). This latter in particular also affects the strict definition of the  
55 *deltaIO*, depending on whether technical losses are included or not in commercial losses.

56 In order to better understand and analyze the issues related to the *deltaIO* estimation and the typical  
57 trends and consistencies, the authors performed a literature analysis of other natural gas distribution  
58 networks, with particular reference to European networks [7, 9].

59 In the European Union, the natural gas market has developed considerably according to specific  
60 energy policy objectives aimed at promoting the growth of competitiveness, security of supply and  
61 sustainability. These objectives were mainly pursued through the third energy package, which  
62 represents the common European legislative framework for the gas market, with particular attention  
63 to cross-border transparency and non-discrimination, for access to transmission networks, to facilitate  
64 the trade of natural gas across the EU.

65 With reference to distribution networks, despite the importance of losses, no scientific literature is  
66 currently available that address this issue in a systematic way, also for benchmark purposes between  
67 the various countries. However, some interesting institutional studies are available such as: i) the  
68 Council of European Energy Regulators [5, 16]; ii) the Energy Community Regulatory Board [7, 11],  
69 iii) the association of European gas transmission system operators [12], iv) the Agency for the  
70 Cooperation of Energy Regulators (ACER, formerly ERGEG) which, however, carried out an  
71 analysis of the problem only in the context of electricity networks [13].

72 In particular, in [5] the methods of estimating and managing the *deltaIO* adopted in the various EU  
73 countries have been focused. One of the main findings of the aforementioned study is that no uniform  
74 approach to the *deltaIO* issue is adopted, probably due to structural differences between countries in  
75 terms of the number of distribution companies, number of final customers, network size, etc. There  
76 are, in fact, differences in the identification of the components of the natural gas leaving the network  
77 and in the time period considered for its calculation, as well as in the role assigned to the various  
78 operators for the management and setting of values which can be considered as “physiological” of  
79 the network. Among the aspects addressed by the study, the most interesting is the implementation  
80 of actions aimed at reducing the *deltaIO*. In particular, it is highlighted that some components of the  
81 *deltaIO* can only be reduced by DSO, for example through appropriate network maintenance and  
82 control procedures, as well as with the use of accurate meter reading tools. Some study participants  
83 highlighted that they do not have a direct incentive scheme, but require the DSO to cover all costs  
84 associated with the *deltaIO*. However, this threshold value is determined differently among EU  
85 countries that participated in the study. For example, the maximum cap can be calculated as the  
86 arithmetic average of the losses recorded over a fixed period (e.g. 4 years), or calculated as a  
87 percentage of consumption. In some countries this latter is a single value, in others it has different  
88 values for different categories of DSO (e.g. as a function of the pressure of the network). In general,  
89 where present, the threshold values are always less than 3%; meaning that exceeding the identified  
90 threshold value, the costs associated with the *deltaIO* are borne by the DSO. The *deltaIO* procurement  
91 methods are also different: i) in some countries the Balancing Operator (hereinafter BO) allocates the  
92 *deltaIO* to the users who must procure it and bear the costs (in other words, the BO bears the *deltaIO*  
93 and shares the related cost between users); ii) in one country, the BO shares the cost between final  
94 users; iii) there are also countries where the *deltaIO* cost is borne by DSO and then shared among  
95 final consumers.

96 An interesting comparative study on *deltaIO* has been carried out by CEER in 19 EU countries [10].  
97 In most of the analyzed countries, network losses are defined as "the absolute difference between the  
98 volume of gas entering the system (measured or estimated at the entry point) and that leaving the  
99 system (measured or estimated at the exit points)". Some of the analyzed EU countries have set an  
100 allowable limit on losses. This limit ranges between 1% (in Spain for low pressure networks) and 2-  
101 3% (in Austria, Poland and Croatia).

102 A detailed comparative study on the treatment of technical and commercial losses in distribution  
103 networks in Europe based on questionnaires (to collect information on existing practices) and on a  
104 survey on regulatory practices has been performed in [7]. This study shows the difference in treating  
105 *deltaIO* in distribution networks, the criteria for detecting losses and for determining the price for

106 permitted losses and the maximum allowed level of loss. Some countries define *deltaIO* as the  
107 difference between the quantities entering and leaving the network, others apply a formula to  
108 determine losses (e.g. as a percentage of the entering gas). Therefore, commercial losses are  
109 considered only in some cases. A further difference exists in the way in which these costs are  
110 determined and charged (i.e. cubic meters, energy, percentage) and the related taxation.

111 As regards the allowed loss levels set by the Regulatory Authorities, in most cases a maximum cap  
112 is established which, with the exception of Macedonia, is quite high and ranging between 2% and  
113 5%. In most countries the so-called "thefts" (i.e. illegal consumption) and "commercial losses" are  
114 dealt with by national legislation and included in the overall system losses. Loss determination is  
115 generally on the responsibility of DSO, but only a few countries apply the benchmark technique. Tax  
116 principles also often differ: in some countries allowable losses are excluded from taxation (e.g. Bosnia  
117 Herzegovina, Georgia and Serbia), in others they are not (e.g. Poland, Croatia, Ukraine, Moldova).

118 In the United States, the NRRI Institute [3] has launched a qualitative survey of the Public Utility  
119 Commissions investigating policies and practices on the *deltaIO* management, receiving responses  
120 from 41 states showing attention to *deltaIO* is paid especially when it increases with respect to  
121 historical trends or in any case when presenting significant variations with respect to previous periods.  
122 In some states, current levels of *deltaIO* are considered too high (both for economic and for safety  
123 reasons). Several commissions have compared *deltaIO* levels over different historical periods in order  
124 to determine whether to take further actions. A common concern of commissions has been to establish  
125 adequate incentives for DSO to manage *deltaIO* in order to prevent negligence from tolerating  
126 inadequate infrastructure and gas leaks that compromise safety.

127 Legislation in the United States generally limits the recovery of unjustified *deltaIO* by operators. In  
128 Connecticut, Ohio, Pennsylvania, Texas and West Virginia, the legislation is similar, setting a  
129 maximum allowable rate of loss (expressed as a percentage of the entry gas) and preventing the  
130 recovery of losses exceeding that rate. In Texas and West Virginia, maximum allowable rate of loss  
131 is set depending on the nature of the pipeline and the size of the operator, ranging between 3% and  
132 10% [14].

133 In Australia, in the state of Victoria, the "Essential Services Commission" regulates the gas market  
134 and free access to gas from the transportation networks. The distribution networks have a *deltaIO*  
135 benchmark required by the code which varies between 3 and 4.5% and reflects the different dispersion  
136 rate of the distribution networks. For example, Melbourne, which has old networks with a large  
137 percentage of cast iron pipelines, is known to have high emission factors. Other benchmark values  
138 are reported by Zincara [15]. Also, in Canada the distribution networks have quite high average

139 *deltaIO*s estimated at around 2.15% [16]. In New Zealand Maunsell estimates the average *deltaIO* of  
140 distribution networks equal to 2.45% [17].

141 Due to the objective difficulty of estimating and predicting the *deltaIO*, in the literature very few  
142 model studies to estimate, correlate and a priori predict the *deltaIO* in distribution networks are  
143 available. These mainly refer to two different methods of *deltaIO* analysis. The first is a top-down  
144 model of differential estimation of the *deltaIO* based on the disaggregation of the various factors that  
145 determine the *deltaIO* [18], where, however, no detailed elements are provided to support the  
146 application of the proposed methodology in the different types of networks. The second method refers  
147 to a bottom-up model based on the statistical analysis of the *deltaIO* estimated in the various  
148 distribution networks. In particular, in [19] a top down benchmark model based on three elements is  
149 proposed: i) the technical characteristics of the network; ii) the local operating procedures; iii) the  
150 operator performance indicator.

