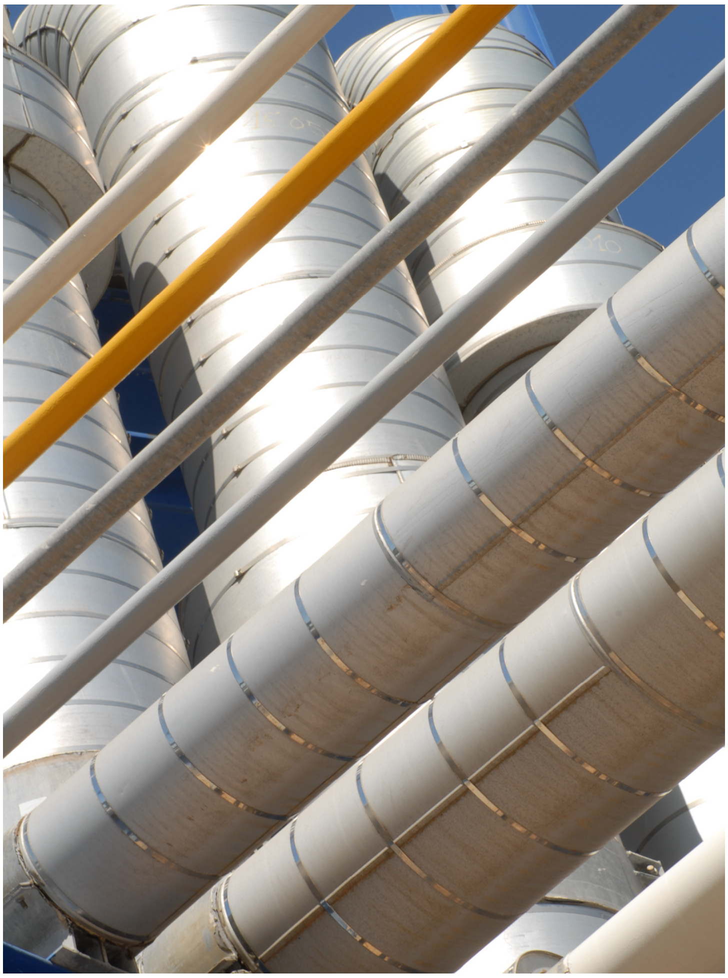


# Development Study 2018-2027

June 2017

DESFA
Hellenic Gas Transmission System Operator S.A.

## Contents

*The English translation is not binding. In the event of discrepancies between the Greek and English version, the Greek text prevails.*

# EXECUTIVE SUMMARY

DESFA drafted a study regarding the forecast of demand and allocation for the reference period 2018-2027 taking into consideration:

i. The latest developments in electricity market
ii. The most recent historical data of gas demand
iii. The latest forecasts regarding the Gross Domestic Product
iv. The latest forecasts regarding the development on crude oil and CO2 emission allowances prices
v. Data and estimations from Gas Distribution Companies, as established in January 2017, and as expected to be formed in the future

The demand scenario of the abovementioned study is based on two distinct sections and constitutes Chapter 3.1. of the Development Study 2018-2027.

- Section A: "Gas consumption forecast for electricity production provided in the wholesale market during the next decade (2018-2027)", as performed by the School of Electrical and Computer Engineering of the Aristotle University of Thessaloniki (AUTH)

- Section B: "Annual Demand Forecast and geographical-daily allocation of other consumers' demand for the period 2018-2027", performed by DESFA

The study conducted by the Aristotle University of Thessaloniki led to four possible scenarios (1st high demand scenario, 2nd medium demand scenario, 3rd and 4th low demand scenarios). DESFA in collaboration with AUTH and taking into account the latest data of the market, considered that the 2nd scenario (medium demand scenario) is the most likely scenario to be realized, which combined with the results of the study for Other Consumers, constitutes the basic scenario of the reference period 2018-2027. The key assumptions for this scenario are presented below.

**Key assumptions of the Study**

The key assumptions used for the drafting of the study are summarized below:

- In the study performed by AUTH the correlation of the estimated GDP with the demand and the peak of the system was done and the expected increase of the system load (consumption) and the peak load of the electricity sector for years 2018-2027 is estimated. Thus, the total power production over the reference period is estimated to range from 50,3 TWh (in 2017) to 56,4 TWh (in 2027).
- The assumption regarding the $CO_2$ emission allowances will be kept at low levels. AUTH's estimate is that the prices will range from 5,1 €/tn $CO_2$ for year 2017 to 5,2 €/tn $CO_2$ (in 2018) – 6 €/tn $CO_2$ (in 2027).
- The procurement price of natural gas is the main parameter for the determination of the variable cost of n.g. thermal units. AUTH's forecast for Brent prices are equal to 51 $/barrel for year 2017, 55 $/barrel for year 2018, and of 60 $/barrel for years 2019 and onwards.

- RES injections are calculated by AUTH based taking into account the target at a national level as well as historical data from both ADMIE website and Monthly RES reports of LAGIE.
- Environmental constraints in a series of lignite units (KARDIA &AMYNDAIO), from January 2016 onwards, with the obligation of limited operation for the following years until their full withdrawal are taking into account. This units will operate for a maximum of 17,500 hours.
- The new lignite unit "PTOLEMAIDA 5" is expected to operate commercially in June 2021. MELITI 2 unit is considered to start commercial operation in January 2025.
- In years 2018-2020 two new hydro units are expected to start commercial operation, "Metsovitiko" (29 MW) and "Mesochora" (160 MW).
- The Cyclades are expected to be interconnected with the mainland until year 2019, while Crete is expected to be interconnected with the mainland system in year 2022 through an AC transmission line (underwater cable) at 150 kV with a maximum transmission capacity equal to 2x140 = 280 MW. In 2025, it is expected that a second underwater cable (DC) of Crete (2x350 MW) will be operational, and hence there will be no congestion anymore between the mainland transmission system and Crete.
- The expected growth of medium and low pressure distribution networks of EDA is considered to begin from 2020 onwards.

- The impact of huge landslides that took place in the AMYNTAIO mine, the PPC's lignite center of Western Macedonia, on 10$^{th}$ of June 2017, was assessed ex post by AUTH and the results are the following:

  1) In the case that AMYNTAIO units will not operate at the peak of demand within July 2017, the impact on the demand of n.g. will be small, i.e. up to 0,046 bil. $Nm^3$ additional demand. Similar results will be realized for July 2018 and 2019, of the reference period of the study.

  2) In the case that AMYNTAIO units will not operate during the winter 2017-2018, the impact on the demand of n.g. will be significant, i.e. about 0,21 bil. $Nm^3$ additional production from PP units. The impact for the winter 2018-2019 will be similar, and the impact for the winter 2019-2020 will be less due to the final withdrawal of units in January 2020, according to most recent data.

However, no impact is taken into account in the results of this study, due to the lack of data on how PPC will address the problem occurred.

**Main conclusions**

a) Annual natural gas demand for year 2018 is expected to be equal to 3.679 $Nm^3$.

From year 2019 onwards, new Small Scale LNG projects will contribute to the annual demand quantities and from year 2018 onwards annual demand related to gas transit via reverse flow and through Greece-FYROM interconnector is taken into account.

The total estimates of gas demand per consumption category for the reference period 2018-2027, is presented in the following table.

***Estimation of Natural Gas demand***

| Estimation of natural gas demand [mil. Nm3/year] | PP n.g. demand | Other Consumers | | Transit of n.g. | Small Scale LNG | Total |
|---|---|---|---|---|---|---|
| | | Costomers connected to HP network | Distribution networks | | | |
| 2016* | 2.629 | 386 | 821 | - | - | **3.835** |
| 2017** | 2.684 | 522 | 905 | - | - | **4.111** |
| 2018 | 2.218 | 569 | 891 | 10 | - | **3.689** |
| 2019 | 2.275 | 570 | 934 | 50 | 1 | **3.829** |
| 2020 | 2.204 | 572 | 990 | 100 | 2 | **3.867** |
| 2021 | 1.921 | 573 | 1.039 | 500 | 18 | **4.050** |
| 2022 | 2.229 | 573 | 1.085 | 550 | 29 | **4.466** |
| 2023 | 2.454 | 573 | 1.122 | 600 | 53 | **4.802** |
| 2024 | 2.422 | 574 | 1.163 | 620 | 82 | **4.861** |
| 2025 | 2.326 | 574 | 1.193 | 650 | 93 | **4.836** |
| 2026 | 2.294 | 574 | 1.225 | 650 | 122 | **4.866** |
| 2027 | 2.340 | 574 | 1.255 | 650 | 151 | **4.971** |

*actual data **forecasted data

b) The peak daily demand for the year 2018 is expected to be equal to 19,6 mil Nm3/day. The expected peak of the system for the years of the reference period is presented in the following table. The notable deviation in between the forecasted following peak of year 2018 in comparison with the actual 2017 peak, is due to beyond the usual electricity exports from Greece to the northern neighboring countries due to the Europe-wide energy deficit, combined with the extremely unfavorable weather conditions during this winter in Greece, resulting in a much higher than expected consumption of natural gas. Such extraordinary harsh conditions are not expected to take place frequently during the years to come, especially in combination.

***Estimation of Daily Peak demand***

| | TOTAL NNGS (Nm3/day) | | | | | |
|---|---|---|---|---|---|---|
| | Power Production | Other Consumers | | Transit of n.g. | Small Scale LNG | Total |
| | | Customers connected to h.p. network | Distribution network | | | |
| **2016*** | 12.353.154 | 1.622.084 | 5.621.659 | - | - | 19.596.897 |
| **2017**** | 15.407.642 | 1.337.983 | 6.834.595 | - | - | 23.580.220 |
| **2018** | 11.350.110 | 2.504.195 | 5.737.968 | 34.247 | - | 19.626.519 |
| **2019** | 10.728.628 | 2.506.330 | 6.059.411 | 171.233 | 49.300 | 19.465.602 |
| **2020** | 10.609.464 | 2.508.465 | 6.566.117 | 342.466 | 49.300 | 20.026.512 |
| **2021** | 10.108.731 | 2.512.735 | 7.119.238 | 1.579.148 | 94.701 | 21.414.553 |
| **2022** | 11.733.845 | 2.513.392 | 7.620.051 | 1.750.381 | 166.702 | 23.784.370 |
| **2023** | 12.566.821 | 2.514.059 | 7.990.198 | 1.921.613 | 261.403 | 25.254.094 |
| **2024** | 13.748.585 | 2.514.783 | 8.351.849 | 1.990.107 | 329.505 | 26.934.829 |
| **2025** | 12.291.786 | 2.515.470 | 8.689.004 | 2.092.846 | 374.906 | 25.964.012 |
| **2026** | 13.154.577 | 2.516.166 | 9.003.514 | 2.092.846 | 488.409 | 27.255.512 |
| **2027** | 12.558.259 | 2.516.166 | 9.281.039 | 2.092.846 | 601.912 | 27.050.222 |

*actual data
**until 6/7/2017 the peak of the system amounts to 23,6 mil Nm3 and was realized on 12/1/2017

c) The following table summarizes the abovementioned results:

*Estimation of Natural Gas demand 2018-2027*

| Unit/load category | 2016* | 2017** | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Lignite units [MWhe]** | 14.897.661,83 | 14.833.509,51 | 15.837.777,25 | 15.445.461,66 | 15.370.192,02 | 16.912.051,31 | 16.045.088,50 | 14.668.034,04 | 14.867.885,35 | 16.611.005,75 | 16.914.845,19 | 16.760.331,07 |
| Gas units (PPC) [MWhe] | | | 4.738.950,50 | 4.893.999,96 | 4.752.692,32 | 4.857.444,69 | 5.564.476,59 | 6.170.639,40 | 6.049.126,83 | 5.696.846,12 | 5.723.180,03 | 5.902.320,23 |
| Gas units (IPPs) [MWhe] | | | 6.346.604,27 | 6.489.018,73 | 6.230.487,74 | 4.643.324,90 | 5.762.313,80 | 6.484.334,84 | 6.437.700,15 | 6.861.489,99 | 6.675.799,79 | 6.730.845,84 |
| **Gas units [MWhe]** | 13.624.757,35 | 13.932.115,02 | 11.085.554,77 | 11.383.018,69 | 10.983.180,06 | 9.500.769,59 | 11.326.790,39 | 12.654.974,24 | 12.486.826,98 | 12.558.336,11 | 12.398.979,82 | 12.633.166,07 |
| **Crete CCGT Unit [MWhe]** | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 687.449,85 | 681.102,75 | 664.056,90 |
| **Hydros [MWhe]** | 4.843.292,99 | 4.678.070,74 | 4.377.067,97 | 4.378.193,89 | 4.639.301,93 | 4.637.553,75 | 4.637.140,00 | 4.632.793,72 | 4.639.508,56 | 4.635.441,70 | 4.638.482,87 | 4.638.786,31 |
| Imports [MWhe] | | | 11.400.352,38 | 11.410.045,24 | 11.398.702,68 | 11.287.647,32 | 11.428.272,33 | 11.547.869,54 | 11.603.375,47 | 11.460.462,68 | 11.474.384,95 | 11.559.587,45 |
| Exports [MWhe] | | | 1.514.268,48 | 1.448.497,14 | 1.475.651,18 | 1.528.161,66 | 1.486.577,63 | 1.433.774,59 | 1.413.970,04 | 1.457.741,30 | 1.448.706,17 | 1.445.291,65 |
| **Net imports [MWhe]** | 8.796.000,00 | 8.388.846,12 | 9.886.083,90 | 9.961.548,10 | 9.923.051,51 | 9.759.485,66 | 9.941.694,71 | 10.114.094,95 | 10.189.405,43 | 10.002.721,38 | 10.025.678,78 | 10.114.295,80 |
| Wind plants [MWhe] | | | 5.277.677,01 | 5.742.060,86 | 6.149.751,50 | 6.527.986,19 | 6.761.501,63 | 6.873.138,68 | 7.001.783,89 | 7.096.413,08 | 7.208.049,88 | 7.319.686,54 |
| PVs [MWhe] | | | 3.794.022,82 | 3.887.689,55 | 3.940.819,39 | 3.987.489,37 | 4.037.038,57 | 4.086.356,05 | 4.138.715,44 | 4.184.291,59 | 4.232.909,78 | 4.281.294,83 |
| Biomass/Biogas [MWhe] | | | 346.455,70 | 404.975,98 | 466.645,86 | 525.840,71 | 586.274,01 | 646.705,68 | 709.050,92 | 767.570,58 | 828.003,12 | 888.436,30 |
| Small hydros [MWhe] | | | 756.672,64 | 780.220,51 | 801.967,23 | 819.290,90 | 838.826,99 | 858.362,36 | 880.326,90 | 897.433,12 | 916.969,16 | 936.504,69 |
| Small co-generation [MWhe] | | | 160.183,51 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 |
| **Total RES/Co-generation units [MWhe]** | 9.140.434,04 | 9.693.216,12 | 10.335.011,68 | 10.978.160,08 | 11.523.052,24 | 12.023.820,35 | 12.386.854,38 | 12.627.775,95 | 12.893.745,41 | 13.108.921,55 | 13.349.145,12 | 13.589.135,54 |
| **Total production [MWhe]** | 51.302.146,21 | 51.525.757,49 | 51.521.495,57 | 52.146.382,42 | 52.438.777,76 | 52.833.680,66 | 54.337.567,98 | 54.697.672,90 | 55.077.371,73 | 56.916.426,49 | 57.327.131,78 | 57.735.714,79 |
| **Gas units' percentage [%]** | 26,56% | 27,04% | 21,52% | 21,83% | 20,94% | 17,98% | 20,85% | 23,14% | 22,67% | 22,06% | 21,63% | 21,88% |
| **Pumping [MWhe]** | 32,00 | 21.069,05 | 60.778,32 | 57.457,44 | 62.594,48 | 61.043,98 | 57.168,77 | 50.761,24 | 58.123,76 | 55.044,45 | 52.593,81 | 60.663,13 |
| **System load [MWhe]** | 51.302.114,21 | 51.504.688,30 | 51.460.717,24 | 52.088.924,79 | 52.376.183,10 | 52.772.636,62 | 54.280.399,06 | 54.646.911,57 | 55.019.247,65 | 56.861.381,80 | 57.274.538,05 | 57.675.051,61 |
| **System losses [MWhe]** | 1.134.000,00 | 1.220.808,38 | 1.006.397,24 | 1.020.144,82 | 1.045.743,19 | 1.098.216,61 | 1.123.043,11 | 1.139.695,51 | 1.157.898,81 | 1.244.421,73 | 1.273.418,00 | 1.286.831,67 |
| **Total demand of consumers (with distribution network losses) [MWhe]** | 50.168.114,21 | 50.283.879,92 | 50.454.320,00 | 51.068.779,97 | 51.330.439,91 | 51.674.420,01 | 53.157.355,95 | 53.507.216,05 | 53.861.348,84 | 55.616.960,06 | 56.001.120,05 | 56.388.219,94 |
| **PP n.g. demand [kNm3]** | 2.628.810,67 | 2.684.035,22 | 2.218.260,10 | 2.275.315,28 | 2.203.690,41 | 1.920.497,04 | 2.228.533,73 | 2.453.950,83 | 2.422.438,11 | 2.325.623,52 | 2.294.276,51 | 2.339.848,97 |
| **Other Consumers demand [kNm3]** | 1.206.507,56 | 1.427.033,48 | 1.460.528,08 | 1.504.130,21 | 1.561.262,14 | 1.611.770,05 | 1.657.821,22 | 1.695.036,18 | 1.737.103,75 | 1.766.500,73 | 1.799.364,14 | 1.829.399,86 |
| **Transit of n.g. [kNm3]** | | | 10.000,00 | 50.000,00 | 100.000,00 | 500.000,00 | 550.000,00 | 600.000,00 | 620.000,00 | 650.000,00 | 650.000,00 | 650.000,00 |
| **Small Scale LNG [kNm3]** | | | | 1.183,20 | 2.366,40 | 17.516,00 | 29.232,00 | 52.664,00 | 81.896,00 | 93.496,00 | 122.496,00 | 151.496,00 |
| **Total transmission of n.g. [kNm3]** | 3.835.318,23 | 4.111.068,70 | 3.688.788,18 | 3.830.628,69 | 3.867.318,95 | 4.049.783,09 | 4.465.586,96 | 4.801.651,01 | 4.861.437,87 | 4.835.620,25 | 4.866.136,65 | 4.970.744,83 |

