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Renewable and Sustainable Energy Reviews
7 (2003) 99–130

RENEWABLE
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ENERGY REVIEWS

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# A regional energy planning methodology including renewable energy sources and environmental constraints

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Received 20 December 2002; accepted 24 December 2002

## Abstract

In this paper, a bottom-up energy system optimisation model is proposed in order to support planning policies for promoting the use of renewable energy sources. A linear programming optimisation methodology based on the energy flow optimisation model (EFOM) is adopted, detailing the primary energy sources exploitation (including biomass, solid waste, process by-products), power and heat generation, emissions and end-use sectors. The modelling framework is enhanced in order to adapt the model to the characteristics and requirements of the region under investigation. In particular, a detailed description of the industrial cogeneration system, that turns out to be the more efficient and increasingly spread, is incorporated in the regional model. The optimisation process, aiming to reduce environmental impact and economical efforts, provides feasible generation settlements that take into account the installation of combined cycle power plants, wind power, solid-waste and biomass exploitation together with industrial combined heat and power (CHP) systems. The proposed methodology is applied to case of the Apulia region in the Southern Italy.


*Keywords:* Regional energy planning; Linear programming optimisation; EFOM methodology; Renewable energy; Cogeneration systems

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doi:10.1016/S1364-0321(03)00004-2

**Contents**



## 1. Introduction

As widely acknowledged, energy consumption is one of the most reliable indicators of the development and quality of life reached by a country and the necessity of satisfying a forecasted energy demand, over a certain time period, is the basis of energy planning. In particular, energy planning builds and verifies strategies in energy economy, which is, using the definition of World Energy Council, “that part of economics applied to energy problems, taking into account the analysis of energy supply and demand, as well as implementation of the means for ensuring coverage of energy needs in a national or international context” [1].

The energy planning discipline must take into account political aspects, social and environmental considerations, and is carried out taking into account the historical data collected in the previous energy plans of the country under examination.

Energy planning methods are generally classified in three categories [2]: planning by models, by analogy and by inquiry. The accuracy of these methods depends on the time interval under investigation: short-term and medium-term (up to 10 and 20 years), long-term (beyond 20 years).

The planning by models methodology includes the econometric model and optimisation model. The econometric model generally relies on mathematical and statistical methods (such as regression analysis) to study economic systems. In particular, its aim is the empirical testing (validation) of theoretical models, as well as the derivation of quantitative statements about the operation of economic aggregates [1,3]. All the econometric models are based on the use and implementation of statistical data. They deal with problems implying one or several energy forms, different energy sectors and energy uses. Seldom do they take any explicit optimisation approach into consideration. Sometimes an implicit optimisation tendency is understood.

The optimisation model, when the approach of the best possible solution according to a goal function is required, makes the step from a description by a model to a prescription by a model, as an optimisation procedure will demonstrate that any deviation from a determined situation leads to a degraded one [4,5]. This is the most important and broadest category of tools for energy planning. In particular, great relevance goes to the family of the multi-period linear programming models [6–8]. In the following, some of these models are described. The Brookhaven energy system optimisation model (BESOM) attaches all costs to energy flows and minimises their sum over 1 year, while the time-stepped energy system optimisation model (TESOM) makes consecutive BESOM-type optimisations for single years [9]. The market allocation model (MARKAL), a successor of BESOM, is a large scale, technology-oriented activity analysis model which integrates the supply and end-use sectors of an economy, with emphasis on the description of energy related sub-sectors [10,11]. It can include 1 to 16 time periods of the same length, each one indexed with the central year. The multiple energy systems of Australia (MENSA) [12] is an improved and regionalized version of MARKAL that chooses the combination of demand-side and supply-side technologies which delivers the energy services at least cost, averaged over a specific time period. Analogously to MARKAL, the energy flow optimisation model (EFOM) provides an engineering oriented bottom-up model of a national energy system and has been developed under the approval of the Commission of the European Communities [13]. The EFOM describes the energy system as a network of energy flows, by combining the extraction of primary fuels, through a number of conversion and transport technologies, to the demand for energy services or large energy consuming materials. In the EFOM, the planning horizon is defined by a certain number of periods, generally of different length, consisting of two seasons each divided into two periods [14,15]. A further application of the EFOM model, named energy planning optimisation model (EPOM), is adopted in [16], where the planning horizon is split into time periods of the same length each divided into no more than eight sub-periods.

The planning by analogy methodology [17] allows the simulation of the same quantity, with a time lag, in a less developed country, through the use of a leading case as reference and the knowledge of the time behaviour of a quantity in a more developed country. The 'analogue' approach is often used to check and compare outputs produced by other methods.

The previously mentioned tools may loose reliability when a long-term investigation is carried out, although MARKAL model covered a 45-year span when involved in greenhouse gases (GHG) emission abatement optimisation [18]. In this case, the inquiry system, called Delphi method [19,20], is applied, based on questionnaires submitted to a selected panel of experts, in order to achieve, by statistical evaluation of their answers, an accurate chart of the future.

Independently of the method, the energy planning requires a detailed preliminary study of the energy system. This important step assumes that a careful observation of all the phenomena involved in the evolution of energy demand and supply has to be carried out.

Recently, the energy systems are undergoing a development trend characterized by the following principal guidelines [21,22]:

- The privatisation of the most important energy sectors (electricity and natural gas), turning the previous monopolies into free competition among different companies; in particular, the unbundling of vertically integrated energy companies occurred in the electricity sector, by splitting the generation, transmission and distribution activities;
- The community growing awareness about the environmental impact caused by large conventional power plants, joined with a greater interest towards distributed generation technologies based upon renewable resources and cogeneration;
- The energy planning activities as regional concerned instead of national.

In such a scenario, the energy planner has to shift the border of the system under study towards a smaller observation area where, invariably, several new constraints of different nature are involved.

This paper aims to provide a methodology for regional energy planning over a time interval of some decades. To this purpose, the typical modular structure of the EFOM, usually applied for supporting planning policy in a whole country [23,14], has been tailored to the requirements of a regional energy system, including the description of primary energy source exploitation, power and heat generation, emissions and end-use sectors. A detailed description of the industrial cogeneration system has been incorporated in the model so that a more realistic representation of the actual industrial sector of the region under investigation is provided. The results from scenarios on strategies to reduce emissions and to improve the energy production from renewables turn out to be useful for a real implementation on actual regional energy system with reasonable costs.

## 2. Energy system structure and general assumptions

The proposed optimisation method aims at the determination of an optimal mix of technologies for the energy system, subject to a number of boundary conditions, such as emission limits, cost reduction, etc. The overall structure of the adopted model is shown in Fig. 1.

The energy system is represented as a network of energy chains, starting from the primary energy supply and ending in the end-use sectors. The model is driven by an exogenous demand for useful or final energy. Following the energy chain representation, the model is built, in a modular way, into sub-systems according to relevant region specific availabilities and requirements. The sectors incorporated in the model include primary supply sectors, the power and heat generation sectors and end-user sectors: industrial, transport, agriculture and fishery, residential and commercial.

### 2.1. Primary energy supply sector

The primary supply sector includes fossil fuels (coal, oil, natural gas, etc.), industrial by-products (blast furnace gas and cokery gas) and local renewables (biomass,

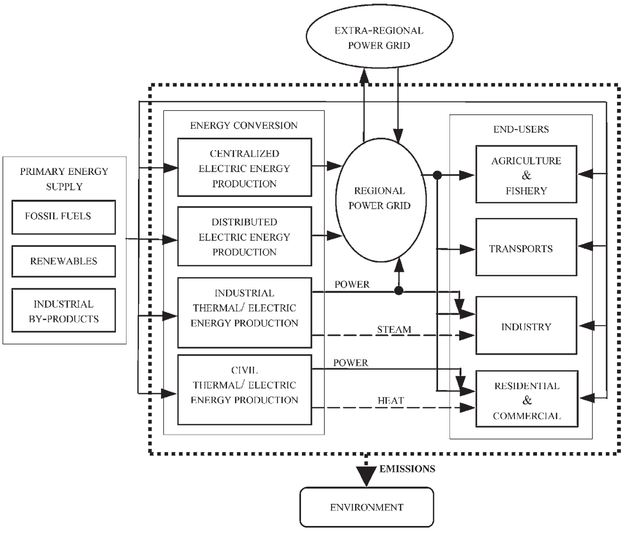


Fig. 1. Modular structure of the regional energy system.

solid waste and natural resources). All the primary energy flows are evaluated in tons of oil equivalent (toe) units. This sector provides for electricity and heat production deriving from large-scale as well as small-scale technologies and for other needs directly in the end-use sector.

### 2.2. Intermediate conversion of primary energy

The large-scale technologies are adopted both for centralized electricity generation and for industrial power and process steam production. Whereas small-scale technologies largely dominate distributed electricity production by local renewable exploitation and civil thermal/electric energy production. The whole net electricity production delivered to the power grid comes from power plants, distributed generation and from industrial combined heat and power (CHP) plants. The total generation capacity to be installed takes into account the possibility to export energy to the neighbouring regions.

Various technologies, such as conventional thermoelectric plants, combined cycle plants, photovoltaic panels, micro-turbine systems and etc., have been supposed for intermediate conversion of primary energy. The choice and the adoption of these technologies depends on the objective of the optimisation process: if a greater importance is given to economical requirements, cheapest options will be considered; on the other hand, when the goal is to reduce pollutant emissions, the environmentally friendly technologies are preferred.

