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Energy Network Optimization Model for supporting Generation Expansion Planning and Grid Design

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Abstract. Generation and transmission expansion planning consists of finding the optimal long-term plan for the construction of new generation and transmission capacity. It usually involves solving a large-scale, non-linear discrete and dynamic optimization problem in a highly constrained and uncertain environment. The current literature continuously looks for quantitative muti-perspective strategies and models, including and best balancing such issues. This paper is concerned with the generation and transmission expansion planning of large-scale energy systems with high penetration of renewables. Particularly, this paper presents and applies an optimization model for the energy mix planning and the electrical grid design. The model formulation is general and does not focus on a specific geographical area, although it can be adapted and applied to specific contexts. The model results include the optimal production mix planning, the energy flows analysis, and the identification of critical energy areas. Finally, the model is applied to a case study, based on the Italian context, to test and validate it.

Keywords: Optimization model, Generation expansion planning, Electrical grid management, Renewable energy, Energy system.

1 Introduction and Literature Review

The Generation and Transmission Expansion Planning (GEP and TEP) is one of the most discussed topics within the academia and decision makers in the energy sector, especially related to meeting the emission reduction targets. GEP and TEP are complex tasks, combining techno-economic, financial, spatial and environmental aspects. Several models, strategies and techniques are developed to GEP and TEP, applying different methodological approaches [1-3]. Table 1 shows a preliminarily classification of the relevant literature on GEP and TEP. The review shows that the single-objective methods often integrate environmental aspects as constraints or external costs, while the multi-objective formulations consider them as one of the objectives. Furthermore, the review emphasizes that GEP and TEP optimization approaches represent a great opportunity in terms of applications to national/regional power systems, providing realistic and robust simulations for decision-makers.

Table 1. Literature contributions classification (C=Costs, E=Emissions, SR=System Reliability, SO= Single-Objective, MO= Multi-Objective, S=Solver, A/H= Algorithm/Heuristics).

Optimization KPI			Problem Formulation		Solving Method		Planning Procedure	Case Study/ Application	Reference
C	E	SR	SO	MO	S	A/H			
✓	✓		✓			✓	GEP	Thailand	[4]
✓		✓		✓	✓		GEP	Portugal	[5]
✓	✓		✓		✓		GEP	China	[6]
✓	✓	✓		✓	✓		GEP	Test system	[7]
✓			✓		✓		GEP, TEP	-	[8]
✓		✓	✓			✓	GEP	Test system	[9]
✓	✓		✓		✓		GEP	United States	[10]
✓			✓		✓		GEP	Japan	[11]
✓	✓			✓	✓		GEP, TEP	Test system	[12]
✓	✓		✓		✓		GEP, TEP	Italy	This Paper

This paper tries to contribute to this research stream introducing and applying a Mixed-Integer Linear Programming (MILP) optimization cost model for the GEP and TEP. The problem formulation considers environmental aspect as the carbon tax and promotes a distributed production to minimize the transmission losses and costs. The case study, based on the Italian context, considers a major set of power plants and connections (currently operating in Italy) and the option to increase the energy producers through a set of new wind and solar plants. Furthermore, to best represent the current and future Italian energy scenario, reliable forecast on the fuels cost, carbon tax and the energy demand are included.

The remainder of the paper is structured as follows: Section 2 describes and presents the model formulation, while Section 3 applies the model to a case study. In Section 4 the case study results are presented and discussed. Finally, Section 5 concludes with final remarks and future research opportunities.

2 Methodology

Bortolini et al. [8] defined a MILP cost model for the energy mix planning and the electrical grid management. In the formulation proposed by Bortolini et al. [8], as in several other studies [1-3], all producers, nodes and consumers belonging to the same geographical area are grouped together and considered as a sole entity in terms of energy flows origin, destination and dispatching. Instead, this paper proposes a model formulation where each demand point is supplied independently and all the energy flows are between independent couples of entities (producers, dispatching nodes, consumers). The proposed model belongs to the class of Location Allocation Problems (LAP) and considers an electrical grid structure consisting of three levels. In particular, the electricity flows from the power plants (production level) through the nodes of the electrical grid (dispatching level) to reach the demand areas (consumption level). The grid connections are divided into six subsets, three for the Existing Connections (EC) and three for the Future Connections (FC): plant-node (EC_1 and FC_1), node-node (EC_2 and FC_2) and node-consumer (EC_3 and FC_3). The main characteristics of the LAP model are described below in terms of entities, indices and parameters (Table 2), decisional variables (Table 3) and analytic formulation of the model.