151 In this paper, a first theoretical study on the causes of *deltaIO* in natural gas distribution networks, on  
152 the analysis methodologies and historical performance in various networks in EU and non-EU  
153 countries is presented. Moreover, the statistical data of *deltaIO* in Italian distribution networks have  
154 been analyzed, in order to highlight the relevant aspects contributing to *deltaIO* formation and to  
155 identify the related reduction strategies. In particular, the results of the statistical analysis of the  
156 *deltaIO* (national, by DSO size and by climatic zone) in the five-year period 2013-2017 are presented  
157 basing on public data available according to the Integrated Gas Settlement Text (the so-called TISG).

158

## 159 **2. Materials and Methods**

160

161 The *deltaIO* in a distribution network is the difference between the sum of gas quantities measured at  
162 the entry points of the network and the sum of the gas quantities measured at the exit points of  
163 commercial, industrial and residential users ( $E_{end\ users}$ ), in a fixed period of time (i.e. day, month,  
164 year, etc.). It is therefore a balancing quantity to compensate the differences between the natural gas  
165 inputs and outputs from the network over a given period. In particular, the entry points are represented  
166 by the so-called city-gates ( $I_{City\ Gate}$ ), namely the interconnections of the distribution network with  
167 the transmission network and/or with the other distribution networks, and by the possible  
168 "Renewable" gas production ( $I_{Gas\ RES}$ ) in the networks (e.g. biogas injection points). The balancing  
169 equation includes two further terms: i) linepack changes ( $\Delta_{LP}$ ), i.e. the gas accumulated in the  
170 network, and ii) losses and emissions from the network, thefts and shortages ( $\Delta_{Losses}$ ), as reported in  
171 eq. (1).

172

$$\sum I_{City\ Gate} + \sum I_{Gas\ RES} = \sum E_{End\ users} + \Delta_{LP} + \Delta_{losses} + \delta_{IO} \quad (1)$$

173

174 It should be noted that gas accumulations ( $\Delta_{LP}$ ) in distribution networks can be neglected, given the  
 175 low pressure and the small size of the networks, unlike the transmission networks in which they play  
 176 a significant role due to the higher pipeline dimensions and the variations in pressure and temperature.  
 177 Some authors distinguish technical causes of  $\delta_{IO}$ , represented by losses and emissions from the  
 178 networks (i.e. technical losses), from non-technical ones (i.e. commercial losses) represented by all  
 179 other causes. Generally, the causes of  $\delta_{IO}$  in distribution networks are considered cumulatively  
 180 (e.g. in France, Spain, Austria, Poland, Croatia, Ukraine, Georgia, Serbia), whereas only in few  
 181 countries (e.g. Moldova and Bosnia) the different contributions to  $\delta_{IO}$  are promptly taken into  
 182 consideration and estimated using a methodology that defines and distinguishes the different types of  
 183 losses, measurement/accounting errors and thefts. Consequently, only some countries rely on detailed  
 184 information on the structure of the  $\delta_{IO}$  while the others simply evaluate the difference between  
 185 the quantities entering and leaving the distribution network.

186 Therefore, the causes of  $\delta_{IO}$  in distribution networks are attributable to numerous factors referring  
 187 to four main areas:

- 188 1. losses and emissions;
- 189 2. measurement errors both of the metering plants at the entry points (i.e. city gates) and of the  
 190 simpler gas meters at the exit points, this latter together with accounting errors of withdrawals  
 191 (for non-remotely-read users);
- 192 3. thefts and shortages (e.g. deriving from uncensored withdrawals);
- 193 4. delta line pack (associated to gas accumulation in the network).

194 In table 1 the causes that contribute to  $\delta_{IO}$  together with the related impact have been summarized.

195

196

**Table 1.** Causes of  $\delta_{IO}$  and related impact on  $\delta_{IO}$

<i>Type</i>	<i>Cause</i>	<i>Description</i>	<i>Impact</i>
Losses and emissions	Voluntary losses (Vented)	Intentional release of gas into the atmosphere, usually through a specially designed vent or during pipeline maintenance and repair.	+
	Unvoluntary losses (accidents)	Unintentional and exceptional release of gas resulting from external damage to the pipeline.	+
	Emissions	Fugitive emissions from pipelines, from regulation and metering plants and network services.	+
Measurement errors of the natural gas	Metering system	Measurement errors of the volumes of gas entering or leaving the network (generally due to the average drift of the meter and to installation and operating conditions).	+/-

volumes at entry and exit points	Standard volume correction	Errors due to volume conversion at standard conditions and energy (e.g. calculation algorithm, temperature and pressure measurement, gas composition assumptions in homogeneous areas).	+/-
	Consumption estimates for not remotely read users (accounting error)	Errors due to readings frequency and load profiling method (which generally doesn't overlap with meters reading and self-reading cycles)	+/-
	Consumption estimates for not metered users	Errors due to flat rate gas consumptions estimates (when applicable).	+/-
Thefts and shortages	Thefts	Gas illegally withdrawn from the network, either from the distribution pipelines, or bypassing or tampering the meter.	+
	Not metered self consumptions	Not metered gas used by DSO for network functioning (e.g. back-up energy production, process devices, network heaters, etc.)	+
	Shortages	Gas used but not billed (e.g. termination of a contract and delay in transferring to the new user).	+
Delta Line-Pack	Variation of energy/mass of natural gas in the network	Variation in the quantity of gas contained in the pipelines of the distribution network. Variations in these quantities occur as the temperature and pressure of the pipes vary and as new pipelines are added. Generally, in low pressure distribution networks this contribution can be considered negligible.	+/-

197

198

### 199 2.1. Losses and emissions estimation methods

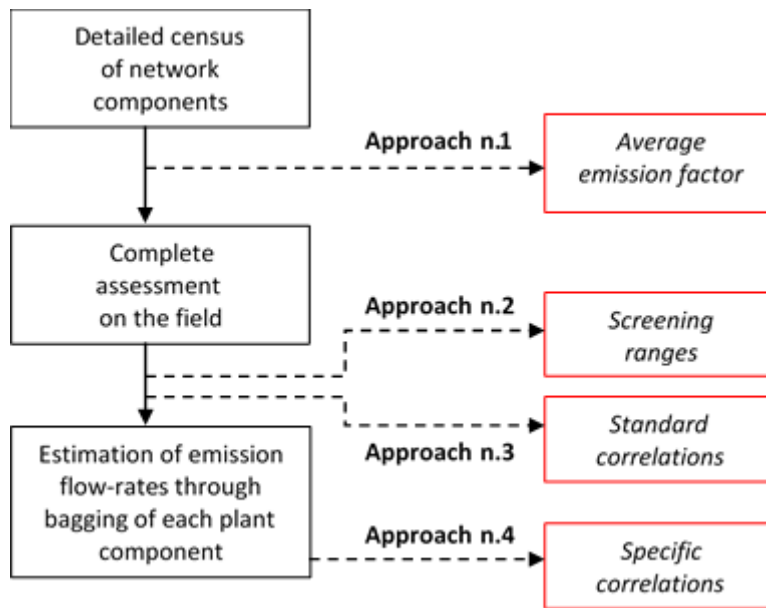
200 In the specific context of the natural gas infrastructures, losses and emissions are generally classified  
 201 into four categories:

- 202 • fugitive emissions resulting from a gradual loss of tightness of operation components (e.g.  
 203 valves, pumps, flanges, compressors, etc.);
- 204 • pneumatic emissions due to the discharge of compressed gas into the atmosphere during the  
 205 operation of certain equipment;
- 206 • vented, namely controlled releases (e.g. for maintenance, pipeline repairs, etc.) or  
 207 uncontrolled (i.e. for breakages and accidents);
- 208 • combustion emissions deriving from exhausts from combustion systems (such as those from  
 209 turbines and compressor engines).