the use of natural gas from the AdG unit for thermal use is included
*actual data **forecasted data

In Chapter 3.4. of the present study, all scenarios results are presented.

**Hydraulic stability of the Transmission system**

DESFA tested the hydraulic adequacy of the NNGS on the basis of the estimated demand for the reference period and concluded to the following results:

1. Reception of gas from the TAP pipeline, requires upgrade of the System with the installation and operation of the compressor station in Ambelia in order to ensure the transmission of gas from the North Entry Points to the consumption points in all different consumption scenarios.

2. With the full operation of the 2nd upgrade of the LNG terminal, the reverse flow capacity towards Bulgaria may reach 4.1 mNm3/day (or 1.5 bcm/year with LF=1), while, taking into account the operation of the compressor station in Ambelia (which may also operate in reverse flow mode) and the increase of the pressure level of the gas entering from Kipi Entry point (eg with compressor installation), the daily reverse flow is expected to reach 10.8 mNm3/day (or 3.9 bcm/yr with LF = 1).

**Estimation of NNGS hydraulic limitation**

The scenario refers to a peak demand day with low consumption north of N. Messimvria. The simulation (no offtake of transit gas in Komotini) resulted to the following:

In case of operation only of the existing compression station in N. Messimvria, the sum of Kipi + Sidirokastron Entry points cannot exceed 15,1 mNm3/day, while in case of operation of the upgrade of N. Messimvria station, the sum of flows from Entry points Kipi + Sidirokastron + N. Messimvria (new Entry Point downstream of the compression station), cannot exceed 15.8 mNm3/day, without the need to further upgrade the network south of N. Messimvria. In case of an additional compressing station in Ambelia, the sum of flows from Kipi + Sidirokastron + N. Messimvria Entry points cannot exceed 19,9 mNm3/day.

In case of gas injection from Entry point “Kipi” and exit of a gas proportion from Exit point “Komotini”, the capacity of the Entry Point "Kipi" can be increased to approx. 32 mNm3/day, of which about 24.5 mNm3/day can exit from the new exit point In Komotini.

# CHAPTER 1: INTRODUCTION

According to Article 91 of the Network Code for the Regulation of the National Natural Gas System as in force, *"…the Operator establishes and publishes a NNGS Development Study which includes:*

*A) The estimates of the Operator for the annual demand of Natural Gas for the entire country, per administrative region and per category of Users, as well as the maximum Daily and hourly demand of Natural Gas per Year, for the next ten (10) Years.*

*B) The estimates of the Operator concerning the feasibility to cover the demand in a cost effective and reliable way using the existing and new sources of Natural Gas supply, including the LNG supply sources, as well as for the necessary, for this purpose, support and expansion of the NNGS.*

*C) The estimates of the Operator for the cost of the necessary investments for the reinforcement and development of the NNGS".*

Taking into account the aforementioned data the Development Study for the period 2018-2027 is conducted. The study evaluates the regulatory changes in the electricity market as well as the transition of the country's economy from the prolonged recession of recent years to expected growth.

At the same time a study for the hydraulic simulation of the NNGTS for the period 2018 - 2027 is prepared, the conclusions of which are presented in Chapter 4 of the Study.

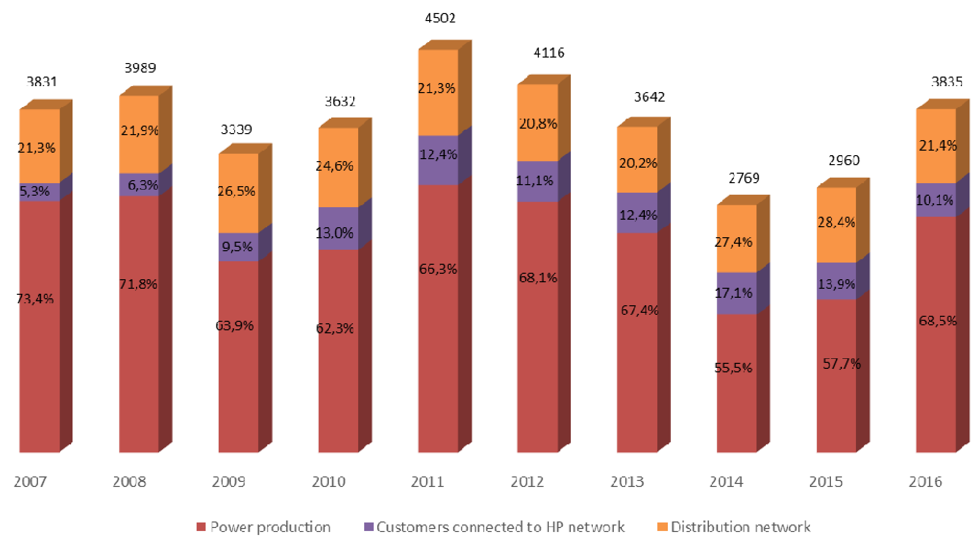
# CHAPTER 2: EVOLUTION OF NATURAL GAS DEMAND

The introduction of the natural gas in the Greek energy system constitutes one of the most important energy projects of the country in the recent decades. In this chapter statistical data of natural gas consumption as well as of n.g. imports from the Entry Points of the National Natural Gas System of previous years are presented.

## 2.1. HISTORICAL DATA ON NATURAL GAS DEMAND

Annual gas consumption in Greece reached its peak in 2011 and since then, until 2014, it has been in gradually decline due to two main reasons: a) the prolonged recession of the country that affects obviously the energy sector b) the direct impact of the changes in the electricity sector on natural gas consumption. The aforementioned situation is reverting from 2015 inwards.

The following graph 1 presents the gas consumption percentages in Greece from 2007 to 2016, per sector of consumption, including operating gas.




**Graph 1 : Natural Gas Consumption percentages (mil. Nm³)**

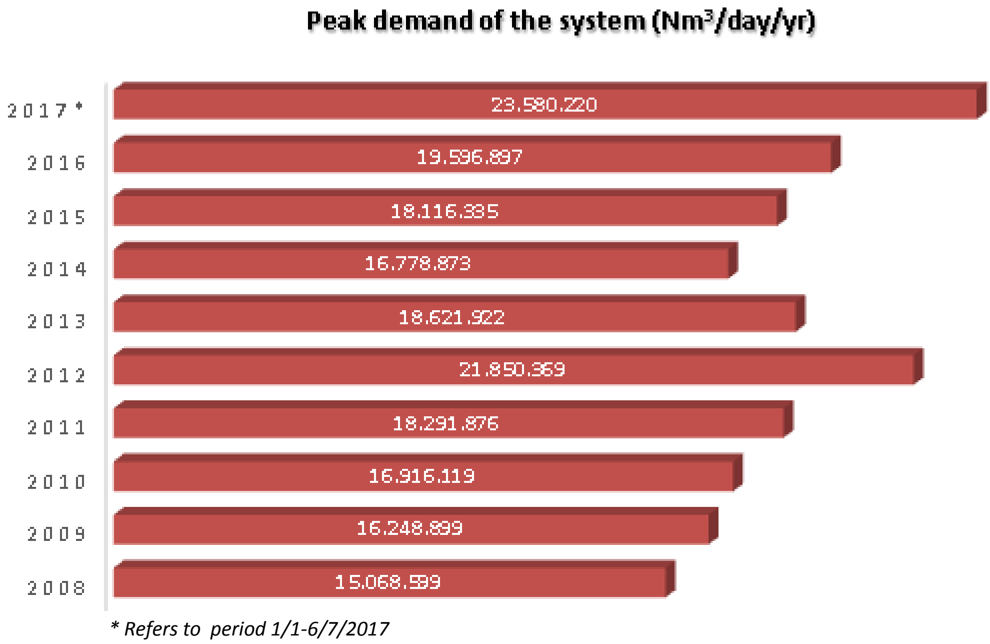
The largest percentage of natural gas consumed during the previous years was used for the production of electricity both from PPC and private electricity producers units.

Table 1 and graph 2 below present the historical data of peak demand for the period 2008-2017.

**Table 1: Peak of the system 2008 – 2017**

| Year | Peak Demand ($Nm^3/d/yr$) | Date |
|---|---|---|
| 2008 | 15.068.599 | **29/1/2008** |
| 2009 | 16.248.899 | **14/12/2009** |
| 2010 | 16.916.119 | **17/12/2010** |
| 2011 | 18.291.876 | **10/3/2011** |
| 2012 | 21.850.369 | **9/2/2012** |
| 2013 | 18.621.922 | **8/1/2013** |
| 2014 | 16.778.873 | **5/2/2014** |
| 2015 | 18.116.335 | **21/12/2015** |
| 2016 | 19.596.897 | **14/12/2016** |
| 2017 * | 23.580.220 | **12/1/2017** |

** Refers to period 1/1-6/7/2017*



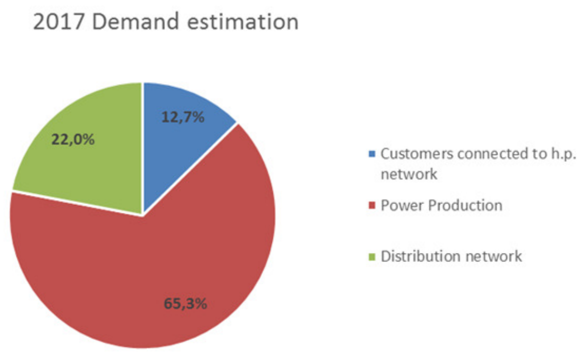

**Graph 2: Peak of the system 2008 – 2017 ($Nm^3/day/yr$)**

As shown in table 1, the maximum daily consumption up to the first five months of 2017 is 23.580.220 $Nm^3$ and occurred on 12th January of 2017.

It should be noted that during the period November 2016 until the beginning of February 2017 the situation in the Greek power system was unprecedented, due to an inspection in nuclear infrastructure (generating units) in France, which led to the need for closure of the units and consequently in a deficit in power supply in a European level. France turned to be a net energy importer, unlike historical data so far, importing energy from many neighboring (and even non-neighboring) countries. The change in the commercial trades so far also affected Greece, while increased energy exports took place throughout that period to the northern neighboring countries (which is quite extraordinary for Greece in normal conditions); the energy price in such countries reached 100 €/MWh for most hours and even

150 €/MWh for many hours during this time period, due to the Europe-wide energy deficit. The exports from Greece to the northern neighboring countries, combined with the extremely unfavorable weather conditions during this winter in Greece, created an energy deficit also in Greece, where all thermal units and many hydro units were dispatched at their maximum available capacity to cover the system load. Such extraordinary harsh conditions are not expected to take place frequently during the years to come.

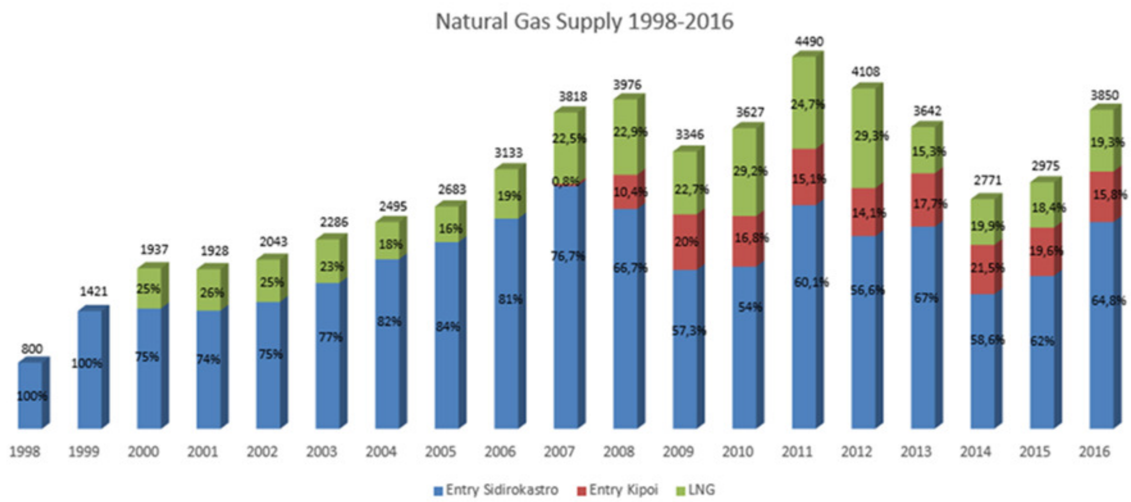
The abovementioned events led to the need for the update of the demand estimation for the year 2017. Taking into account the latest developments and the actual data for January 2017, the total yearly demand was recalculated at the beginning of February 2017 and it is estimated to be 4,1 billion Nm3, an increase of 24,9% from the estimated demand in the Development Study 2017-2026. The breakdown in the demand consumption categories is shown in the following graph.