Table 2. LAP model indices and parameters

Index: t	Set: Existing Plants (EP)		Index: s	Set: Future Plants (FP)	
co_t	Plant area	in AR	co_s	Plant area	in AR
st_t	Source type	in SO	st_s	Source type	in SO
cp_t	Installed capacity	MW	cp_s	Installed capacity	MW
η_t	Composite outage	in [0,1]	η_s	Composite outage	in [0,1]
e_t	Earliest online year	in YS	e_s	Earliest online year	in YS
lt_t	Plant lifetime	in years	lt_s	Plant lifetime	in years
χ_t	Capacity factor	in [0,1]	χ_s	Capacity factor	in [0,1]
i_t	Investment cost	€/MW	i_s	Investment cost	€/MW
f_t	Annual fix cost	€/MW	f_s	Annual fix cost	€/MW
v_t	Variable cost	€/MWh	v_s	Variable cost	€/MWh
u_t	Decommissioning	€/MW	u_s	Decommissioning	€/MW
b_t	Base-load plant	Boolean	b_s	Base-load plant	Boolean
Index: k	Set: Existing Connections (EC)		Index: m	Set: Future Connections (FC)	
cp_k	Installed capacity	MW	cp_m	Installed capacity	MW
η_k	Transmission losses	in [0,1]	η_m	Transmission losses	in [0,1]
e_k	Earliest online year	in YS	e_m	Earliest online year	in YS
lt_k	Line lifetime	in years	lt_m	Line lifetime	in years
i_k	Investment cost	€/MW	i_m	Investment cost	€/MW
f_k	Annual fix cost	€/MW	f_m	Annual fix cost	€/MW
v_k	Variable cost	€/MWh	v_m	Variable cost	€/MWh
u_k	Decommissioning	€/MW	u_m	Decommissioning	€/MW
Index: p	Set: Demand Points (DP)		Index: j	Set: Sources (SO)	
co_p	Demand point area	in AR	r_j	Renewable	Boolean
d_{ph}	Demand entity	MWh h in TP	c_{jy}	Source cost	€/MWh y in YS
Index: h	Set: Time Points (TP)		Index: y	Set: Years (YS)	
yr_h	Year	in YS	α_y	Discount factor	R^+
dr_h	Time point duration	hours	φ_{ay}	% from renewables	in [0,1] a in AR
Index: a	Set: Geographical Areas (AR)		Index: n	Set: Dispatching Node (DN)	

Table 3. LAP model decisional variables.

Decisional variables		
Ic_{sy}	FP installed capacity	in MWh, s in FP, y in YS
En_{th}	EP produced energy	in MWh, t in EP, h in TP
En_{sh}	FP produced energy	in MWh, s in FP, h in TP
B_{th}	EP activation	in $\{0,1\}$, t in EP, h in TP
B_{sh}	FP activation	in $\{0,1\}$, s in FP, h in TP
Ic_{m_1y}	FC plant-node installed capacity	in MW, m_1 in FC_1, y in YS
Ic_{m_2y}	FC node-node installed capacity	in MW, m_2 in FC_2, y in YS
Ic_{m_3y}	FC node-demand point installed capacity	in MW, m_3 in FC_3, y in YS

En_{k_1h}	EC plant-node dispatched energy	in MWh, k_1 in EC_1, h in TP
En_{k_2h}	EC node-node dispatched energy	in MWh, k_2 in EC_2, h in TP
En_{k_3h}	EC node-demand point dispatched energy	in MWh, k_3 in EC_3, h in TP
En_{m_1h}	FC plant-node dispatched energy	in MWh, m_1 in FC_1, h in TP
En_{m_2h}	FC node-node dispatched energy	in MWh, m_2 in FC_2, h in TP
En_{m_3h}	FC node-demand point dispatched energy	in MWh, m_3 in FC_3, h in TP

The LAP model objective function, expressed in (1), minimizes the sum of the variable costs related to the energy production and distribution, the plant and grid connection investment, fix and decommissioning costs, the energy source costs for the energy production, e.g., the fuel costs and the carbon tax.