210 The GRI-EPA [20] protocol defines four approaches for estimating emissions, in increasing order of  
 211 accuracy and depth (see also Figure 1):

- 212 1. *Average emission factor*, through average emission factor of each component type;
- 213 2. *Screening ranges*, through the measurement of the natural gas concentration emitted in the  
 214 proximity of each component;
- 215 3. *Correlation*, through standard correlations available in the literature of each component type;
- 216 4. *Specific correlation* for each component type.

217



218

219

**Figure 1.** Flow chart scheme for emission estimate

220

221 With the exception of the approach of the average emission factor, in which the total emission is  
222 simply obtained by knowing the number of elements present on the network and the use of specific  
223 average emission coefficients for the single network components, the other three approaches rely on  
224 field measurements (qualitative/quantitative) of the emission concentration aimed at attributing  
225 specific emission factors to each dispersing component or device in the network.

226

### 227 2.2. Measurement and accounting errors estimation

228 The demand for natural gas in the distribution networks shows high seasonal, daily and hourly trends.  
229 The transmission and storage system allow to manage the demand variability both through the use of  
230 storage plants and through the variation of pressure and gas flows in the transmission network.  
231 However, these variations cause issues in the measurement and accounting of gas and consequently  
232 in the networks balance also at the interconnection points between transmission and the distribution  
233 networks. Furthermore, the measurement in Italian distribution networks is even more complex due  
234 to the incomplete roll-out of traditional meters with smart meters (which would allow complete  
235 remote reading and correction into standard volumes with at least the measured temperature and, only  
236 for larger meters, of both measured pressure and temperature) and the presence (typical of the Italian  
237 infrastructure) of natural gas from different sources with not negligible differences in the gas  
238 composition within the different withdrawal areas.

239 The measurement and accounting errors of the quantities entering and leaving the distribution  
240 network, although attributable to the same physical problems, are strongly different from a  
241 quantitative point of view. In fact, metering plants at the entry points (i.e. city gates) are much more  
242 complex and accurate. However, they play a more relevant role for the *deltaIO* due to the high  
243 quantities measured in respect of those measured by small utility meters at exit points [21]. On the  
244 other hand, errors in the numerous utility meters are subject to the probabilistic laws of large numbers,  
245 which tend to compensate for the error contributions of individual meters in the balance sheets,  
246 supposed that these errors are not strictly correlated with each other. This happens, for example, when  
247 all meters are calibrated in comparison with the same transfer standard and through the same  
248 calibration procedure [22].

249 Here below the individual causes of measurement and accounting errors contributing to the *deltaIO*  
250 are summarized:

- 251 • error of the measurement systems (i.e. typical accuracy of the meter or MID metrological  
252 class, drift of the meter; installation and operation);
- 253 • error of the conversion in standard volumes/energy (i.e. temperature and pressure sensors,  
254 compressibility factor; gas quality);
- 255 • accounting error (i.e. reading, transmission, estimate of consumption of non-remote users in  
256 the period, estimate of consumption of users not equipped with meters permanently or  
257 temporarily due to faults and malfunctions).

258

### 259 2.2.1 Error of the measurement system

260 As regards the typical accuracy of measurement systems, it should be highlighted that this can be  
261 very different depending on the type and size of the entry points (i.e. city gate) and of the end user  
262 (e.g. continuous/discontinuous). In particular, the metering plants at the entry point of the distribution  
263 networks is generally made up of: i) a primary element (i.e. flowmeter) volumetric (e.g. turbine,  
264 ultrasonic or rotary pistons) or venturimetric (i.e. orifice plate); ii) a volume conversion device for  
265 the conversion of metered volumes at standard conditions, iii) depending on the size of the metering  
266 plant, a field gas chromatograph for measuring gas composition and higher calorific value. Such  
267 measurement chain generally shows measurement errors ranging between 0.5% and 1% when they  
268 are run above the transitional flowrate and below the maximum one. Conversely, measurement errors  
269 are about double in the range between the minimum flowrate and the transitional one. Moreover, they  
270 are also subject to periodic metrological checks.

271 On the other hand, meters at exit points are different depending on the type of user (i.e. residential,  
272 large building, commercial, light industry). Such meters must comply with the measuring instrument

273 directive [23] which requires: i) class 1.5 meters for residential use (i.e. with maximum permissible  
274 error, MPE, within  $\pm 1.5\%$  at  $Q_t < Q < Q_{max}$  and  $\pm 3.0\%$  at  $Q_{min} < Q < Q_t$ ), ii) class 1 meters (i.e. with  
275 MPE within  $\pm 1.0\%$  at  $Q_t < Q < Q_{max}$  and  $\pm 2.0\%$  at  $Q_{min} < Q < Q_t$ ) are generally envisaged for light  
276 industrial and commercial users or for large residential buildings.

277 Therefore, for the aim of this paper, utility meters can be classified into three sub-categories:

- 278 • meters installed at industrial users, generally remotely read, showing technical and  
279 metrological characteristics comparable to those at the entry points (i.e. city gates), with  
280 typical accuracy ranging between 0.5% and 1.0%;
- 281 • large meters (i.e. which maximum flowrate is above  $10 \text{ m}^3/\text{h}$ ), generally remotely read at  
282 large users in residential, commercial and/or light industry, with typical accuracy ranging  
283 between 1.0% and 1.5%;
- 284 • small meters (i.e. which maximum flowrate is equal or below  $10 \text{ m}^3/\text{h}$ ), generally traditional  
285 diaphragm or static (i.e. thermal or ultrasonic) for residential user, with typical accuracy  
286 between 1.5% and 2.0%.

287 Small meters are certainly the most widespread in distribution networks, although in terms of  
288 measured volumes those with high capacity (industrial or commercial) can represent a significant  
289 share of the distributed volumes in some networks.

290

### 291 2.2.2 Error of the conversion in standard volumes/energy

292 The meters installed in distribution networks do not allow direct measurement of either the volumes  
293 at standard conditions neither the quantities of gas expressed in energy. Therefore, to convert the  
294 volumes at operating conditions ( $V$ ) into the standard conditions ( $V_s$ ) it is necessary to know the  
295 thermodynamic state of the gas (i.e. temperature and pressure of the gas flow) as well as its chemical  
296 composition and therefore to indirectly measure the compressibility factor, the density (if necessary)  
297 and the higher calorific value. To this end, at least four different correction methods can be used in  
298 distribution networks:

- 299 • a PTZ volume conversion device (type 1 or type 2) with pressure and temperature  
300 transmitters (used in city gates and light industries);
- 301 • a pressure and temperature conversion device PT (e.g. integrated in the large smart meter);
- 302 • a temperature conversion device (e.g. integrated in the meter and used in small smart meters);
- 303 • an average correction factor estimated at the billing stage and determined on the basis of the  
304 average supply temperature and pressure in the network.

305 In the first three cases, volume conversion devices integrated into the meter or separated devices  
306 (consisting of a calculator, a temperature transducer and possibly a pressure transducer installed on  
307 the pipeline) are used.

308 In all the above described cases, the measured volumes  $V$  in the operating conditions are converted  
309 into the volume  $V_S$  at standard reference conditions ( $P_S, T_S, Z_S$ ) by measuring the thermodynamic  
310 parameters in operation ( $P, T$ ) and the composition of the gas by means of the equation (2), in which  
311  $KTV_o$  is the so-called volumetric correction coefficient.