**Graph 3: Demand percentages per consumption category**

## 2.2. HISTORICAL DATA OF NATURAL GAS IMPORTS

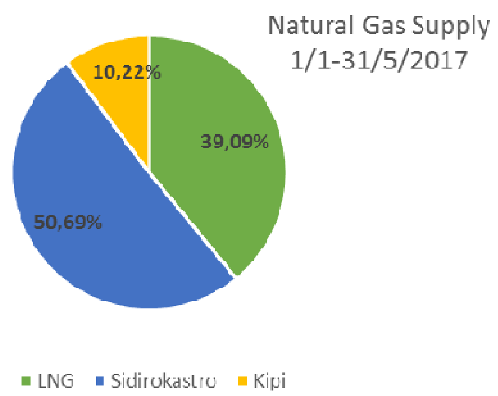
Graph 4 shows the natural gas supply from the pipelines and LNG from 1998 until 2016.




**Graph 4: Procurement of natural gas 1998-2016 (mil.Nm$^3$/yr)**

For 2016 the percent contribution of natural gas imports per Entry Point was as follows: Entry Point Sidirokastro 64,8%, Entry Point Kipi 15,8% and LNG 19,3%.

Similarly, graph 5 shows the natural gas supply from the pipelines and LNG for the first five months of 2017.




**Graph 5 : Procurement of Natural Gas 1/1-31/5/2017**

# CHAPTER 3: DEVELOPMENT OF NATURAL GAS MARKET 2018-2027

## 3.1 DEMAND FORECAST FOR THE PERIOD 2018-2027

The term "demand scenario" refers to the forecast of annual total consumption of n.g. as well as to the natural gas daily peak demand per year, where both are based on certain estimations/assumptions.

For the preparation of the Development Study 2018-2027, all latest data currently in force concerning the Greek natural gas market have been taken into account.

Demand forecast is one of the most important responsibilities of the Operator of the NNGS, as it forms the basis for its design, development and operation. The forecasted demand is also a key parameter for the calculation of the NNGS charges and the hydraulic simulation of the system in order to evaluate new investments related to connection or development projects.

The demand scenario is based on two distinct sections:

A. the gas demand for electricity generation has been particularly analysed and quantified in a study named "Gas consumption forecast for electricity production provided in the wholesale market during the next decade (2018-2027)", as performed by the School of Electrical and Computer Engineering of the Aristotle University of Thessaloniki and

B. the gas demand for clients other than electricity producers for the period 2018-2027 has been quantified and analysed in a study named "Annual Demand Forecast and geographical-daily allocation of other consumers' demand for the period 2018-2027", performed by DESFA

### 3.1.1 Natural gas demand forecast for power production

To estimate the natural gas consumption from power producers on an annual and daily basis for the 2018-2027 period a simulation of the greek wholesale electricity market on a daily basis is executed for the relevant period, taking into account the specificities of each mechanism for the solution and clearing of the market (mandatory pool for 2018 or simple power exchange for years 2019-2027) based on the most updated regulatory framework.

According to the provisions of the Power Exchange Code (PEC) and the Market Operation Manual, the greek wholesale day-ahead electricity market is currently organized as a centralized mandatory pool, in which the market operator solves on a daily basis a short-term unit commitment problem for the following day (also known as "Day-Ahead Scheduling" or DAS), performing a co-optimization of energy and reserves (primary, secondary). These models take also into account several unit technical constraints and hence the problem is formulated and solved as a Mixed-Integer Linear Program (MILP). Consequently, the production units, provided that they will be committed in the DAS schedule, are dispatched from their technical minimum to their available capacity (or within the corresponding limits when they operate under Automatic Generation Regulation, according to the provisions of Article 44 of PEC).

However, by the beginning of 2019 the greek wholesale electricity market is expected to be transformed to a decentralized market, based on the operation of a simple voluntary day-ahead Power Exchange (PX), in order to become compliant with the European Target Model. Furthermore, the free signing of bilateral contracts between producers and suppliers, for the sale of electricity, is expected to constitute a basic feature of the new target model, in parallel with the operation of the PX.

The study realized by the Aristotle University of Thessalonki (AUTH) carried out a sensitivity analysis in a baseline realistic scenario for the system load forecast from which the following four scenarios stem with a change in the prices of critical parameters (crude oil price and $CO_2$ emission allowance):

a) **1st scenario**: High $CO_2$ emissions prices and medium gas prices (high scenario)
b) **2nd scenario**: Low $CO_2$ emissions prices and medium gas prices (medium scenario)
c) **3rd scenario**: High $CO_2$ emissions prices and high gas prices (low A scenario)
d) **4th scenario**: Low CO2 emissions prices and high gas prices (low B scenario)

DESFA in collaboration with AUTH and taking into consideration the latest available data of the market considered that the 2nd scenario (medium scenario) is the most possible to be realized. However, especially for the hydraulic simulation of the system DESFA uses Scenario 1 of the aforementioned study which reflects the highest demand from power producers for the following years. The main assumptions of the four scenarios are presented below:

**a) Electricity load forecast for the next decade**

Based on:
i) the expected consumption and peak load for the period 2018-2027, as these are estimated based on historical data from ADMIE for 2016

ii) the GDP evolution forecast for years 2018-2027[1] and

iii) the correlation between consumption and peak load with Gross Domestic Product (GDP) reduced for the years 2018-2027 based on AUTH's estimates

the expected increase of the system load (consumption) and peak load of the electricity sector for years 2018-2027 is estimated. The total demand of consumers for the reference period on which the AUTH Study is based, will fluctuate from 50,3 TWh (in 2017) to 56,4 TWh (in 2027).

**b) Imports/Exports**

The imports from the Greek northern interconnections (Bulgaria, FYROM and Albania) follow a monthly pattern, according to the monthly net transfer capacity on the respective interconnections, the historical data and the maintenance program of the interconnections.

[1] It is noted that in case that the macroeconomic variables of the Greek economy will change (debt settlement, etc) the forecast will be revised in the next Development Study

For the imports/exports on the interconnections with Italy and Turkey and for the exports to the northern interconnections which fluctuate according to the prices of the Greek wholesale market, a statistical analysis of the imports/exports per interconnection is performed in correlation with the corresponding SMPs for years 2015 and 2016.

**c) RES injections**

They are calculated based on the forecasted installed capacity per RES technology, and on the studier's forecasts for the hourly injection quantities per year's hour per unit installed capacity. It shall be mentioned that the historical data from ADMIE's site and from the Monthly RES Statistics of LAGIE are used.

**d) Pumping**

The monthly measured pumping quantity of year 2012 is used as maximum possible pumping quantity that can be executed by pumping stations (on a monthly basis). This pumping quantity is inserted in the yearly market simulation algorithm (1st solution phase of LTS[2] software), and the hourly pumping quantity to be executed is derived.

**e) Hydro mandatory injections**

The yearly mandatory injection quantities are taken as the mean value of the total annual hydro mandatory injections during the past 25 years excluding years with high hydro production (considered as outliers). Consequently, the hydro units' usage factor is taken equal to 15.636% for the next year. It shall be mentioned that during 2020 the hydro injection will increase due to commissioning of the hydro units "Metsovitiko" (29 MW) and "Mesochora" (160 MW) proportionally to the increase of installed capacity.

**f) Construction/withdrawal of production units**

The timeline and the processes regarding the construction of new production units as well as those regarding the withdrawal of old lignite unIts of PPC are taken into consideration. Specifically:

1) Units "PTOLEMAIDA 2", "AG. GEORGIOS 8", "AG. GEORGIOS 9", "LAVRIO 1", "LAVRIO 2", "LAVRIO 3", "ALIVERI 3" and "ALIVERI 4" have already withdrawn from the Greek power system.

2) Units "PTOLEMAIDA 3", "PTOLEMAIDA 4" suffered a complete damage (by a major fire) and they have been withdrawn in November 2014.

3) Units KARDIA 1, 2, 3 and 4 will operate up to 17,500 hours from the 1$^{st}$ January 2016 till the 31$^{st}$ December 2023 (according to the recent Decision of the Environment and Energy Ministry of the Ministry for Energy).

According to the Transitional National Emissions Reduction Plan (TNERP), conducted pursuant to Article 33 of the Directive 2010/75/EU, the proposed actions concerning the above-mentioned lignite

[2] *LTS : Long Term Scheduling*

units are the following three:

- Direct (from year 2016) and adequate environmental adjustment
- Gradual environmental adjustment
- Inclusion in regime of limited operation duration and then withdrawal

The regime of limited operation duration deviation is valid from 01/01/2016 to 31/12/2023 and allows the Units, which adopt it, 17,500 operation hours per chimney (according to the recent Decision of YPEKA).

Since each unit (KARDIA 1, 2, 3 and 4) bears a separate chimney, there will be no time-binding constraints in its operation distribution and obviously during periods when its production is necessary for the system.

Units KARDIA 3 and 4 provide district heating services at the area of Kozani, which is close to the units. Therefore, they should operate during the winter months, in order to satisfy their contractual obligations for such district heating services. Therefore, these units are expected to operate for about 4 months per year (for the following 5 years), namely for months December-February and July (to cover the peak summer loads), and withdraw late 2021, when the new lignite unit “PTOLEMAIDA 5” is expected to operate commercially and undertake the district heating services at the area of Kozani (because from a construction point of view it will have such capability).

However, units KARDIA 1 and 2 do not provide heating services at the area of Kozani. Therefore, it is not necessary to operate during the winter months. Provided that units KARDIA 3 and 4 will operate during the winter months (during the winter system peak), units KARDIA 1 and 2 will minimize the annual overall system cost if operate during the summer peak load months (June to August for years 2018-2021) and during January in order to cover the winter peak loads. In that way, they shall complete exactly the remaining 17,500 hours of their operation (about 24 months in total).

4) Units “AG. DIMITRIOS 1-4” do not have environmental restrictions in their operation, so they are expected to operate for the whole scheduling time horizon (until the end of year 2027).

5) Unit “MEGALOPOLI 3” is expected to be available until year 2022 (due to gradual reduction of the lignite reserves in the area), while unit “MEGALOPOLI 4” is expected to be available for the whole scheduling time horizon (until the end of year 2027).

6) The recent units “MELITI” and “AG. DIMITRIOS 5” have no environmental issues in their operation, and thus will be in normal operation until year 2027.

7) Unit “MEGALOPOLI 5” has already started commissioning operation in April 2015, and is expected to start commercial operation with decreased capacity (up to about 620 MW) within year 2017. The reason for this delay lies on the fact that the current transmission system in Peloponnese (150 kV) is not capable to transfer the full capacity of the unit. The expansion of the transmission system (400 kV) in the Peloponnese is expected to be completed until December 2020. Consequently, in this study, the commercial operation of the unit at full capacity (811 MW) is considered to be

achieved from January 2021.

8) Units AMYNTAIO 1 and 2 have the same environmental SOx emission problem as units of KARDIA station. It is noted that the units AMYNTAIO 1 and 2 have one common chimney; therefore, since the constraint of the remaining hours is applied per chimney (not per generating unit), it is necessary to operate at the same hours in order to optimize their use. It is also noted that these units provide heating services to the city of AMYNTAIO (located very close to the units). Therefore, it is necessary to operate during the winter months December-February (for the next four years, till February of year 2021) and also in August (for years 2018-2020) in order to assist in covering the summer peak load conditions.

9) As referred above, unit “PTOLEMAIDA 5” is expected to enter in commissioning operation during the 1st semester of 2021 and in commercial operation in July 2021.

10) In this study, it is assumed that unit MELITI 2 will start commercial operation in January 2025.

11) Two new hydro units are expected to start commercial operation during year 2020, “Metsovitiko” (29 MW) and “Mesochora” (160 MW). It is expected that these two units will increase the water potential of hydros on an annual basis, as already described in Section 5.1.4 of this study.

**g) Unit techno-economic data of power production units**

All parameters affecting the unit variable cost as indicatively the efficiency level and the cost of emissions allowances $CO_2$ of thermal units are taken into consideration.

In Scenarios 2 and 4 it is assumed that the market of $CO_2$ emission allowances will be kept at low levels. AUTH’s estimate is that the prices will fluctuate between 5,2 €/tn $CO_2$ (in 2018) – 6 €/tn $CO_2$ (in 2027). In Scenarios 1 and 3 the $CO_2$ price is expected to be higher namely between 6,5 €/tn $CO_2$ (in 2018) – 11 €/tn $CO_2$ (in 2027).

**h) The Equivalent Forced Outage Rate (EFOR) and the scheduled periods for maintenance purposes.**

**i) The units’ injection offers**

The units’ injection offers are based on the minimum variable cost of each generating unit, which stems from both form the $CO_2$ emission allowances cost and the fuel cost.

The procurement price of natural gas is the main parameter for the determination of the variable cost of n.g. thermal units. Within the framework of the present study two possible cases are considered in respect to this parameter.

In scenarios 1 &2 the brent prices are equal to 51 $/barrel for year 2017, 55 $/barrel for year 2018, and of 60 $/barrel for years 2019 and onwards. In scenarios 3&4, the projections of the Brent prices are taken from the World Bank.

**j) Interconnection of islands with the mainland transmission system**

In the relevant study of University of Thessaloniki, the Cyclades are expected to be interconnected with the mainland until year 2019. Crete is expected to be interconnected with the mainland system in year 2022 through an AC transmission line (underwater cable) at 150 kV with a maximum transmission capacity equal to 2x140 = 280 MW. In 2025, it is expected that a second underwater cable (DC) of Crete (2x350 MW) will be operational, and hence there will be no congestion anymore between the mainland transmission system and Crete.
The results of the study include:

a) the estimation of the total electricity demand in Greece for the period 2018-2027, based on the estimation of International Organizations for the evolution of the growth rate as well as on historical demand data of previous years,
b) the estimation of the electricity production percentage of thermal natural gas units (in MWhe) taking into consideration all the significant parameters that may affect it (penetration of PVs, wind, inclusion/extraction of conventional units), and
c) the estimation of Natural Gas Consumption from gas units, based on each unit's specific function of heat rate.

The following Tables 2-5 summarize the main results of the study for the four defined scenarios[3]. It shall be highlighted the difference in demand of power producers between 2018 and 2017. This large fluctuation is due to the increased gas consumption during the first months of 2017 due to extraordinary circumstances, as mentioned in Chapter 2.1 of this study "Historical data on natural gas demand"
At this point, it should be mentioned that on June 10, 2017, huge landslides took place in the AMYNTAIO mine, the PPC's lignite center of Western Macedonia. For this reason, DESFA asked from AUTH to examine the impact of such a case on the results of the PP demand study, as presented above.

