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Synthesis of Mechanical Driver and Power Generation Configurations, Part 1: Optimization Framework

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This article presents a novel, systematic, and robust procedure for driver and power plant selection based on mathematical programming. The discrete nature of gas turbines is considered as gas turbine drivers and gas turbine-based power plants are selected from a group of candidates. Plant availability with considering parallel compression has also been included, which allows a more comprehensive exploitation of the trade-offs between capital costs, operating costs, and availability. When neglecting process heating and any steam equipment, the formulation can be applied to heavily power dominated processes, such as LNG. However, a more comprehensive formulation, allowing waste heat recovery and the integration with a multilevel steam system, is also proposed to produce more thermally efficient systems. This approach proved to be flexible and robust and is the first in producing solutions ranging from no-steam to all-steam systems, including all-gas turbine, all-motor and hybrid gas turbine/motor/steam systems. © 2010 American Institute of Chemical Engineers *AIChE J,* 56: 2356–2376, 2010
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Introduction

A novel superstructure-based approach for driver and power plant selection based on mathematical programming is presented in this article. The detailed problem formulation for synthesis and optimization is described, showing the multiple functionalities of the optimization model and how these can be applied to problem analysis. LNG processes are of particular interest because of the very large power demands that result from providing refrigeration between ambient temperature and typically $-160°C$. Furthermore, LNG is nowadays rapidly increasing its share in the global energy market and is today the object of enormous investment and engineering activity, with countries such as Qatar, Nigeria, Australia, Trinidad and Tobago and Egypt seriously committed or committing as global suppliers. High energy prices and the increasing worldwide preference for cleaner fuels have accelerated the monetization of gas reserves.

Previous work

Plenty of work has been published in relation to the synthesis and design of utility systems, dealing with electricity generation, process heating and, in some cases, driver selection. Some approaches are based purely on thermal performance, focusing on optimizing the energy efficiency of the system. Although rich in thermodynamic insights, capital-energy trade-offs are not considered in these methods and, consequently, the resulting solutions are often not economically attractive in practice, even when energy costs are dominant.[1,2]

Mathematical programming allows the automated design of processes at the conceptual level. Mixed integer programming has been particularly useful, as it is able to handle discrete design decisions. Process synthesis approaches based on mathematical programming are usually based on a

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superstructure in which all the potential process alternatives are contained and from which the optimization algorithm will identify the best combination. Thermodynamic insights have usually a lower priority. Papoulias and Grossmann[3] introduced the Mixed Integer Linear Programming (MILP) approach to the synthesis of utility systems. Although in principle the problem formulation would result nonlinear, simplifications such as linearized cost functions and fixed operating conditions were made to make it linear. This work proved the strength of mathematical programming applied to the synthesis of utility systems and its advantage over heuristic-based approaches regarding the optimality of the solutions and the capacity to properly consider capital-energy trade-offs. On the basis of the work by Papoulias and Grossmann,[3] Bruno et al.[4] formulated the same problem in a Mixed Integer Nonlinear fashion (MINLP), in an attempt to provide greater accuracy.

Petroulas and Reklaitis[5] opted for decomposing the design problem into two subproblems, namely steam header selection and driver allocation. The overall objective was to minimize a linear combination of operating costs. This work introduced a discretization technique which allowed a choice of steam pressure levels from a set of candidate pressures in a linear fashion. No capital costs, electricity trading, or gas turbines were considered.

Colmenares and Seider[6] proposed a Nonlinear Programming (NLP) strategy for the synthesis of utility systems that satisfy the heating and power demands of a process. Their superstructure consists on a cascade of simple Rankine cycles operating in several temperature intervals which are dictated by the temperature levels at which heat is required by the process. The objective of the optimization was defined as the minimization of either the cost of external utilities or the annualized cost of the utility system (capital and operating costs). However, Colmenares and Seider[6] did not address the problem of driver selection and did not consider gas turbines or electric motors as options in their superstructure. Also, because of the nature of the NLP model, there is no option for choosing among different steam turbine configurations. Electricity trading was not allowed.