Due to the wide adoption of CHP facilities in industrial processes, a particular care is spent for the description of the relevant cogeneration system. On the basis of the sample cogeneration system schemes, reported in [24,25], the cumulative representation of the whole industrial cogeneration system producing high, medium and low pressure steam has been obtained, as shown in Fig. 2.

The industrial cogeneration system includes gas turbines (GTs) and/or extraction condenser steam turbines (STs) for power generation. The STs may be fed by high pressure (HP) boilers and/or by the high pressure steam from heat recovery steam generators (HRSGs), which are set downstream the exhaust of GTs. The high pressure boiler system may fire various fuels such as oil, blast furnace gas and cokery gas, while the combustion chamber (CC) of the GTs fires only natural gas. A cascade system of pressure reducing valves (PRVs) grants the availability of three process steam levels.

### 2.3. End-use sector

The end-use subsystem defines a set of energy demand disaggregated in electric power, industrial process steam, civil heat and other needs (coal for blast furnace, natural gas for cooking systems, petrol and diesel oil for means of transportation, etc.). In particular, civil and industrial users can satisfy their electricity needs both withdrawing energy by the grid and self-producing power. However, electric energy production by civil sector cannot be delivered to the grid. The other sectors are only allowed to buy electric energy from the grid.

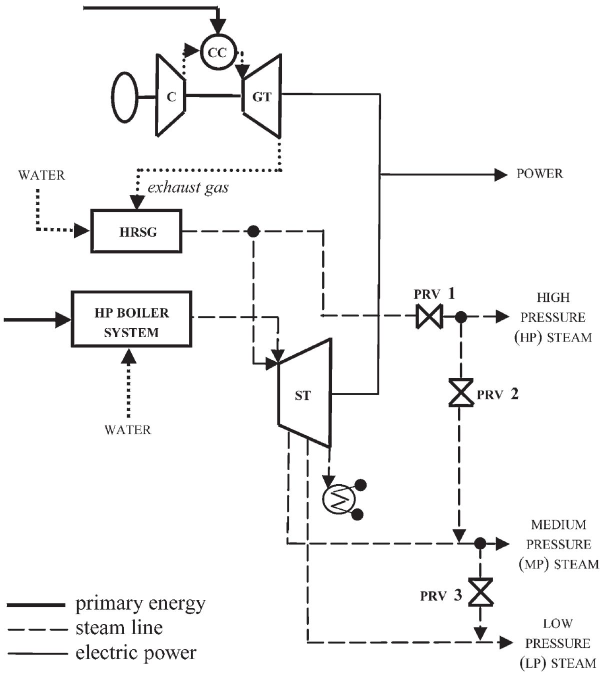


Fig. 2. Schematic outline of the industrial cogeneration system.

## 2.4. Environmental impact assessment

Two main aspects concerning environmental impact are considered. The first aspect deals with the quantification of emissions to air, most notably $CO_2$, $NO_x$, $SO_x$, $PM_{10}$, due to consumption of fuels. To this purpose, suitable specific emission factors, able to assess the tons of pollutant per toe of burned fuel, are adopted. The pollutant emissions are limited below a certain tolerance threshold, such as the Kyoto Protocol (KP) requirements, by proper inequality constraints in the mathematical formulation.

The further quantification of environmental impacts consists in evaluating the resulting damage costs following the ExternE methodology [26]. The ExternE procedure is a bottom-up methodology assessing the whole life and fuel cycle of a specific plant. It employs an impact pathway approach tracing the emissions from the source to the impact, assessed by means of dose–response functions. A broad variety of burdens is considered, starting from impacts on human life and health up to visual amenity. The monetary valuation of the resulting welfare losses follows the approach of ‘willingness-to-pay’ for improved environmental quality [26]. In this paper, the whole regional ‘willingness-to-pay’ is managed to fit with medium external costs and is included in the objective function to be minimised in the optimisation process.

### 2.5. Multi-period approach

In order to simulate the dynamics of the energy system, over a period typical of the regional energy planning (10–20 years) the total study period is divided into sub-periods (years), and the solution of the model is obtained by optimising an objective function over the whole study period. The annual demand of electricity, industrial process steam and civil thermal power is represented by a load duration curve (LDC) that is fitted by a step-wise behaviour, as reported in Fig. 3.

Each step corresponds to the demand level expected throughout the relevant time interval. Practical computational reasons allow a maximum of eight time steps for the load duration curve fitting.

## 3. Model formulation

The EFOM-based optimisation model, described in this section, aims to determine the optimal use of resources in energy supply and conversion and, to some extent, in final energy demand. The total present cost of the entire energy system is optimised by a linear programming procedure over the whole study period. The resulting objective function is minimised in the presence of suitable equality and inequality constraints. In this section, after a list of all used indices, parameters and variables, a detailed description of the cost function and of the equality/inequality constraints is given.

### 3.1. Indices

$t$ represents mid-time periods (year): $t = 1,\ldots,N_t$;
$p$ represents the time intervals of LDC: $p = 1,\ldots, N_p$ and $N_p = 8$;
$i$ stands for primary energy forms:

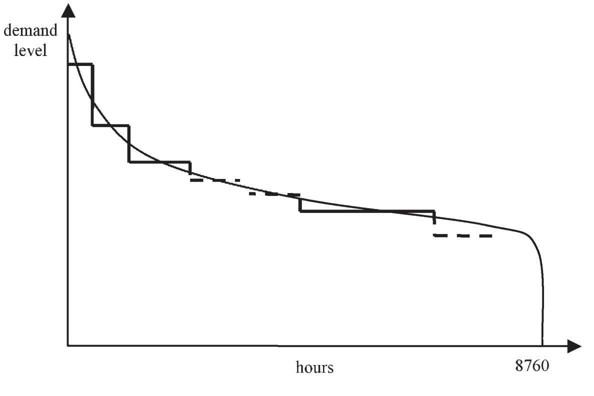


Fig. 3. Step-wise curve fitting the annual LDC.

$i = 1$ fuel oil
$i = 2$ coal
$i = 3$ natural gas
$i = 4$ diesel oil
$i = 5$ petrol
$i = 6$ liquid propane gas
$i = 7$ municipal waste
$i = 8$ biomass
$i = 9$ blast furnace gas
$i = 10$ cokery gas
$i = 11 = N_i$ refinery gas;
$j$ represents the primary energy conversion options:

*centralized electric energy production plants*
$j = 1$ multi-fuelled thermoelectric
$j = 2$ combined cycle

*distributed electric energy production plants*
$j = 3$ hydroelectric
$j = 4$ photovoltaic
$j = 5$ wind
$j = 6$ solid waste-to-energy
$j = 7$ biomass-to-energy

*civil thermal/electric energy production facilities*
$j = 8$ solar thermal collectors
$j = 9$ photovoltaic roofs
$j = 10$ gas micro-turbines

*industrial CHP facilities*
$j = 11$ gas turbines
$j = 12 = N_j$ steam turbines;

$k$ stands for fuel mix inputs of thermoelectric plants:
$k = 1$ oil (30%)–coal (70%)
$k = 2$ oil (40%)–coal (60%)
$k = 3 = N_k$ oil (50%)–coal (50%);

$s$ stands for end-use sectors:
$s = 1$ residential and services
$s = 2$ industry
$s = 3$ agriculture and fishery
$s = 4 = N_s$ transports;

$r$ represents the atmospheric pollutants:

$r = 1$ $CO_2$
$r = 2$ $NO_x$
$r = 3$ $SO_x$
$r = 4 = N_r$ Particulates.

### 3.2. Parameters

Generally speaking, a value which remains constant in a study or for which only two or three specifically fixed amounts are assigned, is considered as a parameter. In our model, the following parameters are adopted:

$T_p$ operation time fraction of the LDC $p$-th interval (h)
$\delta$ corrective factor taking into account a reserve margin on annual load peak
$\alpha$ energy transmission line losses factor
$DR$ discount rate
$\epsilon_{i,r}$ $r$-th pollution factor per unit of the $i$-th fuel consumption (ton/toe)

*Energy conversion system*
$AV_j$ availability factor of the $j$-th installation type (h/y)
$A_j$ amortization period of an investment in the $j$-th installation type (y)
$D_j$ life period of the $j$-th installation type (y)
$\mu_{i,k}$ mass percentage of the $i$-th fuel in the $k$-th mix
$c_{i,j}$ unit consumption of the $i$-th fuel by the $j$-th conversion option (toe/MWh)

*Industrial sub-system*
$h_i$ unit consumption of the $i$-th fuel by HP steam boilers (toe/ton)
$m_i$ unit consumption of the $i$-th fuel by MP steam boilers (toe/ton)
$\sigma_{GT}$ linear gas turbine power-to-exhaust flow curve slope (MWh/ton)
$\sigma_{\underline{E}}$, $\sigma_E$, $\sigma_W$ linear steam turbine power equation coefficients (MWh/ton)
$\nu$ HRSG specific exhaust steam outflow rate (ton/ton)
$\lambda_H$, $\lambda_M$, $\lambda_L$ PRV efficiencies
$\gamma$ medium unit extraction limit ($ton_{extr}/ton_{in}$) for steam turbines

*Civil sub-system*
$\eta_i$ $i$-th primary energy conversion efficiency of boiler systems
$hpr_p$ heat-to-power ratio ($MW_t/MW_e$) of gas micro-turbines at the $p$-th load condition.

### 3.3. Variables

The choice of variables is based on the degree of freedom and flexibility that the planner means to attribute to some quantities. In this case, a distinction between ‘explanatory’ and ‘explained’ variables is adopted [2].

