Distribution tariff setting methodologies in Italy

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ARERA - Regulatory Authority for Energy, Networks and Environment

ECRB - Training on Gas and Electricity Distribution Tariffs
Wien, 17th October 2019

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(Ethical code of ARERA)
TOPICS

1. Introduction
2. Allowed cost calculation
3. Rate of return calculation method
4. Cost allocation approach
5. Tariffs structure
6. The new challenges
1. Introduction

2. Allowed cost calculation

3. Rate of return calculation method

4. Cost allocation approach

5. Tariffs structure

6. The new challenges
REGULATORY PROCESS

Assessment of the state of the industry:
- adequateness of the grid
- needs for future investments

Theory and technique (regulatory schemes):
- cost of service/rate of return
- incentive regulation
- price cap
- menu regulation

Data collection

Regulatory policy objectives

Choosing the Regulatory scheme

Public consultation

Final Decision
EVOLUTION OF TARIFF REGULATION IN ITALY

QUALITY >

COST OF SERVICE

PRICE CAP (CAPITAL COSTS AND OPERATING COSTS)

PRICE CAP (OPERATING COSTS)

QUALITY OF SERVICE (OUTPUT BASED)

QUALITY OF SERVICE (OUTPUT BASED)

RATE OF RETURN (CAPITAL COSTS) + extra-WACC

RATE OF RETURN (CAPITAL COSTS) + phase-out extra-WACC

ROSS

INNOVATION SUPPORT

OUTPUT-BASED INCENTIVES (QUALITY, RESILIENCE)

FW-LOOKING APPROACH

EFFICIENCY INCENTIVES (IQI MATRIX)

PRE-PRIVATISATION 2000 2004 2008-12 2016 ... 202x

1997 REG. AUTHORITY CONSTITUTED

2017 TOTEX For metering 2G
## GAS AND ELECTRICITY DISTRIBUTION INDUSTRY

<table>
<thead>
<tr>
<th>Electricity distribution and metering</th>
<th>Gas distribution and metering</th>
</tr>
</thead>
<tbody>
<tr>
<td>- number of companies</td>
<td>&gt;100</td>
</tr>
<tr>
<td>- smallest company</td>
<td></td>
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<tr>
<td>relevant variable</td>
<td>number of clients served</td>
</tr>
<tr>
<td>size</td>
<td>&lt;5.000</td>
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<tr>
<td>- largest company</td>
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</tr>
<tr>
<td>relevant variable</td>
<td>number of clients served</td>
</tr>
<tr>
<td>size</td>
<td>&gt;31,000,000</td>
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<tr>
<td>Volume distributed</td>
<td>&gt;300 TWh</td>
</tr>
</tbody>
</table>

### Big five companies

<table>
<thead>
<tr>
<th></th>
<th>Electricity Distribution and Metering</th>
<th>Gas Distribution and Metering</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>ENEL DISTRIBUZIONE S.P.A.</td>
<td>Italgas Spa</td>
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<tr>
<td>2</td>
<td>ARETI</td>
<td>2i Rete Gas</td>
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<tr>
<td>3</td>
<td>UNARETI SPA</td>
<td>A2A Spa</td>
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<td>4</td>
<td>IRETI SPA</td>
<td>Hera Spa</td>
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<tr>
<td>5</td>
<td>SET DISTRIBUZIONE SPA</td>
<td>Iren Spa</td>
</tr>
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Aggregated RAB (billion Euro)  

<table>
<thead>
<tr>
<th>Electricity Distribution and Metering</th>
<th>Gas Distribution and Metering</th>
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</thead>
<tbody>
<tr>
<td>23</td>
<td>17</td>
</tr>
</tbody>
</table>
THE CURRENT DISTRIBUTION TARIFF SYSTEM IN ITALY

1. **Allowed Cost Calculation**
   - Reference Tariff
   - Allowed Revenue
   - Revenue Equalisation Fund

2. **Cost Allocation**
   - Tariff for Final Customers
   - Actual Revenue

3. **Tariff Decoupling**
   - Reference Tariff
   - Allowed Revenue
   - Revenue Equalisation Fund

4. **Allowed Revenue**
   - Reference Tariff
   - Allowed Cost Calculation
   - Tariff Decoupling

5. **Tariff for Final Customers**
   - Cost Allocation
   - Actual Revenue
   - Revenue Equalisation Fund
1. Introduction

2. Allowed cost calculation

3. Rate of return calculation method

4. Cost allocation approach

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6. The new challenges
ALLOWED COST CALCULATION – BUILDING BLOCK

