PROJECT CEER-TCB18

Pan-European cost-efficiency benchmark for electricity transmission system operators

APPENDIX

2019-07-17 V1.2

Appendix

A. Electricity asset reporting guide, 2018-03-08

CEER TSO Cost Efficiency Benchmark

Electricity asset reporting guide

Final version

8 March 2018

1. Introduction

1. The CEER benchmarking projects for electricity and gas Transmission System Operators (TSOs) use two data calls to collect the required data:
   1. the financial data call, and
   2. the asset data call.

2. For both calls TSOs report their data in a separate reporting template (Excel) based on separate reporting guides which are meant to explain how the templates have to be filled in. The current guide deals with the electricity asset call and goes with its associated asset reporting template. Basically the asset reporting presents a snapshot of the asset base at a specific date set by project management.

3. Note that this guide (and its associated reporting template) is essentially a further development of the asset reporting guide used in the previous CEER electricity TSO cost efficiency benchmark E3grid (2012-2013).

4. Please fill in all fields of the financial reporting template. To avoid misunderstandings, always fill in an explicit "0" or "N/A" if that is the case.

5. This guide is structured as follows. Chapter 2 of this guide describes the different asset categories that need to be reported. Chapter 3 provides general reporting directions. Chapter 4 contains specific instructions per asset category.

2. Network components (asset categories)

6. To describe the network (grid) several components (asset categories) that can be distinguished. In the reporting template there is a sheet for each asset category.

Transmission system

7. The transmission system is composed of different network layers characterized by their respective voltages. From interconnection level (380 and 400 kV in Europe), down to sub-transmission networks generally being part of the distribution system (in general using voltages under 100 kV). The boundaries between transmission and distribution activities can differ following the system that is considered. Some transmission systems are characterized by a single functional layer, like in the UK (made of 132kV, 275 or 400 kV). Other systems are made of two superimposed layers, in continental Europe these are often made of 380 and 225 kV networks. Transmission systems made of more than two layers also exist, e.g. the French system is made of at least three functional layers, most often 380, 225, and 90 or 63 kV.

8. By default, the installations are considered as being AC operated.

Layer composition

9. Each layer is composed of (and further characterized by):
   1. Substations
      a. Outdoor or indoor.
      b. Air insulated or metal clad (gas insulated, i.e. SF_6).
      c. Single, double or triple bus bars (possibly operated in sections connected via circuit breakers).
   2. Electrical circuits
      a. Overhead lines (single, double, triple, quadruple), all circuits not necessarily being operated at a same voltage level.
      b. Underground or underwater cables.
      c. DC connection (and their converters).
   3. Connections to other layers that are implemented using transformers or auto-transformers:
      a. Presenting 2 or 3 operational windings (connected or connectable to a grid).
      b. Equipped with tap changer:
         - In phase (for implementing voltage control).

- Or in quadrature[1] (phase shifter; for active power control).
- Or both in a compound device.

c. Tap changer operation:
- Off load
- Or on load (OLTC, On Load Tap Changer).

4. This is completed by specific AC devices:
   a. Shunt compensation devices:
   - Capacitive.
   - Inductive.
   - Or both in a single compound device.
   b. Characterized by their control:
   - Continuous (SVC, STATCOM, synchronous compensator).
   - Mechanically switched (synchronously operated).
   - Mechanically switched (non-synchronously operated).
   c. Series components:
   - Series inductance for short-circuit limiting.
   - Series capacitors for increased transfer capacity (fixed, on-off, continuously variable).
5. Converter stations:
   a. HVDC (line commutation).
   b. HVDC (self commutated converters).
6. Control centers.

10. Conceptually systems are roughly developed following two distinct schemes:
   1. A system based on the reactive compensation scheme. In that case the voltage control in the HV system is mainly implemented using HV reactive compensation.
   2. An approach based on transformers with OLTC[2], assuring reactive power transfers between layers while decoupling layers voltages.

   Systems exist where both approaches have been concurrently implemented.

Offshore grids

11. Offshore assets comprise:
   1. Offshore transmission networks, i.e. all assets used to connect off shore wind farms (e.g. cables, platforms, converters), ending with and including the circuit end in the first (seen from the perspective of the off-shore wind farm) onshore AC substation, and

[1] Technologically, the series voltage is not necessarily based on a 90° phase shift (“quadrature” booster).

[2] On Load Tap Charger, sometimes also ULTC for Under Load Tap Changer.

2. Subsea interconnectors, i.e. subsea cables between (and including) two onshore (converter) stations from different countries that for a dominant part lie on the seabed or below it and is used to transport electricity from one country to another, e.g. the electricity interconnector between Norway and the Netherlands).

12. For the purpose of reporting, subsea cables that connect parts of the same network (i.e. intra-TSO) are not considered as offshore assets.

3. General reporting directions

Asset reporting

13. Assets are reported as they appear at a specific moment ("snapshot") defined by project management, see Article 2.

14. Offshore assets are excluded from reporting. Please note that according to Article 12, subsea cables that connect parts of the same network (i.e. intra-TSO) will be reported as cables (see Article 47) and indicated as submerged (ref. Articles 53 and 54).

15. Unless otherwise requested, the assets reported should relate to
    1. The reporting TSO's own assets that have not been decommissioned (i.e. those assets that are permanently not in use anymore by the TSO, no matter if these are removed or not) and that are partly or fully operated by the reporting TSO to fulfil its own supply obligations.
    2. Network components not owned by the reporting TSO, but leased, rented or otherwise made available (fully or partly) to the reporting TSO by third parties and used by the reporting TSO to fulfil its own supply obligations. For sake of asset reporting such components are considered as assets of the reporting TSO.

16. Assets which are owned by the reporting TSO, but not used by the reporting TSO to fulfil its own supply obligations because the assets are fully leased, rented or made available otherwise by the reporting TSO to third parties should be attributed to these third parties and should not be reported here.

17. With reference to Article 15, in case the asset is only used partly by the reporting, the share of usage must be reported. This share is based on capacities granted on a contractual basis and not on property or ownership shares. So, the reporting TSO has the asset to its free disposal for that part, regardless of the actual utilization. In such cases the name(s) of the parties with which the sharing is done will also be reported.

18. In the reporting transformers, circuit ends, compensating devices or series compensation reported must be related to a substation for validation purposes. In some countries, due to interests of national security, this information can only be available for the relevant NRA. If so, this will be ensured by the relevant NRA.

19. For the purpose of reporting towers and substations are not considered as primary assets, unlike all other assets to be reported. Towers and substations will be reported in order to better understand the complexity of the network.

Asset properties

20. Any asset reported must be given a unique ID, unless stated otherwise.

21. Reporting of all assets (except control centers) require information about nominal voltage. Unit of measurement is kV for all assets. The reporting will explicitly state the lowest represented voltage level and its prevalence in circuit km.

22. For circuit ends capacity in terms of breaking current must be reported (in kA). Deviations between nominal values and operational limits (e.g. due to climatic conditions) are neglected.

23. For lines, cables, transformers, compensating devices and series compensation nominal power in MVA must be reported. For transformers, the highest power value has to be considered, this is often the one of the higher voltage winding. For phase shifters the total of the series and shunt power values has to be reported.

24. In case of multiple circuits lines, each circuit must be considered separately. This permits to account for different operational voltages for circuits on the same tower.

25. A cable connection usually consists of multiple cables in a trench or a tunnel, where e.g. a trench can easily be 10 or more meters wide and different cables can be operated at different voltage levels. A cable connection consisting of a number of cables, all being operated at the same voltage level, is reported as a single asset. So, if the cable connection consists of cables operated at two different voltage levels, this is reported as two assets (two cable connections in the same corridor).

Commissioning, acquisition, and rehabilitation

26. The commissioning year of an asset is the year when the asset was put in operation (for the first time), irrespective of this was done by the TSO or a third party.

27. In case the asset has been obtained from a third party, in addition to the commissioning year, the acquisition year (year of investment, or at least the major part of it) also needs to be provided.

28. By default the commissioning year is equal to the acquisition year (in the template indicated as “N/A”).

29. In case the asset has been significantly rehabilitated the rehabilitation year also needs to be provided. Significant rehabilitation means a large incremental investment into an existing asset without change of any characteristics (i.e. its dimensions and properties). Large is defined as at least 25% of the (real) initial investment. Regular preventive and reactive maintenance, e.g. replacement of system components at or before their lifetime is not counted as a “rehabilitation”. Investments changing the characteristics are considered as “upgrades” and not as rehabilitation. The default reporting is “N/A”, i.e. there is no significant rehabilitation.

Generic data to be provided (per asset)

30. For each asset, the following information is asked for in the reporting template:

31. <u>ID:</u> See Article 20.

32. <u>Usage share:</u> A percentage, see Article 17. By default, full usage by the reporting TSO, 100% is filled in explicitly.

33. <u>Third parties:</u> These are the names of the parties the sharing is done with, see Article 17. By default “N/A” is reported to signal that no sharing is done (Usage share in Article 32 is 100%).

34. <u>Commissioning year:</u> See Articles 26 to 29.

35. <u>Acquisition year:</u> See Articles 26 to 29.

36. <u>Rehabilitation year:</u> See Articles 26 to 29.

37. Please refer to Chapter 4 for the required specific information per asset.

4. Specific reporting directions

38. Below, we introduce the data to be provided specifically for each asset.

Lines (Sheet "1. Lines")

39. An item in the overhead transmission line category is defined as a circuit, with a certain nominal current, operated at a certain voltage, installed on towers equipped with a certain number of circuits. Line specifics to report are the following:

40. Length: Length of the circuit (km).

41. Voltage: Nominal voltage (kV).

42. Power: Nominal power (MVA).

43. Number of circuits: Number of circuits per tower (1,2,3,…).

44. AC/DC: AC or DC.

45. Number of sub-conductor: Simplex (1), duplex (2) , or triplex (3).

46. Tower type: Dominant tower type (Wood, Steel, Concrete, Composite).

Cables (Sheet "2. Cables")

47. Definition of cables follow the same principles as lines, but lay underground or under water (submerged). Reporting is done at the level of cable connections, not at the level of individual cables that the connection consists of, see Art. 25 for a further explanation.

48. Offshore cables should not be reported here (see Article 11 for what is meant with offshore). Cable specifics to report are the following:

49. Length: Length of the circuit (km).

50. Voltage: Nominal voltage (kV).

51. Power: Nominal power (MVA).

52. AC/DC: AC or DC.

53. Usage: Land or Submerged. Submerged cables are defined as cables that lie at least 2 meters below the water surface for at least 1.000 meters and for at least 75% of their length.

54. Water crossed: In case the cable is submerged (Usage = Submerged), state the name of the water crossed (otherwise fill in N/A). This is the name as it is known to the public.

55. Number of cables: Number of cables the cable connection consists of (1,2,3,…), see Article 25.

56. Number of conductors: Number of conductors (1,2,3,…) per cable of the of connection. Usually this is 1 or 3. For high voltage cables this is usually 1. In case there are cables with different numbers of conductors, report the dominant type.

57. Insulation: PEX, XLPE, Oil, Gas filled, or Other.

Transformers (Sheet "3. Transformers")

58. All types of transformers playing a role in transmission shall be reported. Transformers supplying substations auxiliaries are excluded here from reporting as these are implicitly taken into account through circuit ends. Transformers of HVDC installations are included within the convertors and must also not be reported under transformers. Transformer specifics to report are the following:

59. Substation: ID of the substation the transformer is located in.

60. Primary: Primary voltage (kV).

61. Secondary: Secondary voltage (kV).

62. Tertiary: Tertiary voltage (kV), if applicable.

63. Power: Nominal power (MVA).

64. Number of transformers: Number of identical transformers in the relevant substation (1,2,3,…). Identical means that they have the same attribute values (voltages, Power, Type, Tap Changer, Phase Shift) and have the same commissioning year.

65. Type: Transformer type (Transformer, or Auto-transformer).

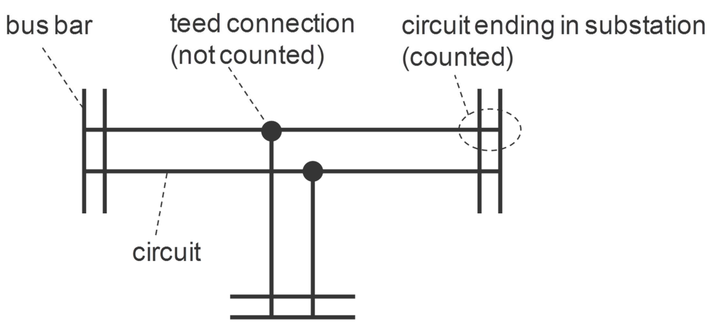
66. Tap Changer: Tap changer type (With or Without), i.e. with or without On Load Tap Changer (OLTC).

67. Phase shift: Phase shift yes/no (Yes or No).

Circuit ends (Sheet "4. Circuit ends")

68. A circuit end is generally a bay in a substation. This applies to all types of devices connected in a substation (e.g. lines, cables, transformers, compensation devices, but also transverse couplers between bus bars, or longitudinal couplers between bus sections). For example, a UHV-HV two windings transformer has two circuit ends, one connected to the UHV bus and the other to the HV bus. "Auxiliary" devices such as earthing switches or measurement units shall not be counted here. Circuit end specifics to report are the following:

69. Circuit ends are only counted if the respective switchgear is owned by the TSO. Teed connections are not specifically taken into account in the present guide. Only the terminals ending in a substation will only be considered (see figure below). For the calculation of circuit length, the total length of the teed structure must be considered, at least when the type of the line is similar. Otherwise the different circuits must be sorted following the type of line. The circuit ends at the connection point on the line is considered as non-existent.



70. Circuit end specifics to report are the following:

71. Substation: ID of the substation the circuit end is located in.

72. Voltage: Nominal voltage (kV).

73. Current: Current breaking capacity (kA).

74. Number of circuit ends: Number of identical circuit ends (1,2,3,…) in the relevant substation. Identical means that they have the same attribute values

(Voltage, Current, Busbar, Coverage, Insulation) and have the same commissioning year.

75. Busbar: Single (1), double (2), triple (3), quadruple (4), Other.

76. Coverage: Outdoor (open air) or Indoor (in a building).

77. Insulation: Air insulated or Metal clad (gas insulated, i.e. SF_6).

Shunt compensating devices (Sheet "5. Compensating devices")

78. There are discrete (bank) and continuous compensating devices, for banks, single (fixed) and multiple steps (adjustable). For shunt reactor compensated lines, where inductance cannot be disconnected, compensating devices are considered as bank of fixed inductive compensation. Shunt compensating device specifics to report are the following:

79. Substation: ID of the substation the device is located in.

80. Voltage: Nominal voltage (kV).

81. Power: Nominal power (MVA).

82. Number of devices: Number of identical compensating devices (1,2,3,…) in the relevant substation. Identical means that they have the same attribute values (Voltage, Power, Type, Fixed or adjustable, Capacitive or inductive) and have the same commissioning year.

83. Type: Type of compensating device, i.e. Banks, SVC, STATCOM, or synchronous compensator (SynComp). See also Article 78 regarding reactors.

84. Fixed or adjustable: Single (Fixed) or multiple steps (Adjustable) for banks.

85. Capacitive or inductive: Capacitive (Cap), Inductive (Ind), or both (Both).

Series compensation (Sheet "6. Series compensations")

86. The series compensations are divided in two categories, inductive (for short-circuit current limiting) on one side and capacitive (for increased transfer capacity) on the other side. Inductive compensation is generally made of fixed components while capacitive series compensation can be made discretely or continuously adjustable. Series compensation specifics to report are the following:

87. Substation: ID of the substation the series compensation is located in.

88. Voltage: Nominal voltage (kV).

89. Power: Nominal power (MVA).

90. Number of devices: Number of identical series compensations (1,2,3,…) in the relevant substation. Identical means that they have the same attribute values (Voltage, Power, Control, Fixed or adjustable, Capacitive or inductive) and have the same commissioning year.

91. Control: (Discrete, or Continuous).

92. Fixed or adjustable: (Fixed, or Adjustable).

93. Capacitive or inductive: Series capacitors for increased transfer capacity, either discretely (CapDis) or continuously adjustable (CapCon), or series inductance (Ind) for short-circuit limiting.

Control centers (Sheet "7. Control centers")

94. Control centers in electricity transmission operations measure, regulate and control electricity flows from sources to consumers. ICT (hard- and software) used in a control centers is seen as integral part of it. This also includes grid related telecommunications (telecommunications solely related to the network). This comprises of transmission of electronic information for metering, control and supervision of the network with means other than through third-party operators. This also includes SCADA and optical fibers and other infrastructure that is used for telecommunication. For control centers the following is reported:

95. Name: Name of the control center.

96. Functions: A description of the main functions and characteristics of the control center.

97. Staffing: The control center is an operational unit that is staffed during normal operations (Yes) or an emergency (reserve or back-up) center that is fully equipped but not normally staffed (No).

Other installations (Sheet "8. Other")

98. FACTS or HVDC conversion stations are very specific installations. Their number worldwide is less than one hundred. Each constitutes a specific plant. To ensure a correct validation, converter stations are reported in a free format, specifying the adequate parameters. Use one line for each station without aggregation.

Other transmission installations of particular values may also be entered here. Specifics to report are the following:

99. <u>Type:</u> Type of installation (e.g. HVDC)

100. <u>Characteristics:</u> Further specification of the installation in terms of its main characteristics (e.g. voltage, capacity, power, etc.)

Towers (Sheet "9. Towers")

101. Reporting of towers differs from the other asset types in that they are not reported item by item but as a sum of identical asset, where identical refers to the attributes being reported. Tower specifics to report are the following:

102. <u>Number:</u> Number of identical towers (1,2,3,…), where identical means that they have the same reported attributes (Usage share, Third parties, Commissioning year, Acquisition year, Rehabilitation year, Voltage, Material, Type).

103. <u>Voltage:</u> Voltage level (kV). In case of towers for multiple circuits the highest voltage level applies (nominal, not operational).

104. <u>Material:</u> Main material the tower is composed of (Wood, Steel, Concrete, Composite, or Other).

105. <u>Type:</u> Type of tower (Suspension, or Angular).

Substations (Sheet "10. Substations")

106. An item in the substation category is generally defined as a grid connection point with transformers, switches, compensating devices or series compensation. Substation specifics to report are the following:

107. <u>Voltage:</u> Highest nominal voltage (kV) in the substation. This is the nominal voltage on the primary side of the highest voltage transformer within the substation. This is also referred to as rated voltage.

108. <u>Type:</u> Transformer, Switching, or Other.

B. Financial reporting guide, 2018-03-08

CEER TSO Cost Efficiency Benchmark

Financial reporting guide

Final version
8 March 2018

1. Introduction

1. The CEER benchmarking projects for electricity and gas Transmission System Operators (TSOs) use two data calls to collect the required data:
   1. the financial data call, and
   2. the asset data call.

2. The financial reporting templates (Excel) and this associated financial reporting guide constitute the financial data call. The reporting of assets is defined in the asset data call.

3. TSOs report their data in the financial reporting template. There are separate templates for electricity and gas. This guide is valid for both electricity and gas and is meant to explain how the reporting template(s) has/have to be filled in.