312

$$V_S = V \cdot \frac{P}{P_S} \cdot \frac{T_S}{T} \cdot \frac{Z_S}{Z} = V \cdot KTV_o \quad (2)$$

313

314 In Italy, standard reference conditions are represented by 15°C for temperature and 1,01325 bar for  
315 pressure. The uncertainty estimation of the volume correction is easy to apply since it depends on the  
316 known propagation laws applied to relation (2) and on the metrological performance of the  
317 temperature and pressure measurement systems and of the compressibility factor calculation [24]. On  
318 the other hand, the uncertainty estimation of measurement systems not equipped with volume  
319 conversion devices is more complex. Generally, in fact, the operative pressure on residential user  
320 meters is almost constant and equal to about 2 kPa (20 mbar), which corresponds to a conversion  
321 factor due to pressure equal to 1.02. Due to the instability of the regulation system, the supply pressure  
322 can vary between 1.5 and 2.5 kPa; in the same way, the barometric pressure varies due to weather  
323 conditions and to the altitude of the installation, with effects on measurement uncertainty even higher  
324 than 1%. Similarly, the actual monthly temperatures also vary with respect to the historical average  
325 and the temperatures of the gas flow in a single user may be affected by even large errors. In fact, the  
326 air and soil temperatures vary with the geographical position and the season and show significant  
327 daily fluctuations. Furthermore, for residential users, most of the gas is consumed during the winter,  
328 when and where the climate is coldest, therefore, not always an average annual correction factor for  
329 the whole distribution network is appropriate for all the supplied residential and industrial users.

330

### 331 2.2.3 Accounting error

332 The error deriving from the accounting method, or from the estimation and processing of the  
333 measurement data, essentially derives from the cycle of reporting consumption and related  
334 commercial budgets. In fact, accounting is rarely completely automated due to the incomplete remote  
335 reading of the meters and to the need for post-processing of the consumption data. This can lead to  
336 various errors [25]: a) in the manual reading of the non-remote-read meter or in the transmission of

337 remote-read data, b) in the estimate of non-remote users consumption through load profiling  
 338 techniques (carried out on the basis of forecast models, classification of users and periodic readings);  
 339 c) in the estimation of consumption of not metered users both permanently (e.g. gas for public  
 340 lighting) and temporary due to breakdowns and malfunctions (e.g. blocking of meter).  
 341 Finally, in Table 2, for each cause of error, the dependence on the various influencing factors and the  
 342 methods of estimating the related uncertainties.

343

344

**Table 2.** Typical error sources of accounting

Cause	Description	Estimation
Reading, transmission, reporting and data post-elaboration	Accounting errors strongly depend on the complexity of the distribution network and on the spreading of remote reading/automation. Such errors are difficult to quantify and often have irregular characteristics (for example, omitting a zero when manually entering data will result in a completely different order of magnitude).	A fully remote-controlled and automated measurement and accounting system could theoretically be immune to such errors (unless for system defaults, etc). The percentage in terms of quantity supplied to remote-read users compared to the total one can represent a useful tool to quantify these effects.
Estimated consumption of not remote-read users (billing cycle error)	Not all meters in distribution networks are remote-read and therefore consumption data of non-remote users must be aligned by interpolating or extrapolating the measurement data using “settlement” estimation models which introduce further unavoidable calculation errors. Generally, on field readings of residential customers consumptions are performed every six months (2 reading attempts per year, although this is an average value not always obtained by several DSOs).	These error depends on: - the actual reading frequency; - the classification of users; - the accuracy of the forecast model; - the accounting period (annual, monthly or daily).
Estimated consumption of not metered users	In distribution networks there should be no users permanently not metered and therefore this error could occur only for users with meters temporarily out of service. In this case, it is possible to estimate the error on a flat-rate basis; in fact, the failure of the meters can lead to the failure to record consumption until the meter is identified and replaced after one or more billing cycles.	These error depends on: - the age of the meters or the average number of meter failures per year; - the period in which the meter operated under abnormal conditions.

345

346

347 2.3. Estimation methods of thefts and shortages

348 In the literature, gas thefts are recognized as the largest component of non-technical losses in  
 349 networks and in general they can be represented by: i) illegal connections and reconnections to the  
 350 distribution network by not registered users (e.g. where a customer reconnects his supply when has

351 been disconnected); ii) bypassing or tampering with the meter to completely avoid or partially reduce  
352 metered consumption by registered users (e.g. where the meters may not work properly either due to  
353 internal or external tampering of the meter itself). Typical cases of thefts of natural gas are for  
354 example: i) volumes of gas stolen in portable tanks, illegal connection on the underground supply  
355 pipeline, by-pass of the meter; ii) meter jam (e.g. meter filled with sugar to attract insects, addition of  
356 liquids, magnetic jam, etc.); iii) meter tampering (e.g. holes on the diaphragm, tampered gears, meter  
357 inversion, etc.).

358 The relative estimates of gas thefts, however, are intrinsically uncertain, not only due to the difficulty  
359 of estimating with adequate accuracy the "certain theft" during the period in which it is occurred, but  
360 above all due to the objective difficulty of presuming its existence, and therefore, to estimate the  
361 "undetected thefts".

362 In the natural gas sector, this phenomenon could appear marginal due to the complexity and implicit  
363 danger of the gas theft, but some studies show that this circumstance is anything but irrelevant even  
364 in so-called "advanced" countries. In the United Kingdom, for example, it is estimated that as many  
365 as 400 million pounds of gas and electricity are stolen every year. In particular, British Gas has  
366 surveyed about 65% of all cases of energy theft for over 10,000 cases per year. A study conducted in  
367 Spain by the University of Seville [26] estimated that energy theft accounted for around 35-45% of  
368 non-technical losses in 2011. The analysis has shown that there is certainly a strong relationship  
369 between energy theft and organized crime, but it has also surprisingly recorded significant cases of  
370 tampering among wealthy customers, contradicting the common sense of predicting the theft of  
371 electricity and gas concentrated only in poor areas with high levels of crime. An interesting  
372 correlation was in fact also found in medium and small business companies in specific commercial  
373 sectors (such as the hotel industry). In some areas of the United States, there were also average rates  
374 of thefts of natural gas equal to 5% of the distributed gas, with peaks in Detroit of as much as 20%.  
375 Naturally, the percentage of gas thefts grows significantly in depressed areas and emerging countries  
376 such as Pakistan where in 2015 about 50 thousand cases of tampered users were ascertained summing  
377 over 96 million m<sup>3</sup> of gas stolen and over 540 million m<sup>3</sup> of gas consumed by non-registered users  
378 [19]. In Bangladesh such percentage is over 6% of thefts of the total distributed gas [27].

379 This issue is closely related to energy poverty, an increasingly emerging problem even in  
380 economically advanced countries. Energy poverty can be defined as "a situation in which a family or  
381 individual is unable to pay for the primary energy services (i.e. heating, cooling, lighting, travel and  
382 electricity) necessary to ensure a decent standard of living, due to a combination of low income, high  
383 energy spending and low energy efficiency in their own homes" [28]. According to the European  
384 Observatory on Energy Poverty in Europe, about 8% of the population is unable to adequately heat

385 their home or is late in paying their bills. In Italy this form of poverty affects about 8.5% of the  
386 number of families, for a total of 2.2 million families. Statistics on energy poverty and correlations  
387 with the level of crime in the area, but also with the number of customers disconnected due to arrears  
388 and on the number of non-connected resident users and business companies, could represent  
389 qualitative indicators in this regard.

390 Theft mitigation could be carried out through different techniques such as: i) data mining with a  
391 systematic approach [29]; ii) big data statistical approach, iii) smart meters [30]; iii) protection of the  
392 meter in box; iv) periodic checks.