- PRICE CAP/INCENTIVE REGULATION
- ACTUAL OPERATING COSTS
  - EFFICIENCY INCENTIVES
  - ALLOWED OPERATING COST
- ALLOWED DEPRECIATION
  - GROSS INVESTED CAPITAL
  - REGULATORY ASSET LIFE
  - ALLOWED DEPRECIATION
- ALLOWED RETURN ON INVESTED CAPITAL
  - NET INVESTED CAPITAL
  - ALLOWED RATE OF RETURN
  - ALLOWED RETURN ON INVESTED CAPITAL

With some exception
ACTUAL OPERATING COSTS

• Allowed operating costs are basically aligned to **actual cost** at the beginning of each regulatory period

• Regulatory period of 6 years (previously 4 years)

• Actual costs are calculated on the basis of costs reported in the **separated annual accounts** according to the unbundling rules defined by the regulator

• Actual costs considered to set the allowed operating costs are net of non-recurring costs, financial costs, advertising and marketing costs, sanctions, tax funds, litigation costs (if unsuccessful), not compulsory insurance costs
EFFICIENCY INCENTIVE MECHANISMS

In relation to the determination of allowed operating costs two incentive mechanisms are applied:

• **price-cap**: annual tariff reviews are based on the *price-cap (RPI-X)* and include **adjustments** reflecting cost variations arising from unforeseeable and exceptional events, changes in regulation and changes in universal service obligations, where applicable (*RPI-X+Y*)

• in the first regulatory periods **x-factor** was based on productivity targets set by the regulators. Since the third regulatory period x-factor are basically used as a tool to redistribute to network users the efficiency gains of the previous regulatory periods, which were temporarily retained by network operators under the so-called ‘profit-sharing mechanism

• on the basis of this **profit-sharing mechanism**, at the end of the regulatory period, in order to set tariffs for the following period, efficiency gains are shared between network operators and network users
SETTING THE ALLOWED OPERATING COST

Effect of price-cap
Incentive to reduce costs = efficiency gains

Effect of profit
Sharing mechanism

Allowed operating costs
INVESTMENTS: A KEY PROBLEM FOR REGULATORS

• A relevant portion of the costs related to network is cost of capital (about 2/3 of total costs)

• In competitive markets usually the subject who pays for wrong investments is not the customer, but the company. In regulated markets regulators face two opposite risks: on one side the risk of overinvestment. On the other side in regulatory context, the long-lived nature of investment in regulated networks means that the risk of creating an underinvestment problem is likely to be an important consideration.

• Lumpiness: how much to invest? Taking into account only the actual needs of the customer already connected to the network or anticipating investments in order to achieve economies of scale?
VARIABLES INFLUENCING INVESTMENTS

Certainty of regulatory framework

Future cash flow level

Investments

Specific incentive

Generic incentive

Quality regulation

Tariff regulation

Allowed rate of return

RAB

ALLOWED OPEX

ALLOWED DEPRECIATION
GENERIC TARIFF INCENTIVE TO INVEST

- Tariff component, covering return on capital
  - Normal profit
  - Expected return on equity
  - Regulatory lag
  - Allowed rate of return
  - Margins (extra-profits)

- D/E actual > D/E regulatory
- Cost of debt (actual) < cost of debt (allowed)
GROSS INVESTED CAPITAL

- **Gross invested capital** is expressed at historical reevaluated costs
- **Historical costs** are derived from the accounting records of network operators
- **Revaluation** is obtained using the *gross investment deflator index*
- Fixed assets are included in the regulatory asset base (RAB), with a **one-year lag** if investment costs are efficiently incurred and are consistent with system security, follow cost-effective criteria
REGULATORY ASSET BASE

Net invested capital

- **net invested capital constitutes the** regulatory asset base (RAB) **and** is derived from gross invested capital subtracting depreciation fund
- **assets under construction** are also included in the RAB

RAB is adjusted for:

- the net real-term (revaluated) value of public grants for infrastructure developments and connection charges
- the pensionable retirement fund (TFR), calculated parametrically (-1% of net invested capital)
- the net working capital, calculated parametrically

Yearly update

RAB is updated on a yearly basis taking into account:

- New investments and divestitures
- Changes in depreciation fund
- Changes in public grants and connection charges
- Revaluation - gross investment deflator index
GAS DISTRIBUTION – FIXED ASSET CATEGORIES

• Invested capital can be distinguished by function between:
  o centralized invested capital
  o centralized invested capital relative to metering (remote metering and concentrators)
  o local invested capital relative to distribution
  o local invested capital relative to metering

• Local fixed assets are:
  o land and buildings
  o citygates
  o mains
  o customers connections
  o conventional meters
  o electronic meters and volumes converter with a data transmission system

• Centralized assets relative to distribution are tangible assets not classified as local assets and intangible assets
GAS DISTRIBUTION – EVALUATION CRITERIA

