

REPORT

ON UNIT INVESTMENT COST INDICATORS AND CORRESPONDING REFERENCE VALUES FOR ELECTRICITY AND GAS INFRASTRUCTURE

GAS INFRASTRUCTURE

Gas Infrastructure Unit Investment Costs Report

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1 Executive summary

This Report contains the established set of indicators and corresponding reference values for the comparison of unit investment costs for comparable projects of the infrastructure categories included in Annex II of Regulation (EU) 347/2013 (“the Regulation”) for gas infrastructure. The Report is the result of collaborative work carried out by national regulatory authorities (NRAs) cooperating in the framework of the Agency for developing the set of indicators and corresponding reference values as required by Article 11(7) of the Regulation. The Report is without prejudice to the development and the publishing by NRAs of such indicators and reference values at individual Member State or regional level as NRAs may wish to develop and publish.

The Report contains separate volumes for electricity and gas infrastructure. This volume covers the set of indicators and corresponding reference values for onshore transmission pipelines, compressor stations as well as historic values for liquefied natural gas (LNG) reception, storage and re-gasification’s terminals. Scarce data provided at European level by NRAs for underground gas storage (UGS) have not permitted to develop and publish reliable unit costs indicators for this type of infrastructure, but the results are provided in Annex A¹. The Report also provides a review of the legal basis, objectives, work methods and procedures used for developing the indicators and the corresponding values, as well as guidance on how to interpret and use the indicators and the reference values.

The underlying information is mainly historic (empirical, *de-facto*) data about the relevant gas projects. The scope of the analysis was specified by defining minimum thresholds for the value of investment (total cost) and for selected technical specifications as well as by defining the time period under consideration, in order to improve the consistency of the data by leaving very small or very old investments out of the scope of the Report. The analysis also takes into consideration the impact of outliers², i.e. observed values of unit investment costs which are very distant from other observed values. For transmission infrastructure, data were provided on the investment cost and other necessary parameters of 293 transmission pipelines and 101 compressor stations put in service during the last 10 years (2005-2014). Similarly, data for 19 UGS and 31 LNG infrastructure projects (new facilities and expansions) commissioned over the last 15 years (2000-2014) were collected. The total value of the investment in such facilities over the reviewed period of time is about €32 billion, of which €15 billion in transmission pipelines, €8 billion in LNG facilities, €5 billion in UGS and €4 billion in compressor stations.

The indicators and the corresponding reference values contained in the Report constitute a body of reference which could help bridge information gaps where investment costs are not currently available. For example, the European Network of Transmission System Operators for Gas (ENTSOG) may use the indicators and the reference values as a reference in the context of the 10-year network development plan (TYNDP), to complement the cost information provided by project promoters³. The indicators and the reference values could also be used as a point of reference in the context of the selection of projects of common interest (PCI) and for the development of better informed cross-border cost allocation (CBCA) decisions. A complementary objective is to help raise transparency levels regarding gas infrastructure investment cost in Europe.

The results of the analysis (i.e., the indicators and the corresponding reference values) are provided in the form of average values and standard statistics and, where relevant, accompanied by a brief explanation of the trends observed. For reasons explained in the Report, the indicators and the corresponding reference values should be used with caution and must not be regarded as a substitute for the due diligence in each instance of an existing or planned investment in gas infrastructure. For example, independently from the final size of the

¹ For UGS in depleted fields only. Data for other types of storage (in salt caverns and in aquifers) were only available for a single facility of each of these two types of UGS and consequently is not used for the development of the indicators.

² For pipelines and compressor stations.

³ ENTSOG may provide assessments on a comparative basis by using the cost information of project promoters and the reference values. Project promoters may also choose to describe their projects in more detail by using the actual and the reference unit investment cost.

samples analysed, indicators and reference values for transmission pipelines and compressor stations can be seen as more robust than the equivalent indicators for UGS and LNG, due to the specific characteristics of the assets in question: transmission pipelines and compressor stations tend to be more standardised, while LNG and especially UGS facilities can be really unique.

The objective of the published indicators and the reference values is not to serve as any guidance for the acceptable ranges within which unit costs of any project(s) would have to fall or as a justification for any project cost(s). It is also important to underline that this Report cannot be seen as legal advice and neither the Agency nor any NRA can be held responsible for any consequence of the use of the unit investment cost indicators and their reference values.

The **set of indicators and corresponding reference values** for the comparison of unit investment costs for comparable projects of the considered gas infrastructure categories **are published in Chapter 5** of the Report.

2 Background and objectives

2.1 Legal basis

Pursuant to Article 11(7) of the Regulation, by 16 May 2015 national regulatory authorities (NRAs) cooperating in the framework of the Agency shall establish and make publicly available a set of indicators and corresponding reference values for the comparison of unit investment costs for comparable projects of the infrastructure categories included in Annex II of the said Regulation, defined as follows:

<...>

(2) concerning gas:

- (a) *transmission pipelines for the transport of natural gas and bio gas that form part of a network which mainly contains high-pressure pipelines, excluding high-pressure pipelines used for upstream or local distribution of natural gas;*
- (b) *underground storage facilities connected to the above-mentioned high-pressure gas pipelines;*
- (c) *reception, storage and re-gasification or decompression facilities for liquefied natural gas (LNG) or compressed natural gas (CNG);*
- (d) *any equipment or installation essential for the system to operate safely, securely and efficiently or to enable bi-directional capacity, including compressor stations. <...>.*

The Regulation also establishes that “*those reference values may be used by the ENTSO for Electricity and the ENTSO for Gas for the cost-benefit analyses carried out for subsequent 10- year network development plans.*”

2.2 Objectives

The main objective of the work undertaken by NRAs cooperating in the framework of the Agency is to arrive at such a set of unit investment cost indicators and corresponding values that could be useful for the following practical purposes:

1. Preparation of the Ten-Year Network Development Plans (TYNDP);
2. PCI selection, where the indicators and the values could provide a reference point for the assessment of the project promoters’ submissions;
3. Development of better informed CBCA decisions, where the indicators and the values could be of help to NRAs and, where appropriate, the Agency, when deciding on investment requests and considering cross-border cost allocation;
4. Analyses associated with public financial assistance, where the indicators and the values could be informative for the agencies and the authorities in charge of the evaluation of proposals for grants to project promoters.

A complementary objective is to provide transparency regarding the levels of costs of gas infrastructure in the European Union, as well as the changes in these levels, in the structure of the costs, and the role of various factors affecting the costs. The aim is to help raise transparency levels regarding electricity and gas infrastructure cost information in Europe (in other regions of the world⁴ cost reference information for regulated gas infrastructure has been publicly available for at least 30 years). The published indicators and reference values are commensurate to this objective to the extent that they should not undermine or put at risk the protection of commercial interests of project promoters or transmission system operators.

The objective of the published indicators and reference values is not to serve as any guidance for the acceptable ranges within which unit costs of any project(s) would have to fall or as a justification for any project cost(s).

2.3 Scope of analysis

Depending on the definition of the infrastructure's physical and non-physical elements, investment costs⁵ may encompass a great variety of elements and the possible cost elements will appear in different combinations in the various projects. In acknowledgement of this variety, the work methodology for the preparation of this Report was developed with the intent to provide a solid basis for analysing and unitising investment costs across the European Union, by the provision of ranges of reference values and explanatory notes regarding the cost drivers affecting these values. The published unit investment cost indicators and their reference values have been developed by taking into account relevant cost categories which apply to most projects, and for which cost drivers can be identified and analysed. Costs which are heavily dependent on particular contexts, for example financing costs and taxes, were left out of the scope of the work since these types of costs are non-investment cost specific items.

The analysis aims at achieving a balance between the level of detail and the robustness of the values provided. In this respect, the objective is not to have a large number of detailed "case studies" which would provide information of several individual projects (which may differ in their core elements from other projects and between themselves), but rather to derive from the collected empirical data meaningful reference values for the analysis of infrastructure projects in general.

The work approach pursued appropriately detailed cost information, considering that the availability of records of investment cost information varies among NRAs (some NRAs collect cost data on a regular basis in a detailed and disaggregated way, while other NRAs do not have such an experience), and that some NRAs could face difficulties in collecting too detailed cost information, for instance, when the requested information is not registered by operators in their internal records systems.

There are also many possible cost drivers, and those included in the scope of this study are the ones which are presumed to be the most representative. To the extent possible, the drivers were defined and grouped by categories in a way which avoids subjective interpretations when entering the data. Some of the drivers are common to all types of infrastructure (e.g. prices of inputs such as labour and material) while others can be technology or asset-specific (e.g. the operating pressure of pipelines, offshore or onshore location of the facilities, etc.).

Given the time constraints and limited resources available for the performance of the analysis, several assumptions were made when designing the empirical data collection questionnaires regarding the factors which are likely to be the main cost drivers. To avoid leaving important cost drivers out of the scope of the work, industry practice was consulted. Work did not pursue complete coverage of all cost drivers, nor did it look at the impact of uncertainties or delays on the costs of an infrastructure project, but focused on fact-

⁴ Cf. Oil & Gas Journal, Sep. 2, 2013, pp. 112-124, where data is sourced from U.S. Federal Energy Regulatory Commission – FERC. Promoters of federal transmission pipelines have to file annually with FERC pipeline cost information on annual basis since at least 1984.

⁵ Cf. the definitions of the investment costs for each type of infrastructure and the collected additional information in Section 3.2 below.

finding, i.e. on the actual “field” experience of project promoters regarding costs and the factors that affect them, in the natural market environment of the industry.

3 Work Methodology

3.1 Expert team

An *ad-hoc* expert team was established consisting of volunteers from NRAs and Agency staff members. The expert team analysed the data, produced a draft Report, collected comments and suggestions from the NRAs, and compiled the final draft version of the Report.

The process of collecting and analysing the data followed a five step approach:

- The NRAs distributed the data collection forms to the national operators (TSOs, LNGSOs, UGSSOs⁶) in order to gather the data for every single project within the specified types and thresholds;
- Data received from operators was checked by the NRAs;
- The raw data at project level was anonymised by the respective NRA (the names of the operators, the project name and code identifiers were removed) and transferred to the expert team, but left otherwise unchanged except for cases where the check performed by the NRA revealed gaps, errors and inconsistencies;
- The expert team checked the data for errors and inconsistencies, sought - where appropriate - clarifications from NRAs on data issues, and analysed the data, eliminated the outliers, assessed the unit investment cost indicators, calculated the reference values, prepared draft interpretative guidelines on the use of the indicators, and drafted the Report;
- The draft Report was reviewed by the NRAs and subsequently a final version was prepared based on the results of the discussions and the received comments on the draft.

3.2 Identification and definition of types of infrastructure

To assure the consistency of the scope of the reported cost information, the assets specific to the relevant type of infrastructure were defined in line with the Regulation and in sufficient detail.

3.2.1 Transmission Network

3.2.1.1 Transmission Pipeline

- “Gas pipeline” refers to high pressure pipeline, other than an upstream pipeline network or the part of high-pressure pipelines primarily used in the context of local distribution of natural gas, with a view to its delivery to customers, but not including supply.
- Assets whose cost was reported include all auxiliary systems, equipment and services required for the pipeline’s normal operation and servicing, including, but not limited to, connections to branch lines, access roads, corrosion protection systems, valves, metering stations, pigging stations, pressure regulation stations, communication lines and equipment, monitoring systems, SCADA⁷, backup power systems, etc., but not compressor stations.
- Structures associated with the line and its integrity are also included, for example crossings (aerial, bridge, tunnel), impact protection (walls, escarpments, etc.), water deviation / channelling, erosion prevention, etc.
- The interconnection stations (complex nodes where two or more transmission pipelines connect) are included when they are part of the pipeline project.

⁶ Transmission system operators, LNG facilities (system) operators, and UGS facilities (system) operators.

⁷ Supervisory control and data acquisition systems.

- Differentiation is made between onshore and offshore pipelines, since the unit investment cost is *a priori* expected to differ due to different environment, technology, operating pressures, technical specifications, construction techniques, etc.
- The main technical features characterising a pipeline are its maximum technical capacity, diameter, length, and maximum operation pressure.

3.2.1.2 Compressor Station

- “Compressor station” refers to a facility which provides gas pressure for the transportation of natural gas and is located along the transmission line.
- Assets whose cost information was reported include compressor units and all auxiliary systems, equipment and services required for the station’s normal operation and servicing, including, but not limited to, land and buildings, access roads, coolers, filters, separators / strainers, SCADA, communications, monitoring and metering, electric substations, power generators, gas vent systems, etc.
- The main technical features characterising a compressor station are its installed shaft power, inlet and outlet pressure ratio, number of compressors and back-up configuration, and technology (e.g., compressors driven by gas-firing engines, electricity motors, or other).

3.2.2 Underground Gas Storage

- “Underground gas storage (UGS)” is a facility for the storage of natural gas in reservoirs of porous rock or caverns at various depths beneath the surface of the earth in large quantities not native to these reservoirs.
- Depending on the geological structure, the following types of UGS can be distinguished: in aquifers, in depleted field reservoirs, in salt formations, and in rock caverns. UGS will typically have a compressor station on-site which can be used for gas injection or for both injection and boosting pressure after gas withdrawal for delivery to a connecting or to a main gas line, wells, flow lines from the wells to the central facility, and surface facilities such as dehydrators, metering stations, etc.
- The main technical features of a UGS are the maximum working gas volume, the operating pressure, the cushion gas volume (extractable and non-extractable), the maximum injection and maximum withdrawal capacity per injection / withdrawal cycle and per day, and the number of cycles per given period of time, typically a year.

3.2.3 LNG terminals

- “LNG re-gasification terminal” (LNG terminal) refers to a facility for the reception of LNG (usually from oceangoing tankers), the storing and re-gasification of the LNG, and the delivery of the gas to a gas transportation system or directly to a customer.
- LNG terminals may be “onshore” or “offshore” terminals. Depending on the exact configuration of the LNG facilities, some or all of its assets may be onshore or offshore, and may also perform combined functions, such as the transshipment of part or all of the received LNG cargo on a different carrier (seaborne or inland) without the LNG’s re-gasification, along with continuing re-gasification of LNG. Offshore LNG terminals may be permanently resting on the seabed or floating storage and re-gasification units (FSRU). A FSRU is a LNG terminal whose main structure is a special ship that is moored next to the port. The floating LNG re-gasification projects involve taking conventional re-gasification technology and placing it on a floating structure, which can be made in different ways, and for which cost information was collected where applicable:
 - Energy bridge re-gasification vessels (EBRV);
 - Shuttle re-gasification vessels (SRV);
 - Conversion of conventional oil tankers.
- In an onshore or permanently moored LNG terminal the following main assets can be distinguished:
 - *LNG storage tanks*: Investment in LNG storage tanks refers to civil works and establishment of facilities required for discharging and handling liquefied natural gas (LNG) to and from these tanks to the re-gasification unit, including the flare.

- *Re-gasification units*: Refers to LNG high pressure pumps for increasing the pressure of the LNG up to the vaporisers, and the vaporisers themselves, which ensure the re-gasification of the high pressure LNG. The vaporisers could be open rack vaporizers (ORV), which use directly the sea water for re-gasification, and submerged combustion vaporizers (SCV), which use hot water heated by the submerged combustion gas burners.
- *Jetty, unloading/ loading arms and LNG transfer lines*: Refers to the discharge facilities and unloading facilities for a re-gasification plant (discharge or unloading arms and vapour return arms to the LNG ship), the jetty and the transfer lines.
- *Rest of civil works (including other costs related to the terminal)*: Refers to all civil works, not included in the previous categories, and the material necessary for the construction of an LNG terminal, i.e. acquisition / land concession, the infrastructure or the main building / auxiliary buildings and facilities designed to service and ensure the proper operation and condition of the equipment and facilities of the LNG terminal, including systems (protection, security, communication, control, power) and any other system or auxiliary equipment necessary for the proper terminal operation. It also includes related equipment used for unloading LNG from the LNG terminal storage tanks to LNG trucks, railcars or containers, if such equipment exists.

3.3 Data collection forms

Data collection forms were designed in view of collecting empirical data at project level and building a sample of data points which would allow proper analyses and the drawing of conclusions with sufficient confidence. Cost information was collected by NRAs with the input of transmission system, storage and liquefied natural gas facility operators. Data collected in the different forms were structured in three sections:

- 1) Project identification;
- 2) Technical information (including possible cost drivers);
- 3) Cost information.

The projects included in the sample are restricted to those already constructed and commissioned. No information about planned or currently implemented infrastructure is included in the assessment.

3.3.1 Selection of data sample and items thresholds

Promoters were requested to submit data for all the investment items for a given reference period of time, but only for projects exceeding the following investment cost or physical thresholds in order to make sure that the sample is representative for the infrastructure specified in the Regulation:

- Transportation pipelines: historic costs of more than €10 million or length of more than 5 km;
- Compressor stations: historic costs of more than €5 million;
- UGS: historic costs of more than €50 million;
- LNG: historic costs of more than €30 million.

3.3.2 Project identification

Information collected included data points that allow project identification, such as the project's code in various plans and lists of projects, the name of the project promoter, the year when the project was put in operation, etc. Where confidentiality concerns existed, the data provided by the promoters were anonymised by its respective NRA (the names of the promoter, the project name, code and other identifiers were removed) before the transfer of the data to the expert team.

3.3.3 Technical information (including possible cost drivers)

Information was collected on the technical characteristics of the projects and possible cost drivers, including both country-specific and asset-specific drivers. For the sake of simplicity, only those cost factors which were identified as potentially the most significant ones were included in the data collection forms. The following is a non-exhaustive illustration of the types of data collected under the heading of technical and cost driver information:

Transmission network

For pipelines (except compressor stations):

- Maximum design pressure;
- Diameter;
- Placement (onshore, offshore, both);
- Type of pipeline (new line or parallel line / expansion);
- Number of compression stations, pigging stations, metering stations, valve stations, number of off-take points, special crossings (rivers, channels, roads, motorways, railways, etc.), interconnection stations (complex nodes where two or more transmission pipelines connect);
- Environmental mitigation measures;
- Geology / type of terrain;
- Urban-rural area;
- Technical capacity;
- Existence of sensitive areas, e.g. archaeological areas, nature protection areas;
- Other data as deemed necessary.

For compressor stations:

- Type (new or expansion);
- Number of buildings for the compressor units;
- Total installed compressors, including stand-by and reserve;
- Inlet and outlet pressure;
- Technology of the compressor (electricity, natural gas, other);
- Power (installed power and stand-by / reserve power);
- Type of operation (parallel, serial or both);
- Security standards;
- Soundproofing and other environmental measures;
- Other data as deemed necessary.

Underground Gas Storage

- Type (depleted field, aquifer, salt cavern, rock cavern);
- Total number of wells;
- Productivity per well (maximum short-term and sustained daily injection / withdrawal rates);
- Compression power and technology;
- Volume of working gas, cushion gas;
- Surface facilities need / sizing (e.g. dehydrators, condensate removal and storage, etc.);
- Distance to main gas transmission line;
- Other data as deemed necessary.