### 3.3.1. Explanatory variables

The ‘explanatory’ variables generally define the evolutionary scenarios of the system. For our purpose, the following ‘explanatory’ variables are used:

$f_{i,t}$, $F_{i,t}$ lower and upper bounds for the $i$-th fuel consumption at the $t$-th year (toe)
$RP_{j,t}$ available energy potential for renewable-based generation option ($j$ = 3–9) at the $t$-th year (toe)
$B_{j,t}$ total capacity of the $j$-th generation option, already existing at the beginning of the planning horizon and still in operation at the $t$-th year (MW)
$Exp_{t,p}$ electric power exported during the $p$-th interval of the $t$-th year (MW)
$PP_{s,t,p}$ purchased electric power by the $s$-th end-use sector during the $p$-th interval of the $t$-th year (MW)
$SP_{s,t,p}$ electric power amount delivered to the grid and self-produced by the $s$-th end-use sector ($SP_{s,t,p}\neq 0$ only for $s$ = 2), during the $p$-th interval of the $t$-th year (MW)
$QP_{s,t,p}$ electric power demand of the $s$-th end-user during the $p$-th interval of the $t$-th year (MW)
$QT_{t,p}$ civil thermal power demand at the $p$-th interval of the $t$-th year (MW)
$\Phi_{i,t}$ share of civil thermal demand in the $t$-th year satisfied by firing the $i$-th energy form (%)
$QH_{t,p}$, $QM_{t,p}$, $QL_{t,p}$ high, medium and low pressure industrial process steam demand during the $p$-th interval of the $t$-th year (ton/h)
$QF_{i,s,t}$ demands for the $i$-th fuel by the $s$-th sector in the $t$-th year (toe) not included in the optimisation process
$TOL_{r,t}$ emission limits of the $r$-th air pollutant in the $t$-th year (ton).

The set of the ‘explanatory’ variables also include the unit costs used to assess annuities in the objective function. The description of these further variables will be provided in Section 3.4.

### 3.3.2. Explained variables

In each planning study, one or more ‘explained’ variables have to be evaluated within a logical framework. The level of detail, chosen for the proposed methodology, suggests the adoption of the following ‘explained’ variables:

$I_{j,t}$ additional capacity of the $j$-th installation type at the $t$-th year (MW)
$R_{j,t,p}$ recovered thermal power from the $j$-th generation option during the $p$-th interval of the $t$-th year (MW)
$P_{j,k,t,p}$ power output of generation option $j$ = 1, from the $k$-th mix, during the $p$-th interval of the $t$-th year (MW)
$P_{j,t,p}$ power output of the $j$-th generation option during the $p$-th interval of the $t$-th year (MW)
$H_{i,t,p}$ industrial HP steam boilers outlet from $i$-th fuel during the $p$-th interval of the $t$-th year (ton/h)

$S_{i,t,p}$ steam turbine inlets from the HP boilers burning the $i$-th fuel ($i = 1,9,10,11$) during the $p$-th interval of the $t$-th year (ton/h)
$S_{t,p}$ steam turbine inlets from HRSGs during the $p$-th interval of the $t$-th year (ton/h)
$V_{t,p}$, $\underline{V}_{t,p}$ steam flows degraded by PRV during the $p$-th interval of the $t$-th year (ton/h)
$M_{i,t,p}$ industrial MP steam boilers outlet from $i$-th fuel during the $p$-th interval of the $t$-th year (ton/h)
$E_{t,p}$,$\underline{E}_{t,p}$ extractions from steam turbines during the $p$-th interval of the $t$-th year (ton/h)
$W_{t,p}$ condensing flow from steam turbines during the $p$-th interval of the $t$-th year (ton/h).

The main part of the above defined ‘explained’ variables refers to the industrial cogeneration model detailed in Appendix A.

### 3.4. Objective function

The objective function consists in the total actualized cost $C_T$ of the primary energy conversion over the selected time horizon:

$$C_T = CI + CF + CV + CE \quad (1)$$

where $CI$ is the total actualized investment cost of the installed plants, $CF$ represents the total fixed cost, $CV$ takes into account the variable costs and $CE$ the external costs.

The investment costs $CI$ is composed of two terms:

$$CI = CI^C + CI^S \quad (2)$$

$CI^C$ being the capital investment cost and $CI^S$ the stripping cost. Each of these terms is obtained as sum of annuities over the period of plant lifetime and assumes the following expression:

$$CI^C = \sum_{t=1}^{N_t} \frac{1}{(1+DR)^t} \sum_{j=1}^{N_j} \frac{1}{AF_j} \sum_{\tau \in \Omega_{AM_{j,t}}} KI_{j,\tau} \cdot I_{j,\tau} \quad (3)$$

where $KI_{j,\tau}$ is the unit capital cost (€/MW) of the $j$-th installation type at the $\tau$-th year, $\Omega_{\mathrm{AM}_{\mathrm{j,t}}} = \{\max(1,t - A_j + 1),...,t\}$ and $AF_j$ the $j$-th investment type amortization factor:

$$AF_j = \sum_{\tau=1}^{A_j} 1/\left(1 + \frac{\rho-\varphi}{1+\varphi}\right)^{\tau}$$

$\rho$ being the interest rate of capital and $\phi$ the inflaction rate.

The stripping cost $CI^S$ is expressed as follows:

$$CI^S = \sum_{j \in \Omega_{STRP}} \sum_{t=1}^{N_t - D_j} \frac{KS_{j,t+D_j} \cdot I_{j,t}}{(1+DR)^{t+D_j}} \quad (4)$$

where $KS_{j,t+Dj}$ is the unit stripping cost (€/MW) of the $j$-th generation option installed at the $t$-th year, $\Omega_{STRP}$ is the set of all $j \in \{1,...,Nj\} \ni$ ' $N_t - D_j > 0$.

The total actualized fixed cost $CF$ has the following expression:

$$CF = \sum_{t=1}^{N_t} \frac{1}{(1+DR)^t} \sum_{j=1}^{N_j} KFX_{j,t} \sum_{\tau \in \Omega_{DUR_{j,t}}} I_{j,\tau} \tag{5}$$

where $KFX_{j,t}$ is the unit operation and maintenance cost (€/MW) of the $j$-th installation type at the $t$-th year and $\Omega_{DURj,t} = \{\max(1,t-D_j+1),\ldots,t\}$.

The cost $CV$ represents the procurement costs for all fuels necessary for the electrical energy generation and process steam production over the planning horizon:

$$\begin{aligned} CV = \sum_{t=1}^{N_t} \frac{1}{(1+DR)^t} \Bigg[ \sum_{i=1}^{N_i} KFL_{i,t} \Bigg( \sum_{k=1}^{N_k} \mu_{i,k} \cdot c_{i,1} \sum_{p=1}^{N_p} P_{1,k,t,p} \cdot T_p \\ + \sum_{j=2}^{11} c_{i,j} \sum_{p=1}^{N_p} P_{j,t,p} \cdot T_p \Bigg) + \sum_{i \in \Omega_{HPB}} KFL_{i,t} \cdot h_i \sum_{p=1}^{N_p} H_{i,t,p} \cdot T_p \\ + \sum_{i \in \Omega_{MPB}} KFL_{i,t} \cdot m_i \sum_{p=1}^{N_p} M_{i,t,p} \cdot T_p \Bigg] \end{aligned} \tag{6}$$

where $KFL_{i,t}$ is the unit price (€/toe) of the $i$-th fuel in the $t$-th year and $\Omega_{HPB} = \Omega_{MPB} = \{1,9,10,11\}$. The coefficient $\mu_{i,k}$, representing the percentage of the $i$-th fuel in the thermal multi-fuel units, weights the produced power [27].

The external costs consist in the economical estimation of burdens occurred to people and environment because of energy chains including the life-cycle both of primary energy sources $CE^F$and power generation plants $CE^P$:

$$CE = CE^F + CE^P \tag{7}$$

For the cost $CE^F$ the following expression is adopted:

$$\begin{aligned} CE^F = \sum_{t=1}^{N_t} \frac{1}{(1+DR)^t} \Bigg[ 2 \sum_{i=1}^{N_i} KEF_{i,t} \Bigg( \sum_{k=1}^{N_k} \mu_{i,k} \cdot c_{i,1} \sum_{p=1}^{N_p} P_{1,k,t,p} \cdot T_p \\ + \sum_{j=2}^{11} c_{i,j} \sum_{p=1}^{N_p} P_{j,t,p} \cdot T_p \Bigg) + \sum_{i \in \Omega_{HPB}} KEF_{i,t} \cdot h_i \sum_{p=1}^{N_p} H_{i,t,p} \cdot T_p \\ + \sum_{i \in \Omega_{MPB}} KEF_{i,t} \cdot m_i \sum_{p=1}^{N_p} M_{i,t,p} \cdot T_p \Bigg] \end{aligned} \tag{8}$$

where $KEF_{j,t}$ is the unit cost (€/toe) assessing impacts related to transportation, treatment and utilization of the $i$-th fuel in the $t$-th year.

As well as for the cost $CE^P$ the following expression is assumed:

$$CE^{P} = \sum_{j=1}^{N_j}\sum_{t=1}^{N_t}\frac{KEI_{j,t}\cdot I_{j,t}}{(1+DR)^t} + \sum_{j\in\Omega_{STRP}}\sum_{t=1}^{N_t-D_j}\frac{KES_{j,t+D_j}\cdot I_{j,t}}{(1+DR)^{t+D_j}} + \sum_{t=1}^{N_t}\frac{1}{(1+DR)^t}\cdot\sum_{j=1}^{N_j}KEL_{j,t}\sum_{\tau\in\Omega_{DUR_{j,t}}} I_{j,\tau} \quad (9)$$

where $KEI_{j,t}$, $KEL_{j,t}$, $KES_{j,t}$ (€/MW) take into account the impacts related respectively to installation, operative life and stripping of the $j$-th generation option in the $t$-th year.