4. Note that this guide (and its associated reporting template) is essentially a further development of the financial reporting guide used in the previous CEER electricity TSO cost efficiency benchmarks E3grid (2012-2013) and E2gas (2015/2016).

5. TSOs report their data based upon their audited financial statements[1]. This way the costs reported in the investment stream align with the costs of investments in the audited financial statements and the reported expenses align with the expenses in the profit and loss account of the audited financial statements.

6. Although it is important that total investments and expenses match the audited financial statements, it might be possible that the required breakdown of costs and expenses does not match your audited financial statements. In that case it is acceptable if you use your general ledger and project administration in order to make estimates as good as possible. Please provide clarification if you have made estimates.

7. Regarding assets owned by the group to which the TSO belongs, but not by the TSO itself, the relevant investment data of the group company have to be used.

[1] This means that only financial accounting data has to be reported. Regulatory (accounting) data shall not be reported.

8. In case TSOs do not publish their audited financial statements, the reported investments and expenses should be visible in the segmented financial information of audited consolidated financial statements of the parent company.

9. TSOs report their data for a given year in the currency used in the audited financial statements of that year.

10. Please note that not all reported investments and expenses will be in scope of the benchmark study, but that some elements are required only for verification purposes.

11. The International Financial Reporting Standards (IFRS) have been used as the basis for this guide, although this does not exclude the possibility that some TSOs use other accounting systems.

12. Please fill in all fields of the financial reporting template. To avoid misunderstandings, always fill in an explicit “0” or “N/A” if that is the case.

13. This guide is structured as follows. In Chapter 2, the activities of TSOs in which the financial reporting is decomposed are described. Chapter 3 of this guide deals with investment reporting. Chapter 4 describes the expense reporting.

2. Activities

Definitions

14. This financial guide uses definitions in accordance with the glossaries of ENTSO-E[2] and ENTSOG[3] where possible. Main definitions can be found per chapter. The appendix contains other definitions.

15. The various asset categories for the transport activity are defined in the asset guide.

Activities

16. When reporting investments and expenses, a distinction is made between different activities:
    T Transport;
    M Grid maintenance;
    P Grid planning;
    S System operations;
    X Market facilitation;
    TO Offshore;
    SF Storage Facility;
    L LNG facility (gas only); and
    O Any other activity;
    I Indirect expenses.
    Note that I is not a real activity, but for the reporting dealt with as such.

17. Four elements of expenses are, for the amounts reported in the profit and loss account of the audited financial statements, excluded from allocation to activities:
    a) depreciation, impairment and amortization of assets (excluding depreciation of equipment and vehicles and non-grid related telecommunications);
    b) finance income and expenses (interest); and
    c) taxes on declared annual profits
    d) extraordinary expense and income[4].

    These elements are reported on a separate sheet of the reporting template.

[2] https://www.entsoe.eu/data/data-portal/glossary/Pages/home.aspx

[3] https://www.entsog.eu/publications/glossary-of-definitions#GLOSSARY-OF-DEFINITIONS

[4] IFRS prohibits reporting expenses and income as extraordinary, other accounting systems however may still be allowing this.

18. Main changes in comparison to previous CEER TSO cost efficiency benchmarks (E3Grid in 2012/2013 and E2Gas in 2015/2016) are:
    - The term 'function' in E3Grid was changed into 'activity' in E2Gas. This financial guide uses the term 'activity'.
    - The A activity was renamed into the I activity to represent all indirect costs and expenses.
    - E2Gas introduced the T activity, which is now common to both electricity and gas.
    - The construction activity (C) has been removed since almost all activities of construction are capitalized and the activity appeared to have no assets or expenses in the audited financial statements of TSOs.
    - The grid ownership activity (F) has been removed since finance income and expenses are omitted from allocation to activities.
    - TO is included in order to have a more refined understanding of the grid.

T Transport

19. For investments (CAPEX) this activity includes all costs regarding construction and maintaining the network[5], excluding offshore.

20. For expenses (OPEX) this activity includes the expenses for metering, the purchase of energy for operating the network[6], grid-related insurance and day-to-day management of the network functionality.

21. For revenues this activity includes revenues from third parties for assets used by these parties with a usage share higher dan 0% and lower than 100%[7], reported in the audited financial statements as revenues.

M Grid maintenance

22. For investments (CAPEX) the maintenance is included in the T activity.

23. For expenses (OPEX) this activity includes all expenses regarding maintaining the network.

P Grid planning

24. For investments (CAPEX) this activity includes planning costs which are capitalized as a part of the investment stream[8]. These planning costs are

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[5] This includes grid-related equipment and vehicles which are not specified in the asset reporting.

[6] Mainly purchase of energy for network losses.

[7] Costs and expenses of assets with a usage share of 0% are reported under O (Other activities). Assets with a usage share of 100% do not have revenues from third parties.

the costs associated with receiving the permit to construct (a part of) the transmission system and includes costs for environmental studies.

25. For expenses (OPEX) this activity includes all expenses regarding the analysis, planning and drafting of network expansion and network resources, including the expenses for the ten-year network development plan and non-capitalized research and development. This includes long-term planning.

S System operations

For electricity only

26. For expenses (OPEX) this activity includes all expenses regarding balancing services, primary and secondary reserves, capacity management, ancillary services (disturbance reserves, voltage support) and the purchase of energy for congestion management and redispatching. This activity excludes day-to-day management of the network functionality.

For gas only

27. For expenses (OPEX) this activity includes all expenses regarding ancillary services and congestion management. This activity excludes day-to-day management of the network functionality.

X Market facilitation

28. For expenses (OPEX) this activity includes all direct involvement in energy exchanges through information provision or contractual relationships. This comprises regulated tasks through procurement or renewable power, residual buyer obligations or capacity allocation mechanisms, capacity auctioning mechanisms, and work on coordination of feed-in tariffs. This activity includes direct expenses related to the contractual relations excluding transport and storage, primarily information expenses and energy purchases for other purposes than the consumption in the network of the TSO.

29. For revenues this activity includes pass-through income regarding market facilitation, reported in the audited financial statements as revenues .

TO Offshore

30. This activity is defined like T, but for offshore only.

[8] These only need to be reported for the most recent five years

SF Storage facility

31. All direct and indirect costs and expenses of (gas) storage facilities and peak-shaving plants.

L LNG Facility (gas only)

32. All direct and indirect costs and expenses associated with LNG facilities.

O Other activities

33. This includes all costs and expenses for activities that are not covered by any other activity, for example:
    a. costs and expenses for all assets which are owned by the reporting TSO, but not used by the reporting TSO to fulfil its own supply obligations because the assets are *fully* (100%) leased, rented or made available otherwise by the reporting TSO to third parties. Note that none of these assets should be reported in the asset reporting;
    b. personnel on the payroll of the TSO and working for a group company.

I Indirect expenses[9]

34. For expenses (OPEX): expenses (e.g. personnel) for administrative support, non-grid related insurance, non-grid related telecommunications, non-grid related equipment, non-grid related vehicles, management, and expenses for the main office. This activity does not include research & development, grid related telecommunications, grid-related insurance and grid-related equipment and vehicles.

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[9] Indirect expenses have to be accounted for separately in the OPEX sheet only. A TSO may have indirect cost allocated to CAPEX, but specification of that is not asked for. In contrast to all other activities, which are direct activities, the indirect activity is not an actual activity but for the reporting will be dealt with as such.

3. Investment reporting

Main definitions

35. Investments are expenditures for assets (or components thereof[10]) that are recognized in the audited financial statements as tangible fixed assets.

36. Investments in used assets are expenditures for second-hand assets which were previously owned by a different company (not being a group company), e.g. a DSO or another TSO. Contrary to investments in new assets the acquisition year will differ from the commissioning year. The opening balance assets for a new TSO is also an investment in used assets.

37. Significant rehabilitation investments are large incremental investments into an existing asset without change of any characteristics (i.e. its dimensions and properties). Large is defined as at least 25% of the (real) initial investment. Regular preventive and reactive maintenance, e.g. replacement of system components at or before their lifetime is not counted as a "rehabilitation".

38. Upgrades are investments in existing assets changing the characteristics. Upgrades should be reported as investments.

39. Acquisition year is the year assets are recognized in the audited financial statements.

40. Commissioning year is the year assets, when they are new, are put into operation.

41. Disinvestments are disposals of assets (or components thereof) that are derecognized in the audited financial statements.

42. Capitalized borrowing costs are defined in International Accounting Standard 23, *Borrowing costs*.

43. Capitalized land are the costs of the investments that are due to purchase of land and capitalized payments to third parties as a result of a legal process (e.g. expropriation or compensation agreement), procurement or negotiation, related to the damage, injury of land, and /or the right to use land, roads or waterways for the activities of the TSO. This includes the capitalized direct expenses for judicial assistance, court fees etc. for legal

[10] Including fences, security cameras, etc.

processes (terminated or non-terminated) related to the use, damage or injury of land for the activities of the TSO.

44. Capitalized planning costs are the costs of the investments that are due to planning.

45. Gross investment stream is defined as investments per calendar year over time.

46. Disinvestment stream book year is defined as the original cost[11] of disinvestments per year, as occurred in the book year, over time.

47. Disinvestment stream acquisitioning year is defined as the original cost of disinvestments per year, as occurred in the acquisition year, over time.

48. Investment contributions are defined as payments by third parties for investments, investment grants and subsidies received.

49. Net investment stream is defined as the gross investment stream minus the disinvestment stream acquisitioning year.

50. Asset categories are identifiable groupings of assets. The definitions of the asset categories within the T, M and P activities can be found in the asset guides, with the exception of the asset category 'grid-related equipment and vehicles' (see the appendix for the definition). For the financial reporting the following asset categories are combined:
    - Lines and towers (electricity only)
    - Substations, transformers and circuit ends (electricity only)

51. Cost is defined in International Accounting Standard 16, *property, plant and equipment.*

52. Capitalization threshold is the amount above which assets are recognized in the audited financial statements.

53. Major spare parts, stand-by equipment and servicing equipment are defined in International Accounting Standard 16, *property, plant and equipment.*

[11] Ref. article 60

Investment stream and disinvestment stream

54. Investments are reported in the investment stream in the year the underlying assets are put *into* operation.

55. Disinvestments are reported both in the year they occurred and also in the acquisition year. The sum of all disinvestments in the disinvestment stream book year has to be equal to the sum of all disinvestments in the disinvestment stream acquisitioning year[12].

56. The investments in the investment stream for a given year should correspond to the investments in tangible fixed assets in the audited financial statements of the TSO for that year.

57. The disinvestment stream book year should correspond to the disinvestments as reported in the audited financial statements of the TSO for that year.

58. Investments are reported at cost[13] and have to be based on evidence, e.g. invoices.

59. Investment contributions[14] have to be reported separately.

60. Disinvestments are reported at the original cost of the corresponding investment and have to be based on evidence, e.g. invoices.

61. (Dis)investments are reported in asset categories as specified in chapter 2 of this guide (Activities).

62. The investment stream data for asset categories in activity T should correspond to the assets reported in the asset data call.

63. Major spare parts, stand-by equipment and servicing equipment are included in the investment stream only if they are recognized as tangible fixed assets in the audited financial statements of the TSO.

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[12] For example: a disinvestment in 2017, regarding an asset acquired in 2000 for €100.000, has to be reported in the year 2000 in disinvestment stream acquisitioning year at €100.000 and the year 2017 in disinvestment stream book year at €100.000.

[13] Revaluations or write-ups are not taken into account.

[14] Depending on the accounting methods in the audited financial statements an investment of € 100 million with an investment contribution of €10 million was reported at €100 million or €90 million. The TSO has to report which of the two methods was used.

64. Investments in significant rehabilitations are reported both in the (dis)investmentstream and separately. TSOs report the ID of the rehabilitated asset (as reported in the asset reporting), asset category, commissioning year, rehabilitation year and the rehabilitation investment amount.

65. Investments in used assets are reported both in the (dis)investmentstream and separately. The remaining weighted average[15] technical lifetime of these assets as estimated by the TSO is reported as well.

66. Figure 1 below shows a flowchart of how to deal with monetary items spent on assets in terms of this reporting.

Gas only

67. Some specific asset categories are reported both in the (dis)investmentstream and separately. These asset categories are inshore pipes, odorization assets, gas chromatographs, and integrated delivery stations (including the reported assets it comprises, like regulators).

[15] Weighted average is necessary when a TSO acquires multiple used assets in one year, with different remaining lifetimes per asset.

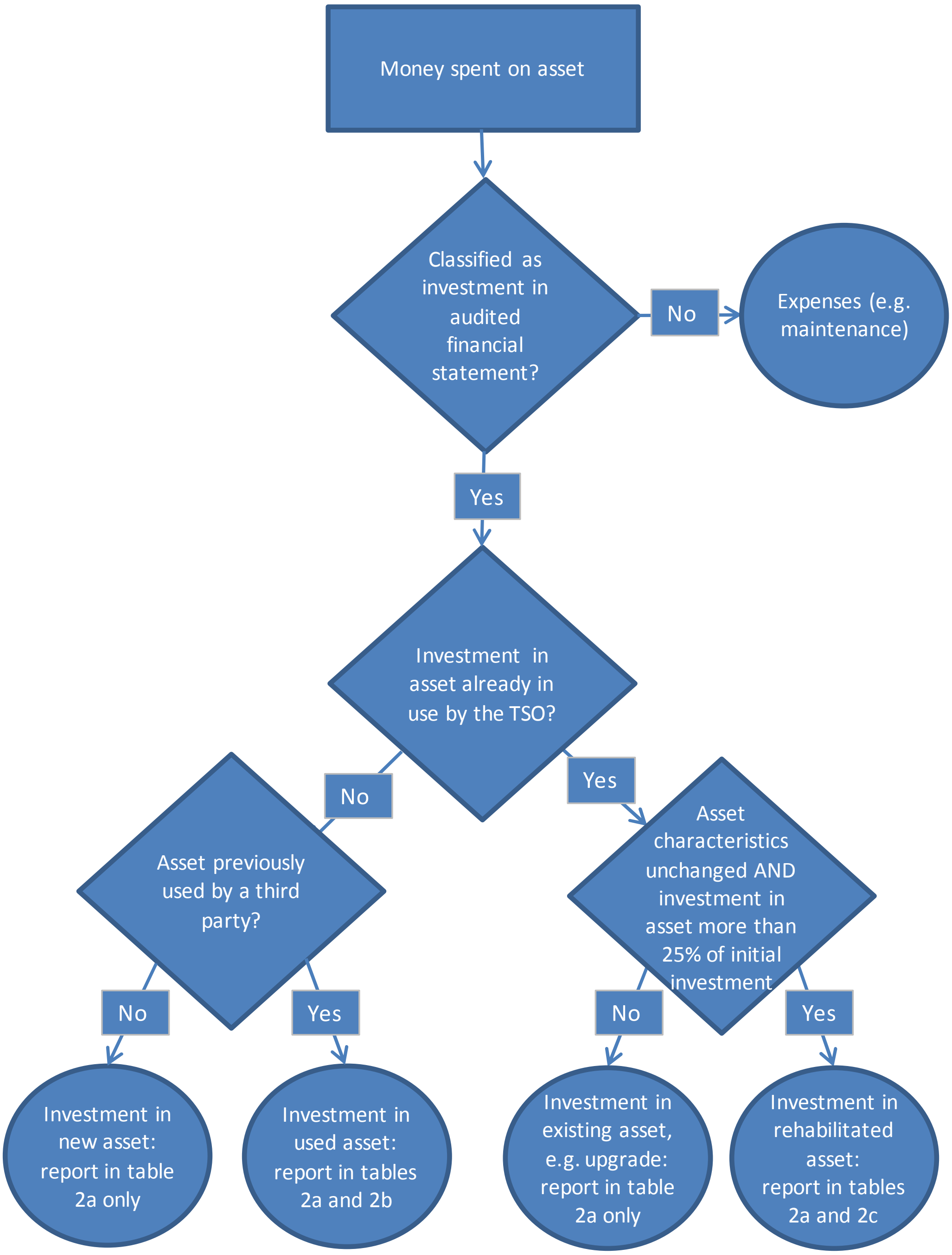

Figure 1: Flowchart for treating investments in this reporting

4. Expense reporting

Main definitions

68. Personnel expenses are the non-capitalized expenses for internal and external personnel including all taxes, charges or fees related to salaries, pensions and other payroll items. This includes personnel on the payroll of the TSO, personnel on the payroll of a group company and carrying out activities for the TSO and hours of temporary personnel carrying out activities for the TSO.

69. Energy expenses are the non-capitalized expenses for purchasing gas and/or electricity to operate machinery and buildings, for energy losses during transport, and for congestion management and redispatch.

70. Expenses for landowner compensation, right-of-way and easement fees are the non-capitalized payments to third parties as a result of a legal process (e.g. expropriation or compensation agreement), procurement or negotiation, related to the damage, injury of land, and /or the right to use land, roads or waterways for the activities of the TSO. This includes the direct expenses for judicial assistance, court fees etc. for legal processes (terminated or non-terminated) related to the use, damage or injury of land for the activities of the TSO.

71. Expenses for taxes and levies are non-capitalized state, municipal and regional taxes, levies and public fees paid for the ownership of specific assets (e.g. property taxes, packaging), the use of specific processes (e.g. environmental levies), for investments and procurement (stamp taxes, legal fees, customs), for non-claimed value-added taxes (foreign VAT).

Expense reporting[16]

72. The total expenses reported for a given year should be equal to the expenses in the audited financial statements of the TSO for that year, excluded the expense elements as in Article 17 of this guide.

73. The TSO specifies cost elements per activity as required in the template.

74. The TSO clarifies, per activity, on other expenses.

[16] Any revenue classified in the profit & loss account in the audited financial statements as revenue should not be reported in table 3 (expenses) of the financial reporting template but in table 4 (P&L) only.

Appendix - glossary

Ancillary services
All services necessary for access to and the operation of transmission networks, distribution networks, LNG facilities, and/or storage facilities, including load balancing, blending and injection of inert gases, but not including facilities reserved exclusively for transmission system operators carrying out their functions (source: ENTSOG glossary).

CAPEX
Capital expenditure

Control center
See asset guides for the definition.

Control center expenses
The profit & loss items associated with control centers.

Day-to-day management
The activity to ensure the daily operational availability of the network, including personnel safety (instructions, training), equipment security including relay protection, operation security, cyber security, coordination with operations management of the interconnected grids, coupling and decoupling in the network and allowances to personnel/contractors acting on the live grid. This includes staffing of the control centers.

Energy expense
The profit & loss item for energy.

Expense for landowner compensation, right-of-way and easement fees;
The profit & loss item for landowner compensation, right-of-way and easement fees.

Expense for odorization
The profit &loss item for odorization.

Expense for rent/lease of main office building
The profit &loss item for the main office of the TSO.

Expense for taxes and levies;
The profit & loss item for taxes and levies.

Full-time equivalent
The number of employees on full-time schedules plus the number of employees on part-time schedules converted to a full-time basis.

Grid maintenance
The activity preserving an asset's operational status without extending its life.

Grid planning
The activity concerning planning the development of a network including individual assets.

Grid-related equipment and vehicles
Auxiliary items meant to ensure the functioning of the grid, including vehicles meant for equipment and spare-parts.

Grid-related insurance
Insurance premiums covering the network.

Grid-related telecommunications
See asset guides for the definition.
Investments in grid-related telecommunications have to be reported under the asset category ‘control centers’.

Inshore water crossing
See asset guides for the definition.

Integrated delivery station (gas only)
In case the connection point has a delivery station, there can be two situations. Either the delivery station is not an integrated part of the TSO’s network, i.e. the connection point lies directly behind a safety valve, or the delivery station is an integrated part of the TSO’s network, i.e. the connection point lies behind the delivery station (Integrated). The latter type of delivery station is referred to as an integrated delivery station.

LNG facility (gas only)
A terminal which is used for the liquefaction of natural gas or the importation, offloading, and re-gasification of LNG, and includes ancillary services and temporary storage necessary for the re-gasification process and subsequent delivery to the transmission system, but does not include any part of LNG terminals used for storage (source: ENTSOG glossary).

Long-term planning (electricity only)
The planning of the need for investment in generation and transmission and distribution capacity on a long-term basis, with a view to meeting the demand of the system for electricity and securing supplies to customers (source: ENTSO-E glossary).

Long-term planning (gas only)
The planning of supply and transport capacity of natural gas undertakings on a long-term basis with a view to meeting the demand for natural gas of the system, diversification of sources and securing supplies to customers (source: ENTSOG glossary).

Main office
The main office of the TSO (expenditure for renting/leasing the building and the underlying land).

Main office expenses
Non-capitalized expenses for renting or leasing the main office and the underlying land.

Non-grid related insurance
Insurance premiums not related to the network.

Non-grid related telecommunications
Telecommunication cost and expenses not related to the grid. This includes telecommunications for third parties for (e.g. optical fiber or mobile infrastructure) and associated costs, income and expenses which have to be reported under the activity O.

Offshore
See asset guides for the definition.

OPEX
Operational expenditure

Other expenses.
Expenses not attributable to any other expense item.

Pass-through
Monetary item for market facilitation in which expenditure equals income.

Personnel expense
Expenses for internal and external personnel, both on payroll and temporary.

Research & development
Innovative activities in developing new services or products, or improving existing services or products.

Revenue
The profit & loss items reported in the financial statements as revenue.

Storage facility (electricity only)
A facility used to capture energy produced at one time for use as electricity at a later time.

Storage facility (gas only)
A facility used for the stocking of natural gas and owned and / or operated by a natural gas undertaking, including the part of LNG facilities used for storage but excluding the portion used for production operations, and excluding facilities reserved exclusively for transmission system operators in carrying out their functions (source: ENTSOG glossary).

System operations (electricity)
Activities regarding balancing services, primary and secondary reserves, capacity management and ancillary services (disturbance reserves, voltage support).

System operations (gas)
Ancillary services and congestion management.

Transport
The transport of electricity or gas on the network with a view to its delivery to final customers or to distributors.

Usage share
See asset guides for the definition.

C. Special conditions reporting guide, 2018-09-13

CEER TSO Cost Efficiency Benchmark

Special conditions reporting guide

FINAL VERSION

13 September 2018

1. Introduction

1. This reporting guide belongs to the CEER benchmarking project and is meant to give TSOs an opportunity to signal conditions that are not taken into account by the benchmark model, but should have been. Such conditions are referred to as special conditions and may call for correction of benchmarked scope or data, or the benchmark model. The concept of special conditions evolves from the concept of so-called Z-factors in previous CEER benchmarks.

2. Defining and implementing special conditions is meant to get closer to the purpose of the benchmark, i.e. to define best practices. As all TSOs in the sample will be related to frontier companies, it is therefore important that special conditions should only be labelled as such if they stand a number of criteria. We explain these in Chapter 2.

3. Special conditions can be claimed by TSOs in a process that starts once the draft benchmark model has been presented. In Chapter 3 we describe the procedure for this.

4. The criteria set in Chapter 2 are cumulative, forming a firewall to improper claims in order to protect the hygiene of the best practice frontier, which is in the interest of all TSOs. Individual interests can only impact the benchmark if this is reasonable to all. This is why the criteria will be evaluated critically and why transparancy of claims is necessary.

5. Nevertheless, as the benchmark can be used in regulation, individual interests are of course quite relevant, think of a severe unfortunate incident in the reference year, strong political pressure on the TSO, legacy, or regulatory decisions. However, such cases boil down to interpretation of an individual benchmark score, which is a national affair between individual NRAs and TSOs, just like with implementation of benchmark results afterwards in regulatory decisions. So it is important to bear in mind that there is a cut-off point where international benchmarking stops and national interpretation and implementation starts. The benchmark model defines that point and the criteria for special conditions are instrumental to that. Note that by accepting or denying claims, CEER does not mean to interfere in national discussions, let alone regulatory decisions. CEER's only intention here is to set a proper best practice frontier.

6. Note that most claims made in previous benchmarks for so-called Z-factors that were accepted have been implemented in the data definition guides for the current benchmark and will probably be included in the current benchmark

model. Therefore, for these claims there may be little point in re-claiming these as special condition again, unless of course the current benchmark model fails to include these Z-factors adequately.

7. Claims that were denied as Z-factors in previous benchmarks can be re-claimed. However, validation of re-claims will strongly focus on new relevant information, where having a very different sample of TSOs can be new relevant information too, and will probably be relatively brief. Hence, without substantial new information, the outcome will probably be negative again.

8. Finally, in previous benchmarks a relatively small portion of claims was accepted as Z-factor. Given the above and ceteris paribus, CEER does not expect many special conditions reported or accepted in the current benchmark. Also, claiming many special conditions does not make a credible case. However, CEER does not want to rule out that special conditions exist. Hence the current procedure for claiming and validating special conditions.

2. Special conditions

9. Below we explain the (cumulative) criteria for special conditions, without suggesting an order of importance.

Complementarity

10. This criterion is meant to distinct conditions that are already sufficiently dealt with by the benchmark model from conditions that are not and may need complementary treatment. For example, if the condition can be dealt with by building additional standard assets, and if the model would "credit" TSOs for their asset base, then the condition is likely to be already taken into account sufficiently by the model.

11. Note that there can be two reasons for complementary treatment. First of all, this could be the case if the benchmark model is insufficiently specified. A typical example of complementary treatment in such case would be the change or addition of a modelling parameter. Secondly, complementary treatment may be called for if the claimed condition is something very specific that only one or few TSOs in the sample have to live with, i.e. the condition is relatively unique to the claimant.

12. With reference to Article 5, complementary treatment implies that reporting/acceptance of the condition as special fits the purpose of the benchmark.

Objectification

13. A special condition is something that, so to say, overcomes a TSO, i.e. it can reasonably not be held against the TSO and this should not be arguable.

14. Special conditions must not be defined in terms of the (subjective) strategy to deal with the condition. So a claim cannot be formulated like "we do A because of condition C", because A would only refer to a choice made by the TSO that may be up for efficiency analysis. Instead a claim should be formatted like "we are faced with condition C and dealing with it inevitably comes with a disadvantage (compared to not having C)." So, both the condition C and the unavoidability of a disadvantage must fully and inarguably be beyond control of the TSO.

15. Objectivity also implies that the condition is conceptually simple, obvious, and transparent, even to less informed public. The rationale for this is that the more reasoning is needed to explain the condition, the more subjective, hence arguable, arguments it will be based on. Note that transparency includes the

vision that it must be clear to all parties which TSO is claiming what, without of course violating data confidentiality.

Durability

16. Incidents do not qualify as special conditions, think e.g. of a flooding in a certain year. Instead, special conditions are supposed either to exist over a substantial part of the reporting period, i.e. many years, or to exist for many years in the future impacting operations in the past. There is no explicit norm for this as it may depend on the precise nature of the condition (geographical, technical, economical, etc.). At any rate, this criterion is meant to separate structural circumstances from incidents.

Materiality

17. Special conditions can only be recognized as such if they come with a well-defined and significant cost impact. Below we elaborate on this.

18. The cost impact of a special condition is defined as the minimum unavoidable cost to deal with the condition. This is what is seen as the value of the claim. Put differently, the value of the claim is the cost difference between the lowest cost alternative to deal with the condition (this is not per se the alternative that is actually implemented) and the cost that would have been made if the condition would not exist. The value of the claim may be an estimate as it is at least partly based on counter factual information. Note that the value of the claim can be zero if there is an alternative to deal with the condition without additional cost (claims of that kind do not have to be reported.)

19. Hence, the cost impact of a special condition must be clearly quantifiable. If quantification is ambiguous or poorly documented, it will be difficult to correct in the benchmark for the condition. Moreover, it would signal that the condition does not have (had) the explicit attention of management as such, which makes the condition being a special one less credible.

20. Also, the (monetary) value of the claim must be significant, i.e. it must be big enough to significantly impact the outcome of the benchmark. A soft norm for this is about 5 percent of the benchmarked gross investment stream of the claimant or, if the claim is about expenses only, about 5 percent of its benchmarked expenses. With “benchmarked” we refer to the activities in scope of the (draft) benchmark. Significance is important to avoid erosion of the best practice frontier by relatively small peculiarities of which all TSOs will have some, some fortunately, some unfortunately.

3. Guidelines for submitting claims

21. Any TSO that, after having taken notice of this guide and the draft benchmark model, believes or suspects that the model does not take some condition (properly) into account, can make this clear by submitting a claim for a special condition.

22. With draft benchmark model we refer to the following elements:
    a) Scope of the benchmark model.
    b) Selected output parameter candidates.
    c) Control parameters, like the rate of return, scaling assumptions, indexations, or environmental factors.

23. A claim will be taken into consideration if it contains the following information:
    a) A brief description of the condition, ref. Article 14.
    b) Whether or not the claim has been claimed before in a Z-factor process and if so, why the claimant thinks he has substantial new information, ref Article 7.
    c) A motivation why the condition should lead to complementary treatment by the benchmark model, ref. Articles 10-12.
    d) A motivation why and how the condition is objectifiable, ref. Articles 13-15.
    e) A motivation why the condition is structural, ref. Article 16.
    f) A motivation why the condition is material, ref. Articles 17-20.

24. There is no template document for a claim, but the format of it should be consistent with Article 23. Motivations and quantification include all relevant documentation and/or other evidence.

25. A claim can be submitted by uploading the following documents to the private TSO folder of the project platform:
    a) The information under Article 23, items a-e, put together in a single document that is readily publishable to other TSOs and NRAs.
    b) Any supporting material, to which reference is made in the document meant under (a) of this article. This material must also be readily publishable to other TSOs and NRAs.
    c) The information under Article 23, item f, including supporting material. This information will not be published, except for percentage(s) stating the materiality like meant in Article 20.

26. Although the whole procedure is designed and meant to process claims from TSOs, the procedure is also open to NRAs in a similar way.

D. Method to treat upgrading, refurbishing and rehabilitation of assets in TCB18

Method to treat upgrading, refurbishing and rehabilitation of assets in TCB18

Background

In the benchmarking CAPEX is calculated as real annuities from full investments, valid for the duration of a standardized techno-economic lifetime across operators. Investments in the CAPEX correspond to assets reflected in the normalized grid. However, TSOs may also undertake partial investments during the life of an asset, e.g. upgrades or rehabilitation, that require specific attention.

In e2GAS TSOs report investment values per asset type and also possible upgraded investments by type, as described in Call C art 5.34-5.36 and in the template as described in Call C 7.09-7.10. In e3GRID the asset upgrades were processed by asset investment year and year of refurbishing, requiring information about age, intial investment and upgrading cost. Upgradings, refurbishing and rehabilitation are examples of partial investment

Types of partial investments

A TSO may undertake three types of partial investments, where part of the initial asset is retained in the new installation:

(i) Investment to change the dimension, power or other output features of the installation, e.g. an increase of the crossection on an existing overhead line or a change of compressor pumps to offer a higher power. We call this 'upgrading' in this note.
(ii) Investment to replace component(s) in order to achieve effects that are desirable but not counted as system outputs. E.g. retrofitting access protection or telecommunication antennas in towers. We call this 'refurbishing' in this note.
(iii) Investment to replace outdated or worn-out component in a system while keeping the residual components and not changing the output features of the installation. E.g., replacing the transmission lines while keeping the towers or replacing all control equipment in a station to permit interoperability and improved control. We call this 'rehabilitation' in this note.

The investments of type (i) are to be treated as normal investments where the original asset is removed from the asset database (X) and the new asset is added to the database (X) with the year of commissioning stated. The full value of the investment is kept in the investment stream, both for the initial and secondary investment.

The investments of type (ii) are not specifically addressed in the benchmarking, the associated cost is either OPEX (maintenance) or CAPEX (kept in normal investments, no change of asset description in X). To the extent that such upgrades would concern significant amounts and be triggered by regulatory imposition, this could be addressed as TSO specific elements in the benchmark.

Minor investments of type (iii) are part of normal maintenance; replacing worn-out components. These are kept in OPEX and trigger no change of the asset description in Call X.

Large investments of type (iii), see the threshold for that below, can be considered as 'significant rehabilitation' of an installation; a station or a line segment. Since no output data is changed, the investment would lead to a lowered CAPEX-efficiency if no adjustment is made. Although significant rehabilitations may have multiple objectives, intentionally these investments will be compensated for through a mechanism that considers it as resetting the age of the rehabilitated asset to zero.

Considerations

In defining a method for acknowledging significant rehabilitation of assets, attention should be paid to the tradeoff between the added complexity in reporting (for all) compared to the attained precision (for some TSOs) as well as the robustness to missing or unverifiable historial investment values for old assets.

To avoid a double system, introducing a strategic choice for operators, a simple approximation of the underlying asset value for the rehabilitated asset should be used.

Principle

An asset that is rehabilitated lowers the overall cost for the asset through spreading the real capex over a longer period.

Example:

- an asset with a standard techno-economic lifetime of 60 years is installed at an investment of 200 in year 0 in Figure 1 below. The capex annuity factor for this corresponds to about 2.87% per year with a real interest rate of 2%. Thus, the CAPEX for this item is 5.75 (2.87% of 200) per year until year 60 (red curve in Figure 1).
- Without other action, the asset is expected to die in year 60 at which time a new full investment of 200 (real) is necessary to replace the asset. Hence, the expected real annuity is 5.75 per year for as long as the system is in use.
- In year 35 the asset is subject to a significant rehabilitation at an additional real investment of 50. The asset state is restored as new and this implies that the economic life is prolonged to 35 + 60 = 95 years. The capex annuity factor corresponding to the incremental investment for this significant rehabilitation is 2.87% per year for the period 35 - 95, leading to an additional annuity of 1.44 (2.87 % of 50).
- In real terms, the underlying original investment still has to amortize 25/60 * 200 = 83.3. This is done over the period from year 35 to year 95 (60 years), hence, an annuity of 2.40 (2.87% of 83). So, effectively the CAPEX for the underlying investment is lowered from 5.75 to 2.40 for extended period 35-95.
- In total, the real CAPEX for this intervention is 3.84 (2.40 + 1.44) per year from 35 to 95, as shown by the blue curve in Figure 1.

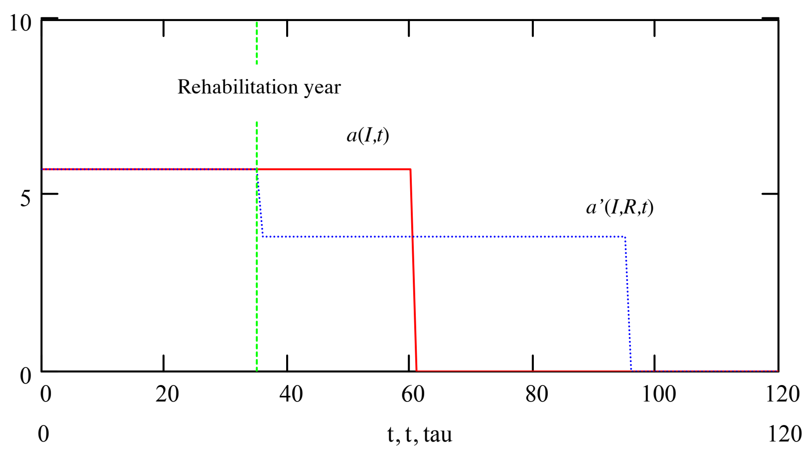

Figure 1 Annuities for example, significant rehabilitation in year 35.

Implementation

Consider in year t the choice of rehabilitating an asset invested at I € in year t_0 for R €, extending its life to T years.

In practice, the TSO may not be able to identify the specific investment I, either because it is part of a larger system (e.g. substation) or because it has been acquired at a bookvalue that has been modified through acquisitions, revaluations and other accounting operations.

To implement the method above, we may estimate the initial real investment value by using the normgrid share of the assets as key. Thus, in the initial investment year t_0 the specific intial investment corresponds to a normgrid value of g and the normgrid sum of all assets commissioned in that year is G and the real initial investment is given as IT, then the estimate of I is obtained as

$$I = \frac{g}{G} IT$$

since the normgrid metric is timeinvariant and IT is given in real terms.

The method above was implemented in e3GRID where assets are identified by year of investment. In e2GAS investment values were stated per year, but the individual assets had no age. Thus, the incumbent age of the underlying assets cannot be identified.

The real annuity a of initial investment I for a real interest rate of $r > 0$ is obtained as

$$a = I \cdot \left(\frac{r}{(1-(1+r)^{-T})}\right)$$

Investing R in a significant rehabilitation will increase the overall life to T+t-t_0 years for the underlying asset. The remaining (real) asset value is $I(T-(t-t_0))/T$. The new annuity for the rehabilitated asset (including both the old and new investments) is obtained as:

$$a' = \left(R + I \cdot \left(\frac{T-(t-t_0)}{T}\right)\right)\left(\frac{r}{(1-(1+r)^{-T})}\right)$$

Note that if the underlying asset has reached or is past its techno-economic life (i.e when $t \geq T + t_0$), the annuity is just equal to the rehabilitation investment as the initial investment is fully amortized.

Of course, the profitability of a significant rehabilitation depends its timing and magnitude. As illustrated in Figure 2 below for the same investment values as in the example above, a significant rehabilitation occurring already in year 10 would have a negative impact on CAPEX whereas a postponement of the rehabilitation to year 50 would have an additional positive effect.

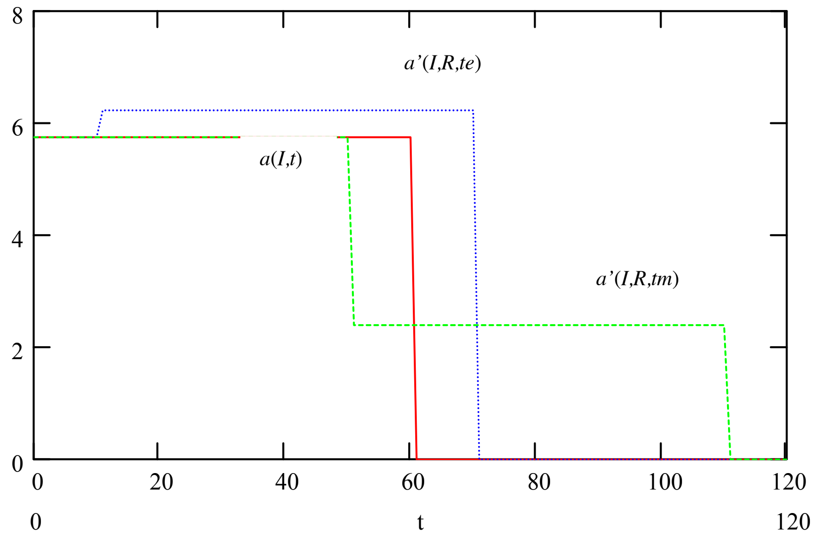

Figure 2 Example annuities for a (too) early (blue, t_e) and a very late (green, t_m) significant rehabilitation compared to base case (red).

Data requirements

The advantage of the proposed system is that incremental investments can be valued in the benchmarking without complex calculations. The following data are necessary:

(i) Aggregate investment value (nominal) per year, IT
(ii) Rehabilitation investment per asset category and year, *R*
(iii) Asset data for each rehabilitated asset, *g*
(iv) Commissioning year for each rehabilitated asset, t_0

For validation purposes the following date may also be desirable to have:

(v) Short description of the significant rehabilition per concerned asset

The limitations are that the underlying asset must still be identified by year of commissioning and the investments this year should correspond to the assets commissioned. As resort, a correction procedure with identification of the asset might be implemented.

Threshold

To distinguish normal maintenance from significant rehabilitation we propose that the incremental investment *R* should be at least 25% of the (real) underlying investment value, *I*.

E. Modelling opening balances and missing initial investments, 2018-01-11

Modelling opening balances and missing initial investments

Background

In a heavy infrastructure industry like the transmission of electricity, the efficiency of investments plays a very significant role in the overall evaluation of Totex efficiency.

This note explains how we can

a) make alternative measures that are less sensitive to historical capex efficiency and
b) analyze the sensitivity to opening balance adjustments.

We will explain how the investment streams shall be adjusted to accommodate such issues. The adjusted capital investment streams are used in the unit costs and DEA based models in the same way as the basic investment streams.

Problem analysis

The Capex measurement for benchmarking is repercussions on two relevant issues for benchmarking; incentive provision and structural comparability.

From the point of view of *incentive provision*, it is not obvious that the efficiency of historical investments shall continue to impair or benefit present management. It may be useful in some cases to forgive past investment inefficiencies in the overall evaluations, i.e. to consider investments before a given day as sunk cost that shall not influence today's efficiency. In particular, performance related to actions before deregulation or beyond the scope of managerial authority is less effective to provide incentives for current management.

A second problem relates to the benchmarking of, and towards, units with reestablished opening asset balances. In practice, this refers to TSO unable to produce historical investment streams due to late unbundling, reevaluation of assets, or that historical investment streams contain (fully depreciated) assets that are currently owned by other firms (distribution or generation). The investment stream for such firms therefore starts with a large opening balance investment followed by annual additions to the asset base.

A concern can be that the opening balances may be influenced by other than managerial factors, such as legal, political, regulatory and macro- economic factors prevailing at the time of the unbundling. If the opening balance is relatively low, the TSO may effectively be forgiven past investment inefficiency and if it is set relatively high, e.g. to pave the pay for capital cost reimbursement in a regulatory scheme, past efficiencies may be undermined.

Such phenomena are not necessarily a problem for the TSO itself. After all, we do not try to explain in details why some TSOs are more efficient than others, eg. due to careful planning and execution of the installation process, due to successful negotiations with asset providers, or due to market power in the acquisition of networks from previous owners. The opening balance might therefore reflect managerial skills.

On the other hand, the benchmarking should assure *structural comparability* among firms in the reference set. In particular, it should be possible to achieve the performance of TSOs designated as fully efficient peers without replicating exogenous and country-specific (political, fiscal) actions potentially involved in the establishment of an artificially low opening balance. The benchmarking should also be fair in the sense that units reporting a full historical investment stream should not be worse off than those merely reporting an opening balance.

Capex

Consider an investment stream I_t, $t = 0,\ldots, T$ for a given TSO (we suppress subscripts for TSO to simplify the notation). The investment in a specific year t concerns assets with a techno-economic lifetime of τ_t years. In the evaluations, the investment stream is transformed into a standardized constant annuity as follows

$$CAPEX = \sum_{t=0}^{T} \mathrm{I}_t^* \alpha(r, \tau_t)$$

where α is the annuity factor that spreads an investment as a constant cost over τ_t years when the interest rate is r, and I^* is the investment level we assign to year t. The difference between I_t and I_t^* is that the latter is transformed to EUR for a given reference year.

The capital investment corresponds to a technical asset base, the normalized grid unit, measured as

$$NormGrid_{CAPEX} = \sum_t \sum_a n_{at} v_{at} \alpha\,(r, T_{g(a)})$$

where n_{at} is the number of assets of type a installed in year t, v is the capex weight such an asset and $g(a)$ is the asset group that asset a belongs to (since we allow different techno-economic depreciation horizons for different asset groups). The normgrid can be seen as a sum of equivalent assets, e.g if v = 1 for 1 circuitkm overhead line of 300 kV at 500 mm^2 crossection, then v = 1.44 for 1 circuitkm overhead line of 300 kV at 900 mm^2 would mean that 144 circuit km of (300 kV, 500 mm^2) would correspond to an asset base equivalent to 100 circuit km of (300 kV, 900 mm^2). In the same manner, all assets can be summed to an equivalent measure of the size of the asset based, the normalized grid. As such, the normgrid is unitless, but it is usually calibration to average cost in a given reference year, thus NormGrid can be given an interpretation as average cost for a grid (capex or opex).

The capital investment efficiency is in general evaluated by considering CAPEX as an input that generates the output NormGrid_CAPEX. The Capex Unit Cost for example is simply the ratio of the two, i.e.

$$UC_{CAPEX} = \frac{CAPEX}{NormGrid_{CAPEX}} = \frac{\sum_t I_t^* \alpha(r, \tau_t)}{\sum_t \sum_a n_{at} v_{at} \alpha(r, T_{g(a)})}$$

Of course, the unit cost measure can be used as a single-dimensional (investment) efficiency measure in itself. The unit with the lowest UC would then be the most (investment) efficient, meaning that the Capex per equivalent grid unit is the lowest. An average TSO would have a unit cost of 1 with the standard calibration.

Opening balance adjustments

Consider a TSO where the investment stream is missing for all years before H. In year H, the TSO acquired an existing asset base for a (real) value of R.

As discussed above, this opening balance could be artificially *low* if the incumbent accepts a settlement below the (real) techno-economic depreciated value. This gives the TSO an idiosyncratic cost advantage that other operators cannot replicate with managerial action. If R is a large proportion of the CAPEX of the operator, the impact on the efficiency assessment may be important, potentially making the firm a peer for other firms. Since an efficiency target should be feasible, the Capex of a peer-firm with a biased opening balance must be corrected to protect the frontier.

A second possibility is that the operator has been forced to pay too much for the assets, i.e. an *R* that is above the average depreciated techno-economic value. This may occur in unbundling if the incumbent seeks an advantage in terms of capital structure. In this case, the operator is most likely inefficient and the frontier is unharmed. However, it is in the interest of the operator to obtain an estimate of the managerial efficiency obtained – excluding the idiosyncratic cost shock caused by the opening balance.

In both cases, we can obtain such estimate by calculating an estimate of the opening balance value *R** as if it was proportional to the unit-cost investment efficiency during the succeeding period, when the managerial action of the TSO has had influence over the outcome.

The Capex Break Method

Consider a TSO with an opening balance from year *H* at real value *R*. Since we know the composition of the asset base at the opening balance, the annuity for *R* can be obtained using an asset-weighted average techno-economic lifetime;

$$\mathrm{T}^* = \frac{\sum_a v_a n_a T_{g(a)}}{\sum_a v_a n_a}$$

The annuity then is given as:

$$Capex_R = R\alpha(r, T^*)$$

Let the NormGrid Capex for the assets acquired (after adjustments of age) for the period 0 to *H* be denoted *NG*(0,*H*)

The Capex Unit Cost for year *H* then becomes:

$$UC_{Capex}(0,H) = \frac{Capex\_R}{NG(0,H)}$$

We also have observed investment data for the period *H*+1, …, *T*. The average Capex Unit Cost for this period is calculated as:

$$EUC_{Capex}(H+1,T) = \frac{\sum_{t=H+1}^{T} \alpha(r,\tau_t)}{\sum_{t=H+1}^{T} \sum_a n_{at} v_{at} \alpha(r, T_{g(a)})}$$

Assume that the two unit cost measures are significantly different. Then a correction, the *capex break*, can be obtained by using the average investment unit cost also for the opening balance.

The Capex Break value is then calculated through:

$$Capex_{break} = EUC_{capex}(H+1,T)NG(0,H) + \sum_{t=H+1}^{T} I_t^* \alpha(r, T_t)$$

The idea of this adjustment is simple – if the TSO in the periods after H tends to be efficient and only spend 80% of the expected costs on its installations, we assume that this was the case prior to the opening balance also, and we use the asset register to reconstruct a likely historical investment stream. Hence, the logic behind the correction is based on the assumption that the investment behavior after the unbundling is the best indication of the managerial behavior prior to the unbundling.

Specific cases

The information situation prior to the opening balance may be different, leading to three solutions for the capex break calculation:

1. Commissioning years available for all assets in operation at time H
2. Average age available per asset group in operation at year H
3. Average age available for the entire asset based acquired at year H
4. No information exists on the age or state of the assets acquired before H

In case (1) the formulae above can be fully calculated.

In case (2) the formulae can also be used with minor modification without loss of precision.

In case (3) the initial NormGrid will have to use an average lifetime without any differentiation.

In case (4) the default estimate will be based on acquisition at full remaining lifelength at year H.

Application

For TSO without opening balance:	No application
For TSO with opening balance, peer:	Application in the reference set, not for the unit itself.
For TSO with opening balance, non-peer:	No application in the reference set, application in specific report.

As mentioned, the principle of application is to protect the frontier from peers that are characterized by non-replicable idiosyncratic cost-biases that render the overall cost targets and scores underestimated.

F. Norm Grid Development Technical Report, 2019-02-27 V1.3

Norm Grid Development

TCB18 PROJECT

TECHNICAL REPORT

2019-02-27 / ver V1.3

Disclaimer

This technical report describes methods and parameters used in the CEER TCB18 project.

This document may be updated and made available at Worksmart for project participants.

Norm Grid Development

Technical report, project release, version V1.3.

Project TCB18 / 370.

Release date: February 22, 2019

Version history

Version	Date	Status	Auth	Concerns
X1.0	2018-09-10	Draft	JT,JD	Prerelease for PSG PW3
X2.0	2018-09-21	Draft	PA	Second release for PSG
V1.0	2018-09-27	Final	PA	PSG review, release for W3
V1.1	2018-10-03	Rev	JD	Corrections to Elec part
V1.2	2018-11-13	Rev	JD,JT	Opex 4.1 – 4.7, new sections 2.9+2.12 Opex gas
V1.3	2019-02-21	Rev	JD	Red marks in 4.5, 4.4, 4.6, 4.7, 4.9.1, 4.9.2, 4.9.4

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1 The Norm Grid in Benchmarking

Prof. Per J. AGRELL and Prof. Peter BOGETOFT

1.1 Background

The modelling of transmission system performance necessitates a proxy measure for the size of the grid system. A simple counting of the assets (e.g. km of overhead lines or pipelines) would ignore differences in the cost of building and operating assets of different dimensions, leading to an underestimation of the size for those with assets larger or more powerful than the average operator. Thus, the proxy should be detailed enough to address the relevant scope of different asset types per energy. On the other hand, the proxy cannot be built to correspond to a specific brand or instance of assets or locations, as in a detailed catalogue model. The tradeoff between these two objectives: inclusion of relevant assets and dimensions, but aggregation across suppliers and specific installations, has been the study of benchmarking projects ever since ECOM+ in 2005 and subsequent projects for electricity and gas.

The construction of the proxy measure, the normalized grid (NormGrid) is based on relative ratios for capital and operating expenditure per asset type. In addition, environmental conditions must be taken into consideration when estimating the overall comparable size of the grid asset base.

This technical report describes

a) The construction of the norm grid measure in gas transmission,
b) The proposed environmental factors for gas transmission,
c) The construction of the norm grid measure in electricity transmission,
d) The proposed environmental factors for electricity transmission,

Care has been taken in the project management to provide a robust development process that can be repeated and adjusted for future use, as well as procedural transparency to promote cross-validation of system components by project participants.

1.2 NormGrid structure

In the method note TCB18 2018-01-11 "*Modelling opening balances and missing initial investments*" the normalized grid (NormGrid) is defined as a weighted sum of grid assets such as

$$NormGrid_{CAPEX} = \sum_t \sum_a n_{at} v_{at} \alpha\,(r, T_{g(a)})$$

where n_{at} is the number of assets of type *a* installed in year *t*, *v* is the capex weight such an asset and *g*(*a*) is the asset group that asset *a* belongs to (since we allow different techno-economic depreciation horizons for different asset groups). The NormGrid can be seen as a sum of equivalent assets, e.g if $v = 1$ for 1 circuitkm overhead line of 300 kV at 500 mm^2 crossection, then $v = 1.44$ for 1 circuitkm overhead line of 300 kV at 900 mm^2 would mean that 144 circuit km of (300 kV, 500 mm^2) would correspond to an asset base equivalent to 100 circuit km of (300 kV, 900 mm^2). In the same manner, all assets can be summed to an equivalent measure of the size of the asset based, the normalized grid. As such, the NormGrid is unitless, but it is usually calibrated to average cost in a given reference year, thus NormGrid can be given an interpretation as average cost for a grid (capex or opex).

The NormGrid structure is a greenfield system without any specific adjustments for environmental conditions, ageing or integration with non-grid systems (existing infrastructure; corridors, waterways).

The development of the NormGrid asset weights in electricity was based on systematic work in several international projects (ECOM+, e3GRID 2009, 2012) primarily by Sumicsid and CONSENTEC. As no public complete sources exist for these cross-asset comparisons, the initial work compiled different public and private sources used by operators and contractors in grid system planning. The current revision is reviewing the entire system by comparing the reference values, the functional form (linear/non-linear) and the optimal scale variables (voltage, crossection area, power, et c.).

For gas transmission, the seminal work in estimation was made by Sumicsid in the e2GAS project where a complete assessment was made of both greenfield and individual complexity factors by asset type. As for electricity, the work here involves consolidation of public and private sources used in planning and international assessments.

The calibration of the asset weight systems is made through linear regression towards the Capex and Opex data obtained in the project. This step scales the relative NormGrid metric towards average practice (not best practice) such that the relevant cost measures are attributed to the size proxy. Naturally, this means that the scope for both Capex and Opex are defined exactly as in the study.

1.2.1 Use of NormGrid in benchmarking

The NormGrid proxy can be used in several ways in assessing the performance of transmission system operators.

As an *output* the NormGrid represents the grid provision (complementary to flow or peak-related capacity utilization metrics) independent of the dynamic use of the grid. The underlying assumption for this approach is that any and all grid assets are providing some utility for grid users.

As an *input* the NormGrid be used as a proxy for capital expenditure, a cost that should be minimized for each level of exogenous output (typically flow, service and peakload measures). In this approach, serving grid users with a smaller or weaker grid for the same energy and capacity provision is seen as efficient.

In TCB18, the policy adopted by the NRAs is to promote past grid provision, quality provision and grid expansion investments. Hence, the intended use of NormGrid in this project is to form part of the outputs for the TSOs.

1.2.2 Validation of NormGrid

The validity of a proposed NormGrid parametrization can be tested in partial detail and as goodness of fit. A partial test could be to challenge the progression factors e.g. in voltage across transformers of a particular type by using data from tenders or installations with sufficient specifications. This might lead to corrections, if the data are more representative than the data used in the estimation. A goodness of fit analysis is testing the overall power of the NormGrid to explain Capex and/or Opex across real validated data for the operators, across time. The latter test is more important as the average effects prevail in the evaluation of TSOs, rather than detailed ratios that may point at particular installations that only form a minor part of the overall asset base.

1.2.3 Documentation for participants

The documentation for the NormGrid base weight system will consist in the following deliverables to project participants:

1. A note for the respective NormGrid system from the ELEC and GAS teams, respectively, including the principles of construction, the main sources, the points of possible revisions from earlier versions and some examples of the partial cost functions used.
2. Excel calculators for all relevant assets
3. Regression results for the goodness of fit of the specific NormGrid system towards Totex, Capex and Opex with the scope defined in the study, both standard and robust regression.

This report constitutes part (1) of the documentation and will be presented at W3. The final weight system including documentation (2) and (3) will be uploaded on Worksmart in the Common sections two or three weeks prior to W5.

1.2.4 Crossvalidation: NormGrid

The NormGrid system will be ready-to-use and released after tests and validation at levels at least corresponding to those in the previous projects e3GRID 2012 and e2GAS.

1.3 Environmental factors

It was decided in the TCB18 study to deploy an exogenous system where open sources are used to estimate environmental effects to prepare for long-term future use. The selection of factors for study is made by the engineering teams and is documented in this report.

The engineering teams (ELEC and GAS) initially screen and validate the eligible public factors that may have a techno-economic impact on the cost. These and only these factors are subject to econometric validation. A pure “data mining” approach might suggest country-specific factors (e.g. “language”) without causality on cost, but fully capturing all country-specific residuals as “environmental”. Naturally, this is of no relevance in this study, thereof the prior selection of candidate variables that technically can be claimed to have an impact.

1.3.1 Documentation and process

The documentation for the environmental factors will consist in the following deliverables to project participants:

1. A note from the engineering teams listing the sources and the candidate variables with full definition and their hypothesized cost impact on totex, capex and/or opex.

2. Estimation results from the econometric team for the candidate variables individually, as well as the retained factors with their numerical estimates and possible intervals of uncertainty,
3. Excel sheets with numerical factors per area or operator

This report contains part (1) of the documentation above for discussion at W3. Input from project participants may lead to the collection of additional or alternative factors, if relevant. The final environmental system including documentation (2) and (3) will be uploaded on Worksmart in the Common sections two or three weeks prior to W5.

Participants will be able to access the numerical values for the factors used for all other participants from the open sources used. In the case a TSO would find that a relevant open factor or source has been neglected or eliminated incorrectly, a request for completion or correction may be filed. In case of changes to the environmental factors, the deliverables (2) and (3) will be updated accordingly by the release of the final coefficients

2 Cost modelling GAS

Technical team GAS, headed by Jacques TALARMIN

Head of the gas system team, Jacques TALARMIN in Sumicsid has an double engineering degree from the University of Bretagne. After four years as a research engineer in CNRS, Mr. TALARMIN has been active over 33 years in gas transmission pipeline engineering, as Head of the Gas Transmission Pipeline Department, then as international expert for the World Bank, IEC and PENSPEN. He has made techno-economic evaluations of large scale gas transmission, LNG and gas storage projects in Belgium, France, Ireland, Italy, Norway, Portugal, Spain, Armenia, the Ivory Coast, Kazakhstan, Kuwait, (South Stream underwater), Bangladesh, Tunisia, Morocco, Iraq, Iran, Cameroon, Algeria, Turkey, Georgia, Jordan, Libya, Myanmar, et al. Ing. TALARMIN has been involved in Sumicsid projects for gas transmission including RAMIEL (Fluxys, BE), PE2GAS (CEER, 2014), E2GAS (2015-16), in the latter responsible for the development of the grid asset system.