LNG storage and re-gasification terminals

- Type of LNG terminal (onshore, offshore-permanently moored, offshore-FSRU);
- LNG storage tanks technology (type of tank), size of the tank, onshore or offshore (floating);
- Send-out capacity technology (type of vaporizer, ORV or SCV or FSRU);
- Vaporizer capacity, onshore or offshore (floating);
- Jetty, unloading arms and LNG transfer lines data;
- Other data as deemed necessary.

3.3.4 Cost information, treatment of factors affecting the reporting of cost information

Type of cost information

Empirical data (historic, factual and quantitative) were collected. For transmission infrastructure (pipelines and compressor stations), data were collected for infrastructure commissioned during the last 10 years (2005-2014). In pursuit of building up a sufficiently large sample that would allow the development of indicators and their corresponding values with sufficient confidence, in the case of UGS and LNG data were collected for infrastructure commissioned over the last 15 years (2000-2014).

Cost categories and type of cost record

In the case of transmission assets (pipelines and compressor stations), information for the total investment cost was requested (based on general industry and regulatory practice) with a breakdown by the following major cost components:

1. Engineering, and project management;
2. Civil, mechanical, and electro-mechanical works (CIME);
3. Materials;
4. Right-of-way (ROW) and permitting (including allowances for damages);
5. Miscellaneous, such as contingencies, telecommunication equipment, freight and other costs not included in the previous categories.

In the case of UGS, the investment cost information was requested with the following breakdown:

1. Engineering and project management cost;
2. Cost of wells and lines;
3. Cost of compressor stations;
4. ROW, permitting, and purchasing of land;
5. Injected cushion gas needed to put the UGS in operation;
6. Miscellaneous.

In the case of LNG terminals, the investment cost information was requested with the following breakdown according to the types of assets:

1. LNG storage tanks;
2. Re-gasification units (vaporizers);
3. Jetty, unloading arms and LNG transfer lines;
4. Rest of civil works and other costs in the terminal.

Promoters were asked to whether the requested cost information at the moment when the investment was put into service corresponded to book values or to audited values. ‘Book values’ are defined as the investment costs as entered in the operators books by its accountants, whilst ‘audited values’ are book values as certified by an auditor external to the operator.

Treatment of taxes

All cost information was requested to be reported net of taxes (direct or indirect), in order to help filter out the effects of taxation on the reported investment costs. Taxation may vary significantly between the Member States⁸.

Treatment of inflation and transformation of observed values to a common reference (base) year

There are significant methodological difficulties in using specific inflation rates for the transformation of the observed investment cost values to a common reference (base) year. Technological and market changes, including changes in the exchange rates, purchasing power parities, and other factors of specific or general nature that affect the cost of a project cannot be captured by the use of inflation. At this time, no “absolute” scale could be developed for comparing the total and unit cost of a recent infrastructure investment with one commissioned 10 or more years ago. Nevertheless, it was considered opportune to provide also values which take into account general country-specific inflation rates as provided by Eurostat. Reference values in Chapter 5 are provided as “nominal” (as observed in the specific year) and as “indexed” (escalated to the base year of 2015).

⁸ For analogous reasons financing costs were not considered.

Exchange rates

Due to the fact that some Member States do not use the Euro or were not in the Euro zone at the moment when the investments were made, the data forms collected information about the currency and the exchange rate to the Euro, to allow for the costs as actually incurred at the time of the commissioning of the projects to be “translated” into Euro. Accordingly, the data collection forms asked the operators to indicate the value in local currency, and the currency’s applicable exchange rate to the Euro as of the year when the project was put in operation, as well as indicate the resulting value in Euro, and NRAs were asked to review the information related to the use of various currencies and exchange rates. The values as reported in Euro were used in the analysis.

3.4 Data collection process, stakeholder input, data analysis, and reporting

The intention was to build up a sample as complete as possible within the specified ranges for the defined types of infrastructure within the specified thresholds (period of time, size, value) across all Member States, with the understanding that in some Member States no gas infrastructure of the specified types has yet been constructed.

Stakeholders (ENTSOG for transmission pipelines and compressor stations, GSE⁹ for UGS and GLE¹⁰ for LNG, as the relevant European associations of gas infrastructure) were given the opportunity to submit comments on the draft data collection forms and proposed set of indicators.

ENTSOG, GLE and GSE warned about the risk of drawing-up simplistic conclusions about average values for indicators without providing an adequate explanation about possible limitations in the use of the indicators. In the view of some stakeholders, unit investment costs can be carefully used as indicative references (they constitute something to which an estimate can be compared), but are not a sign of efficiency or a benchmark.

Comments from ENTSOG

ENTSOG was of the view that there is no merit in the use of indicators in the Union-wide TYNDP and that having cost and justification directly provided by project promoters for specific projects would be preferable¹¹. ENTSOG considered that results should be provided as ranges rather than single value, in particular if indicators are defined at EU level, which should be accompanied by a proper explanation of the differences observed.

ENTSOG considered that the following factors could influence the investment costs, the indicators and the reference values:

- The collection of historic data too far in the past;
- The collection of data for small transmission projects;
- The definition of the type of terrain, since it may be subject to interpretation;
- Local conditions (e.g. local cost of labor, national safety and permitting rules);
- The use of tendering, and the number of participants in the tendering;
- The associated cost of interconnection stations (if applicable);

⁹ Gas Storage Europe, representing the gas storage system operators.

¹⁰ GLE - Gas LNG Europe, representing the LNG terminal operators.

¹¹ Project promoters may calculate the unit investment cost indicators and their values for their own projects themselves.

- Difficulties for the TSOs to provide disaggregated investment costs by the cost categories specified in the questionnaire.

ENTSOG presumed that the level of investment costs may be linked to the “cost of life” levels in various locations across Europe (purchasing power), so they expressed preference for indicators at regional level rather than at EU level.

Comments from GLE

GLE highlighted the fact that it is very difficult to get a sound and comparable set of indicators related to investments in LNG facilities. Due to the difficulty of getting a unique and reliable value for the proposed indicators, GLE noted that it would make sense to use a range of values instead of an average value for the unit investment cost reference values.

In GLE’s view, the costs of investments in LNG facilities depend on several factors and may be difficult to define due to the following reasons:

- Public acceptance of the project, local environmental constraints and legislation in force, which may have a substantial impact on LNG projects in terms of a longer process for permit granting and more costly solutions for adapting to local constraints;
- Different technologies chosen for the project;
- Local specific elements such as land reclamation, population density, etc.;
- Sharp variations over time in the cost of the material that represents a large part of the cost of the LNG terminal;
- Unclear definitions of the perimeter of the investment (e.g. whether works done by ports and interests incurred during construction are included or not);
- Difficulty in collecting reliable cost information for infrastructure commissioned a long time ago;
- GLE considered that for these reasons, the indicators should be used very carefully, bearing in mind that their representativeness is limited. GLE recommended comparing the data with data used by engineering institutes / companies.

Comments from GSE

GSE considered it very challenging to have general statements on the cost of gas storages and suggested using broad ranges of values rather than an average.

GSE considered that, *inter alia*, the following factors could influence the investment costs of an UGS:

- Whether a project is onshore or offshore;
- Whether gas has to be injected or was already in the reservoir;
- Not only the type of geology, but also characteristics such as the depth of the storage in depleted fields, as important driver for compression power.

GSE also made additional general comments with respect to the development of UGS:

- It is challenging to build up robust indicators and corresponding reference values for unit costs, because gas storage facilities do not only differ in working volume, but also speed of withdrawal (deliverability) and injection. The relevant unit should be a combination of volume and speed (injection and withdrawal);
- Historic costs of UGS are not necessarily reflecting costs of new investments. Investment costs depend heavily on availability of equipment and specialist manpower. Too old information would also not reflect using the state-of-the-art techniques available.

The comments received were analysed and taken into account to the possible extent in the final design of the data collection forms, the design of the analytical procedures, and the modality of reporting of the unit

investment cost indicators and their associated values. The views of stakeholders were also accounted for in this report regarding the guidelines for the use of the indicators.

4 Analysis of the information collected

4.1 Sample size by type of infrastructure

The project database was populated with the historic data on all gas infrastructure projects as provided by 22 NRAs (AT, BE, CZ, DE, DK, ES, FI, FR, GR, HU, HR, IE, IT, LT, NL, PL, PT, RO, SE, SI, SK, UK¹²). It should be noted, however, that for some Member States, such as Malta and Cyprus, it was *a priori* known that no relevant gas projects have been implemented in their markets until the moment when the data collection forms were distributed to NRAs. Luxembourg and Latvia also informed that as of the date of data collection there are no investments that meet the relevant criteria on their territory. The Bulgarian and Estonian NRAs did not provide any response. Finally, the coverage of LNG and UGS projects was more difficult for some NRAs as these types of infrastructure are in some instances non-regulated, and at least some LNG and UGS projects thus remained outside the scope of the sample.

Operators were requested to submit data to NRAs for the investment items for the defined reference period and over the threshold limits only. Overall, the sample covered 444 investment items, of which 293 transmission pipelines, 101 compressor stations (new and expansion of existing), 19 underground gas storages and 31 liquefied natural gas facilities. The sample was deemed sufficiently representative, particularly for pipelines and compressor stations, for the purpose of developing the unit investment cost indicators and the associated reference values, albeit with some caveats regarding potential deficiencies due to factors such as incomplete or heavily concentrated geographical coverage, heterogeneity of commissioning dates, and changing exchange rates, among others. In any possible future reassessment of unit investment costs and their associated values, the experience of data collection, particularly regarding cost drivers roster and definitions, could be accounted for and used for developing a more precise representation of cost trends and the factors that shape them.

Table 1: Summary of raw data availability

| Type of infrastructure | Investment items | Period ¹³ | Number of responding NRAs |
|-------------------------|------------------|----------------------|---------------------------|
| Transmission pipelines | 293 | 1983-2015 | 21 |
| Compressor stations | 101 | 2004-2014 | 15 |
| Underground gas storage | 19 | 1999-2014 | 7 |
| Liquefied natural gas | 31 | 2000-2014 | 6 |

4.2 Verification of the information

Primary verification of the information provided by TSOs was carried out by the NRAs. In the process of gathering information from NRAs, deficient data¹⁴ and data not meeting the thresholds or out of the reporting period were discarded. Thus, the investment items eventually considered for the unit cost indicators are less in number than the collected raw data items, by about 4% for pipelines, 8% for compressor stations, and 5% for UGS (cf. Table 2). In order to ensure the consistency of the information, in some instances additional clarifications were requested. For the analysis of information, no further filtering of the project data provided by the NRAs was carried out; thus, all projects providing the basic technical data to enable the calculation of

¹² Ofgem for GB.

¹³ Some NRAs sent data of their TSOs out of the requested time period or not meeting the threshold, with the earliest covered year being 1983. Table 11 compares data analysed (with erroneous data taken out) vs. raw data as received.

¹⁴ For example, investments for which the basic technical data - such as length, compressor power, etc., needed for the calculation of the indicators and the reference values were not provided, or where obvious typos were present.

the indicators were considered for the analysis. Overall, 423 investment items were analysed, of which 281 are transmission pipelines, 93 are compressor stations, 18 are underground gas storages and 31 are liquefied natural gas facilities.

Table 2: Analysed data vs. raw data

| Type of infrastructure | Investment items [raw] | Investment items [analysed] | Period |
|-------------------------------|------------------------|-----------------------------|-----------|
| Transmission pipelines | 293 | 281 | 2005-2014 |
| Compressor stations | 101 | 93 | 2005-2014 |
| Underground gas storage (UGS) | 19 | 18 | 2000-2014 |
| Liquefied natural gas (LNG) | 31 | 31 | 2000-2014 |

4.3 Sample specific features

The sample is unevenly distributed across Europe due to the actual way in which the investments were made, but also, to some extent, due to the response pattern of the operators to the NRAs. Thus, the following should be noted:

- For pipelines, 30% of the sample (investment items) is in a single Member State, 50% of the sample is in three Member States, and 90% of the sample is in eleven Member States;
- For compressor stations, 30% of the sample (investment items) is in two Member States, 50% of the sample is in three Member States, and 90% of the sample is in eight Member States;
- For UGS: 30% of the sample (investment items) is in a single Member State, 50% of the sample is in two Member States, and 90% of the sample is in five Member States;
- For LNG: 75% of the sample (both new LNG terminals and expansions) is in a single Member States, and 90% of the sample is in three Member States. For new LNG terminals, 50% of the sample in two Member States, and 90% of the sample is in six Member States; for expansions of LNG terminals, 90% of the sample is in a single Member State.

Table 3: Sample summary of analysed data by type of infrastructure and Member State before outliers' analysis

| Type of infrastructure | AT | BE | CZ | DE | DK | ES | FI | FR | GR | HR | HU | IE | IT | LT | NL | PL | PT | RO | SI | SK | UK | EU |
|-------------------------------|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|-----|
| Transmission pipelines | 6 | 14 | 2 | 18 | 1 | 38 | 3 | 14 | 2 | 14 | 7 | 8 | 94 | 6 | 3 | 17 | 1 | 18 | 4 | 1 | 10 | 281 |
| Compressor stations | 11 | 4 | | 16 | 1 | 11 | | 21 | 1 | 4 | | | 10 | 1 | 3 | 1 | | | 2 | 5 | 2 | 93 |
| Underground gas storage (UGS) | | | 1 | | | 2 | | | | | 2 | | 6 | | 4 | | | 3 | | | | 18 |
| Liquefied natural gas (LNG) | | | | | | 24 | | 1 | | | | | 2 | 1 | 1 | | 2 | | | | | 31 |
| <i>New LNG</i> | | | | | | 3 | | 1 | | | | | 2 | 1 | 1 | | 1 | | | | | 9 |
| <i>Expansion LNG</i> | | | | | | 21 | | | | | | | | | | | 1 | | | | | 22 |

The geographic distribution of the sample across Member States should be kept in mind when interpreting or using the reference values at aggregated European level. Thus, the results are not meant to be some kind of instruction on what the values should or should not be in any country, but to provide an overview of the historic cost of commissioned infrastructure in Europe, using just matter-of-fact data. Depending on the type of infrastructure, information gathered is more concentrated in some Member States. For LNG the results are heavily influenced by the fact that most of the reported investments are in ES, especially for expansions of LNG facilities. For pipelines, IT and ES reported more investment items than other countries. For compressor stations and UGS, the sample seems to be more evenly distributed across Member States.

The next tables and graphs provide an overview of the dataset finally considered for statistical analysis by type of infrastructure.

Table 4: Pipeline sample summary¹⁵

| | <i>Total [2005-2014]</i> |
|--|--------------------------|
| Pipeline projects analysed (after elimination of outliers) | 266 |
| Total km | 12.801 |
| Total CAPEX [€ billion] | 14,066 |

Table 5: Compressor station sample summary

| | <i>Total [2005-2014]</i> |
|---|--------------------------|
| Total compressor stations projects analysed (after elimination of outliers) | 81 |
| Electric | |
| Expansion | |
| Total costs (€) | 683.779.111 |
| Power installed (MW) | 283 |
| New | |
| Total costs (€) | 517.269.381 |
| Power installed (MW) | 205 |
| Electric total costs (€) | 1.201.048.492 |
| Electric power installed (MW) | 488 |
| Gas | |
| Expansion | |
| Total costs (€) | 1.085.047.307 |
| Power installed (MW) | 892 |
| New | |
| Total costs (€) | 1.227.887.290 |
| Power installed (MW) | 750 |
| Gas total costs (€) | 2.312.934.597 |
| Gas power installed (MW) | 1.642 |
| Total costs (€) | 3.513.983.090 |
| Total power installed (MW) | 2.131 |

¹⁵ Data refers only to onshore pipelines after exclusion of outliers. Due to the small number of offshore projects (3), it was not possible to carry out standard statistical analysis and develop reference values for offshore pipelines. Unit investment costs in this Report refer only to onshore pipelines.

Table 6: UGS sample summary

| | <i>Total [2000-2014]</i> |
|---|--------------------------|
| Total UGS projects (including expansions) | 18 |
| <i>Aquifer</i> | <i>1</i> |
| <i>Depleted field</i> | <i>15</i> |
| <i>Salt cavern</i> | <i>1</i> |
| <i>Other</i> | <i>1</i> |
| Total working gas [maximum, NMm3] | 14.271 |
| Total daily injection capacity [maximum, NMm3/day] | 124 |
| Total daily withdrawal capacity [maximum, NMm3/day] | 221 |
| Total of CAPEX [€ million] | 4.862 |

Table 7: LNG sample summary

| | Total investment items [number of investments] | Total LNG storage [m3 LNG] | Total re-gasification capacity [Nm3/h] | Total LNG unloading capacity [m3 of LNG] ⁽¹⁾ | Total CAPEX [€ million] |
|----------------------------------|---|-------------------------------|---|--|----------------------------|
| Total [2000-2014] | | | | | |
| LNG terminal expansions | 22 | 2.182.000 | 2.450.000 | - | 1.838 |
| New LNG terminals ⁽²⁾ | 9 | 2.567.500 | 8.140.465 | 1.869.000 | 6.358 |
| Total [expansion + new] | 31 | 4.749.500 | 10.590.465 | 1.869.000 | 8.197 |

(1) Calculated as the sum of maximum capacity of LNG ships which can be unloaded at the facilities.

(2) Out of the 9 new LNG terminals, 6 are onshore, 2 are offshore (FSRU) and 1 is offshore (permanently moored).

4.4 Statistical tools and methods

The first step of the analysis was the determination of outliers, based on the statistical method of the median absolute deviation (MAD). This methodology is a robust measure of the variability of a univariate sample of quantitative data. By the application of this method, about 30 projects (pipeline and compressor stations) were excluded from the sample. The outliers were located in both the “upper” and “lower” range of the sample.

As a rule, outliers are projects where costs have risen unexpectedly for various reasons related, but not limited, to: significant special crossings, unprecedented environmental conditions, crossing of national parks, exceptionally tight delivery schedules, protests of local communities, adverse weather conditions, engineering errors, etc., and, for electrically driven compressor stations in particular, due to the construction of the power lines to the nearest connection point with the power network. Project promoters and/or TSOs generally provided information for the investments done in exceptional conditions which could have significantly impacted costs.

Once the sample was established, standard statistics were computed on the sample clean of outliers, whenever the size of the sample was sufficient for the purpose, including the calculation of the median and average values and the standard deviation of the sample. In cases where the sample was relatively small, only the statistics which could be meaningfully derived are provided.

The results of the performed analysis are the unit investment costs for the sample of infrastructure projects, within the pressure ranges as indicated in the tables in Chapter 5.1.

5 Set of indicators and their corresponding reference values

The following is the set of indicators and corresponding reference values for unit costs of investment in gas infrastructure. Values are rounded to the nearest Euro and provided as average, median and standard deviation and other typical statistics of the sample analysed of projects. A complete set of statistics is provided for pipeline and compressor stations. For LNG and UGS, the lack of a sufficient number of projects

as informed by NRAs did not allow the sample to be sufficiently robust to conduct a complete statistical analysis. The specific infrastructure characteristics of LNG and UGS projects, which are often “tailor made”, in particular UGS, make such projects less prone to standardisation, and hence it is not possible to release reliable unit infrastructure cost indicators for such infrastructure projects.