The results are the following:

1) In the case that AMYNTAIO units will not operate at the peak of demand within July 2017, the impact on the demand of PP will be small, i.e. up to 0,046 billion $Nm^3$ additional demand for electricity production. Similar results will be realized for the July 2018 and 2019, of the reference period of the study.

2) In the case that AMYNTAIO units will not operate during the winter 2017-2018, the impact on the demand of PP will be significant, i.e. about 0,21 billion $Nm^3$ additional demand for electricity production. The impact for the winter 2018-2019 will be similar, and the impact for the winter 2019-2020 will be less due to the final withdrawal of units in January 2020, according to most recent data.

However, no impact is taken into account in the results of this study, due to the lack of data on how PPC will address the problem occurred.

[3] Tables 2-5 do not include the use of natural gas from the AdG unit for thermal use

**Table 2.** Energy balance in the interconnected power system (per year) – Scenario 1

| Unit/load category | 2017* | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Lignite units [MWhe]** | **14.833.509,51** | **15.599.442,57** | **15.300.638,77** | **14.897.451,41** | **14.847.488,11** | **13.964.231,52** | **13.506.476,21** | **13.745.476,44** | **15.409.444,22** | **15.041.477,82** | **14.867.579,31** |
| Gas units (PPC) [MWhe] | | 4.875.057,35 | 4.771.231,89 | 4.793.604,63 | 5.551.525,76 | 6.263.737,80 | 6.511.849,71 | 6.465.372,42 | 6.059.699,46 | 6.401.483,64 | 6.552.837,80 |
| Gas units (IPPs) [MWhe] | | 6.388.789,89 | 6.602.385,23 | 6.465.498,31 | 5.645.708,13 | 6.738.200,77 | 7.004.676,28 | 6.862.085,36 | 7.384.847,00 | 7.484.572,44 | 7.576.907,21 |
| **Gas units [MWhe]** | **13.932.115,02** | **11.263.847,24** | **11.373.617,12** | **11.259.102,94** | **11.197.233,89** | **13.001.938,57** | **13.516.525,99** | **13.327.457,78** | **13.444.546,46** | **13.886.056,08** | **14.129.745,01** |
| **Crete CCGT Unit [MWhe]** | | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 687.496,60 | 680.526,15 | 664.096,00 |
| **Hydros [MWhe]** | **4.678.070,74** | **4.374.004,47** | **4.377.155,32** | **4.636.644,10** | **4.632.144,79** | **4.633.216,12** | **4.626.585,82** | **4.633.621,42** | **4.632.380,32** | **4.629.028,54** | **4.631.967,46** |
| Imports [MWhe] | | 11.427.135,11 | 11.468.363,40 | 11.483.341,00 | 11.433.698,57 | 11.626.899,96 | 11.677.548,02 | 11.729.417,70 | 11.594.489,78 | 11.672.972,26 | 11.761.767,35 |
| Exports [MWhe] | | 1.481.018,24 | 1.355.099,82 | 1.369.253,71 | 1.343.532,40 | 1.309.152,80 | 1.290.999,84 | 1.282.672,42 | 1.305.003,27 | 1.272.446,27 | 1.276.432,95 |
| **Net imports [MWhe]** | **8.388.846,12** | **9.946.116,88** | **10.113.263,58** | **10.114.087,29** | **10.090.166,18** | **10.317.747,17** | **10.386.548,18** | **10.446.745,28** | **10.289.486,50** | **10.400.525,99** | **10.485.334,40** |
| Wind plants [MWhe] | | 5.277.677,01 | 5.742.060,86 | 6.149.751,50 | 6.527.986,19 | 6.761.501,63 | 6.873.138,68 | 7.001.783,89 | 7.096.413,08 | 7.208.049,88 | 7.319.686,54 |
| PVs [MWhe] | | 3.794.022,82 | 3.887.689,55 | 3.940.819,39 | 3.987.489,37 | 4.037.038,57 | 4.086.356,05 | 4.138.715,44 | 4.184.291,59 | 4.232.909,78 | 4.281.294,83 |
| Biomass/Biogas [MWhe] | | 346.455,70 | 404.975,98 | 466.645,86 | 525.840,71 | 586.274,01 | 646.705,68 | 709.050,92 | 767.570,58 | 828.003,12 | 888.436,30 |
| Small hydros [MWhe] | | 756.672,64 | 780.220,51 | 801.967,23 | 819.290,90 | 838.826,99 | 858.362,36 | 880.326,90 | 897.433,12 | 916.969,16 | 936.504,69 |
| Small co-generation [MWhe] | | 160.183,51 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 |
| **Total RES/Co-generation units [MWhe]** | **9.693.216,12** | **10.335.011,68** | **10.978.160,08** | **11.523.052,24** | **12.023.820,35** | **12.386.854,38** | **12.627.775,95** | **12.893.745,41** | **13.108.921,55** | **13.349.145,12** | **13.589.135,54** |
| **Total production [MWhe]** | **51.525.757,49** | **51.518.422,84** | **52.142.834,87** | **52.430.337,98** | **52.790.853,32** | **54.303.987,76** | **54.663.912,15** | **55.047.046,33** | **56.884.779,05** | **57.306.233,55** | **57.703.761,72** |
| **Gas units' percentage [%]** | 27,04% | 21,86% | 21,81% | 21,47% | 21,21% | 23,94% | 24,73% | 24,21% | 23,63% | 24,23% | 24,49% |
| **Pumping [MWhe]** | **21.069,05** | **60.844,57** | **57.144,88** | **62.650,18** | **54.473,37** | **46.571,38** | **45.118,57** | **55.404,99** | **52.432,61** | **50.975,85** | **54.769,76** |
| **System load [MWhe]** | **51.504.688,30** | **51.457.578,05** | **52.085.689,78** | **52.367.687,69** | **52.736.379,88** | **54.257.416,22** | **54.618.793,85** | **54.991.641,13** | **56.832.346,46** | **57.255.257,60** | **57.648.991,90** |
| **System losses [MWhe]** | **1.220.808,38** | **1.003.258,05** | **1.016.909,81** | **1.037.247,78** | **1.061.959,86** | **1.100.060,27** | **1.111.577,80** | **1.130.292,29** | **1.215.386,40** | **1.254.137,55** | **1.260.771,96** |
| **Total demand of consumers (with distribution network losses) [MWhe]** | **50.283.879,92** | **50.454.320,00** | **51.068.779,97** | **51.330.439,91** | **51.674.420,01** | **53.157.355,95** | **53.507.216,05** | **53.861.348,84** | **55.616.960,06** | **56.001.120,05** | **56.388.219,94** |
| **Gas consumption [kNm3]** | **2.586.100,77** | **2.125.122,78** | **2.147.675,17** | **2.126.512,48** | **2.065.661,48** | **2.370.760,85** | **2.460.553,09** | **2.429.160,23** | **2.340.705,36** | **2.412.046,69** | **2.455.891,03** |
| **Daily gas peak [Nm3/day]** | **11.037,22** | **10.847,37** | **10.538,84** | **11.089,30** | **11.170,32** | **11.871,88** | **12.347,40** | **13.033,78** | **12.159,46** | **12.798,82** | **12.312,30** |
| **Brent price [$/bbl]** | 51,00 | 55,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 |
| **$CO_2$ price [€/T]** | 5,14 | 6,50 | 7,00 | 8,00 | 10,00 | 11,00 | 11,00 | 11,00 | 11,00 | 11,00 | 11,00 |
| **GDP increase [%]** | 1,60% | 1,50% | 1,50% | 1,50% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% |
| **Consumption increase [%]** | | 0,26% | 1,22% | 0,51% | 0,67% | 2,87% | 0,66% | 0,66% | 3,27% | 0,69% | 0,69% |

*estimation based on real data of January 2017 and on simulations of the wholesale electricity market for the period February – Decembe ** commercial operation of PTOLEMAIDA 5 in July 2021, MELITI 2 in January in 2025, withdrawal of KARDIA 1-4 and AMYNDEO 1-2 in 2021, withdrawal of MEGALOPOLI 3 in 2022

**Table 3. Energy balance in the interconnected power system (per year) – Scenario 2**

| Unit/load category | 2017* | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Lignite units [MWhe]** | **14.833.509,51** | **15.837.777,25** | **15.445.461,66** | **15.370.192,02** | **16.912.051,31** | **16.045.088,50** | **14.668.034,04** | **14.867.885,35** | **16.611.005,75** | **16.914.845,19** | **16.760.331,07** |
| Gas units (PPC) [MWhe] | | 4.738.950,50 | 4.893.999,96 | 4.752.692,32 | 4.857.444,69 | 5.564.476,59 | 6.170.639,40 | 6.049.126,83 | 5.696.846,12 | 5.723.180,03 | 5.902.320,23 |
| Gas units (IPPs) [MWhe] | | 6.346.604,27 | 6.489.018,73 | 6.230.487,74 | 4.643.324,90 | 5.762.313,80 | 6.484.334,84 | 6.437.700,15 | 6.861.489,99 | 6.675.799,79 | 6.730.845,84 |
| **Gas units [MWhe]** | **13.932.115,02** | **11.085.554,77** | **11.383.018,69** | **10.983.180,06** | **9.500.769,59** | **11.326.790,39** | **12.654.974,24** | **12.486.826,98** | **12.558.336,11** | **12.398.979,82** | **12.633.166,07** |
| **Crete CCGT Unit [MWhe]** | | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 687.449,85 | 681.102,75 | 664.056,90 |
| **Hydros [MWhe]** | **4.678.070,74** | **4.377.067,97** | **4.378.193,89** | **4.639.301,93** | **4.637.553,75** | **4.637.140,00** | **4.632.793,72** | **4.639.508,56** | **4.635.441,70** | **4.638.482,87** | **4.638.786,31** |
| Imports [MWhe] | | 11.400.352,38 | 11.410.045,24 | 11.398.702,68 | 11.287.647,32 | 11.428.272,33 | 11.547.869,54 | 11.603.375,47 | 11.460.462,68 | 11.474.384,95 | 11.559.587,45 |
| Exports [MWhe] | | 1.514.268,48 | 1.448.497,14 | 1.475.651,18 | 1.528.161,66 | 1.486.577,63 | 1.433.774,59 | 1.413.970,04 | 1.457.741,30 | 1.448.706,17 | 1.445.291,65 |
| **Net imports [MWhe]** | **8.388.846,12** | **9.886.083,90** | **9.961.548,10** | **9.923.051,51** | **9.759.485,66** | **9.941.694,71** | **10.114.094,95** | **10.189.405,43** | **10.002.721,38** | **10.025.678,78** | **10.114.295,80** |
| Wind plants [MWhe] | | 5.277.677,01 | 5.742.060,86 | 6.149.751,50 | 6.527.986,19 | 6.761.501,63 | 6.873.138,68 | 7.001.783,89 | 7.096.413,08 | 7.208.049,88 | 7.319.686,54 |
| PVs [MWhe] | | 3.794.022,82 | 3.887.689,55 | 3.940.819,39 | 3.987.489,37 | 4.037.038,57 | 4.086.356,05 | 4.138.715,44 | 4.184.291,59 | 4.232.909,78 | 4.281.294,83 |
| Biomass/Biogas [MWhe] | | 346.455,70 | 404.975,98 | 466.645,86 | 525.840,71 | 586.274,01 | 646.705,68 | 709.050,92 | 767.570,58 | 828.003,12 | 888.436,30 |
| Small hydros [MWhe] | | 756.672,64 | 780.220,51 | 801.967,23 | 819.290,90 | 838.826,99 | 858.362,36 | 880.326,90 | 897.433,12 | 916.969,16 | 936.504,69 |
| Small co-generation [MWhe] | | 160.183,51 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 |
| **Total RES/Co-generation units [MWhe]** | **9.693.216,12** | **10.335.011,68** | **10.978.160,08** | **11.523.052,24** | **12.023.820,35** | **12.386.854,38** | **12.627.775,95** | **12.893.745,41** | **13.108.921,55** | **13.349.145,12** | **13.589.135,54** |
| **Total production [MWhe]** | **51.525.757,49** | **51.521.495,57** | **52.146.382,42** | **52.438.777,76** | **52.833.680,66** | **54.337.567,98** | **54.697.672,90** | **55.077.371,73** | **56.916.426,49** | **57.327.131,78** | **57.735.714,79** |
| **Gas units' percentage [%]** | 27,04% | 21,52% | 21,83% | 20,94% | 17,98% | 20,85% | 23,14% | 22,67% | 22,06% | 21,63% | 21,88% |
| **Pumping [MWhe]** | **21.069,05** | **60.778,32** | **57.457,44** | **62.594,48** | **61.043,98** | **57.168,77** | **50.761,24** | **58.123,76** | **55.044,45** | **52.593,81** | **60.663,13** |
| **System load [MWhe]** | **51.504.688,30** | **51.460.717,24** | **52.088.924,79** | **52.376.183,10** | **52.772.636,62** | **54.280.399,06** | **54.646.911,57** | **55.019.247,65** | **56.861.381,80** | **57.274.538,05** | **57.675.051,61** |
| **System losses [MWhe]** | **1.220.808,38** | **1.006.397,24** | **1.020.144,82** | **1.045.743,19** | **1.098.216,61** | **1.123.043,11** | **1.139.695,51** | **1.157.898,81** | **1.244.421,73** | **1.273.418,00** | **1.286.831,67** |
| **Total demand of consumers (with distribution network losses) [MWhe]** | **50.283.879,92** | **50.454.320,00** | **51.068.779,97** | **51.330.439,91** | **51.674.420,01** | **53.157.355,95** | **53.507.216,05** | **53.861.348,84** | **55.616.960,06** | **56.001.120,05** | **56.388.219,94** |
| **Gas consumption [kNm3]** | **2.586.100,77** | **2.090.047,50** | **2.147.102,69** | **2.075.126,54** | **1.792.284,44** | **2.100.321,14** | **2.325.738,24** | **2.293.874,25** | **2.197.410,93** | **2.166.063,91** | **2.211.636,37** |
| **Daily gas peak [Nm3/day]** | **11.037,22** | **10.998,84** | **10.377,36** | **10.258,20** | **9.757,46** | **11.382,58** | **12.215,55** | **13.397,32** | **11.940,52** | **12.803,31** | **12.206,99** |
| **Brent price [$/bbl]** | 51,00 | 55,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 | 60,00 |
| **$CO_2$ price [€/T]** | 5,14 | 5,18 | 5,23 | 5,31 | 5,40 | 5,48 | 5,58 | 5,67 | 5,77 | 5,87 | 5,97 |
| **GDP increase [%]** | 1,60% | 1,50% | 1,50% | 1,50% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% |
| **Consumption increase [%]** | | 0,26% | 1,22% | 0,51% | 0,67% | 2,87% | 0,66% | 0,66% | 3,27% | 0,69% | 0,69% |

*estimation based on real data of January 2017 and on simulations of the wholesale electricity market for the period February - December

** commercial operation of PTOLEMAIDA 5 in July 2021, MELITI 2 in January in 2025, withdrawal of KARDIA 1-4 and AMYNDEO 1-2 in 2021, withdrawal of MEGALOPOLI 3 in 2022