- Central Assets - RAB
- Local Assets - Net Revaluated Historical Cost
- Local Assets - Standard Invested Capital per Final Customer Served
- Local Assets - Smart Meters - RAB
- Local Assets - Mix of Net Revaluated Historical Cost and Standard Cost
ELECTRICITY DISTRIBUTION – FIXED ASSET CATEGORIES

- Land
- Buildings
- EHV-HV lines: 220, 120-150, 40-80 kV*
- Electric stations: 220*, 120-150, 40-80 kV
- Electric sub-stations
- Electric sub-stations transformers;
- MV lines (from 1 to 35 kV)
- LV lines (230-380 V)

* - mostly owned and operated by TSOs

- Furnitures
- Other tangible assets (Equipment, Vehicles)
- IT (remote transmission, pc stations, data processing systems)
- Intangible assets (licences, R&D, patent rights and trademarks, third party assets improvements, other intangible assets)
Fixed assets related to high voltage distribution:
• Historical revaluated cost, calculated for each asset group, identified by the year in which the asset is placed in service and the regulatory lifetime

Fixed assets related to medium and low voltage distribution:
• Asset placed in service before 2008: Historical revaluated cost calculated parametrically

• Asset placed in service after 2007: historical revaluated cost, calculated for each asset group, identified by the year in which the asset is placed in service and the regulatory lifetime
ELECTRICITY DISTRIBUTION - DEPRECIATION

- Depreciation is calculated under a straight-line method for each asset included into RAB.
- The yearly allowance is calculated as a ratio between:
  - net invested capital
  - residual regulatory lifetime of each asset.
- Regulatory assets lifetime has been defined on the basis of technical lifetime.

Depreciation is updated on a yearly basis taking into account:

- New net investments depreciation and divestitures depreciation.
- Revaluation through gross investment deflator index.

<table>
<thead>
<tr>
<th>ASSETS</th>
<th>TECHNICAL LIFETIME</th>
</tr>
</thead>
<tbody>
<tr>
<td>LAND</td>
<td>NOT DEPRECIATED</td>
</tr>
<tr>
<td>BUILDINGS</td>
<td>40</td>
</tr>
<tr>
<td>TRANSMISSION AND HV LINES</td>
<td>45</td>
</tr>
<tr>
<td>TRANSMISSION STATIONS</td>
<td>33</td>
</tr>
<tr>
<td>ELECTRIC SUBSTATIONS</td>
<td>30</td>
</tr>
<tr>
<td>MV AND LV LINES</td>
<td>35</td>
</tr>
<tr>
<td>FURNITURE</td>
<td>17</td>
</tr>
<tr>
<td>OTHER TANGIBLE ASSETS</td>
<td>10</td>
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<tr>
<td>IT</td>
<td>5</td>
</tr>
<tr>
<td>INTANGIBLE ASSETS</td>
<td>5</td>
</tr>
<tr>
<td>HV AND MV METERS</td>
<td>20</td>
</tr>
<tr>
<td>LV SMART METERS</td>
<td>15</td>
</tr>
</tbody>
</table>
• The yearly allowance for asset depreciation of local assets is the ratio between the gross revaluated historical cost and the regulatory life.

• Depreciation for central assets is set parametrically per customer served.

<table>
<thead>
<tr>
<th>ASSET</th>
<th>REGULATORY LIFE (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Municipal concessions</td>
</tr>
<tr>
<td>Buildings</td>
<td>40</td>
</tr>
<tr>
<td>Mains</td>
<td>50</td>
</tr>
<tr>
<td>Customer connections</td>
<td>40</td>
</tr>
<tr>
<td>Citygates</td>
<td>20</td>
</tr>
<tr>
<td>Other tangible assets and intangible assets</td>
<td>7</td>
</tr>
<tr>
<td>Remote meters</td>
<td>15</td>
</tr>
<tr>
<td>Concentrators</td>
<td>15</td>
</tr>
<tr>
<td>Electronic meters</td>
<td>15</td>
</tr>
<tr>
<td>Traditional meters (&gt;G6)</td>
<td>20</td>
</tr>
<tr>
<td>Traditional meters (&lt;=G6)</td>
<td>15</td>
</tr>
<tr>
<td>Volumes converter with a data transmission system</td>
<td>15</td>
</tr>
</tbody>
</table>
With decision 583/2015/R/COM ARERA reformed the criteria for the determination and updating of the allowed rate of return in the electricity and gas sectors.

The previous allowed rate of return methodology adopted by ARERA was first introduced in the second electricity transmission and distribution regulatory period (2004).

At the time, yields on Italian government bonds were a reasonable proxy for risk-free rates and it was generally assumed that market risk premium and interest rates were non correlated.

Since the start of the global financial crisis (2008), a number of unusual events have affected capital markets and macroeconomic condition across the globe, including the Eurozone countries.