Whenever the final sample allowed it, graphics are added to the statistical analysis.

Only infrastructure within the pressure ranges indicated in the tables were considered for the analysis.

In order to deliver the most exhaustive set of results, both nominal and indexed (inflation-adjusted) values are reported in the tables.

The indexed values were reconstructed on the basis of the nominal values of the investments (cost of the project when put into operation), adjusted by using the national inflation indexes as published by Eurostat¹⁶. The present value of the historical costs data refers to the year 2015.

5.1 Transmission network

5.1.1 Transmission Pipelines

Table 8: Unit investment cost indicators (nominal and indexed) and reference values for transmission pipelines
Pipelines “all in”¹⁷

| Pipeline diameter size | Pipelines sample pressure ranging from / to | | Average 2005-2014, €/Km | Median (2005-2014), €/Km | St. Deviation (2005-2014), €/Km | Average 2005-2014, €/Km | Median (2005-2014), €/Km | St. Deviation (2005-2014), €/Km |
|------------------------|---|---------|-------------------------|--------------------------|---------------------------------|-------------------------|--------------------------|---------------------------------|
| | min | max | <i>nominal</i> | <i>nominal</i> | <i>nominal</i> | <i>indexed</i> | <i>indexed</i> | <i>indexed</i> |
| Less than 16” | 12 bar | 85 bar | 475.731 | 396.492 | 277.374 | 526.248 | 448.860 | 282.207 |
| 16”-27” | 12 bar | 100 bar | 630.148 | 585.982 | 287.773 | 705.542 | 636.324 | 313.099 |
| 28”-35” | 12 bar | 100 bar | 959.784 | 917.232 | 373.970 | 1.061.445 | 1.014.918 | 416.141 |
| 36”-47” | 63 bar | 100 bar | 1.338.131 | 1.256.532 | 531.543 | 1.459.810 | 1.381.489 | 553.931 |
| 48”-57” | 75 bar | 100 bar | 2.224.465 | 2.211.334 | 381.543 | 2.426.907 | 2.351.764 | 397.950 |

¹⁶ <http://ec.europa.eu/eurostat/tgm/table.do?tab=table&plugin=1&language=de&pcode=tec00118>

¹⁷ “All in” refers to the cost of all activities and material, such as, for example, engineering, permitting, construction, commissioning, material procurement, the sum of investing in which covers the costs of the entire project at the time of its commissioning. See also Section 4.2.

Figure 1: Nominal unit investment costs of pipelines, boxplot¹⁸

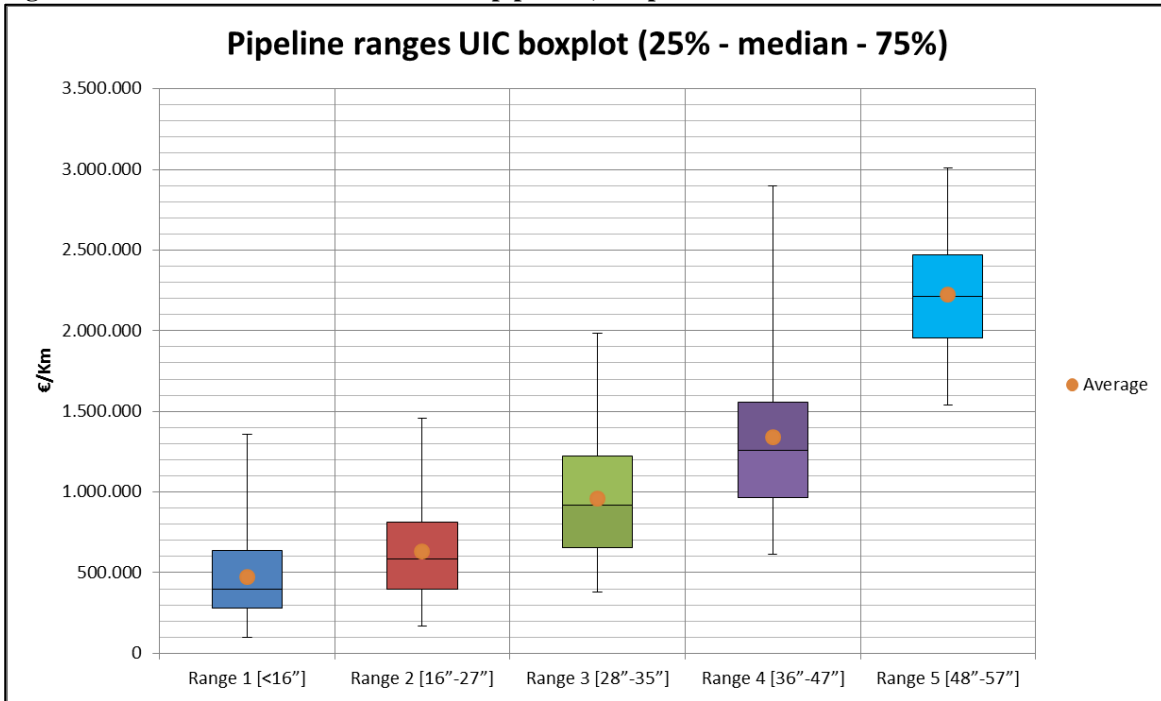
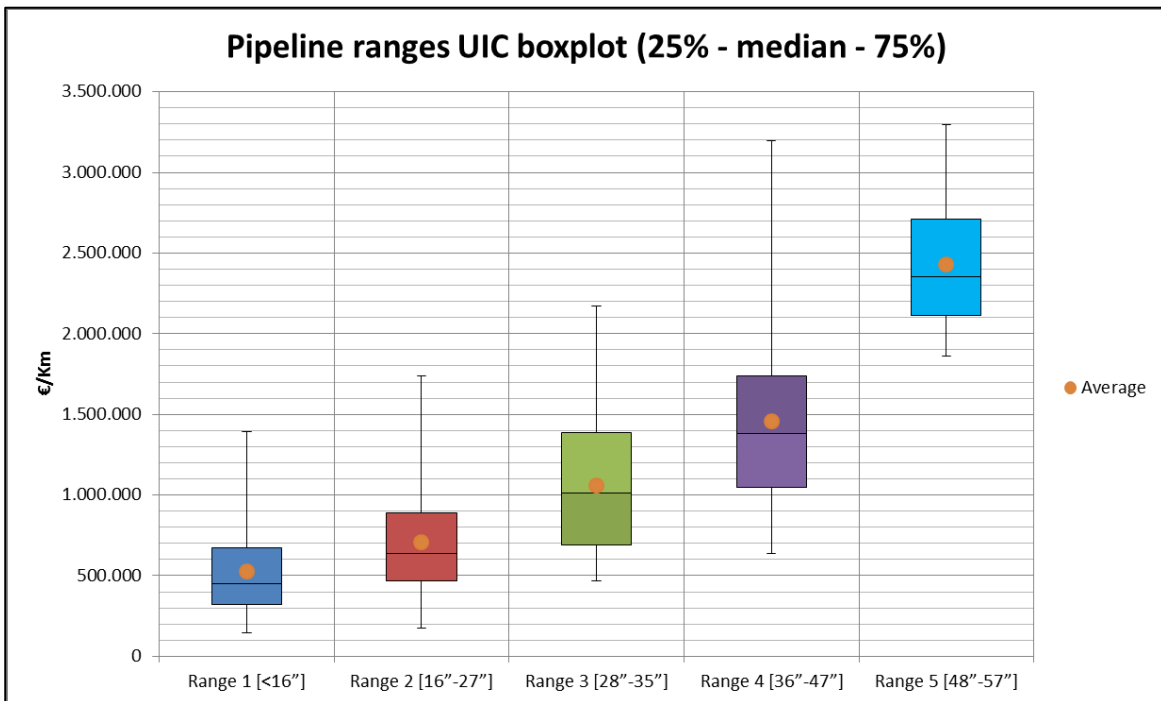


Figure 2: Indexed unit investment costs of pipelines, boxplot



¹⁸ In the boxplot, the central rectangle spans the first quartile to the third quartile (the interquartile range or IQR). The segment inside the rectangle shows the median and the "whiskers" above and below the box show the locations of the minimum and maximum of the sample (outliers excluded). Arithmetic average is also provided.

Table 9: Nominal Unit investment cost of transmission pipelines per-year (average values, median)

| Year | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|
| Range 1 [<16"] | | | | | | | | | | |
| Average of [€/Km] | 224.188 | 347.546 | 302.115 | 613.826 | 503.408 | 446.575 | 525.754 | 622.525 | 617.838 | 642.001 |
| Median of [€/Km] | 244.766 | 279.494 | 324.956 | 656.667 | 398.839 | 448.437 | 478.845 | 519.152 | 680.005 | 618.431 |
| Range 2 [16"-27"] | | | | | | | | | | |
| Average of [€/Km] | 450.172 | 586.611 | 653.752 | 730.959 | 664.286 | 576.261 | 594.774 | 642.054 | 625.873 | 744.800 |
| Median of [€/Km] | 455.696 | 493.115 | 689.039 | 728.387 | 648.101 | 502.636 | 589.935 | 576.562 | 542.842 | 652.115 |
| Range 3 [28"-35"] | | | | | | | | | | |
| Average of [€/Km] | 377.512 | 1.179.046 | 1.092.603 | 956.769 | 1.000.469 | 1.061.858 | 1.052.414 | 797.939 | 875.506 | 847.190 |
| Median of [€/Km] | 377.512 | 1.250.272 | 1.091.808 | 987.148 | 1.027.610 | 959.156 | 901.379 | 565.827 | 875.506 | 679.679 |
| Range 4 [36"-47"] | | | | | | | | | | |
| Average of [€/Km] | - | - | 1.227.631 | 1.129.720 | 1.125.227 | 1.200.970 | 2.075.282 | 1.306.233 | 1.912.028 | 1.415.715 |
| Median of [€/Km] | - | - | 1.215.966 | 977.124 | 1.043.446 | 896.821 | 2.209.299 | 1.456.409 | 1.912.028 | 1.415.715 |
| Range 5 [48"-57"] | | | | | | | | | | |
| Average of [€/Km] | 1.617.808 | 2.125.003 | 2.159.664 | 2.316.646 | 2.559.148 | 2.546.308 | 2.319.164 | 2.139.961 | 2.251.163 | 2.089.522 |
| Median of [€/Km] | 1.617.808 | 2.115.536 | 2.159.664 | 2.357.337 | 2.559.148 | 2.858.767 | 2.307.104 | 2.147.260 | 2.217.173 | 2.089.522 |

Table 10: Indexed Unit investment cost of transmission pipelines per-year (average values, median)

| Year | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|--------------------------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|
| Range 1 [<16"] | | | | | | | | | | |
| Average of [€/Km] | 289.238 | 415.096 | 371.046 | 700.120 | 542.848 | 491.652 | 567.251 | 648.661 | 627.122 | 643.936 |
| Median of [€/Km] | 304.631 | 333.204 | 394.721 | 736.060 | 441.206 | 488.610 | 516.639 | 544.342 | 690.223 | 619.668 |
| Range 2 [16"-27"] | | | | | | | | | | |
| Average of [€/Km] | 553.236 | 720.329 | 778.534 | 839.235 | 731.685 | 641.448 | 641.531 | 668.312 | 635.748 | 746.801 |
| Median of [€/Km] | 561.086 | 603.559 | 818.011 | 845.042 | 705.551 | 553.947 | 639.027 | 598.057 | 553.621 | 654.442 |
| Range 3 [28"-35"] | | | | | | | | | | |
| Average of [€/Km] | 543.407 | 1.404.690 | 1.292.393 | 1.100.541 | 1.113.811 | 1.180.071 | 1.141.337 | 838.744 | 884.273 | 847.966 |
| Median of [€/Km] | 543.407 | 1.509.016 | 1.261.378 | 1.101.699 | 1.135.469 | 1.051.002 | 976.807 | 598.399 | 884.273 | 678.999 |
| Range 4 [36"-47"] | | | | | | | | | | |
| Average of [€/Km] | - | - | 1.433.530 | 1.243.197 | 1.232.694 | 1.313.222 | 2.257.397 | 1.363.762 | 1.942.736 | 1.427.041 |
| Median of [€/Km] | - | - | 1.418.680 | 1.090.512 | 1.135.941 | 1.006.019 | 2.383.677 | 1.521.280 | 1.942.736 | 1.427.041 |
| Range 5 [48"-57"] | | | | | | | | | | |
| Average of [€/Km] | 1.971.135 | 2.551.533 | 2.371.122 | 2.619.170 | 2.827.760 | 2.739.020 | 2.507.291 | 2.244.825 | 2.308.424 | 2.098.567 |
| Median of [€/Km] | 1.971.135 | 2.522.081 | 2.371.122 | 2.667.070 | 2.827.760 | 2.977.091 | 2.489.202 | 2.248.326 | 2.282.690 | 2.098.567 |

Figure 3: Nominal unit investment costs of pipelines, evolution in 2005-2014 by ranges of diameters (annual average, €/km)

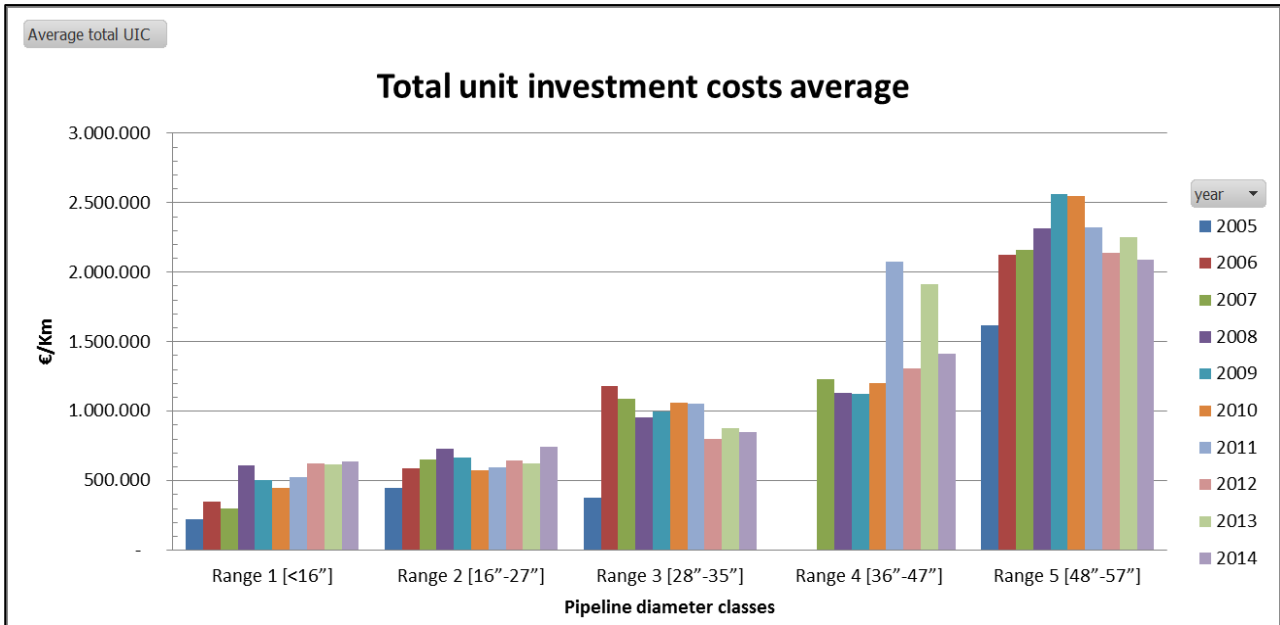
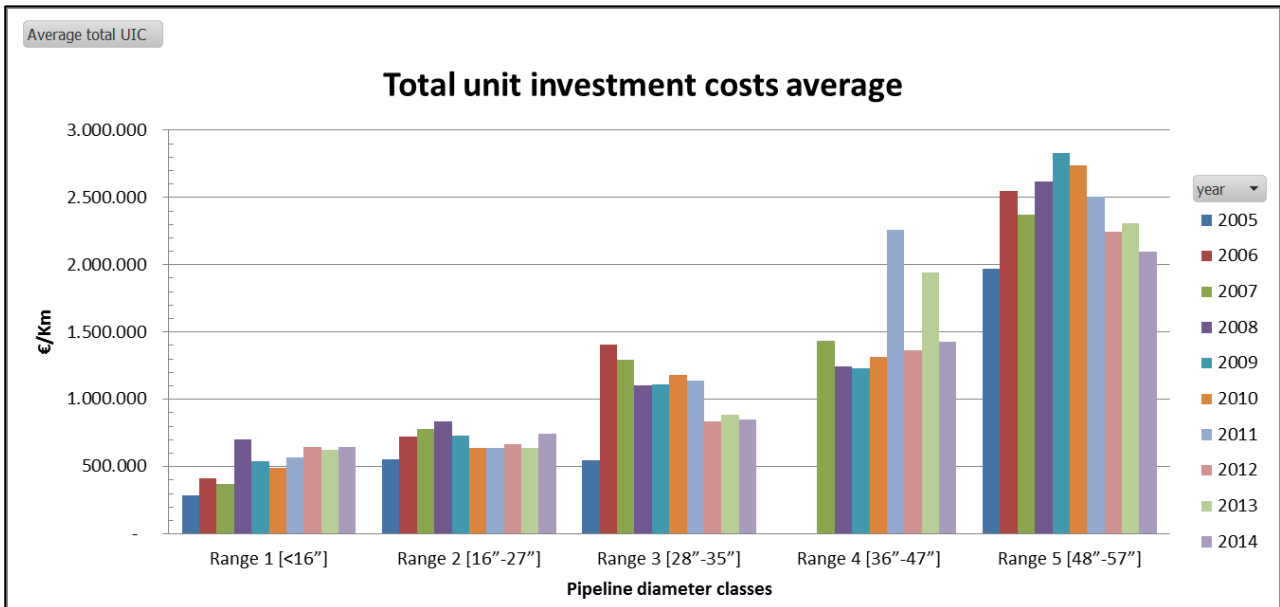


Figure 4: Indexed unit investment costs of pipelines, evolution in 2005-2014 by ranges of diameters (annual average, €/km)