### 3.5. Equality and inequality constraints

The optimisation procedure has to run within a logical framework that drives the evaluation of the 'explained' variables. To this purpose, the definition of the following relationships is needed.

#### 3.5.1. Construction time constraints

At the beginning of the time horizon, construction time is taken into account, by adding in the optimisation procedure suitable constraints able to delay the energy production of the new installations. The time delay depends on the particular type of plant/facility installation. As a consequence, the following equality constraints are included:

$$\begin{cases} I_{j,1} = I_{j,2} = I_{j,3} = 0 & j = 1 \\ I_{j,1} = I_{j,2} = 0 & j = 2,6,7 \\ I_{j,1} = 0 & j = 3,4,5,11,12 \end{cases} \quad (10)$$

For the generation options corresponding to $j = 8,9,10$ it is assumed a construction time less than 12 months; thus the installation of this options can occur starting from $t = 1$.

#### 3.5.2. Peak demand satisfaction

The first time step of each defined LDC corresponds to the forecasted annual peak load. Then the total electricity generation capacity in this period has to cover, with a suitable reserve margin, the internal load demand and the exported power:

$$\sum_{\substack{j=1 \\ j\neq 8}}^{N_j}\left(B_{j,t} + \sum_{\tau\in\Omega_{DUR_{j,t}}} I_{j,\tau}\right) \geq (1+\delta)\cdot\left(\sum_{s=1}^{N_s} QP_{s,t,1} + Exp_{t,1}\right) \quad t = 1,\ldots,N_t \quad (11)$$

### 3.5.3. Plant/facility operation limits

The net power output of each generation option cannot exceed the relevant installed capacity:

$$\begin{cases} \sum_{k=1}^{N_k} P_{j,k,t,p} \leq B_{j,t} + \sum_{\tau \in \Omega_{DUR_{j,t}}} I_{j,\tau} & j = 1 \\ P_{j,t,p} \leq B_{j,t} + \sum_{\tau \in \Omega_{DUR_{j,t}}} I_{j,\tau} & j = 2,\ldots,12 \end{cases} \tag{12}$$

for $t=1,\ldots,N_t$ and $p=1,...,N_p$.

### 3.5.4. Limits on renewable energy potentials

Limits on energy production (heat and/or power) from renewable and local energy sources have to be considered. Limitations are imposed directly on the power output of the generation options: hydroelectric, photovoltaic power plants, wind, solar thermal and photovoltaic roofs. The corresponding constraints are expressed as follows:

$$\frac{1}{4.86} \sum_{p=1}^{N_p} P_{j,t,p} \cdot T_p \leq RP_{j,t} \qquad j = 3,4,5,8,9 \tag{13}$$

where 4.86 is the gross MWh-to-toe ratio, for $t = 1,\ldots,N_t$ and $p = 1,...,N_p$. Limits on energy production by local renewable fuels, such as biomass and municipal waste, are taken into account by fixing a maximum consumption threshold and are illustrated in Section 3.5.10.

### 3.5.5. Limits on electrical energy generation

Through the availability factor $AV_j$ (hours/year), maintenance and failure periods are defined and, contemporaneously, the maximum energy production is obtained for each generation option. Therefore, the annual energy production does not have to exceed this threshold, that is:

$$\begin{cases} \sum_{p=1}^{N_p} \left( \sum_{k=1}^{N_k} P_{j,k,t,p} \right) \cdot T_p \leq AV_j \cdot \left( B_{j,t} + \sum_{\tau \in \Omega_{DUR_{j,t}}} I_{j,\tau} \right) & j = 1 \\ \sum_{p=1}^{N_p} P_{j,t,p} \cdot T_p \leq AV_j \cdot \left( B_{j,t} + \sum_{\tau \in \Omega_{DUR_{j,t}}} I_{j,\tau} \right) & j = 2,...,12 \end{cases} \tag{14}$$

for $t = 1,\ldots,N_t$.

### 3.5.6. Electricity generation and consumption balancing

The balance among the electricity generation, the internal consumption and the net power exchange with the grid has to be satisfied. The following expressions establish the electric power balance for each economic sector and for the overall regional system during the planning horizon:

$$PP_{1,t,p} + \sum_{j=9,10} P_{j,t,p} = QP_{1,t,p} \tag{15}$$

$$PP_{2,t,p} - SP_{2,t,p} + \sum_{j=11,12} P_{j,t,p} = QP_{2,t,p} \tag{16}$$

$$PP_{3,t,p} = QP_{3,t,p} \tag{17}$$

$$PP_{4,t,p} = QP_{4,t,p} \tag{18}$$

$$\sum_{k=1}^{N_k} P_{1,k,t,p} + \sum_{j=2}^{7} P_{j,t,p} + SP_{2,t,p} = \alpha\cdot\left(Exp_{t,p} + \sum_{s=1}^{N_s} PP_{s,t,p}\right) \tag{19}$$

for $t = 1,\ldots,N_t$ and $p = 1,\ldots,N_p$. It should be noted that the produced power in the civil sector is assumed to cover the sole internal needs. Whereas the industrial sector is allowed to deliver energy to the network.

### 3.5.7. *Industrial CHP facilities*

The most common cogeneration options used for industrial applications are: simple and double-extraction steam turbines, back pressure steam turbines, gas turbines with waste heat boiler and combined cycles [28]. As shown in Fig. 2, the purpose of our model is to include all these options in a simple scheme.

*3.5.7.1. Inlet boundaries* The steam turbine system may receive input steam both from HP boilers and HRSG systems. These input flows derive from leading flows, namely the whole output of HP boilers and HRSG systems, that cannot be exceeded:

$$S_{i,t,p} \leq H_{i,t,p} \qquad \forall i \in \Omega_{HPB} \tag{20}$$

$$S_{t,p} \leq \frac{\nu}{\sigma_{GT}} \cdot P_{j,t,p} \qquad j = 11 \tag{21}$$

for t = 1,…,$N_t$ and p = 1,…,$N_p$.

*3.5.7.2. Power balance* Assuming linear steam-flow/electric-power characteristics for the steam turbine generators and negligible heat loss, the power equation may be written in the form:

$$P_{j,t,p} = \sigma_E \cdot E_{t,p} + \sigma_{\underline{E}} \cdot \underline{E}_{t,p} + \sigma_w \cdot W_{t,p} \qquad j = 12 \tag{22}$$

for t = 1,…,$N_t$ and p = 1,…,$N_p$.

*3.5.7.3. Mass balance constraint* The sum of the input steam flows of the turbine system has to be equal to the sum of the output steam flows:

$$S_{t,p} + \sum_{i \in \Omega_{HPB}} S_{i,t,p} = E_{t,p} + \underline{E}_{t,p} + W_{t,p} \tag{23}$$

for $t = 1,\ldots,N_t$ and $p = 1,\ldots,N_p$.

*3.5.7.4. Extraction boundary* The sum of the extraction flows is constrained below a fixed portion of the total input:

$$E_{t,p} + \underline{E}_{t,p} \leq \gamma \cdot \left( S_{t,p} + \sum_{i \in \Omega_{HPB}} S_{i,t,p} \right) \tag{24}$$

for $t = 1,\ldots,N_t$ and $p = 1,\ldots,N_p$.

### 3.5.8. Industrial process-steam balance

Since the self-produced electric power is already fixed in Eq. (16), the thermal load following is carried out by integrating the HRSGs with boiler outputs. Referring to Fig. A1 of Appendix A, the industrial process-steam balance is expressed by the following equations:

$$\sum_{i \in \Omega_{HPB}} (H_{i,t,p} - S_{i,t,p}) + \nu \cdot \frac{P_{j,t,p}}{\sigma_{GT}} - S_{t,p} = \frac{QH_{t,p} + V_{t,p}}{\lambda_H} \qquad j = 11 \tag{25}$$

$$\sum_{i \in \Omega_{MPB}} M_{i,t,p} + E_{t,p} + \lambda_M \cdot V_{t,p} = QM_{t,p} + \underline{V}_{t,p} \tag{26}$$

$$\underline{E}_{t,p} + \lambda_L \cdot \underline{V}_{t,p} = QL_{t,p} \tag{27}$$

for $t = 1,\ldots,N_t$ and $p = 1,\ldots,N_p$.

### 3.5.9. Civil thermal power non-conventional production

In order to satisfy hot water and heating requirements, civil users may either use conventional boilers or non-conventional facilities as solar collectors and micro-turbines. The thermal power, recovered from the non-conventional facilities, has to respect the following conditions:

$$R_{j,t,p} = P_{j,t,p} \qquad j = 8 \tag{28}$$

$$R_{j,t,p} \leq hpr_p \cdot P_{j,t,p} \qquad j = 10 \tag{29}$$

$$\sum_{j = 8,10} R_{j,t,p} \leq QT_{t,p} \tag{30}$$

for $t = 1,\ldots,N_t$ and $p = 1,\ldots,N_p$. Eq. (30) imposes that the total recovered power cannot exceed the internal needs.

### 3.5.10. Primary energy consumption

Fuel consumption is related to plant/facilities power production, conventional civil thermal plants output, industrial boiler output and other needs. The whole sum of these contributions, for the $i$-th fuel at the $t$-th year, has to be comprised between suitable lower and upper boundaries:

$$f_{i,t} \leq \sum_{k=1}^{N_k} \mu_{i,k} \cdot c_{i,1} \sum_{p=1}^{N_p} P_{1,k,t,p} \cdot T_p + \sum_{j=2}^{11} c_{i,j} \sum_{p=1}^{N_p} P_{j,t,p} \cdot T_p + \\ + \frac{\Phi_{i,t}}{12.44 \cdot \eta_i} \sum_{p=1}^{N_p} \left( QT_{t,p} - \sum_{j=8,10} R_{j,t,p} \right) \cdot T_p + + h_i \sum_{p=1}^{N_p} H_{i,t,p} \cdot T_p \\ + m_i \sum_{p=1}^{N_p} M_{i,t,p} \cdot T_p + \sum_{s=1}^{N_s} QF_{i,s,t} \leq F_{i,t} \tag{31}$$

where $h_i = 0(m_i = 0) \forall i \notin \Omega_{HPB}(\Omega_{MPB})$ and 12.44 is the net MWh-to-toe ratio; for $i$=1,…,$N_i$ and $t$=1,…,$N_t$.

### 3.5.11. *Environmental constraints*

The unit consumption of an energy form is related to pollutants emission through suitable emission factors. Therefore, the total annual emission of the $r$-th pollutant is evaluated with the same approach adopted for fuel consumption assessment. The environmental scenario defines the time evolution of the emission tolerance to be satisfied by the annual emission level of each pollutant:

$$\sum_{i=1}^{N_i} \varepsilon_{i,r} \cdot \left[ \sum_{k=1}^{N_k} \mu_{i,k} \cdot c_{i,1} \sum_{p=1}^{N_p} P_{1,k,t,p} \cdot T_p + \sum_{j=2}^{11} c_{i,j} \sum_{p=1}^{N_p} P_{j,t,p} \cdot T_p + \right. \\ \left. + \frac{\Phi_{i,t}}{12.44 \cdot \eta_i} \sum_{p=1}^{N_p} \left( QT_{t,p} - \sum_{j=8,10} R_{j,t,p} \right) \cdot T_p + \sum_{s=1}^{N_s} QF_{i,s,t} \right] + \\ + \sum_{i \in \Omega_{HPB}} \varepsilon_{i,r} \cdot h_i \sum_{p=1}^{N_p} H_{i,t,p} \cdot T_p + \sum_{i \in \Omega_{MPB}} \varepsilon_{i,r} \cdot m_i \sum_{p=1}^{N_p} M_{i,t,p} \cdot T_p \leq TOL_{r,t} \tag{32}$$

for $r = 1,\ldots,N_r$ and $t = 1,\ldots,N_t$.

## 4. The energy system under study

The procedure described is applied to the assessment of optimal energy plans for Apulia region, in southern Italy. The actual snapshot of the energy system is assumed as the starting point of the planning horizon. Therefore, following the modular structure illustrated in Fig. 1, the primary energy supply sector, the intermediate energy sector, the end-use demand (electricity and heat) sector and the environmental impact are detailed.

Due to the presence of great iron and steel production sites, a remarkable quantity

Table 1
Energy balance of the system under study

| | Solid fuels (ktoe) | Oil products (ktoes) | Gas fuels (ktoe) | Renewable | | Electric energy (ktoe) | Total (ktoe) |
|---|---|---|---|---|---|---|---|
| | | | | Fuels (ktoe) | Non-fuels (ktoe) | | |
| Gross consumption | 6528 | 4940 | 1570 | 111 | 89 | -958 | 12 280 |
| Electric energy conversion | -3697 | -1252 | 0 | -111 | -89 | 5149 | 0 |
| Consumptions/losses of energy sector | -893 | 152 | -20 | 0 | 0 | -2797 | -3558 |
| Other uses | 128 | 815 | 0 | 0 | 0 | | 943 |
| End-use consumption | 1810 | 3025 | 1550 | 0 | 0 | 1394 | 7779 |

of by-product gases is available and utilized in industrial energy self-production. Moreover, Apulia imports from neighbouring regions and countries the greatest part of the fossil fuels.

The forecasted gross energy balance of the system under investigation is reported in Table 1. The data, illustrated in this table, come from a previous study developed in Ref. [29]. The primary energy sources are classified as solid fuels (coal, blast furnace gas and cokery gas); oil products (fuel oil, diesel oil, petrol, LPG and refinery gas); gas fuels (natural gas); renewable fuels (municipal waste, biomass) and renewable non-fuels (hydro, wind, photovoltaic).

It is worth remarking that the actually exploited renewable fuels are biomass whereas the main electric energy from renewable non-fuels is produced by wind power plants.

In Table 2, the installed electric generation capacity is reported for every existing generation option. The total generation capacity of the region is 4850 MW.

The main part of the conventional thermoelectric capacity (2447 MW) has been operating since 1998 whereas the remaining 625 MW since 1980. The hydro-electric plants started working in 1987, as well as the photovoltaic plants. The wind power

Table 2
The installed electric generation capacity

| Generation option | Installed capacity at 2002 (MW) |
|---|---|
| Thermal power plant | 3102 |
| Hydro power | 2 |
| PV power | 0.6 |
| Wind power | 163 |
| Biomass power | 43 |
| Industrial steam turbine | 1540 |

Table 3
The End-use consumption

| | Civil | Industry | Agr and fishery | Transport | Total(ktoe) |
|---|---|---|---|---|---|
| Solid fuels (ktoe | 33.7 | 1776 | 0 | 0 | 1809.7 |
| Oil-Products (ktoe) | 181.6 | 470.6 | 328.9 | 2044.3 | 3025.4 |
| Gas-Fuels (ktoe) | 692.2 | 853.6 | 2.4 | 2.0 | 1550.2 |
| Electric Energy (ktoe) | 584.9 | 745.6 | 50.1 | 13.3 | 1393.9 |
| Total (ktoe) | 1492.5 | 3846.0 | 381.4 | 2059.6 | 7779.0 |

Table 4
Emission to air total amounts

| | $CO_2$ (ton) | $NO_x$ (ton) | $SO_x$ (ton) | Particulates (ton) |
|---|---|---|---|---|
| Solid fuels | 7 976 457 | 23 591 | 35 145 | 25 898 |
| Oil products | 8 971 610 | 78 972 | 22 976 | 6647 |
| Gas fuels | 3 627 433 | 6356 | 0 | 310 |
| Electric energy | 21 016 220 | 63 149 | 118 140 | 60 255 |
| Total | 41 591 720 | 172 068 | 176 261 | 93 110 |

plants have been installed in the period 1996–1998, while the biomass exploitation dates back to 1997. The industrial steam turbine installations were undertaken from 1990–1997, though most of the installations (984 MW) occurred in 1997.

The end-use consumptions of the region under investigation are illustrated in Table 3, for every economic sector.

It can be noted that thanks to the widely spread gas network, both the civil and industrial sectors greatly exploit natural gas for all purposes, whereas the oil products are essentially used for transport.

The total emission amount of $CO_2$, $NO_x$, $SO_x$ and particulates due to the end-use consumption of fuels, as reported in Tables 1 and 3, and electric energy production at year zero are reported in Table 4.

Table 5
Annual growing rates of the electricity and heat demand

| | Civil | Industry | Agr and fishery | Transports |
|---|---|---|---|---|
| Electricity demand annual rate (%) | 1.10 | 1.93 | 1.95 | 0.30 |
| Heat demand annual rate (%) | 1.75 | 1.00 | – | – |

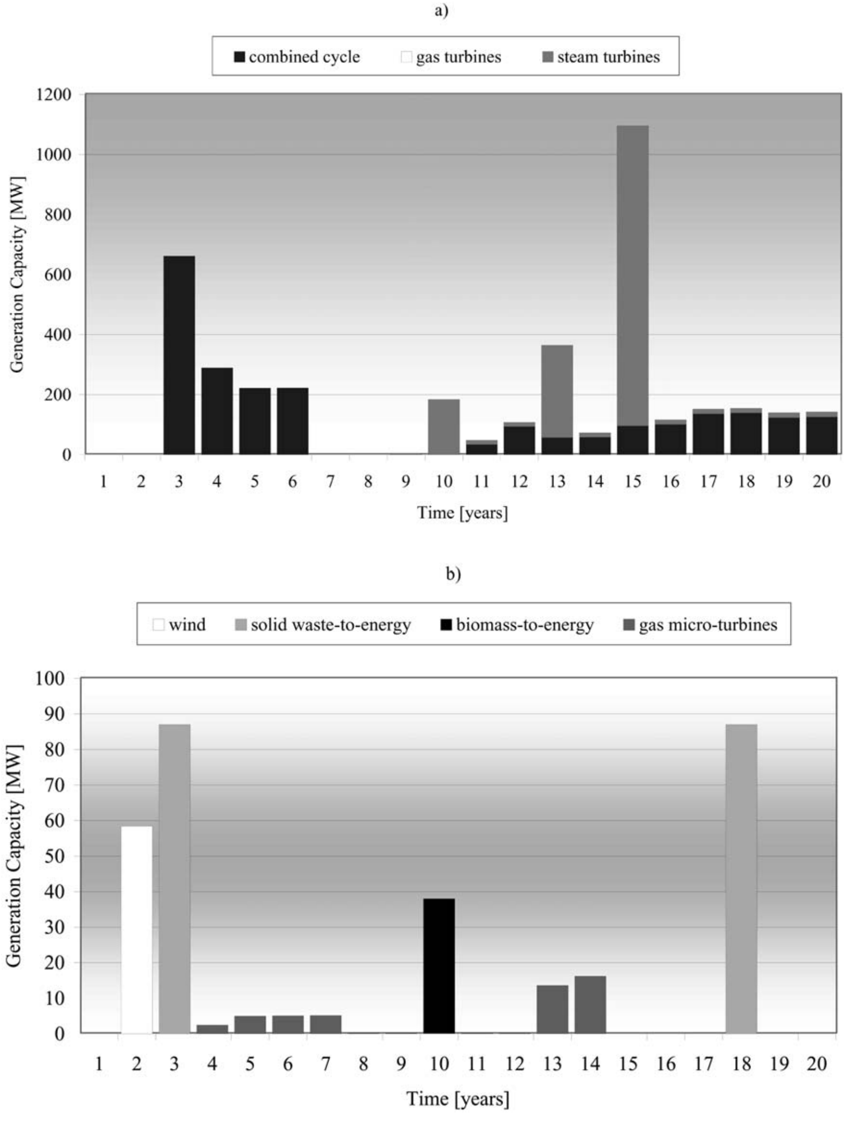


Fig. 4. Scenario 1: Generation capacity to be installed.

## 5. Numerical results

The proposed energy planning methodology is applied to the regional system illustrated in Section 4. To this purpose suitable scenarios are considered taking into account different regional economic and environmental policies.

Table 6
Scenario 1. Detail of the generation capacity to be installed (MW)

| Generation options | Years of the planning horizon | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| Combined cycle | 0 | 0 | 662 | 290 | 222 | 223 | 0 | 0 | 0 | 0 | 34 | 94 | 57 | 58 | 96 | 101 | 136 | 139 | 123 | 126 |
| Wind | 0 | 58 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solid waste-to energy | 0 | 0 | 87 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 87 | 0 | 0 |
| Biomass-to-energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 38 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas micro-turbines | 0 | 0 | 0 | 2 | 5 | 5 | 5 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 14 | 16 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas turbines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Steam turbines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 185 | 14 | 14 | 308 | 15 | 999 | 15 | 16 | 16 | 17 | 17 |

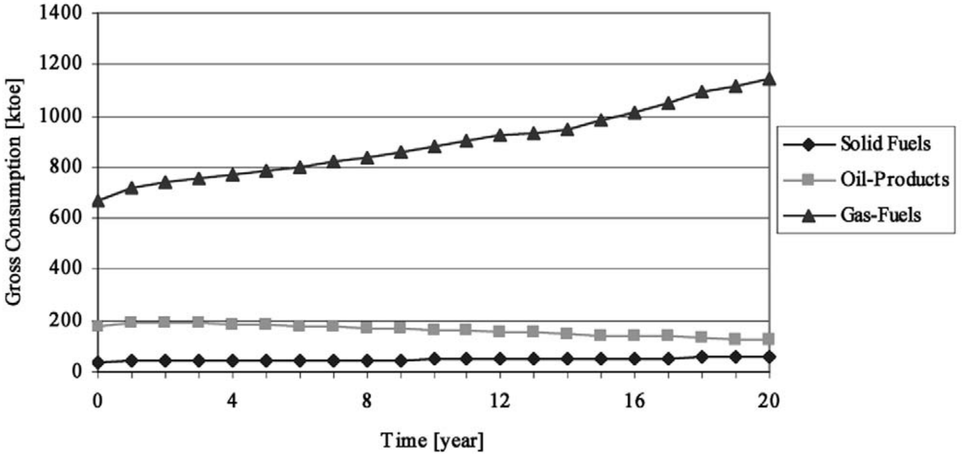


Fig. 5. Scenario 1: Civil primary energy gross consumption for heating purposes.

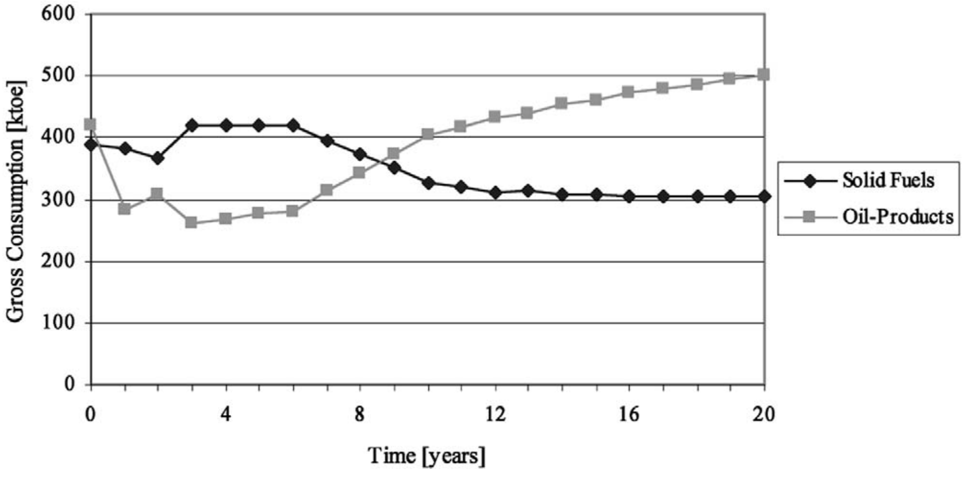


Fig. 6. Scenario 1: Industrial primary energy gross consumption for steam production.

### 5.1. Scenario 1

The annual rates of the electricity required by every end-use sector, as well as the heat demand, are supposed growing as described in Table 5.

It can be noted that, since no heat power is demanded by the sectors other than civil and industrial, no per cent increase is assumed for these sectors. The allowable emission amount of $CO_2$ is considered in accordance with the Kyoto Protocol requirements, i.e. 5–7% decreasing total rate, with regard to 1990 emission amount, for the first 10 years and then constant. Analogous limitations are assumed for the

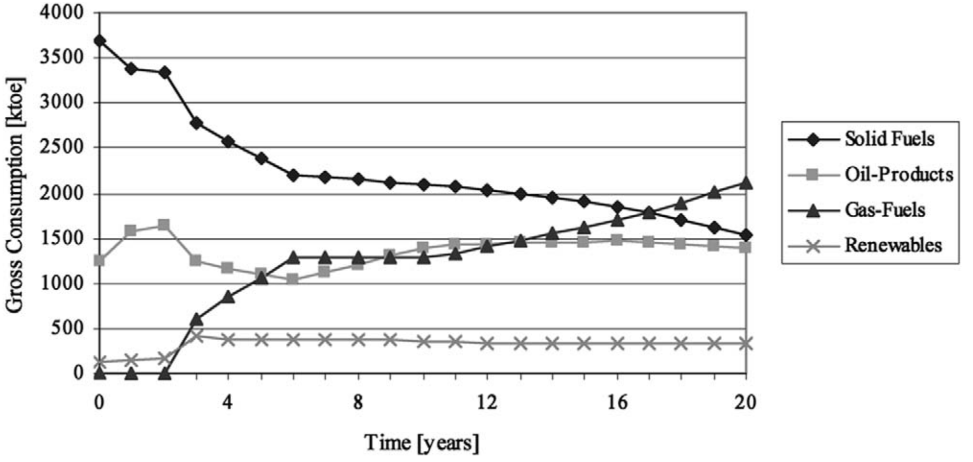


Fig. 7. Scenario 1: Primary energy gross consumption for electricity production.

other pollutants. Furthermore, all the unit costs, defined in Section 3, are supposed increasing with a rate able to offset the inflation rate. The external costs of the electricity production are neglected in this scenario.

The resulting capacity to be installed over the planning horizon is reported in Fig. 4 and Table 6.

The main new production capacity, for the first 6 years and for the last 10 years,

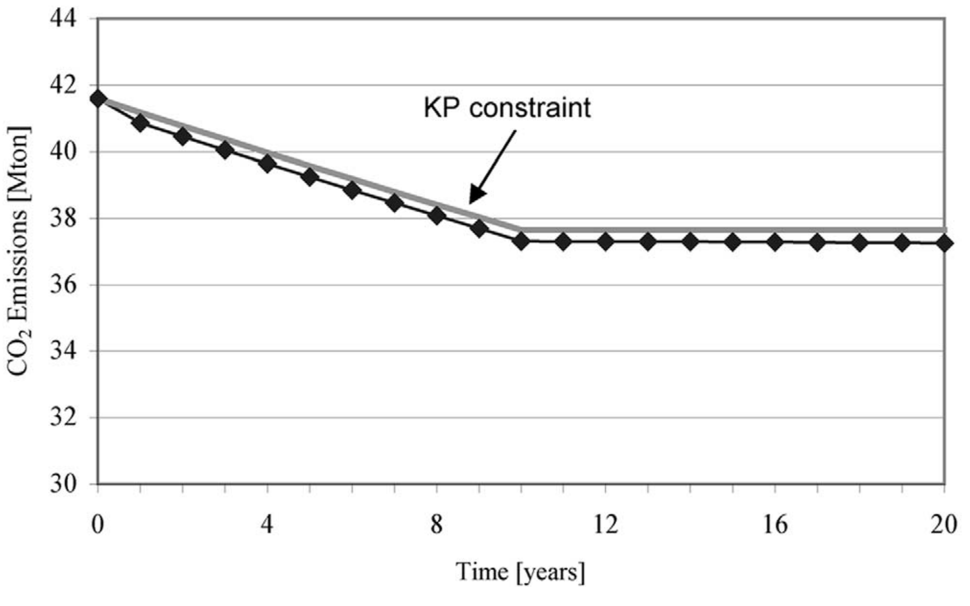


Fig. 8. Scenario 1: $CO_2$ emissions to air.