Some of the equipment used in utility systems are discrete in nature (e.g., gas turbines and associated power plants). This is reflected in the form of a set of available sizes, performance, and costs. Using continuous functions (e.g., from data regression) for these items would be inappropriate. If standard models with capacities higher than those given by synthesis results are adopted, the optimal conditions might be lost because the consequent higher costs and performance variations have been neglected. Thus, it is critical that these discrete variables remain discrete in the formulation of the problem.

Maia et al.[7] were the first in considering standard equipment sizes in the synthesis of utility systems. Their approach was based on a simulated annealing algorithm able to handle discrete variables and discontinuous cost functions. Their method allowed steam turbines and electric motors as mechanical drive options although not gas turbines. Only one mechanical demand was allowed per driver and vice versa. Although the approach is able to handle discrete equipment sizes (e.g., gas turbines), as defined by the designer before the optimization, their costs and efficiency are obtained by using continuous correlations. In this way, the strength of the standard equipment approach is not fully exploited since cost and efficiency are unique for each gas turbine model in the market and do not follow a regression approximation in a satisfactory way.

Wilkendorf et al.[8] addressed the supply of heat, power, and cooling to processes, electricity export and import and fuel selection. The formulation allowed for the minimization of combined capital costs and operating costs. They did not show how to tackle the problem of driver selection. As in the case of Maia et al.,[7] Wilkendorf et al.[8] used standard equipment sizes with continuous capital cost data. The problem was formulated as MINLP and solved with a simulated annealing algorithm to overcome local optima.

Maréchal and Kalitventzeff[9] tackled the synthesis of utility systems with a three-step procedure. The first step addresses the optimization of a generic superstructure considering rough equipment performance and costs by use of an MILP formulation. The second step identifies a set of suitable equipment able to satisfy the recently identified requirements and considers standard sizes where applicable. The third step reintroduced the equipment choices from the second step to the superstructure to obtain several alternative configurations via optimization. There are two main drawbacks of this decomposition strategy. First, the inaccuracies from using typical equipment efficiency and cost functions in the first step will influence and may well mislead the standard equipment selection performed in the second step. Second, since the equipment costs are not considered until after a screening based on preset rules is made (in step two), there is a bias toward favoring high-efficiency units over less efficient but cheaper ones. Also, the problem of mechanical driver selection was not addressed.

Shang[10] proposed another superstructure-based formulation for the synthesis of utility systems. This work considered multiple operating periods to account for seasonal and other scheduled variations of the energy demands and equipment performance. The MILP optimization is performed on a reduced superstructure, which is generated after an initial screening of various design alternatives based on energy efficiency and features only the most efficient options. This screening will inevitably bias the final solutions toward the higher end of energy efficiency, therefore not fully exploring the capital-energy trade-off. A discretization method is proposed to identify the sizes of the candidate steam and gas turbines. Turbine sizes are not discretized to match standard equipment available in the market but to avoid nonlinearities in the problem formulation. Their performance and cost are still dictated by data regression models. There are no mechanical drive considerations.

Later, the method by Varbanov[11] allowed for simultaneous steam level selection and utility system design and operation under multiple time periods. The original MINLP nature of the problem is tackled by alternating MILP optimizations with rigorous nonlinear simulations, resulting in a successive mixed integer linear approach (SMILP). The data required by the initial MILP optimization are obtained by applying a superstructure initialization procedure, which is based on even more approximate models to produce an initial solution to the problem. However, by so doing, there is a risk that the initial solution might produce a bias in the final solution. Also, like in many of the previous approaches, the allocation of mechanical drivers was not addressed and the gas turbine costs and nominal performance are represented by continuous functions.

Frangopoulos and Dimopoulos[12] addressed the synthesis and multiperiod optimization of cogeneration systems by maximizing the net present value of the investment considering capital, operating, and availability costs. The latter was incorporated as a penalty representing the estimated production loss when the energy needs of the process are not covered due to equipment failure. The problem formulation was MINLP. By incorporating availability in the objective function, their approach benefits from the capacity of trading-off capital costs, operating costs, and lost production. However, the system superstructure is very limited, which restricts the applicability of this approach. There are no steam turbines and gas turbine generators without heat recovery are not possible. Mechanical power demands are not supported and the gas turbines are represented as continuous in size with their costs and performance parameters from data regression.