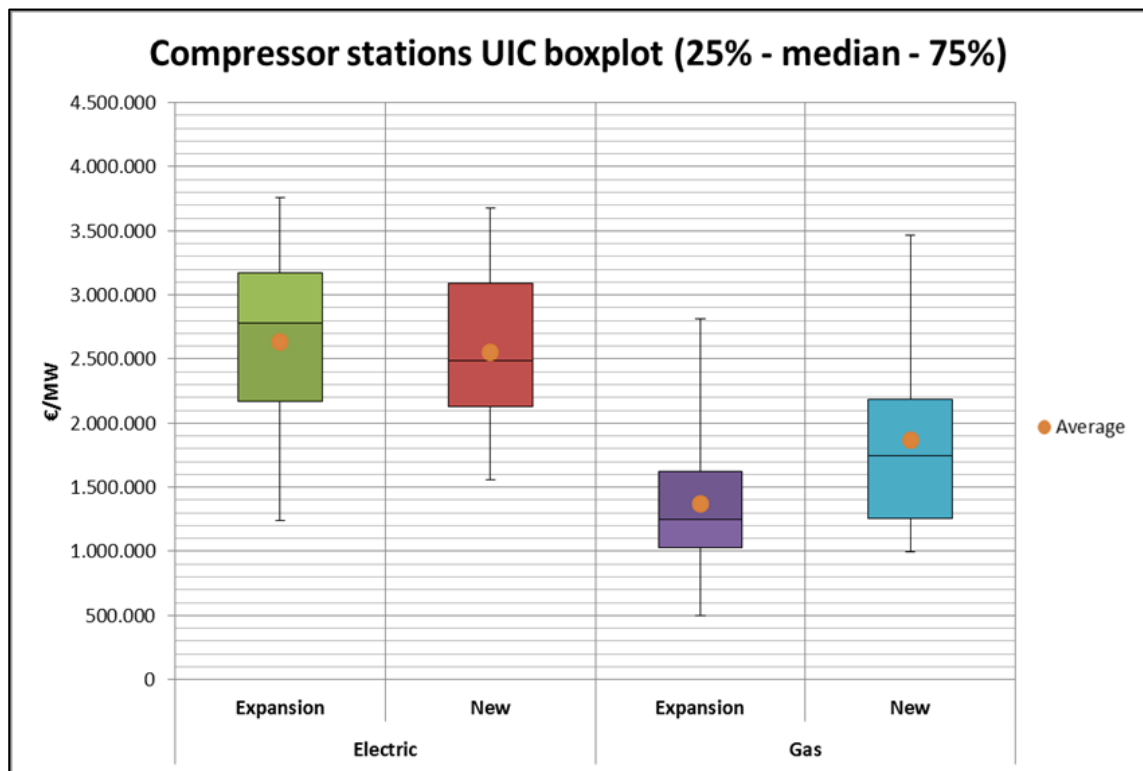
5.1.2 Compressor stations

Table 11: Unit investment cost indicators (nominal and indexed) and reference values for compressor stations

Compressor Stations “all in”¹⁹

| | Compressor stations sample output pressure ranging from / to | | Average (2005-2014), €/MW | Median (2005-2014), €/MW | St.Deviation (2005-2014), €/MW | Average (2005-2014), €/MW | Median (2005-2014), €/MW | St.Deviation (2005-2014), €/MW |
|---------------------------|--|---------|---------------------------|--------------------------|--------------------------------|---------------------------|--------------------------|--------------------------------|
| | min | max | Nominal | Nominal | Nominal | indexed | indexed | indexed |
| Gas drive, expansion | 43 bar | 115 bar | 1.369.317 | 1.249.028 | 641.714 | 1.534.459 | 1.376.428 | 707.585 |
| Gas drive, new | 54 bar | 140 bar | 1.871.773 | 1.748.588 | 706.800 | 2.100.609 | 2.029.648 | 781.183 |
| Electric drive, expansion | 68 bar | 85 bar | 2.762.155 | 2.852.381 | 632.934 | 2.931.455 | 3.168.672 | 617.825 |
| Electric drive, new | 68 bar | 91 bar | 2.553.495 | 2.489.872 | 686.697 | 2.801.865 | 2.620.545 | 702.306 |

Figure 5: Nominal unit investment costs of compressor stations, boxplot



¹⁹ “All in” refers to the cost of all activities and material, such as, for example, engineering, permits, construction, commissioning, material procurement, the sum of investing in which covers the costs of the entire project at the time of its commissioning.

Figure 6: Indexed unit investment costs of compressor stations, boxplot

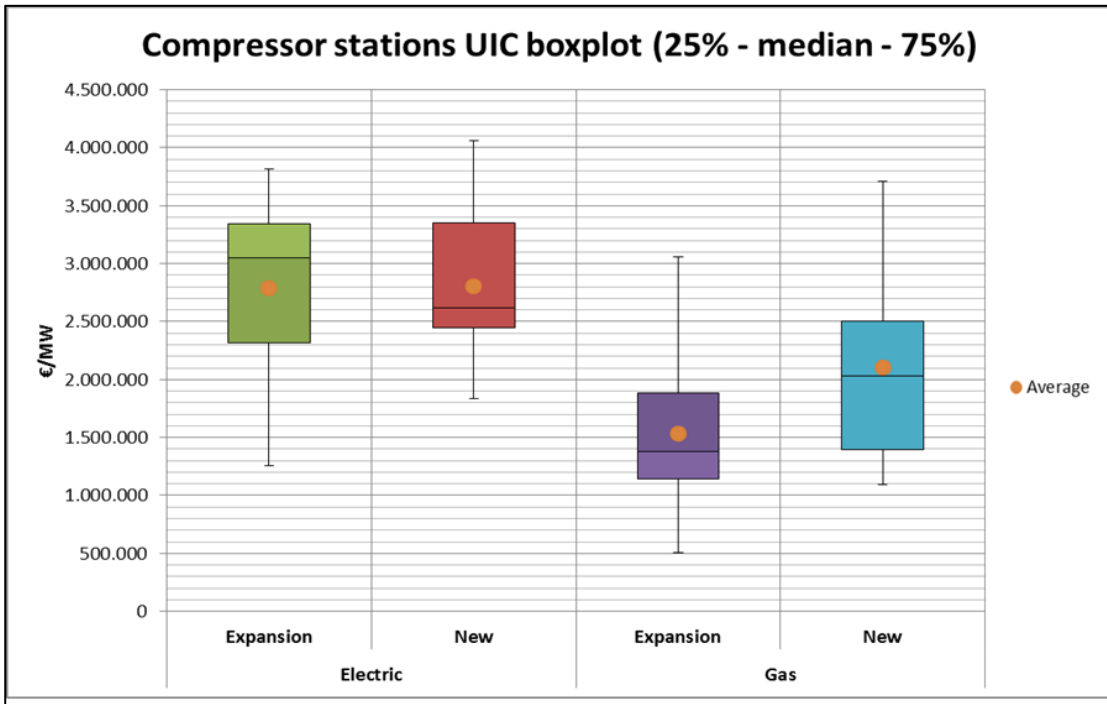


Figure 7: Nominal unit investment costs compressor stations, evolution in 2005-2014 by ranges of power and technology²⁰ (annual average, €/MW)

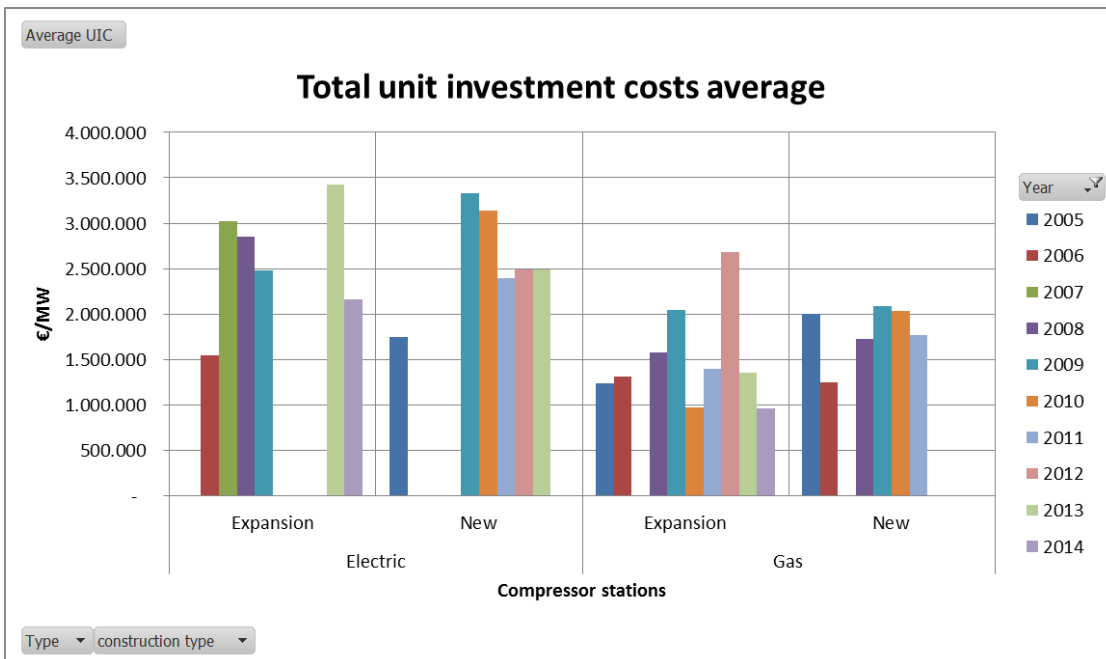
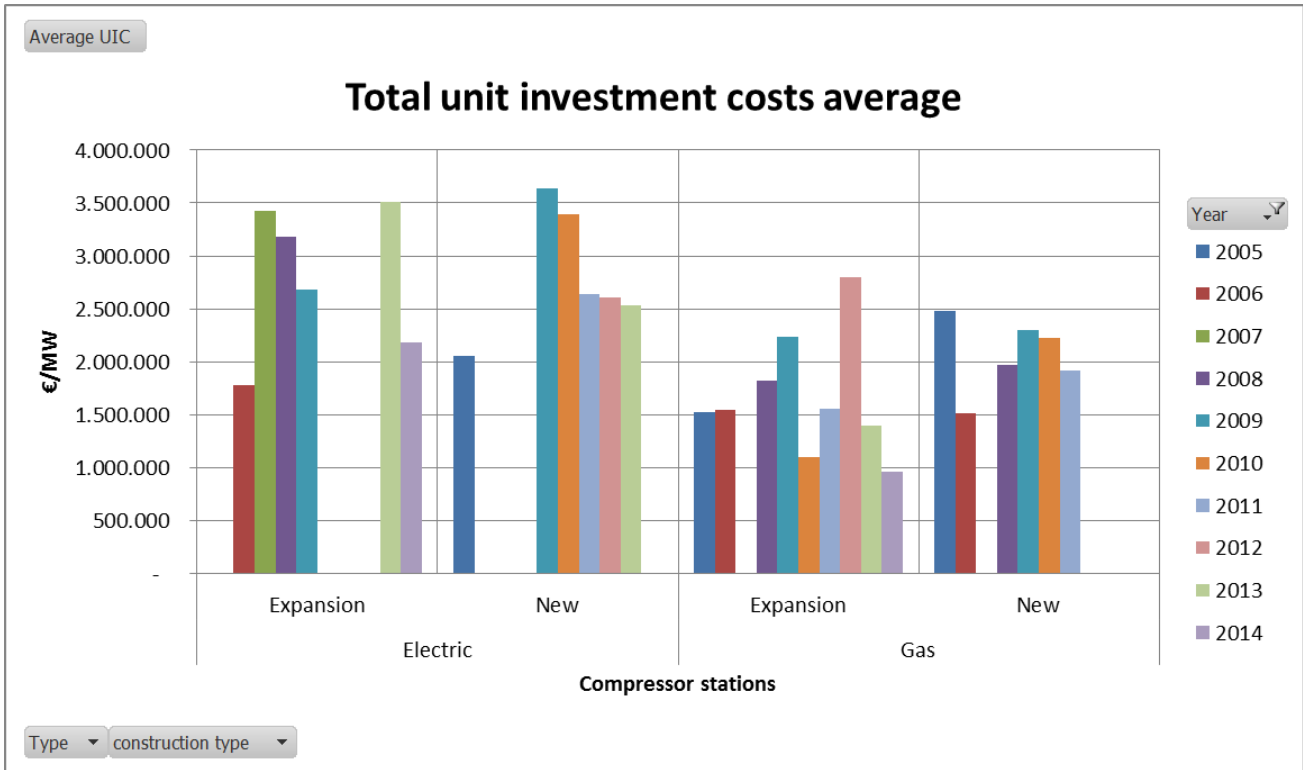


Figure 8: Indexed unit investment costs compressor stations, evolution 2005-2014 by ranges of power and technology (annual average, €/MW)



5.2 Underground Gas Storage

The sample and the type of data for UGS are not sufficient to draw sound conclusions on UGS. Hence, the values available cannot be treated with any reasonable confidence. The scant number of projects for which data was delivered, the very project-specific features of storage facilities, and the difficult standardisation process do not allow making available a set of indicators and corresponding reference values for the comparison of unit investment costs for comparable projects for UGS. Nevertheless, in order to demonstrate the commitment of the NRAs to be compliant with the Regulation, as well as to provide an overview of data collected on UGS, historical values for UGS in depleted fields are provided in Annex A. The NRAs stress that the values provided in Annex A are not true reference values and should not be seen as a reliable point of reference if used for the assessment the cost of a specific new UGS project.

5.3 LNG storage and re-gasification terminals²¹

The size of the sample, the type of data, and the unique characteristics of LNG assets are not sufficient to derive robust indicators and corresponding reference values for LNG. LNG terminals are less standardised than pipelines and compressor stations, but these facilities are seen as more standardised than UGS. In order to demonstrate the commitment of the NRAs to be compliant with Regulation (EU) 347/2013, as well as to provide an overview of data collected on LNG, the following indicators and historic statistics are provided. The NRAs stress that the values provided should not be seen as a reliable point of reference if used for the assessment the cost of a specific new LNG project. The geographic distribution of the sample of LNG projects (see Chapter 4.3) is also to be considered when interpreting the indicators and the values provided.

²¹ Interconnection pipelines between a LNG facility and transmission/ distribution networks are not in the scope of the unit cost indicators.

New LNG terminals

Investment in new LNG terminals includes all CAPEX needed to put the LNG terminal under operation. No breakdown by cost elements is presented, as some new LNG terminals were constructed under EPC contracts and the operators were unable to provide the cost breakdown. Due to the limited number of investments in offshore terminals, no differentiation is made in the tables between onshore and offshore facilities. However, the unit cost of some offshore LNG terminals, due to its specific and unique features, is significantly higher than the unit cost observed for onshore terminals, which explains why the historic average value of the indicators for LNG projects considerably exceeds the median value.

Table 12: Unit investment costs and historic values for new LNG terminals

| UIC Indicator | Average value (2000-2014) | Median (2000-2014) | Investment items considered |
|--|---------------------------|--------------------|-----------------------------|
| LNG storage [€ total terminal / m3 LNG] | 2.853 | 1.238 | 9 |
| Send-out capacity [€ total terminal / Nm3/h] | 819 | 461 | 9 |
| Docking terminal, jetty, unloading arms and LNG transfer lines [€ total terminal / m3 LNG cargo of largest size] | 3.934 | 1.976 | 9 |

Expansions of LNG terminals

Investment in LNG terminals expansion includes all CAPEX pertinent to the type of expansion. This should be considered when comparing the historic values for new LNG terminals with those for expansions of LNG terminals.

Table 13: Unit investment costs and historic values for expansions of LNG terminals

| Type of infrastructure | Average value (2000-2014) | Min-max range (2000-2014) | Median (2000-2014) | Investment items considered |
|---|---------------------------|---------------------------|--------------------|-----------------------------|
| LNG storage [€ LNG expansion / m3 LNG] | 612 | 354 - 791 | 625 | 15 |
| Send-out capacity [€ send-out capacity expansion / Nm3/h] | 194 | 82 - 447 | 181 | 8 |

6 Analysis and guidelines for the use of the indicators and the reference values

6.1 General considerations

The main value of the unit cost indicators and reference values is precisely in the provision of a reference point, without, however, being able to substitute for due diligence and due justification of costs in each separate instance of an investment in gas infrastructure. The indicators and the reference values provide an overview of how costs evolved in the European Union over the defined period of time. Insights on some factors which may affect unit investment costs of gas infrastructures are also provided in Section 6.2.

However, there are multiple factors, of a very diverse nature, that affect the unit investment cost of gas infrastructure. In a broad sense, these factors relate to:

- Technology;
- Location, including the location of the material manufacturer's facilities and the base (camp) of operations of the contractor(s);
- Size, required level of redundancy / oversizing / backup;
- Services required to be performed;
- Cost of capital available to the project promoter;
- Prices of inputs (material, services, access to land, etc.);
- Exchange rate variations;

- Inflation rates over the time from the moment procurement starts to commissioning
- Modality of contracting (for example, via tendering), number of contractors qualified for the required job, and number of competing bids received;
- Other factors.

It is clearly impossible to capture the impact of all these factors in synthetic unit cost indicators and reference values that could be informative to the extent that an investment decision could be based on them. The indicators and the reference values should not be used for benchmarking and only constitute an indicative reference, and as such should be interpreted. The development of the indicators and the reference values is not intended and cannot be used either as a reliable indicator of the efficiency of project promoters / TSOs operating in any given country, or to compare the efficiency of TSOs across Europe.

6.1.1 Transmission Pipelines

Figures and tables in this section illustrate the evolution of investment in transmission pipelines over 2005-2014. About half of the investment (49%) made during these years covered the cost of services associated with the construction of the infrastructure (CIME), with material cost adding about 33%. All other cost components constitute about 18% of the cost of investment (5-7% each for engineering and management, right-of-way and permitting, and miscellaneous other cost).

Total investment expenditure in pipelines lived through two distinct peaks (2008 and 2012) and troughs (2005 and 2009) separated by about 5 years, while overall trending upwards. During peak times, the share of CIME in overall costs tended to increase, about 60% in 2008 and 2012 (as opposed to 49% over the entire period of 2005-2014), which may be evidence of the relative tightness of the European market for qualifying CIME services in comparison to the markets for material needed for pipeline construction. The share of cost associated with right-of-way and permitting remains almost stable throughout the period. Overall, operators and NRAs should probably keep an eye first and foremost on CIME costs, including on the modality in which CIME contracting is executed and effective competition in bidding for CIME contracts²² is assured, as well as the specific market conditions (supply of and demand for CIME services) at a given moment of time.