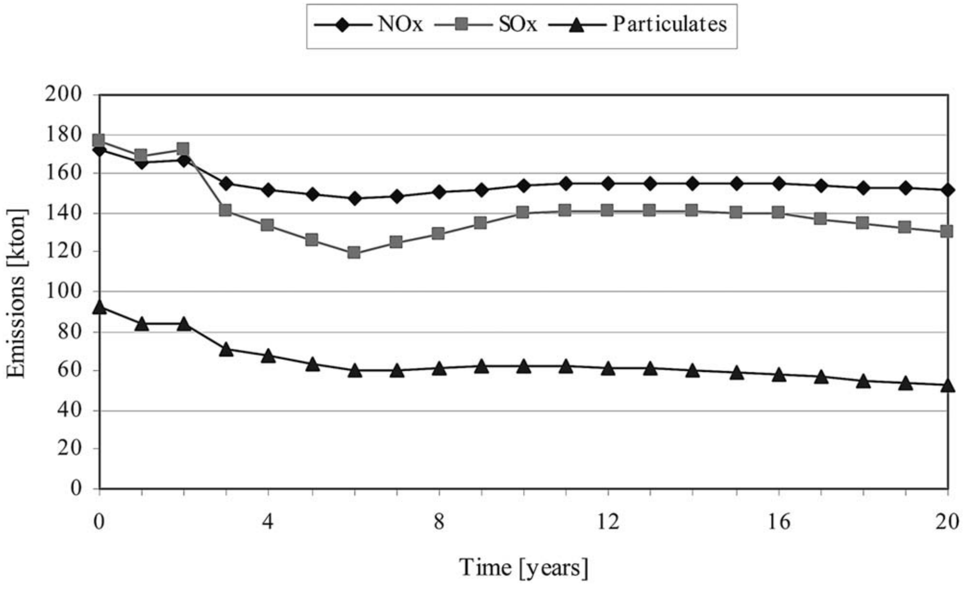


Fig. 9. Scenario 1: Other pollutant emissions to air.

derives from combined cycle power plants which turn out to be the most economic and efficient technology, whereas a great number of industrial steam turbines are installed at the 15th year because of the end-life of the industrial thermoelectric power plants.

The primary energy gross consumption concerning civil heating is shown in Fig. 5. It can be noted a growing use of the gas-fuels and a light decreasing use of the oil-products over the studied interval.

The industrial process steam production requires the sole consumption of solid fuels and oil products as shown in Fig. 6. A reduction in the oil product consumption is noted in the first years in an attempt to minimise the costs, though the increased use of less expensive solid fuels (such blast furnace and cokery gas) yields higher emissions. This explains the turnround in consumption behaviour in the last 12 years.

The gross consumption of the primary energy sources, due to electric energy production is reported in Fig. 7. In accordance with the policy of promoting efficient technologies and renewables, the growing installation of combined cycle power plants is pointed out by the gas-fuel gross consumption rise and the fall in solid fuel gross consumption.

It can be further remarked that the electric energy from the renewable fuels and non-fuels experiences a small increase.

The corresponding emission to air levels, over the time horizon, respect the fixed limitations. In particular, the $CO_2$ emission strictly follows the Kyoto Protocol constraints, as reported in Fig. 8.

In Fig. 9, the behaviour of the $NO_x$, $SO_x$ and Particulates emissions is shown too. It has been verified that these emission values are well above the imposed limits.

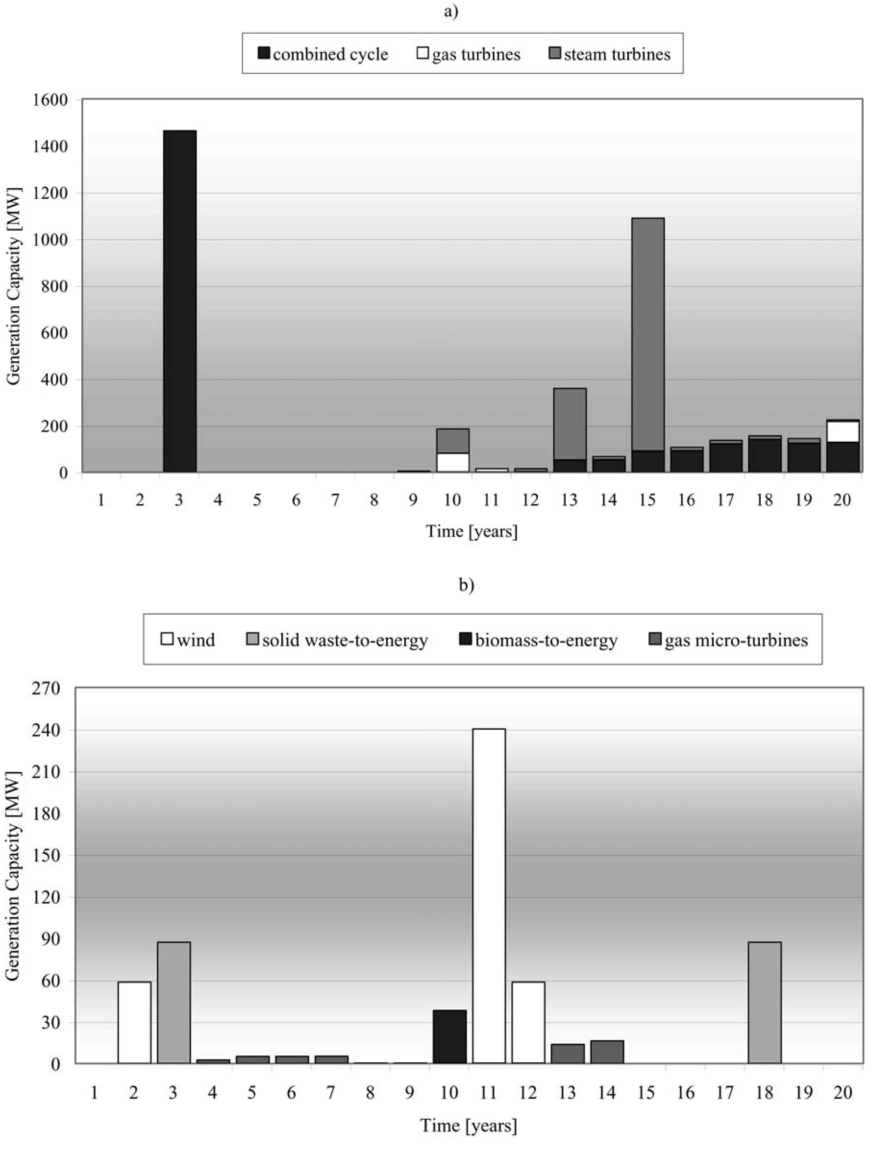


Fig. 10. Scenario 2. Generation capacity to be installed.

### 5.2. Scenario 2

Assuming the same conditions of the previous case, the new scenario includes the external costs in the objective function. The external costs, related to MW of installed plant/facility and to toe of burned fuel, are obtained by adapting the ExternE methodology study cases to the Apulia region situation [30]. The further limitation on

Table 7
Scenario 2. Detail of the generation capacity to be installed (MW)

| Generation options | Years of the planning horizon | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| Combined cycle | 0 | 0 | 1.462 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 51 | 89 | 91 | 120 | 139 | 123 | 127 |
| Wind | 0 | 58 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 240 | 58 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solid waste-to energy | 0 | 0 | 87 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 87 | 0 | 0 |
| Biomass-to-energy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 38 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas micro-turbines | 0 | 0 | 0 | 2 | 5 | 5 | 5 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 14 | 16 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gas turbines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 80 | 14 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 89 |
| Steam turbines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 105 | 0 | 13 | 307 | 14 | 998 | 15 | 16 | 16 | 21 | 7 |

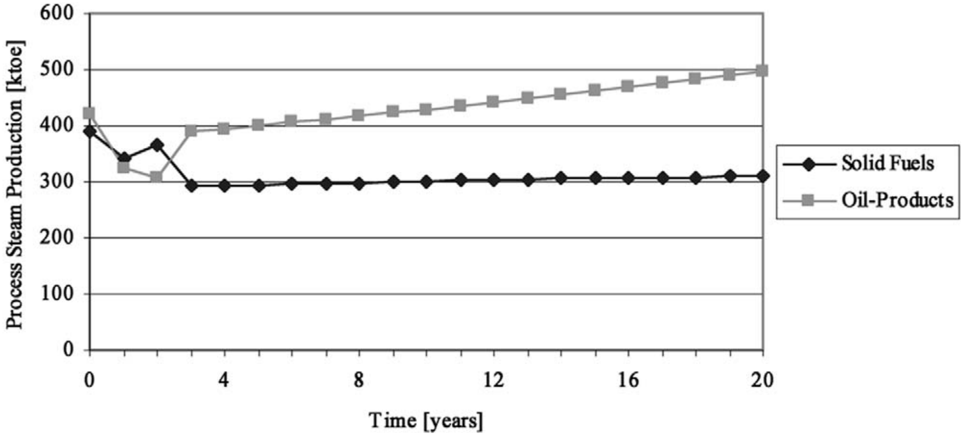


Fig. 11. Scenario 2: Industrial primary energy gross consumption for steam production.