$$
\begin{aligned}
\phi_{LAP} = {} & \sum_{t\epsilon EP} i_t \cdot cp_t \cdot \alpha_{e_t} + \sum_{s\epsilon FP}\sum_{y\epsilon YS} i_s \cdot Ic_{sy} \cdot \alpha_y + \sum_{k_1\epsilon EC_1} i_{k_1} \cdot cp_{k_1} \cdot \alpha_{e_{k_1}} + \\
& \sum_{m_1\epsilon F_1}\sum_{y\epsilon YS} i_{m_1} \cdot Ic_{m_1y} \cdot \alpha_y + \sum_{k_2\epsilon EC_2} i_{k_2} \cdot cp_{k_2} \cdot \alpha_{e_{k_2}} + \sum_{m_2\epsilon FC_2}\sum_{y\epsilon YS} i_{m_2} \cdot \\
& Ic_{m_2y} \cdot \alpha_y + \sum_{k_3\epsilon EC_3} i_{k_3} \cdot cp_{k_3} \cdot \alpha_{e_{k_3}} + \sum_{m_3\epsilon FC_3}\sum_{y\epsilon YS} i_{m_3} \cdot Ic_{m_3y} \cdot \alpha_y + \\
& \sum_{t\epsilon EP}\sum_{\substack{y\epsilon YS \\ e_t\le y\le e_t+lt_t}} f_t \cdot cp_t \cdot \alpha_y + \sum_{s\epsilon FP}\sum_{y\epsilon YS} f_s \cdot \sum_{\substack{y_1\epsilon YS \\ y\le y_1}} Ic_{sy_1} \cdot \\
& \alpha_y + \sum_{k_1\epsilon EC_1}\sum_{\substack{y\epsilon YS \\ e_{k_1}\le y\le e_{k_1}+lt_{k_1}}} f_{k_1} \cdot cp_{k_1} \cdot \alpha_y + \sum_{m_1\epsilon FC_1}\sum_{y\epsilon YS} f_{m_1} \cdot \sum_{\substack{y_1\epsilon YS \\ y\le y_1}} Ic_{m_1y_1} \cdot \\
& \alpha_y + \sum_{k_2\epsilon EC_2}\sum_{\substack{y\epsilon YS \\ e_{k_2}\le y\le e_{k_2}+lt_{k_2}}} f_{k_2} \cdot cp_{k_2} \cdot \alpha_y + \sum_{m_2\epsilon FC_2}\sum_{y\epsilon YS} f_{m_2} \cdot \sum_{\substack{y_1\epsilon YS \\ y\le y_1}} Ic_{m_2y_1} \cdot \\
& \alpha_y + \sum_{k_3\epsilon EC_3}\sum_{\substack{y\epsilon YS \\ e_{k_3}\le y\le e_{k_3}+lt_{k_3}}} f_{k_3} \cdot cp_{k_3} \cdot \alpha_y + \sum_{m_3\epsilon FC_3}\sum_{y\epsilon YS} f_{m_3} \cdot \sum_{\substack{y_1\epsilon YS \\ y\le y_1}} Ic_{m_3y_1} \cdot \\
& \alpha_y + \sum_{t\epsilon EP}\sum_{h\epsilon TP} v_t \cdot En_{th} \cdot \alpha_{yr_h} + \sum_{s\epsilon FP}\sum_{h\epsilon TP} v_s \cdot En_{sh} \cdot \alpha_{yr_h} + \sum_{k_1\epsilon EC_1}\sum_{h\epsilon TP} v_{k_1} \cdot \\
& En_{k_1h} \cdot \alpha_{yr_h} + \sum_{m_1\epsilon FC_1}\sum_{h\epsilon TP} v_{m_1} \cdot En_{m_1h} \cdot \alpha_{yr_h} + \sum_{k_2\epsilon EC_2}\sum_{h\epsilon T} v_{k_2} \cdot En_{k_2h} \cdot \\
& \alpha_{yr_h} + \sum_{m_2\epsilon FC_2}\sum_{h\epsilon TP} v_{m_2} \cdot En_{m_2h} \cdot \alpha_{yr_h} + \sum_{k_3\epsilon EC_3}\sum_{h\epsilon TP} v_{k_3} \cdot En_{k_3h} \cdot \alpha_{yr_h} + \\
& \sum_{m_3\epsilon FC_3}\sum_{h\epsilon T} v_{m_3} \cdot En_{m_3h} \cdot \alpha_{yr_h} + \sum_{t\epsilon EP} u_t \cdot cp_t \cdot \alpha_{e_{t+lt_t+1}} + \sum_{s\epsilon FP} u_s \cdot \sum_{y\epsilon Y} Ic_{sy} \cdot \\
& \alpha_{e_{s+lt_s+1}} + \sum_{k_1\epsilon EC_1} u_{k_1} \cdot cp_{k_1} \cdot \alpha_{e_{k_1+lt_{k_1}+1}} + \sum_{m_1\epsilon FC_1} u_{m_1} \cdot \sum_{y\epsilon YS} Ic_{m_1y} \cdot \\
& \alpha_{e_{m_1+lt_{m_1}+1}} + \sum_{k_2\epsilon EC_2} u_{k_2} \cdot cp_{k_2} \cdot \alpha_{e_{k_2+lt_{k_2}+1}} + \sum_{m_2\epsilon FC_2} u_{m_2} \cdot \sum_{y\epsilon YS} Ic_{m_2y} \cdot \\
& \alpha_{e_{m_2+lt_{m_2}+1}} + \sum_{k_3\epsilon EC_3} u_{k_3} \cdot cp_{k_3} \cdot \alpha_{e_{k_3+lt_{k_3}+1}} + \sum_{m_3\epsilon FC_3} u_{m_3} \cdot \sum_{y\epsilon YS} Ic_{m_3y} \cdot \\
& \alpha_{e_{m_3+lt_{m_3}+1}} + \sum_{j\epsilon SO}\sum_{y\epsilon YS} c_{jy} \cdot \left(\sum_{\substack{t\epsilon EP \\ st_t=j}}\sum_{\substack{h\epsilon TP \\ yr_h=y}} En_{th} + \sum_{\substack{s\epsilon FP \\ st_s=j}}\sum_{\substack{h\epsilon TP \\ yr_h=y}} En_{sh} \right) \cdot \alpha_y \qquad (1)
\end{aligned}
$$