Total costs evolution

Table 14: Nominal historical total costs for pipeline ranges of diameters (2005 -2014, aggregated annual - €)

| | Range 1 [$<16''$] | | Range 2 [$16''-27''$] | | Range 3 [$28''-35''$] | | Range 4 [$36''-47''$] | | Range 5 [$48''-57''$] | | Total € | Total Km |
|--------------|---------------------|--------------|-------------------------|--------------|-------------------------|--------------|-------------------------|--------------|-------------------------|--------------|-----------------------|---------------|
| | total costs | km | total costs | km | total costs | km | total costs | km | total costs | km | | |
| 2005 | 55.127.895 | 253 | 150.784.355 | 359 | 23.670.000 | 63 | | | 336.010.380 | 207 | 565.592.630 | 881 |
| 2006 | 62.222.255 | 270 | 239.098.156 | 474 | 98.741.837 | 109 | | | 247.063.908 | 118 | 647.126.157 | 972 |
| 2007 | 52.319.180 | 155 | 260.162.697 | 495 | 76.396.264 | 71 | 358.070.000 | 297 | 293.110.402 | 130 | 1.040.058.542 | 1.149 |
| 2008 | 66.250.090 | 97 | 169.582.954 | 267 | 194.934.335 | 211 | 521.026.020 | 499 | 415.564.218 | 178 | 1.367.357.616 | 1.252 |
| 2009 | 45.215.902 | 105 | 264.921.440 | 417 | 100.443.591 | 92 | 405.967.177 | 380 | 85.155.644 | 33 | 901.703.754 | 1.028 |
| 2010 | 102.500.661 | 247 | 204.040.523 | 325 | 172.607.673 | 207 | 326.442.056 | 312 | 289.644.112 | 133 | 1.095.235.024 | 1.224 |
| 2011 | 43.128.442 | 76 | 244.391.466 | 410 | 271.217.015 | 276 | 354.802.637 | 268 | 1.705.619.828 | 802 | 2.619.159.388 | 1.832 |
| 2012 | 53.648.253 | 115 | 192.030.696 | 391 | 287.680.303 | 389 | 559.863.677 | 468 | 1.657.715.066 | 779 | 2.750.937.997 | 2.142 |
| 2013 | 12.146.183 | 19 | 215.728.888 | 451 | 173.670.443 | 201 | 127.778.000 | 74 | 1.470.934.915 | 621 | 2.000.258.429 | 1.366 |
| 2014 | 38.895.566 | 86 | 79.970.524 | 116 | 393.860.593 | 451 | 125.149.188 | 88 | 441.473.807 | 215 | 1.079.349.678 | 956 |
| Total | 531.454.428 | 1.424 | 2.020.711.699 | 3.706 | 1.793.222.053 | 2.070 | 2.779.098.755 | 2.386 | 6.942.292.279 | 3.216 | 14.066.779.214 | 12.802 |

²² For 61% of the pipelines, the construction contract was awarded via a tender, 1% of projects did not apply a tendering procedure, and for the remaining 38% of the projects the modality in which the construction contract was awarded was not informed. For the projects subject to a tendering procedure, the average number of companies participating in the tender was 4.

Figure 9: Nominal historical total costs for pipelines by ranges of diameters (2005 -2014, aggregated annual - €)

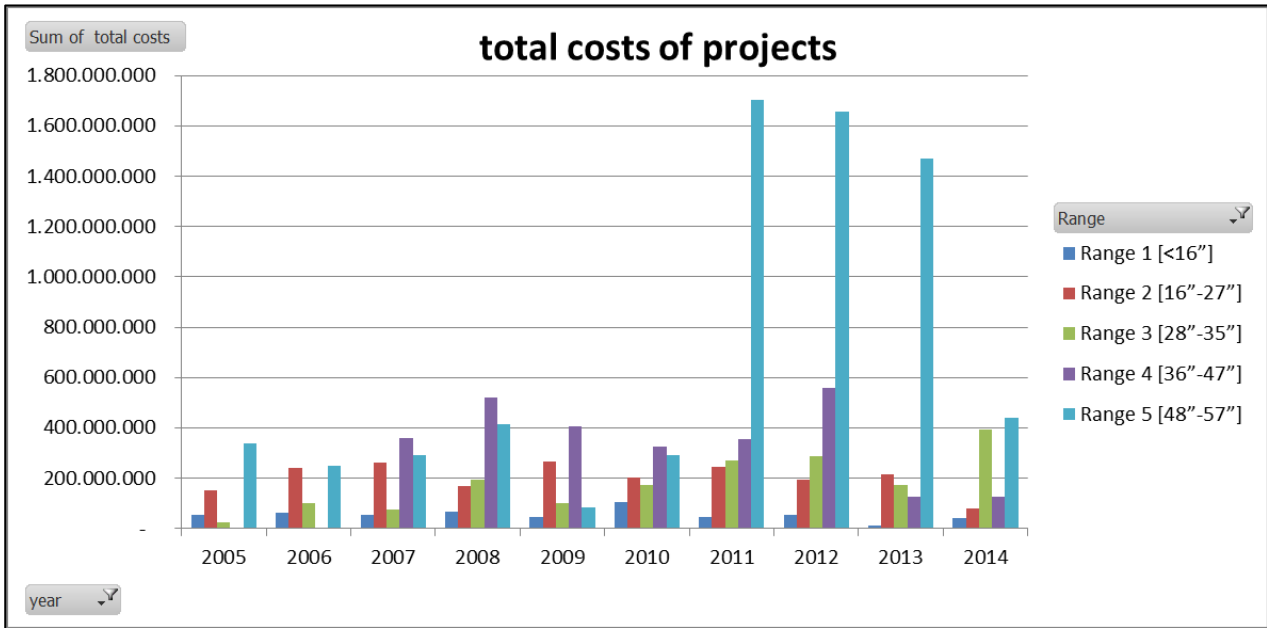
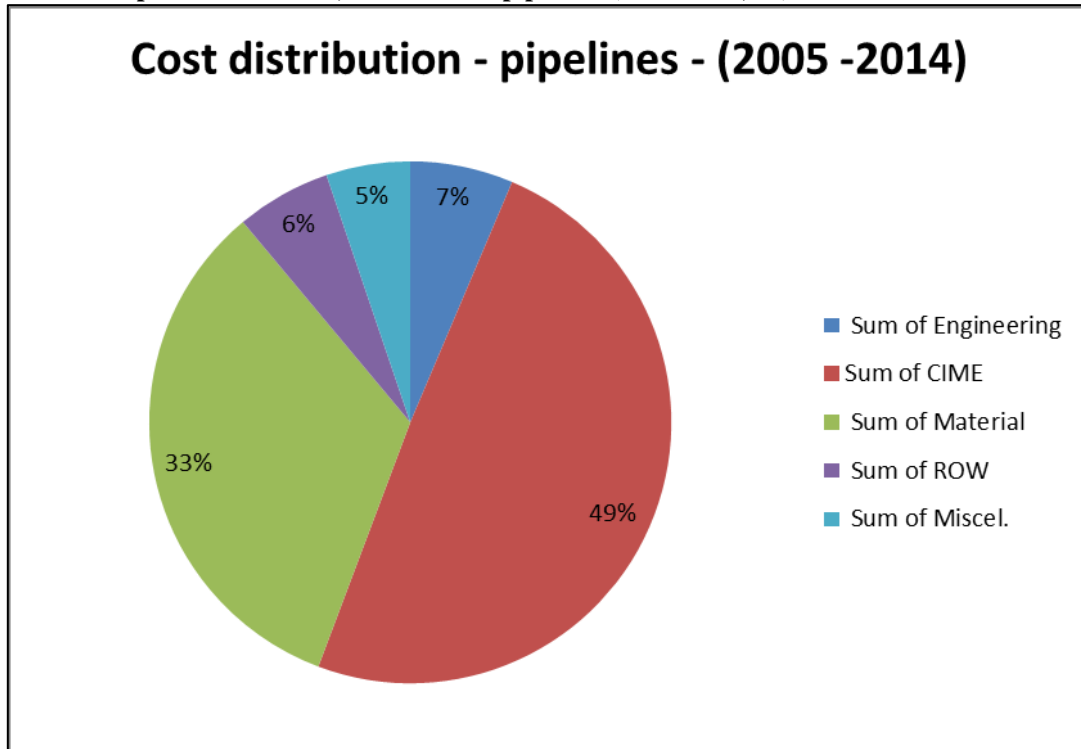


Figure 10: Cost components structure, transmission pipelines (2005 -2014, %)



Note: The sum of the reported cost by cost components (~ €14,0 billion) is not equal to the sum of total CAPEX of the sample since not all the operators were able to provide the cost breakdown.

Figure 11: Nominal value of total investment by cost components for transmission pipelines, (2005-2014, €)

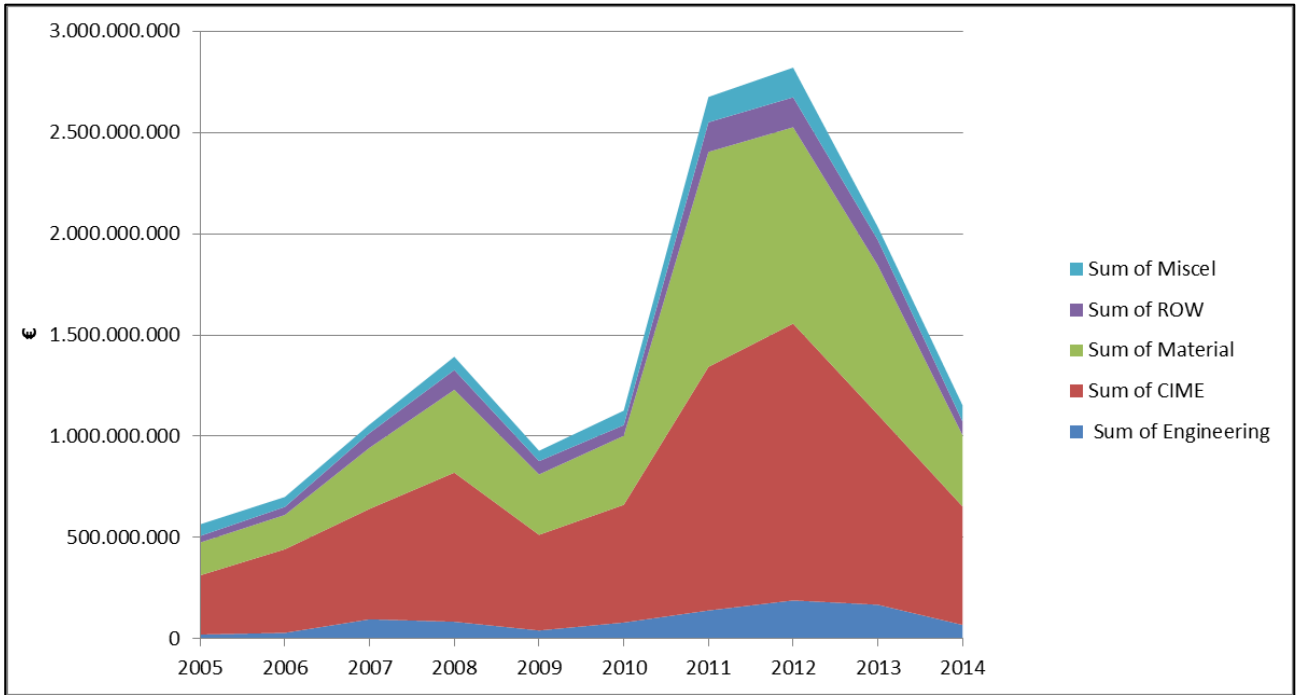
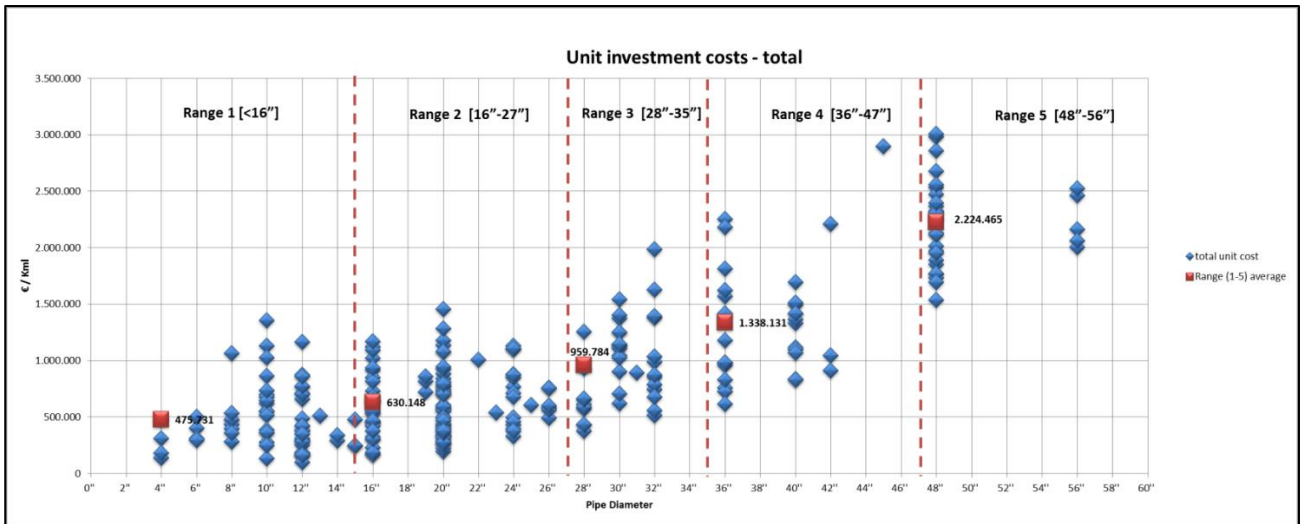
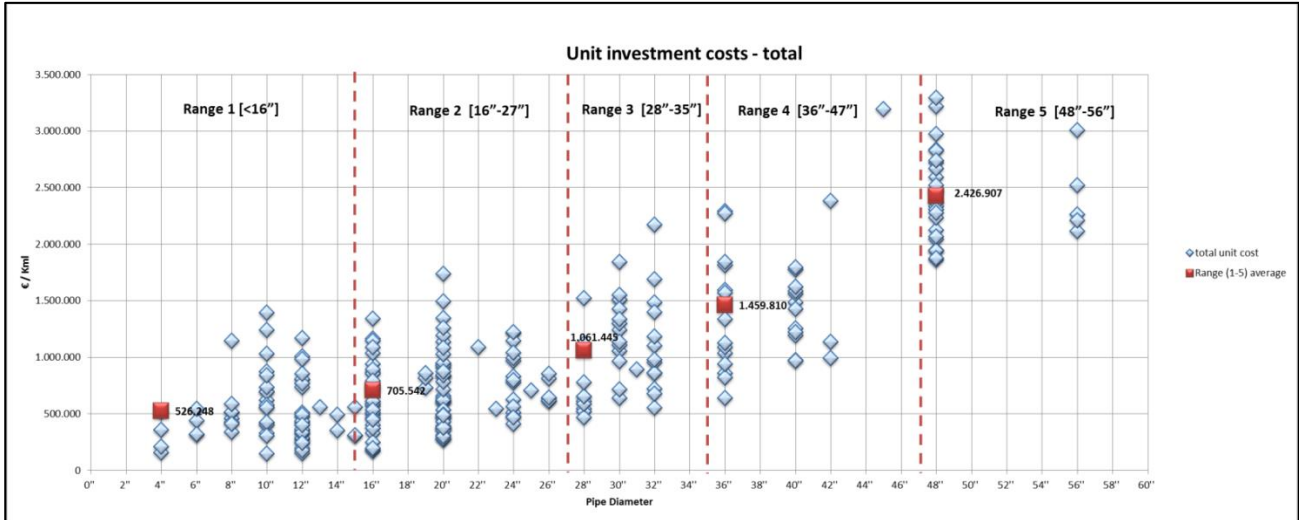


Figure 12: Evolution of nominal unit investment costs of pipelines, overall sample scatter (2005-2014 by ranges of diameters)²³



²³ For the analysis of data relative to pipelines of different diameters, an equivalent diameter was calculated based on identical physical volume (capacity), by keeping the overall length of the real and the equivalent pipelines unchanged.

Figure 13: Evolution of indexed unit investment costs of pipelines, overall sample scatter (2005-2014 by ranges of diameters)



6.1.2 Compressor Stations

While material cost is the dominant cost element for investments in compressor stations (about 51% of total costs), the most variable cost component for such investments is the cost of CIME. The average share of CIME in total cost is about 31%, but can be as high as 44% and as low as about 23%. The share of material costs in compressor station investments is much more variable than the share of material cost in pipeline investments and can reach as high as almost 62% and as low as 32%. Variations of material costs may be due not only to changes in the market conditions over time, but also to variations of the predominant types of compressor stations put in operation in a given year.

Overall investment expenditure in compressor stations peaked in 2009 and 2013. The share of CIME was highest in 2007 and 2012, in concert with the peak share of CIME in pipeline cost observed in these two years. Unlike pipelines, the share of the cost of right-of-way for compressor stations is very low (about 1% of total) while the cost of miscellaneous elements is around 7% for the period.

Investors in compressor stations and NRAs would probably have to pay the greatest attention to CIME and material costs, including the modality of extending material and services procurement contracts and the ways in which effective competition can be assured in the bidding for such contracts²⁴.

²⁴ For 60% of the compressor stations, the construction contract was awarded via a tender, 2% of projects did not apply a tendering procedure, and for the remaining 38% of the projects data whether tendering was applied was not informed. For the projects which applied a tendering procedure, the average number of companies participating in the tender is 4.