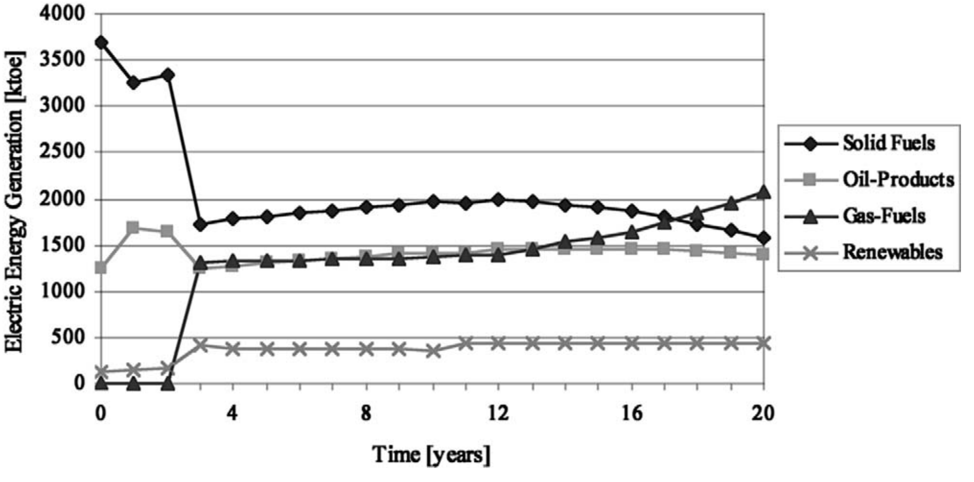


Fig. 12. Scenario 2: Primary energy gross consumption for electricity production.

environmental impacts gives rise to a new settlement of the generation capacity to be installed over the planning period as reported in Fig. 10 and detailed in Table 7.

The main part of the combined cycle power plants (1462 MW) is installed at the 3rd year and a remarkable installation (240 MW) of wind power can be observed at 11th year, whereas the installation of the industrial steam turbines at 15th year is still the same.

The primary energy gross consumption for civil heating does not change, whereas a different behaviour can be observed for the solid fuel and oil product gross consumption for industrial steam production as shown in Fig. 11.

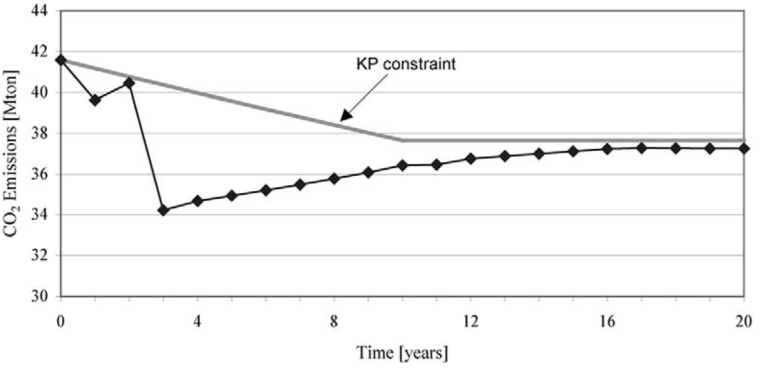


Fig. 13. Scenario 2: $CO_2$ emissions to air.

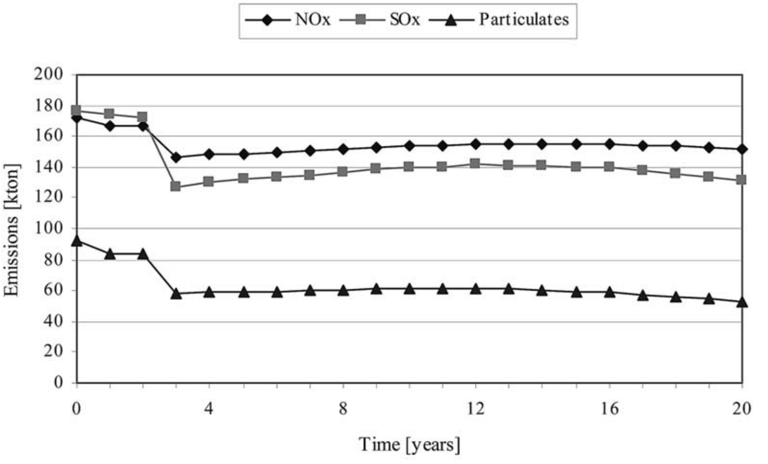


Fig. 14. Scenario 2: Other pollutant emissions to air.

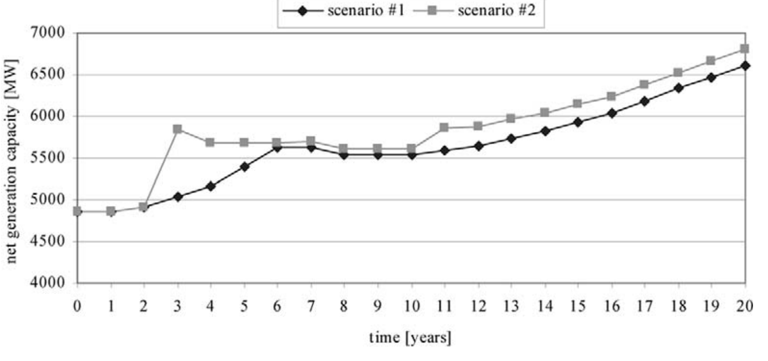


Fig. 15. Comparison between the total net capacities to be installed.

After a considerable decreasing in the first 2 years, the burned oil product assumes an increasing trend. On the other hand, the solid fuel consumption decreases in the first 3 years and then it keeps an almost constant value.

The gross consumption of the various fuels, due to the electricity production, remarkably changes in the first years of the planning horizon because of the further restrictions on the environmental impacts, as reported in Fig. 12.

The related emissions to air change as well, so that the strict dependence of the $CO_2$ and $SO_x$ emission on the solid fuel consumption is put in evidence. In Fig. 13, the $CO_2$ emission behaviour is illustrated and the other pollutant emissions are reported in Fig. 14.

It can be noted that the inclusion of the external costs in the objective function drives the $CO_2$ emissions well below the Kyoto Protocol constraints.

In order to summarize the main differences of the two scenarios, the total net generation capacity is drawn in Fig. 15. For each year of the time period, the net capacity includes the plants still in service and the new installations selected by the optimisation process.

It can be noted an increase (about 800 MW) of the net generation capacity at the 3rd year that is ascribable to the rise of the combined cycle installations observed in Fig. 10. A further deviation (about 200 MW) of scenario 2 from the scenario 1 occurs starting form the 11th year of the planning horizon, owing to the greater employment of generation options such as wind power plants, waste-to-energy systems, gas turbines for industrial cogeneration systems.

## 6. Conclusions

A bottom-up energy system optimisation model has been adopted to support regional energy planning policies. The proposed approach is based on EFOM modular structure, detailing the primary energy sources exploitation (including biomass, solid waste, process by-product), power and heat generation, emissions and end-use sectors. Moreover, particular care has been given to the description of the industrial cogeneration system scheme that has been incorporated in the regional energy model. The effectiveness of the proposed methodology has been shown by carrying out simulations on the Apulia region energy system. Test results proved that the regional policy, aimed satisfying the increasing heat and power demand by various end-use sectors through environmental friendly technologies, can be supported mainly by combined cycle installations and with less effort of wind to power, waste-to-energy and biomass exploitation and industrial cogeneration systems. The inclusion of the external costs, in the objective function permitted to further force the conventional thermoelectric power plants out of the energy planning, increasing the adoption of more efficient and less polluting facilities, such as cogeneration systems and wind power. Although, it needs to be remarked that other renewable options such as PV power turn out to be still not competitive because of the high capital costs.

## Appendix A

This appendix provides a detailed description of the industrial energy system, including cogeneration facilities already shown in Fig. 2 and all the external and internal linkages. The CC of the GTs fires only natural gas ($i = 3$), the GT outputs are both the electric power, delivered to the utility grid or directly satisfying the internal demand, and the recovered HP-steam which feeds the STs and satisfies the HP process-steam requirements. The HP and MP boiler systems burn oil ($i = 1$), and all industrial by-products ($i = 9, 10, 11$). Their outputs supply steam to industrial processes at various pressure levels through a system of PRVs. The STs may be fed by high pressure boiler systems and/or the high pressure steam from HRSG systems. The ST outputs are the electric power delivered to the utility grid or withdrawn by industrial sector and the extracted steam suitable for satisfying the MP/LP process steam requirements.

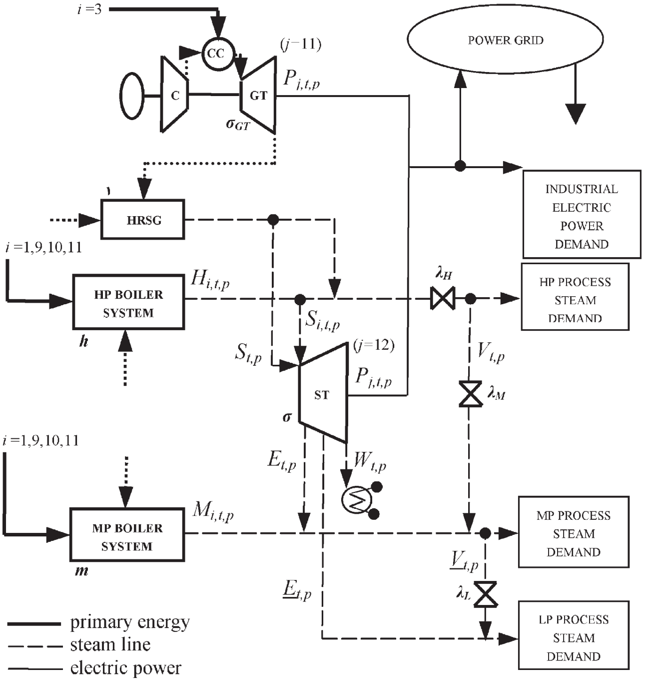


Fig. A1 Overall outline of the industrial sector.

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