The following set of constrains complete the proposed LAP optimization model to guarantee its feasibility.

$$
\sum_{\substack{k_3=(n^f,p^t)\in EC_3 \\ p^t=p}} En_{k_3h} \cdot (1-\eta_{k3}) + \sum_{\substack{m_3=(n^f,p^t)\in EC_3 \\ p^t=p}} En_{m_3h} \cdot (1-\eta_3) = d_{ph} \quad p \in DP, h \in TP \qquad (2)
$$

$$
En_{th} = \sum_{\substack{k_1=(t^f,n^t)\in EC_1 \\ t^f=t}} En_{k_1h} \quad t \in EP, h \in TP \qquad (3)
$$

$$
En_{sh} = \sum_{\substack{m_1=(s^f,n^t)\in FC_1 \\ s^f=s}} En_{m_1h} \quad s \in FP, h \in TP \qquad (4)
$$

$$\sum_{\substack{k_1=(t^f,n^t)\in EC_1\\ n^t=n}} En_{k_1h}\cdot\left(1-\eta_{k_1}\right)+\sum_{\substack{m_1=(s^f,n^t)\in FC_1\\ n^t=n}} En_{m_1h}\cdot\left(1-\eta_{m_1}\right)+\sum_{\substack{k_2=(n^f,n^t)\in EC_2\\ n^t=n\wedge n^f\neq n}} En_{k_2h}\cdot\left(1-\eta_{k_2}\right)+\sum_{\substack{m_2=(n^f,n^t)\in FC_2\\ n^t=n\wedge n^f\neq n}} En_{m_2h}\cdot\left(1-\eta_{m_2}\right)=\sum_{\substack{k_2=(n^f,n^t)\in EC_2\\ n^t=n\wedge n^f\neq n}} En_{k_2h}+\sum_{\substack{m_2=(n^f,n^t)\in FC_2\\ n^t=n\wedge n^f\neq n}} En_{m_2h}+\sum_{\substack{k_3=(n^f,p^t)\in EC_3\\ n^f=n}} En_{k_3h}+\sum_{\substack{m_3=(n^f,p^t)\in FC_3\\ n^f=n}} En_{m_3h}\quad n\in DN,h\in TP \tag{5}$$