Table 4. Energy balance in the interconnected power system (per year) – Scenario 3

| Unit/load category | 2017* | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Lignite units [MWhe]** | **14.833.509,51** | **15.840.472,61** | **15.372.946,91** | **15.164.248,24** | **16.364.086,54** | **15.603.407,51** | **14.604.889,18** | **14.810.438,46** | **16.526.205,91** | **16.502.538,88** | **16.680.513,59** |
| Gas units (PPC) [MWhe] | | 4.893.909,57 | 4.919.551,54 | 4.877.569,71 | 5.099.878,07 | 5.669.699,96 | 6.053.556,76 | 5.996.873,91 | 5.449.792,27 | 5.433.726,34 | 5.541.516,24 |
| Gas units (IPPs) [MWhe] | | 6.048.756,03 | 6.409.263,14 | 6.099.394,85 | 4.593.573,03 | 5.616.969,51 | 6.127.304,91 | 5.970.447,28 | 6.408.477,50 | 6.425.449,32 | 6.224.294,61 |
| **Gas units [MWhe]** | **13.932.115,02** | **10.942.665,60** | **11.328.814,68** | **10.976.964,56** | **9.693.451,10** | **11.286.669,47** | **12.180.861,67** | **11.967.321,19** | **11.858.269,77** | **11.859.175,66** | **11.765.810,85** |
| **Crete CCGT Unit [MWhe]** | | **0,00** | **0,00** | **0,00** | **0,00** | **0,00** | **0,00** | **0,00** | **687.425,44** | **680.850,54** | **664.157,34** |
| **Hydros [MWhe]** | **4.678.070,74** | **4.378.667,08** | **4.375.711,73** | **4.638.960,99** | **4.633.086,84** | **4.638.189,53** | **4.635.628,40** | **4.645.103,32** | **4.637.669,74** | **4.643.064,94** | **4.652.545,44** |
| Imports [MWhe] | | 11.476.025,10 | 11.468.416,49 | 11.502.980,58 | 11.483.974,93 | 11.730.748,73 | 11.905.328,78 | 11.985.057,38 | 12.037.948,41 | 12.181.339,42 | 12.256.997,18 |
| Exports [MWhe] | | 1.432.199,37 | 1.360.461,73 | 1.352.406,29 | 1.354.718,81 | 1.294.162,74 | 1.249.474,85 | 1.219.820,42 | 1.239.828,07 | 1.197.504,89 | 1.200.713,36 |
| **Net imports [MWhe]** | **8.388.846,12** | **10.043.825,72** | **10.107.954,76** | **10.150.574,29** | **10.129.256,12** | **10.436.586,00** | **10.655.853,93** | **10.765.236,95** | **10.798.120,34** | **10.983.834,52** | **11.056.283,82** |
| Wind plants [MWhe] | | 5.277.677,01 | 5.742.060,86 | 6.149.751,50 | 6.527.986,19 | 6.761.501,63 | 6.873.138,68 | 7.001.783,89 | 7.096.413,08 | 7.208.049,88 | 7.319.686,54 |
| PVs [MWhe] | | 3.794.022,82 | 3.887.689,55 | 3.940.819,39 | 3.987.489,37 | 4.037.038,57 | 4.086.356,05 | 4.138.715,44 | 4.184.291,59 | 4.232.909,78 | 4.281.294,83 |
| Biomass/Biogas [MWhe] | | 346.455,70 | 404.975,98 | 466.645,86 | 525.840,71 | 586.274,01 | 646.705,68 | 709.050,92 | 767.570,58 | 828.003,12 | 888.436,30 |
| Small hydros [MWhe] | | 756.672,64 | 780.220,51 | 801.967,23 | 819.290,90 | 838.826,99 | 858.362,36 | 880.326,90 | 897.433,12 | 916.969,16 | 936.504,69 |
| Small co-generation [MWhe] | | 160.183,51 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 |
| **Total RES/Co-generation units [MWhe]** | **9.693.216,12** | **10.335.011,68** | **10.978.160,08** | **11.523.052,24** | **12.023.820,35** | **12.386.854,38** | **12.627.775,95** | **12.893.745,41** | **13.108.921,55** | **13.349.145,12** | **13.589.135,54** |
| **Total production [MWhe]** | **51.525.757,49** | **51.540.642,69** | **52.163.588,16** | **52.453.800,32** | **52.843.700,95** | **54.351.706,89** | **54.705.009,13** | **55.081.845,33** | **56.929.187,31** | **57.337.759,12** | **57.744.289,24** |
| **Gas units' percentage [%]** | 27,04% | 21,23% | 21,72% | 20,93% | 18,34% | 20,77% | 22,27% | 21,73% | 20,83% | 20,68% | 20,38% |
| **Pumping [MWhe]** | **21.069,05** | **60.374,03** | **57.523,31** | **62.516,39** | **58.983,69** | **55.092,68** | **45.338,96** | **51.766,34** | **55.010,20** | **50.548,60** | **57.651,55** |
| **System load [MWhe]** | **51.504.688,30** | **51.480.268,43** | **52.106.064,96** | **52.391.283,71** | **52.784.717,46** | **54.296.614,11** | **54.659.670,19** | **55.030.079,18** | **56.874.176,92** | **57.287.210,37** | **57.686.638,05** |
| **System losses [MWhe]** | **1.220.808,38** | **1.025.948,43** | **1.037.284,99** | **1.060.843,80** | **1.110.297,45** | **1.139.258,16** | **1.152.454,14** | **1.168.730,34** | **1.257.216,86** | **1.286.090,32** | **1.298.418,11** |
| **Total demand of consumers (with distribution network losses) [MWhe]** | **50.283.879,92** | **50.454.320,00** | **51.068.779,97** | **51.330.439,91** | **51.674.420,01** | **53.157.355,95** | **53.507.216,05** | **53.861.348,84** | **55.616.960,06** | **56.001.120,05** | **56.388.219,94** |
| **Gas consumption [kNm3]** | **2.586.100,77** | **2.066.144,78** | **2.136.216,70** | **2.075.777,39** | **1.823.536,11** | **2.085.811,59** | **2.240.764,65** | **2.202.943,95** | **2.066.042,44** | **2.067.025,00** | **2.051.597,10** |
| **Daily gas peak [Nm3/day]** | **11.037,22** | **10.525,75** | **10.531,38** | **10.264,88** | **9.479,46** | **10.955,68** | **11.945,04** | **12.910,39** | **11.480,47** | **12.107,92** | **11.893,85** |
| **Brent price [$/bbl]** | 51,000 | 60,000 | 61,456 | 62,947 | 64,474 | 66,039 | 67,641 | 69,282 | 70,963 | 72,770 | 74,578 |
| **$CO_2$ price [€/T]** | 5,14 | 6,50 | 7,00 | 8,00 | 10,00 | 11,00 | 11,00 | 11,00 | 11,00 | 11,00 | 11,00 |
| **GDP increase [%]** | 1,60% | 1,50% | 1,50% | 1,50% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% |
| **Consumption increase [%]** | | 0,26% | 1,22% | 0,51% | 0,67% | 2,87% | 0,66% | 0,66% | 3,27% | 0,69% | 0,69% |

*estimation based on real data of January 2017 and on simulations of the wholesale electricity market for the period February - December

** commercial operation of PTOLEMAIDA 5 in July 2021, MELITI 2 in January in 2025, withdrawal of KARDIA 1-4 and AMYNDEO 1-2 in 2021, withdrawal of MEGALOPOLI 3 in 2022

**Table 5. Energy balance in the interconnected power system (per year) – Scenario 4**

| Unit/load category | 2017* | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Lignite units [MWhe]** | **14.833.509,51** | **15.956.327,42** | **15.516.536,27** | **15.540.800,85** | **17.126.561,86** | **16.203.737,92** | **14.832.191,67** | **15.043.831,41** | **16.883.385,32** | **17.339.016,57** | **17.155.091,67** |
| Gas units (PPC) [MWhe] | | 4.716.663,99 | 4.791.449,13 | 4.664.849,19 | 4.749.480,50 | 5.196.043,89 | 5.726.643,17 | 5.652.698,59 | 5.184.937,26 | 5.128.511,01 | 5.249.159,29 |
| Gas units (IPPs) [MWhe] | | 6.130.050,31 | 6.402.375,80 | 6.052.334,85 | 4.355.088,34 | 5.725.482,24 | 6.413.146,56 | 6.279.306,06 | 6.589.485,48 | 6.245.980,20 | 6.252.384,40 |
| **Gas units [MWhe]** | **13.932.115,02** | **10.846.714,30** | **11.193.824,93** | **10.717.184,04** | **9.104.568,84** | **10.921.526,13** | **12.139.789,73** | **11.932.004,65** | **11.774.422,74** | **11.374.491,21** | **11.501.543,69** |
| **Crete CCGT Unit [MWhe]** | | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 0,00 | 687.566,15 | 681.048,58 | 664.557,84 |
| **Hydros [MWhe]** | **4.678.070,74** | **4.380.479,34** | **4.381.067,61** | **4.641.534,79** | **4.642.794,95** | **4.645.639,96** | **4.641.610,61** | **4.647.993,89** | **4.647.601,99** | **4.651.383,57** | **4.660.334,43** |
| Imports [MWhe] | | 11.451.869,17 | 11.467.859,23 | 11.439.218,33 | 11.378.270,99 | 11.579.145,59 | 11.775.961,82 | 11.855.376,50 | 11.838.033,46 | 11.925.091,61 | 12.126.545,49 |
| Exports [MWhe] | | 1.449.232,04 | 1.390.772,12 | 1.419.014,82 | 1.442.768,43 | 1.401.875,23 | 1.324.748,28 | 1.299.515,04 | 1.338.346,49 | 1.316.665,15 | 1.301.273,21 |
| **Net imports [MWhe]** | **8.388.846,12** | **10.002.637,13** | **10.077.087,11** | **10.020.203,52** | **9.935.502,56** | **10.177.270,36** | **10.451.213,53** | **10.555.861,46** | **10.499.686,96** | **10.608.426,47** | **10.825.272,28** |
| Wind plants [MWhe] | | 5.277.677,01 | 5.742.060,86 | 6.149.751,50 | 6.527.986,19 | 6.761.501,63 | 6.873.138,68 | 7.001.783,89 | 7.096.413,08 | 7.208.049,88 | 7.319.686,54 |
| PVs [MWhe] | | 3.794.022,82 | 3.887.689,55 | 3.940.819,39 | 3.987.489,37 | 4.037.038,57 | 4.086.356,05 | 4.138.715,44 | 4.184.291,59 | 4.232.909,78 | 4.281.294,83 |
| Biomass/Biogas [MWhe] | | 346.455,70 | 404.975,98 | 466.645,86 | 525.840,71 | 586.274,01 | 646.705,68 | 709.050,92 | 767.570,58 | 828.003,12 | 888.436,30 |
| Small hydros [MWhe] | | 756.672,64 | 780.220,51 | 801.967,23 | 819.290,90 | 838.826,99 | 858.362,36 | 880.326,90 | 897.433,12 | 916.969,16 | 936.504,69 |
| Small co-generation [MWhe] | | 160.183,51 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 | 163.868,26 | 163.213,18 | 163.213,18 | 163.213,18 |
| **Total RES/Co-generation units [MWhe]** | **9.693.216,12** | **10.335.011,68** | **10.978.160,08** | **11.523.052,24** | **12.023.820,35** | **12.386.854,38** | **12.627.775,95** | **12.893.745,41** | **13.108.921,55** | **13.349.145,12** | **13.589.135,54** |
| **Total production [MWhe]** | **51.525.757,49** | **51.521.169,87** | **52.146.676,00** | **52.442.775,44** | **52.833.248,56** | **54.335.028,75** | **54.692.581,49** | **55.073.436,82** | **56.914.018,56** | **57.322.462,94** | **57.731.377,61** |
| **Gas units' percentage [%]** | 27,04% | 21,05% | 21,47% | 20,44% | 17,23% | 20,10% | 22,20% | 21,67% | 20,69% | 19,84% | 19,92% |
| **Pumping [MWhe]** | **21.069,05** | **59.172,32** | **56.658,29** | **62.594,49** | **60.473,17** | **55.641,42** | **48.399,69** | **57.092,64** | **55.566,15** | **49.785,85** | **59.085,80** |
| **System load [MWhe]** | **51.504.688,30** | **51.461.997,72** | **52.090.017,40** | **52.380.180,89** | **52.772.775,09** | **54.279.387,26** | **54.644.181,43** | **55.016.343,96** | **56.858.452,31** | **57.272.677,14** | **57.672.291,89** |
| **System losses [MWhe]** | **1.220.808,38** | **1.007.677,72** | **1.021.237,43** | **1.049.740,97** | **1.098.355,08** | **1.122.031,31** | **1.136.965,37** | **1.154.995,12** | **1.241.492,25** | **1.271.557,09** | **1.284.071,94** |
| **Total demand of consumers (with distribution network losses) [MWhe]** | **50.283.879,92** | **50.454.320,00** | **51.068.779,97** | **51.330.439,91** | **51.674.420,01** | **53.157.355,95** | **53.507.216,05** | **53.861.348,84** | **55.616.960,06** | **56.001.120,05** | **56.388.219,94** |
| **Gas consumption [kNm3]** | **2.586.100,77** | **2.046.729,33** | **2.113.655,85** | **2.032.311,34** | **1.723.228,68** | **2.025.462,07** | **2.229.291,87** | **2.188.325,86** | **2.045.925,33** | **1.973.611,76** | **2.003.387,78** |
| **Daily gas peak [Nm3/day]** | **11.037,22** | **10.272,74** | **10.309,82** | **10.026,38** | **9.106,18** | **11.272,47** | **11.861,56** | **12.914,70** | **11.426,10** | **12.393,34** | **12.173,23** |
| **Brent price [$/bbl]** | 51,000 | 60,000 | 61,456 | 62,947 | 64,474 | 66,039 | 67,641 | 69,282 | 70,963 | 72,770 | 74,578 |
| **$CO_2$ price [€/T]** | 5,14 | 5,18 | 5,23 | 5,31 | 5,40 | 5,48 | 5,58 | 5,67 | 5,77 | 5,87 | 5,97 |
| **GDP increase [%]** | 1,60% | 1,50% | 1,50% | 1,50% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% | 1,30% |
| **Consumption increase [%]** | | 0,26% | 1,22% | 0,51% | 0,67% | 2,87% | 0,66% | 0,66% | 3,27% | 0,69% | 0,69% |

*estimation based on real data of January 2017 and on simulations of the wholesale electricity market for the period February - December

** commercial operation of PTOLEMAIDA 5 in July 2021, MELITI 2 in January 2025, withdrawal of KARDIA 1-4 and AMYNDEO 1-2 in 2021, withdrawal of MEGALOPOLI 3 in 2022

### 3.1.2 Estimated consumption of natural gas from Other Consumers

For the estimation of gas consumption from other consumers, the annual demand allocation of natural gas to the Users of the NNGTS, excluding those that are considered to consume natural gas for the power generation and Small Scale LNG infrastructure consumers, is calculated per metering station. The calculation aims to estimate the maximum daily peak of the Year for the transmission system.