Figure 14: Cost component structure of compressor stations (2005-2014, share in %)²⁵

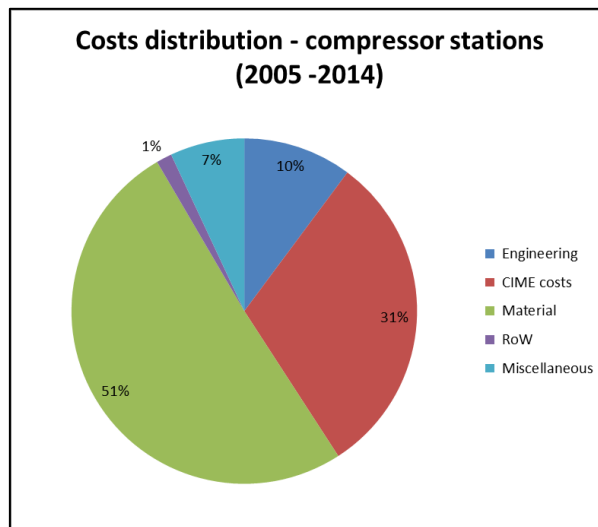
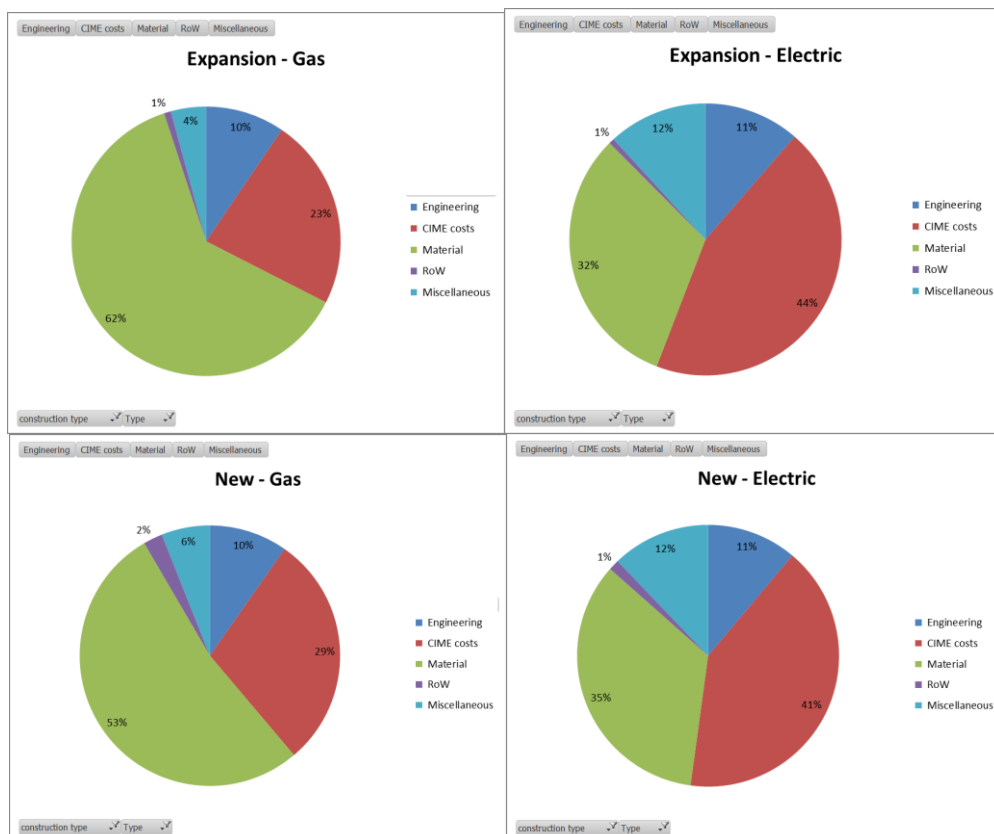
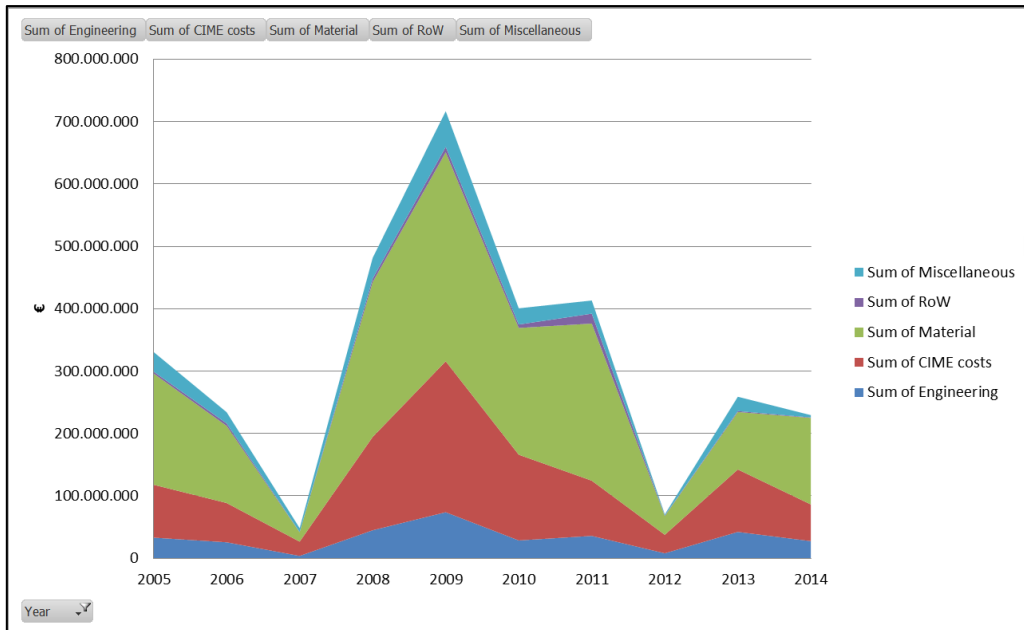


Figure 15: Cost component structure of investment in compressor stations (2005-2014, by categories, share in percent)



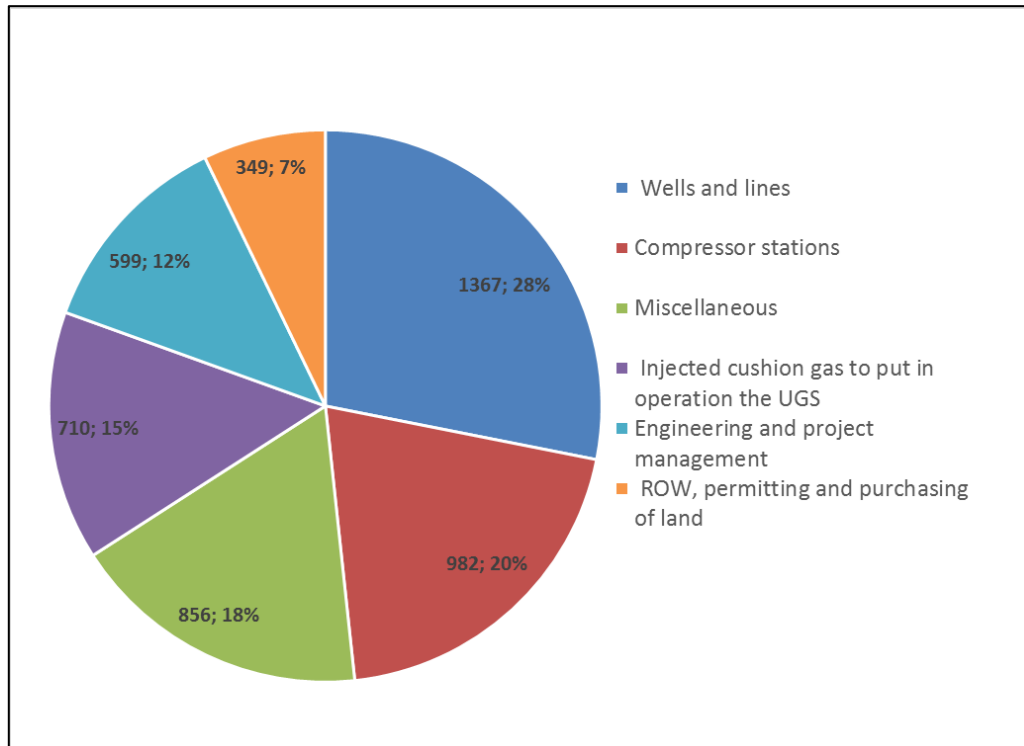
²⁵ Note: The sum of the reported cost by components (€3,7 billion) is not equal to the sum of total CAPEX of the sample (€4,3 billion) since some operators were unable to provide the cost data component breakdown.

Figure 16: Nominal value of total investment by cost components for compressor stations, (2005-2014, €)



6.1.3 UGS

Figure 17: UGS investment cost structure, 2000-2014 (values in € million and %)



6.1.4 LNG

Figure 18: LNG cost structure 2000-2014 (values in € million and %)

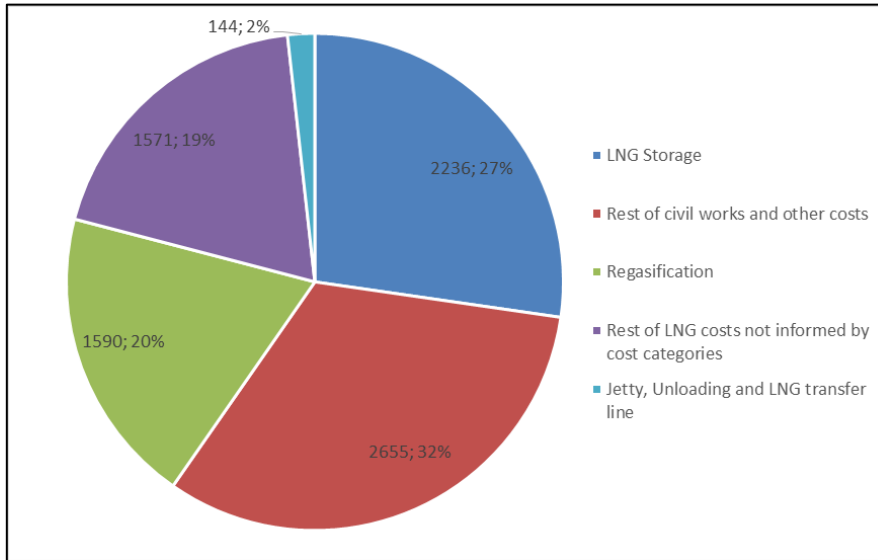
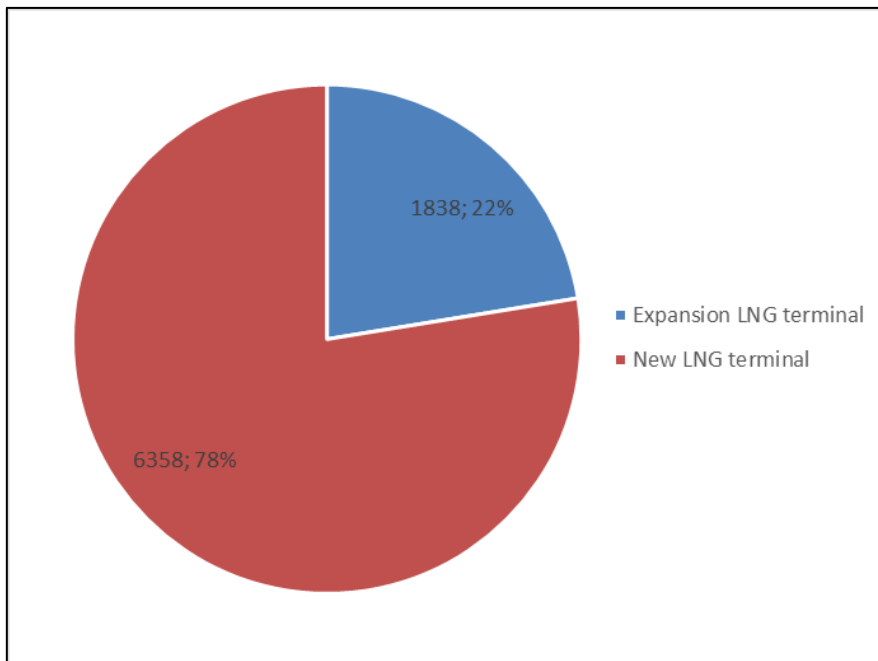


Figure 19: LNG cost 2000-2014: new LNG terminals vs. LNG expansions (values in € million)



6.2 Cost drivers

General cost factors

Several country-specific cost drivers, such as the cost of labour and differences in purchasing power parity, inflation rates, environmental regulations, permit granting procedures, predominant type of terrain, engineering standards, etc., may have an impact on the cost of projects in different Member States. It is important to note that this Report does not look in depth at Member State or regional differences of costs that are due to such factors.

Specific to gas transmission

Pipelines

In gas transmission assets, factors such as type of terrain (easy, medium, difficult), density of services, contract awarding method, number of special crossings and tunneling, off-take points, metering stations etc., appear to have an influence on the reference values. Since these factors differ among Member States, unit investment costs are apparently significantly dependent on country-specific features. Furthermore, countries with purchasing power parities below the European average and with a relatively low population density would likely tend to have lower unit investment cost than countries with purchasing power parities over the European average.

The analysis conducted confirms some intuitive assumptions about the impact of various cost drivers on the unit investment cost values. This is the case of factors such as the type of terrain, the density of services, location, the maximum operating pressure and the diameter of the pipeline.

The evidence about the impact of some specific cost factors on the unit investment cost should be carefully considered, since in such specific instances the conclusions are based on a relatively small number of actual investments.

Scale effects are also apparently present. A high density of auxiliary equipment installed on gas transmission pipelines, such as valve stations, off-take points, metering stations, pigging stations, etc., may also lead to higher than typical unit investment costs. The cost of the pipeline per unit of length is quite well correlated to the pipe diameter and in a lower degree to the maximum operating (design) pressure of the pipeline. On the other hand, the correlation with the maximum design pressure is present if just the materials are taken into consideration.

Data confirms that competitive tendering tends to lower unit investment cost. The cost of environmental mitigation measures also may have a discernible impact.

Compressor stations

In compressor stations, the impact on unit investment cost was considered factors such as the total installed power, the drive train technology (gas turbines, electric motors, gas and electric), the need for and the length of a connection to the power grid for electric driven compressors, the inlet-outlet pressure ratio, the maximum operating pressure, the type of project (new or expansion) as well as the expected mode of operation.

Data suggests that unit investment costs of gas turbine-driven compressor stations tend to be lower than those of electric motor-driven compressor stations, and that the unit investment costs for expansions of compressor stations are lower than the typical values of the unit costs for new compressor stations.

The need of a dedicated connection line to the main electricity grid, especially for electric drive compressor units, appears to increase the unit investment cost substantially.

Specific to UGS

Due to the specific characteristics of each UGS project, the analysis of the UGS unit investment cost drivers is challenging. The unique features pertinent to UGS also pose difficulties for arriving at robust and reliable unit cost indicators and reference values for UGS.

Specific to LNG

The type of project (new or expansion) and the type of location (onshore or offshore), among many other factors, cause differences in the typical unit investment cost reference values. Offshore LNG projects tend to be considerably more expensive on a per-unit basis than onshore projects.

6.3 Other unit investment cost indicators and reference values in the European Union

NRAs have strived to find a balance between the obligation of defining unit investment cost indicators and publishing corresponding reference values, and confidentiality concerns highlighted by some NRAs, TSOs,

ENTSO, GSE and GLE. As a result, data collected at project level has not resulted in data disclosed at project level, and has just been instrumental to calculate the reference values on a European level. For instance, cost information at TSO level or for individual projects is not released.

The report is the result of collaborative work carried out by NRAs cooperating in the framework of the Agency for developing the set of indicators and corresponding reference values as required under Article 11(7) of the Regulation.

The publication of the indicators does not prevent individual NRAs from the development of indicators and reference values at national level without the involvement of the expert team that has developed this document.

Standard investment costs already published

NRAs and promoters noted that standard investment costs are already in place in some EU Member States, like Spain²⁶, Greece, Germany and UK. These are also valuable and readily available sources of information (cf. next table).

Table 15: National unit investment cost indicators²⁷

| Member State | Type of source (Public institution, industry source, other) | Name of institution / document | Link to public source of information |
|--------------|---|---|---|
| ES | Public institution | Ministry, at the proposal of the NRA | http://www.boe.es/diario_boe/txt.php?id=BOE-A-2013-13768 |
| DE | n.a. | NDP 2013-2015 (at the proposal of TSOs) | http://www.fnb-gas.de/ |

²⁶ In Spain, the unit investment costs and reference values are set by the Ministry at the proposal of the NRA. The proposal and the adopted values are the result of an in-depth analysis of recent investments by TSOs. The indicators and the reference values are taken into account when setting the values of the regulated asset base of the TSOs, and thus, the regulated revenues allowed to the TSOs.

²⁷ In GR and the UK, national unit investment cost indicators exist, but the link to the public source of information was not provided by the NRA.

Annex A – Overview of historical values for UGS in depleted fields

The NRAs stress that values provided in this Annex **are not reference values** and shall not be seen as reliable point of reference if used for the assessment of the cost of a specific new UGS project.

The indicators and the corresponding reference values for UGS are only provided for UGS in depleted fields and are developed by dividing the value of the total CAPEX in the storage by the technical parameters of the storage, namely UGS physical capacity for working gas, maximum daily withdrawal capacity, and installed compressor power (cf. next table).

Table 16: Unit investment cost indicators and nominal historic values for UGS in depleted fields²⁸

| UIC indicator | Min-max range (2000-2014) | Interquartile range [25% - 75%] (2000-2014) | Investment items considered ⁽⁴⁾ |
|---|---------------------------|---|--|
| UGS physical capacity (working gas) [€ million / Nmcm] ⁽¹⁾ | 0,2 – 2,9 | 0,2 – 0,5 | 14 |
| Withdrawal capacity [€ million / Nmcm/d] ⁽²⁾ | 10,8 – 146,2 | 19,7 – 38,7 | 13 |
| Injection capacity [€ million / MW] ⁽³⁾ | 3,9 – 33,4 | 5,1 – 19,0 | 9 |

- (1) Euro million per million cubic meters of natural gas in normal conditions.
- (2) Euro million per million cubic meters of natural gas in normal conditions per day.
- (3) Euro million per megawatt installed of mechanical power at compressor shaft.
- (4) Number of UGSs where the parameters needed for the calculation of the indicators where available.

Annex B – Additional analysis of transmission pipelines

This annex presents a more detailed view on pipeline costs.

Cost components evolution

Table 17: Nominal historical CIME costs by pipeline ranges (2005 -2014, aggregated annual - €)

| Sum of CIME costs | Range 1 [<16"] | Range 2 [16"-27"] | Range 3 [28"-35"] | Range 4 [36"-47"] | Range 5 [48"-57"] | Total |
|-------------------|--------------------|----------------------|--------------------|----------------------|----------------------|----------------------|
| 2005 | 29.079.448 | 65.198.868 | 13.346.700 | | 184.589.358 | 292.214.374 |
| 2006 | 31.582.155 | 120.173.253 | 43.087.234 | | 217.838.319 | 412.680.960 |
| 2007 | 32.423.099 | 125.263.640 | 38.862.959 | 160.284.000 | 188.687.683 | 545.521.381 |
| 2008 | 35.560.168 | 89.922.886 | 91.942.671 | 261.931.865 | 256.663.654 | 736.021.244 |
| 2009 | 20.978.990 | 137.023.427 | 52.630.695 | 207.363.096 | 54.288.491 | 472.284.698 |
| 2010 | 65.590.314 | 108.916.848 | 84.121.680 | 136.517.083 | 185.951.663 | 581.097.588 |
| 2011 | 28.468.238 | 130.927.983 | 91.932.671 | 170.971.156 | 780.289.370 | 1.202.589.417 |
| 2012 | 30.688.026 | 86.934.096 | 160.012.929 | 298.611.167 | 790.398.393 | 1.366.644.611 |
| 2013 | 5.542.832 | 119.174.138 | 88.069.024 | 71.124.000 | 654.812.727 | 938.722.720 |
| 2014 | 23.461.216 | 35.780.504 | 189.358.782 | 55.867.281 | 280.314.779 | 584.782.563 |
| Total | 303.374.487 | 1.019.315.642 | 853.365.345 | 1.362.669.648 | 3.593.834.437 | 7.132.559.558 |

²⁸ **Note on UGS:** The indicators and the values provided in the table only consider UGS in depleted fields. New UGS and UGS expansions are not differentiated in the reference values. It should also be stressed that the characteristics of UGS investments are very much project-specific, even when the UGS are of the same type (for example, unit investment costs for UGS in depleted fields heavily depend on reservoir properties and depth). Data on UGS investment items was provided by only 6 NRAs and does not reflect in full the reality of UGS investments in Europe during the last 15 years. This lack of complete coverage is mainly due to the non-regulated nature of the UGS business in several Member States (non-regulated UGS operators are not obliged to provide cost data to the NRAs).

Figure 20: Nominal historical CIME costs by pipeline ranges (2005 -2014, aggregated annual - €)

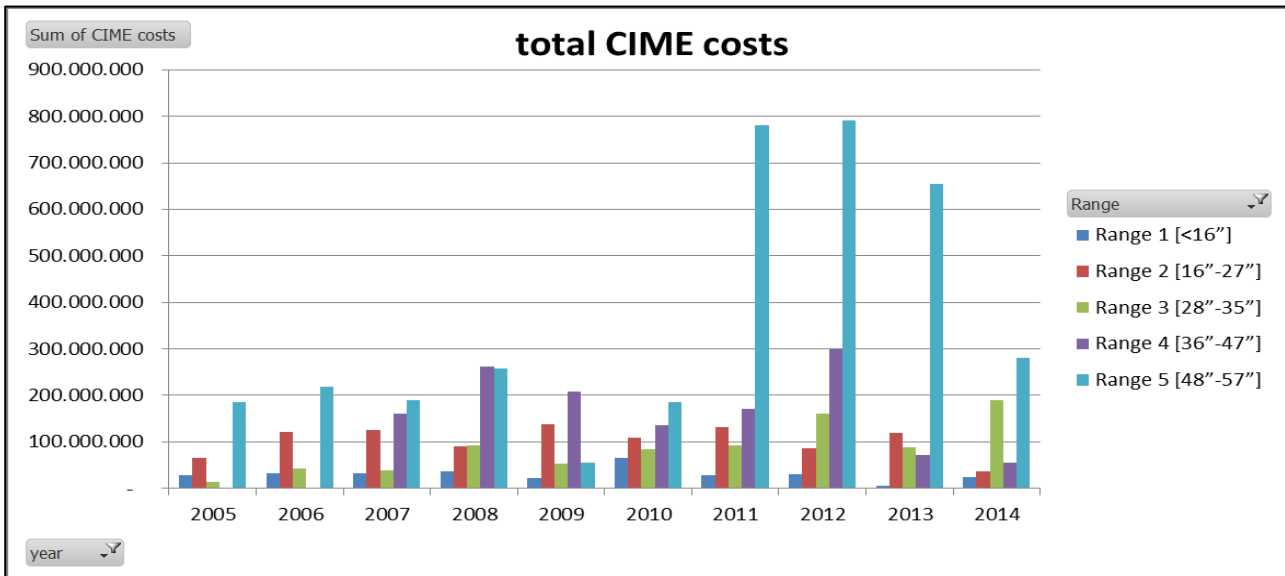


Table 18: Nominal historical material costs by pipeline ranges (2005 -2014, aggregated annual, €)

| Year | Range 1 [<16"] | Range 2 [16"-27"] | Range 3 [28"-35"] | Range 4 [36"-47"] | Range 5 [48"-57"] | Total |
|--------------|-------------------|--------------------|--------------------|----------------------|----------------------|----------------------|
| 2005 | 12.469.006 | 43.638.018 | 8.968.600 | | 97.012.391 | 162.088.016 |
| 2006 | 7.825.539 | 54.765.040 | 38.599.960 | | 68.139.634 | 169.330.173 |
| 2007 | 10.196.934 | 83.564.368 | 23.231.098 | 125.563.000 | 58.927.342 | 301.482.742 |
| 2008 | 10.200.342 | 43.176.046 | 70.065.021 | 174.331.509 | 111.111.341 | 408.884.260 |
| 2009 | 12.026.757 | 70.119.188 | 31.519.774 | 157.511.961 | 26.955.682 | 298.133.362 |
| 2010 | 17.508.935 | 43.661.394 | 69.049.167 | 128.811.355 | 81.491.333 | 340.522.184 |
| 2011 | 5.085.358 | 63.849.865 | 141.060.651 | 134.218.219 | 716.795.470 | 1.061.009.562 |
| 2012 | 9.503.086 | 25.279.499 | 87.468.100 | 211.197.227 | 635.498.793 | 968.946.705 |
| 2013 | 2.134.818 | 62.756.781 | 55.687.360 | 39.635.000 | 575.295.707 | 735.509.666 |
| 2014 | 5.335.668 | 22.797.755 | 154.751.763 | 38.499.891 | 130.283.969 | 351.669.046 |
| Total | 92.286.443 | 513.607.955 | 680.401.493 | 1.009.768.162 | 2.501.511.662 | 4.797.575.715 |

Figure 21: Nominal historical material costs for pipeline ranges (2005 -2014, aggregated annual, €)

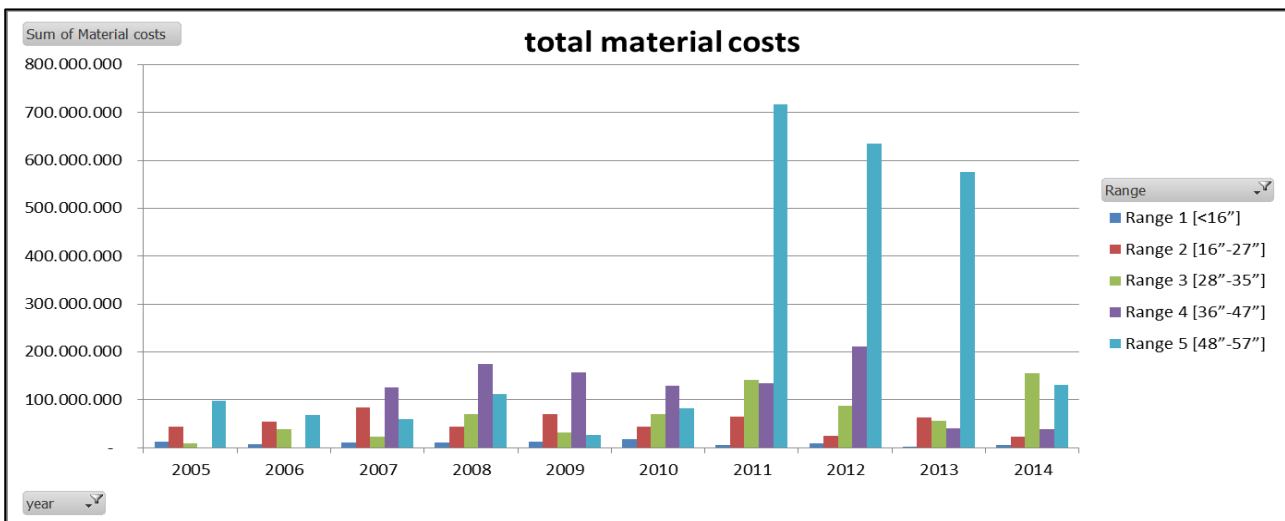


Table 19: Nominal historical engineering costs by pipeline ranges (2005 -2014, aggregated annual, €)

| Sum of Engineerir | Range 1 [<16"] | Range 2 [16"-27"] | Range 3 [28"-35"] | Range 4 [36"-47"] | Range 5 [48"-57"] | Total |
|-------------------|-------------------|--------------------|--------------------|--------------------|--------------------|--------------------|
| 2005 | 2.560.463 | 6.307.462 | 1.137.200 | | 11.526.657 | 21.531.782 |
| 2006 | 1.918.567 | 8.497.728 | 7.068.436 | | 12.206.750 | 29.691.481 |
| 2007 | 2.683.044 | 26.192.844 | 4.023.457 | 41.569.000 | 22.167.185 | 96.635.530 |
| 2008 | 3.576.969 | 10.483.998 | 10.239.829 | 34.740.115 | 25.503.277 | 84.544.188 |
| 2009 | 1.990.585 | 18.311.985 | 3.908.413 | 15.894.411 | 1.209.905 | 41.315.299 |
| 2010 | 4.096.042 | 11.847.217 | 4.402.651 | 43.281.966 | 16.903.846 | 80.531.723 |
| 2011 | 1.967.169 | 12.142.758 | 15.029.033 | 14.533.845 | 96.533.370 | 140.206.175 |
| 2012 | 3.803.446 | 11.443.254 | 26.553.756 | 40.031.774 | 108.048.320 | 189.880.551 |
| 2013 | 467.758 | 12.514.359 | 12.867.739 | 17.557.000 | 125.163.569 | 168.570.425 |
| 2014 | 2.112.349 | 4.935.020 | 14.910.329 | 13.322.275 | 33.699.776 | 68.979.748 |
| Total | 25.176.392 | 122.676.626 | 100.140.843 | 220.930.386 | 452.962.655 | 921.886.903 |

Figure 22: Nominal historical engineering costs by pipeline ranges (2005 -2014, aggregated annual, €)

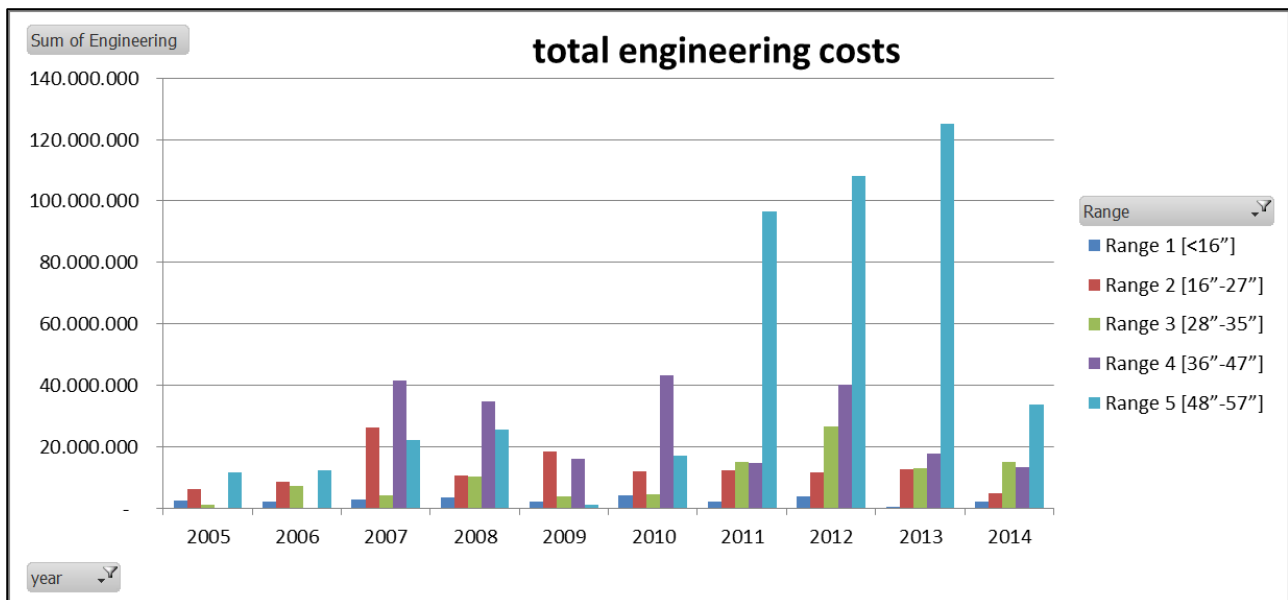


Figure 23: Nominal value of total investment by cost components, transmission pipelines range 1, (2005-2014, €)

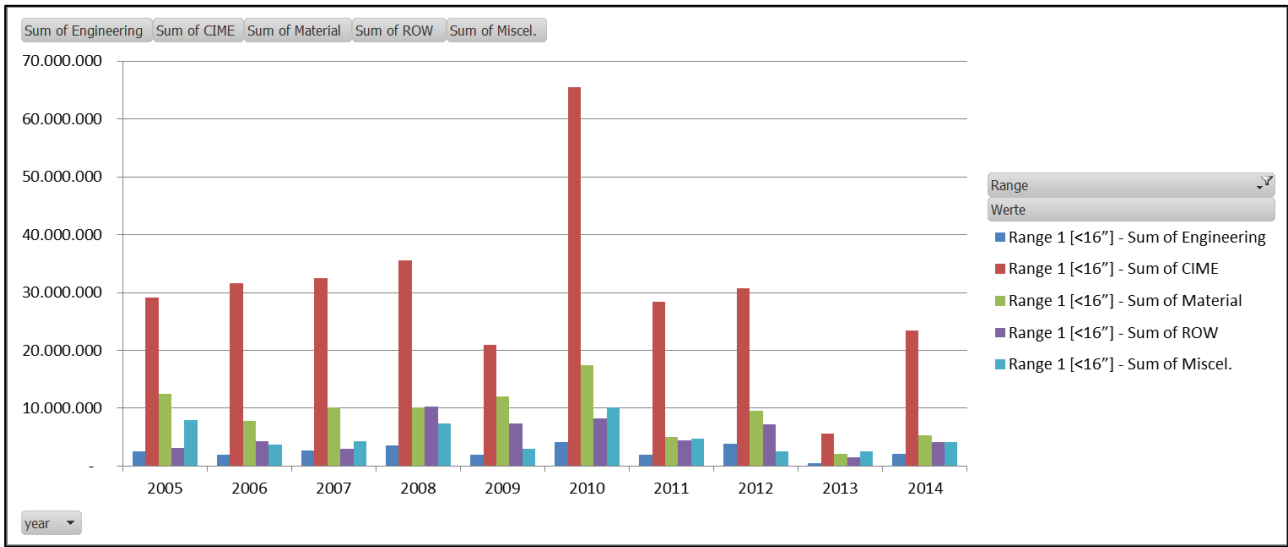


Figure 24: Nominal value of total investment by cost components, transmission pipelines range 2, (2005-2014, €)

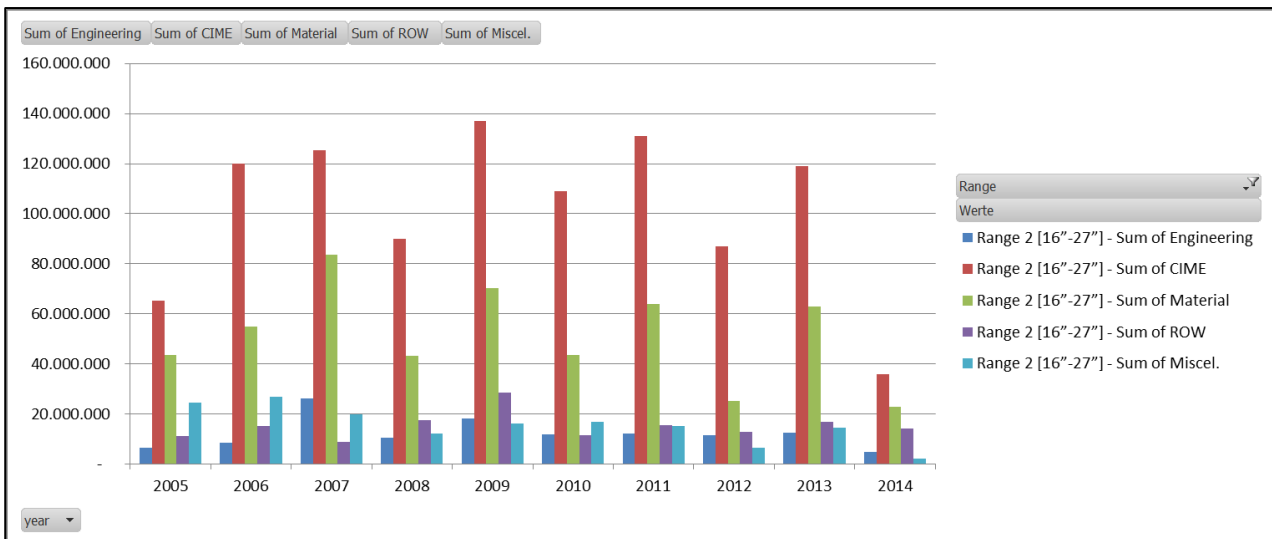


Figure 25: Nominal value of total investment by cost components, transmission pipelines range 3, (2005-2014, €)

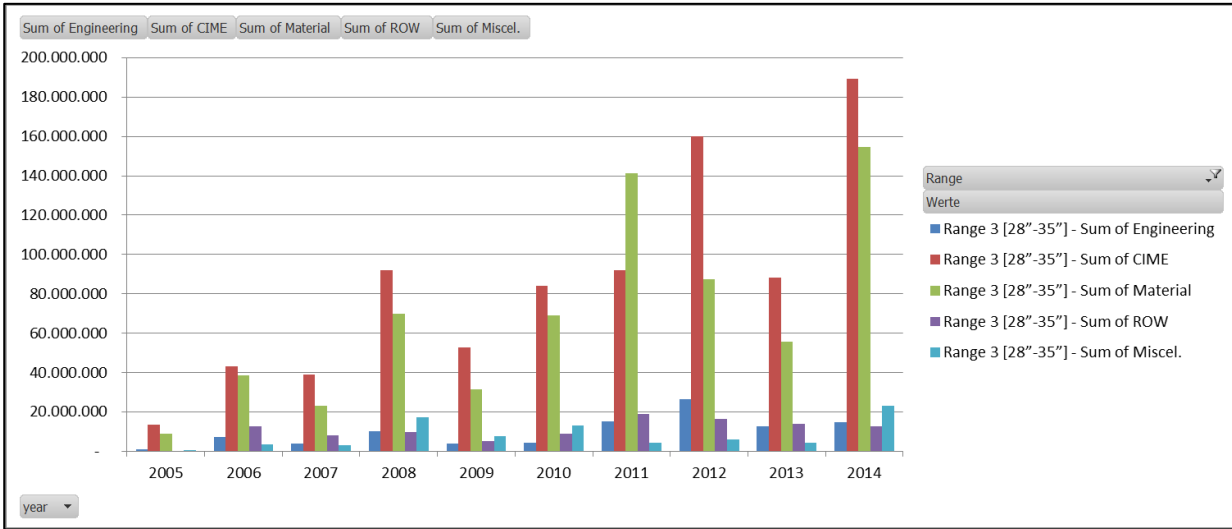


Figure 26: Nominal value of total investment by cost components, transmission pipelines range 4, (2005-2014, €)

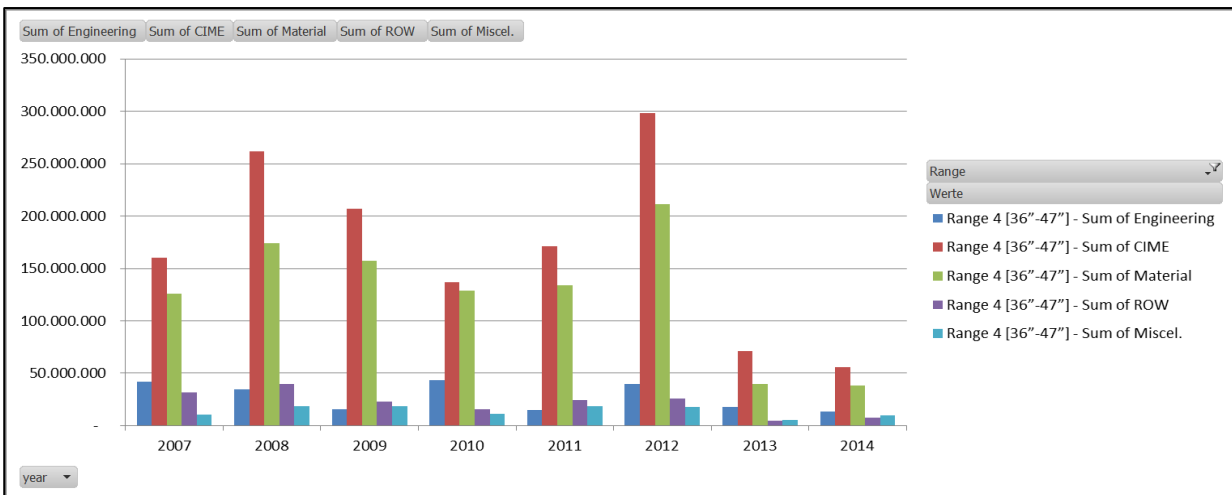


Figure 27: Nominal value of total investment by cost components, transmission pipelines range 5, (2005-2014, €)