$$\sum_{\substack{t\in EP\\ r_{st_t}=1}}\sum_{\substack{h\in TP\\ yr_h=y}} E_{n_{th}}+\sum_{\substack{s\in FP\\ r_{st_s}=1}}\sum_{\substack{h\in TP\\ yr_h=y}} E_{n_{sh}}\geq\varphi_{ay}\cdot\left(\sum_{t\in EP}\sum_{\substack{h\in TP\\ yr_h=y}} E_{n_{th}}+\sum_{s\in FP}\sum_{\substack{h\in TP\\ yr_h=y}} E_{n_{sh}}\right)\quad a\in AR,y\in YS \tag{6}$$

$$\sum_{y\in YS} Ic_{sy}\leq cp_s\quad s\,\epsilon\,FP \tag{7}$$

$$Ic_{sy}=0\quad s\,\epsilon\,FP,y\in YS\wedge(y<e_s\vee y>e_s+lt_s) \tag{8}$$

$$\sum_{y\in YS} Ic_{m_1y}\leq cp_{m_1}\quad m_1\,\epsilon\,FC_1 \tag{9}$$

$$Ic_{m_1y}=0\quad m_1\,\epsilon\,FC_1,y\,\epsilon\,ES\ \wedge\left(y<e_{m_1}\vee y>e_{m_1}+lt_{m_1}\right) \tag{10}$$

$$\sum_{y\in YS} Ic_{m_2y}\leq cp_{m_2}\quad m_2\,\epsilon\,FC_2 \tag{11}$$

$$Ic_{m_2y}=0\quad m_2\,\epsilon\,FC_2,y\,\epsilon\,ES\ \wedge\left(y<e_{m_2}\vee y>e_{m_2}+lt_{m_2}\right) \tag{12}$$

$$\sum_{y\in YS} Ic_{m_3y}\leq cp_{m_3}\quad m_3\,\epsilon\,FC_3 \tag{13}$$

$$Ic_{m_3y}=0\quad m_3\,\epsilon\,FC_3,y\,\epsilon\,ES\ \wedge\left(y<e_{m_3}\vee y>e_{m_3}+lt_{m_3}\right) \tag{14}$$

$$En_{th}=0\quad t\in EP,h\in TP\wedge(yr_h<e_t\vee yr_h>e_t+lt_t) \tag{15}$$

$$En_{th}=cp_t\cdot dr_h\cdot\chi_t\cdot B_{th}\quad t\in EP\wedge b_t=1,h\in TP\wedge(e_t\leq yr_h\leq e_t+lt_t) \tag{16}$$

$$En_{th}\leq cp_t\cdot dr_h\cdot\chi_t\cdot B_{th}\quad t\in EP\wedge b_t=0,h\in TP\wedge(e_t\leq yr_h\leq e_t+lt_t) \tag{17}$$

$$En_{sh}=0\quad s\in FP,h\in TP\wedge(yr_h<e_s\vee yr_h>e_s+lt_s) \tag{18}$$

$$En_{sh}=\sum_{\substack{y\in YS\\ y<yr_h}} Ic_{sy}\cdot dr_h\cdot\chi_s\cdot B_{sh}\quad s\in FP\wedge b_s=1,h\in TP\wedge(e_s\leq yr_h\leq e_s+lt_s) \tag{19}$$

$$En_{sh}\leq\sum_{\substack{y\in YS\\ y<yr_h}} Ic_{sy}\cdot dr_h\cdot\chi_s\cdot B_{sh}\quad s\in FP\wedge b_s=0,h\in TP\wedge(e_s\leq yr_h\leq e_s+lt_s) \tag{20}$$

$$En_{k_1h}=0\quad k_1\in EC_1,h\in TP\wedge\left(yr_h<e_{k_1}\vee yr_h>e_{k_1}+lt_{k_1}\right) \tag{21}$$

$$En_{k_1h}\leq cp_{k_1}\cdot dr_h\cdot\left(1-\eta_{k_1}\right)\quad k_1\in EC_1,h\in TP\wedge\left(e_{k_1}\leq yr_h\leq e_{k_1}+lt_{k_1}\right) \tag{22}$$

$$En_{k_2h}=0\quad k_2\in EC_2,h\in TP\wedge\left(yr_h<e_{k_2}\vee yr_h>e_{k_2}+lt_{k_2}\right) \tag{23}$$

$$En_{k_2h} \leq cp_{k_2} \cdot dr_h \cdot \left(1-\eta_{k_2}\right) \quad k_2 \in EC_2, h \in TP \wedge \left(e_{k_2} \leq yr_h \leq e_{k_2} + lt_{k_2}\right) \quad (24)$$

