Classification and Comparison Criteria for Generation Production Cost Models

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Abstract

The main objectives of production cost models are the evaluation of future system operation, the scheduling of generation at minimum cost, and the coordination of the use of limited resources. Since it is not possible to represent all aspects of the operation of a power system in much detail, depending on the intended application and the nature of the system, some compromise is always needed, so that certain aspects are emphasized at the expense of others. A taxonomy of potential model options and capabilities with their associated computational burden, estimated incurred errors and other factors is of much help in the complex task of model functional specification. Based on the experience of development and analysis of several production cost models for actual large-scale power systems, this paper presents a methodology that can be systematically applied in production cost model specification: any potential model is classified according to its scope and class of formulation with a meaningful set of attributes; a number of criteria have been chosen to establish comparisons between alternative options; the criteria have been numerically examined in the context of the Spanish power system. Trends and directions for research in generation production cost models are also commented.

Keywords – *Power Generation Planning, Generation Production Cost Models, Classification Attributes, Comparison Criteria, Large-scale, Optimization, Simulation, Probabilistic, Deterministic, Stochastic.*

1 Introduction

Variable generation cost represents a great portion of the cost of electricity supply. Hence, it is very important to predict it correctly so that medium term operations are accurately planned. This task is carried out by production cost models. Their main objectives are the evaluation of future system operation, the scheduling of generation at minimum cost subject to operation constraints, and the coordination of the use of limited resources. The models must represent the relevant decision variables and the real operation of the power system adequately.

Unfortunately, with the present state-of-the-art no single model can cover all aspects of interest in production costing, which range from strictly generation cost computations [18, 39], to reliability calculations [6, 7, 16, 17, 35, 51], and from models used in generation expansion planning, [34, 49], to detailed short term evaluations [2, 25]. Depending on the particular system and the specific application of interest, models may or not accurately represent the demand curve, technical minima of thermal units or the complexity of hydroelectric generation, among other issues. There are also options available at the methodological level: simulation of predefined operation strategies may be preferred to optimization approaches, or viceversa.

From this perspective, it is believed that a taxonomy of potential model options and capabilities with a critical comparative evaluation of their associated computational burden, estimated incurred errors and other attributes, can be of much help in the task of model functional specification. Based on the experience of the authors in the development and analysis of several production cost models for actual large-scale power systems, this paper presents a methodology that can be systematically applied in production cost model specification: any potential model is classified according to its scope (section 2) and class of formulation (section 3) with a meaningful set of attributes that are used to define the main families of models (section 3.1); a number of criteria have been chosen to establish comparisons between alternative options and some interesting numerical results have been obtained in the context of the Spanish electric power system (section 4). Trends and directions for research in generation production cost models are also commented (section 5).

2 Classification of Production Cost Models: Functional Scope

Three main criteria are used in this section to broadly classify production cost models according to their scope in the representation of the system: level of detail in network modelling, relevance of hydro generation and temporal horizon of concern.

According to the level of detail in *network* representation, the models can be classified into the following types, see [7]:

1. *Generation. Hierarchical Level I*

   - *Monoarea*

     It is assumed that all the generators and demands are connected to the same node. The transmission system is totally ignored. These models are mainly used for generation production costing.

   - *Multiarea*

     Several systems are now considered, each one with its independent dispatch, connected by tie lines allowing certain level of support (e.g., shared spinning reserve, emergency reserve). These models are commonly used to analyze power transfers among utilities, to determine differences in generation with and without dispatch coordination, and to evaluate the economic benefits of interconnections. See [1, 28, 36, 42, 44, 45, 51] for instance.

2. *Generation-Transmission. Hierarchical Level II*

   Both generators and transmission facilities are explicitly included. These models are typically used in operation and planning studies where it is explicitly wanted to evaluate the impact of the network on the results. See [4, 5, 15, 16, 17, 32, 35, 38] as medium term planning tools and [49] as a long term planning tool.

Another classification can be made according to the relevance of the*hydro subsystem* in the model, see [33]:

1. *Thermal*

   These models are addressed to deal with the thermal subsystem operation in detail, although they may include a simplified version of the hydro subsystem. They are most suitable for systems with a comparatively small part of hydro generation.