More recently, Aguilar[13] proposed an MILP formulation for the synthesis of utility systems with driver allocation and multiperiod considerations. Steam turbines, gas turbines, and electric motors were all mechanical drive options. The equipment sizes and loads for each operating period were optimized simultaneously and the best maintenance scheduling for the equipment in the system was also obtained. Availability issues were addressed by implicitly optimizing the degree and type of equipment redundancy during the synthesis stage, although availability did not actually contribute to the objective function. Instead, the synthesis of the system was constrained in such a way that it was forced to overcome a set of input failure scenarios (i.e., always satisfying the energy demands). However, the designer is left with the responsibility of defining these failure scenarios (in the form of special operating periods) in advance of the optimization. Furthermore, the redundancy considerations were limited to steam and electricity generation but no indication was provided as to how to design the system so that it can overcome or mitigate the impact of mechanical drive failures. As in other approaches only one mechanical demand per driver was allowed, although the combination of two drivers to run a single demand was supported. Standard gas turbine sizes were not considered and their cost and performance were modeled as continuous functions.

Other approaches that have tackled the synthesis of utility systems with multiperiod considerations are those by Maia and Qassim,[14] which extended the formulation by Maia et al.[7] and Iyer and Grossmann,[15] with a further extension later by Oliveira and Matos,[16] and also Maréchal and Kalitventzeff,[17] based on the main strategy by Maréchal and Kalitventzeff.[9] However, the more frequent limitations already discussed still persist in these approaches; only steam-based utility systems, lack of flexibility when addressing mechanical driver allocation, no use of gas turbine drivers and helper motors, use of continuous cost and performance functions for gas turbines (except by Maréchal and Kalitventzeff[17]) and no availability considerations in the objective function. Also, there are further inherited limitations in the cases of follow-up papers.[14,17]

In most of the approaches discussed for the synthesis of utility systems, a steam system is playing the central role as the energy supply through steam generation and its distribution is assumed to be more efficient than systems without steam being present. Gas turbines were included in some cases as an option for electricity generation and for heat recovery from their exhaust, but not for mechanical drive service except in Aguilar.[13] Steam turbines and electric motors were the only available options for satisfying mechanical demands and these were limited to run just one piece of equipment and not a combination on the same shaft.

The provision of a steam system as part of the overall utility system is not always essential. Such is the case, for instance, of LNG plants, where the current practice is to use a hot oil circuit for process heating and a full steam system is usually considered an unnecessarily expensive and complex option since gas turbine drivers have become normal practice. Nevertheless, running steam turbine drivers or generators with heat recovered from gas turbine exhaust could still be attractive when looking for improvements in thermal efficiency and atmospheric emissions.

Other limitations of the existing approaches include lack of flexibility when addressing mechanical driver allocation, no use of gas turbine drivers and helper motors, use of continuous cost and performance functions for gas turbines (except by Maréchal and Kalitventzeff[17]), and no availability considerations in the objective function (except by Frangopoulos and Dimopoulos[12]).

A novel synthesis and optimization framework for driver and power plant selections has been developed, to accommodate practical considerations and to reflect those drawbacks which have not fully addressed in the available design methods. Before presenting detailed problem formulation, design issues associated with driver and power plant selections will be addressed, which will then be followed by the implementation of these issues into the optimization model.

Power Systems

The energy demands in a process site are in the form of heat, electricity, and mechanical power. Equipment such as pumps, fans, etc., demand some amount of mechanical power to perform their functions. However, it is compressors that may demand such an amount of power as to significantly affect the decisions at the design stage regarding the thermal efficiency of the supporting (power) system.

Low temperature processes can be particularly power intensive due to the requirements of the refrigeration compressors. Each compressor, or compressor stage, represents a demand for mechanical power, which must be supplied by a driver, connected via a shaft. It is possible to run several compressors on the same shaft, hence consuming power from a common driver and running at the same speed. When the total mechanical power demand of a shaft is beyond a practical limit for the driver, it is necessary to use more than one shaft (more than one driver) to satisfy the compressor demands.