$$En_{k_3h} = 0 \quad k_3 \in EC_3, h \in TP \wedge \left(yr_h < e_{k_3} \vee yr_h > e_{k_3} + lt_{k_3}\right) \quad (25)$$

$$En_{k_3h} \leq cp_{k_3} \cdot dr_h \cdot \left(1-\eta_{k_3}\right) \quad k_3 \in EC_3, h \in TP \wedge \left(e_{k_3} \leq yr_h \leq e_{k_3} + lt_{k_3}\right) \quad (26)$$

$$En_{m_1h} = 0 \quad m_1 \in FC_1, h \in TP \wedge \left(yr_h < e_{m_1} \vee yr_h > e_{m_1} + lt_{m_1}\right) \quad (27)$$

$$En_{m_1h} \leq \sum_{\substack{y \in YS \\ y < yr_h}} Ic_{m_1y} \cdot dr_h \cdot \left(1-\eta_{m_1}\right)$$
$$m_1 \in FC_1, h \in TP \wedge \left(e_{m_1} \leq yr_h \leq e_{m_1} + lt_{m_1}\right) \quad (28)$$

$$En_{m_2h} = 0 \quad m_2 \in FC_2, h \in TP \wedge \left(yr_h < e_{m_2} \vee yr_h > e_{m_2} + lt_{m_2}\right) \quad (29)$$

$$En_{m_2h} \leq \sum_{\substack{y \in YS \\ y < yr_h}} Ic_{m_2y} \cdot dr_h \cdot \left(1-\eta_{m_2}\right)$$
$$m_2 \in FC_2, h \in TP \wedge \left(e_{m_2} \leq yr_h \leq e_{m_2} + lt_{m_2}\right) \quad (30)$$

$$En_{m_3h} = 0 \quad m_3 \in FC_3, h \in TP \wedge \left(yr_h < e_{m_3} \vee yr_h > e_{m_3} + lt_{m_3}\right) \quad (31)$$

$$En_{m_3h} \leq \sum_{\substack{y \in YS \\ y < yr_h}} Ic_{m_3y} \cdot dr_h \cdot \left(1-\eta_{m_3}\right)$$
$$m_3 \in FC_3, h \in TP \wedge \left(e_{m_3} \leq yr_h \leq e_{m_3} + lt_{m_3}\right) \quad (32)$$

$$Ic_{sy}, En_{th}, En_{sh}, Ic_{m_1y}, Ic_{m_2y}, Ic_{m_3y}, En_{k_1h}, E_{n_{k_2h}}, En_{k_3h}, En_{m_1h}, En_{m_2h}, En_{m_3h} \geq 0$$
$$s \in FP, y \in YS, t \in EP, h \in TP, m_1 \in FC_1, m_2 \in FC_2, m_3 \in FC_3, k_1 \in EC_1, k_2 \in EC_2, k_3 \in EC_3 \quad (33)$$

$$B_{th}, B_{sh} \; bynary \quad s \in FP, t \in EP, h \in TP \quad (34)$$

(2) guarantees the complete electricity supply to all the demand and time points, while (3-4) ensure that the energy produced by plants is equal to the energy dispatched through the plant-node connections for each power plants and time points. (5) balance the electric energy flows at the production and dispatching levels. (6) forces the system to produce at least a fraction of the electricity from renewables. (7)-(14) consider the future plants and connections and force not to exceed the maximum power capacity. They further set to zero the installed capacity for all the years out of the plant lifetime. (15)-(20) limit the plants energy production according to their technical features and set to zero the production level out of the plant lifetime. (21)-(32) force not to exceed the transmission capacity and the connection operating period. Finally, (33) and (34) give consistence to the non-negative continuous and binary decisional variables.

3 Case study Description

A case study applies the proposed model to the Italian scenario considering a long-term horizon from 2023 to 2040, a significant subset of the existing plants and connections (currently operating in Italy) and the probable electricity demand profile until 2040. In addition, according to the forecast about the evolution of the total installed capacity in Italy [13], the case study considers the option to increase the energy producers using a set of new wind and solar plants. All the input data, reviewed below, come from the major electric energy producers, the electricity transmission grid operator, and other relevant sources. The production level includes 421 EP and 167 FP distributed over the Italian territory. For the EP the total installed capacity is 94.34 GW, while for the FP is 39 GW (30.5 solar and 8.5 wind). Wind, solar, and biogas capacity are aggregated on a provincial scale considering the 107 Italian provinces. This results in 214 solar (107 FP) and 116 wind plants (60 FP). 57 hydro, 33 geothermal, 102 biogas, 57 natural gas, 7 coal and 2 oil complete the production level [14-17]. Fig. 1 a) and Fig 1 b) show the capacity and the distribution over the Italian territory of the EP and FP, respectively. The capacity factors for the different sources are calculated starting from the data provided on a provincial scale by TERNA [18]. The investment, fix and variable costs for the power plants are considered using the Levelized Cost of Energy (LCOE) values of the different sources reported in [19]. The expected increases from 2023 to 2040 in cost of fuel and carbon tax are considered according to [19, 20].