2. *Hydrothermal Coordination*

   These models are designed to analyze the interrelation between the hydro and the thermal subsystem. Typically, they optimize the operation of the hydro plants in multiple periods, where the economic behavior of the system with respect to the amount of hydro generation is separately obtained. Now the hydro subsystem modelling level is detailed. The objective function is the minimization of variable generation costs (or maximization of hydro dual prices). See [10, 13, 21, 46, 48] for example.

3. *Hydro*

   These models exclusively optimize a hydro subsystem, without interaction with other subsystems. They are normally used to schedule hydro generation in the short term. The objective function can be minimization of risk of spillage or evaporation, or maximization of hydro units performance. See [14, 20, 37].

These three models may also be used in conjunction. The first one determines the thermal subsystem operation. A hydrothermal model is used to refine the hydro operation considering the hydro subsystem in more detail. Both thermal and hydrothermal models must deal with the whole generation system. A strong coordination and an iterative procedure between them are needed. The third model is used to implement the optimal policies defined by the other two in each one of the hydro basins.

The third classification criterion regarding the scope of the model is the time horizon of concern. Production cost models can be used to analyze snapshots of system behavior (e.g. peak load conditions), to plan daily or weekly operation or to evaluate an entire year. Of course the modelling emphasis varies much from one application to another: unit dynamic response and start-up costs are relevant in the very short term level, while fuel purchases and scheduled maintenance have to be accounted for in annual studies.

For the sake of simplicity, the rest of the material in this paper only refers to purely generation models, for the medium term operation range (i.e., time horizon of about 1 year) and with little emphasis on hydro generation. Most of the concepts presented in this paper can be easily extended to the other model categories.

3 Classification of Production Cost Models: Formulation

This section reviews the basic approaches to formulation of the production cost problem. The mathematical algorithms and the computer implementation of the models critically depend on their formulation. To clarify the issues, a streamlined prototype version of a production cost model is presented next. At the core of any production cost model there are always some basic ingredients: the cost function to be evaluated (and minimized in the vast majority of the models), the decision variables representing the operational degrees of freedom whose value must be chosen trying to achieve the best possible operation, and the constraints that the system has to meet (they include the equations that describe the systems behavior, such as the load flow equations).

- *Objective function*

  Variable production costs plus unreliability cost (cost of non-served energy to consumers) during the considered time horizon.

- *Operational constraints*

  At least the following constraints must be met:

  1. Generation limits for each unit.
  2. Global technical minima constraint: The sum of the technical minima of all committed units cannot exceed the minimum demand.
  3. Maximum demand constraint: Balance equation between generation and demand (served and unserved demand).
  4. Reserve margin constrain:. Provision for some operational reserve margin.

  Constraints encompassing the entire time horizon being considered may also be included:

  1. Priority or limitation in fuel consumption.
  2. Total hydro inflows along the time horizon.

- *Decision variables*

  For each time interval being considered, a value has to be determined for the decision variables that define the system operating conditions:

  1. Commitment status of each unit.
  2. Power generation of each unit.
  3. Unserved demand.

For any given time interval, one possible (and simple) mathematical formulation of the previous verbal problem statement may be as follows:

$$\min \sum_{i=1}^{I}\sum_{k=1}^{K} v_k t_{ik} d_i + \sum_{i=1}^{I} w u_i d_i$$

subject to:

$$\underline{T}_{ik} c_{ik} \leq t_{ik} \leq \overline{T}_{ik} c_{ik}$$

$$\underline{H}_{il} c_{il} \leq h_{il} \leq \overline{H}_{il} c_{il}$$

$$\sum_{k=1}^{K} \underline{T}_{ik} c_{ik} + \sum_{l=1}^{L} \underline{H}_{il} c_{il} \leq \underline{D}_i \qquad i = 1 \dots I$$

$$\sum_{k=1}^{K} t_{ik} + \sum_{l=1}^{L} h_{il} + u_i \geq \overline{D}_i \qquad i = 1 \dots I$$

$$\sum_{k=1}^{K} \overline{T}_{ik} c_{ik} + \sum_{l=1}^{L} \overline{H}_{il} c_{il} + u_i \geq \overline{D}_i (1+R) \qquad i = 1 \dots I$$

$$\sum_{i=1}^{I}\sum_{l=1}^{L} h_{il} \leq H^o$$

where t_{ik} and h_{il} are the generation outputs of thermal unit k and hydro unit l in period i; c_{ik} and c_{il} are the commitment decisions on the units; u_i is the unserved demand in period i. All of them are variables; v_k represents the generation variable cost of unit k; w is the unserved demand cost; d_i is the duration of period i; $\underline{T}_{ik}$ and $\overline{T}_{ik}$ are the minimum and maximum thermal generation outputs of unit k in period i; $\underline{H}_{il}$ and $\overline{H}_{il}$ are the minimum and maximum hydro generation outputs of unit l in period i; $\underline{D}_i$ and $\overline{D}_i$ are the minimum and maximum demands of period i; R is the reserve margin and H^o is the total hydro inflow over all periods.