393

### 394 **3. Results and discussions**

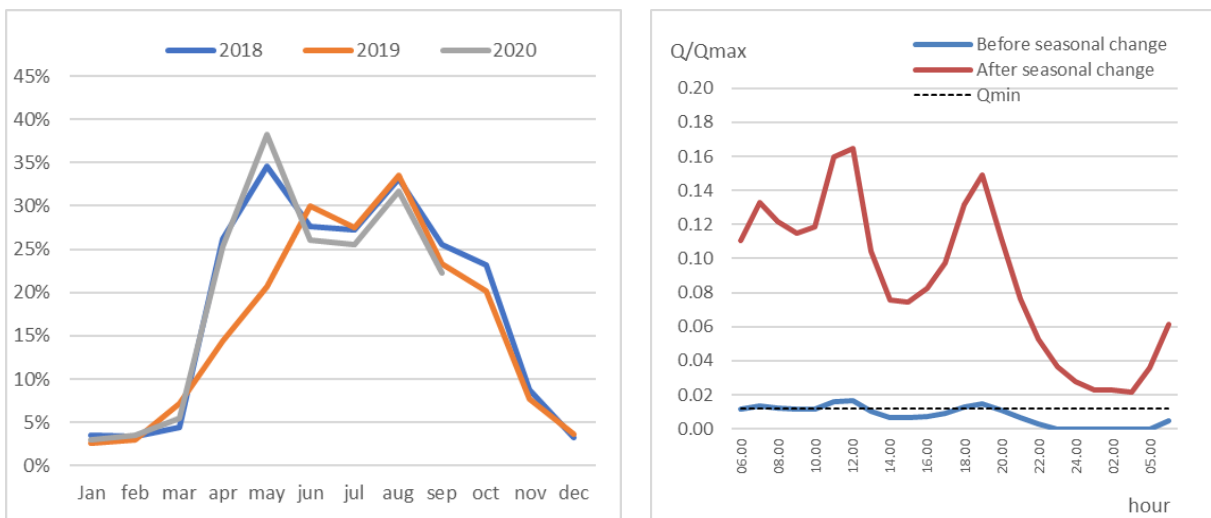
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396 As far as the drift of the meter is concerned, this depends on the construction technology and, of  
397 course, on its age of installation. In Italy, Decree 93/2017 establishes that gas meters which maximum  
398 flowrate is equal or below  $10 \text{ m}^3/\text{h}$  (i.e. up to G6) have to be replaced after 15 years. For larger meters  
399 which maximum flowrate is above  $10 \text{ m}^3/\text{h}$  (i.e. above G10), subsequent verifications are required at  
400 variable frequencies ranging between 8 years (for static meters) and 16 years (for diaphragm meters).  
401 In this regard, the drift of traditional diaphragm meters can be positive or negative, even if in the  
402 literature an intrinsic propensity to overestimate in the short term and to underestimate in the long  
403 term has been found [31]. Furthermore, in the current energy transition scenario, the injection of green  
404 fuels (e.g. biogas) and of hydrogen produced from renewable sources, although in small extent, will  
405 determine changes in the properties of the gas and likely consequences on the accuracy of the  
406 measurement [32-34]. In this regard, in [35] it has been demonstrated new smart thermal gas meters  
407 (which spreading in distribution networks is rapidly increasing) show significant drift. In particular,  
408 negative errors exceeding acceptable limits have been found when a gas mixture with hydrogen  
409 content of 10 and 15% is used, unlike the traditional diaphragm gas meter which are almost unaffected  
410 by changes in gas composition [36]. Finally, some types of installation (e.g. outdoors, in boxes,  
411 exposed to solar radiation, etc.), can significantly affect the measurement accuracy of residential  
412 utility meters of final users.

413 On the other hand, large flowmeters used at City Gates entering points (e.g. turbines and rotary  
414 pistons), although more accurate, generally show a shorter life and they are verified or replaced every  
415 10 years. In fact, wear causes a significant deterioration of the rotary components and then of the  
416 metrological performance of the meter. For these flowmeters, the effect of the installation and  
417 operating conditions is often underestimated, although in some cases it may represent a critical factor

418 for the accuracy of the measurement. In fact, although the manufacturers' standards and type approval  
 419 certificates provide for punctual specifications for the installation and operation of such flow-meters,  
 420 these requirements are often disregarded. The main critical issues are those relating to the respect of  
 421 the straight sections upstream and downstream of the meter (e.g. in turbine, ultrasonic and  
 422 venturimetric flow-meters) and to the operative conditions out of the optimal measurement range of  
 423 the meter (i.e. between the minimum and the maximum flow rate).  
 424 In fact, the volumes measured when the flowmeter is operated out of its approved range are affected  
 425 by significant errors, which are difficult to be a priori estimated. To date, there are still numerous  
 426 cases of flowmeters at City Gates entry points that are operated for long periods below their minimum  
 427 flowrate value. This is due to the to the reduction in residential gas consumption in the transition  
 428 period between winter and spring and to the missed or delayed change of the large flowmeter with a  
 429 smaller one. In some cases, the oversizing or limited rangeability of the flowmeter itself enhances  
 430 such issue (see Figure 2). This impacts unaccounted for gas in the transmission network, given the  
 431 high number of city gates measuring points, but also  $\Delta IO$  in the distribution networks, given the  
 432 systematic errors at the entry point.

433



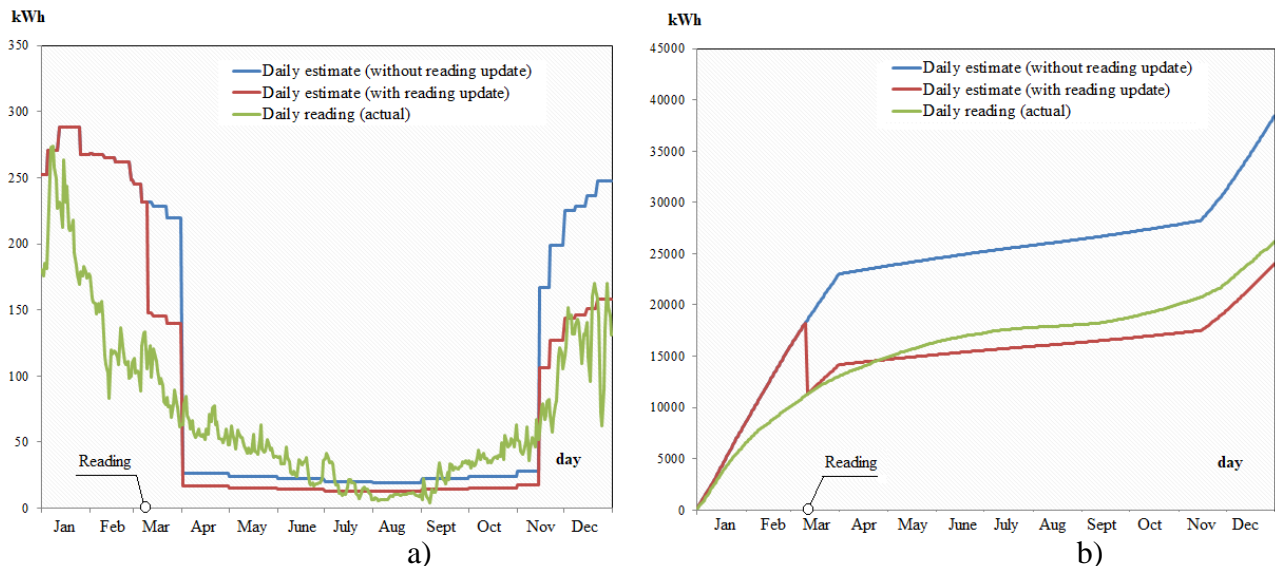
434 **Figure 2:** a) Trend of the percentage of City Gates operated below  $Q_{min}$  for more than 25% of the  
 435 hours in the month; b) Trend of daily flowrate measured at a DSO City Gate before and after the  
 436 seasonal change  
 437