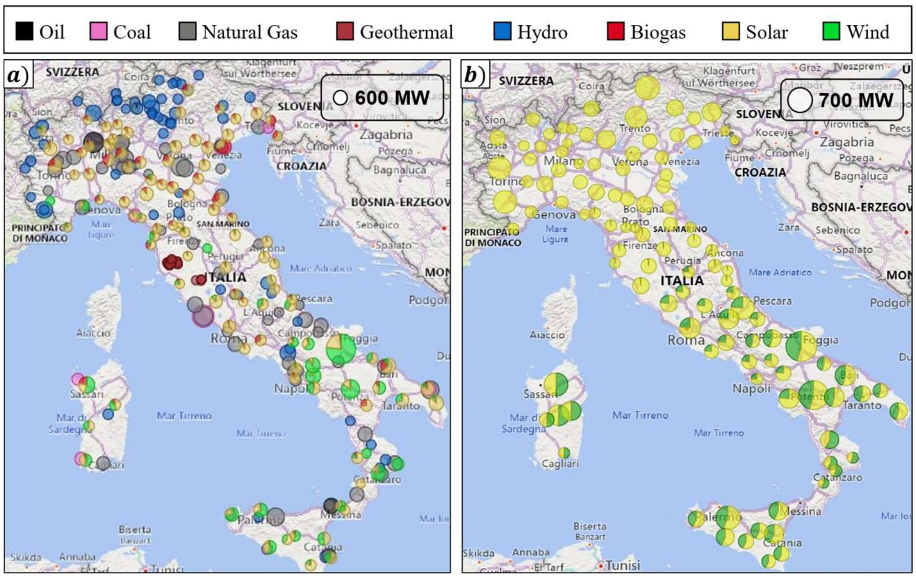

Fig. 1. Location and capacity of plants by energy source. (a) Existing plants. (b) Future plants.

The consumption level includes 107 DP representing the Italian provinces and 216 TP corresponding to all months between 2023 and 2040. The demand forecasts are defined starting from the National Trend scenario for Italy described in [13], which assumes an increase in annual demand to 2040 about 20% compared to 2023. Concerning the dispatching level, 70 DN are considered and the EP, FP and DP are connected to the DN according to the minimum distance criteria. The transmission losses are considered according to [8, 18]. Finally, φ_{ay} is set to zero to analyze the system behavior in the absence of constraints on minimum renewables level, new production capacity can be installed from the year 2031 onwards, no constrains limit the connection capacity and no plants and connections are decommissioned. The total set of input data (i.e., parameters) used to feed the LAP model are available upon request to the authors.

The model and the input data are coded in AMPL language and processed adopting Gurobi Optimazer© v.9.5.2 solver. An Intel® CoreTM i5-8250U CPU @ 1.60GHz and 8.0GB RAM workstation is used. The total solving time is about 300 seconds.

4 Results and Discussion

The application of the model to the considered case study results in an average LCOE of 110 €/MWh, calculated over the entire time horizon of the study. In the following, the main results of the paper are presented and discussed.

In the model application, it is assumed that the new solar and wind capacity can be installed from the year 2031 onwards. As a result, the entire new available solar and wind capacity, shown in Fig. 1b), is installed in the year 2031. From 2023 to 2030, the results show that Italy is still dependent on the fossil fuels for the 57% of its electricity production, where natural gas accounts for 48% of the total. From 2031 to 2040, the installation of the new solar and wind plants significantly increases the shares of renewables in the energy mix to 55%. In this period, solar and wind cover respectively the 25% and 12% of the total. Overall, the north of Italy presents the highest production and consumption levels, respectively 55% and 62% of the total. Lombardy, Emilia-Romagna and Piedmont together account for more than 40%. In central Italy, the production and consumption levels are very low (15% and 13%). Finally, in the south and the islands the production and consumption levels cover 30% and 25%, respectively.