In general, this optimization problem is *nonlinear* (demand, cost functions), *stochastic* (generation availability, demand, hydro inflows), and *integer* (commitment of each unit).

Production cost models may be hierarchically decomposed to facilitate their solution. The approach that is most frequently used consists of dividing the time horizon into *periods* that are handled separately. Each period is characterized by a specific set of external conditions (e.g., demand, or the set of available generation units). A typical period for a time horizon of 1-2 years may be one week or one month; or perhaps shorter at the beginning and longer at the end of the time horizon.

The basic core structure that has just been presented, is shared by any production cost model, which will be now classified into families according to the class of formulation that is chosen to represent the reality of a power system. Three independent attributes (coordinates), see figure 1: *uncertainty*, *intraperiod decisions* and *interperiod decisions* are used to define the class of formulation.

According to the approach that is adopted to represent *uncertainty*, models can be classified into: *Probabilistic* or *Deterministic*. In an electric power system, generation, demand and hydro inflows are stochastic parameters depending on external factors. A deterministic model considers some kind of average values for the uncertain parameters; therefore the model itself intrinsically ignores stochasticity. A probabilistic model explicitly represents uncertainty, in any of many possible ways. Many probabilistic models use techniques of aggregation of properly weighted scenarios or "uncertainty states"; the scenarios are typically obtained by enumeration or simulation. When the models are simple, it is possible to use analytical approaches to avoid dealing with one scenario at a time; the well known method of probabilistic simulation, see [3, 8], falls into this category.

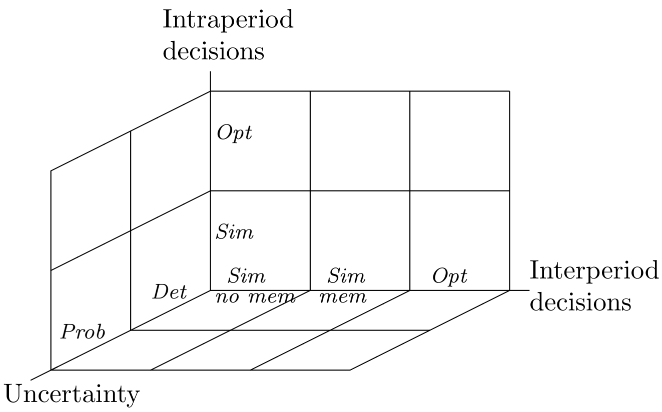

Figure 1: Classification attributes of generation production cost models.

The second attribute of classification according to formulation concerns how operation decision-making is represented within a given period (the complete time horizon is assumed to have been divided into periods, where decisions are made internally for each one of them: loading order of units, unit commitment, etc). *Intraperiod decisions* can be formulated as an *optimization* problem or as a *simulation.* An optimization problem formulates the system operation within each period as the mathematical problem of finding the optimal set of values for the decision variables that maximizes or minimizes an objective function subject to constraints as the ones formulated previously. On the other hand, simulation models determine heuristically the decision variables (or accept externally provided values for them) and obtain from them the desired features characterizing the performance of the system. As this is a simpler task than optimization, the accuracy in the representation of the operation of the system can be much higher. Typically optimization models are used to determine the critical decision variables within a period, while simulation models can be used later to improve the accuracy of the results, particularly regarding uncertainty or detailed aspects of modelling, such as in hydro generation systems.