If several shafts are required, there will be many options for allocating the compressors to the shafts and even for separating stages of the same compressor into different shafts. Consecutive stages belonging to the same compressor that run on the same shaft could be built into a single casing provided they are of the same nature (e.g., centrifugal), which is an economic incentive. The lowest compressor cost would result from having all stages in a single casing. However, the power supplied by each driver must be in balance with the sum of the demands on its respective shaft. This constraint, together with a practical upper limit for the driver size, means that sometimes a large compressor must be split into several casings to allow being driven by more than one shaft. The three driver options considered in this article are described below, as well as the options for on-site electricity generation.

Mechanical drivers

Steam Turbines. Steam turbines have been the classic choice for drivers in conventional utility systems for many years. In that case, the system design was relatively straightforward as steam turbines can usually be manufactured to the customer requirements. If present, the refrigeration cycle(s) could be optimized with minimum consideration of the driving system. The steam turbines were designed solely to match the power and speed requirements of the refrigerant compressors, which were in turn fixed by the refrigeration cycle design.[18]

The need for a complete steam system to support the operation of such turbines has been the main drawback of the steam option for power dominated processes such as LNG, since water treatment and steam production, distribution, and condensing represent a significant capital investment.[18,19] Given that the heating demands in these processes are minor, steam turbine drivers have been avoided since the use of gas turbine drivers became a common practice. Steam could then be removed from the plant completely and process heating provided via alternative systems such as a hot oil circuit. The thermal efficiency of the system can increase with the introduction of steam generation from the exhaust heat of gas turbines.[20,21]

Gas Turbines. In cases where steam systems are avoidable, direct drive gas turbines (DDGTs) generally reduce the plant complexity and capital investment. An added advantage is that gas turbine systems are more efficient for standalone power generation, hence requiring less fuel and producing fewer emissions per unit of product than steam-based power systems. The acceptance of gas turbine drivers is also due to increased availability, operating range, and operating experience of the industrial gas turbine as well as its relatively easy start up.[19,22] Aeroderivative gas turbines, more compact and efficient, are still unproven as direct mechanical drivers although this is a feasible concept.

Unlike steam turbines, gas turbines are available in the market only in standard models and cannot be custom-designed in practice since that would involve impractically high development costs. Gas turbines are rather a package concept. Each model is unique and corresponds to a predefined set of components defining its performance (air compressor, combustor, expander, lube oil system, etc.). The overall trend is that the larger the turbine of the same type, the higher its efficiency and the lower its specific cost. It is also worth noting that aeroderivative gas turbines provide a significant improvement in efficiency but at a higher specific cost than industrial ones.

Performance data of gas turbines is normally available at ISO conditions (atmospheric conditions of 1 atm, 15°C, and 60% relative humidity, no inlet or outlet losses, and methane as fuel). When atmospheric conditions or the fuel composition are different so will be the performance of the gas turbines. The turbine power output and other performance parameters (e.g., efficiency, exhaust gas flowrate, and temperature) will have to be adjusted to reflect the actual operating conditions. GE Power Systems has published some plots from where derating factors can be estimated.[23] For instance, a given gas turbine operating at ambient temperature of 27°C would show a power output around 7% inferior to that reported at ISO conditions. Additional factors should also be considered to account for the effect of fouling and ageing. Coyle et al.[24] estimate that the air compressor fouling in gas turbines occurs very quickly and that a constant factor of 2% can be applied to account for the turbine power lost due to fouling. They also report a factor of 4% normally taken to account for power losses due to ageing, which occurs rapidly during the first year.

Usually, no gas turbines larger than frame 7 are considered for mechanical drive applications because concentrating multiple compression demands onto fewer drivers could lead to an important decrease in availability. However, a frame 9 gas turbine model was recently released by GE as mechanical drive and several units will be installed for the Qatargas II LNG project.