ARERA found it necessary to review the previous allowed rate of return methodology also to avoid that different market conditions at the time of the tariff revision could lead to unjustified differentiations of allowed returns among regulated services.
Decision 597/2014/R/COM stated the general approach to be followed in the allowed rate of return calculation methodology review:

- the allowed rate of return is calculated as a **weighted average cost of capital (WACC)**
- the allowed rate of return is calculated as **real** and **pre-tax**
- the cost of equity is calculated according to the **Capital Asset Pricing Model (CAPM)**
WACC REGULATORY PERIOD (PWACC)

• ARERA intended to unify the WACC parameters, except $\beta$ and gearing, for all the regulated activities of electricity and gas sectors.
• Unified WACC parameters are set by ARERA for a period of time, called WACC regulatory period (PWACC).
• The length of the ‘WACC regulatory period’ is six years. The PWACC consists of two sub-periods, each one lasting three years.
• In the interim PWACC review are reviewed the following parameters:
  o risk-free rate;
  o Country Risk Premium;
  o inflation rate;
  o fiscal parameters.
WACC FORMULATION

\[
W^{\text{real}}_{\text{pre-tax}, p, s} = Ke^{\text{real}}_{p, s} \cdot \frac{(1 - g_{p, s})}{(1 - T_p)} + Kd^{\text{real}}_p \cdot \frac{g_{p, s}}{(1 - T_p)} \cdot (1 - tc_p) + F_{p, s}
\]

- Gearing (D/(D+E))
- Tax rate
- Tax shield
- Return on equity
- Cost of debt
- Tax adjustment factor
The cost of equity is calculated adding to the traditional CAPM formulation a specific term reflecting the *Country Risk Premium (CRP)*:

\[ K_e = RF + \beta \cdot ERP + CRP \]

where:
- RF is the risk-free rate
- \( \beta \) is a measure of the systematic risk of an activity
- ERP is the equity risk premium

The introduction of parameter CRP allows to explicitly capture the impact of the fiscal crisis on required returns for regulated utilities in Italy.
POST TAX RETURN ON EQUITY

\[ Ke_{p,s}^{\text{real}} = \max \left( \frac{RF_p^{\text{nominal}} - isr_p}{1 + isr_p} ; 0.005 \right) + \beta_{s,\text{asset}} \cdot \left[ 1 + (1 - tc_p) \cdot \frac{g_{p,s}}{1 - g_{p,s}} \right] \cdot ERP_p \cdot CRP_p \]

- **Risk-free rate**
- **Beta levered**
- **Country Risk Premium**

**Equity Risk Premium**

\[ ERP_p = TMR - \max \left( \frac{RF_p^{\text{nominal}} - isr_p}{1 + isr_p} ; 0.005 \right) \]

where:

- \( isr_p \) is the expected inflation rate.
In the new approach a greater weight was placed on the concept of total equity market return, to ensure a consistent set of assumptions for the risk-free rate and the equity risk premium, rather than estimating them separately.

TMR was estimated on the basis of long term evidences:
- time horizon: 1900-2014
- countries considered in the calculation: Belgium, France, Germany and Netherlands (rated at least “AA”)
- weighted average of the arithmetic (6.6%) and geometric (3.5%) averages

`Range of the weight of arithmetic average` doc. 509/2015

- 50%  
- 80%  

TMR 5.1%  

6.0%
**REAL RISK-FREE RATE**

**Nominal risk-free rate:**
average of nominal ten-year benchmark government bond yields in Eurozone countries with minimum rating “AA” (Belgium, France, Germany and Netherlands) in the period 1 October 2014 – 30 September 2015

![0.79%](image)

Real risk-free rate

**Inflation rate:**
average of ten-year inflation linked swap rate in the period 1 October 2014 – 30 September 2015

![1.39%](image)

In order to avoid negative yields, not consistent with economic expectations, ARERA introduced a **floor** for the real risk-free rate. On this basis, the real risk-free rate was set equal to **0.5%** for years 2016-2018.
EQUITY RISK PREMIUM (ERP)

AEEGSI adopted a ‘TMR constant’ approach, according to which the ERP is calculated as the difference between TMR and RF.

\[
\begin{align*}
+\text{TMR} & \ 5.1\% \\
- \text{RF} & \ 0.5\% \\
\text{ERP} & \ 4.6\% \\
\end{align*}
\]

Range doc. 509/2015

Final decision

The approach followed for the setting of the risk-free rate and of the equity risk rate allows to reflect “normal” market conditions, before considering the impact of the fiscal crisis in Italy on required returns.
COUNTRY RISK PREMIUM

*CRP* reflects the compensation investors require to operate in a certain country.

Rating differentials among countries affect also companies ratings. *CRP* affects both cost of debt and cost of equity.

Two approaches to estimate *CRP* can be followed:

- evidence from corporate debt markets
- evidence from equity markets

According to initial evaluations *CRP* was estimated to vary between 0.5% and 1.0%.

In the final decision ARERA set *CRP* equal to 1.0% for years 2016-2018 for both equity and debt.
COST OF DEBT

From a theoretical point of view, cost of debt can be estimated adding to RF a spread determined on the basis of debt $\beta$. The implementation of this approach, however, presents some practical difficulties.

ARERA examined the structure and the stratification of regulated companies’ medium and long term debt.

ARERA set the cost of debt in order to reflect the cost of efficiently incurred debt, considering the economic sustainability, giving incentive to define efficient debt portfolios and taking into account evidences from capital markets.

$$Kd_{p}^{real} = \max \left( \frac{RF_{p}^{\text{nominal}} - isr_{p}}{1 + isr_{p}} ; 0,005 \right) + CRP_{p} + DRP$$

- **Risk-free rate**
- **Country Risk Premium**
- **Debt Risk Premium**
FISCAL PARAMETERS

\[ W_{pre-tax,p,s}^{real} = Ke_{p,s}^{real} \cdot \frac{(1 - g_{p,s})}{(1 - T_p)} + Kd_{p}^{real} \cdot g_{p,s} \cdot \frac{(1 - tc_p)}{(1 - T_p)} + F_{p,s} \]

- Gearing (D/(D+E))
- Tax rate
- Tax shield
- Return on equity
- Cost of debt
- Tax adjustment factor
Fiscal parameters in the WACC formulation allow to take into consideration:

- the effect of the tax rate on the return on equity and on the cost of debt (parameter $T$)
- the effect of tax shield on the cost of debt (parameter $tc$)
- the fact that taxes are paid on nominal returns (tax adjustment factor)
ARERA decided to estimate specific $\beta$ for each regulated activity, considering evidences coming from the Eurozone equity markets related to companies with high credit rating, in a period of at least two years.

In ARERA’s opinion $\beta$ estimate cannot be considered as a pure mechanistic exercise. It is necessary to analyse the results and evaluate the coherence with the general regulatory framework evolution.

ARERA decided to set the *gearing* level taking into account the actual levels for regulated companies and considering the perspective of a gradual alignment towards the average levels adopted by other regulators.
For the second sub-period beginning in year 2019 ARERA, in the perspective of a gradual convergence towards the levels adopted by other European regulators, envisaged a revision of gearing level for all regulated activities, with a maximum level of 0.5.

The revision of gearing implies, as a consequence, also a revision of beta levered, on the basis of the following formula:

\[
\beta^{levered} = \beta^{asset} \cdot \left(1 + (1 - tc) \cdot \frac{D}{E}\right)
\]
In the final decision ARERA adopted a trigger approach for the review of the CRP, based on the following formula:

\[
CRP_{II} = CRP_{I} \cdot \left[ 1 + \left( \frac{Spread^{corr}}{Spread^{base}} - 1 \right) \cdot SC \right]
\]

where:

- \(Spread^{corr}\) is the average spread between the Italian ten-year BTP benchmark and the German ten-year Bund in the period 1 October 2017 - 30 September 2018
- \(Spread^{base}\) is the average spread between the Italian ten-year BTP benchmark and the German ten-year Bund in the period 1 October 2014 - 30 September 2015
- \(SC\) is a dummy variable equal to 0 if the difference between \(Spread^{corr}\) and \(Spread^{base}\) (in absolute terms) is \(\leq 20\%\) and equal to 1 else
Other parameters will be reviewed as follows:

- the risk-free rate will be calculated on the basis of the following formula:

\[ RF_{II}^{real} = \max \left( \frac{RF_{II}^{nominal} - isr_{II}}{1 + isr_{II}}, 0.005 \right) \]

where:

- \( RF_{II}^{nominal} \) is the average of yields on government bonds issued by Eurozone countries rated at least “AA” in the period 1 October 2017 – 30 September 2018

- \( isr_{II} \) is the average of ten-year inflation linked swap rates in the Eurozone in the period 1 October 2017 – 30 September 2018

- the parameter \( ERP_p \) will be recalculated as the difference between the TMR (set equal to 6.0%) and the risk-free rate

- the parameter \( ia_p \) will be defined on the basis of the most recent forecasts of the ECB

- parameters \( T_p \) and \( tc_p \) will be defined on the basis of a detailed analysis in order to estimate taxation levels.
TOPICS

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COST ALLOCATION - GENERAL APPROACH

NETWORK COSTS

CONNECTION CHARGES

USE OF THE NETWORK CHARGES

- High level of socialisation

- Unique national tariff for electricity
- Six macro-regional tariffs for gas

Considered the weight on the customer total bill (13%) and the ample socialization criteria adopted, price signals related to distribution tariffs are considered very weak

A shallow approach is adopted

G=0%, L=100% is the current split

Basically an average cost approach is adopted
GAS DISTRIBUTION COST ALLOCATION CRITERIA - 1

- GAS DISTRIBUTION COST OF CAPITAL: 50% fixed charge, 50% variable charge (Euro/point of delivery)
- GAS DISTRIBUTION OPERATING COST: 100% variable charge (Euro/scm)
- METERING COST OF CAPITAL: 100% fixed charge (Euro/point of delivery)
- METERING OPERATING COST: 100% fixed charge (Euro/point of delivery)
So far, the cost of each network has been covered by clients connected to the same or to lower voltage levels. This means that:

- **HV clients** contribute to cover costs of **HV+VHV networks**,  
- **MV clients** contribute to cover costs of **MV+HV+VHV nets**,  
- **LV clients** contribute to cover costs of **all networks**.

**Legend:**
- Energy flows [MWh]
- Revenues from tariffs [€]
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GAS DISTRIBUTION – TARIFFS FOR FINAL CUSTOMERS

- Tariffs paid by final customers are differentiated per tariff area.
- In particular, 6 tariff areas have been defined, corresponding to aggregations of Regions.
- The tariff in each area reflects the cost of service in the tariff area.
- Since year 2015 fixed components are differentiated on the basis of the class of the meter, distinguishing between:
  - meter class <= G6;
  - meter class > G6 and <= G40;
  - meter class > G40.
Tariff areas:

- North Western
- North Eastern
- Centre South Eastern
- Centre
- Centre South Western
- South

Tariff areas:
GAS DISTRIBUTION – STRUCTURE OF VARIABLE CHARGE

- Variable charges $\tau^f_3 (dis)$, differentiated per tariff area, are calculated on the basis of a **national tariff articulation** and of the specific costs incurred in each tariff area.
- The national tariff articulation is in principle **degressive**, in order to reflect costs.
- The **first band of consumption**, for **social reasons**, has been set equal to zero.

### National tariff articulation

<table>
<thead>
<tr>
<th>Consumption band (scm/year)</th>
<th>eurocent/scm</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-120</td>
<td>0,00</td>
</tr>
<tr>
<td>121-480</td>
<td>7,79</td>
</tr>
<tr>
<td>481-1,560</td>
<td>7,13</td>
</tr>
<tr>
<td>1,561-5,000</td>
<td>7,16</td>
</tr>
<tr>
<td>5,001-80,000</td>
<td>5,35</td>
</tr>
<tr>
<td>80,001-200,000</td>
<td>2,71</td>
</tr>
<tr>
<td>200,001-1,000,000</td>
<td>1,33</td>
</tr>
<tr>
<td>More than 1,000,000</td>
<td>0,37</td>
</tr>
</tbody>
</table>
• Allowed revenues are calculated on the basis of the reference tariff and the relevant scale variables.
• The reference tariff is a vector of fixed charges (expressed in €/point of delivery/year) reflecting different cost elements.

![Diagram of gas distribution reference tariffs]

- Centralized asset capital costs: \( t(cen)_{i}^{cap} \)
- Local asset capital costs: \( t(dis)_{i,c,i}^{amm} \), \( t(dis)_{i,c,i}^{rem} \), \( t(mis)_{i,c,i}^{rem} \), \( t(mis)_{i,c,i}^{amm} \)
- Operating costs: \( t(dis)_{t,d,r}^{ope} \), \( t(ins)_{t}^{ope,b} \), \( t(ins)_{t}^{ope,v} \), \( t(rac)_{t}^{ope} \), \( t(cot)_{t} \)
- Distribution
- Metering
- Commercial activities
<table>
<thead>
<tr>
<th>CLASS OF NETWORK USERS</th>
<th>METERING COSTS</th>
<th>DISTRIBUTION NETWORK COSTS</th>
<th>COMMERCIAL COSTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>LV HOUSEHOLDS</td>
<td>FIXED CHARGE</td>
<td>CAPACITY CHARGE, ENERGY CHARGE</td>
<td>FIXED CHARGE</td>
</tr>
<tr>
<td>LV PUBLIC RECHARGING OF ELECTRICAL VEHICLES</td>
<td>ENERGY CHARGE</td>
<td>ENERGY CHARGE</td>
<td>ENERGY CHARGE</td>
</tr>
<tr>
<td>LV PUBLIC LIGHTING</td>
<td>ENERGY CHARGE</td>
<td>ENERGY CHARGE</td>
<td>ENERGY CHARGE</td>
</tr>
<tr>
<td>LV OTHER USES</td>
<td>FIXED CHARGE</td>
<td>CAPACITY CHARGE, ENERGY CHARGE</td>
<td>FIXED CHARGE</td>
</tr>
<tr>
<td>MV PUBLIC LIGHTING</td>
<td>ENERGY CHARGE</td>
<td>ENERGY CHARGE</td>
<td>ENERGY CHARGE</td>
</tr>
<tr>
<td>MV OTHER USES</td>
<td>FIXED CHARGE</td>
<td>CAPACITY CHARGE, ENERGY CHARGE</td>
<td>FIXEX CHARGE</td>
</tr>
<tr>
<td>HV</td>
<td>FIXED CHARGE</td>
<td>ENERGY CHARGE</td>
<td></td>
</tr>
<tr>
<td>EHV</td>
<td>FIXED CHARGE</td>
<td></td>
<td></td>
</tr>
<tr>
<td>GENERATORS</td>
<td>NO G-CHARGE TARIFF AT ANY VOLTAGE LEVEL</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Allowed revenues for each DSO are calculated on the basis of the reference tariff (calculated for each DSO) and the relevant scale variables (Point of delivery served for fixed charge and energy served for energy charge).

The reference tariff are differentiated by class of final users and have a fixed charge, expressed in €/point of delivery/year and an energy charge, expressed in €/kWh.
TOPICS

1. Introduction
2. Allowed cost calculation
3. Rate of return calculation method
4. Cost allocation approach
5. Tariffs structure
6. The new challenges
THE NEW CHALLENGES

EU ENERGY POLICY OBJECTIVES – GREEN PACKAGE

TECHNOLOGICAL DEVELOPMENT

DIGITALIZATION

DISTRIBUTED GENERATION

DEMAND RESPONSE

RENEWABLES

SMART GRID

SMART METER

AND THE REGULATORS?
ADAPTING THE REGULATORY TOOLKIT

FOCUSING ON OUTPUT

TRENDS OF THE REGULATORY REFORMS

REVIEWING COST ALLOCATION AND TARIFF DESIGN

FOCUSING ON FUTURE EXPENDITURE

TOTEX EFFICIENCY

INNOVATION SUPPORT

Preparation and discussion of business plans

Cost-benefit-analysis

Menu regulation
ARERA proposed in DCO 5/2015 the adoption of a new approach based on total expenditure (\textit{totex})

\textit{Totex} approach is considered by ARERA more efficient compared to the present hybrid approach (\textit{price cap} applied to operating costs and \textit{cost of service regulation} applied to capital costs)

In the new regulatory strategic framework approved with the decision 242/2019/A (June 2019) the \textit{totex} approach has been integrated in a more comprehensive regulation by objectives of service and expenditure approach (ROSS)
**TOTEX APPROACH - 2**

- DCO 335/2015 outlines the key features of *totex* approach:
  - focus on future expenditure;
  - output orientation;
  - stronger incentive to improve total productivity.

- The adoption of a *totex* approach implies giving more relevance to forecast and business plans. Due to information asymmetry, it is therefore necessary to introduce *truth telling* incentives in order to obtain credible business plans from regulated companies.

- *Totex* are generally managed with menus, aimed at combining productivity incentives and truth telling incentives.

- Cost assessment and total expenditure analysis play a key role in the implementation of *totex*.

- The adoption of *totex* requires also to strengthen enforcement, in order to control the actual level of outputs and of expenditure.
ROLL-OUT OF ELECTRICITY SECOND GENERATION SMART METER (2G)

DECISION 646/2016

CONFIDENTIAL ANNEX
Forecast of detail expenditure, demand scenarios and volumes

“FAST TRACK” TEST (TARIFF INVARIANCE)

KO

OK

CBA

ROLL-OUT PLAN (“PMS2”), 15 YRS HORIZON

PMS2 TABLE OF CONTENT DEFINED BY REG

PUBLIC CONSULTATION PROCESS (LED BY DSO)

iterations with the regulator

PUBLIC VERSION
Expected performance, scope for innovation, Aggregated cost, Qualitative benefits/impacts Customer service Communication plan

REGULATORY APPROVAL WITH CONDITIONALITIES

APPROVED PUBLIC VERSION
Modified according to regulatory approval decision
### IQI MATRIX – ROLL-OUT 2G SMART METER