The third basic attribute that defines the formulation concerns how *inter-period decision-making* (e.g., maintenance scheduling, yearly hydrothermal coordination, fuel purchases) is represented. It should be recognized that these decision variables couple the operation of each period to one another≪s. The basic issue now is how to model *dependency* among time periods. Interperiod decisions can alternatively be formulated as an *optimization* problem encompassing all the periods (this is a full representation of dependence, e.g., limited hydro resources are allocated to each period in an optimal way), or as a *simulation with memory* which recurs to simpler methods than optimization to determine the inter-period decision variables, but takes into account the effects that the operation of one period has on the following ones (e.g., water remaining in the reservoirs for future periods depends on previous generations and inflows), or finally dependence among periods may be ignored, just by treating them as independent, which is termed here as *simulation without memory.*

3.1 Realizations and challenges.

Although every combination of attributes is possible theoretically, there are combinations that have proved difficult to obtain. For example, both the probabilistic treatment of uncertainties and the optimization of intraperiod variables are computationally demanding. This is why probabilistic optimization models are not common. This is even more so for probabilistic models with interperiod optimization. These almost unchartered regions in the 3-dimensional space of figure 1 clearly show the directions for further research (see section 5).

The historic evolution of generation production cost models has presently converged to two main families:

- *deterministic optimization* (at interperiod and/or intraperiod levels).
- *probabilistic simulation* models, which may be further classified according to the demand representation and ensuing implications:
  - non chronological demand or load duration curve, typically resulting in the well known *probabilistic simulation models.*

    Probabilistic simulation models are based on the Booth-Baleriaux technique [3, 8]. They consider stochasticity in demand and generation. Only recently, stochastic hydro inflows have been also considered, see [53]. They do not optimize the intraperiod decisions (e.g., they may use heuristic criteria to obtain the loading order), although they may optimize the pumped energy [12], and simulate without memory the interperiod decisions. These models have become many popular and are used everywhere.
  - chronological demand, yielding the so called *stochastic*[1] *simulation models*)

    Stochastic simulation models, which may use either next-event or fixed- increment time advance mechanisms, explicitly consider uncertainty, simulate the intraperiod decisions and also simulate with memory the interperiod decisions.

The following list includes some of the existing commercial-grade generation models that are known to the authors:

[1]This word is usually reserved for chronological models.

- deterministic optimization models:

  SIMON [52] and CODENE-MODEX [23]

- probabilistic simulation models:

  ORSIM [39, 50], SYSGEN [18], PROSIMO [22], EGEAS [34], and UPLAN [30]

- stochastic simulation models:

  POWRSYM [2], BENCHMARK [25], and UPLAN-C [31]

4 Comparison criteria

This section is devoted to establish a basis for the comparative evaluation of the different production cost models for large generation systems. Most of the capabilities and weakness of the models are a direct result of the choice of the functional scope or the class of formulation; others still depend on additional features, such as the particular optimization algorithm or additional modelling detail. The proposed systematic comparison will be based on a reduced list of criteria; alternatively, these criteria may be used when preparing the functional specification of a model, to arrive at conclusions about scope, formulation and modelling emphasis.

The adopted criteria can be classified into three categories: modelling capabilities, ability to produce certain results and computational burden. They are depicted in table 1. In the following subsections, comments are provided for each criterion; these comments are the result of the experience of the authors in developing and applying several production cost models to the Spanish electric system (appendix 1 summarizes the characteristics of the Spanish system, and a detailed description of this work can be found in [40]).

4.1 Representation of the plants loading order

The loading order and commitment status of the thermal units are the most important intraperiod decisions. The problem with them is that, except for the trivial cases where the strict economic order is possible, it is very difficult for the existing algorithms to represent the actual operation of a generation system in an efficient way. It must be realized that, whenever a thermal unit is committed, its generation must be at least equal to its minimum technical load. This creates difficulties because at all times it requires an explicit definition of the committed units and also of the decisions to be made when a committed unit is forced out. Moreover, it has to be checked that the total sum of the technical minima does not exceed the off peak load. The loading order is also related to other operational requirements, such as the thermal and hydro operational reserves. Taking into account start-up and shut-down costs further complicates the situation.

Comparison criteria	
Plants loading order	∗ one/several loading orders
	∗ loading order constraints
Thermal subsystem	∗ aggregation level
	∗ stochasticity
	∗ weekend shutdown
Hydro subsystem	∗ aggregation level
	∗ interperiod management
	∗ stochasticity
Pumped storage subsystem	∗ interperiod management
Reliability measures	∗ probabilistic
	∗ deterministic
Demand	∗ numerical approximation
	∗ analytical approximation
	∗ linear approximation
Maintenance scheduling	∗ economic criterion
	∗ reliability criterion
Sensitivity analysis	
Computational effort	

Table 1: Comparison criteria for generation production cost models.