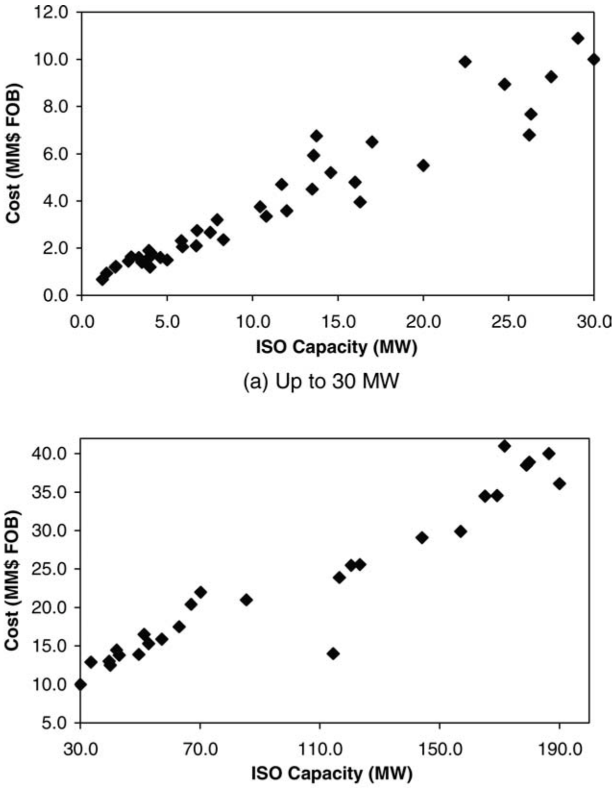
Although gas turbines have a relatively good efficiency, their performance deteriorates significantly at partial load. Using partially loaded gas turbine drivers during normal operation is not a common practice because of their unattractive efficiencies and because the capital utilization would not be appropriate.

Electric Motors. Driving major mechanical demands with electric motors is also an alternative. This would result in a simpler application since motors do not need as many support systems as gas turbines (air compression, combustion, fuel gas, etc.) or as steam turbines (water treatment, boilers, condensers, etc.). If the plant is not able to import electricity or it is not economically attractive, it will be necessary to have at least a power plant on the site and is evident that some of the saved complexity will be transferred to the gas turbines used there. However, it would still be a simplification as the support systems would be kept to one central application.[25]

If the electricity were to be generated on site, the use of electric motors could lead to a higher overall thermal efficiency since very large gas turbines (e.g., frame 9) or combined cycle power plants, with improved thermal efficiency and specific cost, could be used to this effect. This would lead to a decrease in atmospheric emissions per unit of power generated and probably in total capital investment—the extra cost for the motors themselves, as well as for the electric system (transformers, lines, substations, etc.), must be considered.

A practical limit for a suitable motor (synchronous, 3000–3600 rpm) is around 60 MW, although larger but slower motors have been manufactured at more than 100 MW, which certainly would require gearboxes if intended for compressor drivers.[26,27] The use of electric motors around these sizes and beyond involves a technological risk.

Precedents exist in the air separation industry employing 49 and 52 MW motors. The Snøhvit LNG project in Norway



(a) Up to 30 MW

(b) 30 to 190 MW

Figure 1. Cost of heavy-duty gas turbine generators in simple cycle.

went recently online and is a pioneering move of the LNG industry toward large electric motors. There, 65 MW electric motors are fed by several aeroderivative gas turbine generators. A connection to an external grid is also available.

Helper Motors and Generators. Gas turbines themselves require a smaller driver to provide the torque needed during the start up of the compression system. This starting torque depends on the system inertia, compressor gas loading, the acceleration rate required for safe control of turbine temperatures, and other factors. A variable speed electric motor is normally used as the starter driver. Sizing these motors is not a trivial task. A dynamic simulation of the system during start up might be required for such purpose.[28]

It is often economically attractive to use this installed capability (starter motor) in a continuous fashion as a helper to the gas turbine, supplementing the turbine power output and maximizing the production capacity with the installed equipment.[29,30] Starter motors could also act as electric generators in case the capacity of the turbine is in excess of the total shaft power demands.[31,32] The installation of helper motor size up to 20 MW had been reported for a LNG liquefaction plant.[32]

With the mechanical power demands being imposed by the process, only discrete DDGT options available to choose from and avoiding partial load operation of the gas turbines, it would be very difficult to perfectly match the supply with the demands in each particular shaft. The use of continuous size elements such as helper motors or generators makes it possible to keep the shaft in balance and to smooth the effect of the discrete nature of gas turbines on the design of the power system.