438 In Figure 2a, the trend of the percentage of DSO City Gates operated below the minimum flowrate  
 439 for more than 25% of the hours in the month has been depicted. From the analysis of the curve two  
 440 systematic peaks can be noticed. The first peak is registered in the period April-May (i.e. before the  
 441 seasonal change of the flowmeter in the transition period from winter to spring), whereas the second  
 442 one is registered in August when gas consumption in distribution networks are greatly reduced due

443 to the holiday period and the subsequent emptying of the cities, meaning that also the smaller  
 444 flowmeter becomes oversized. In Figure 2b the hourly average flowrate trend measured in the weeks  
 445 immediately before and after the seasonal change of the flowmeter has been depicted (in this case  
 446 represented by a rotary piston meter, rangeability 80:1, change from size G1600 to size G160). From  
 447 the analysis of Figure 2b, it can be pointed out that gas consumption measured by the larger flowmeter  
 448 were often below  $Q_{min}$  and that during nightly hours they were always null, despite the ones measured  
 449 by the smaller one.

450 As well known, the occurrence of *deltaIO* in a real distribution network involves allocation, invoicing  
 451 and reconciliation aspects which require that energy off-takes of the final users (i.e. residential,  
 452 commercial and industrial) are split into predefined time-periods such as day, month and year. In real  
 453 networks, the amount of gas off-taken in the relevant periods by not-daily metered users can only be  
 454 estimated through load profiling techniques. Thus, the estimate of the gas consumed in a fixed period  
 455 instead of the punctual reading leads to a *deltaIO* occurrence in the same period and adjacent periods.  
 456 Nevertheless, since a share of *deltaIO* in distribution networks comes from a shift of an amount of  
 457 gas between different time periods, the settlement of *deltaIO* can be performed in periods different to  
 458 those of the actual injections and off-takes. In Figure 3 the simulated consumptions of a large  
 459 residential building estimated by using the applicable load profiling technique have been compared  
 460 with the available punctual reading remotely read in a one-year period.

461



462 **Figure 3.** Actual data vs load profiling estimates for a large residential building: a) readings, b)  
 463 aggregate consumptions.  
 464

465 In Figure 3a it can be observed a *deltaIO* formation when a load profiling technique is used (blue and  
 466 red lines) instead of the daily punctual readings (green line) and this affects the adjacent time periods.  
 467 The updating of the annual consumption value (on which the load profiling technique is built) with

468 the actual reading attenuates but does not cancel the *deltaIO* formation (red vs blue lines). On the  
 469 other hand, in Figure 3b the trend of estimated consumptions has been simulated and compared with  
 470 the corresponding actual consumption of the user. The different performance of the load profiling  
 471 method clearly emerges when estimated data consider or not the updating of the annual consumptions  
 472 value after subsequent readings. As matter of fact, the more readings are performed in a time period,  
 473 the more effective the load profiling.

474 The data of the *deltaIO* of Italian distribution networks in the period 2013-2017 have been analyzed  
 475 and the related statistical analysis is below reported. The dataset used was that published in  
 476 compliance with the disclosure obligations defined by the National Authority for Energy, Networks  
 477 and Environment (ARERA). In particular, the summary reports of the annual physical balances for  
 478 each network were analyzed in the last multi-year adjustment sessions available in 2020 on which  
 479 there was at least one adjustment session in the observation period described above [37]. The  
 480 distribution networks analyzed are those that were continuously operated throughout the entire period  
 481 2013-2017 for a total of 2727 networks (out of 2907 total). For the sack of simplicity, the term  $\Delta_{losses}$   
 482 in equation (1) have been included in the *deltaIO* term (which can be then considered the losses and  
 483 unaccounted for gas) whereas the term  $\Delta_{LP}$  can be considered negligible on a yearly basis in  
 484 distribution networks due to limited pipeline diameters and the fact that operational pressures are low  
 485 and nearly constant.

486 The analysis of the overall synthetic indicators of the investigated sample in the five-year period  
 487 2013-2017 presents an average weighted *deltaIO* value (i.e. the ratio between the overall *deltaIO* and  
 488 the total gas entered into the networks) equal to + 0.88% with a standard deviation of approximately  
 489 7.64%, as shown in table 3. It should be noted that the arithmetic average value obtained from the  
 490 *deltaIO* of the individual networks is slightly lower (+ 0.47%) in respect of the weighted average  
 491 obtained through the balance of the entire distribution network sample. This is due to the fact that the  
 492 outliers (i.e.  $|deltaIO| > 100\%$ ) have been excluded from the calculation. Furthermore, the average of  
 493 the absolute values of the annual *deltaIO* is equal to 1.61%. This means that compensations occur  
 494 between *deltaIO* (positive and negative) which reduce the average value of the *deltaIO* of the five-  
 495 year period compared to the annual ones to a value just below 1%, whereas the *deltaIO* average  
 496 absolute yearly value is about double (i.e. just below 2%).

497

498 **Table 3.** Analysis of average *deltaIO* in the five-year period 2013-2017 (data after adjustment of  
 499 2727 distribution gas networks)

<i>Year</i>	<i>Number of adjustment sessions</i>	<i>Gas entering</i>	<i>Gas leaving</i>	<i>deltaIO (Sm<sup>3</sup> 10<sup>8</sup>)</i>	<i>Weighted deltaIO (%)</i>	<i>Average deltaIO (%) *</i>	<i>Standard deviation (%)*</i>
-------------	--------------------------------------	---------------------	--------------------	--	-----------------------------	------------------------------	--------------------------------

		$\Sigma I_{City\ Gate}$ ( $Sm^3\ 10^{10}$ )	$\Sigma E_{End\ users}$ ( $Sm^3\ 10^{10}$ )				
2013	1 (2013-16)	3.23	3.19	4.43	1.39	1.25	8.90
2014	2 (2014-17)	2.77	2.81	-4.41	-1.57	-2.67	8.68
2015	2 (2014-17)	3.04	2.99	4.79	1.60	1.42	8.91
2016	3 (2014-17)	3.04	3.02	1.57	0.52	-0.27	8.37
2017	3 (2014-17)	3.13	3.06	6.95	2.27	2.41	7.74
2013-2017	-	15.2	15.1	13.3	0.88 (1.47)	0.47 (1.61)	7.64

\* without outliers (i.e.  $\Delta IO > 100\%$ ) Absolute values are reported in brackets

500  
501

502 The trend of the average annual  $\Delta IO$  after the first adjustment session does not change  
503 significantly in subsequent adjustments. In particular, it is noted that the annual average values are  
504 generally positive and show a maximum value of approximately 2.27% in 2017. Just in 2014 a  
505 negative  $\Delta IO$  occurred (-1.57%), corresponding to a significant decrease in natural gas yearly  
506 consumption. The standard deviation of the  $\Delta IO$  values on the networks (net of outliers) is also  
507 substantially constant (i.e. in the range between about 7.7% and 8.9%), being calculated through the  
508 following equation in which  $\Delta IO_i$  is the  $\Delta IO$  of the  $i$ -th network and  $\Delta IO_{av}$  is the average  
509  $\Delta IO$  of the  $N$  analysed networks of the sample.

510

$$\sigma = \sqrt{\frac{\sum_{i=1}^N (\Delta IO_i - \Delta IO_{av})^2}{N - 1}} \quad (3)$$

511

512 Aimed at focusing the most influencing factors of  $\Delta IO$ , in the following the analysis of the  $\Delta IO$   
513 trend is presented considering both the quantity of gas distributed in the networks and the climatic  
514 zone.

515

### 516 3.1. $\Delta IO$ analysis by distributed natural gas quantity

517 Given the homogeneity of the types of users of the various networks analyzed, it is evident that the  
518 increase in the quantities of natural gas distributed in the network generally corresponds to an increase  
519 in the number of users delivered. Therefore, it is useful to divide the investigated distribution  
520 networks according to the volumes supplied into three categories:

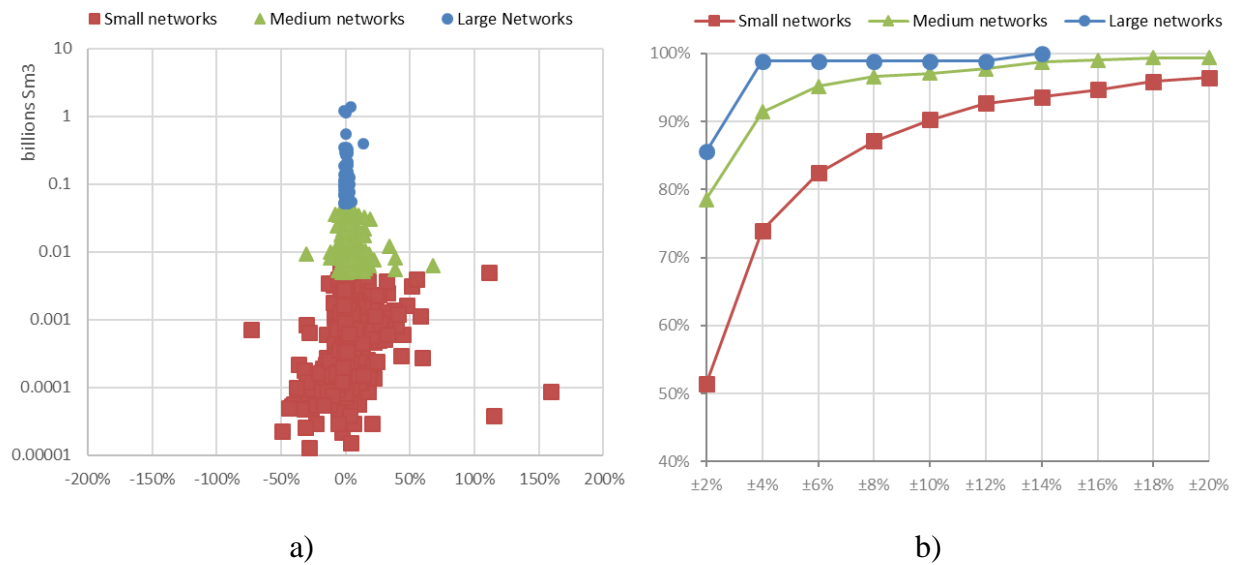
521

- large networks, with average annual gas entering above 50 million  $Sm^3$ ;
- medium networks with average annual gas entering between 5 and 50 million  $Sm^3$ ;
- small networks with average annual gas entering below 5 million  $Sm^3$ .

522

523

524 Figure 2 and Table 4 show the data of the  $\Delta IO$  recorded on the individual networks in relation to  
525 the corresponding input quantities in the entire 2013-2017 period.



527 **Figure 2.** a) average  $\Delta IO$  in the five-year period 2013-2017 registered in the single networks  
 528 related to the corresponding entering volumes, b) Pareto chart for the analysis of  $\Delta IO$  in  
 529 distribution networks

530

531

**Table 4.** Analysis of average  $\Delta IO$  in the five-year period 2013-2017

Network dimension	Distrib. networks	Gas entering $\sum I_{City Gate}$ ( $Sm^3 10^{10}$ )	Gas leaving $\sum E_{End users}$ ( $Sm^3 10^{10}$ )	$\Delta IO$ ( $Sm^3 10^8$ )	Weighted $\Delta IO$ (%)	Average $\Delta IO$ (%)*	Standard deviation (%)*
Large (>50 $M Sm^3$ )	92	1.46	1.45	1.28	0.88	0.52	1.91
Medium (5-50 $M Sm^3$ )	923	1.28	1.27	0.96	0.75	0.89	3.41
Small (<5 $M Sm^3$ )	1712	0.30	0.29	0.42	1.41	0.24	9.30
All networks	2727	3.04	3.01	2.66	0.88	0.47	7.64

532 \* without outliers (i.e.  $\Delta IO > 100\%$ )

533

534

### 535 3.2. $\Delta IO$ analysis by climatic zone

536 To assess the influence of the climate zone, the investigated distribution networks have been classified  
 537 according to the territorial areas identified by Resolution ARG/gas 159/08, as shown in figure 3: i)  
 538 NW, north-western area; ii) NE, north-eastern area; iii) CEN, central area; iv) SE, central-south-  
 539 eastern area; v) SW, central-south-western area; vi) SOUTH, southern area.

540



541

542 **Figure 3.** Climatic zones and regional areas of Italian natural gas network (source SNAM Rete Gas)

543

544 Table 5 shows the average values and standard deviation of the *deltaIO* recorded in the five-year  
 545 period 2013-2017 on the entire distribution network sample and in the different climatic zones.

546

547 **Table 5.** Average *deltaIO* by climatic zone in the five-year period 2013-2017

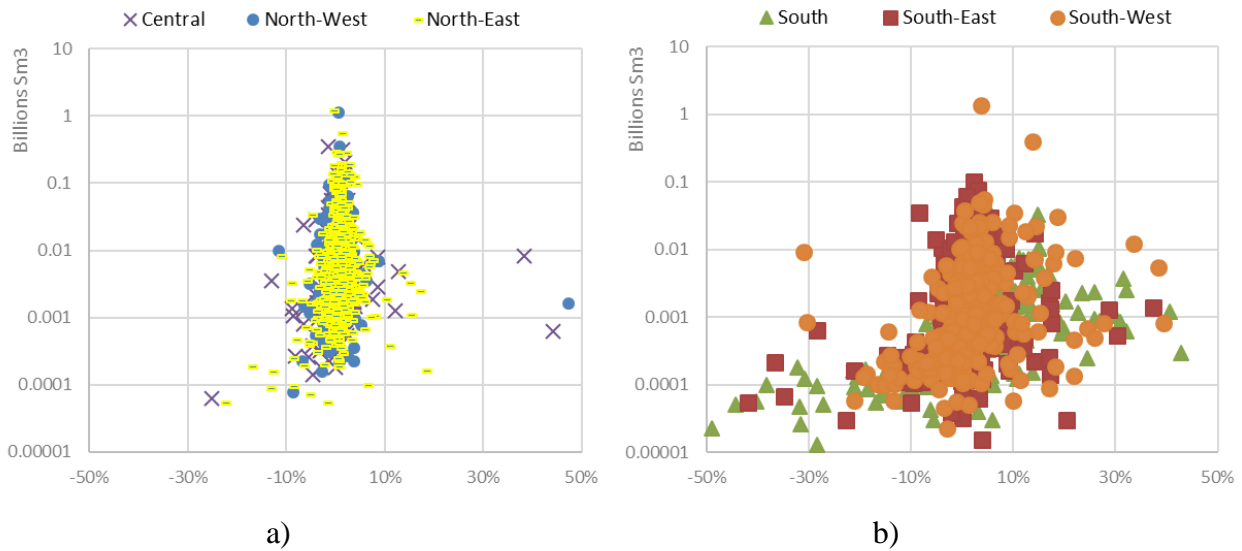
<i>Climatic Zone</i>	<i>Distrib. networks</i>	<i>Gas entering</i> $\sum I_{City\ Gate}$ ( $Sm^3 10^9$ )	<i>Gas leaving</i> $\sum E_{End\ users}$ ( $Sm^3 10^9$ )	<i>deltaIO</i> ( $Sm^3 10^7$ )	<i>Weighted deltaIO</i> (%)	<i>Average deltaIO</i> (%)*	<i>Standard deviation</i> (%)*
CEN	225	3.35	3.34	1.67	0.50	0.30	5.72
NW	247	4.31	4.3	1.64	0.38	0.31	3.72
NE	1116	17.1	1.71	1.75	0.10	0.03	2.37
Tot. Center-North	1588	24.8	2.47	5.06	0.20	0.11	3.28
SW	351	2.96	2.82	14.0	4.73	1.35	8.65
SE	411	1.74	1.71	2.39	1.38	0.47	7.36
South	377	0.95	0.90	5.19	5.49	1.15	15.71
Tot. South and Islands	1139	5.64	5.43	21.6	3.82	0.97	11.16
All the networks	2727	30.4	3.01	26.6	0.88	0.47	7.21