To evaluate the quantitative implications of this problem, the authors have recently developed a *probabilistic optimization* model with benchmarking purposes, see [41]. It optimizes the loading order of the thermal units for any availability state of the system obtained by Monte Carlo simulation (combined with variance reduction techniques). This model, although needing more computing time than probabilistic simulation models or deterministic optimization models, still has reasonable computational requirements for some applications and captures all the realistic constraints related to the loading order of the units.

Usually, deterministic optimization and probabilistic simulation models use only one loading order, regardless of the demand level or the unit availability status.

Two types of errors associated with loading order decisions have been examined (see [41] for further details; the quantitative conclusions correspond to studies on the Spanish power system):

1. Only one loading order is considered.

   This approach usually separates the units in committed and uncommitted. The main consequences caused by this assumption are:

   - important errors in utilization factors of the units (up to 0.44). Technical minima of committed units have too large utilization factors, while the opposite is true for uncommitted units.

   - the a priori division of the set of units into two frozen subsets regarding unit commitment, introduces an artificial step in the utilization factors of the units.

2. Constraints associated with loading order (e.g., sum of technical minima must not exceed minimum demand) are ignored although they are binding.

   The main errors are:

   - units with higher technical minima actually produce less energy than if the constraints are ignored. The differences in utilization factors of the technical minima of the units can reach 0.8 if the constraints are very restrictive.
   - total production costs increase exponentially with respect to the allowed excess of technical minima total capacity over the minimum demand, reaching 21 % if no excess is allowed.
   - in an approximate manner it can be concluded that the utilization factor of a unit is inversely proportional to the product of its technical minimum coefficient times its variable cost if the technical minima constraint is very tight. Units with very similar variable costs can have very different utilization factors because of this constraint.

4.2 Representation of the thermal subsystem

A full representation of a thermal unit may consist of an individual model, with several loading blocks (the first one is the minimum load block), each one with a different variable running cost and mean availability. In addition, technical and economic characteristics of unit start-up and shut- down can be included; this requires a corresponding division of the time periods into subperiods.

In cruder models "technologies" can be used instead of individual generators. This has the computational advantage that the number of decision variables is drastically reduced and integer variables are avoided. Obviously the information about individual units is lost. These models are useful for strategic studies about future global performance of the system or comparisons between technologies. Note that the simplifications in formulation can be exploited to increase other modelling features (e.g., optimization of interperiod and/or intraperiod decisions).

A deterministic treatment of the uncertain availability of thermal generation units causes important errors. Those observed for the Spanish system are:

- important errors in utilization factors (up to 0.25). They are positive for the first units of the loading order and negative for the last ones.
- total variable production cost is 2.2 % lower in the deterministic case.

4.3 Representation of the hydro subsystem

For the purpose of these models, the hydro subsystem can be grouped into subbasins and basins with homogeneous hydrological characteristics. Some criteria to validate the aggregation of hydro subsystems are presented in [43].

Stochastic inflows and their influence in medium term policies should be considered.

4.4 Pumped storage subsystem

Energy can be pumped and stored with two criteria: one, for *reliability purposes* and the other, for *economic reasons*. In systems with enough hydro power, only the second is relevant.

The pumping-storage-generation cycle can be *diary*, *weekly* or even *seasonal* as in the Spanish system. The two first cycles can determine the division of periods further into subperiods and the seasonal cycle causes dependence among periods.

The main modelling issue is the optimization of the energy to be produced by pumped storage units.

4.5 Demand representation

When demand is represented by means of the load-duration curve, several approximations are possible: *numerical* (or piecewise linear), *analytical* (cumulant method is the best known), *linear* (i.e., several blocks with the same demand, for linear optimization models). Other recent analytical approximations include: mix of normals, large deviation, equivalent energy function, fast Fourier transform, discrete convolution, segmentation method, etc. See in [29] a comparison among analytical methods, regarding their speed and accuracy.

The numerical approximation is usually considered as a benchmark and, although requiring more computer time, it cannot be considered excessive in most applications of production cost models. In very large systems, numerical instability problems may appear, see [9], but there are means to alleviate them [19].

The analytical approximations are focused on improving computer time while keeping enough accuracy in the representation of the load-duration curve. They are necessary in production cost models that have to be used very heavily, as for instance in generation expansion planning tools.