For the year 2040, in Fig. 2 a) the dark red color represents the provinces with a high energy deficit, while dark blue indicates the provinces with a high energy surplus. The shades of the two colors indicate the intermediate values. Fig. 2 b) shows the preferred directions of energy flows on the Italian high-voltage electrical grid. The line color is function of the amount of energy cross the connection.

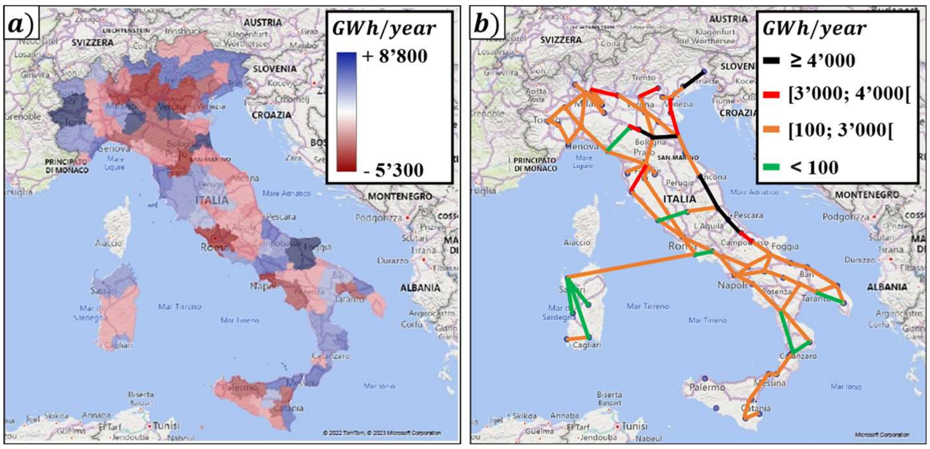

Fig. 2. Spatial distribution of energy deficit/surplus and energy flows on the high-voltage grid for 2040. (a) Energy deficit and surplus by province. (b) Node-node long distance energy flows.

As shown in Fig. 2, the Italian high-voltage electrical grid presents a cobweb structure in the north and two parallel north-south energy corridors (Tyrrhenian and Adriatic corridor). In both the Tyrrhenian and the Adriatic corridor, energy flows from south to north to fill the deficits of critical areas. Concerning the islands, the energy flows from Sardinia and Sicily towards the Italian peninsula. Overall, densely populated provinces with low production capacity and/or energy-intensive industrial districts are in energy deficit and are the terminals of energy flows.

5 Conclusions and future research

Energy use strongly influences modern society and represents a key element of global development. In such a context, this paper presents and applies an optimization cost model for the energy mix planning and the electric network design. The problem formulation considers environmental aspect and promotes a distributed production to minimize the transmission losses and costs. The case study, based on the Italian context, considers a major set of power plants and connections (currently operating in Italy), as well as the option to increase the energy producers through a set of new wind and solar plants. Furthermore, reliable forecast on the fuels cost, the carbon tax and the monthly energy demand profiles for the 107 Italian provinces between 2023 and 2040 are included. From 2023 to 2030, the outcomes show that Italy is still dependent on the fossil fuels for the 57% of its electricity production, where natural gas accounts for 48% of the total. From 2031 to 2040, the installation of the new solar and wind plants significantly increases the shares of renewables in the energy mix to 55%. Solar and wind cover respectively the 25% and 12% and represent a great opportunity from both economic and environmental point of view. Although in this scenario the share of natural gas in the energy mix decreases to 38% by 2040, it remains the main source for electricity production. In the Italian peninsula, most of the energy demand and production is concentrated in the north of Italy, where energy intensive industrial districts and large conventional plants are located. The south of Italy, Sicily and Sardinia are the areas with the highest wind and solar potential, due to the greater availability of sites and the higher producibility of them. Consequently, as the results of the paper highlight (Fig. 2), the transmission of energy from the south to the north and from the islands to the Italian peninsula is extremely important. This implies expanding and improving the performance of the transmission network to minimize losses and increase system reliability, as well as significant investments in storage systems to cope with the increasing share of non-programmable renewables in the energy mix.

Future research focuses on two directions of developments. The former deals with the model improvement considering further relevant technical, environmental and cost drivers in a multi-objective perspective. The latter deals with further model applications.

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