The calculation model was based on data processing of the following sources:

i) Daily consumption historic data at each NNGS metering station.
ii) Forecast of the annual gas market demand, as notified by the NNGS Users in accordance with Article 90 of Chapter 12 of the Network Code.
iii) The evolution of the regulatory framework regarding the reform of the Greek gas market through the new regulatory framework that imposed the reconstruction of the retail gas market in the beginning of 2017. Distribution and supply activities that were implemented by Gas Supply Companies (EPAs), are now administrative and operationally independent, and Gas Distribution Companies (EDAs) are now responsible for the distribution.
iv) The estimations and data regarding demand and connections to the distribution networks by consumption category, as published with the approvals on the charges for the basic distribution activity of EDAs.
v) The population data of cities with urban gas consumption, where required
vi) Historical data from previous years from the Athens Observatory
vii) Data regarding the Gross Domestic Product, as estimated by the Aristotle University of Thessaloniki, in the study "Gas Consumption Forecast for Electricity Production Provided in the Wholesale Market during the next decade (2018-2027)".

To begin with, the first stage of the study was the separation of the NNGTS consumers into two main categories: a) Individual Consumers and b) consumers of natural gas that consist entry points in the gas distribution networks. Subsequently, network consumption was geographically distributed to individual, existing or new, consumption points within the network.

*Individual Consumers are considered to be points of consumption which do not belong to power generating units and either are points directly connected to the high pressure pipeline of the NNGS or points which, while belonging to an EDA, correspond to an individual consumption point for the supply of a particular installation/ geographic area and therefore a typical daily profile results from historical data available to the Operator.*

The breakdown at points of consumption was made for two main categories of natural gas use: a) industrial use (industrial and commercial sector) and b) urban use (residential sector).

The abovementioned sectors were grouped based on the end-user categories[4] as adopted by EDAs.

It should be noted that the Gas Distribution Companies, as established, are the following: EDA Attikis, EDA Thessalonikis, EDA Thessalias and EDA of the rest of Greece, which is composed by distribution networks in the areas of Central Greece, Central Macedonia, Eastern Macedonia and Thrace and Corinth.

In particular, further development of medium and low pressure distribution networks is envisaged in EDA of the rest of Greece, as the networks in the aforementioned areas have not reached yet the desired level of growth in all categories of consumers. Mainly the distribution network related to industrial sector, and not the residential sector, has already been developed. The present study considers that the expected growth of these networks will begin from 2020 onwards.

**The total natural gas demand for the period 2018-2027 by each category of use was estimated as follows:**

**INDIVIDUAL CONSUMERS**

Historical data of consumptions until March 2017, data send by Users under Article 90 of the Network Code and data send by distribution network operators were evaluated and processed for the estimation of the consumption from Individual Consumers (including industrial areas).

**REGIONS WITH DISTRIBUTION NETWORKS**

In order to assess the gas demand, data from the Users, that are available to the Operator, were taken into account as well as the demand per end-user category in accordance with the business plans of the distribution networks operators, as used for the calculation of their usage charges. Thereafter, the abovementioned data were processed and the evolution of the gas consumption in each sector I) residential, ii) commercial and iii) industrial for the four distribution networks is estimated.

Regarding the commercial and industrial consumptions, the published estimates within EDAs approvals of charges were taken into account. Those data were evaluated against data from Users and historical data. For the years that no data are available, a gradual annual increase equal to the estimation of percentage growth of GDP is considered.

The estimate of percentage growth of GDP is shown in Table 6, as adapted by the Aristotle University of Thessaloniki (AUTH) in the study “Gas Consumption Forecast for Electricity Production Provided in the Wholesale Market during the next decade (2018-2027)”, and is

[4] end-user categories: i) residential (central and autonomous domestic and small commercial heating), ii) commercial and iii) industrial

used for the study “Annual demand forecast and geographical - daily allocation of other consumers demand for the period 2018-2027”.

**Table 6: Percentage growth of GDP**

| year | Percentage growth of GDP (AUTH) [%] |
|---|---|
| 2017 | 1,6 |
| 2018 | 1,5 |
| 2019 | 1,5 |
| 2020 | 1,5 |
| 2021 | 1,3 |
| 2022-2027 | 1,3 |

The consumption of the residential sector per region with network was approached in two different ways, depending on whether the distribution network is fully developed in the region or not yet.

Specifically, for the consumption of the residential sector of EDAs with a developed distribution network (EDA Attikis, EDA Thessalonikis and EDA Thessalias) the estimation from the network operators is used for the first years of the reference period while a methodology has been developed by the Operator for the estimation of the consumption for the remaining years. The methodology is based on historical data of consumption/ active connections for the region. In particular, the annual change in number of connections between 2022 and 2027 has been assessed as a gradual slowdown in the rate of implementation of new connections and the consumption per connection according to the estimation of percentage growth of GDP has been estimated.

To estimate the average consumption in the residential sector, the actual consumption data of 2016 is used and normalized to the temperature factor. Namely for the effect of temperature, the average consumption for residential sector based on year 2016 is calculated and normalized to the temperature factor, taking into account the days of the latest most representative cold or warm years.

For the estimation of gas consumption of the residential sector of EDA of the rest of Greece, that is considered to be developed in the next years, the Operator’s forecast is based on Users data, EDA’s data and the mileage development expected in the network. The abovementioned data are processed within the demand forecast model.

The total gas demand estimation per category of use for the reference period 2018-2027 is shown in Table 7.

Table 7 : Total Gas Demand estimation of Other Consumers per category of use

| Demand estimation of other consumers (mil.Nm³) | | | |
|---|---|---|---|
| | Industrial use | Urban use | Total |
| **2018** | 1.060,88 | 399,64 | **1.461** |
| **2019** | 1.082,77 | 421,36 | **1.504** |
| **2020** | 1.101,15 | 460,11 | **1.561** |
| **2021** | 1.114,83 | 496,94 | **1.612** |
| **2022** | 1.122,11 | 535,71 | **1.658** |
| **2023** | 1.129,49 | 565,55 | **1.695** |
| **2024** | 1.138,94 | 598,17 | **1.737** |
| **2025** | 1.144,55 | 621,95 | **1.767** |
| **2026** | 1.152,21 | 647,15 | **1.799** |
| **2027** | 1.159,68 | 669,72 | **1.829** |

**In the total gas demand estimation, suitable daily profiles are adopted for each category of consumption of every exit point, in order the peak of the system and each point separately to be identified.**

In terms of consumption for industrial use, the most representative industrial consumption profile is used for each consumption point based on historical daily consumption data.

Specifically, for the choice of the daily industrial consumption in Athens, a graphic depiction of the daily consumption of year 2002 onwards for the exit point Athens is done, resulting that year 2004 is the most representative for the industrial profile. This assumption is based on the fact that during the first years of operation of the Attiki Gas Supply Company (EPA Attiki was the operator of the distribution network until the end of 2016) the target group of consumers was mainly industrial consumers with larger and more stable consumption.

It should be noted that in the case that the natural gas consumption growth took place simultaneously in the industrial and residential sectors, the best choice is considered to be the daily profile of the exit point Oinofyta or in some cases, mainly in northern Greece, the daily profile of the exit point of the industrial area of Larisa, while both are purely industrial areas. The daily profile of consumption in both points is determined by multiple categories of industries, which on average provides a more representative daily industrial consumption profile.

In terms of consumption for urban use, and taking into account the impact of the use of natural gas consumption for heating, it is necessary to count the impact of temperature in the calculation of the daily profile.

Therefore the daily allocation of urban use consists of:

a) the daily allocation of demand for heating and
b) the daily allocation of demand for other use.

To determine the above daily allocations, the next steps were followed:

1. The "initial" daily profile of consumption for urban use was calculated by the difference of the average consumption of the years 2011-2016 from the industrial consumption based on the consumption allocation of year 2004 for Athens and for the rest of the exit points by the difference of the average consumption of the years 2011-2016 from the industrial profile of year 2016 of Oinofyta or of the industrial area of Larisa. For the calculation of the difference, the weekdays were adjusted to whether a day is a working one or not.

2. Period 1/5 to 15/10 was matched to natural gas consumptions only for other urban use (period 16/7 to 31/8 is treated separately due to holiday season).

3. The average consumption for the period 1/5 to 15/10 gives the daily profile for other urban use, and is considered to be constant for the whole year (daily allocation of demand for other use, point b above).

4. The consumption of natural gas due to heating (daily allocation of demand for heating) is the additional daily quantity resulting from the "initial" profile for the abovementioned intervals. This consumption is reallocated on the basis of the degree days.

Degree day of a given calendar day of the year is an impact indicator of the effect of the temperature. Degree days measure the difference of the mean outdoor temperature from 16,8$^{o}$C and are taken into account in the sum of degree days of the year only when the aforementioned difference has a positive sign.

The daily profile of gas consumption for heating is calculated considering that the use of natural gas for heating is expected to take place in the period 16/10 to 30/4 and results from the following steps

- Taking into consideration that the gas consumption for heating begins when temperature is below 16,8°C (outdoor temperature), the degree day for each consumption point results from the average temperature of the last most representative years on this point. Temperature historical data of each relative city were derived from the published data from the Observatory of Athens. For cities where temperature data are not available, data of closest points/cities of consumption were used.

- The daily profile for heating is recalculated by using the degree days coefficient, based on the percentage of degree days for each day for which there is consumption due to heating and the estimated quantity for such use (point 4 above)

## 3.2. ESTIMATION OF CONSUMPTION RELATED TO SMALL SCALE LNG PROJECTS

The need to deploy Small Scale LNG infrastructure projects is now evident in Greece. Based on the increasing demand for the LNG truck loading station both from industries and shipping industry, DESFA has begun all necessary steps for the completion of relative infrastructures that will lead to an increased use of LNG.

As a consequence, the study for the pilot LNG truck loading station has been completed, it is estimated to be commissioned in 2017 and expected to operate by mid-2019.

At the same time, the new jetty is planned to be constructed in the northern eastern part of Revythousa to supply small vessels between 1.000 $m^3$ and up to 20.000 $m^3$. The smallest of them will supply vessels, either coastal or seagoing, to the port of Piraeus, while the larger ones will supply satellite LNG storages and distribution stations to other ports of Greece or abroad.

The annual demand from Small Scale LNG projects is expected to begin from 2019 onwards and is presented in a summarized form in the table below.

**Table 8: Total volumes from Small Scale LNG projects for the period 2018-2027**

| Demand in Nm3 | Natural Gas | LNG |
|---|---|---|
| **2017** | 0 | 0 |
| **2018** | 0 | 0 |
| **2019** | 2.040 | 1.183.200 |
| **2020** | 4.080 | 2.366.400 |
| **2021** | 20.000 | 11.600.000 |
| **2022** | 30.000 | 17.400.000 |
| **2023** | 50.000 | 29.000.000 |
| **2024** | 80.000 | 46.400.000 |
| **2025** | 100.000 | 58.000.000 |
| **2026** | 150.000 | 87.000.000 |
| **2027** | 200.000 | 116.000.000 |

* 1Nm3 LNG=580Nm3 n.g.

## 3.3. FORECAST OF TRANSIT VOLUMES

The interconnection Greece-FYROM is mainly expected to procure gas to two new power stations (400 MW each) in FYROM, which will come into operation from 2021 onwards. Therefore, taking into account that no final decision has been taken for the transmitted quantities, it is expected that the yearly quantity transmitted through the Greece-FYROM pipeline will be equal to 350 mil. $Nm^3$, taking into account the (conservative) assumption that only one of these two power stations will be fed with natural gas through Greece (note that FYROM is also supplied with n.g. through Bulgaria).

Further to that, the national gas transmission system can transmit gas in firm reverse flow from Sidirokastro to Bulgaria. Specifically, up to 2017, the system can transmit on a daily basis the amount of 1mil. Nm3/day, while from 2018 onwards, when the 2nd upgrade of Revithoussa will be operational, the technical capacity is expected to be increased to 4,1 mil $Nm^3$/day. A further increase up to the dominant flow capacity (10,8 mil. Nm3/day) can be achieved by operating a compressor station in Ambelia in reverse flow (from South to North) and a compressor station in Kipi.

For the purposes of estimating reverse flow quantities, a conservative scale-up scenario is used while currently there are no available data or contracts related to those quantities. Hence, in 2018 the demand expected to be transmitted to Bulgaria in reverse flow is considered to be equal to 10 mil. $Nm^3$/year, gradually scaling up to 300 mil. $Nm^3$/year in 2025.

The annual gas transportation demand for the NNGTS for the reference period is presented in Table 9 below.

**Table 9: Total transit volumes of natural gas for the period 2018-2027**

| | Transit volumes through A) reverse flow and B) Greece-FYROM interconnector [Nm3] |
|---|---|
| **2018** | 10.000.000 |
| **2019** | 50.000.000 |
| **2020** | 100.000.000 |
| **2021** | 500.000.000 |
| **2022** | 550.000.000 |
| **2023** | 600.000.000 |
| **2024** | 620.000.000 |
| **2025** | 650.000.000 |
| **2026** | 650.000.000 |
| **2027** | 650.000.000 |

## 3.4. PRESENTATION OF SCENARIOS

When Chapters 3.1.1., 3.1.2., 3.2. and 3.3 are combined they result in four scenarios. In particular, the total estimated consumption of natural gas from other consumers, the estimated demand for transit n.g. and from Small Scale Infrastructure users in combination with each of the four scenarios of natural gas consumption for power generation is shown in Table 10.

The peak of the system for scenario 2 that is considered to be the main scenario, for each year of the reference period and per customer category, is shown in Table 11.

The forecast of the peak of the system is calculated by the sum of the daily peak of the total of all exit points of other consumers, transit n.g. and Small Scale LNG in the year and the daily peak of all power producers in the winter period of the same year.