<table>
<thead>
<tr>
<th>Ratio DSO/NRA estimation</th>
<th>0.75</th>
<th>0.80</th>
<th>0.85</th>
<th>0.90</th>
<th>0.95</th>
<th>1.00</th>
<th>1.05</th>
<th>1.10</th>
<th>1.15</th>
<th>1.20</th>
<th>1.25</th>
</tr>
</thead>
<tbody>
<tr>
<td>&quot;Admissible&quot; expenditures</td>
<td>93.75</td>
<td>95.00</td>
<td>96.25</td>
<td>97.50</td>
<td>98.75</td>
<td>100.00</td>
<td>101.25</td>
<td>102.50</td>
<td>103.75</td>
<td>105.00</td>
<td>106.25</td>
</tr>
<tr>
<td>Efficiency Incentive coeff.</td>
<td>26.25%</td>
<td>25.00%</td>
<td>23.75%</td>
<td>22.50%</td>
<td>21.25%</td>
<td>20.00%</td>
<td>18.75%</td>
<td>17.50%</td>
<td>16.25%</td>
<td>15.00%</td>
<td>13.75%</td>
</tr>
<tr>
<td>Information Incentive</td>
<td>0.86</td>
<td>0.75</td>
<td>0.61</td>
<td>0.44</td>
<td>0.23</td>
<td>0.00</td>
<td>-0.27</td>
<td>-0.56</td>
<td>-0.89</td>
<td>-1.25</td>
<td>-1.64</td>
</tr>
</tbody>
</table>

| Expenditure estimation (NRA) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Expenditure estimation (DSO) | 75 | 80 | 85 | 90 | 95 | 100 | 105 | 110 | 115 | 120 | 125 |
| Actual expenditure | | | | | | | | | | | |
| 75 | 5.78 | 5.75 | 5.66 | 5.50 | 5.28 | 5.00 | 4.66 | 4.25 | 3.78 | 3.25 | 2.66 |
| 80 | 4.47 | 4.50 | 4.47 | 4.38 | 4.22 | 4.00 | 3.72 | 3.38 | 2.97 | 2.50 | 1.97 |
| 85 | 3.16 | 3.25 | 3.28 | 3.25 | 3.16 | 3.00 | 2.78 | 2.50 | 2.16 | 1.75 | 1.28 |
| 90 | 1.84 | 2.00 | 2.09 | 2.13 | 2.09 | 2.00 | 1.84 | 1.63 | 1.34 | 1.00 | 0.59 |
| 95 | 0.53 | 0.75 | 0.91 | 1.00 | 1.03 | 1.00 | 0.91 | 0.75 | 0.53 | 0.25 | -0.09 |
| 100 | -0.78 | -0.50 | -0.28 | -0.13 | -0.03 | 0.00 | -0.03 | -0.13 | -0.28 | -0.50 | -0.78 |
| 105 | -2.09 | -1.75 | -1.47 | -1.25 | -1.09 | -1.00 | -0.97 | -1.00 | -1.09 | -1.25 | -1.47 |
| 110 | -3.41 | -3.00 | -2.66 | -2.38 | -2.16 | -2.00 | -1.91 | -1.88 | -1.91 | -2.00 | -2.16 |
| 115 | -4.72 | -4.25 | -3.84 | -3.50 | -3.22 | -3.00 | -2.84 | -2.75 | -2.72 | -2.75 | -2.84 |
| 120 | -6.03 | -5.50 | -5.03 | -4.63 | -4.28 | -4.00 | -3.78 | -3.63 | -3.53 | -3.50 | -3.53 |
| 125 | -7.34 | -6.75 | -6.22 | -5.75 | -5.34 | -5.00 | -4.72 | -4.50 | -4.34 | -4.25 | -4.22 |
• Rebalancing the G&L split? G>=0%?
• Review of the approach to connection charges? Adoption of a deep approach instead of a shallow approach? Connection charges based on LRMC?
• Use of the network charges: how to decline the principle of cost reflectivity?

A strict *short run marginal cost approach* combined with *Ramsey pricing* in order to guarantee revenue collection (assuming the absence of transfers from the State)?

This approach would be consistent with economic theory, but the implementation of Ramsey pricing could produce relevant redistributive effects.
• **Use of the network charges:** to what extent costs have to be socialized?

The costs of gas and electricity distribution grid have always been socialized in order to reduce price discrimination. Socialization is to a certain extent a necessity since network companies anticipate investments in order to satisfy at lower costs the future demand, since the lumpiness of investments in the grid and since the administrative costs of setting an individual tariff would be very high and probably not proportionate to the benefits coming from perfectly tailored tariffs for each customer.

Is an ample socialization of costs compatible with the development of effective demande response mechanisms?

Is **nodal pricing** viable for distribution networks?
• How to respect the universal service obligation?

Optimal linear pricing as a response to the problems connected with nonnegligible fixed premium (with potential exclusion of customers with low incomes whose welfare is given substantial weight in the social welfare function)?

Specific fuel poverty support schemes (in Italy we have specific «bonus» for gas and electricity final customers)
The move towards capacity tariff which seem to be the solution to treat the «prosumer» problem, could in the medium term produce grid defections?

Which is the power of network price signals in orientating the consumption patterns of final customers?

Signal coming from time of use energy pricing can be in conflict with signals of local congestions coming from dynamic network tariffs and time of use network tariffs.
THE WAY FORWARD?

- Cost Reflectivity
- Simplicity
- Affordability
- Financial Sustainability
- Equity

?
Thank you for your attention!