Electricity generation

In addition to the mechanical demands, there will also be some electricity demands for running equipment such as smaller compressors, fans, pumps, instrumentation, utilities, etc. If the plant is not able to import electricity, an on-site generation system will be required.

The gas turbine engine has a relatively low capital cost compared with pure-steam power plants. Their efficiency and flexibility make gas turbine-based cycles the dominant energy converters for the production of electricity today and in the foreseeable future.[33] Besides pure steam systems, gas turbines in simple or combined cycle are also power generation options. Combined cycles offer a step improvement in efficiency but have higher specific capital costs than simple cycle plants. Even very large gas turbines, such as frame 9s, are suitable for electricity generation.

As previously mentioned, one could claim that combined cycle plants imply a steam system and hence high capital costs. However, combined cycle power plants are available as pre-engineered, self-contained packages, which partially mitigate the cost of the auxiliary systems.

To demonstrate the uniqueness of each gas turbine, Figures 1 and 2 show the cost and efficiencies of a set of 67 heavy-duty gas turbine generators in simple cycle as published in Gas Turbine World 2000–2001.[34] It can be easily appreciated that the data points are significantly scattered and that any type of data regression function cannot represent these costs and efficiencies without incurring large errors. Also, there are size regions with a significantly smaller number of options available.

Plant capacity and power balance

If the power system is based purely on steam, the design procedure would be straightforward. Once the process capacity is chosen, the characteristics of the driven equipment are obtained and a set of specifications for the steam turbine drivers can be produced. The same procedure applies for the steam turbines intended for electricity generation. The virtually continuous size nature of steam turbines facilitates this procedure.

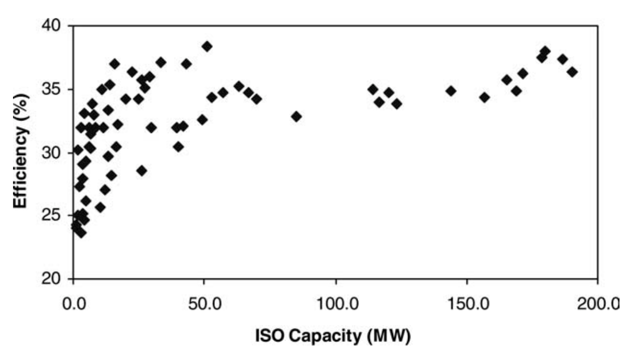


Figure 2. Efficiency of heavy-duty gas turbine generators in simple cycle.

Table 1. Inherent Availability Values for Some Equipment

Item	Availability
Pump	0.9346*
Centrifugal compressor	0.9973*
Axial compressor	0.9973**
Gas turbine frame 5	0.9918*
Gas turbine frame 6	0.9890*
Gas turbine frame 7	0.9863*
Electric motor (variable speed)	0.998†
Steam turbine	0.994†

*From De La Vega et al.[35]
**Assumed the same as centrifugal compressor.
†From Shu et al.[27]

There is a different story when gas turbines are part of the power system since they are discrete options. The use of helper motors or generators could eventually help in balancing the power in individual gas turbine shafts. Also, when using main electric motor drivers, there should be no major difficulty in balancing the shafts. However, if gas turbines are involved in the electric generation, either in simple or in combined cycles, the overall energy balance will rely on discrete sized elements. It will be more difficult then to achieve an exact global match between the power demands and sources.

Importing or exporting electricity could be an option to achieve overall power balance but this is not always possible, either because of a remote location (e.g., offshore), or because it is not economically attractive. In this type of situation, and for a given production rate, the designer would often have to select a power system with oversized components. One could choose to run the power system at partial load to achieve the proposed plant capacity, but it would imply poorer gas turbine performance besides an incomplete capital utilization. To avoid this, the plant capacity can sometimes be slightly adjusted to obtain a better match between power supply and demands, pursuing a full utilization of the available power.[24,35] Even when the overall capital investment increases due to the larger equipment in general, the specific fuel consumption, atmospheric emissions, and capital utilization would be definitely more favorable.