4.6 Ability to incorporate maintenance scheduling

A survey of the methods used for maintenance scheduling is found in [26]. It can be done by *economic criterion* (when the decisions on scheduled maintenance are embedded into the production cost model) or by *reliability criterion* (when only reliability measures are used to determine the maintenance schedule). Because of its simplicity, the latter is the most commonly used, see [34, 47]. The economic criterion implies more interdependence among periods, see [23]. In systems with a hydro component, maintenance scheduling is coupled to yearly hydrothermal coordination, resulting in a complex problem of very large dimension; frequently the coupling is disregarded and maintenance scheduling is determined first.

4.7 Capability to obtain reliability measures

Although production cost models are not specifically designed to compute reliability measures, these can be obtained as a byproduct. They are *adequacy* indexes that measure the existence of enough generation to satisfy future demand, see [6, 7]. The term adequacy is related to static conditions, excluding transients between system states and including only generation stationary situations.

These reliability measures should be considered only as relative indications, useful for comparison of different system conditions. In systems with a significant hydro component the computation of reliability measures is more involved, because of the difficulty in representing the response capability of hydro units in providing reliable operational reserves in case of thermal unit failure. Besides, the uncertainty in hydro resources has to be also considered.

For the most part, reliability measures are used in maintenance scheduling algorithms, see [26], or as indicators representing expected system performance.

4.8 Sensitivity analysis

As an additional method of assessment of the uncertainties affecting the operation of the system, it is very convenient that production cost models may allow the realization of sensitivity analysis with respect to the decision variables. Sensitivities are easy to compute in optimization models, as a byproduct of the optimization algorithms, while they have to be calculated analytically in probabilistic simulation models, see [11] for example.

4.9 Computational effort

Within reasonable limits, computer time is not a critical parameter in most applications of production cost models. However, the choice of formulation results in widely different computation requirements. Roughly speaking analytical simulation models require seconds, optimization models need minutes and Monte Carlo simulation models spend hours.

5 Conclusions and directions for research

The classification of production cost models that has been proposed and discussed in the present paper, shows the complete range of existing possibilities, some of which are still unexplored. This provides hints on future directions of research, where the effort should concentrate, and what rewards are to be expected.

Some lines of improvement for the currently available and prevailing families of models can be suggested:

- For probabilistic simulation models, it is suggested to include (exact or approximately) multiple loading orders, embedded into their efficient convolution algorithms, as well as providing a stochastic treatment of hydro inflows in each period.

  Another desirable feature would be the capability to optimize hydro energy generation among periods and also to be able to perform optimal maintenance scheduling. The work in [24, 27] follows these directions.

- For deterministic optimization models, it is suggested to introduce a stochastic treatment of generation availability, which may be possible with the use of decomposition techniques. In this way, the problem would be divided into a master problem and many subproblems (dealing each one with an availability scenario). In conjunction, variance reduction techniques (importance sampling, for example) could be applied to reduce the number of scenarios to be considered. An interesting application for generation and transmission planning can be found in [49].

Classifying attributes and comparison criteria have been presented for production cost models that are meant for application within a traditional regulation setting. Presently, the electric utilities in many countries are experiencing regulatory changes in the direction of unbundling the supply services (generation, transmission and distribution) and introducing competition in generation.

New information and responses will be demanded from production cost models in these new environments. Spot prices (time and location- dependent short term marginal costs of electricity), time-varying cost of generation, different dispatching strategies (bidding-price-oriented instead of generation-cost-oriented), scheduled or unscheduled interchanges among utilities are new issues that production cost models will have to cope with. So far it seems more a question of adaptation, emphasis and capability improvement, rather than radical changes in the conception of the models. The traditional paradigm of minimizing production cost subject to operation constraints has not been altered, although it may be disguised with a different attire.

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Appendix 1

According to data extracted from 1991 statistical records, the Spanish power system met a maximum peak load of 24393 MW and a yearly energy demand of 138230 GWh. The installed generation capacity is 41960 MW (16060 MW are hydro, 10590 MW coal, 7970 MW oil/gas and 7340 MW nuclear). The transmission network includes 12830 km of 400 kV and 15060 km of 220 kV.

There are about 65 thermal generators (9 nuclear, 35 coal and the remaining oil/gas). Their production is about 82 % of the total generation.

There are 60 hydro units with capacity greater than 5 MW and annual energy production greater than 100 GWh, that can be grouped into about 10 basins. The maximum capacity at the same location is 915 MW. They produce as an average about 18 % of the total generation, ranging in between 13 % and 28 %, depending on the hydrology.

There are several pumped storage units, but their impact on annual energy production is minimum (about 1 %).