The norm grid proxy for gas transmission assets is designed to be proportional to the construction costs of gas transmission pipelines.

After detailing the various expenses involved in the realization of a gas pipeline, in particular, the following cost items:

- Cost of material supply;
- Cost of pipeline installation and commissioning;
- Cost of miscellaneous works (project management, engineering, surveys, work supervision, etc.);
- Cost of damage during installation and operation
- In-line stations costs;

In the following, each of the categories are discussed to form the full cost function.

Besides some general sources (Page, 1977) there are very few published papers providing full cost functions for gas transmission assets under the TCB18 definitions. The analysis below is therefore based on our experience and proprietary data from numerous gas transmission projects and from valuation projects of transmission assets internationally. However, to demonstrate the face validity of our cost model, prior to and independent of the TCB18 data analysis, we include a quantitative analysis of a recent public study, ACER (2015) involving the operators in the TCB18 project.

2.1 Cost of material supply

2.1.1 Linepipes

The linepipe manufacturing process has been selected on the following base (see Figure 2-1):

- Seamless linepipes for D ≤ 4"1/2;
- 50 % High Frequency Welded (HFW) pipes and 50 % Longitudinally Submerged Arc Welded (LSAW) and Helical Submerged Arc Welded (HSAW) pipes for 6"5/8 ≤ D ≤ 24";
- 50 % LSAW pipes and HSAW pipes for 26" ≤ D ≤ 56".

D being the pipeline diameter generally expressed in inch (").

The average linepipes unit costs are as follows:

- 1300 €/t for seamless pipes;
- 800 €/t for high frequency induction (HFI) pipes;
- 1200 €/t for LSAW pipes;
- 1000 €/t for PSSAW pipes.

In the cost estimation of pipes, we will assume the average distribution of the following class locations:

For the pipes of diameter less than or equal to 16 "(ND 400):

- Rural areas :25%;
- Suburban areas: 50%;
- Urban areas: 25%.

For the pipes of diameter larger than or equal to 18 "(ND 450):

- Rural areas: 80%;
- Suburban areas: 10%;
- Urban areas: 10%.

It should be noted that the distribution of class locations indicated above is not strictly related to the external environment of the pipeline for small diameters.

Linepipes wall thicknesses have been calculated according to a MAOP of 71 bar(a) (70 bar(g)). Wall thicknesses distribution are shown in Figure 2-1.

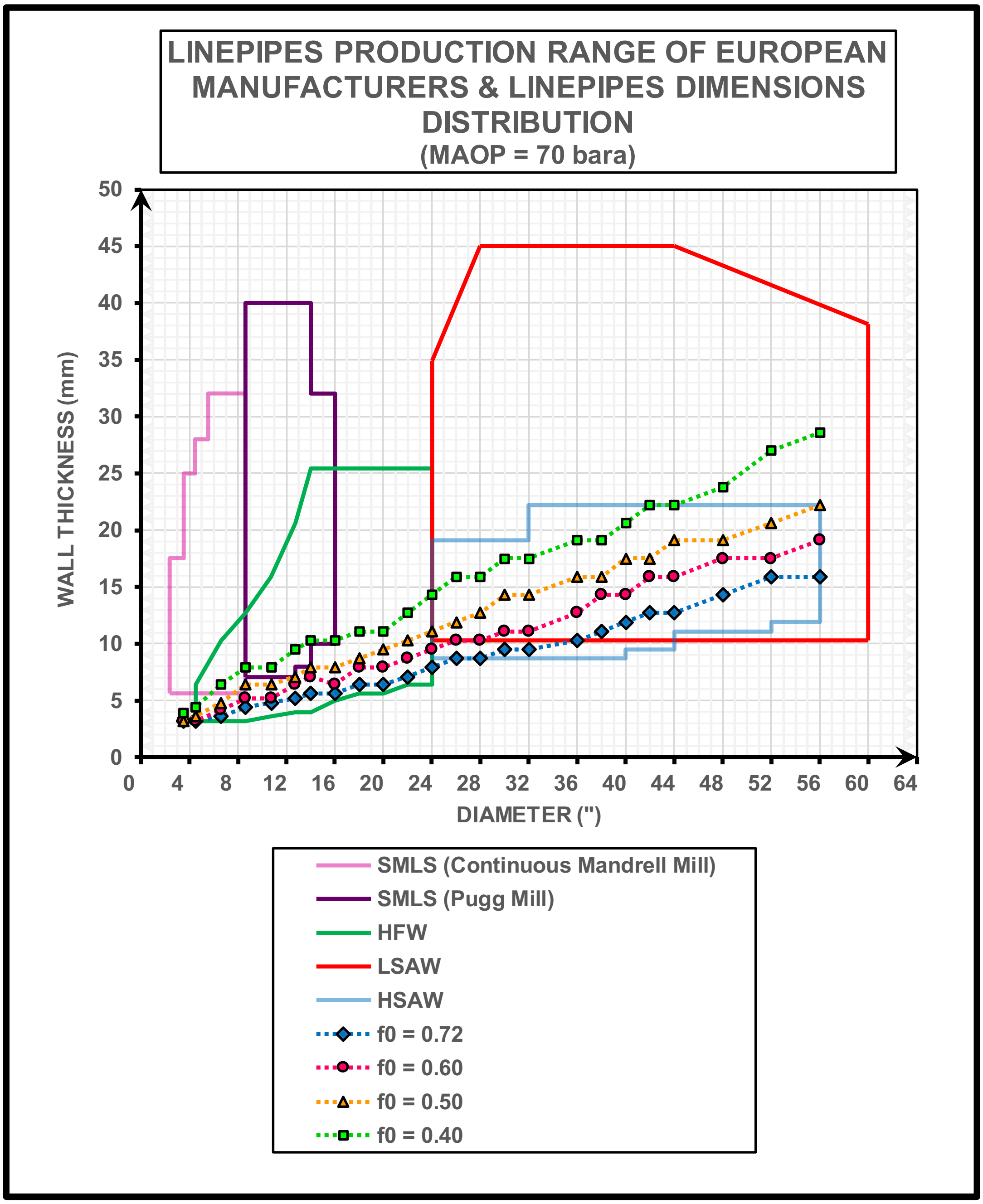
LINEPIPES PRODUCTION RANGE OF EUROPEAN MANUFACTURERS & LINEPIPES DIMENSIONS DISTRIBUTION
(MAOP = 70 bara)
WALL THICKNESS (mm)
0
5
10
15
20
25
30
35
40
45
50
0 4 8 12 16 20 24 28 32 36 40 44 48 52 56 60 64
DIAMETER (")
SMLS (Continuous Mandrell Mill)
SMLS (Pugg Mill)
HFW
LSAW
HSAW
f0 = 0.72
f0 = 0.60
f0 = 0.50
f0 = 0.40

Figure 2-1

2.1.2 Linepipe coating

2.1.2.1 External coating

Unit costs of external coating (3LPE) are ranged from 17 €/m^2 to 25 €/m^2 according to coating thickness which increases with the pipeline diameter.

2.1.2.2 Internal coating

It has been considered that the lining (which is intended to improve the flow of gas) is applied only for diameters equal to or greater than 16 ".

The average unit cost is estimated to 10 € / m2.

2.1.3 Miscellaneous supplies

Miscellaneous supplies (manufactured bends for example) are included in the supply cost and valued at 3% of the total linepipe cost.

2.1.4 Transport to site, unloading and storage

This cost is about 12/% of the supply cost.

2.2 Pipeline installation cost

The cost of pipeline installation, valued at 12.5 €/"/m, corresponds to a typical installation (not ideal or minimal cost). These costs include the crossing of special points (major crossings).

2.3 Miscellaneous costs

The miscellaneous costs, estimated at around 5 €/"/m, correspond to project management, surveys, engineering, supervision of construction work, owner expenses, and planning. These costs have been steadily increasing since the beginning of the 1990s mainly because of environmental and administrative constraints to obtain authorization to construct and operate the pipeline.

2.4 Damages costs

The costs related to the instruction and payment of direct damages caused during pipeline installation have been estimated at an average value of 1.2 €/"/ m. These cost exclude the capital costs of land and right-of-way, excluded from the TCB18 benchmarked capex.

2.5 In-line stations

The in-line stations are not considered separate assets, but parts of the pipeline system. The unit costs for sectionalizing valve stations (block valve stations) have been valued as shown below in Table 2-1 below.

Table 2-1

SECTIONALZING VALVE STATIONS				
Diameter			Cost	
"	mm	ND	€	€/"
3 1/2	88.9	80	96 098	27 457
4 1/2	114.3	100	104 481	23 218
6 5/8	168.3	150	112 489	16 979
8 5/8	219.1	200	142 204	16 487
10 3/4	273.1	250	154 404	14 363
12 3/4	323.9	300	167 727	13 155
14	355.6	350	205 437	14 674
16	406.4	400	240 856	15 053
18	457.2	450	257 997	14 333
20	508.0	500	304 477	15 224
22	558.8	550	327 329	14 879
24	609.6	600	347 891	14 495
26	660.4	650	384 844	14 802
28	711.2	700	419 888	14 996
30	762.0	750	454 551	15 152
32	812.8	800	503 655	15 739
36	914.4	900	551 635	15 323
38	965.2	950	583 106	15 345
40	1 016.0	1 000	614 882	15 372
42	1 066.8	1 050	646 880	15 402
44	1 117.6	1 100	676 595	15 377
48	1 219.2	1 200	738 308	15 381
52	1 320.8	1 300	801 554	15 415
56	1 422.4	1 400	860 984	15 375

The cost of pig trap stations (one launcher and one receiver) is obtained by multiplying the cost of sectioning stations in Table 2-1 by a coefficient of 3.5.

The cost of cathodic protection stations and corresponding on-line control equipment has been estimated by multiplying the cost of sectionalizing valve stations by a factor of 0.4.

The following assumptions have been made for the distribution of these in-line stations along the pipeline route:

- 1 sectionalizing valve station installed every 20 km;
- 1 pig launcher and 1 pig receiver installed every 100 km;
- 1 Cathodic Protection Station installed in half of the sectionalizing valve stations perimeter, i.e : approximately one station every 40 km. The cost of cathodic protection therefore represents approximately 0.5% of the total construction price of the gas pipeline.

The average total cost of in-line stations (including Cathodic Protection stations) is in the range of 1.2 to 1.4 €/"/m.

2.6 Pipeline total construction cost

Based on the elements above, we can now derive the total construction cost (€/km) of a gas pipeline is shown in Figure 2-2 below as a quadratic function of the pipeline diameter D (")

- Pipeline Construction Cost (€/km) = 420.3693 D^2 (") + 12,126.1250 D (") + 100,432.6361 (1)

If we consider the variation of unit cost expressed in €/"/m, we can see that this cost decreases rapidly for small diameters from nearly 50 €/"/m, then goes through a minimum of about 25 €/"/m for a diameter of 12 "3/4 before increasing almost linearly to reach nearly 38 €/"/m for a diameter of 56".

The average unit cost of construction of the line is of the order of 29.8 €/"/m.

This cost includes in-line stations with an average unit cost of around 1.3 €/"/m, so the overall cost of the line without in-line stations is about 28.5 €/"/m.

The relative importance of the different pipeline construction cost items is as follows:

- Materials supply 32.6 %
- Pipeline Installation 41.5 %
- Miscellaneous works 16.6 %
- Right-Of-Way 4.2 %
- Inline stations 5.1 %
- Total 100.0 %.

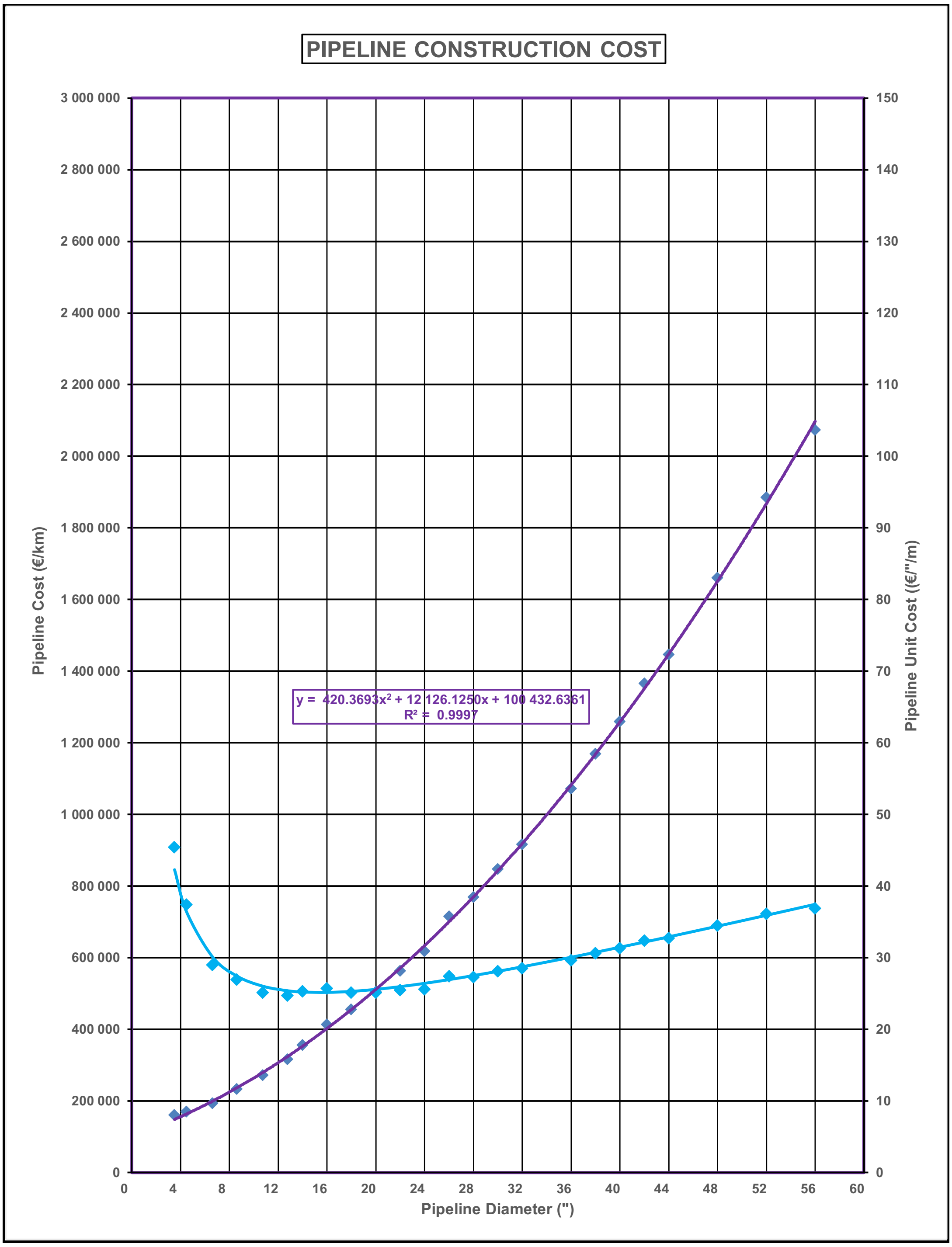
PIPELINE CONSTRUCTION COST
y = 420.3693x² + 12 126.1250x + 100 432.6361
R² = 0.9997
Pipeline Cost (€/km)
Pipeline Unit Cost ((€/"/m)
Pipeline Diameter (")
3 000 000
2 800 000
2 600 000
2 400 000
2 200 000
2 000 000
1 800 000
1 600 000
1 400 000
1 200 000
1 000 000
800 000
600 000
400 000
200 000
0
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
0 4 8 12 16 20 24 28 32 36 40 44 48 52 56 60

Figure 2-2

2.7 Validation on ACER data

ACER carried out a study of the investments related to transmission networks in 2015, ACER (2015).

These investments were classified into the following two items:

- Pipelines;
- Compressor stations.

The pipeline cost item therefore includes all the investments relating to the realization of a transmission system (line pipe supply, pipeline installation, engineering, work supervision, ROW, in-line stations, corrosion protection equipment, metering and pressure reducing/regulating stations, interconnection stations, telecommunications, control centers, maintenance centers, spare parts warehouse, etc.).

The results of the ACER study are summarized in Figure 2-3. This graph represents the cost of pipeline construction (€/"/m) in relation to its diameter (").

The first observation that can be made is the very strong dispersion of data: the price per km of a pipeline may vary from 1 to 5 for many diameters. This variability can be explained at least partially by the external environment in which the pipeline is constructed.

The second observation relates to the average unit price (€/"/m) of pipeline construction which is in the range of about 42 to 44 €/"/m, or about 50 USD/"/m; which seems high. It is possible, however, that these costs may be explained by the fact that the pipeline cost item includes all the implementation costs listed above, while in general, the cost of pipeline construction is limited to the line, in-line stations and corrosion protection equipment.

From these data, ACER proposed average costs in €/km (indicated by green circles on the graph). It is then possible to calculate the following relation according to the diameter:

- Pipeline Construction Cost (€/km) = 935.655 D^2 (") – 13,922.435 D (") + 589,595.980 (2).

ACER data were then averaged for each of the diameters (indicated by red diamonds on the graph). These averages have established the following relationship between the pipeline construction cost (€/km) and the outside diameter (") with a correlation coefficient of 0.905:

- Pipeline Construction Cost (€/km) = 642.985 D^2 (") + 2,464.295 D (") + 398,135.326 (3)

It can be noted that the two curves are close. However, the relationship (3) defines better the costs at both ends of the graph, so for small diameters and large diameters.

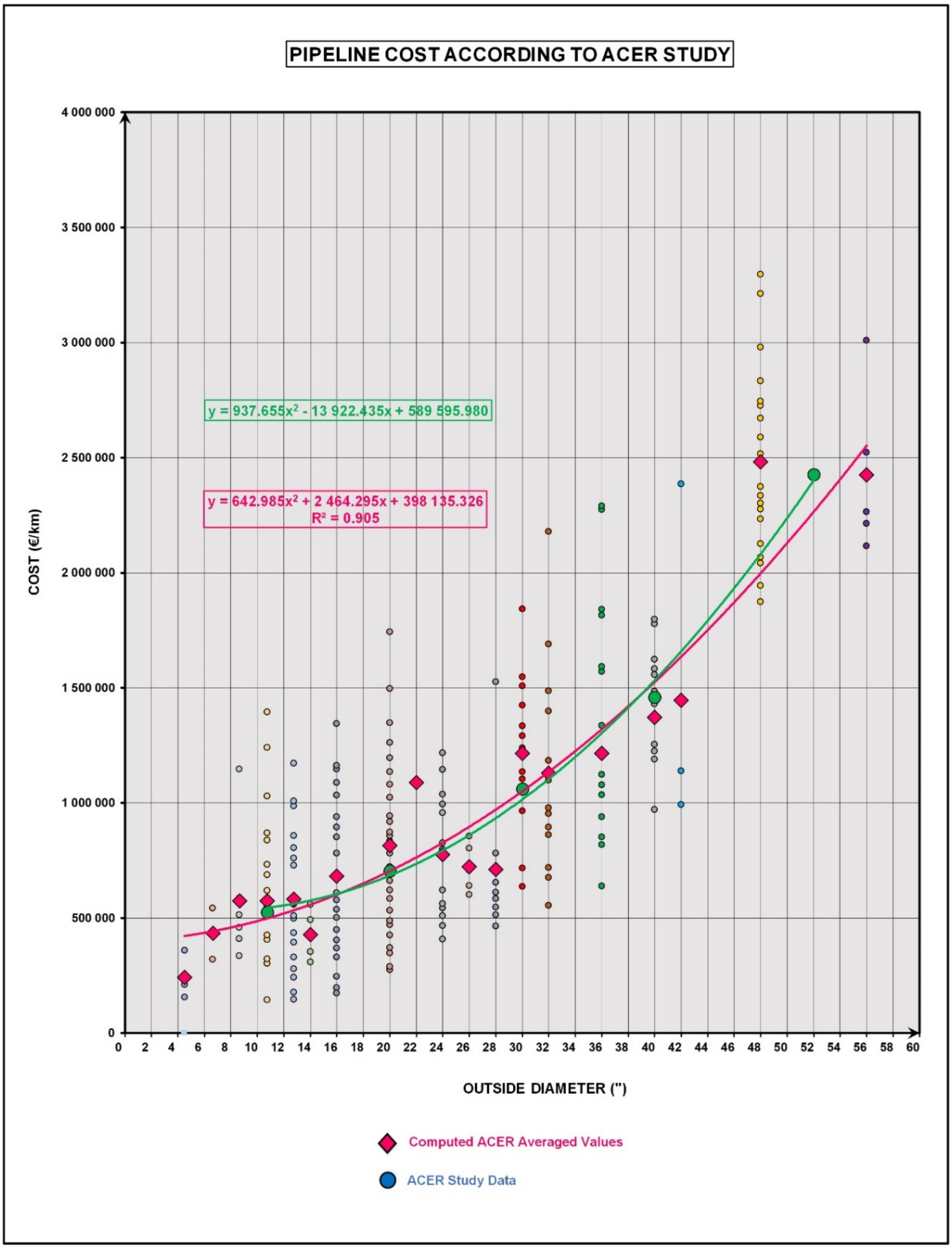
PIPELINE COST ACCORDING TO ACER STUDY
y = 937.655x² - 13 922.435x + 589 595.980
y = 642.985x² + 2 464.295x + 398 135.326
R² = 0.905
COST (€/km)
OUTSIDE DIAMETER (")
Computed ACER Averaged Values
ACER Study Data

Figure 2-3

2.8 Comparison with ACER data

The costs estimated in ACER (2015) are higher than those proposed by our analysis. The differences observed mainly concern diameters less than 20 "and are greater than 30%. For diameters greater than 20", the cost differences are between 17% and 27% (see Figure 2-4).

These differences are primarily explained by the fact that ACER costs for pipelines include all transmission system facilities with the exception of compressor stations. The ACER costs therefore include metering and pressure regulation stations, interconnection stations, remote control and command of pipeline system (SCADA and telecommunications), etc., which are evaluated separately in this study. The cost of these facilities, not included in the cost of the present study, can be estimated between 10% and 15% of the total pipeline cost and therefore cannot explain the differences observed for small diameters.

In addition, we note that the cost scenario in ACER(2015) in fact is for a relatively difficult installation site. Consider below the distribution of costs between the different items involved in the construction cost of a gas pipeline is as follows in the ACER study:

- Materials supply 33 %
- Pipeline Installation 49 %
- Miscellaneous works 12 %
- Right-Of-Way 6 %
- Total 100 %.

The ratio of the Installation / Supply items is 1.50, which with international data indicates a difficulty above average because of the relative importance of construction works compared to supplies of equipment. We recall that the norm grid weights in TCB18 are based on a construction site of average difficulty.

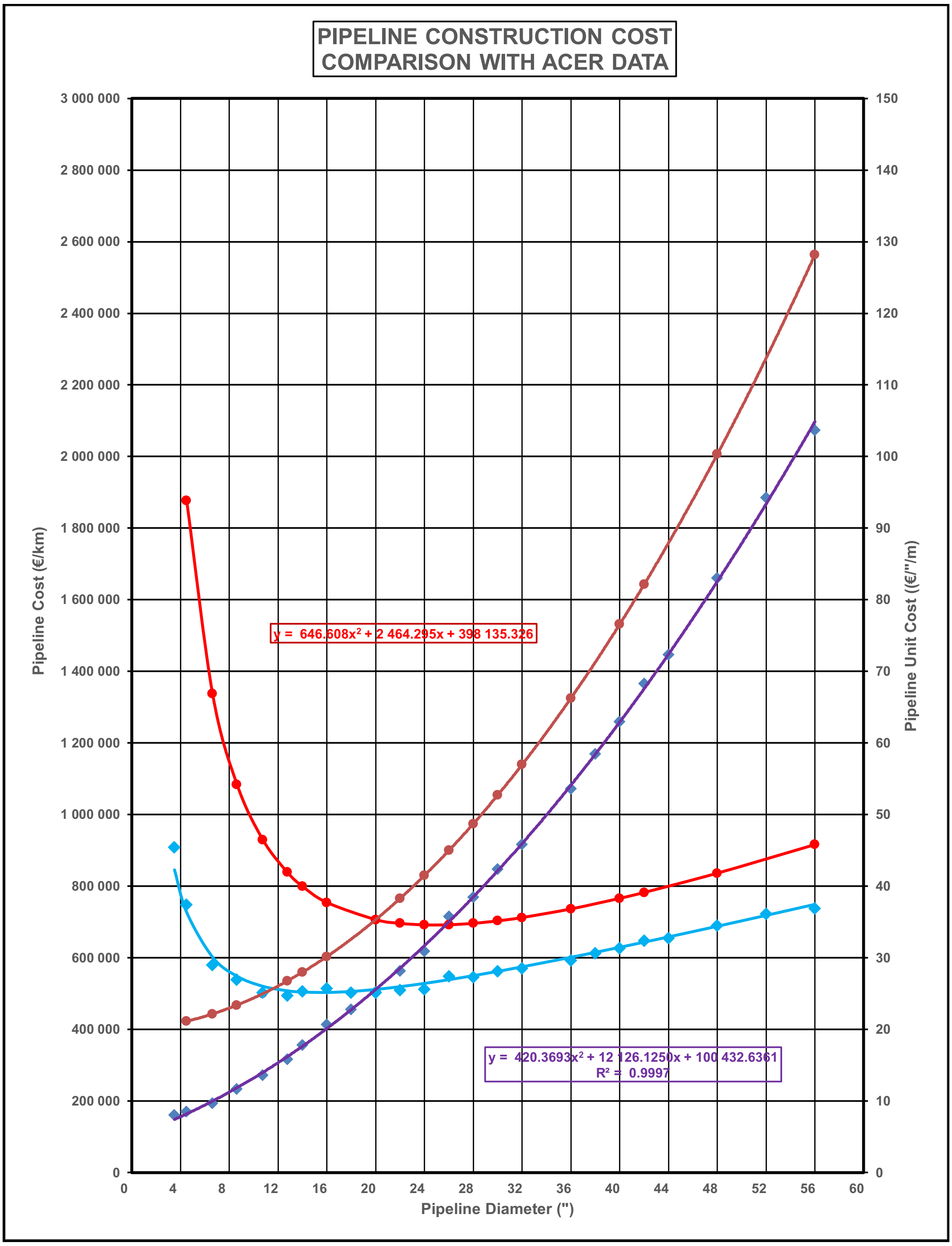
PIPELINE CONSTRUCTION COST
COMPARISON WITH ACER DATA
Pipeline Cost (€/km)
Pipeline Unit Cost ((€/"/m)
Pipeline Diameter (")
y = 646.608x² + 2 464.295x + 398 135.326
y = 420.3693x² + 12 126.1250x + 100 432.6361
R² = 0.9997

Figure 2-4

2.9 Compressor costs

The Compressor Station cost mainly depends on the capacity of installed machines and on the type of machines:

- Centrifugal compressors driven by gas turbines or electrical motors
- Reciprocating compressors generally driven by gas engines,
- Other types (not frequent)

Our cost function, illustrated in Figure 2-5 is based on a study conducted in the US and published in 2012. Costs were updated in 2017 using the following Nelson-Farrad indexes:

- Compressors
- Labor (construction)
- General inflation

The costs in € were obtained taking into account the average exchange rate with the US dollar in 2017. The study involves only gas turbine drivers.

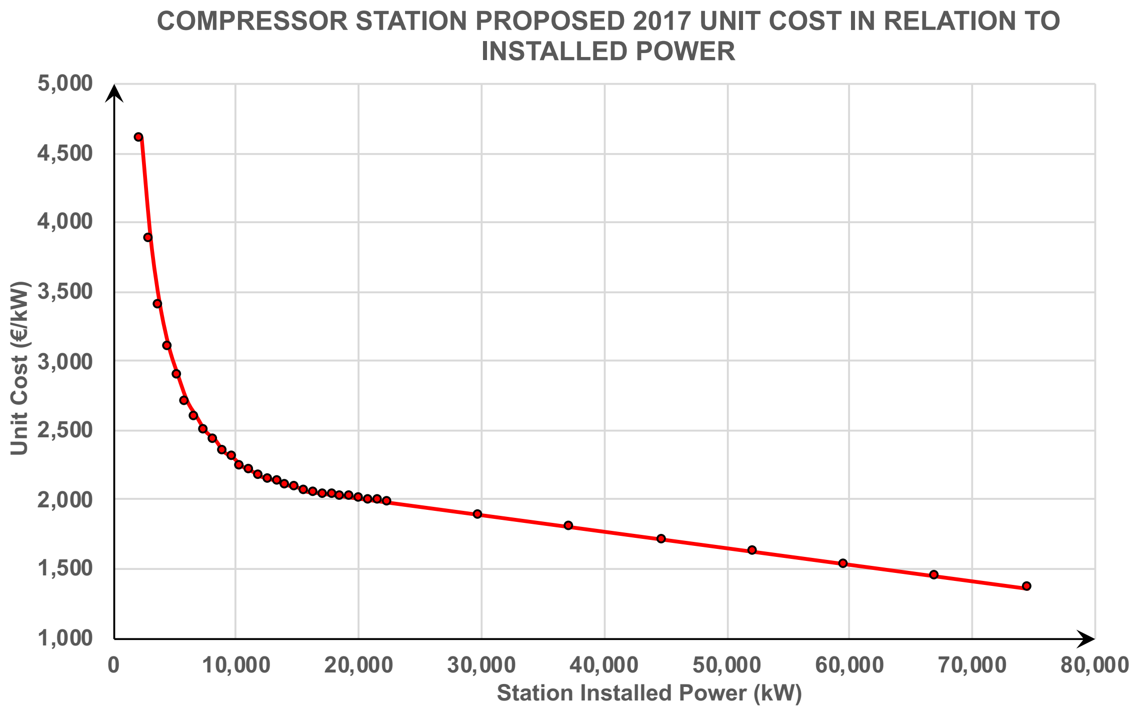

Figure 2-5

The cost function above is built on proprietary international data. Thus, as validation we use the ACER study from Europe is used. The graph in Figure 2-6 compares the proposed unit costs with the results of the ACER study and the data provided by the Spanish NRA (the only one to have transmitted complete and reliable cost data on their gas transmission network).

Note (in the graph) that ACER only provides averaged unit costs (flat curves) and does not take into account the variation of the unit cost with the installed capacity, which leads to maximizing the unit costs associated to large compressor stations and to minimizing unit costs of small compressor stations.

The Spanish data correspond to the reality of compression unit costs but are a little lower than the costs that we propose for gas turbines in 2017.

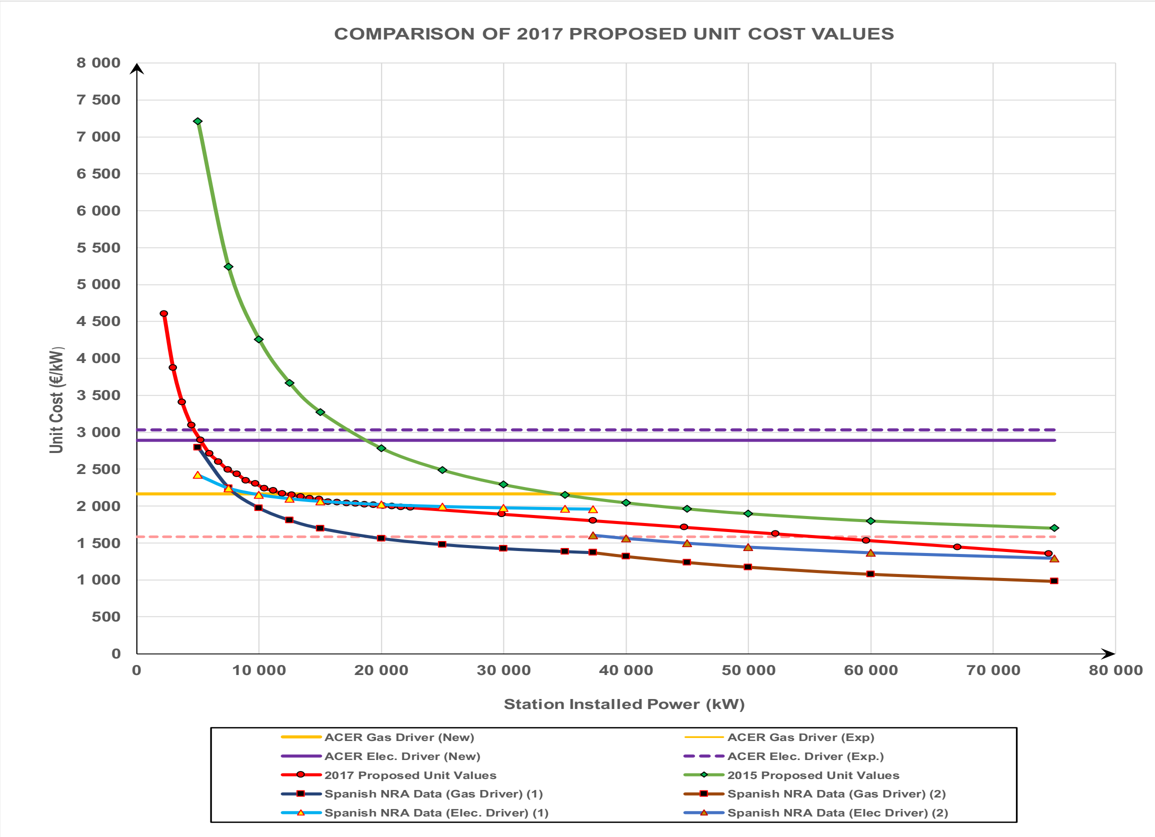

Figure 2-6

In Figure 2-7 the costs are recalculated for a compressor station as a function of installed power. As expected, the economies of scale give a concave cost function that can be estimated using a nonlinear cost function. However, we note that a simpler and more linear function provides an almost perfect fit.

Thus, we retain the following formula for compressor station CAPEX as a function of total installation capacity by

- $Cost(P)_{gas}$ = 1,359 P + 10,368,790 (€)

where P = Installed capacity (kW ISO, gas turbines).

With regard to **electric drivers**, it is necessary to take into account the cost of power lines, transformers, etc.; which may significantly increase the price of these facilities. The average cost, we have in hand, concerns stations of 25 - 32 MW and is in the range of 2800 to 3350 €/kW, which corresponds to the values indicated by ACER. We propose consequently the following formula :

- $Cost(P)_{elec}$ = 3,000 P (€)

where P = Installed capacity (kW ISO, electric engines).

For the reciprocating compressors (both gas and electrical drivers), the cost function is defined as with a power function for best fit:

- $Cost(P)_{rec\text{-}comp} = 2.2 \cdot 33{,}860\ P^{0.714}$ (€)

where P = Installed capacity (kW ISO).

Finally, the class of 'other' compressors: for smaller compressors (≤ 10 MW) of other types than the ones mentioned above, the cost function $Cost(P)_{rec\text{-}comp}$ applies, for larger compressors (> 10MW) we use $Cost(P)_{gas}$.

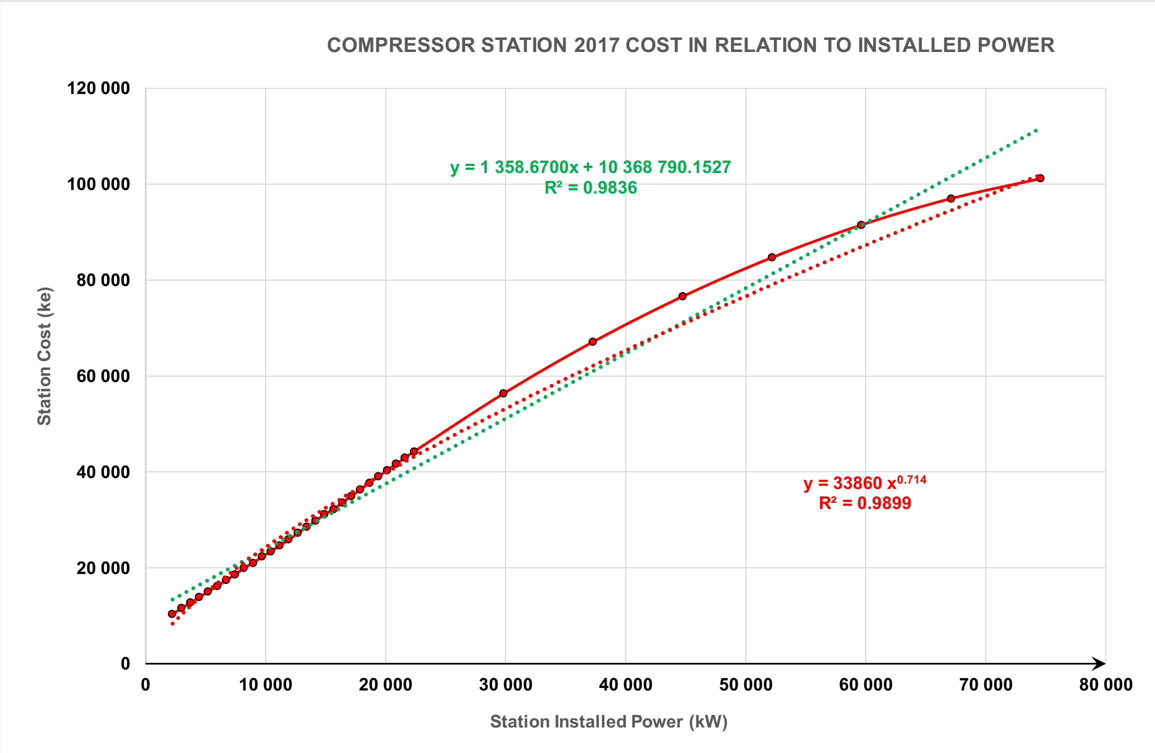

Figure 2-7

2.10 Costs for Pressure Regulation and Metering Stations

The investment costs for Pressure Regulating and Metering Stations have been estimated using proprietary data from a mid-size French TSO. Concerning piping, valves and fittings, electrical and civil engineering (supply & installation), conventional ratios have been used to determine costs. 10% have been added for engineering. The resulting cost function depends on the total flow rate as:

- Cost(Q)prms = 799.84 x $Q^{0.5503}$ (€)

Where Q = Total Flow Rate (m^3(n)/h).

Fit with international metering stations in France for pipeline and stations connected to underground storage: 0.94. The specific cost for gas heating facilities is not included in data (estimated max +10%).

2.11 Costs for Control Centers

Based on the control center costs for a complete renovation of a control center (including a back-up center) of a medium-sized operator (5000 km of lines; several compressor stations; underground storage facilities, international network, the cost is estimated to € 2.5M€.

2.12 Operating and maintenance cost

The exact operating expenditure (OPEX) for operations and maintenance of the assets is not uniquely defined by existing external documents, since the full OPEX also includes elements related to overhead and allocation of costs from other functions and their equipment. However, the percentages in (OPEX excluding energy expenses) are indicative of the relative costs of OPEX per asset category.

Table 2-2

Facilities Designation		**OPEX (% of investment present value)**
Pipeline (incl. in-line stations & Cath. Protection)		2.00
Compressor Stations	Type 1 (Gas Turb + Cent. Comp.)	6.00
	Type 2 (Elec. Mot. + Cent. Comp.)	3.50
	Type 3 (Gas Eng. + Recip. Comp.)	5.50
	Type 4 (Elec. Mot. + Recip. Comp.)	3.00
Metering & Pressure regulating/control stations		3.50
System telesupervision (SCADA, telecom., Cont. Cent.)		*7.00*

3 Environmental modelling GAS

Technical team GAS, headed by Jacques TALARMIN

This chapter relates to the determination of environmental factors, mainly related to the external environment of the pipeline, affecting the construction costs of the pipelines.

Traditionally, the overall cost of pipeline construction can be broken down into the following 4 items:

- Supply of materials and equipment;
- Pipeline installation and commissioning;
- Miscellaneous works (engineering, project management; owner expenses; etc.);
- Right-of-Way operations.

For each of these four operations involved in the construction of the pipeline, an analysis of the factors (cost drivers), related to the external environment of the pipeline that could change the cost of these operations, was carried out.

These cost drivers have been listed and quantified for the supply of materials and pipeline installation items. But, it was not possible to perform the same evaluation for miscellaneous works and Right-of-Way items due to the lack of data available on this subject. It should be noted, however, that the relative importance of these last two items in the overall pipeline construction cost of the pipeline should not exceed 20 -25%.

Knowing the relative importance of the four operations involved in the construction of the pipeline, it was possible to determine the influence of each cost driver on the overall base price of construction of the gas pipeline.

3.1 Pipeline cost breakdown

Pipeline construction costs is generally split into the following four items:

- Supply of materials;
- Pipeline installation;
- Miscellaneous;
- Right-of-Way.

3.1.1 Materials supply

This cost item relates to the purchase and on-site transportation of all materials and equipment related to the pipeline construction.

3.1.2 Pipeline installation

This cost item relates to the cost of construction, pre-commissioning and commissioning of the pipeline and associated in-line stations.

3.1.3 Miscellaneous

Miscellaneous costs correspond to those associated with engineering, surveying, work supervision, project management, overhead, contingencies, financial expenses, etc.

3.1.4 Right-of-way

Right-of-way (ROW) costs in TBCB18 include costs linked to wayleaves, damages, permissions, but not land acquisition and capitalized right-of-way easements.

3.2 Factors influencing the materials supply costs

3.2.1 Cost breakdown

Supply cost item can be broken down into the following sub-items:

- Coated linepipes,
- Other materials
    - Prefabricated bends,
    - Pig trap and block valves materials,
    - Branch line connection materials,
    - Cathodic protection equipment,
    - Fibre optical cables laid in the pipe trench, if any.
    - Etc.

3.2.2 Linepipe

As a general rule, linepipes used for gas transmission are made of carbon steel.

Factors involved in the sizing of the wall thickness of linepipes are as follows:

- The design pressure, or maximum operating pressure (if similar);
- The outside diameter,
- The design factors,
- The Specified Minimum Yield Strength (SMYS).

For a given pipeline where the design pressure and the outside diameter are defined, the sizing factors are therefore limited to design factors and to SMYS.

We can also add the selected linepipe manufacturing process that can possibly differ from one TSO to another.

3.2.2.1 Design Factor

The design factors are specified by the safety regulations in force. These design factors are linked to the urbanisation degree and population density in the immediate vicinity of the narrow corridor within which the pipeline is constructed.

Safety regulations are defined on a European scale, in general, but are supplemented by national or sometimes regional or provincial regulations. The design factors may be consequently slightly different from one country to another.

It can be considered that, on average, the design factors vary as follows depending on the increasing population density:

- F = 0.72 for thinly populated areas, i.e.: rural areas;
- F = 0.60 for intermediate densely areas, i.e.: suburban areas;
- F = 0.40 for densely populated areas, i.e.: urban areas.

It should be observed that the linepipes wall thickness for a given diameter and design pressure is directly proportional to the inverse of the design factors. We can therefore consider the following cost drivers depending on the urbanization of the external environment of the pipeline and their quantification as noted in the following Table 3-1.

Table 3-1

Cost Driver Urbanisation Degree	Cost Factor
Urban area (densely populated)	1.80
Suburban area (intermediate densely populated)	1.20
Rural area (thinly populated area)	1.00

In addition, it is known that some TSOs, possibly within the same country and normally subject to the same regulatory obligations, may go beyond the sole requirements of the regulations in force. Such additional obligations may, for instance, lead to increasing pipe wall thickness in order, first, to improve the safety of the gas transmission pipeline system, and secondly, to face a possible evolution of urbanization after pipeline commissioning. Despite that, it should be noted, that the general philosophies for calculating pipe wall thickness applied from one country to another are very close and there is no need to consider the slight differences that may exist in this field.

3.2.3 Specified Minimum Yield Strength (SMYS)

The SMYS depends on the steel grade selected by the TSOs. It must be noted that, for pipelines of similar dimensions, the steel grades of higher mechanical strength are, in principle, less expensive than the lesser mechanical strength steel grades; as the pipe wall thickness is inversely proportional to the steel SMYS for a given pipeline diameter and design pressure.

It can be, however, assumed that for a given diameter and design pressure, one should not observe a large variability in the choice of steel grades among the different TSOs. Moreover, the available steel grades are normally defined by the same standard in Europe and differences, if any, are expected to be limited to some additional requirements, defined by the specifications of TSOs, and which do not lead to significant cost variations.

3.2.4 Linepipe Manufacturing Process

Likewise, linepipes can be manufactured by different methods (seamless linepipe, welded linepipe with longitudinal or spiral welding, and with or without filler material). Unit costs of linepipe vary according to the selected manufacturing process; seamless pipes, for example, are normally more expensive than welded pipes. However, it can be assumed that for a given pipe dimension, the choice of the manufacturing process should not be fundamentally different from one TSO to another.

3.2.5 External Corrosion Coating

In the past, the linepipe external coating was tarred [coal tar (CTE) or asphalt (AE) enamels] and these coatings could be applied on site.

Currently, linepipes for on-land pipelines are coated at the factory by either tri-layer high density polyethylene (3LHDPE) or fusion bonded epoxy (FBE).

Differences are observed in the choice of the external corrosion coating but should not have a significant impact on overall supply costs.

3.2.6 Internal Coating

The internal lining (applied to improve the gas flow) is recommended, in general, for pipes which diameter exceeds a Nominal Diameter (ND) of 400 mm (or 16 ").

Even if TSOs philosophies for limiting pressure losses in networks can be different, the impact on overall supply costs is not significant.

3.2.7 Other materials

Other materials (manufactured bends, in-line stations valves, piping and fittings cathodic protection, etc.) do not represent an important portion of the total linepipe costs and, therefore, should not lead to significant cost discrepancy among the TSOs.

It shall be observed however that the distance between two successive block valve stations is also linked to urbanization: the regulation, imposing, for safety reasons, a reduction of this distance when the degree of urbanization increases. However, we have no reason to believe that the slight differences that may exist in this area can lead to significant cost variations from one TSO to another.

3.3 Transportation to site, unloading and storage

3.3.1 Transport of coated linepipes

Linepipes are manufactured in factories located in places geographically highly variable in Europe (Northern France, Germany, Greece, Italy, UK, etc.). Depending on their origin and their destination and on the means of transportation (railways, sea, etc.), the linepipe transportation costs may be different.

However, possible cost variations observed among the TSOs should not have a significant impact on the overall cost of supplies given the international market conditions and the number of international suppliers.

3.3.2 Unloading and storage on site of coated linepipes

Costs of linepipe unloading and storage of coated linepipes on construction site are insignificant compared to the cost of pipe supply and therefore possible variations among TSOs are not expected to be important.

3.3.3 Transport, unloading and storage on site of other materials

Transportation, unloading and storage of other materials and pipeline related appurtenance supplies (bends, materials for in-line stations, cathodic protection, etc.) account for a small part of linepipe ones and should not consequently really affect the supply total cost.

3.4 Total linepipe costs

The only source of variability of the linepipe supply cost (ex-factory) essentially depends on the design factors used in the calculation of wall thicknesses. Design factors depends mainly on the degree of urbanization of the immediate pipeline environment which imposes a most severe line sizing in the densely population areas therefore in urban and suburban areas than in rural areas.

Except the materials and equipment related to corrosion protection, the main part of other materials (bends, materials for in-line stations) are also sized according to design factors mentioned above.

It can be considered that the transportation of linepipes to site, unloading and storage to site depend mainly on their weight which is also inversely proportional to the design factors as the supply cost.

The cost of purchasing materials and equipment other than linepipes and their transport and storage on site are not always strictly related to the factors of urbanization defined above for the linepipes. But the expected costs are low compared to the linepipes purchase cost and it can therefore be considered with a good approximation that the cost drivers governing the purchases of linepipes and other materials used in the construction of the pipeline are defined above.

3.5 Factors

Estimating the cost of constructing a pipeline is a difficult subject because it is directly related to the characteristics of the external environment in which the pipeline is laid.

In addition, it must be observed that the environment of a pipe is not homogeneous along its route and that using average characteristics is the only feasible approach without resorting to detailed reporting of each pipeline segment.

3.6 Asset location factor

The country, region or province in which a pipeline is built may also influence its installation and operating costs. The weather conditions may also influence the work productivity. However, note that the labor cost differences are corrected through indexes in the study and not considered here. In addition, the environmental conditions are addressed through separate data.

3.7 Factors affecting pipeline installation cost

Traditionally, the factors influencing the installation cost of a pipeline can be broken down according to the difficulties encountered on the route as follows:

3.7.1 Factors linked to surface features

(i) Land use classified as follows:

- Unproductive areas (open country or desert);
- Agricultural areas (including pastures and cultivated areas);
- Industrial areas;
- Degree of urbanization:
    - Urban areas (densely populated);
    - Sururban areas (intermediate densely populated);
    - Rural areas (thinly densely populated);
- Special Scientific Interest areas (SSI areas) (including national, provincial or regional environment protected areas, archaeological areas, etc.).

(ii) Relief classified as follows in order of difficulty:

- Flat;
- Undulating (slope < 10 %);
- Hilly (10% < slope < 30 %);
- Mountainous (slope > 30 %

(iii) Soil humidity classified as follows in order of difficulty:

- Dry;
- Occasionally wet or floodable;
- Permanently wet or flooded;
- Swampy;
- Peaty.

(iv) Vegetation classified as follows in order of difficulty:

- Grassland;
- Bushes;
- Shrubs;
- Woods;
- Forests.

The vegetation factor was not considered during the last benchmarking exercise, although it is a key factor to consider when assessing the cost of construction of a pipeline. It can be verified that vegetation does not appear in any of the factors (i) to (iii) and (v) used in the previous benchmarking analysis.

3.7.2 Factors linked to subsurface features

(v) Subsoil properties classified as follows in order of difficulty:

- Loose
- Stony
- Soft rock;
- Medium rock;
- Hard rock.

3.7.3 Factors linked to special construction works

It shall be noted that when the work to be done requires special studies and means of construction beyond the means currently available in the construction spread, the corresponding areas are then classified into special points or special areas (or major crossings). The assessment of the major crossings cost can be based on the cost of similar achievements made before. The major crossings correspond to, but not limited to, the following obstacles:

(vi) Major crossings

- Major roads or highways;
- Wide railways;
- Large rivers and canals;
- Large ponds or lakes;

- Mountain massifs;
- Forest massifs;
- Etc.

Crossing of very congested areas, for example, are also often considered as major crossings when it is necessary to implement special construction processes to cross them (directional drilling or tunneling).

3.7.4 Sources of pipeline installation cost factors

There are no comprehensive scientific papers on the environmental impact on pipeline cost and the occasional engineering reports found in open domain are mostly disparate, incomplete and sometimes undoubtedly underestimate the relative cost increase of the obstacle to which it refers. There is of course, the book published by J. S. Page (cost estimating manual for pipeline and marine structures) but it is old and the cost drivers only correspond to pipelines laid in open country only. The crossing of mountainous areas has been the subject of more recent publications such as, for example, Gasca and Sweeney (2005).

In the absence of comprehensive and reliable publications, the cost drivers and associated cost factors, listed below in Table 3-2, have been determined based on detailed and existing cost tables for pipeline construction that we had at our disposal. In a number of cases, these data are proprietary and cannot be published.

A difficulty coefficient of 1 corresponds to the construction of a pipeline built on a flat land and not involving any difficulties or constraints of construction.

A difficulty coefficient is established for each of the factors listed above to quantify the difficulties that can be envisaged. This coefficient, greater than 1, represents the cost supplement associated with each of the cost drivers listed above. For example, a cost factor of 1.20, associated with an agricultural zone, means that the cost of pipeline installation is increased by 20% when it must cross such an area.

Precautions must be taken in applying the cost factors defined above. It is often difficult to describe the reality of the terrain with the precision mentioned in the cost drivers indicated above, especially for the geo-mechanical soils characteristics. This often leads to the application of an intermediate cost factor between two of the cost drivers mentioned above.

3.8 Factors for miscellaneous costs

As mentioned above, miscellaneous costs correspond to those associated with engineering, surveying, work supervision, project management, contingencies, expenses, etc.

We have no reason or data suggesting that these costs would be driven by any identifiable environmental exogenous factor.

3.9 Factors for associated costs

Costs linked to wayleaves and land acquisition, damages, permission granting to build and operate the pipeline, etc., are obviously variable according to the regulations and the cost of land in the countries traversed by the pipelines. The land price (if relevant) is excluded, the other costs are assumed to be proportionally constant among operators

These costs should be in the range of 3 to 8% of the total price of pipeline construction but there is no available data indicating that these costs would be determined by any exogenous factors.

However, possible variations of these costs will not be considered as we do not have accurate information in this area.

3.10 Relative importance of pipeline cost items

The four cost items considered above were allocated as follows throughout the overall pipeline cost in accordance with the values reported in ACER (2015):

- Materials supply : 33 %;
- Installation works : 49 %;
- Miscellaneous : 12 %;
- Right of Way : 6 %;
- Total : 100 %.

It may be objected that these weights can normally vary according to the diameters and design pressure of the pipes, but ACER(2015) is, if not the only study carried out on an European scale, at least the most recent and the most complete in this field.

3.11 Cost drivers for total pipeline cost

Knowing the weight associated with each item cost item in the total cost of pipeline construction, the possible variations of cost depending on the external environment of the pipe associated with each of these items, it is possible to obtain the values indicated in the table. following Table 3-2. It is these cost indications compared to the overall cost of the pipeline that are, in general, published.

A difficulty coefficient has been established for each of the factors listed in Table 3-2 to quantify the difficulties that can be envisaged. This coefficient, greater than 1, represents the cost supplement associated with each of the cost drivers listed in this table. For example, a cost factor of 1.10, associated with an agricultural zone, means that the cost of pipeline is increased by 10% when it must cross such an area. This cost increase of 10 % is only an average in agricultural areas, sometimes, it can exceed this value for crossing of rice fields, orchards, vineyards, etc.

Precautions must be taken in applying the cost factors defined above. It is often difficult to describe the reality of the terrain with the precision mentioned in the cost drivers indicated above, especially for the geo-mechanical soils characteristics. This often leads to the application of an intermediate cost factor between two of the cost drivers mentioned above.

Finally, we recall that the present analysis is prescriptive in the sense that the factors and dimensions described are those ideally identified and reported at the lowest possible level. This report does not address the definitions and availability of publicly available data to assess these factors, nor the possibility to adjust definitions to finer or more coarse resolutions.

Table 3-2

COST DRIVERS & ASSOCIATED COST FACTORS / PIPELINE TOTAL BASE COST						
			FACTORS LINKED TO SURFACE FEATURES			
No.			**DESCRIPTION**	**MIN**	**MEAN**	**MAX**
1			**LAND USE**			
	1		Unproductive area (open country or desert)	0.90	1.00	
	2		Agricultural area (pasture and cultivated area)	1.05	1.10	1.25
	3		Industrial area		1.30	
	4		Urban area (densely populated)		1.75	2.20
	5		Suburban area (intermediate densely populated)		1.25	
	6		Rural area (thinly populated area)		1.05	
	7		Special Scientific Interest areas (SSI) (including national, provincial or regional environment protected areas, archaeological areas, etc.).	1.10	1.25	2.20
2			**TOPOGRAPHY**			
	1		Flat		1.00	
	2		Undulating (slopes < 10 %)		1.15	
	3		Hilly (10 % < slopes < 30 %)		1.35	
	4		Mountainous (slopes > 30%)	1.50	2.25	4.90
3			**SOIL HUMIDITY**			
	1		Dry		1.00	
	2		Occasionally wet or floodable		1.15	
	3		Permanently wet or flooded		1.35	
	4		Swampy	1.40	1.65	2.20
	5		Peaty		Not estimated	
4			**VEGETATION**			
	1		Grass		1.00	
	2		Bushes		1.05	
	3		Shrubs		1.10	
	4		Woods		1.35	
	5		Forests (ø > 20 cm)	1.40	1.60	2.20
			FACTORS LINKED TO SUBSURFACE FEATURES			
5			**SUBSOIL**			
	1		Loose		1.00	
	2		Stony		1.15	
	3		Soft rock		1.35	
	4		Medium rock		1.50	
	5		Hard rock		2.20	
			FACTORS LINKED TO SPECIAL CONSTRUCTION			
6			**MAJOR CROSSINGS (Difficulty Coefficient > 3.5)**			
	1		Major roads and highways			
	2		Wide railways			
	3		Large Rivers and Canals			
	4		Lakes			
	5		Mountain massifs			
	6		Forest massifs			
	7		Others			

Note **When the difficulty coefficient exceeds 3.35, the obstacle to be crossed must be normally considered as a special zone.**

3.12 References GAS

ACER (2015) ACER Report on Unit Investment Cost Indicators and Corresponding Reference Values for Electricity and Gas Infrastructure. Final report. https://www.acer.europa.eu

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4 Cost modelling ELEC

Technical team ELEC, headed by Dr. Jacques DEUSE

Head of the TCB18 electricity transmission system team, Dr DEUSE is PhD in power systems and working for Sumicsid since 2011 as electricity transmission expert, previously Chief Engineer in Tractebel Energy Engineering, responsible for among other projects the development of the STAG (EUROSTAG) software, the TACIS projects ERUS 9411, EREG 9601, as well as the TSO-smart grid project EU-DEEP in the European FP7. He has lead and participated in power system development projects in Belgium, France, Spain, USA, Chile, Peru, New Caledonia, Dubai, Oman, Saudi-Arabia, et al., both operations and asset deployment. For Sumicsid, he was leading the engineering development in the ECOM+ project (2004-05) and the following e^{3}GRID projects (2007-08 and 2012-14), in particular the development of the cost weight system for electricity TSOs and the operator-specific assets

4.1 Development

This chapter provides some detail about the Norm Grid construction for electricity transmission systems. Where do these components come from and how have they been updated for the present project? The chapter does elaborate on the role of the Norm Grid in the benchmarking process itself, already discussed in Chapter 1.

4.1.1 Past

In a first step, a collection of asset types is developed. Such collection must be able to represent at the right level of detail (as detailed as necessary, but remaining as simple as possible) the type of system under consideration: here the electrical power system. In a second step, a cost weight system must be developed that will permit to set up the Norm Grid.

In 2005, for ECOM+, the first benchmark implemented by Sumicsid, the collection of items necessary for building the Norm Grid was inherited from a previous project. At that time, the power system team put its best knowledge at disposal of the project, working as much as possible in continuation with what was implemented earlier. Some structures of the first project, like parts of the asset system classification, are still used in TCB-18.

4.1.2 Present

From ECOM+ to TCB-18 the cost weight system has been built using practically exclusively a *top-down approach*. This means that costs were coming from the compilation of costs from previous high-voltage power systems investments. Naturally, cost observations from real installations are also influenced by factors not modelled initially, such as environmental factors and other operator-specific factors.

For TCB-18 these sets of data have been first updated to present conditions and, further have been completed by publicly available data, but also private data from experts in the field. It is worthwhile to note that a significant part of these new sources of information are based on a *bottom-up approach*. This means that costs are determined from elementary costs of sub-components.

This means that for TCB-18 two different approaches have been jointly used to set-up the cost weight system. Further, the discrete asset classes (e.g. voltage classes) in use in previous projects have been replaced by continuous values for voltage, power and short-circuit breaking currents.

4.2 General principles and sources

Cost weights for TCB-18 have been rebuilt from ground up. As starting point, the raw data used for the previous projects, and particularly from the 2005 project. This basic information has been adjusted to present conditions. Further, these data have been compared and completed using recent public data (see references), but also, for significant part of them, confidential data updated in June 2017.

The integration and consolidation of all these information result in a finer grain system of weights leading to potential better valuation of Norm Grid values.

For this updated approach, it seems worthwhile to note three significant sources:

- The seminal work is from CIGRE (1991), "Parametric Studies of Overhead Transmission Costs" - CIGRÉ Working Group 09. This publication remains a significant contribution for what concerns the "cost structure" of overhead lines. This type of "collaborative work" is unfortunately rare.
- The work performed in the framework of CIGRE in Parsons Brinckerhoff (2012) Study, working in association with CCI Cable Consulting International Ltd for the Institution of Engineering and Technology;
- The reports Black and Veatch (2012, 2014) for the Western Electricity Coordinating Council (WECC);

In addition, an extensive set of public access sources from EU, USA, Canada, UK, Australia, (see references below), has been used to revise estimates and to extend the power ranges of OH Lines and Cables. Further to the range extension, merging these data with the ones already available in the "e3GRID (2013) mean cost database" is an indirect way for database validation.

Finally, the system has had access to proprietary databases from *Global Electricity Transmission Report* for a large range of international projects, albeit with a lower level of detail than used in this study. Detailed data for the Gibraltar Strait connection (31.5 km, 700 MW AC) has led to updates for the cable function.

Most of the O&M costs are based on data from the Norwegian Weight System. Order of magnitude of NGET data for O&M for OH Lines, UG Cables, transformers are similar.

Weight parameters for under-sea Cables have been partly determined using Norwegian Weight System.

For Under-Sea Cables additional data should be necessary for evaluating the rating reduction due to reactive power generation by the cables (for UG Cables, compensating means are regularly installed along the cable route and the corresponding costs are considered in the compensating devices list.)

4.3 Overhead Lines

Initially, in the ECOM+ Project, the weights for Over Head Lines and Under Ground Cables were set up using two basic variables : operating voltages and nominal currents, with as entries, voltage and current ranges. For the second and third applications (e3GRID 2009 & 2013) currents have been replaced by nominal power for OH Lines and UG Cables. This gave rise to new entries for the database of weights for OH Lines and UG Cables, but weights remained, in principle, unchanged, inflation adjustment excluded.

For the present project this approach is confirmed and the process has been restarted from scratch, while keeping the same macroscopic approach. This assures continuity in reporting and updates for relevant cost functions.

Two circuits lines have been considered as the reference, essentially in connection with the new collected data. The power range of these two circuits lines is now extended to about 9000 MVA.

In the updated model, the cost per km is a quadratic function of the rating of the line expressed in MVA. The basic cost has been set-up for two circuits lines.

- $\text{Cost}(\text{k€/km})_{\text{Base}} = 150 + 0.534 \times \text{Rating} - 3.3\text{x}10^{-5} \times \text{Rating}^2$, with Rating in MVA.

This is the base cost, the "effective" cost depends on the length of the line that is built. The following formulae are used, based on a solution from the Spanish NRA (triple and twin):

- For lines with triple bundle: $\text{Cost(k€)}_{\text{Line}} = \text{Cost(k€)}_{\text{Base}} \times (\text{km} + 1.7)$
- For lines with twin bundle: $\text{Cost(k€)}_{\text{Line}} = \text{Cost(k€)}_{\text{Base}} \times (\text{km} + 0.7)$
- For lines with single conductor: $\text{Cost(k€)}_{\text{Line}} = \text{Cost(k€)}_{\text{Base}} \times (\text{km} + 0.3)$

Assumptions :

- the base is 2 circuits lines, factors have been set-up for 1 circuit & multiple circuits line,
- this weight is defined for "mean conditions", that is to say partially open, semi-rural or semi-urban land, and undulating terrain with reasonably flat sections,

Additional factors :

- factors related to land, icing, extreme temperatures, peaking during summer, etc. (see information on environmental parameters),

Remark :

Due to the balance of cost for accessories and their installation compared to the cost of the tower, the reduction of circuit cost for multiple circuits lines is limited to two circuits. This means that circuit cost does not reduce for lines with more than two circuits. The reduction factor for one circuit is $1.25^{-1} = 0.8$.

One circuit line cost = 0.8 x 0.5 x Cost of a two-circuit line (which is the base for TCB-18).

For a two-circuit line with only one circuit installed, the circuit cost is 0.8 of two-circuit line, and when the second circuit is installed, the cost is 0.3 of two-circuit line (this is in line with the position of the NRA in Spain that admits a 110% cost for a 2 circuits line when the second circuit is built afterwards.)

OPEX : 3.7 (k€/km-year).

4.4 Underground cables

The cost per km is defined by two linear models, one valid for low rating and the other for high rating, the formula is based on synthetic isolation cables (here noted PEX):

- $Cost(k€/km)_{Base}$ = max{(3.1081 x Rating + 383) ; (5.725 x Rating – 2059)}, with rating in MVA
- $Cost(k€)_{PEX\ Cable}$ = (Line length (km) + 1) x $Cost(k€/km)_{Base}$, one km is added to the line length for taking account of "fixed costs", essentially cable terminals.
- $Cost(k€)_{Oil\ Cable}$ = 1.41 x $Cost(k€)_{PEX\ Cable}$.

Additional factors:

- Formula is based on synthetic isolation cables
- Factors related to land, etc. (see general information about that elsewhere),
- Tunnels, the way cables are laid down, etc.

Remarks:

- special laid down conditions when multiple cables are required could lead to significantly higher costs
- this is also the case when special conditions have to be fulfilled, like installation under roads with light, medium or high load, using stabilized compounds, etc.

$OPEX_{PEX}$ = 1.4 (k€/km-year).

$OPEX_{OIL}$= 2.0 (k€/km-year).

4.5 Undersea cables

In the present revision, the formulae of UG Cable are used for determining the undersea (US) cable costs $Cost(k€/km)_{BaseUS}$ and $Cost(k€)_{CableUS}$.

$Cost(k€/km)_{BaseUS}$ = 1.35 x $Cost(k€/km)_{Base}$

$Cost(k€)_{CableUS}$ = (Line length (km) + 8.5) x $Cost(k€)_{BaseUS}$,
8.5 km are added to the undersea line length for taking account of higher fixed costs.

$OPEX_{US}$= 0.15 (k€/km-year).

4.6 Transformers

The first step consisted of parameters adjustment of the data from e3GRID (2013) to obtain basic costs for present conditions. Inflation index has been used to that end. In a second step, external costs information coming from other sources have been compared and partially merged with initial updated data. This allowed for setting up a complex cost model based on rating and voltages of transformer windings.

- $Cost(k€) = Rating \times [(377 \times Rating^{-0.701}) \times (0.834 \times e^{(0.00249 \times V1)}) + 0.014 \times V_2]$

With $V_1 > V_2 \geq V_3$, primary, secondary (and tertiary) voltages in kV ; Rating in MVA. The transformer is supposed to be equipped with on load tap changer.

Additional factors :

- Autotransformer : 0.90,
- Phase shifter : 1.15,
- Without on load tap changer : 0.85,
- Power Shifter Transformer: only V1 is given, ($V_2 = V_1$ in formula).

Remark : another feature that can be linked to the nature of the transformer is « single phase » or « three-phase » but this was not considered for this project.

$OPEX_{TRAFO} = 6.5 + 0.0323 \times V_1$ (kV) (k€/year).

4.7 Circuit ends

Two busbars "Open air" substations are used as base (this is directly related to data used for developing the model).

- $Cost(k€)_{Base} = 306.5 + 4.395 \times Voltage$ (kV)

In a second step the current breaking capacity is introduced,

- $Cost(k€)_{BB} = Cost(k€)_{Base} \times (0.01325 \times Current\ (kA) + 0.725)$.

Then, the factor related to the type of substations :

- 1 bus : 0.79
- 2 buses : 1.00
- 3 buses : 1.21
- 4 buses : 1.37
- 1 ½ breaker : 1.19
- 1 bus, no breaker: 0.10

Further, the distinction between "Open air" and "Closed" substations, in case of "closed" substation: this factor (function of voltage) is given by :

- 0.66 ln(Voltage) + 0.8797, Voltage in kV, used for bay isolated in "air".

And finally, the factor for "Metal Clad – GIS" : this is also a function of voltage :

- 0.445 ln(Voltage) – 0.329, Voltage in kV, valid for "closed" cases.

- 0.66 ln(Voltage) + 0.8797, Voltage in kV, valid for "open" cases.

Circuit ends weights have been compared with those found in publications from the USA, but also from private documents from Brazil. Comparisons are not straightforward because substation configurations in these countries differ from those in Europe. However, for similar situations, costs figures are in close agreement.

It seems worthwhile to note that it is now possible to introduce longitudinal and transverse coupling of bus bars. Initially, substations were not considered explicitly and, consequently, the costs corresponding to bus bars and their coupling were implicitly included in the circuit-ends weights.

$OPEX_{CIRCUITENDS}$= 45% of annuity (k€/year).

4.8 Compensating Devices

International data, e.g. Black & Veatch (2014), combined with updated weights, lead to the weights in Table 4-1 below.

Table 4-1 Compensating devices.

Type	Cost	OPEX
Fixed shunt capacitor	5 k€/Mvar	0.51 k€/year
Variable shunt capacitor	17.5 k€/Mvar	0.51 k€/year
Fixed shunt reactor	21 k€/Mvar	0.51 k€/year
Variable shunt reactor	21 k€/Mvar	0.51 k€/year
Variable shunt capacitor – inductor	(should be split in reactor and capacitor)	
SVC	75 k€/Mvar	0.5% investment /year
Statcom	104 k€/Mvar	0.5% of investment /year
Synchronous compensation.	75 k€/Mvar	1% of investment /year
Series capacitor	27 k€/Mvar	0.5% of investment /year
Series inductor	22 k€/Mvar	0.5% of investment /year

4.9 HVDC Installations

For HVDC installations the same approach as the one used for e3GRID 2013 is prolonged as far as data are delivered.

4.9.1 HVDC cost for Line Controlled Converters

The retained cost function is given by:

- Cost LCC (k€ per converter): 395 x Rating$^{1-0.183}$, with Rating in MW,

Cost Maximum cost could be: 485 x Rating$^{(1-0.1932)}$, idem,

Considering California, P&B report and EU: 304 x Rating$^{(1-0.1719)}$.

Remark : Costs given by Siemens show a constant cost of about 60 k€ per MW from 1000-1500 up to 3000-6000 MW. This is perhaps questionable as there is no size effect anymore.

$OPEX_{HVDC\text{-}LCC}$= 0.7% of investment / year.

4.9.2 HVDC cost for Voltage Source Converters:

- Cost VSC (k€ per converter): 340 x Rating$^{(1-0.0992)}$, with Rating in MW

This value is selected using the highest given by ENTSO-E (2011) (in that case for a power of about 500 MW at 300 kV) and from the costs proposed by Parsons Brinckerhoff (2012) for transfer of 3000 and 6000 MW for a bipolar connection at ±320 kV. Taking account of the large power, a number of modules are operated in parallel. Cost in this case decreases only slightly with size. This was not the case for the different low power variants proposed in a proprietary study for Suriname made by A. Hammad, at that time from ABB Switzerland (values used in ECOM+, 2005).

Important variati ons can be expected in this domain : for instance the costs of very similar installations can vary from 1 to 2.

$OPEX_{HVDC\text{-}VSC}$= 0.7% of investment / year.

4.9.3 HVDC overhead lines

The cost weight for of HVDC overhead lines is based on the weight for HVAC line of the same ratings.

A reduction factor from AC to DC based on Black & Veatch (2014) is set to 0.478. Further this is adjusted for an "equivalent voltage", that is to say the peak phase to ground voltage in AC equals the pole voltage in DC. The OPEX is identical to that for HVAC lines.

4.9.4 HVDC undersea cables

Weight is calculated for LLC and VSC installations operated at about 320 – 400 kV. Variations of the cost per MW x km remain below 3.5% when comparing LLC 3000 MW and 6000 MW, 400 kV bipolar connection, with VSC 3000 MW and 6000 MW, 320 kV bi-pole. So a single weight is considered in a formula that includes the cost dependence versus line length.

Formula for single cable:

- $Cost_{SINGLE}$ (k€) = 1.742 Rating x (length + 8.5), Rating in MW, length in km.

The 8.5 km in excess of line length correspond to the incidence of fixed costs.

- $Cost_{BICABLE}$ (k€) = 2 $Cost_{SINGLE}$, for bi-pole cable.
- $Cost_{TRICABLE}$ (k€) = 3 $Cost_{SINGLE}$ if a neutral (reserve) cable is installed.

This weight leads to good order of magnitude for costs, but fluctuations in cost can be quite large for individual installations for various reasons:

- The market conditions at the moment of construction (relative scarcity of specific hardware, ship, etc.),
- Distance from cable production site to installation,
- Special mechanical protection that could be required for the cables,

In PSC (2014), some installations have been compared that use Polymer cables (used with VSC) and Mass Impregnated cables (that presently must be used for LCC). Mass Impregnated cables seem less expensive (ratio 1240/1480 = 0.84).

This has been determined from installations of rather short lengths, hence the incidence of fixed costs is perhaps playing a role which cannot be evaluated using available data.

$OPEX_{HVDC\text{-}US\text{-}CABLE}$ = 0.15 k€/km-year.

5 Environmental modelling ELEC

Technical team ELEC, headed by Dr. Jacques DEUSE

Environmental conditions influence the investment cost for, in particular overhead lines and underground cables, to a lesser extent the costs for transformers and other assets. As discussed below, the relevant factors are a subset of those already described for gas transmission pipeline construction. Operating costs, including maintenance costs, are affected by a some additional factors by virtue of the location and configuration of the assets (height and exposure to wind, salt and sun). We close the section with some suggestions for these additional factors that could complement the analysis.

5.1 Common factors for gas and electricity

For what concerns the electricity part of the project, cost weights are developed considering "mean conditions." If overhead lines are taken as an example, this leads to an "average line." The basic weights that will be used are not considering green field conditions, with flat land, no obstacle, etc., but *average* conditions that are considered the more probable for a significant part of the system. In TCB-18, it means that overhead AC lines are supposed to be installed:

- In gently undulating land;
- With towers that are of the suspension type for 70% of them;
- With basic span capacities that are utilized to about 80%;

These conditions can be considered as typical for construction through partially open, semi-rural or semi-urban land, and undulating terrain with reasonably flat sections;

Sensitivity analyses give tools that allow for adjusting weights for more or less demanding conditions.

For this project, open access data will be used for each country for adjusting the cost weights to national environmental conditions with respect to land use, topography and subsoil structure (see above). These factors are already mentioned in the section for gas transmission installations, Chapter 3.

The use of the land use and topography factors is common also in electricity, cf. the table below from Black and Veatch (2014) gives cost factors for the selected types of environment in California. It is worthwhile to note the significant variation of some of these factors across the different Companies (Pacific Gas & Electric, South California Edison, San Diego Gas & Electric, etc., and the resulting mean values adopted by WECC). Note that the exact adjustment factors may not apply in TCB-18, depending on the granularity and availability of public European data in this regard.

Table 2-5 Terrain Cost Multipliers

TERRAIN	PG&E[3]	SCE[4]	SDG&E[5]	WREZ	WECC
Desert	1.00	1.10	1.00	-	1.05
Scrub / Flat	1.00	1.00	1.00	1.00	1.00
Farmland	1.00	1.00	1.00	1.10	1.00
Forested	1.50	3.00	-	1.30	2.25
Rolling Hill (2-8% slope)	1.30	1.50	-	-	1.40
Mountain (>8% slope)	1.50	2.00	1.30	-	1.75
Wetland	-	-	1.20	1.20	1.20
Suburban	1.20	1.33	1.20	-	1.27
Urban	1.50	1.67	-	1.15	1.59

For underground cables, a similar approach is used. The derivation of weights is made analogously to the gas pipeline construction, the full set of factors in gas may also apply for cable constructions.

Other components are less dependent on external conditions, or, like it is the case for circuit ends, environmental conditions (e.g. weather) are reflected in the specification of the asset itself (open air or closed).

5.2 Electricity-specific environmental factors

In addition to the factors discussed above, a smaller set is proposed in relation with conditions that affect specifically electrical installations, leading to technical choices influencing investments as well as maintenance costs.

- Severe icing conditions that lead to the necessary reinforcement of lines;
- Reduced lines rating ("ampacity") due to high temperatures and high sun radiation, particularly if correlated with low wind speed;
- Winter or summer peak consumption as high load during winter takes advantage of the correlation high load – higher capacity, while summer peak (due to air conditioning load for example) faces high load – lower capacity.

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