Plant availability

The choice of rotating equipment and compression strategy may have a significant influence on the amount of time that a process is down or operating at partial load due to scheduled and unscheduled events. In this section, the main availability issues are discussed. The reader can find further details on these concepts from various literature.[36–40]

Some Concepts. Availability can be generally defined as the probability of a component or system to perform its required function over a stated period of time. Alternatively, it can also be defined as the expected portion of time that a plant or item can perform its function successfully.

For a plant, the achievable availability (A_A) reflects the availability considering planned and unplanned maintenance time, whereas the inherent availability (A_I) measures the availability to be expected when reflecting corrective (unplanned) maintenance only. In the remainder of this paper, the term "availability" is to be understood as achievable availability unless otherwise stated.

For every equipment item, the failure rate does vary along its lifetime. The infant mortality or early failures dominate when the equipment is very recent in service. Later, a lower and relatively constant failure rate is expected when failures occur mostly randomly. Finally, toward the end of the equipment lifetime, the wear-out mechanisms accelerate and the failure rate increases. Availability is then, by definition, a function of time. However, after a relatively short time of operation, it tends to settle down to a rather stable value given by the ratio of MTTF to the summation of MTTF and MTTR (where MTTF is the mean time to failure and MTTR is the mean time to repair of a given system or item).

Table 1 includes typical inherent availability data for some types of rotating equipment. Note that the larger the gas turbine, the lower its availability. The ones for compressors, motors, and steam turbines are also, strictly speaking, a function of size, but average values are presented instead for simplicity.

Scheduled downtime is another factor that affects the annual plant production. Table 2 shows the planned maintenance time for different gas turbines over a period of 6 years. The larger the gas turbine, the more scheduled maintenance is required. Large gas turbines are able to bring the benefit of economy of scale, but one must be aware of the consequent increased scheduled and unscheduled downtime that they imply. Gas turbines sometimes even dominate the scheduled annual maintenance time. For instance, if 10 days/year are required for periodic turnarounds, having a frame 7 gas turbine on site would mean that such period has to be extended for further 3.3 days/year in average. Instead, if the largest gas turbine were a frame 5 then the original 10 days/year target could be met.

Redundancy is related to the provision of additional equipment items above those actually required for satisfactory operation, with the purpose of improving availability. This could be implemented in two ways. If all the items are intended to be in operation simultaneously and, in case of failure, the system is able to keep operating with some of them working properly; it is called active or active parallel redundancy. If, on the contrary, the items in excess are to be normally shut down until they are needed to replace one or several of the items in service, it is called stand-by redundancy. Both types of redundancy have a positive impact on the plant availability and are employed usually to overcome

Table 2. Scheduled Maintenance Time for Gas Turbiness

Year	Frame 5* (days)	Frame 6** (days)	Frame 7* (days)
1	5	7	9
2	5	7	9
3	10	13	17
4	5	7	9
5	5	7	9
6	12	20	27
Average	7.0	10.2	13.3

*From De La Vega et al.[35] It assumes 1 day for shutdown and 1 day for start up.
**Estimated.

any relatively unreliable elements in the system (e.g., a spare pump or parallel valve). Obviously, this implies an increased capital investment.

In availability terminology, items are in series if failure of the system results from failure of any item. On the other hand, items are in parallel if one or some of them can fail without making the whole system fail. Once the series and parallel components of a system have been identified, they can be represented in a reliability block diagram.[41]

When the items are in series, the system will perform its function successfully only if all items do so. Thus, the (inherent) availability of a system with n components in series is the product of those of all components (i.e., $A_{\mathrm{I\,sys}} = \prod_{i=1}^{n} A_{\mathrm{I}i}$). When the items are in parallel, the system will fail only if all items do so. Therefore, the overall availability would be $A_{\mathrm{I\,sys}} = 1 - \prod_{i=1}^{n} (1 - A_{\mathrm{I}i})$.

Improving Availability for Major Rotating Equipment. Plant availability has a major impact on process economics, especially when an important number of rotating equipment is involved. