



HAL
open science

Assessing the security of electricity supply through multi-scale modeling: The TIMES-ANTARES linking approach

Yacine Alimou, Nadia Maïzi, Jean-Yves Bourmaud, Marion Li

► To cite this version:

Yacine Alimou, Nadia Maïzi, Jean-Yves Bourmaud, Marion Li. Assessing the security of electricity supply through multi-scale modeling: The TIMES-ANTARES linking approach. *Applied Energy*, 2020, 279, pp.115717. 10.1016/j.apenergy.2020.115717 . hal-03016019

HAL Id: hal-03016019

<https://hal.science/hal-03016019v1>

Submitted on 14 Sep 2022

HAL is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.



Distributed under a Creative Commons Attribution - NonCommercial 4.0 International License

Assessing the security of electricity supply through multi-scale modeling: The TIMES-ANTARES linking approach.

Yacine ALIMOU^{1,2*}, Nadia MAÏZI¹, Jean-Yves BOURMAUD², Marion LI²

1 Mines ParisTech, PSL Research University, Centre for Applied Mathematics, 1 rue Claude Daunesse, 06904, Sophia Antipolis CEDEX, France

2 Réseau de Transport d'Electricité, Immeuble Window, 7C place du Dôme, 92073, Paris La Défense CEDEX, France

* Corresponding author.

E-mail address: yacine.alimou@mines-paristech.fr

Abstract:

Long-term energy planning models and dispatch simulations are two key stages in the methodology for a cost-effective transition to a low-carbon power system. Although these stages are equally important, they are often performed independently. This decoupled approach can lead to future investment trajectories decided by long-term energy planning models with no guarantee of a reliable electricity supply.

To tackle this problem, the aim of this study was to develop a general methodological framework using a multi-model approach to address adequacy requirements in the long term. An automated soft-linking model was used to successively:

- i. Plan the optimal power generation mix to satisfy a given level of future expected electricity demand subject to various constraints using the TIMES framework (The Integrated MARKAL–EFOM System).
- ii. Assess the adequacy of the obtained power generation mix under several climatic and operational future states using the probabilistic operational open-source model ANTARES (A New Tool for the generation Adequacy Reporting of Electric Systems).
- iii. Implement iterative feedback loops based on the estimated ability of different generating technologies to support peak demand (capacity credit) to ensure a total firm capacity in line with the electricity supply criterion.

This methodology was applied to a case study of power generation planning in France for the period 2013-2050. The results show that using TIMES alone provides a power generation mix for 2030 that risks insufficient supply levels. On the other hand, activating iterative feedback loops over capacity-credit exogenous parameters has the potential to ensure both the economic effectiveness of the mix and the security of the electricity supply criterion set by the French public authorities.

Keywords: Low-carbon power system, power generation adequacy, multi-scale modeling, long-term energy planning models, short-term operational power system models, model coupling

Highlights:

- New framework of long-term generation adequacy assessment developed.
- TIMES and ANTARES models linked via an automated soft-linking approach.
- Feedback loop established to ensure 3-hour/year French adequacy criterion.
- The 2030 Loss of Load Expectation dropped from 79 hours/year to 3 hours/year over iterations.
- 28% additional investment needed over the planning timeframe to satisfy 2030 generation adequacy requirements.

1. Introduction

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

The power system, and more broadly, the whole energy system, is subject to structural changes due to the energy transition, which is advancing simultaneously throughout the world, cutting across social differences, and particularly constrained in time. In France, the Energy Transition for Green Growth Act features a long-term roadmap laying down objectives in terms of climate and energy policies. The main aims of these policies are to reduce greenhouse gas (GHG) emissions, improve energy efficiency, and increase renewable power uptake in the energy system. Faced with this situation, an end-of-pipe approach to the transition involves diversifying the power generation mix through a partial phasing-out of the existing nuclear power fleet (from 75% to 50% by 2035) and the implementation of renewables support (40% generation uptake by 2030) [1]. As electricity constitutes a cornerstone of our modern societies, structural changes within the power system affect a broad range of stakeholders. Owing to the complexity of the problem, decision-makers and planners are obliged to make risk-based assessments regarding the future.

Technical-economic assessments of possible pathways have become essential to both deal with future uncertainty and clarify the implications of alternate policy choices. Among others, long-term energy planning models and operational power system models are key stages in planning the transition of the power sector. Long-term energy planning models have been applied frequently to help policy makers ensure cost-effective pathways. These models typically use a low level of temporal, technical and spatial detail. In contrast, operational power system models, which solve what is known as the unit-commitment problem, focus on the commitment and dispatch of a given power production fleet. They operate at a high level of detail but do not consider the trajectory cost-effectiveness. Although both modeling tools are equally necessary, they are often employed independently [2].

As Variable Renewable Energy (VRE) deployment increases, one challenge involves the concerns raised over the methodologies and underlying assumptions employed in standard energy system modeling tools [3,4]. In fact, these tools were not initially designed to perform capacity expansion in power systems with high shares of VRE. Their modeling was questioned for at least two reasons. First, limited temporal and space granularity is commonly assumed and provides an inadequate basis for capturing the main short-term features of VRE generators. For example, wind and solar in particular have intermittent profiles. Second, omitting the impact of these technologies' characteristics on the system flexibility will introduce biases that will favor or disadvantage more flexible investments. As a result, insufficient variability representation in supply or demand as well as operational details could lead to a sub-optimal, or even inadequate, power generation mix [5]. This could create misunderstanding among policymakers and system operators. Both could begin to view power generation portfolios produced by long-term energy planning models as at odds with the secure provision of electricity requirements [2]. Therefore, two contrasting methodologies have been developed to overcome this drawback: a direct integration approach and a model-coupling approach. A more detailed classification of the current challenges in capacity expansion planning and related modeling approaches can be found in [6].

The direct integration approach involves either increasing temporal and spatial granularity to improve the representation of VRE variability, or integrating new constraints into the long-term energy planning model to more accurately mimic the effects of some short-term dynamic features of the power system [7–10]. A growing body of literature provides significant insights into the impact of directly improving the representation of VRE variability in long-term energy planning models in terms of capacity-mix and dispatch decision [11–17]. [18] show to what extent increasing temporal granularity impacts the capacity and generation mix produced by long-term energy planning models. To this end, two versions of the Belgian TIMES power system model have been developed (without

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

import/export exchanges), one of which applies 12 time slices per year and the other 8,760 time slices per year. In both versions, a renewable electricity generation target share of 50% is imposed for 2050. Their analysis reveals a significant impact on the anticipated curtailment and capacity mix structure [18]. [19] evaluate the effect of the temporal resolution on the dispatch capabilities of an electricity generation planning model. To do so, a new Swiss TIMES electricity model (STEM-E) with an hourly representation of inter-temporal detail is compared to an aggregated model with only two diurnal time slices. The results show significant differences between both models and confirm that the high temporal resolution model offers better insights into the electricity generation schedule [19].

In contrast, model-coupling methodologies are a response to the limitations of using a single model to capture all of a power system's relevant properties. [19] recognize that even with a high temporal resolution TIMES framework, they cannot substitute a dispatch model because some features cannot be represented. Hence, closing the gap between short-term operational models and long-term energy planning models requires additional improvements. This research axis is identified by the energy modeling community as more and more important [2].

Terms commonly used to describe the model linkage include “hardlinking” versus “softlinking”. These terms are adapted from studies that have linked economic and energy models since the mid-1990s. We use the terms as defined in [20], where softlinking is information transfer controlled by the user, and hardlinking is formal links (the two models overlap partially) whereby information is transferred without any user judgment. This author recapitulates the advantages of hardlinking with the terms “productivity”, “uniqueness” and “control”, and characterizes the advantages of softlinking with the words “practicality”, “transparency” and “learning”. A few papers have considered linking approaches in the context of power system planning and operation. One example of power system linked models was reported by [21]. They linked TIMES with PLEXOS for the 2020 Irish power system to analyze the extent to which the temporal resolution and technical constraint¹ of power plants affect investments, as well as dispatch decisions and corresponding costs. Thus, the capacity mix given by TIMES for 2020 was transferred to the unit-commitment model with added degrees of technical detail. The results show that, in the absence of key technical constraints, long-term energy planning models undervalue flexible resources, underestimate wind curtailment, and overestimate the operation of baseload technologies. Recent efforts by the same group involved linking a MONET model (six-region TIMES model of the Italian energy system) to the power systems model PLEXOS_IT (PLEXOS Italian model), with the objective of investigating energy security issues within power systems. Two main outcomes are reported in this study: firstly, an underestimation of the flexibility needs of the Italian system with increasing VRE penetration; secondly, concerns as to whether the Italian energy system can provide adequate supply [22].

In this context, the main purpose of our study is to contribute to the development of a multi-model framework based on two models with proven track records in techno-economic power system assessment. The energy system model employed was MARKAL/TIMES (hereafter TIMES). ANTARES-Simulator (hereafter ANTARES) was selected as the probabilistic unit-commitment and dispatch model. Although the issue of electricity security of supply is extensively discussed in the long-term energy system community, to the best of our knowledge, there is no study using probabilistic measures to tackle power generation adequacy in planning stage. The first objective of this work consists in coupling TIMES with ANTARES as part of a one-directional chain model in

¹ Along this article, the technical constraints (or technical details) refer to the load following constraints (ramping limits, minimum uptimes and downtimes as well as planned and unplanned outages) of power plants and the associated cycling costs (start-up costs).

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

order to transfer the power generation mix decided by TIMES for a given year of interest to the ANTARES input database. For this target year, the second objective is to focus on the ANTARES dispatch results and adequacy metrics to provide consistent feedback to TIMES to ensure sufficient supply. This work represents an initial step in planning both a cost-effective and adequate power system, thereby respecting the generation adequacy requirements. It is important to note that in this work the long-term scenario selected is a case study intended to illustrate and explain our methodological approach rather than to represent specific French power system policies, which are extensively analyzed in Generation Adequacy reports and other long-term forecasting studies [23–26]. The framework proposed and developed was applied to France at on a “copper plate” (i.e. neglecting grid congestions on the French grid) and stand-alone basis (i.e. without taking into account interconnections with other countries).

The remainder of the paper is organized as follows. In section 2 we give a brief overview of the importance of a probabilistic approach in generation adequacy assessment, and then introduce the newly developed framework which enables the prototyping of the automated soft-linking model. Section 3 describes the results with regards to the framework developed and its application for power generation adequacy assessment. The last section summarizes the key findings in a relatively short conclusion.

2. Methodology

This section outlines the methodology developed to link TIMES with ANTARES. The novelty of the proposed framework can be summarized as its ability to ensure the generation adequacy requirements while planning the future power generation mix. The main three steps to achieve this goal are:

- (i) Plan a cost-effective power generation mix to meet future targeted electricity demand subject to various constraints representing energy and environmental policies.
- (ii) Assess generation adequacy using a probabilistic approach and gain technical and economic insights from the power system operation.
- (iii) Establish iterative feedback loops between both models using as a yardstick the electricity security of supply criterion set by public authorities.

2.1. Adequacy assessment process and legal framework

Power system operation consists of two main phases: planning and operating [27]. The main function in the operating phase is to provide energy that satisfies load demand with an acceptable level of quality and continuity. In electricity, reliability, also called security of supply, is fundamentally composed of two **distinct** and **related** components: adequacy and security. The European Network of Transmission System Operators for Electricity (ENTSOE) defines security and adequacy as follows:

- Security assessment determines for a given level of risk the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.
- Adequacy assessment determines the ability of the power system, using existing and new resources, to meet consumer demand at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Our study focuses only on the adequacy aspect of reliability. The evaluation of system adequacy consists of three major steps: system state selection, selected state evaluation, and metrics calculation

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

[28]. In accordance with these stages, different methodologies have been developed in recent decades in an attempt to assess adequacy. These techniques have evolved from deterministic methods to probabilistic ones [27].

Deterministic approaches estimate the availability of generation at a characteristic time point (usually winter and summer peak demand) under the expected fault. Their essential limitation is that they consider only the initial system problems for a few contingencies based on a mixture of established rules, judgment, and experience [29]. These contingencies do not capture the variability and uncertainty of the power system stochastic variables. As defined in the Generation Adequacy Methodologies Report of the European Commission [30], a deterministic approach can provide the following system metrics:

- Reserve Margin (RM): the most common deterministic index. This is a measurement of the available capacity excess with respect to predicted demand. It is defined as the difference between the total available generating capacity² and the peak demand divided by the peak demand³.
- Coverage Index (CI): the ratio between the available generation capacity and the peak demand.

At present, most studies adopt probabilistic methods [31]. Probabilistic approaches estimate the probability that the system will be unable to supply demand considering variabilities and uncertainties associated with the energy resources and power demand. Techniques in this field fit into two categories: analytical methods, and Monte Carlo simulation methods. In analytical techniques, the behavior of the system is described by analytical models, and system risk level is therefore computed by metrics from these models using mathematical solutions. These models assume some probability distribution functions for the different elements of the system and then combine (convolution operation) the probabilities and frequencies of system elements to arrive at the adequacy metrics. These methods are efficient for relatively small areas. By contrast, modeling a multi-area system requires a great number of variables to describe the whole system, and involves excessive computation time [32]. Handling computation in a reasonable amount of time requires numerous approximations, which significantly reduce the accuracy of the results. As a result, in studies on interconnected power system adequacy and economic efficiency, for example, probabilistic approaches based on combinatory techniques have been largely replaced by Monte Carlo simulators [33].

Monte Carlo methods, also called random sampling methods, may be sequential or non-sequential. The principle is to create a random sampling (or snapshots) of the system elements (generating units, demand), and then compute the statistical characteristics of the sample. A non-sequential process (or time-collapsed model) investigates the probability of the margin of available supply over demand by randomly sampling system states without considering the chronology. Consequently, non-sequential simulation cannot be used in applications in which time correlations matter. Therefore, modeling unplanned outages or unit start-ups is impossible with this technique. The sequential approach, however, simulates the occurrences of random events through time, recognizing the chronological characteristics of a system and the behavior of its components. Typically, the thermal unit plant's forced outage is represented by multiplying the unavailability of equipment during contiguous hours by the length of the outage period [32]. Sequential simulation methods can then be used to compute time-related metrics such as frequency and duration of load loss. Weather conditions, for example, have a significant impact on both demand (thermal sensitivity) and renewable power generation (wind speed and solar radiation), and in turn, on reliability indices. Consequently, by

² This is usually calculated by multiplying the installed capacity by an expected availability rate determined by taking into account the historical availability values of each technology.

³ It is important to highlight that some TSOs use this metric expressed only in terms of available generating capacity in MW.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

defining specific sampling rules, weather correlation could be included in a power system reliability assessment. The key metrics used in many generation adequacy regulatory frameworks (USA, France, Belgium) are based on:

- Loss of Load Expectation (LOLE): the expected number of hours per year in which the system will have to shed load.
- Expected Energy Not Served (EENS): the expected number of megawatt hours per year in which the system will not be able to supply.

In fact, the utility industry has for decades used an LOLE of “1 day of shortage in 10 years” (1-in-10 metric) as a reliability standard in generation adequacy studies. Using this definition, the adequacy criterion equates to an LOLE of 2.4 hours per year. In France, when the French electric utility company (EDF) enjoyed a monopoly and was largely owned by the French state, a limit of three hours was assumed as an adequacy criterion. From a legal perspective, appeals were made for more regulation following the 2003 power blackouts in Europe and the USA and Directive 2003/54/EC of the European Parliament and Council of 26 June 2003 concerning common rules for the internal market for electricity [34]. This motivated the adoption of Directive 2005/89/EC of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment, which required greater involvement from governments. Thus, the recitals to the Directive are phrased in terms of ensuring an adequate level of generation capacity, sufficient balance between supply and demand, and an appropriate level of interconnection between EU Member States [35]. In France, Article 11 of the Decree of 20 September 2006 concerning Generation Adequacy Reports, as amended on 24 March 2016, defines the framework, scope and study periods of Generation Adequacy Reports [23]. It therefore establishes a high security of supply (adequacy) target for France. The criterion applied is the LOLE metric, which must not exceed **three hours per year** [23].

2.2. Short model description

Below is a brief description of the two models' constituent structures.

Energy system model: TIMES

Long-term energy planning models based on the French power system are created in TIMES. The TIMES model generator is one of the tools developed and maintained by the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (IEA) [36]. The term “model generator” means that, although the mathematical structure is unchanged, different model instances are generated depending on the input data specified by the modelers. TIMES frameworks have been used by 250 institutions in 100 countries to develop local, national and multi-regional energy systems [37].

Technically, TIMES is a bottom-up (technology-rich), dynamic (full knowledge of future events) and cost-optimization modeling framework. The objective function of TIMES is to minimize over the considered horizon the total discounted energy system cost in its standard version and maximize societal welfare (consumer-producer surplus) in its elastic demand version [38]. The full mathematical linear programming structure in the TIMES model generator is presented in [39]. The scope of the model is usually applied to an analysis of the entire energy sector, but may also represent detailed individual subsectors, such as the power system. In addition, the model can be used to analyze environmental energy policies, which can be accurately represented thanks to its explicit representation of technologies and fuels in all sectors.

At the core of TIMES is a so-called Reference Energy System (RES) that represents an energy system with all of its interrelations and dependencies. The most convenient way of expressing the RES is through a network diagram that depicts all possible flows connecting primary resources, conversion technologies, and end-use demand through different energy commodities. Building the reference energy system therefore requires four types of exogenous data: energy service demands, primary resource potentials, a policy setting, and a description of energy technologies. For the runs reported

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

here, the RES is adapted from the TIMES-FR-ELC (hereafter TIMES-FR) power system model developed by [24] (see Figure 1).

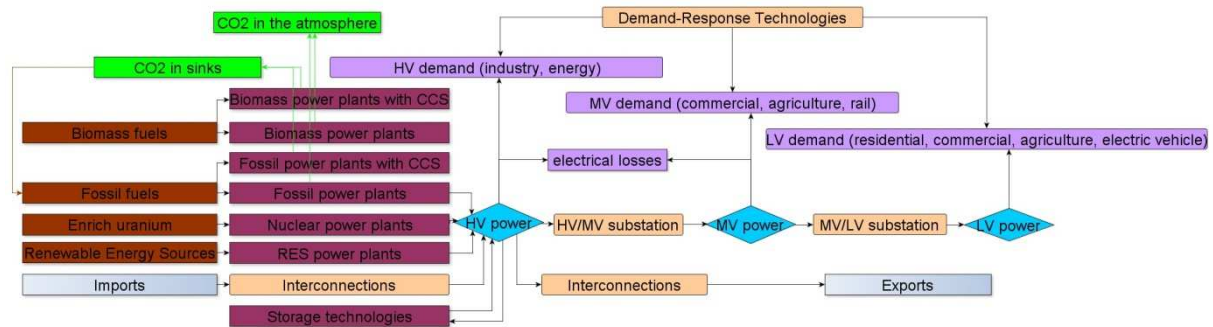


Figure 1 Schematic description of the reference energy system. The RES includes the fossil energy carriers coal, oil, gas, nuclear, and renewables. Final energy is available in the form of electricity, which can be converted into a lower voltage and then consumed by different demand sectors or consumed directly.

TIMES considers several nested levels of time granularity. The timeframe defines how far in the future the specific planning analysis is relevant, and is divided into time periods. Each time period is composed of several years (each year in a given period is considered to be identical), and represented by a milestone year. Investment decisions are only computed in milestone years. Figure 2 shows that for TIMES-FR, used in this work, the time horizon is 2050, and the timeframe is 2013 to 2050. The second level of granularity is the time divisions within a year. With TIMES, it is possible to incorporate more dynamics into either supply or demand by dividing the year into several time periods of different lengths (time slices). In order to model seasonal dynamics, TIMES-FR divides each annual period into seven seasonal periods: six monthly periods, plus one that represents a potential cold spell week (high demand and no wind and solar power generation output). Then, each seasonal period is split into two typical days, representing several similar days and differentiating working days from weekends (weekly divisions). Lastly, each typical day is divided into six hourly periods (daily divisions), with two time slices for the night, two for the morning, one for the afternoon and one corresponding to peak demand at 7 pm).

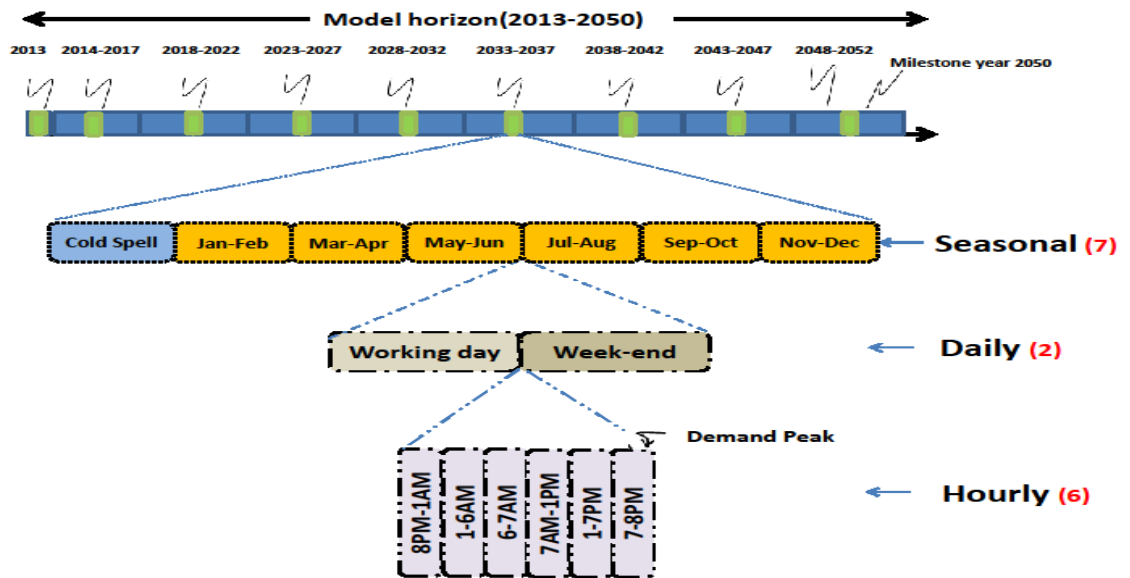


Figure 2 Temporal depiction tree in TIMES-FR. The first stage is dedicated to investment and the three others to the operation.

The TIMES linear program must satisfy a large number of constraints that properly describe the power system. A full description of the main types of TIMES-FR constraints is presented in detail in [24,40]. Given the importance of having sufficient firm capacity to ensure system adequacy, a so-called peaking reserve constraint is introduced in Equation 1. This equation states that all installed capacities generating electricity during the peak time slice must exceed the peak demand by a certain amount. The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

percentage (peak reserve factor), taking into account the actual participation of each technology in the peak (capacity credits):

- The capacity credit describes the share of a technology's capacity available in the peak time slice to cover the peak electricity load. Due to intermittency, VRE (variable renewable energy) has much lower capacity credit levels than conventional energy sources, such as nuclear or natural gas, which have a capacity credit fairly close to one.
- The peak reserve factor (28% in TIMES-FR) is chosen to respond to uncertainty regarding supply (unplanned equipment) and demand (excess high peak demand).

$$\sum_i cc_{i,t} * Cap_{i,t} > (1 + 0.28) * D^{peak} \forall t$$

Equation 1

Where

- $cc_{i,t}$ ⁴ (never higher than 1) and $Cap_{i,t}$ are respectively the capacity credit and installed capacity of technology i in period t .
- D^{peak} is the peak demand occurring in period t .

Note that this constraint only ensures capacity sizing and does not restrict the participation of technologies to meet demand in any of the time periods. The important model outputs include:

- The resulting investment requirements and costs over the planning timeframe,
- energy flow by fuel,
- and pollutant emissions.

Power system model: ANTARES

The unit commitment model used in the scope of this work was ANTARES, an open source probabilistic power system model developed by RTE (French power grid operator). ANTARES simulates the balance between supply and demand over an interconnected system. The model is regularly used in European projects and national assessments (e.g. RTE French Generation Adequacy report [41–44], PLEF adequacy study [45], TwenTies project [46] , e-Highway2050 project [47], ENTSOE-MAF TYNDP[48]).

The paper by [49] provides a general description of the architecture of ANTARES. The mathematical problem formulation can be found in [50]. This power system analysis software determines hydro/thermal schedules and dispatches under the following core specifications:

- Network modeling based on node/edge representation. Each node represents a specific market zone connected by edges representing potentially aggregated transmission lines;
- Sequential simulation throughout a year with hourly time resolution;
- 8,760-hour time series (load, thermal power plants' available capacity, wind and solar power output, etc.) based on historical/forecast time series or stochastic ANTARES-generated time-series;
- For hydro power, a definition of local heuristic water management strategies at the monthly/annual scales;

⁴ The $cc_{i,t}$ coefficient specifies the fraction of technology i 's capacity for a period t that is allowed to contribute to the peak load.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

- The commercial exchange capacities between nodes, modeled through the maximum fixed commercial capacity (NTC- Net Transfer Capacity). However, in this study only one node is modeled (France is a copper-plate model);
- Assumption of a perfect market (no market power, bidding strategies);
- Weekly perfect foresight timeframe optimization;
- Additional constraints on the links flows.

The main simulation scheme behind ANTARES is summarized in Figure 3. The simulation process can be decomposed into two connected modeling components. The first one consists in setting up Monte Carlo scenarios regarding key input variables. This part involves building a set of Monte Carlo years representing possible futures based on technical and meteorological parameters (thermal fleet availability, hydro inflow, wind and solar power output and load). The scenario builder ensures the use of different data pools, from a ‘ready-made’ time series to a time series entirely made up of stochastic generators [51]. Taking this for granted, the second part constitutes the optimization of the hydro/thermal dispatch of each scenario (assuming perfect market conditions). The problem can be formulated as follows, for each Monte Carlo year of the preliminarily drawn sample:

Minimize the overall generation cost of the interconnected system throughout the year, while respecting:

- Minimum and maximum power output of every available thermal plant, as well as the minimum down time and up time.
- Monthly amount of hydro (reservoir) energy available.
- Maximum interconnection capacities between areas.

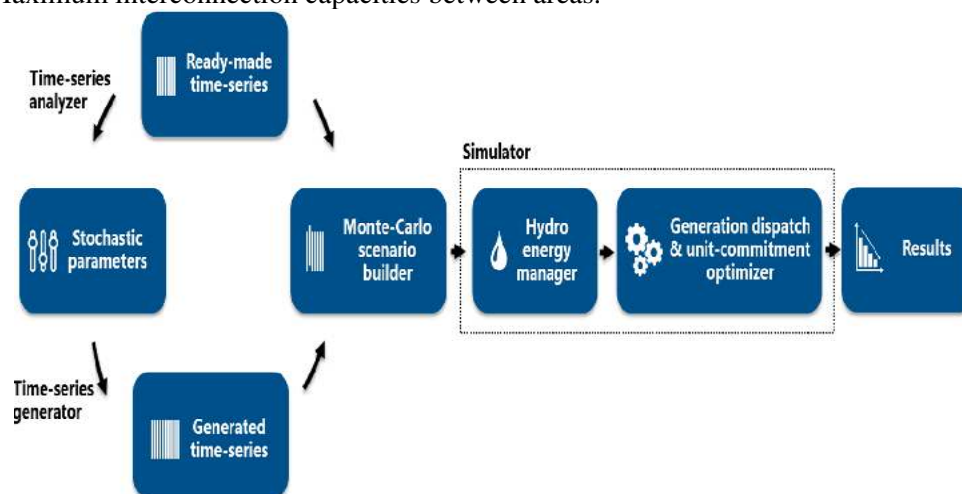


Figure 3 ANTARES simulation scheme. The time-series analyzer learns from historical data, the time-series generator draws new samples according to selected statistical laws.