**Table 10: Total natural gas demand – scenarios**

| Scenario 1_High | *2016** | *2017*** | *2018* | *2019* | *2020* | *2021* | *2022* | *2023* | *2024* | *2025* | *2026* | *2027* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PP n.g. demand [mil. Nm3] | 2.629 | 2.684 | 2.253 | 2.276 | 2.255 | 2.194 | 2.499 | 2.589 | 2.558 | 2.469 | 2.540 | 2.584 |
| Costomers connected to HP network [mil. Nm3] | 386 | 522 | 569 | 570 | 572 | 573 | 573 | 573 | 574 | 574 | 574 | 574 |
| Distribution networks [mil. Nm3] | 821 | 905 | 891 | 934 | 990 | 1.039 | 1.085 | 1.122 | 1.163 | 1.193 | 1.225 | 1.255 |
| Transit of n.g. [mil. Nm3] | | | 10 | 50 | 100 | 500 | 550 | 600 | 620 | 650 | 650 | 650 |
| Small Scale LNG [mil. Nm3] | | | | 1 | 2 | 18 | 29 | 53 | 82 | 93 | 122 | 151 |
| **Total transmission of n.g. [mil. Nm3]** | **3.835** | **4.111** | **3.724** | **3.831** | **3.919** | **4.323** | **4.736** | **4.936** | **4.997** | **4.979** | **5.112** | **5.215** |

| Scenario 2_Medium | *2016** | *2017*** | *2018* | *2019* | *2020* | *2021* | *2022* | *2023* | *2024* | *2025* | *2026* | *2027* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PP n.g. demand [mil. Nm3] | 2.629 | 2.684 | 2.218 | 2.275 | 2.204 | 1.921 | 2.229 | 2.454 | 2.422 | 2.326 | 2.294 | 2.340 |
| Costomers connected to HP network [mil. Nm3] | 386 | 522 | 569 | 570 | 572 | 573 | 573 | 573 | 574 | 574 | 574 | 574 |
| Distribution networks [mil. Nm3] | 821 | 905 | 891 | 934 | 990 | 1.039 | 1.085 | 1.122 | 1.163 | 1.193 | 1.225 | 1.255 |
| Transit of n.g. [mil. Nm3] | | | 10 | 50 | 100 | 500 | 550 | 600 | 620 | 650 | 650 | 650 |
| Small Scale LNG [mil. Nm3] | | | | 1 | 2 | 18 | 29 | 53 | 82 | 93 | 122 | 151 |
| **Total transmission of n.g. [mil. Nm3]** | **3.835** | **4.111** | **3.689** | **3.831** | **3.867** | **4.050** | **4.466** | **4.802** | **4.861** | **4.836** | **4.866** | **4.971** |

| Scenario 3_Low A | *2016** | *2017*** | *2018* | *2019* | *2020* | *2021* | *2022* | *2023* | *2024* | *2025* | *2026* | *2027* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PP n.g. demand [mil. Nm3] | 2.629 | 2.684 | 2.194 | 2.264 | 2.204 | 1.952 | 2.214 | 2.369 | 2.332 | 2.194 | 2.195 | 2.180 |
| Costomers connected to HP network [mil. Nm3] | 386 | 522 | 569 | 570 | 572 | 573 | 573 | 573 | 574 | 574 | 574 | 574 |
| Distribution networks [mil. Nm3] | 821 | 905 | 891 | 934 | 990 | 1.039 | 1.085 | 1.122 | 1.163 | 1.193 | 1.225 | 1.255 |
| Transit of n.g. [mil. Nm3] | | | 10 | 50 | 100 | 500 | 550 | 600 | 620 | 650 | 650 | 650 |
| Small Scale LNG [mil. Nm3] | | | | 1 | 2 | 18 | 29 | 53 | 82 | 93 | 122 | 151 |
| **Total transmission of n.g. [mil. Nm3]** | **3.835** | **4.111** | **3.665** | **3.820** | **3.868** | **4.081** | **4.451** | **4.717** | **4.771** | **4.704** | **4.767** | **4.811** |

| Scenario B_Low B | *2016** | *2017*** | *2018* | *2019* | *2020* | *2021* | *2022* | *2023* | *2024* | *2025* | *2026* | *2027* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PP n.g. demand [mil. Nm3] | 2.629 | 2.684 | 2.175 | 2.242 | 2.161 | 1.851 | 2.154 | 2.358 | 2.317 | 2.174 | 2.102 | 2.132 |
| Costomers connected to HP network [mil. Nm3] | 386 | 522 | 569 | 570 | 572 | 573 | 573 | 573 | 574 | 574 | 574 | 574 |
| Distribution networks [mil. Nm3] | 821 | 905 | 891 | 934 | 990 | 1.039 | 1.085 | 1.122 | 1.163 | 1.193 | 1.225 | 1.255 |
| Transit of n.g. [mil. Nm3] | | | 10 | 50 | 100 | 500 | 550 | 600 | 620 | 650 | 650 | 650 |
| Small Scale LNG [mil. Nm3] | | | | 1 | 2 | 18 | 29 | 53 | 82 | 93 | 122 | 151 |
| **Total transmission of n.g. [mil. Nm3]** | **3.835** | **4.111** | **3.645** | **3.797** | **3.824** | **3.981** | **4.391** | **4.705** | **4.756** | **4.684** | **4.674** | **4.762** |

*actual data **forecasted data

**Table 11: Daily peak of the system for the period 2018-2027**

| | TOTAL NNGS (Nm3/day) | | | | | |
|---|---|---|---|---|---|---|
| | Power Production | Other Consumers | | Transit of n.g. | Small Scale LNG | Total |
| | | Customers connected to h.p. network | Distribution network | | | |
| 2016* | 12.353.154 | 1.622.084 | 5.621.659 | - | - | 19.596.897 |
| 2017** | 15.407.642 | 1.337.983 | 6.834.595 | - | - | 23.580.220 |
| 2018 | 11.350.110 | 2.504.195 | 5.737.968 | 34.247 | - | 19.626.519 |
| 2019 | 10.728.628 | 2.506.330 | 6.059.411 | 171.233 | 49.300 | 19.465.602 |
| 2020 | 10.609.464 | 2.508.465 | 6.566.117 | 342.466 | 49.300 | 20.026.512 |
| 2021 | 10.108.731 | 2.512.735 | 7.119.238 | 1.579.148 | 94.701 | 21.414.553 |
| 2022 | 11.733.845 | 2.513.392 | 7.620.051 | 1.750.381 | 166.702 | 23.784.370 |
| 2023 | 12.566.821 | 2.514.059 | 7.990.198 | 1.921.613 | 261.403 | 25.254.094 |
| 2024 | 13.748.585 | 2.514.783 | 8.351.849 | 1.990.107 | 329.505 | 26.934.829 |
| 2025 | 12.291.786 | 2.515.470 | 8.689.004 | 2.092.846 | 374.906 | 25.964.012 |
| 2026 | 13.154.577 | 2.516.166 | 9.003.514 | 2.092.846 | 488.409 | 27.255.512 |
| 2027 | 12.558.259 | 2.516.166 | 9.281.039 | 2.092.846 | 601.912 | 27.050.222 |

*actual data

**until 6/7/2017 the peak of the system amounts to 23,6 mil Nm3 and was realized on 12/1/2017

## 3.5. FORECAST OF THE HOURLY PEAK DEMAND FOR NATURAL GAS FOR THE REFERENCE PERIOD 2018-2027

The historical data of hourly demand for other consumers, as published on DESFA website, and the hourly demand results from the study that was conducted by the Aristotle University of Thessaloniki regarding power producers, are used to determine the hourly peak demand. The hourly peak demand is calculated for each year of the reference period 2018-2027.

The hourly demand profile of other consumers is calculated by the average of daily consumptions for the months January, February and March for the years 2012 to 2017 for each exit point. For greater accuracy of the results, data related to weekends and holidays are not taken into account.

Based on the above, the maximum hourly peak demand for the years 2018-2027, per customer category, is as follows:

Table 12: Hourly peak demand for NNGS for the period 2018-2027

| | Hourly Peak Demand ($Nm^3/hr$) | | | |
|---|---|---|---|---|
| | Power Production | Customers connected to h.p. network | Distribution network | Total |
| 2018 | 617.162 | 106.306 | 391.338 | **1.114.806** |
| 2019 | 565.137 | 106.389 | 414.509 | **1.086.034** |
| 2020 | 526.592 | 106.472 | 452.212 | **1.085.276** |
| 2021 | 635.973 | 106.638 | 494.746 | **1.237.357** |
| 2022 | 647.113 | 106.663 | 530.118 | **1.283.894** |
| 2023 | 668.216 | 106.689 | 554.081 | **1.328.987** |
| 2024 | 665.499 | 106.718 | 577.720 | **1.349.936** |
| 2025 | 604.329 | 106.744 | 598.979 | **1.310.052** |
| 2026 | 666.455 | 106.771 | 619.148 | **1.392.374** |
| 2027 | 656.714 | 106.771 | 636.154 | **1.399.640** |

**estimates on hourly peak demand regarding the transit n.g. volumes and the volumes related to Small Scale LNG projects are not included*

# CHAPTER 4: HYDRAULIC ASSESSMENT OF THE TRANSMISSION SYSTEM RESPONSE FOR THE PERIOD 2017 – 2026

## 4.1. INTRODUCTION

Based on the demand estimation for the period 2018-2027, as presented in the previous chapters, a study for the simulation of the operation of the National Natural Gas System (NNGS) was carried out in order to evaluate the Transmission System hydraulic response and to identify any necessary investments, in order to maintain its technical adequacy for the next 10 years (2018-2027).

The hydraulic behavior of NNGTS was tested taking into account the forecast for the peak day of the period 2018-2027. The consumption of the peak day is approx. 24 $mNm^3$. The basic characteristics of the peak day are presented in Table 13. The study evaluates the need for the implementation and the preliminary cost estimation of any new investments for the further development of the NNGS.

## 4.2. HYDRAULIC SIMULATION RESULTS

**Table 13: Characteristics of the examined peak day**

| Total daily consumption ($mNm^3$) | Daily consumption north of Nea Messimvria ($mNm^3$) | Daily consumption south of Nea Messimvria ($mNm^3$) | Power production units in operation |
|---|---|---|---|
| 24 | 5 | 19 | LAVRIO, KOMOTINI, ENTHES, HERON (OC), HERON (CC), AdG, ALIVERI, PROTERGIA, THISVI, KORINTHOS POWER, MEGALOPOLI |

The hydraulic stability of the Transmission system is examined under the following conditions:

- Daily flow through the Border Metering Stations (MMS) Sidirokastron and Kipi is equal to the Technical Capacities of the respective Entry Points:
  - Entry Point Sidirokastron: 10,8 $mNm^3$ per day
  - Entry Point Kipi: 4,3 $mNm^3$ per day
- No upgrades are made in the compressor station at Nea Messimvria
- The LNG terminal in Revithoussa operates according to its 2$^{nd}$ upgrade (under completion)

and for the following cases:

Case 1: Highest expected daily peak for 2018-2027 (~24 $mNm^3$) and
Case 2: Highest expected daily peak for 2018-2027 (~24 $mNm^3$) and additional daily flow through interconnection point TAP-NNGTS in Nea Messimvria: approx. 4 $mNm^3$/day. The above mentioned flow is subtracted from the daily flow considered to enter the system from Entry Point Ag. Triada.

<u>Case I: Operation of existing compressor station at Nea Messimvria and the 2nd upgrade of the LNG terminal in Revithoussa.</u>

Daily flow through BMS Sidirokastron: 10,8mNm$^3$
Daily flow through BMS Kipi: 4,3 mNm$^3$
Daily flow of regasified LNG quantity: ~ 9 mNm3
Expected total daily consumption: ~ 24 mNm3

*The hydraulic stability of the system is assured, according to the results of the simulation for the considered daily demand, with the operation of the existing compression unit in N. Messimvria*

<u>Case II: Additional quantity through interconnection point between TAP and NNGTS. Operation of existing compressor station at Nea Messimvria and the 2nd upgrade of the LNG terminal in Revithoussa.</u>

Daily flow through BMS Sidirokastron: 10,8 mNm$^3$
Daily flow through BMS Kipi: 4,3 mNm$^3$
Daily flow through interconnection point of TAP/NNGTS: ~4 mNm$^3$
Daily flow of regasified LNG quantity: ~ 5 mNm$^3$
Expected total daily consumption: ~ 24 mNm$^3$

*The hydraulic stability of the system is not assured for the considered daily demand, according to the simulation results, and there is a need for further upgrading of the Transmission System to the southern and most heavily loaded part of it.*

*With the installation and operation of a compression station in Ambelia, the hydraulic behavior of the network becomes sufficient. The characteristics of the station in order to ensure the hydraulic adequacy for the estimated consumption of 24 mNm$^3$, are presented in Table 14.*

**Table 14: Estimated characteristics of Ambelia CS (Case II)**

| | Estimated flow rate through the station (Nm$^3$/hr) | Estimated compression power (MW) | Estimated compression power in ISO conditions (MW) |
|---|---|---|---|
| Ambelia Compressor station | 553.000 | 6,5 | 7,4 |

For the conversion of compression power needed to ISO conditions, (sea level and ambient temperature 15$^o$C) the following factors (Fig. 1&2) were used.

These factors refer to the calculation of the estimated compression power needed, to ISO conditions, taking into consideration corrections for elevation and ambient temperature.

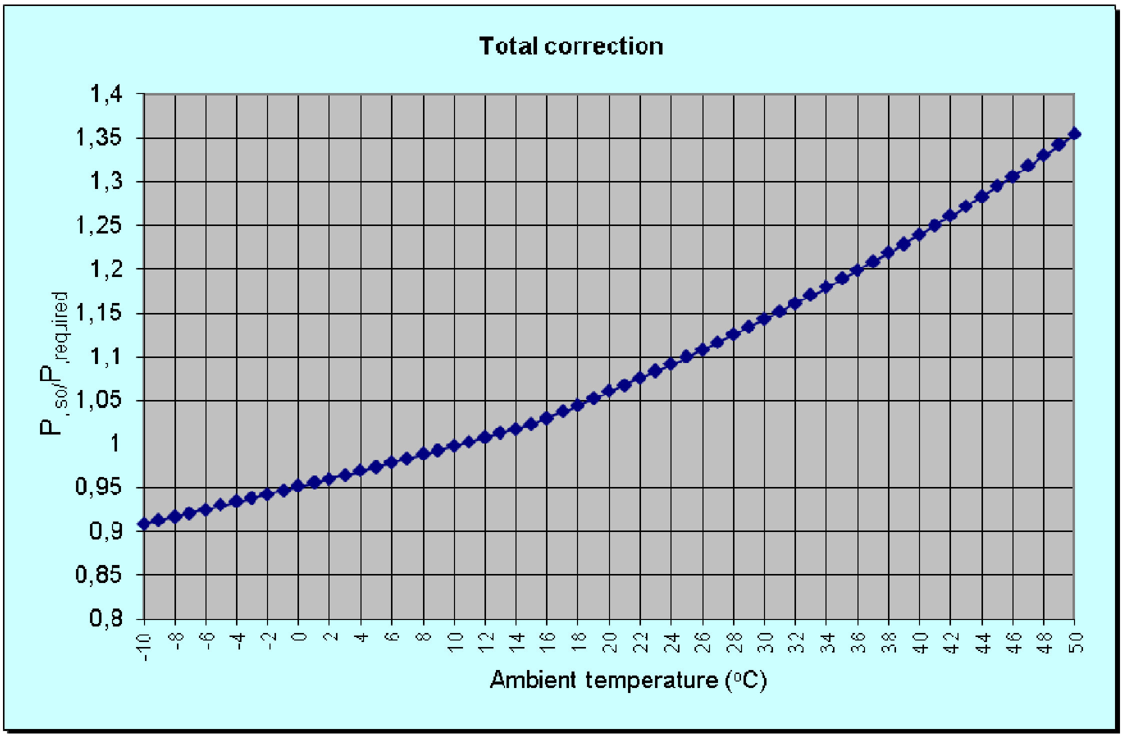



**Figure 1: Correction factor of the estimated compression power in ISO conditions in relation with of the ambient temperature at 190m altitude.**