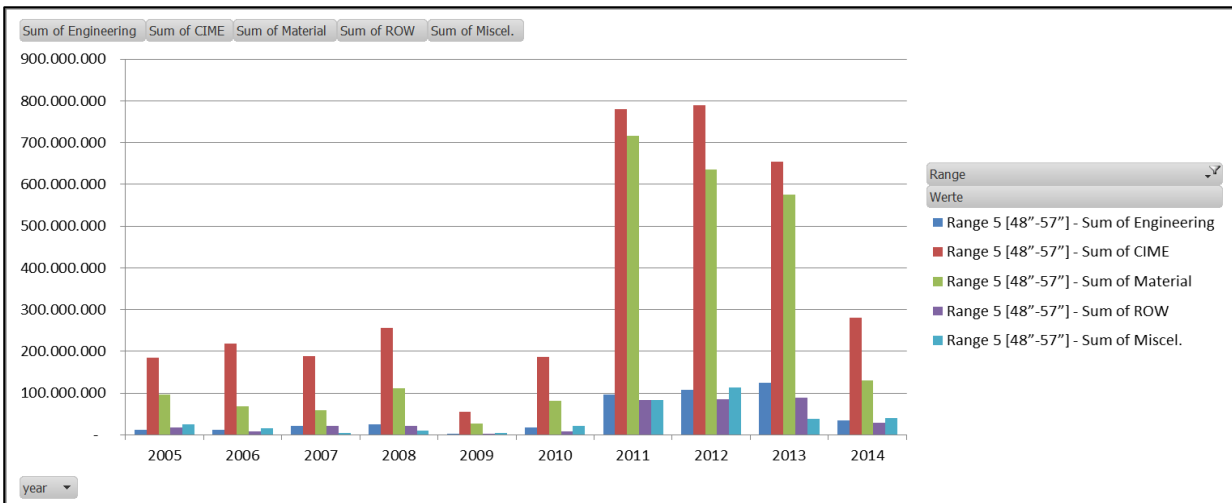
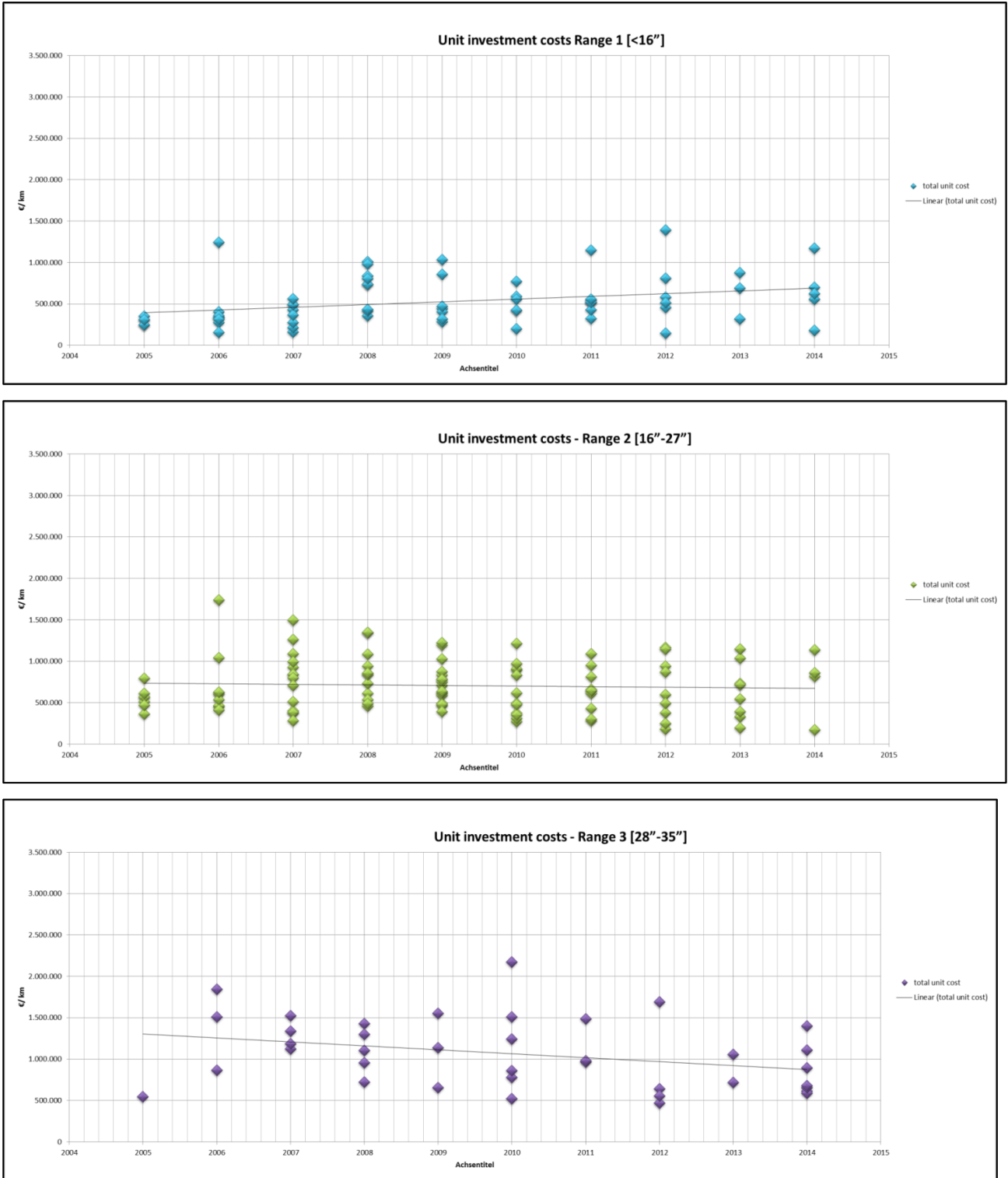


Figure 28: Inflation-indexed unit investment costs of pipelines, evolution (2005-2014 by ranges of diameters, €/km)



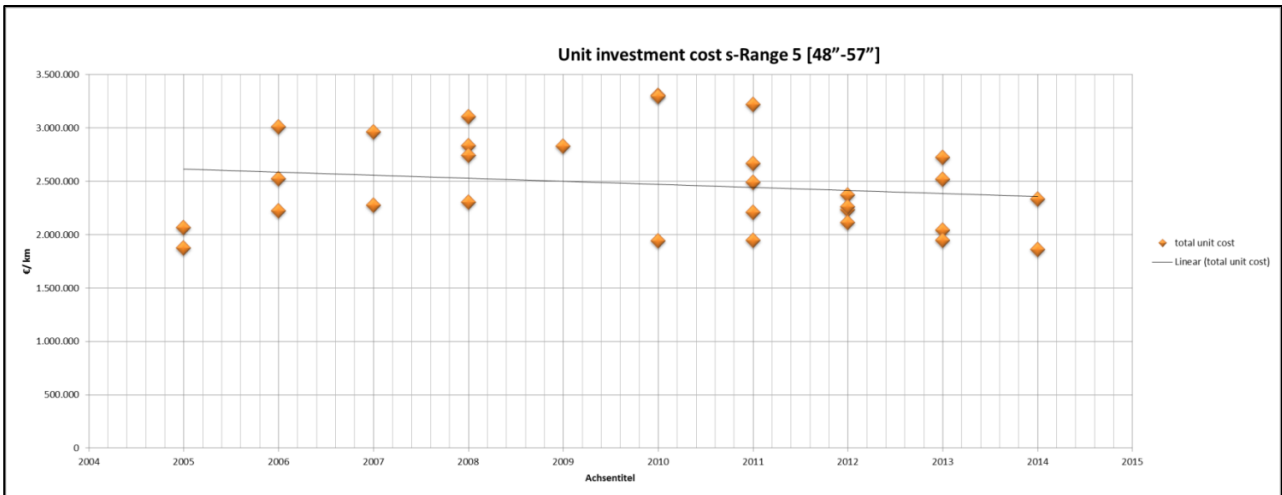
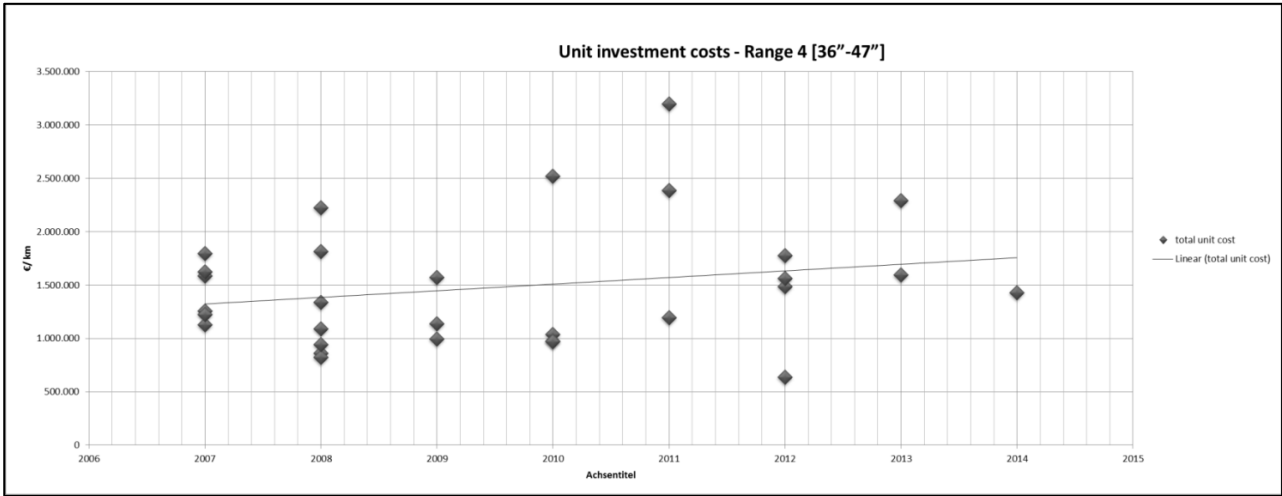


Table 20: Nominal CIME unit investment costs of pipelines, evolution in 2005-2014 by ranges of diameters (annual average - €/km)

| Average CIME UIC | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 Total | |
|-------------------|---------|-----------|-----------|-----------|-----------|-----------|-----------|---------|-----------|------------|------------------|
| Range 1 [<16"] | 118.112 | 143.585 | 168.652 | 333.608 | 233.296 | 272.986 | 318.997 | 380.093 | 285.741 | 335.093 | 255.617 |
| Range 2 [16"-27"] | 204.204 | 316.319 | 340.739 | 381.410 | 316.925 | 308.452 | 301.573 | 308.940 | 302.994 | 330.025 | 316.206 |
| Range 3 [28"-35"] | 212.866 | 376.612 | 544.353 | 431.626 | 526.418 | 481.890 | 412.188 | 474.217 | 442.352 | 398.067 | 446.143 |
| Range 4 [36"-47"] | | | 521.637 | 565.408 | 538.970 | 503.631 | 1.019.490 | 623.540 | 942.117 | 631.983 | 626.265 |
| Range 5 [48"-57"] | 888.409 | 1.216.866 | 1.358.962 | 1.369.300 | 1.494.170 | 1.457.176 | 990.819 | 945.024 | 1.028.298 | 994.963 | 1.144.185 |

Figure 29: Nominal CIME unit investment costs of pipelines, evolution in 2005-2014 by ranges of diameters (annual average - €/km)

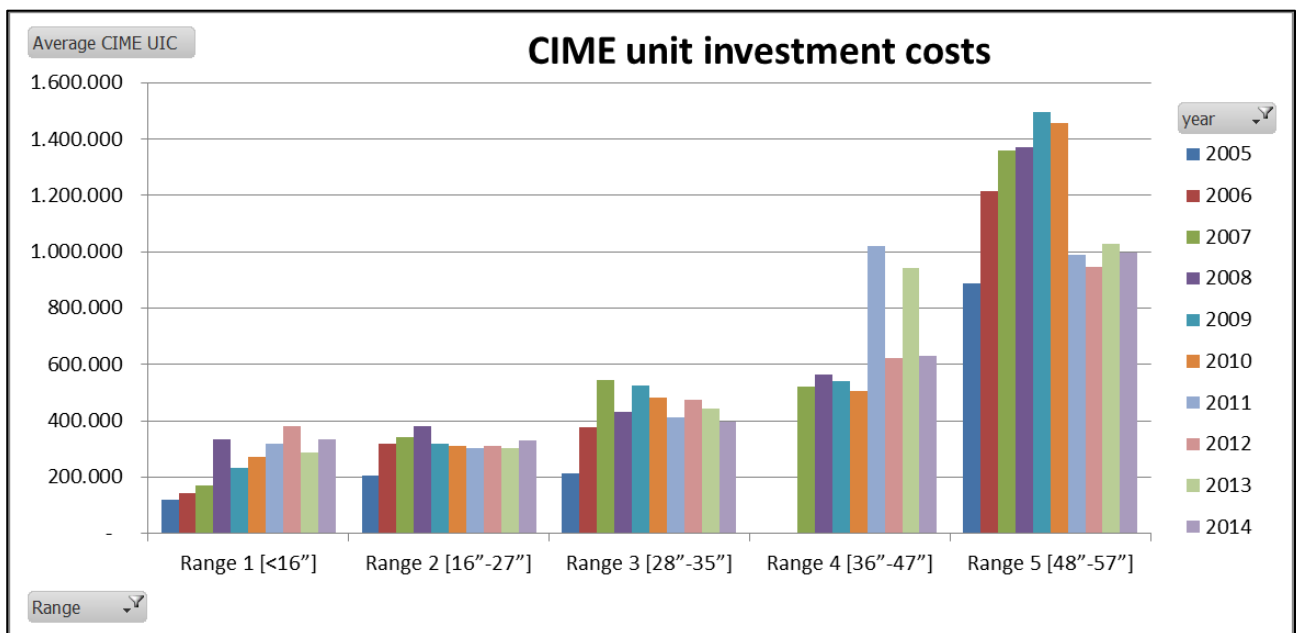


Table 21: Nominal material unit investment costs of pipelines, evolution in 2005-2014 by ranges of diameters (annual average - €/km)

| Average of Material I | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 Total | |
|-----------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|------------|----------------|
| Range 1 [<16"] | 59.828 | 58.029 | 60.213 | 100.499 | 134.964 | 70.735 | 63.475 | 93.506 | 104.474 | 109.669 | 83.445 |
| Range 2 [16"-27"] | 131.947 | 119.795 | 176.215 | 182.534 | 165.780 | 88.960 | 143.753 | 105.698 | 155.598 | 211.712 | 147.308 |
| Range 3 [28"-35"] | 143.040 | 526.087 | 323.424 | 336.986 | 315.528 | 441.868 | 461.499 | 190.367 | 276.921 | 335.467 | 351.205 |
| Range 4 [36"-47"] | | | 395.867 | 356.374 | 416.129 | 437.266 | 689.261 | 490.605 | 529.458 | 435.519 | 446.397 |
| Range 5 [48"-57"] | 466.565 | 584.929 | 475.991 | 628.105 | 810.088 | 695.807 | 904.555 | 803.166 | 770.551 | 608.606 | 702.823 |

Figure 30: Nominal material unit investment costs of pipelines, evolution in 2005-2014 by ranges of diameters (annual average - €/km)

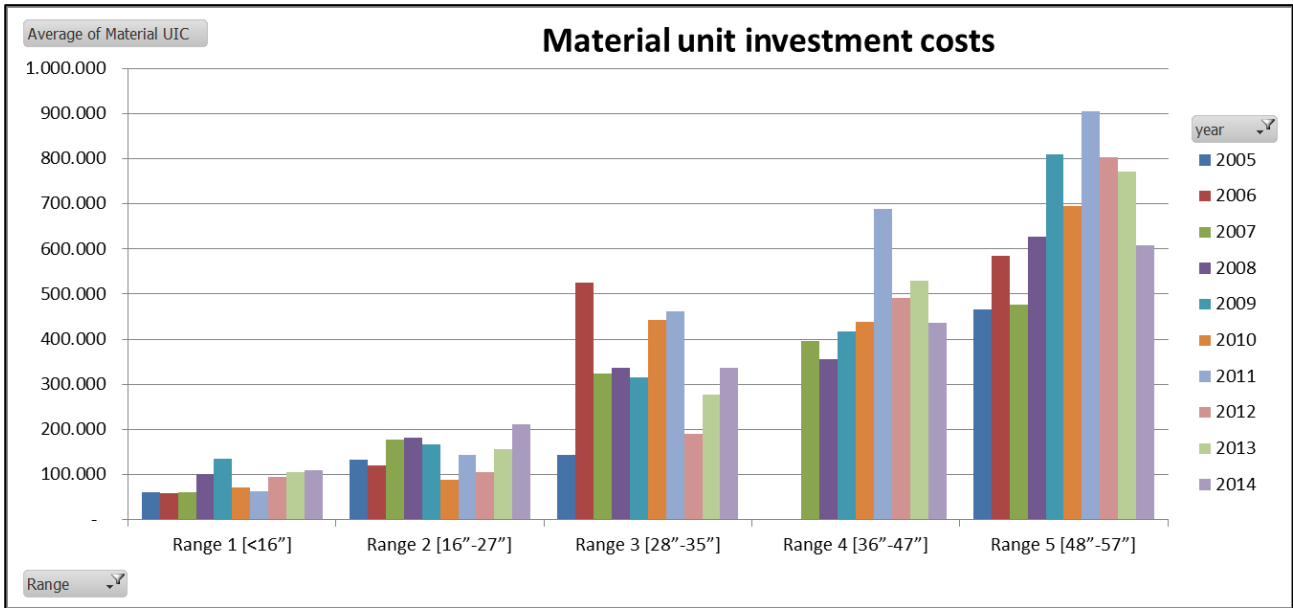


Table 22: Nominal engineering unit investment costs of pipelines, evolution in 2005-2014 by ranges of diameters (annual average - €/km)

| Average Engineering UIC | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 Total | |
|-------------------------|--------|---------|---------|---------|--------|---------|---------|---------|---------|------------|----------------|
| Range 1 [<16"] | 9.293 | 13.678 | 14.728 | 42.254 | 21.403 | 14.841 | 24.359 | 45.910 | 25.205 | 43.034 | 25.268 |
| Range 2 [16"-27"] | 21.375 | 26.022 | 45.682 | 35.696 | 45.942 | 27.488 | 32.967 | 61.322 | 30.842 | 45.807 | 37.982 |
| Range 3 [28"-35"] | 18.137 | 64.091 | 55.339 | 47.418 | 40.478 | 23.434 | 66.526 | 83.453 | 65.240 | 37.039 | 48.791 |
| Range 4 [36"-47"] | 55.944 | 103.673 | 142.120 | 142.618 | 36.361 | 175.386 | 194.130 | 103.689 | 163.698 | 164.370 | 140.303 |

Figure 31: Nominal engineering unit investment costs of pipelines, evolution in 2005-2014 by ranges of diameters (annual average - €/km)