ANTARES simulations take into account key events that could put security of supply at risk:

- The temperature sensitivity of power demand (cold spells can lead to higher peak demand);
- The unavailability risk of the thermal power fleet (reduction in available capacity);
- Variations in water flow (flexibility impact);
- Variable renewable generation (variable and unpredictable).

To this end, the probabilistic simulations incorporate a reference framework for climatic variables including 200 scenarios calculated by Météo France (French Meteorological Office) in partnership with RTE (explained in detail in data and assumptions section 2.4). The power system adequacy assessment based on a probabilistic risk analysis requires simulating a large number of future states (adequacy metrics convergence issues). That is to say, the number of future states that needs to be simulated to ensure the convergence of adequacy metrics must guarantee a desired level of accuracy [44,52]. From 200 to 1,000 Monte Carlo years are required to achieve convergence of the indicator

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

determined by regulations (LOLE metric). This means that all 200 climatic years will be simulated, in combination with the availability of the thermal facilities and hydro conditions, which are different in each of the simulated future states. Following the Monte Carlo simulations, the outcomes provided by the model enable a large range of indicators to be determined:

- Dispatch indicators (generation per fuel/technology, imports/exports).
- Adequacy indicators (LOLE, EENS);
- Economic indicators (operational costs, spillage costs and unsupplied energy costs);
- Sustainability indicators (emissions, renewables shares);

2.3. Modeling framework proposed: an automated data-linking approach

The framework, as shown in Figure 4, illustrates the linkage of TIMES and ANTARES using a platform that we call the automated soft-linking tool. This can be split into two independent main steps: a **coupling part** and a **feedback part**. The first part aims to link TIMES and ANTARES as two separate modeling tools and the second part aims to address generation adequacy issues. In such a way, TIMES is used to optimize the investment in new generation capacity over a 2013-2050 timeframe. The resulting power generation mix for a specific year (2030) is then transferred to ANTARES in which the detailed hydro/thermal dispatch will be decided at an hourly resolution for a large number of probabilistic scenarios representing weather and operational uncertainties. Then, based on the ANTARES results, the main function of the feedback loop is to ensure an adequate generation mix. However, the feedback with the long-term energy planning model is not straightforward and requires an iterative process. In practice, the stopping criterion of the feedback loop is chosen to be a loss of load expectation limit of **3 hours** (see section 2.1).

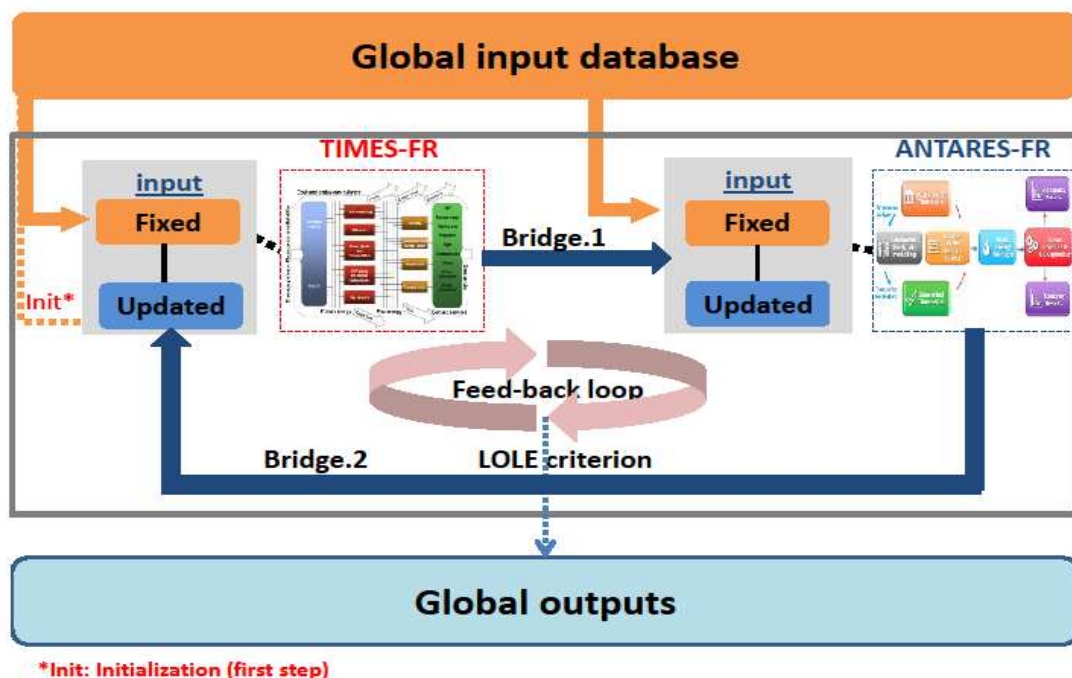


Figure 4 Schematic overview of the TIMES-ANTARES linking model. The uninterrupted line describes the information flow interactions, and the dashed line indicates the initialization step which is considered as the start of the linking process. The first step of the iteration is a TIMES solution. ANTARES is then run with a TIMES solution for a target year, and operates a Monte Carlo dispatch. The iteration ends as soon as the LOLE criterion is achieved. The global outputs are the power generation mix obtained and the insights offered by the linking model.

Coupling part: the following two steps are built to align ANTARES inputs with TIMES outputs:

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

- **Global Input database and TIMES initialization:** Since TIMES and ANTARES are used to model the reality of the same power system, their input data overlap. Before setting up the feedback loop, a necessary first step of the linking exercise is to identify the differences and similarities between the two modeling approaches. [53] explain in detail the following three steps applied in a soft-linking approach.
 - **Identifying basic differences between the models:** In the process of identifying differences between models, we dealt with questions like how to reconcile deterministic/probabilistic model paradigms, technological representation, and hourly/time slice temporal resolution.
 - **Identifying overlaps:** This means that, as both models describe the same power system, it must be possible to obtain a clear mapping of the overlaps. For example, the power generation mix is the principal overlap between both models.
 - **Identifying and deciding upon common exogenous variables:** The exogenous inputs assumptions are defined via scenarios. Since scenario definition has a major impact on a model's outcomes, it is crucial to standardize common inputs between the two models. Typical common inputs in both models are:
 - Electricity demand,
 - PV and wind capacity factors,
 - Technical and economical characteristics of power plants.

Since ANTARES is probabilistic, the electricity demand and VRE capacity factors are described by numerous time-series to simulate multiple years. As TIMES-FR is used in its deterministic version, only one year is represented. It was thus decided to use the ANTARES median scenario⁵ as the TIMES input. In such a way, the orange block labeled “global input data” contains the key input data required in TIMES and ANTARES, and also provides the starting point of our linking exercise.

Once this input consistency is established, the first step is to run the TIMES model for the whole planning timeframe.

- **Bridge.1:** This step is the core of the linking model. Based on the TIMES solution, the power generation mix for a specific year of interest is extracted. ANTARES is then run with this targeted mix as input and simulates the supply/demand balance of the power system under several operational and climatic conditions. It is important to recall that within ANTARES, the stochastic nature of VRE, power demand, hydro generation and thermal power plant availability is taken into account by using a large number of annual scenario conditions (Monte Carlo simulations). Each possible future state corresponds to an alternative realization, created using forecasted meteorological data, and is composed by annual time-series, with hourly resolution using RTE data [54].

Feedback part: This part is designed to assess the power system generation adequacy.

- **Bridge.2 and feedback loops:** After running ANTARES, the outputs are analyzed in terms of the difference between: dispatch decisions, annual expected power generation (measuring points), and finally the adequacy of the power system. Two things can happen:
 - If the outputs show that the legal adequacy criterion is not met ($LOLE > 3h$), then some parameters will need to be updated in the long-term optimization model;
 - If the outputs show that the legal adequacy criterion is met, then the process ends.

⁵ The median scenario corresponds to the median Monte Carlo year (load, renewables capacity factors) simulated within ANTARES.

One central part of this framework involves the feedback loop from ANTARES to TIMES. The approach adopted consists in determining whether the generation portfolio decided by TIMES is able to satisfy the 3-hour limit. The most relevant challenge is then to ensure sufficient firm capacity, i.e. capacity that can be counted on to serve the load at all times, especially during peak hours. Several levers can be envisaged to achieve this. Based on the IRENA report on planning for a Renewable Future, which highlights the importance of integrating exogenous capacity credit into long-term energy planning as a means to ensure that system expansion maintains sufficient firm capacity [2], it was decided to focus on capacity credits. More precisely, by assigning capacity credit values to different types of power plants, including VRE, TIMES model can ensure sufficient power generation expansion. Within the TIMES-FR model, capacity credit is incorporated as an exogenous parameter within the peaking reserve constraint (introduced in section 2.2, Equation 1).

A growing body of literature provides better representations of the capacity credit of variable renewable energy sources into long-term energy planning models and takes different approaches to estimate it [55–59]. All of these studies recognize that the level of capacity credit depends on several parameters, such as the average capacity factor, its day-to-day variance, and the target security of supply level. In our work we propose a new methodology based on the IEA approach to estimate the capacity credit value while taking into account the ANTARES outputs. In the World Energy Model projections, the VRE capacity credit is calculated as the difference between peak demand and peak residual demand, expressed as a percentage of the variable renewables installed capacity [60]. Hence, in the present paper, capacity credit is evaluated with respect to ANTARES outputs following Equation 2.

$$cc_i = \text{median}_{s \in \text{Scenario}} \left(\frac{LDC^s(t_{peak}) - RLDC_i^s(t_{peak})}{Capacity_i} \right)$$

Equation 2

Where

- LDC is the load duration curve, RLDC is the residual load duration curve, and $Capacity_i$ is the installed capacity of a technology i .
- t_{peak} is the peak hour
- Scenario is the set of ANTARES scenarios.

To summarize, the bi-directional data exchange between the two models is set up as follows:

- TIMES mainly provides the generation portfolio;
- For a specific year, ANTARES assesses the generation adequacy criterion and provides capacity credit iteratively over available technologies.

2.4. Data assumptions and simulation strategy

The aim of this section is to explain how major data transfers were carried out from one model to the other and the simulation variants hypothesis.

Electricity demand and renewables capacity factor datasets

Climatic conditions will affect both renewable generation and power demand. Therefore, weather events have a significant impact on the operation and adequacy of the power system. Consequently, it is important to consider the range of climatic conditions that will affect both renewable generation and power demand. Furthermore, wind, solar radiation, temperature and precipitation are mutually correlated. In extremely cold periods, for example, wind energy production often falls while there is a significant increase in consumption due to the thermo-sensitivity of load. In this regard, we employed 200 meteorological time-series databases (wind speed, solar radiation, and temperature) representing different possible states of the linking targeted year (2030). We present in this section the methodology used to handle the reconciliation between TIMES and ANTARES in

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

terms of representing power demand and renewables capacity factors (wind and solar) while maintaining their mutual correlations.

In our study, the average long-term evolution of future electricity demand (independently of specific climatic conditions) during the period 2013-2030 is assumed based on the projections of the “High Consumption” scenario of the Generation Adequacy Report [23]. This specific scenario indicates that increasing demand will be mainly derived from significant end-use electrification and energy efficiency efforts. A flat evolution is considered for the period 2030-2050.

The power demand time series are calculated using an analytical approach and stacking model (ORPHEE, developed by RTE), considering the three following phases:

- ✓ Forecasting the annual energy demand;
- ✓ Forecasting the power demand, applied to an hourly reference profile for temperature;
- ✓ Adding the temperature sensitivity effect for end-uses sensitive to weather conditions using two hundred annual reference temperature series produced by Météo-France.

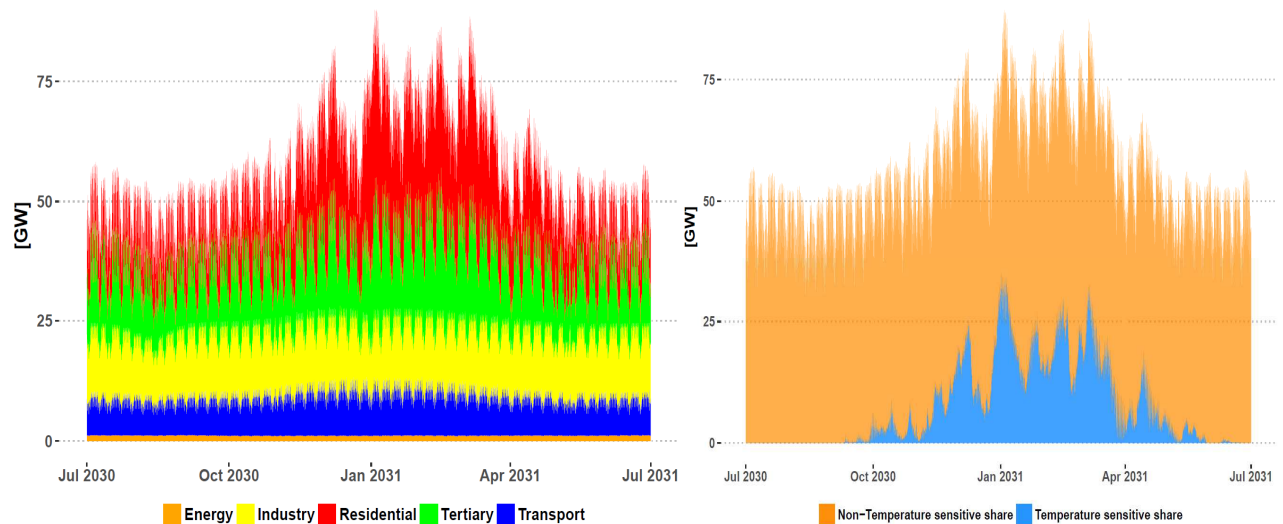


Figure 1 Power load curve of the median climatic scenario: (a) represents the 2030 load curve breakdown by sector of activity and (b) the temperature sensitivity.

The first phase was to forecast the annual total electricity demand. This involved aggregating power demand into sectors of activity (residential, tertiary, industry, energy, transport and agriculture). Each sector was then broken down into a set of end-uses. Once the total annual demand is forecasted, an hourly normalized load curve profile could be constructed for each end-use. To compute this, a profile for each end-use consumption is taken assuming reference temperatures (normal conditions).

The last phase aimed in applying temperature sensitivity to the end-uses that are sensitive to weather conditions (heating and air conditioning). The 200 temperature time series forecasts from the meteorological database are used in this computation. The demand forecasts for each end-use were then aggregated to produce the total load curve scenario inputs (200 hourly time series) for ANTARES. Figure 5-(a) shows the shape of the median scenario load curve broken down into sectors of activity, and (b) the temperature-sensitive share of the same load curve. It appears that very intense consumption occurred in winter, mainly due to seasonal electric heating in the residential and tertiary sectors. Furthermore, the transport, industry and energy sectors were subject to a low level of seasonal and daily fluctuations. More details about French electricity consumption analysis are developed in the Generation Adequacy Report [23].

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

Within the TIMES models, the annual electricity demand for 2030 was calculated for each sector by aggregating correspondent end-use demand levels of the ANTARES median load scenario. The hourly profile was aggregated to affect energy demand level to each time slice. Following this assignment technique, both models give the same total energy consumption. The results in terms of duration load curve representation between ANTARES (hourly resolution) and TIMES (84 time slice resolutions) are shown in Figure 6 . It can be seen that the incorporation of a set of time slices representing a cold week in January-February makes it possible to capture the load peak. In terms of load curve, the methodology used to assign load values to time slices approximates the complete load duration curve⁶ with reasonable accuracy ($R^2 = 80\%$), in particular as far as the very peak is concerned. To sum up, Table 1 summarizes and compares the energy demand data characteristics used in both models.

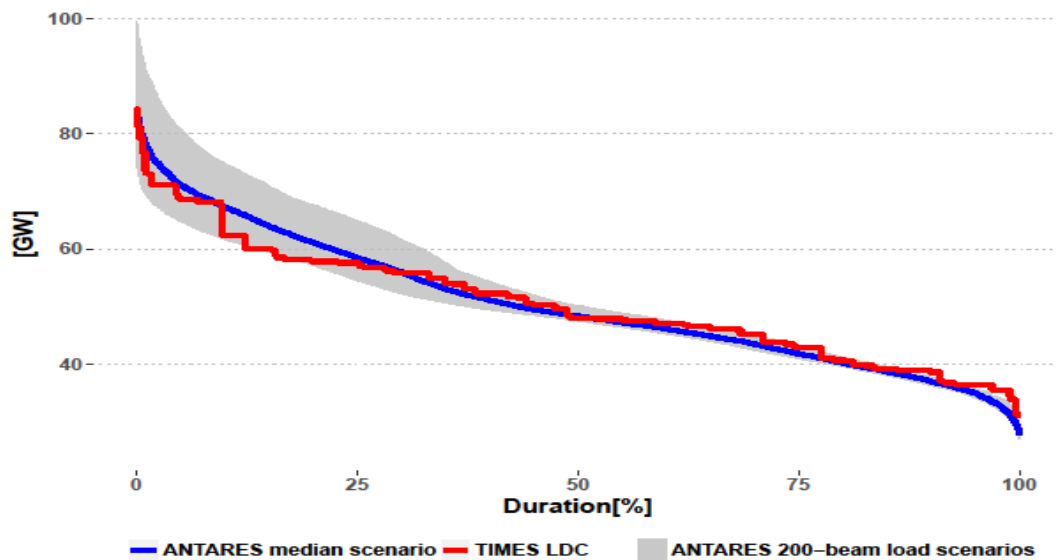


Figure 6 TIMES LDC estimation (red line) based on ANTARES median scenario (blue line). The gray area represents the min-max load scenarios.

Table 1 TIMES and ANTARES demand profiles assumption comparison

Regarding renewables, the capacity factors for onshore and offshore wind turbines and solar PV panels are taken from 200 forecast climatic scenario datasets provided by RTE. ANTARES relied on 200 hourly capacity factor forecasts in order to represent uncertainty about wind and solar conditions. We aimed to replicate the observed mutual correlation between the climatic variables (temperature, wind, solar radiation). A straightforward way to achieve this condition is to use the capacity factor time series issued from the same weather scenario used for the demand time series. Again, the median climatic scenario is selected to serve as availability factor input for 2030 in TIMES. This availability factor is implemented at a time slice level in TIMES by applying an averaging process of the hourly capacity factor profile. As a result, the onshore wind capacity factor duration curve is approximated with poor accuracy due to its high variability. By contrast, the repeated Gaussian shape of solar radiation leads to an adequate approximation of PV capacity factors. Table 2 summarizes and compares the VRE representation in both models.

Table 2 TIMES and ANTARES wind and solar capacity factor input comparison

⁶ The load duration curve shows the fraction of time in which electricity demand exceeds a certain value.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

Fuel costs and thermal marginal costs

Within TIMES models, fuel costs for fossil resources (gas, coal, and uranium) from 2013-2050 are based on *New Policies Scenario* projections from the World Energy Outlook. In ANTARES, marginal costs for thermal units are computed assuming fixed O&M costs, a carbon tax and the fuel price. In this study thermal start-up costs are not taken into account.

Power generation technologies

The TIMES technical power system representation is based on 30 existing technologies (currently in operation) and 89 new technologies (potentially in operation in the future). The existing power fleet in the French electricity system has been modeled at an individual unit level or grouped into several processes based on technology and fuel. Furthermore, a range of new electricity generation technologies is available in nine milestone years during the period 2013-2050. To obtain a technological representation common to both models, the TIMES linear formulation is changed to a **lumpy investment** option to take into account the unit-by-unit granularity of the investments [26]. The set of technologies modeled in TIMES-FR and their respective economic characteristics (cost and price assumptions) and operational characteristics are presented in detail in recent works [24].

Within ANTARES, the thermal power plants are grouped into clusters that have similar generation characteristics. For each cluster, several technical and economic characteristics are taken into account:

- ✓ The number of units and nominal capacities, defining the installed capacities: based on TIMES decisions (new capacity investment and residual capacity);
- ✓ The cost, including marginal cost [MWh/h]: based on fuel price assumptions and technical-environmental technology assumptions.
- ✓ The operational constraints for minimum stable power [MW], and minimum up-and-down duration [Hours]: based on data from the IRENA report [2].
- ✓ Planned and forced outage generation rates and average duration based on RTE data [%].

Table 3 summarizes and compares the thermal power generation technologies characteristics in both models.

Table 3 TIMES and ANTARES thermal power plants comparison

For hydro power generation, three categories of hydro plants are used: Run-of-river (RoR) plants; storage plants that possess a reservoir to postpone the use of water; and pumped-storage stations (PSP).

Simulation strategy

Before examining the simulation strategy adopted, readers should bear in mind that the French power system is modeled in this study without cross-border exchanges with neighbors. TIMES-FR is calibrated for 2013, i.e. the model results for the base year reproduce the historical energy system for France in 2013, as reported by RTE data. Hence cross-border exchanges with the rest of the world are considered only for the base year. We choose in this work to focus on **2030** as a target year for our linking model.

Firstly, within TIMES, a range of French power system policy scenario analyses have been previously produced with TIMES-FR. For this paper, however, the objective is to apply the linking methodology, rather than studying in detail French policy implications in the generation power mix. Hence, the long-term scenario representing 60% VRE uptake in power generation is selected as a case study. This scenario is constructed following these main constraints [24]:

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

- Constraint on nuclear power production, reflecting the French Energy Transition Act, which foresees reducing the nuclear power production share from 75% to 50% by 2025⁷.
- Constraint on the French power system's CO₂ emissions to below 2012 levels (39 Mt) for each period.
- Constraint on VRE penetration assuming legal objectives for 2020 and 2030 while attaining **60% in generation by 2050**.

Based on the above, two simulation variants were applied in the ANTARES model to gain insights into power operation and adequacy. To explore the sensitivity of the power generation mix decided by TIMES to a subset of relevant variables in the power system operation, two variant cases were developed:

- **Sensitivity to climatic events:** This involves simulating 200 future climatic years representing 2030, without taking into account either thermal plant technical constraints or hydro energy conditions. This test assesses the adequacy of the power system derived from TIMES when faced with climatic variability.
- **Sensitivity to climatic events and operational impacts:** This involves combining the climatic impact with thermal power fleet operation constraints (technical detail and unavailability) and different hydro conditions (wet, normal or dry), thus simulating 1,000 future states (or Monte Carlo years). This test quantifies the impact of key operational constraints on the power system adequacy.

The rationale behind the second variant simulations was applied in the Generation Adequacy Report to assess the supply/demand balance in France. Key results from the two simulation variants are described in detail in the Results section.

⁷ A time-horizon update was conducted recently by the French government (2035 instead of 2025) but is not taken into account in this study.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

3. Results

This section comprises two parts. In the first part, the dispatch schedule results from both models are compared and analyzed. This analysis can be achieved based on the first ANTARES variant (200 Monte-Carlo years) using the median scenario dispatch results. The next part assesses the shortages in the median scenario to show whether, for the same input scenario within both models, ANTARES identifies some shortage problems. The third part focuses on an assessment of the generation adequacy of the 1,000 Monte-Carlo years and the impact of the iterative feedback loop on the power generation mix structure and costs.

All simulations were undertaken on an HP Intel core i5 laptop equipped with 2.40GHz processors. The longest TIMES simulation took 20 minutes (only one iteration). The longest ANTARES simulation was the second simulation variant with a running time of approximately 30 minutes (only one iteration). The linking model was fully controlled by several packages written using the R programming language (runs in less than 1 minute).

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

3.1. Generation capacity mix and dispatch schedule

In linking long-term energy planning models with the operational power system (Bridge.1 in Figure 4), the goal is to translate the generation portfolio projections decided by TIMES into detailed, cluster-by-cluster power system model inputs. The long-term energy planning model TIMES is designed to function on a technology detail level, which means that it does not respect the same power generator representation as ANTARES (see data and assumption section 2.4). To help improve the matching between the TIMES output and ANTARES inputs, we created a capacity generation transfer routine. To illustrate how the first bridge works, it is convenient to consider the example of the nuclear power fleet (the same exercise was done for other thermal power technologies). Figure 7 shows the optimum capacity mix decided by TIMES for 2013-2050 following a 60% VRE scenario. On the right side, investments in new power plants are given with a unit-by-unit description (lumpy mode activated in TIMES). Therefore, new investments are aggregated into the same characteristic clusters and then transferred directly to ANTARES. However, as the residual capacity of the existing stock and retrofit is provided on a technology basis, the nuclear residual fleet has to be divided into three standardized technical clusters (using a MILP program which consists of affecting the number of units to each cluster):

- The 900 MW cluster;
- The 1,300 MW cluster;
- 1,400 MW or N4 cluster

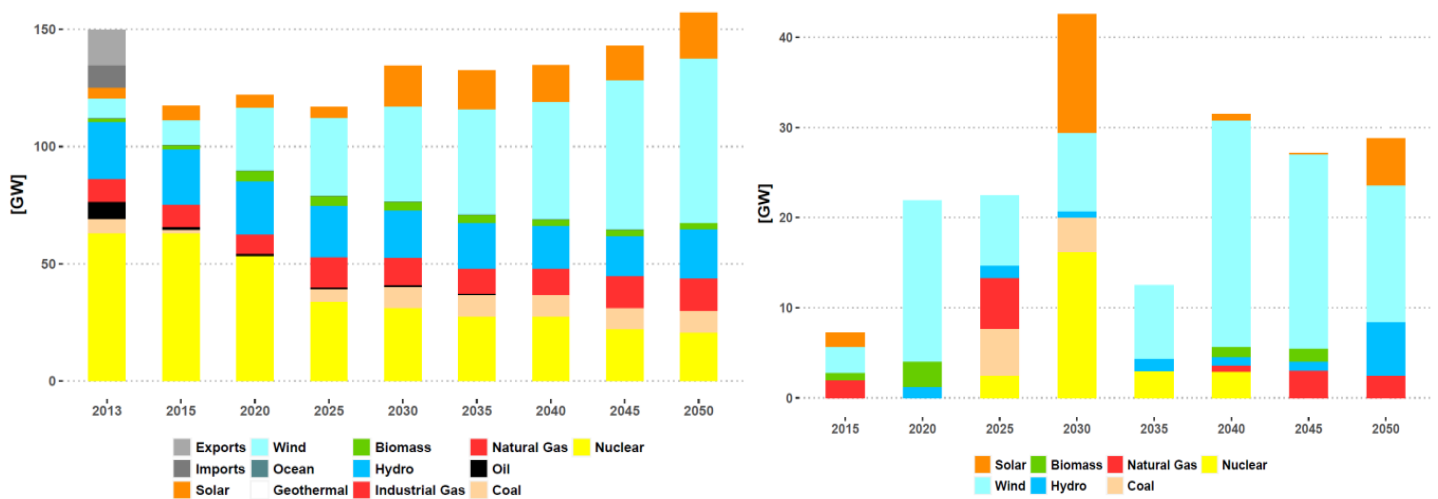


Figure 2 TIMES power generation mix 2013-2050. (a) Total installed capacity and (b) the new installed capacity

This next section explains the underlying impact of the temporal representation on generation scheduling from both models (hourly for ANTARES, by time slice for TIMES). Accordingly, we used the first simulation variant, which simulates 200 possible future climatic states for 2030. Obviously, the median scenario that served as an input in TIMES is used to make consistent comparison between models. Firstly, we concentrate on the production stack outputs, and on how both models approximate the residual load curves. Secondly, we quantify a global comparison indicator, which is the annual power generation. Particularly, this indicator quantifies the differences between the model outputs, and then explicitly evaluates the quality of our linking exercise.

A first observation is that, despite an identical power generation mix in both models, differences in terms of dispatch schedule can be observed (Figure 8). The principal cause of the differences in model results is the way these models approximate the residual load. Residual load is defined as load deducted from non-dispatchable generation. Figure 8 shows the LDC (Load Duration Curve) and RLDC (Residual Load Duration Curve) model approximations and Figure 9 the

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

dispatchable⁸ schedule derived from ANTARES (Figure 9-(a)) and TIMES (Figure 9-(b)). By definition, the energy below RLDC is provided by dispatchable sources of generation (or load-shedding in extreme situations). The empty white area between LDC and RLDC is filled by wind and solar generation.

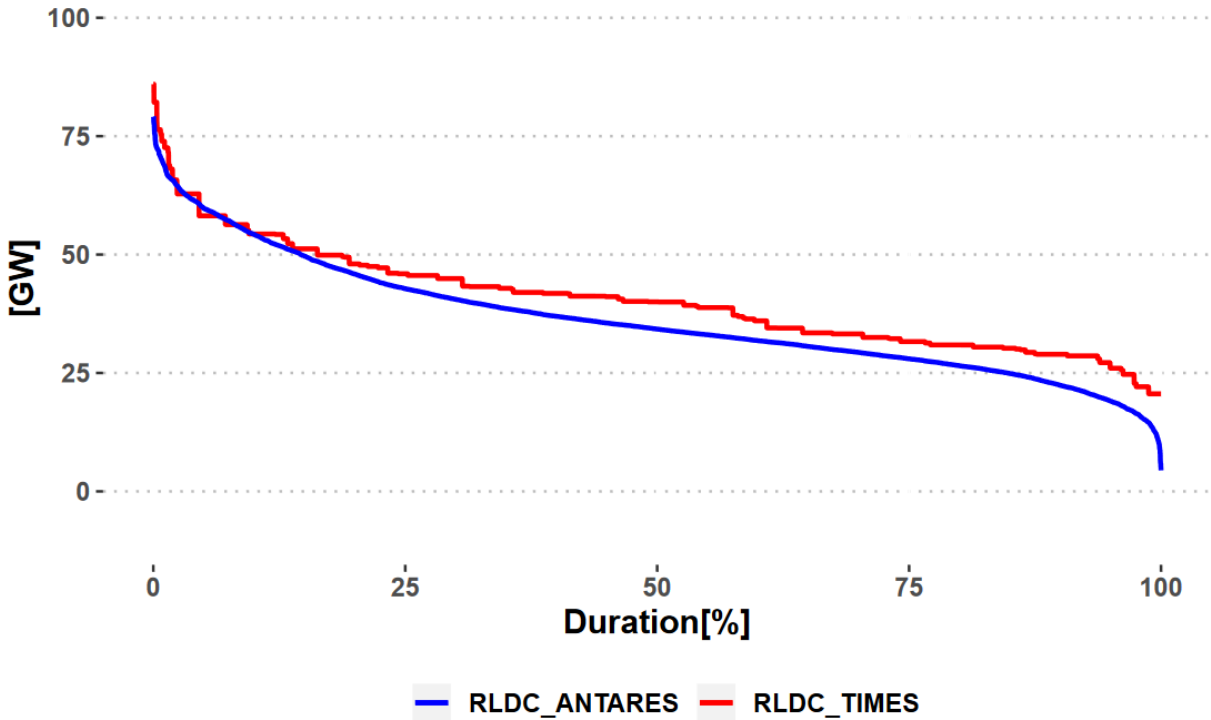


Figure 8 The Residual Load Duration Curve comparison between TIMES and ANTARES median scenario (2030).

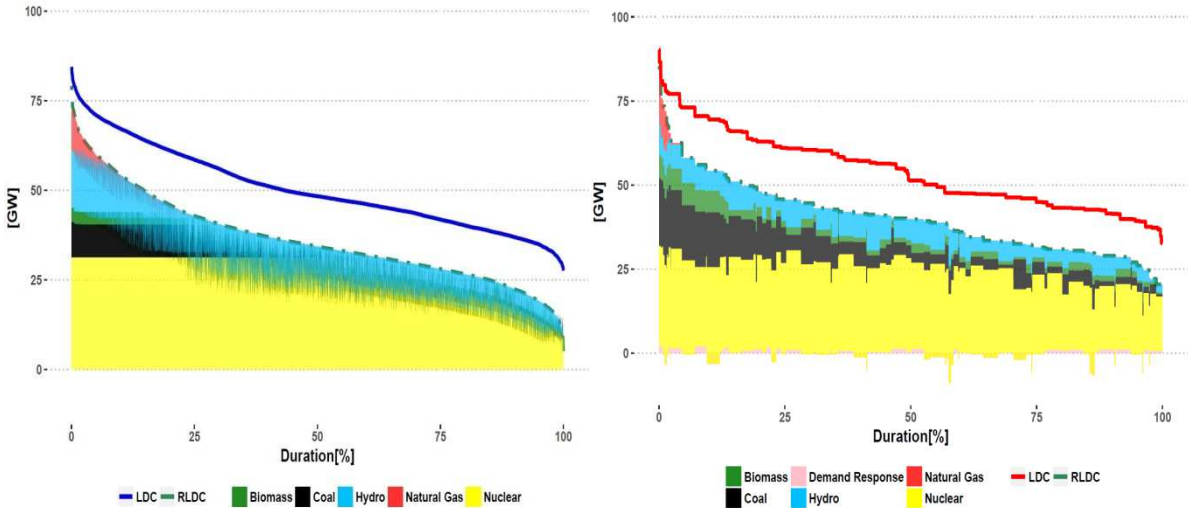


Figure 3 2030 production stack comparison between TIMES and ANTARES. (a) ANTARES hourly production stack for the median scenario and (b) the TIMES 84 time slice production stack.

⁸ Mainly hydro/thermal power fleet and demand-response
 The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

This graphical representation shows two dependent patterns:

- Using 84 time slices within TIMES tends to reduce the high variability of the wind and solar capacity factors. Consequently the ANTARES hourly capacity factor profile is reduced to a piece-wise curve within TIMES. Therefore, the residual load duration curve is overestimated compared to ANTARES (Figure 8).
- Overestimating the thermal power plant flexibility within TIMES by omitting technical constraints (ramping limits, minimum uptimes and downtimes are however taken into account within ANTARES) tends to lead to an over-use of the mid-merit load power plants.

Consequently, differences in terms of annual energy generation can be observed for a set of technologies. Figure 10 presents for each installed technology (2030) the annual power generation computed from the dispatch in the TIMES model (red) and the corresponding ANTARES model (blue). For both non-dispatchable generation technologies (especially wind and solar) and nuclear, we observe negligible differences. These depend on a range of factors, such as the economic merit order behind this aggregated indicator, which ranks renewables and nuclear first. The hydro power generation gap is mainly due to the fact that ANTARES hydro energy stock is defined by the upper bound monthly energy constraint of TIMES. On the contrary, we observe significant differences for mid-merit power plants (i.e. coal and biomass). As a result, TIMES shows approximately 26 TWh of total annual power generation surplus.

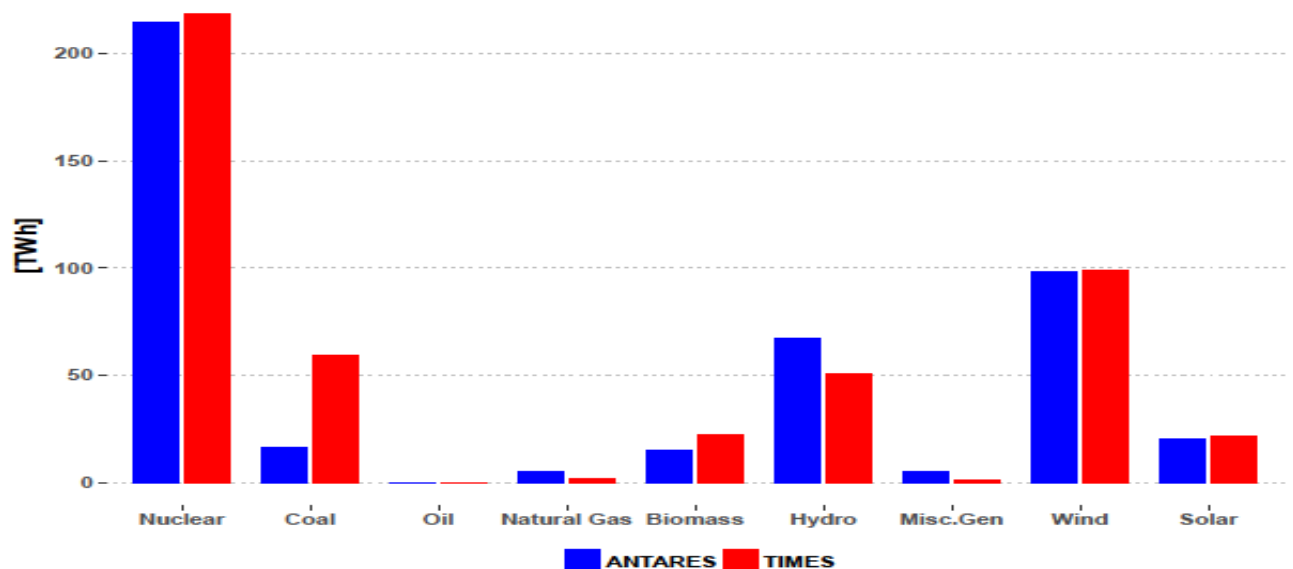


Figure 10 2030, Annual power generation comparison by technology (x axis) and by model (red: TIMES and blue: ANTARES).

Combining these results, we can conclude that, since TIMES captures less residual demand variation and omits thermal power plant flexibility constraints, the model overestimates the use of mid-merit order load technologies compared to an hourly dispatch. These conclusions are broadly consistent with the findings of the work by [61] on the importance of integrating the variability of renewables into long-term energy-planning models.

3.2. Shortfall risk analysis

The objective of analyzing the supply-demand balance of the power generation mix decided by TIMES is to investigate structural shortage that can be accrued. In this respect, the first simulation set is used to characterize the shortfall situations that could occur. First, the median scenario (measuring point) is analyzed to study how using an hourly unit commitment model impacts the adequacy of the

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

power generation mix decided by TIMES. In a second step, the 200 scenarios are used to compute the LOLE adequacy metrics.

With respect to the various adequacy metrics explained in section 2.1, the relevant metric used to assess the median scenario generation adequacy is expressed mainly in terms of LOLD (loss of load duration). Figure 11 depicts the loss of load hours for the median scenario, and highlights that the median scenario that served as an input in TIMES presents **16 hours** of loss of load. First, the hours during which demand is unmet occur in the winter months, mainly in the January-February period, which accounts for 100% of the total. 56% of these risky situations occur close to 7pm, when demand peaks. The remaining 44% are observed in the morning peak. The shortfall hours that occur under the median scenario are of variable duration, ranging from one hour to almost three hours.

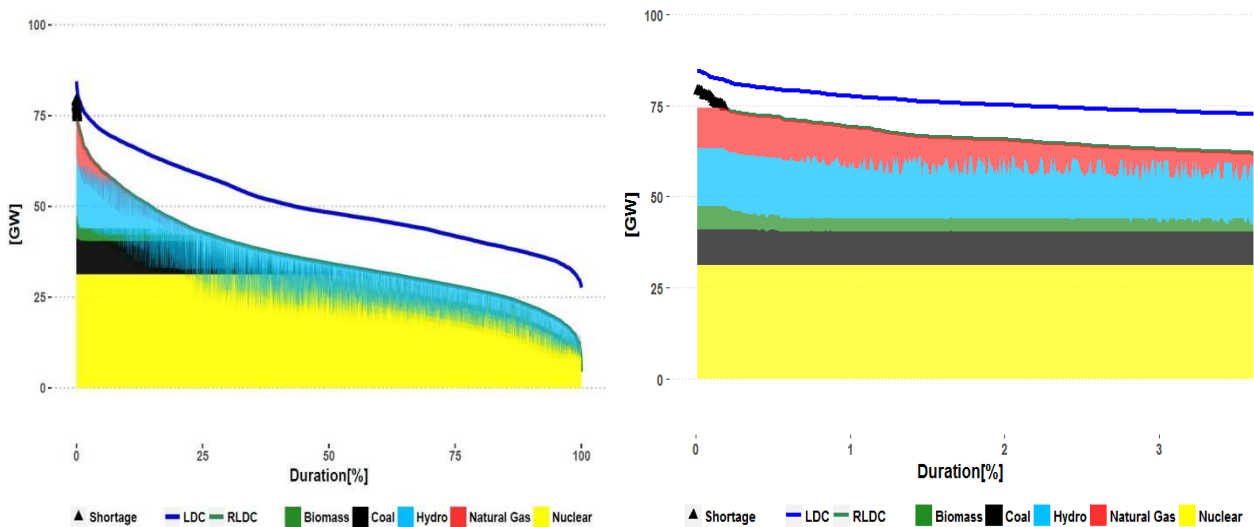


Figure 4 The shortage hours of the ANTARES median scenario. (a) shows the position of shortage hours at the entire RLDC (16 hours), and (b) represents a zoom on the RLDC peak

Second, the situations in which shortfalls occur correspond to a combination of factors. The hours at which structural shortage is detected can be targeted using the residual load duration curve. Figure 11 illustrates how consumption is covered by available generation facilities for every hour of the year. The graph shows that structural generation shortages are mainly located at the peak of the residual load duration curve. That is to say that cold spells exacerbate the shortfall situations. As can be seen from the production stack, the introduction of intermittent renewable energy has a significant effect on the shape of the residual curve, which must be covered by dispatchable technologies. The non-intermittent renewable energy (run-of-river, CHP) plays a role as well, although less important. However, even if all dispatchable generation technologies are used at their maximum power to satisfy the residual load peak, the supply is insufficient. In conclusion, the combination of a high level of load and low renewable power outputs can strongly affect the adequacy of the power system decided for 2030 by TIMES.

In order to assess the overall impact of climatic conditions on adequacy, we employ the ANTARES results for 200 scenarios. The criterion applied is mainly based on loss of load expectation (LOLE) given in hours. In addition, the loss of load cumulative distribution brings important insights because other percentiles can be clearly identified. This distribution is calculated taking the load losses observed over 200 Monte Carlo years (Figure 12). Therefore, ANTARES simulation outputs result in a LOLE equal to **36.19** hours, which does not conform to the three-hour limit. A statistical analysis of loss of load duration shows that close to 10% (i.e. 1 in 10) of the 200 climatic future states last more than 100 hours with a maximum value of **395** h.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

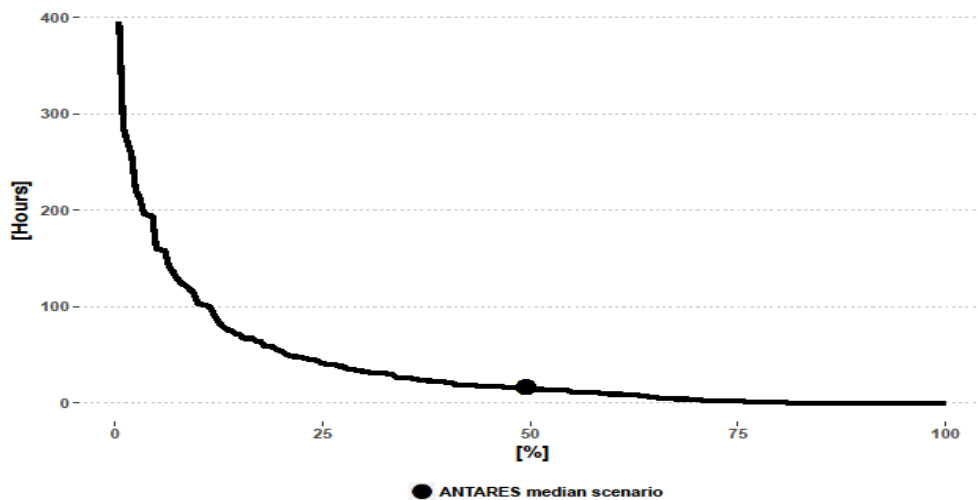


Figure 12 Loss of Load duration curve for the first simulation variant (200 scenarios simulated in ANTARES)

To sum up, the adequacy assessment carried out above indicates that the 2030 capacity mix as derived from TIMES does not respect adequacy requirements. First, under different climatic conditions representing 200 scenarios of load and renewable power output, the loss of load expectation criterion is not met. Second, results for the second set of simulations are broadly similar: when the thermal constraints and hydro power generation variability is added, an increase in the LOLE is observed (from 36 hours to 79 hours). This stresses both the major impact of including technical details in adequacy assessments and the absolute necessity of using a linking approach to check the adequacy requirements.

3.3. Feedback loops: adequacy and cost evaluation

The feedback loop between ANTARES and TIMES is based on the concept of a power plant's capacity credit, which is used to measure the contribution to peak demand. To illustrate the method, the following analysis was applied to the second set of simulations (1,000 Monte Carlo years). In this section, we analyze adjustments of solutions (output models) during the iterative feedback between both models in terms of resulting power generation mix, adequacy, and cost-qualitative evaluation (the first variant simulation feed-back results are presented in Annex A).

The first iteration focuses only on renewables capacity credit (Iteration.1), while the second (Iteration.2) deals mainly with hydro, and the last with the thermal power fleet (Iteration.3). It should be noted that the order is important, since the power generation mix changes from one iteration to the next (therefore altering the capacity credit of all technologies). The issue with thermal capacity credit is that unplanned outages combined with ramping constraints could affect their capacity to serve peak demand. Also, the variability of available hydro energy (wet, dry) could reduce the fraction of its rated capacity.

As a result, based on ANTARES outcomes, capacity values are computed for each simulated scenario. The median value over all scenarios is then chosen. Table 4 shows the evolution of the median of the capacity credit values over the activated iterations. Solar technologies have a capacity credit of zero, because in France in the considered scenario, peak demand occurs during winter evenings. For wind, the TIMES initialization step (Iteration.0) assumes a capacity credit of 22% for wind. However, based on 2030 climatic conditions for load and the renewables capacity factor, the median value is 15% (Iteration.1). In the second iteration, the capacity credit of hydro is estimated

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

based on the same methodology as renewables. The results show that run-of-river participates with 50% of its installed capacity and a 75% level for reservoirs (Iteration.2). The last three iterations estimate the capacity credit for thermal clusters represented in ANTARES. With the addition of technical constraints, and unplanned outages, the thermal power fleet capacity credit level shows a decrease from 100% to 60% (the same capacity credit value was assigned to all of the thermal technologies because ANTARES results show that all clusters have a relatively similar value).

Table 4 Capacity credit values estimation over the iterative feedback loop (the red color indicates the main value change in each iteration).

Once the capacity credit values are determined, the next step consists in running the TIMES model again with the updated values. Figure 13 shows the impact of iteratively updating the capacity credit values on the loss-of-load distribution calculated by ANTARES (Figure 13-(a)) as well as the least-cost power generation mix decided by TIMES (Figure 13-(b)). Following the procedure described above, only seven iterations (3 iterations for the first simulation variant) were necessary to build a power generation mix with sufficient supplies to meet the adequacy criterion. Two important observations are that, the first iteration has a significant impact on reducing the LOLE indicator, while the last iteration affecting the thermal power fleet has a limited impact (1-4 hours). On the other hand, while feedback loops mainly affect the peaking-reserve constraint, which mostly governs behavior during peak time slices, mid-merit power plants (biomass) increase their share over iteration. This is due to the fact that the peaking reserve constraint is an investment constraint and not an operational one: it only ensures excess capacity and does not restrict the contribution of each technology to meet power demand in any of the time periods. Feedback loops do not simply add peak generation to the existing mix; iterations substantially change the mix structure by adjusting all power plant capacities.

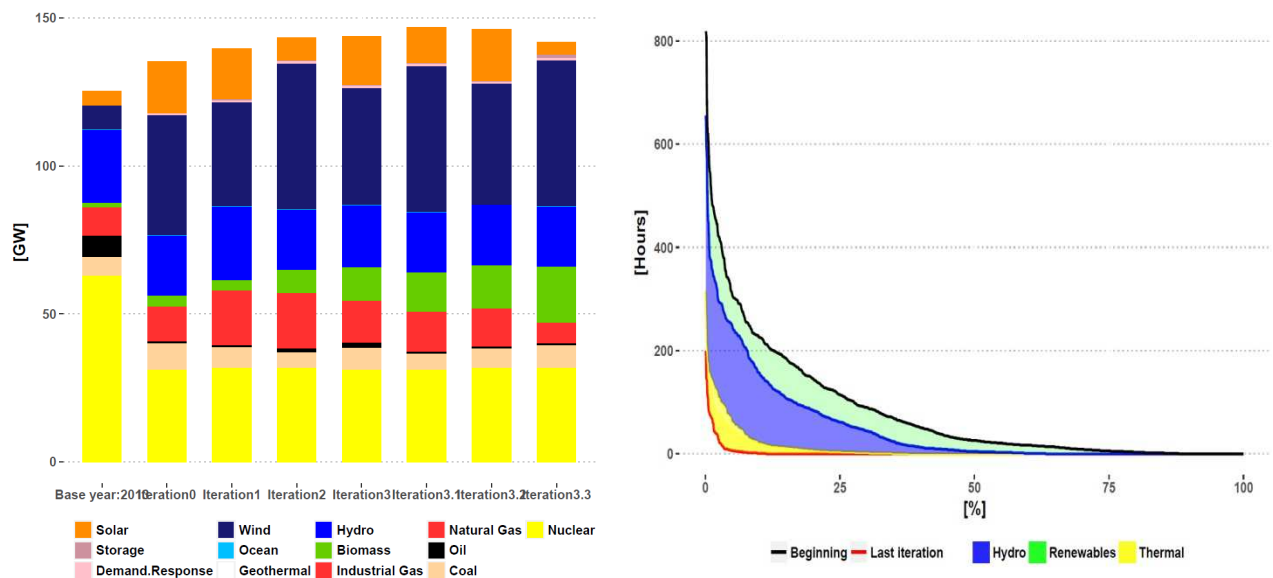


Figure 5 The impact of the feedback loop on the power generation mix and adequacy. (a) represents the power generation mix evolution over iterations and (b) the loss of load duration curve over iterations.

From an economic viewpoint, any improvements in the adequacy of the system involve additional costs. To illustrate this effect, two costs are analyzed here: The discounted total cost calculated by

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

TIMES includes investment costs, variable and fixed costs over 2013-2050. The evolution of this cost over the different iterations is presented in Figure 14-(a). The overall cost calculated in ANTARES represents operating costs and fictional costs (for unsupplied energy and spilled energy) for 2030 only and is plotted in Figure 14-(b).

Figure 14 shows that the total cost calculated by TIMES increases over iterations, while the overall cost displayed by ANTARES decreases. This is due to the correlation which exists between the investment cost of a power system and system adequacy: for each iteration, TIMES invests more in order to lower the amount of unsupplied energy perceived by ANTARES, which reduces the overall cost of the system in the next iteration of ANTARES. At the end of the loop, the overall cost calculated by ANTARES has hence been reduced by 55% to get from an average of 79 hours of loss of load per year to less than 3h/year.

Finally, Figure 14 shows that French energy system costs will increase compared to the initial decision by 28% over iterations to satisfy the 2030 adequacy criterion, driven mainly by the investment share. It should be noted that the first iterations, which reduce the loss of load duration from over 75 hours to around 10 hours, have a very limited impact on the investment cost increase. On the other hand, the last iterations suggest that removing the last few hours (3-4 hours) of adequacy requires approximately half of the total increase in investments.

In our case study, improving adequacy to meet official criteria induces additional costs that are far from negligible with respect to the total investment, and that require consideration.

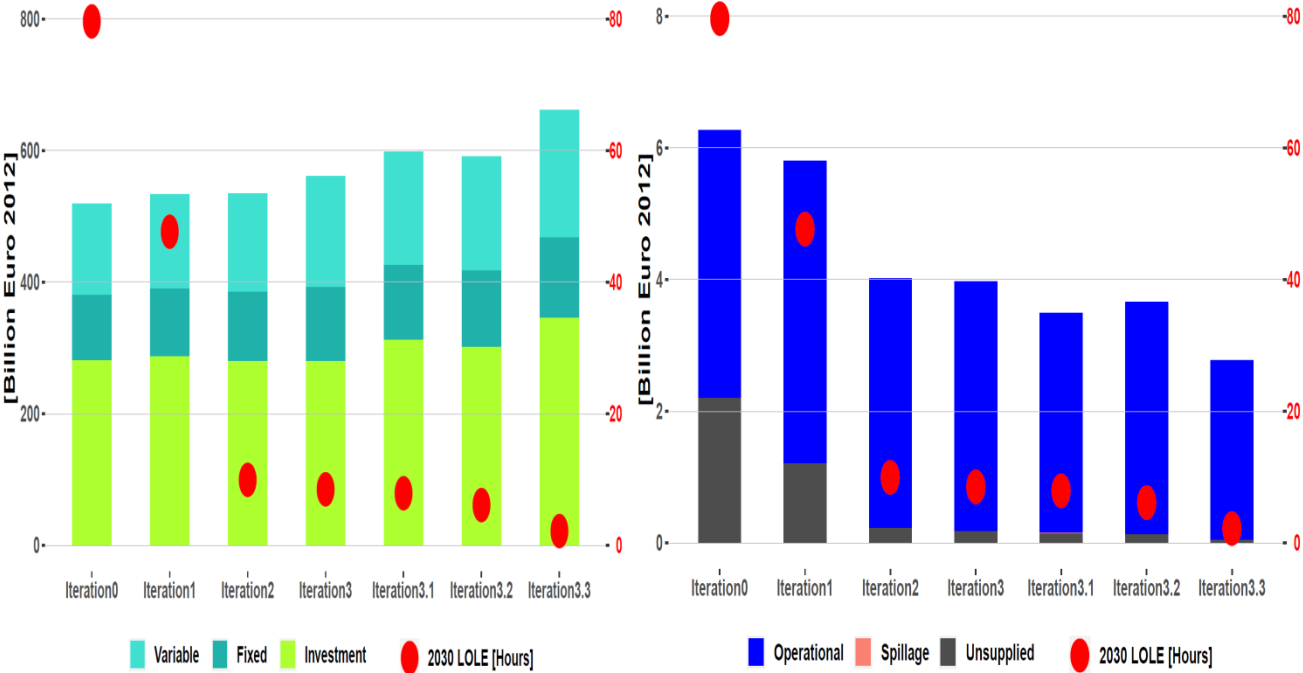


Figure 6 The impact of the feedback loop on the power system costs (derived from TIMES). (a) is the total discounted cost over the planning period over iterations and (b) is the overall operational costs for 2030 over iterations (derived from ANTARES as the sum of operating costs and fictional costs (for unsupplied energy and spilled energy)).

4. Discussion

In 1979, George Box wrote a paper on the philosophy of robust procedures in which he argued that “essentially all models are wrong, but some models are useful”. This aphorism can easily be applied to the significant challenges that stand in the way of the energy systems modeling community. In fact, both conventional energy system planning models and operational power system models have inherent weaknesses which undermine their usefulness to adequately address the challenges of the transition to a low-carbon power system. Accordingly, modelers have explored the development of a new generation of model-linking approaches to deal with the power sector transition. The advantages of this methodology compared to a single integrated model are twofold: First, it is more flexible, since it leaves the constituent models intact for independent runs, thus making further model development easier. Second, the linking approach features both the pathway cost-effectiveness foundation of long-term energy planning models and the operational richness of power system models. Our work contributes to this research axis thanks to its careful focus on generation adequacy risk assessment. Thus, our only key question is, “Do long-term energy planning model (TIMES) outcomes match power systems’ security of supply requirements?”

In this spirit, the purpose of this study was to address electricity security of supply in the long-term power system planning process. State-of-the-art system adequacy assessment is probabilistic by nature. Grid operators around the world have been using probabilistic tools for decades. However, to our knowledge, no previous study has used a similar approach in such linking exercises [21,22,62,63]. By ensuring input-output data consistency, we developed a rigorous methodology for linking a long-term energy planning model (TIMES power system model) with a probabilistic operational power system (ANTARES). For a specific target year, in our model we established an iterative feedback loop with a stopping criterion representing three-hour annual loss-of-load expectation to ensure an adequate power generation mix. Furthermore, most previous studies have highlighted the regrettable lack of consistent long-term energy demand forecasts, as well as capacity factor forecast data sources. As for all models, the quality of our results is conditioned by the quality of the input data. However, our databases benefit from the expertise of the power grid operator (RTE) regarding long-term forecasting studies. Readers who want to form their own opinion about the quality of the data used are referred to the French generation adequacy reports .

One of the key questions concerning the bidirectional linkage (feed-back loop process) between a long-term energy system and a short-term operational model approach is whether the convergence is guaranteed by the feedback loop strategy. At this level, it is important to clearly define two possible definitions of convergence which depend mainly on the goal of the linkage.

- i. The convergence criterion is based on an endogenous variable in both models
- ii. The convergence criterion is based on a metric that is external to both models.

An example of the former definition can be found in the study [64], which proposes a novel bidirectional linkage between a TIMES-Norway energy system model and an EMPS power market model to improve the modeling of hydropower generation and external electricity markets in the TIMES-Norway model. As the Norwegian power system is hydropower-dominated, the chosen convergence criterion is the income difference of hydropower producers, which is endogenous in both models. The feedback strategy, meanwhile, uses electricity trade prices and operational hydropower constraints from EMPS as an input to TIMES-Norway. However, the particular focus in our study is power generation adequacy assessed by the Loss of Load Expectation metric, which is external to both models. Thereby our convergence definition belongs to the second category.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

Taking this for granted, our proposed feed-back loop strategy is based on the peaking-reserve constraint using capacity credit value updates. Two possible extreme outcomes could be considered:

- i. Capacity credit values are over-estimated (100% for all technologies): the power generation as derived from TIMES has insufficient supply and therefore adequacy is not guaranteed.
- ii. Capacity credit values are under-estimated (10% for all technologies): the power generation as derived from TIMES has sufficient supply and therefore adequacy is guaranteed.

Our approach neither over-estimates nor under-estimates capacity credit values. In fact, using ANTARES operational dispatch decisions to estimate the capacity credit values results in a “real” approximation of the contribution of each investment in the overall adequacy. Two simulation variants have been tested, and the number of iterations was 3 for the variant with 200 operational scenarios and 7 iterations for the variant with 1000 operational scenarios. However, at the present stage of research, the authors have decided to not discuss in further detail the mathematical proof of convergence for the TIMES-ANTARES feed-back loop. This pertinent issue will be addressed in further works.

Our contribution to the model-linking approaches for power systems has a limited scope by design. In addition to scenario analysis work, the linking model could be improved in several ways. Future development could include an adequacy assessment of different periods. For tractability reasons, this work focused only on 2030, and did not benefit from the overall evolution yielded by TIMES over the full timeframe. Resolving this time-scale dilemma between both models would be a valuable addition. As the European power grid becomes more interconnected, modeling exchanges between countries must be taken into account. Moreover, thanks to the modeling of interconnections by ANTARES, adequacy assessments performed by RTE model the power mixes of neighboring European countries (Benelux, Germany, Switzerland, Italy, Spain, Portugal, UK and Scandinavia, and the associated cross-border exchanges). Its Generation Adequacy Report results show how vital imports are to ensuring domestic security of supply. The European TIMES model is currently in progress. Thus, a first set of necessary additions would accurately represent neighboring countries’ power systems and their evolution in both models. Furthermore, [65] developed an approach to stability analysis by introducing additional constraints into TIMES based on estimates of instantaneous kinetic and magnetic energies. In a similar way, [66] performed external linking with an off-the-shelf optimal dispatch, while [67] described an internal linking introducing nonlinear transient stability dynamic effects. The automated softlinking model could be interestingly extended to add an interaction with transient stability analysis tools used on a regular basis by power system dynamics experts.

5. Conclusion

This paper presents a new multi-scale modeling approach, with the goal of assessing long-term electricity security of supply. Among others, a key motivation was to dispel growing concerns as to whether the methodologies and underlying assumptions employed in standard long-term energy planning models are suitable to address the short-term features of the future decarbonized power system. By simultaneously considering models at different scales, the proposed linking methodology shares the long-term trajectory cost-effectiveness of TIMES models with the highly detailed temporal resolution and probabilistic aspects of ANTARES models. The purpose of the linkage is to provide long-term power generation mixes that respect the generation adequacy requirements. The emphasis

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

of this work was on methodology and not on power system transition analysis. In this regard, as a case study, the methodology developed has been applied to power generation planning for France without any cross-border exchanges (stand-alone basis). The study focused on the 2013-2050 timeframe, under a constraint to increase renewable power generation uptake to 60% by 2050. For practical tractability reasons, the adequacy assessment was only carried out for 2030 (40% VRE uptake), a year that was assumed to be midway between the starting point and the planning horizon. Up to this point, several conclusions have arisen from this study:

- Dispatch results from both models show significant differences, mainly due to an underestimation of the variability of VRE and load, leading to an overestimation of the residual load duration curve observed by TIMES.
- The capacity mix as derived from TIMES for 2030 does not by and large meet the electricity security of supply requirements set by French public authorities (a LOLE<3h).
- Feedback loops between ANTARES and TIMES based on capacity credit estimation have the potential to ensure sufficient firm capacity (supply) to meet demand.
- 7 iterations were needed to converge to the 3h LOLE criterion.
- From an operational point of view, the ANTARES adequacy outcomes show that the 2030 LOLE drops from 79 hours to 3 hours with an Expected Energy Not Served decrease from 442 GWh to 10 GWh.
- From a planning point of view, the TIMES economic outcomes underestimate the total discounted cost (including investment costs incurred for new investment and retrofit, fixed and variable annual costs) by 28%, driven mostly by investment shares.

The big take-home message from our study is that careful attention to long-term electricity security of supply is important and likely to be underestimated using standard long-term energy system planning models. Given the promising results of this approach, the next step is twofold: first, to extend the system analysis to the whole European interconnected power system; second, to ensure power generation adequacy over the entire planning timeframe.

Acknowledgments

This research was conducted in joint collaboration between RTE, the French power grid operator, and the Modeling for Sustainable Development Chair led by MINES ParisTech, Ecole des Ponts ParisTech, AgroParisTech. It was supported by ADEME, EDF, GRTgaz, Total, RTE, SCHNEIDER ELECTRIC and the French Department for Climate and Energy.

References

- [1] Ruedinger A. The French Energy Transition Law for Green Growth: At the limits of governance by objectives 2015. <https://www.iddri.org/en/publications-and-events/decryptage/french-energy-transition-law-green-growth-limits-governance>.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

- [2] IRENA. Planning for the renewable future: Long-term modelling and tools to expand variable renewable power in emerging economies. /Publications/2017/Jan/Planning-for-the-Renewable-Future-Long-Term-Modelling-and-Tools-to-Expand-Variable-Renewable-Power 2017. /publications/2017/Jan/Planning-for-the-renewable-future-Long-term-modelling-and-tools-to-expand-variable-renewable-power (accessed October 15, 2018).
- [3] Pfenninger S. Energy scientists must show their workings. *Nature News* 2017;542:393. <https://doi.org/10.1038/542393a>.
- [4] Pfenninger S, DeCarolis J, Hirth L, Quoilin S, Staffell I. The importance of open data and software: Is energy research lagging behind? *Energy Policy* 2017;101:211–5. <https://doi.org/10.1016/j.enpol.2016.11.046>.
- [5] Nweke CI, Leanez F, Drayton GR, Kolhe M. Benefits of chronological optimization in capacity planning for electricity markets. 2012 IEEE International Conference on Power System Technology (POWERCON), 2012, p. 1–6. <https://doi.org/10.1109/PowerCon.2012.6401421>.
- [6] Helistö N, Kiviluoma J, Holttinen H, Lara JD, Hodge B-M. Including operational aspects in the planning of power systems with large amounts of variable generation: A review of modeling approaches. *Wiley Interdisciplinary Reviews: Energy and Environment* 2019;0:e341. <https://doi.org/10.1002/wene.341>.
- [7] Drouineau M, Assoumou E, Mazauric V, Maïzi N. Increasing shares of intermittent sources in Reunion Island: Impacts on the future reliability of power supply. *Renewable and Sustainable Energy Reviews* 2015;46:120–8. <https://doi.org/10.1016/j.rser.2015.02.024>.
- [8] Drouineau M, Maïzi N, Mazauric V. Impacts of intermittent sources on the quality of power supply: The key role of reliability indicators. *Applied Energy* 2014;116:333–43. <https://doi.org/10.1016/j.apenergy.2013.11.069>.
- [9] Maïzi N, Mazauric V, Assoumou E, Bouckaert S, Krakowski V, Li X, et al. Maximizing intermittency in 100% renewable and reliable power systems: A holistic approach applied to Reunion Island in 2030. *Applied Energy* 2018;227:332–41. <https://doi.org/10.1016/j.apenergy.2017.08.058>.
- [10] Spiecker S, Weber C. The future of the European electricity system and the impact of fluctuating renewable energy – A scenario analysis. *Energy Policy* 2014;65:185–97. <https://doi.org/10.1016/j.enpol.2013.10.032>.
- [11] Ludig S, Schmid E, Haller M, Bauer N. Assessment of transformation strategies for the German power sector under the uncertainty of demand development and technology availability. *Renewable and Sustainable Energy Reviews* 2015;46:143–56. <https://doi.org/10.1016/j.rser.2015.02.044>.
- [12] Merrick JH. On representation of temporal variability in electricity capacity planning models. *Energy Economics* 2016;59:261–74. <https://doi.org/10.1016/j.eneco.2016.08.001>.
- [13] Nahmmacher P, Schmid E, Hirth L, Knopf B. *Carpe Diem: A Novel Approach to Select Representative Days for Long-Term Power System Models with High Shares of Renewable Energy Sources*. Rochester, NY: Social Science Research Network; 2014.
- [14] Nelson J, Johnston J, Mileva A, Fripp M, Hoffman I, Petros-Good A, et al. High-resolution modeling of the western North American power system demonstrates low-cost and low-carbon futures. *Energy Policy* 2012;43:436–47. <https://doi.org/10.1016/j.enpol.2012.01.031>.
- [15] Nicolosi M. The Importance of High Temporal Resolution in Modeling Renewable Energy Penetration Scenarios 2010. <https://escholarship.org/uc/item/9rh9v9t4>.
- [16] Park SY, Yun B-Y, Yun CY, Lee DH, Choi DG. An analysis of the optimum renewable energy portfolio using the bottom–up model: Focusing on the electricity generation sector in South Korea. *Renewable and Sustainable Energy Reviews* 2016;53:319–29. <https://doi.org/10.1016/j.rser.2015.08.029>.
- [17] Pina A, Silva C, Ferrão P. Modeling hourly electricity dynamics for policy making in long-term scenarios. *Energy Policy* 2011;39:4692–702. <https://doi.org/10.1016/j.enpol.2011.06.062>.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

- [18] Poncelet K, Delarue E, Six D, Duerinck J, D'haeseleer W. Impact of the level of temporal and operational detail in energy-system planning models. *Applied Energy* 2016;162:631–643.
- [19] Kannan R, Turton H. A Long-Term Electricity Dispatch Model with the TIMES Framework. *Environ Model Assess* 2013;18:325–43. <https://doi.org/10.1007/s10666-012-9346-y>.
- [20] Wene C-O. Energy-economy analysis: Linking the macroeconomic and systems engineering approaches. *Energy* 1996;21:809–24. [https://doi.org/10.1016/0360-5442\(96\)00017-5](https://doi.org/10.1016/0360-5442(96)00017-5).
- [21] Deane JP, Chiodi A, Gargiulo M, Ó Gallachóir BP. Soft-linking of a power systems model to an energy systems model. *Energy* 2012;42:303–12. <https://doi.org/10.1016/j.energy.2012.03.052>.
- [22] Deane JP, Gracceva F, Chiodi A, Gargiulo M, Gallachóir BPÓ. Assessing power system security. A framework and a multi model approach. *International Journal of Electrical Power & Energy Systems* 2015;73:283–97. <https://doi.org/10.1016/j.ijepes.2015.04.020>.
- [23] Bilan prévisionnel. RTE France 2018. <https://www.rte-france.com/fr/article/bilan-previsionnel> (accessed November 21, 2018).
- [24] Krakowski V, Assoumou E, Mazauric V, Maïzi N. Feasible path toward 40–100% renewable energy shares for power supply in France by 2050: A prospective analysis. *Applied Energy* 2016;171:501–22. <https://doi.org/10.1016/j.apenergy.2016.03.094>.
- [25] Maïzi N, Assoumou E. Future prospects for nuclear power in France. *Applied Energy* 2014;136:849–59. <https://doi.org/10.1016/j.apenergy.2014.03.056>.
- [26] Seck GS, Krakowski V, Assoumou E, Maïzi N, Mazauric V. Reliability-constrained scenarios with increasing shares of renewables for the French power sector in 2050. *Energy Procedia* 2017;142:3041–8. <https://doi.org/10.1016/j.egypro.2017.12.442>.
- [27] Allan RN, Billinton. *Reliability Evaluation of Power Systems*. Springer US; 1996.
- [28] Abunima H, Teh J, Lai C-M, Jabir HJ. A Systematic Review of Reliability Studies on Composite Power Systems: A Coherent Taxonomy Motivations, Open Challenges, Recommendations, and New Research Directions. *Energies* 2018;11:2417. <https://doi.org/10.3390/en11092417>.
- [29] K. Debnath, L. Goel. Power system planning — a reliability perspective 1995. https://www.researchgate.net/publication/223412624_Power_system_planning_-_a_reliability_perspective (accessed December 3, 2018).
- [30] Marta Poncela Blanco,. Generation Adequacy Methodologies Review - EU Science Hub - European Commission. EU Science Hub 2016. <https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/generation-adequacy-methodologies-review> (accessed December 3, 2018).
- [31] Shiwen Y, Hui H, Chengzhi W, Hao G, Hao F. Review on Risk Assessment of Power System. *Procedia Computer Science* 2017;109:1200–5. <https://doi.org/10.1016/j.procs.2017.05.399>.
- [32] Haringa GE, Jordan GA, Garver LL. Application of Monte Carlo simulation to multi-area reliability evaluations. *IEEE Computer Applications in Power* 1991;4:21–5. <https://doi.org/10.1109/67.65031>.
- [33] Doquet M, Fourment C, Roudergues JM. Generation & transmission adequacy of large interconnected power systems: A contribution to the renewal of Monte-Carlo approaches. 2011 IEEE Trondheim PowerTech, 2011, p. 1–6. <https://doi.org/10.1109/PTC.2011.6019444>.
- [34] Mäntysaari P. *EU Electricity Trade Law: The Legal Tools of Electricity Producers in the Internal Electricity Market*. Springer; 2015.
- [35] Hofmann H, Türk A. *Legal Challenges in EU Administrative Law: Towards an Integrated Administration*. Edward Elgar Publishing; 2009.
- [36] Loulou R, Kanudia A. Using Advanced Technology-Rich Models for Regional And Global Economic Analysis of GHG Mitigation. In: Zaccour G, editor. *Decision & Control in Management Science: Essays in Honor of Alain Haurie*, Boston, MA: Springer US; 2002, p. 153–75. https://doi.org/10.1007/978-1-4757-3561-1_9.
- [37] Connolly D, Lund H, Mathiesen BV, Leahy M. A review of computer tools for analysing the integration of renewable energy into various energy systems. *Applied Energy* 2010;87:1059–82. <https://doi.org/10.1016/j.apenergy.2009.09.026>.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

- [38] Loulou R, Goldstein G, Noble K. Documentation for the MARKAL Family of Models. Energy Technology Systems Analysis Programme 2004:65–73.
- [39] Loulou R, Remne U, Kanudia A, Lehtila A, Goldstein G. Documentation for the TIMES Model, PART I: Energy Technology Systems Analysis Programme. International Energy Agency Paris; 2005.
- [40] Loulou R, Remne U, Kanudia A, Lehtila A, Goldstein G. Documentation for the TIMES Model Part II. Energy Technology Systems Analysis Programme (ETSAP) 2005.
- [41] e-Highway 2050: Objectives n.d. <http://www.e-highway2050.eu/objectives/> (accessed November 21, 2018).
- [42] TWENTIES project. WindEurope 2013. <https://windeurope.org/about-wind/reports/twenties-project/> (accessed November 21, 2018).
- [43] TYNDP 2018 n.d. <https://tyndp.entsoe.eu/tyndp2018/> (accessed November 21, 2018).
- [44] ENTSO-E. Mid-term Adequacy Forecast 2018: Methodology and details results 2018. <https://www.entsoe.eu/outlooks/midterm/> (accessed October 15, 2018).
- [45] ENTSO-E. Mid-term Adequacy Forecast Executive Summary 2019. Mid-term Adequacy Forecast Executive Summary 2019 – ENTSO-E n.d. /outlooks/midterm/glossary/ (accessed June 22, 2020).
- [46] European Commission. Transmission system operation with large penetration of Wind and other renewable Electricity sources in Networks by means of innovative Tools and Integrated Energy Solutions | TWENTIES Project | FP7 | CORDIS | n.d. <https://cordis.europa.eu/project/id/249812> (accessed June 22, 2020).
- [47] The Electricity Highways: Preparing the Electricity Grid of the Future n.d. <https://www.entsoe.eu/outlooks/ehighways-2050/> (accessed June 22, 2020).
- [48] Planning the future grid - TYNDP n.d. <https://tyndp.entsoe.eu/> (accessed June 22, 2020).
- [49] Doquet M, Gonzalez R, Lepy S, Momot E, Verrier F. A new tool for adequacy reporting of electric systems: ANTARES. 42nd International Conference on Large High Voltage Electric Systems 2008, CIGRE 2008 2008.
- [50] RTE. ANTARES optimization problemes formulation 2017. <https://antares-simulator.org/media/files/page/UC4V8-170522-Antares-Optimization-Problems-Formulation.pdf>.
- [51] Doquet M. Use of a stochastic process to sample wind power curves in planning studies. 2007 IEEE Lausanne Power Tech, 2007, p. 663–70. <https://doi.org/10.1109/PCT.2007.4538395>.
- [52] Doquet M, Fourment C, Roudergues J. Generation&transmission adequacy of large interconnected power systems: A contribution to the renewal of Monte-Carlo approaches. 2011 IEEE Trondheim PowerTech, 2011, p. 1–6. <https://doi.org/10.1109/PTC.2011.6019444>.
- [53] Riekkola AK, Charlotte Berg, Erik O. Ahlgren, Patrik Söderholm. Challenges in Soft-Linking: The Case of EMEC and TIMES-Sweden - Konjunkturinstitutet. 2013.
- [54] Réseau de Transport d'Electricité. Forecast assessment of electricity supply-demand balance (Bilan prévisionnel de l'équilibre offre-demande d'électricité en France - édition 2018). RTE France 2018. <https://www.rte-france.com/en/article/forecast-assessment-electricity-supply-demand-balance> (accessed January 30, 2019).
- [55] CEER. Assessment of Electricity Generation Adequacy in European Countries 2014. <https://cleanenergysolutions.org/es/resources/assessment-electricity-generation-adequacy-european-countries> (accessed November 21, 2018).
- [56] D. Mills A, Wisner R, Orlando Lawrence E. Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California 2012. <https://doi.org/10.1109/PVSC-Vol2.2012.6656763>.
- [57] Madaeni SH, Sioshansi R, Denholm P. Comparing Capacity Value Estimation Techniques for Photovoltaic Solar Power. IEEE Journal of Photovoltaics 2013;3:407–15. <https://doi.org/10.1109/JPHOTOV.2012.2217114>.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

- [58] Madaeni SH, Sioshansi R, Denholm P. Comparison of Capacity Value Methods for Photovoltaics in the Western United States. National Renewable Energy Lab. (NREL), Golden, CO (United States); 2012. <https://doi.org/10.2172/1046871>.
- [59] Mills A, Wiser R. An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes 2012. <https://emp.lbl.gov/sites/all/files/lbnl-5933e.pdf>.
- [60] IEA. World Energy Model Documentation. 2015. <https://www.iea.org/weo/weomodel/> (accessed October 19, 2018).
- [61] Poncelet K, Delarue E, Duerinck J, Six D, D'haeseleer W. The importance of integrating the variability of renewables in long-term energy planning models. Rome, Italy 2014. https://www.mech.kuleuven.be/en/tme/research/energy_environment/Pdf/wp-importance.pdf.
- [62] Poncelet K, Delarue E, Six D, Duerinck J, D'haeseleer W. Impact of the level of temporal and operational detail in energy-system planning models. *Applied Energy* 2016;162:631–43. <https://doi.org/10.1016/j.apenergy.2015.10.100>.
- [63] Brouwer AS, van den Broek M, Seebregts A, Faaij A. Operational flexibility and economics of power plants in future low-carbon power systems. *Applied Energy* 2015;156:107–28. <https://doi.org/10.1016/j.apenergy.2015.06.065>.
- [64] Seljom P, Rosenberg E, Schäffer LE, Fodstad M. Bidirectional linkage between a long-term energy system and a short-term power market model. *Energy* 2020;198:117311. <https://doi.org/10.1016/j.energy.2020.117311>.
- [65] Li X, Maïzi N, Mazaauric V. A lattice-based representation of power systems dedicated to synchronism analysis. *International Journal of Applied Electromagnetics and Mechanics* 2019;59:1049–56. <https://doi.org/10.3233/JAE-171300>.
- [66] Daly P, Flynn D, Cunniffe N. Inertia considerations within unit commitment and economic dispatch for systems with high non-synchronous penetrations. 2015 IEEE Eindhoven PowerTech, 2015, p. 1–6. <https://doi.org/10.1109/PTC.2015.7232567>.
- [67] Cardozo C. Optimisation of power system security with high share of variable renewables : Consideration of the primary reserve deployment dynamics on a Frequency Constrained Unit Commitment model. 2016. https://www.researchgate.net/publication/301580170_Optimisation_of_power_system_security_with_high_share_of_variable_renewables_Consideration_of_the_primary_reserve_deployment_dynamics_on_a_Frequency_Constrained_Unit_Commitment_model.

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.

Annex A: Feed-back loop results for the first set of simulations

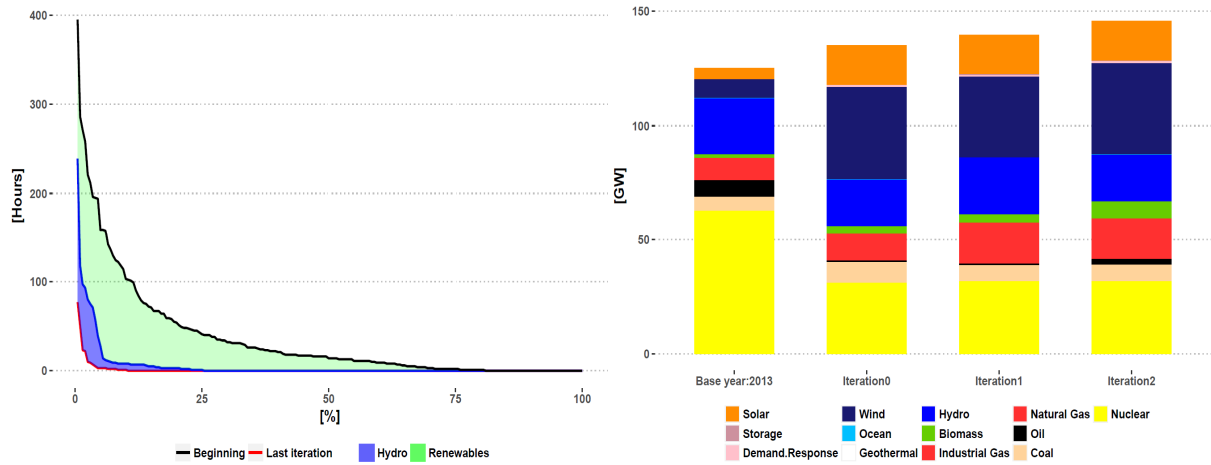


Figure A 1: Loss of Load Duration curve evolution over iterations Figure A 2: 2030 Power generation mix over iterations

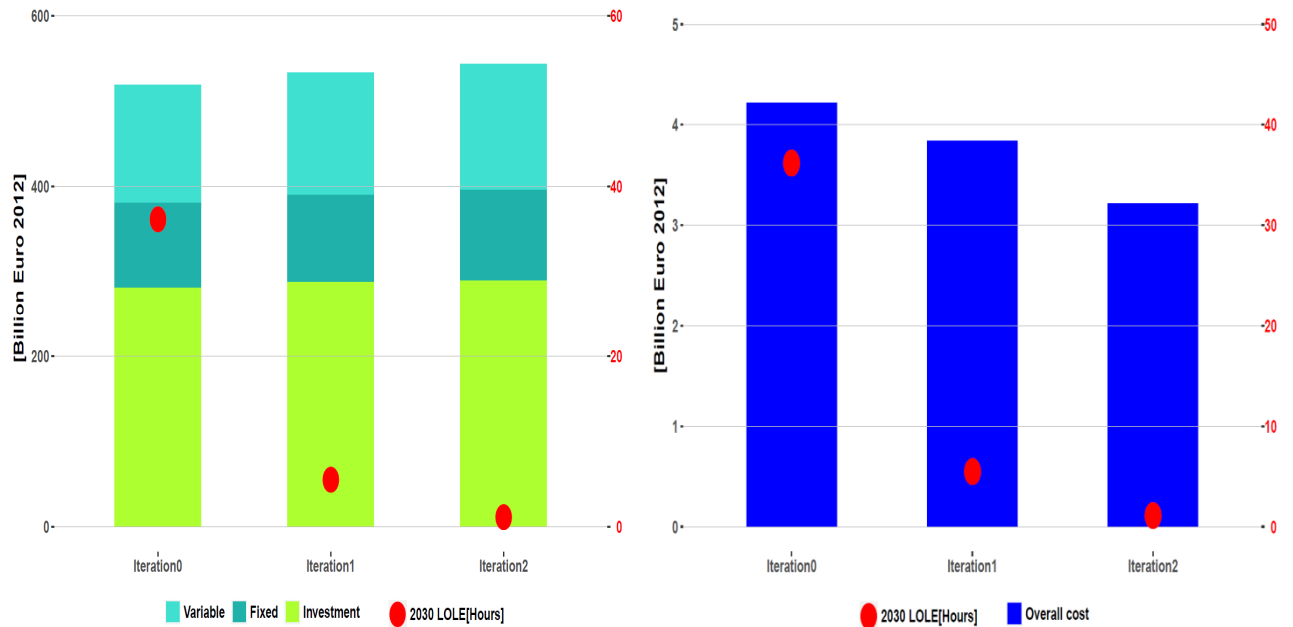


Figure A 3 : Total discounted cost over iterations (2013-2050) Figure A 4: 2030 Overall operational costs over iterations

The short version of the paper was presented at ICAE2019, August 12-15, Västerås. This paper is a substantial extension of the short conference paper.