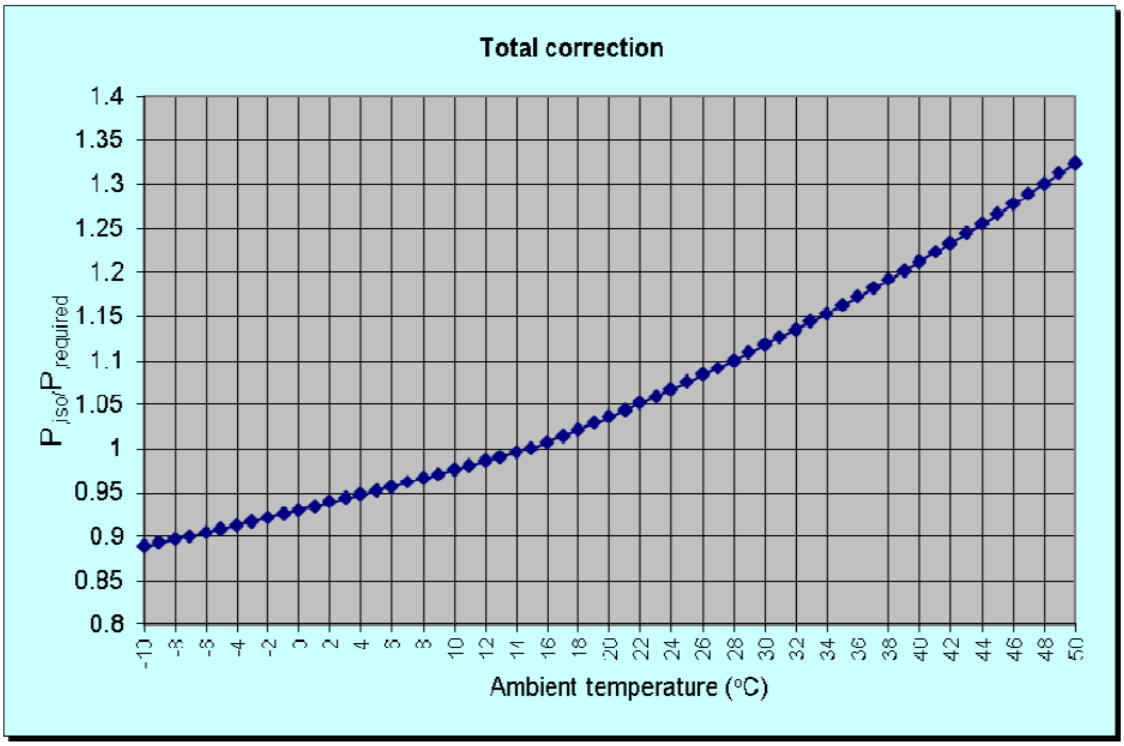



**Figure 2: Correction factor of the estimated compression power in ISO conditions in relation with of the ambient temperature at sea level**

The characteristics of the compression station in Ambelia are determined for the case of maximum flows through the Transmission System (network limitation).

In this case, the aforementioned CS characteristics were determined and are shown in Table 15 below.

**Table 15: Characteristics of the compressor station in Ambelia for the case of the Transmission System hydraulic limitation**

| | Estimated flow rate ($Nm^3/hr$) | Estimated compression power (MW) | Estimated compression power in ISO conditions (MW) |
|---|---|---|---|
| Ambelia Compressor station | 687.000 | 16,5 | 18,8 |

The results of the simulation of the NNGS for the case of physical flow towards Bulgaria through BMS Sidirokastron (Reverse Flow) are presented below. The conditions under which the analysis is carried out are as follows:

- Entry Points of NNGS (Entry Point Kipi and Ag. Triada) are considered to operate at their technical capacity, with the LNG terminal operating according to the 2nd upgrade (under completion) for the cases I, II and IV of table 16:

  Daily flow through BMS Kipi: 4,3 $mNm^3$

  Daily flow of regasified LNG quantity: 19,152 $mNm^3$

  For Case III of table 16 the following were considered:

  Daily flow through BMS Kipi: 2,4 $mNm^3$

  Daily flow of regasified LNG quantity: 19,152 $mNm^3$

- Daily quantity towards Bulgaria through BMS Sidirokastron is considered to be included in the NNGS daily demand (approx. 24$mNm^3$) for the examined day.
- Minimum delivery pressure for reverse flow through Exit Point Sidirokastron is 40 barg.

The configuration of the daily reverse flow towards Bulgaria defines the necessary investments in the Transmission System in order to achieve the hydraulic stability of the network.

The above results for specific values of the daily reverse flow quantity towards Bulgaria, are presented in the table below:

**Table 16: Simulation results for the case of reverse flow towards Bulgaria through BMS Sidirokastron**

| | NNGS daily demand ($mNm^3$) | *Daily reverse flow towards Bulgaria ($mNm^3$)* | Rest of NNGS daily demand ($mNm^3$) | Required investments |
|---|---|---|---|---|
| I | 23,46 | *4,1* | 19,36 | - |
| II | 23,43 | *5,5* | 17,93 | - Compressor station at Kipi:<br>hourly flow 179.000 $Nm^3$<br>Estimated compression power needed 0,5 MW |
| III | 21,546 | *5,5* | 16,046 | - |
| IV | 23,36 | *10,8* | 12,56 | - Compressor station at Kipi:<br>hourly flow 179.000 $Nm^3$<br>Estimated compression power needed 1 MW<br><br>- Reverse flow operation in Ambelia:<br>hourly flow 540.000 $Nm^3$<br>Estimated compression power needed 9,5 MW |

## 4.3. NNGS LIMITATION

The hydraulic behavior of the NNGTS is examined in the case of zero consumption of the Power Production units north of N. Messimvria. The Assessment of the Transmission System hydraulic response refers to a peak demand day of 28 $mNm^3$ with consumption north of N. Messimvria approx. 2.8 $mNm^3$.

Case I: Maximum daily flow from North and East, with operation of the compressor station in N. Messimvria.

Hourly flow from North: 450,000 $Nm^3$ (or 10.8 $mNm^3$ /day)

Hourly flow from East: 180,000 $Nm^3$ (or 4.32 $mNm^3$ /day)

The sum of North and East daily flows is 15.12 $mNm^3$ or 168.790 MWh and sets the limit for the total daily flow through the above points with the operation of the existing compressor station in N. Messimvria for maximum flow operation and output pressure level of 65 barg. The critical parameter for the hydraulic behavior of the North/Northeast part of the Transmission System is the sum of the North and East flows. Any change on the flows entering from the North an East Entry points, keeping their sum unchanged and provided that the consumption in the above section of the Transmission System does not change, has no effect in the hydraulic behavior of the System. In the case of a new Entry point downstream of the N. Messimvria compressor station and in order to maintain a delivery pressure level of 30 bar at Megalopolis node (NNGTS most remote point), the sum of the flows from the three North/East entrances (Kipoi-Sidirokastron-new Entry point in New Messimvria) shall not exceed 15.8 $mNm^3$/day in order to avoid further upgrading of the network south of N. Messimvria.

Case II: Maximum daily flow from the North and East, with the operation of the compression station in Kipi, while upgrading of the compressor station in N. Messimvria and installing a compression station in Ambelia

Hourly flow from North: 490,000 $Nm^3$ (or 11.76 $mNm^3$ /day)

Hourly flow from East: 340,000 $Nm^3$ (or 8.16 $mNm^3$ /day)

For the adequate hydraulic response of the Transmission System, it is necessary to install a compressing station in Ambelia. The limit for the maximum flows entering upstream of N. Messimvria compressor station, while the compressor station in Ambelia is in operation, is set at 19,92 $mNm^3$/day.

Any new Entry point placed downstream to the compression station in N. Messimvria, with the same pressure level as the station operates, does not affect the hydraulic behavior of the southern part of the Transmission System, provided that the flow through the new Entry point reduces respectively the quantity of gas injected from the North and the East.

In case of gas injection from Entry point “Kipi” and exit of a gas proportion from Exit point “Komotini”, the capacity of the Entry Point "Kipi" can be increased to approx. 32 mNm3/day, of which about 24.5 mNm3/day can exit from the new exit point In Komotini.

# CHAPTER 5: FUTURE INVESTMENT PROJECTS

## 5.1. PROJECTS INCLUDED FOR THE FIRST TIME IN DEVELOPMENT PLAN 2017-2026

The following projects are included for the first time in the Draft Development Plan 2017-2026. A detailed description is available in the Development Plan 2017-2026.

### 5.1.1. PROJECTS FOR USERS CONNECTION

***1. M station at SALFA Anthousa***

The project is necessary according to the provisions (art. 5 par. 7) of Tariff Regulation (RAE decision 339/2016) as well as the relevant agreement of Public Gas Corporation ”DEPA SA”. The project refers to the construction of a metering station which will be owned by DESFA in Anthoussa.

***2. M station at SALFA A. Liossia***

The project is necessary according to the provisions (art. 5 par. 7) of Tariff Regulation (RAE decision 339/2016) as well as the relevant agreement of Public Gas Corporation ”DEPA SA”. The project refers to the construction of a metering station which will be owned by DESFA in A. Liossia.

### 5.1.2. PROJECTS FOR NNGS DEVELOPMENT

***1. New jetty for small Scale LNG***

The new jetty is planned to be constructed in the northern eastern part of Revythoussa and will supply small vessels between 1.000 m3 and up to 20.000 m3. The smallest of them will supply vessels, either coastal or seagoing, to the port of Piraeus, while the larger ones will supply satellite LNG storages and distribution stations to other ports of Greece or abroad. The new jetty will provide infrastructure for the mooring and simultaneous refueling of two ships. In the first phase, the necessary equipment (loading arms and binders) will be placed for the function of the one position. The same project includes the addition of a small LNG loading arm to the already existing jetty, in order the loading of small LNG vessels to be feasible.

***2. Pipeline Nea Messimvria – Eidomene/Gevgelija and M/R station***

The project aims at the interconnection of natural gas transmission systems of Greece and FYROM which will enhance the diversification of supply sources for FYROM. The latter one is currently depending one on supply source from Trans Balkan Pipeline. DESFA and MER signed a Memorandum of Understanding for the project in October 2016. Access to NNGS, and especially to the LNG terminal of Revithoussa can benefit market competition, leading the supply of natural gas to lower prices. Meanwhile, the project enhances the role of Greece as a hub, enabling the participation of more natural gas users in the region.

### *3. Compressor Station in Ambelia*

The project is necessary on the basis of the hydraulic simulation studies carried out by DESFA and given that with the start of the TAP pipeline and its interconnection with NNGTS in New Messimvria the expected transported quantities of natural gas from north to south will increase.

In order to ensure the stability and efficiency of the system, it is necessary to progressively increase its technical capacity with the installation of a compressor station at the southern part of Greece, which concentrates the larger part of the demand. The characteristics of the compressor station were preliminary identified to 10 MW (1+1) with the appropriate stab outs for a 3rd unit to be installed in the future, if the natural gas demand justifies it. The compressor station will be designed to provide compression to reverse flow as well.

### *4. Upgrading Projects of NNGS -3rd group*

The project includes the following six subprojects for the modernization of the NNGTS, concerning the transmission system and LNG facility, in order to improve the efficiency of NNGTS and the effective operation to be achieved, preventing emergency situations.

- Implementation of training center
- Procurement and installation of Pipeline Integrity Management System
- Upgrade of electrical switches for medium voltage and internal lighting in the control room of LNG facility
- Procurement of special equipment for detecting corrosion and irregularities in natural gas pipeline
- Upgrade of DCS in CHP unit
- Upgrade of Geographical Information System (GIS) system

### *5. Upgrade of physical protection of DESFA facilities - Physical Safety Control Center*

The aim of the project is to upgrade the physical security of all DESFA infrastructure due to the rapid development of the technological applications in the sector and the establishment of a Physical Security Control Center covering the requirements of the Directive 2008/114/EC concerning critical infrastructure security, which was incorporated into the Greek law with Presidential Decree 39/2011.

The aim is to prevent, mitigate and eliminate risk threats.

### *6. Improvement of metering accuracy in NNGTS stations*

In the context of the public consultation of the Development Plan 2016-2025 it was pointed out that in some distribution networks due to reduced consumption there are differences between the amount of gas resulting from the sum of the metering systems of the distribution networks and the quantity of gas measured in the Metering/Regulating stations that make up the corresponding Distributed Network Exit Point (SIDD) of the NNGTS.

DESFA, as stated with no. 100240 / 13.12.2016 letter to RAE, pledged to examine the matter and come up with a project proposal to a next Development Plan or List of Small Projects.

In order to resolve the problem it is proposed the replacement of turbine meters in 17 stations with new ones that combine improved operational features.

***7. Replacement of metering and control systems on M/R stations of NNGTS***

The proposed project concerns modifications to 30 existing Metering (M) or Metering / Regulating (M / R) stations in order to achieve compatibility with each other as well as with the under construction stations by means of similar equipment and software.

***8. New building for DESFA's headquarters***

It is considered that today, due to the conditions prevailing in the Greek real estate market, will be economically advisable for DESFA to acquire a privately-owned headquarters building, which will constitute a company's fixed asset, and will contribute to the saving of operating expenses and ensure improved health and safety of work. The office area is planned to be approximately 6,500 square meters in line with the existing DESFA headquarters. The goal is to avoid burdening the NNGS users due to the savings that will be achieved, mainly by the rental cost. It is also estimated that there will be energy savings due to higher energy specifications of the new building.

## 5.2. OTHER NEW PROJECTS

***1. Connection with Kavala Oil***

The Kavala Oil connection project, in the Gulf of Kavala, is necessary to connect the industry directly with the NNGS and not through the VFL, as is the case today. This need is imposed both for reasons of regulatory compliance and safety, given that the pipeline supplying it today does not meet the requirements of the current technical regulation. The project consists of a 6" pipeline, about 2 km long, and a metering station that will be installed in a space that will be given by the industry. For the connection of the pipeline to the existing branch of the NNGS, the hot tapping technique will be used.

Furthermore, the possibility of receiving gas from the land exploited by the company, will be considered as well. In the case of a positive result, the station will be doubled-flow and will be regulating. The project will be added to the Development Plan or List of Small Projects when the procedure of art. 95B of the NNGS Network Code will be finalized.

## 5.3. PLANNED PROJECTS

The following projects are included in the already approved Development Plan 2016-2025 and their implementation will continue within the reference period of the new Draft Development Plan 2017-2026. The characteristics of the following projects are described in detail in the Draft Development Plan 2017-2026.

- Construction of High Pressure Pipeline from Mandra Attikis to the Facility of ELPE in Elefsina for the Connection with NNGS and Relevant Metering Station
- Construction of High Pressure Pipeline Mavromati (Vagia)-Larymna and necessary Metering Station for the Connection of LARCO GMM SA with NNGS.
- Compression Station in Kipi
- M/R Station in Komotini
- M/R Station in N. Messimvria for the Connection of NNGTS to TAP

- Komotini-Thesprotia High Pressure Pipeline (part of NNGS)
- 2$^{nd}$ Upgrade of LNG Terminal on the Island Revithousa
- 2$^{nd}$ Upgrade of Boarding Metering Station (BMS) of Sidirokastro
- Upgrading of Electrical and Electronic Equipment, Billing System and Equipment SCADA Field in Stations M/R of 1st generation (1995-2000)
- Extensions and Upgrades of Metering Stations of North and East Thessaloniki
- Upgrade the System of Fixed Communication of NNGS
- IT & Telecomunications projects
- Upgrading projects of NNGS-1$^{st}$ Group
- Upgrading projects of NNGS-2$^{nd}$ Group
- Installation of M/R Kavala
- Upgrade of LNG Loading Arms at Revithoussa LNG Terminal
- Truck Loading Pilot Station
- LNG Terminal Boil-off Gas Compressor Station