548 \* without outliers (i.e.  $|deltaIO| > 100\%$ )

549

550 From the analysis of data in table 5 it can be observed that about 83% of gas consumption is  
 551 concentrated in the center-north areas despite a lower number of distribution networks (i.e. about 59  
 552 % of the total). From Figure 4 it can be pointed out the statistical analysis also shows that both the  
 553 average values and the standard deviation of the *deltaIO* increase in the southern regions (which have  
 554 a warmer climate and therefore lower consumption per user). This aspect is also consistent with the  
 555 above reported analysis in relation to the worsening of the metrological performance of the meters at  
 556 lower flow rates and more generally to the higher uncertainty in the estimation of the correction  
 557 factors when wider seasonal temperature variations occur. A further variability factor of *deltaIO*  
 558 could also be related to imponderable factors deriving from gas thefts in regions with a higher  
 559 incidence of energy poverty such as the southern area. In fact, southern regions show a higher mean  
 560 value of *deltaIO* in respect to central-north ones.

561



562 **Figure 4.** *DeltaIO* trend in the five-year period 2013-2017 by climatic area: a) central-north, b)  
 563 south-islands

564

565 Therefore, as described above, in addition to the classification by the network dimension, it is worthy  
 566 considering a specific climatic and geographical classification of the networks in center-north and  
 567 south-islands.

568

## 569 5. Conclusions

570

571 In this paper, the analysis of the *deltaIO* in the natural gas distribution networks has been presented.  
 572 First, the main causes that determine the errors in the balance of the networks were analyzed and

573 subsequently a statistical analysis of the *deltaIO* was carried out in the Italian distribution networks  
574 in the five-year period 2013-17. In particular, the analysis was carried out considering the data subject  
575 to multi-year adjustment sessions relating to the distribution networks that operated continuously  
576 throughout the 2013-2017 period (i.e. 2727 distribution networks out of the total of 2907).

577 Aiming at assessing the influence of the systematic effects on the *deltaIO*, the statistical national  
578 sample was sorted by dimension (i.e. large, medium and small networks) and by climatic zone (i.e.  
579 center-north and south-islands). From the results of the statistical analysis it can be pointed out that:

- 580 • the annual *deltaIO*, resulting from the balancing sessions, ranges between -1.57 and 2.27% of the  
581 gas entered into the network and this value is very close to the average one after multi-year  
582 adjustments; annual *deltaIO* variations are partially due to changes in annual consumptions, since  
583 the decrease in consumptions causes load profiling techniques to overestimate non-daily metered  
584 users leading to a negative (or reduced) *deltaIO*;
- 585 • the average *deltaIO* after subsequent adjustments in the five-year period 2013-2017 is just below  
586 +1.0% and it does not change significantly with the dimension of the network, whereas, if the  
587 absolute values are considered, the annual *deltaIO* is slightly below 2%;
- 588 • in the five-year period 2013-2017, the standard deviation of *deltaIO* was about 8% and it  
589 significantly decreases as the network dimension increases, ranging from about 2% (in large  
590 networks) to about 10% (in small networks); this is consistent with the behavior in transmission  
591 networks where a negative correlation with transmitted volumes has been demonstrated;
- 592 • the subsequent adjustment sessions seem to have a negligible effect on the annual average  
593 *deltaIO* and on its standard deviation;
- 594 • both the average *deltaIO* and its standard deviation significantly vary as a function of the climatic  
595 zone; in fact, average *deltaIO* is equal to 0.11% and 0.97% (while the standard deviation is equal  
596 to 3.28% and 11.2%) respectively in the center-north and south-islands areas;
- 597 • in the five-year period 2013-2017 the *deltaIO* values and the relative standard deviations did not  
598 undergo significant changes over the years, with the exception of 2014 when a significant  
599 reduction of more than 10% in natural gas consumption on a national basis resulted in the single  
600 negative *deltaIO* value (equal to approximately -1.6%).

601 From the analysis carried out we can conclude that aiming at progressively reducing *deltaIO* in  
602 distribution networks it could be useful: i) to continuously monitor the value of the *deltaIO*, especially  
603 in distribution networks showing average values of the *deltaIO* higher than the standard deviation  
604 recorded and to punctually investigate the causes that determine so high values; ii) to push the roll-  
605 out of old gas meters with new remotely read smart meters; iii) to improve the metrological  
606 characteristics of the metering systems used in the city gates and encourage their correct management;

607 iv) to improve the frequency of readings of non-remote-read meters and the related number of  
608 readings (in order to enhance the accuracy of the consumption prediction models).

609

610 **Nomenclature and Symbols**

ARERA	National Authority for Energy, Networks and Environment
BO	Balancing Operator
CEER	Council of European Energy Regulators
CEN	Central area of Italy (Tuscany, Umbria and Marche)
deltaIO	Delta In-out
DSO	Distribution System Operator
$KTV_0$	Volumetric correction coefficient
MID	Measuring instrument directive
NE	Northern-eastern area of Italy (Lombardy, Trentino Alto Adige, Veneto, Friuli Venezia Giulia, Emilia Romagna)
NW	Northern-western area of Italy (Aosta Valley, Piedmont and Liguria);
PTZ	Pressure, temperature, compression factor volume conversion device
SE	Central southern-eastern area of Italy (Abruzzo, Molise, Puglia, Basilicata);
SOUTH	Southern area of Italy (Calabria and Sicily)
SW	Central southern-western area of Italy (Lazio and Campania)
TISG	Integrated Gas Settlement Text
UAG	Unaccounted for Gas
$\Delta_{LP}$	Linepack changes (Sm <sup>3</sup> )
$\Delta_{losses}$	Losses and emissions from the network, thefts and shortages (Sm <sup>3</sup> )
$E_{end\ users}$	Gas measured at the exit points of DSO (Sm <sup>3</sup> )
$I_{City\ Gate}$	Gas measured at the entry points of DSO (Sm <sup>3</sup> )
$I_{Gas\ RES}$	Gas production from renewable energy sources (Sm <sup>3</sup> )
$P_S$	Standard Reference pressure (Pa)
$Q$	Volumetric flowrate (m <sup>3</sup> /h)
$Q_{max}$	Maximum flowrate (m <sup>3</sup> /h)
$Q_{min}$	Minimum flowrate (m <sup>3</sup> /h)
$Q_t$	Transition flowrate (m <sup>3</sup> /h)
$T_S$	Standard Reference temperature (K)
$V_S$	Standard conditions (Sm <sup>3</sup> )
$Z_S$	Standard reference compression factor, dimensionless
$P$	Gas pressure at operating conditions (Pa)
$T$	Gas temperature at operating conditions (K)
$V$	Volume at operating conditions (m <sup>3</sup> )
$Z$	Gas compression factor at operating conditions, dimensionless

611

612

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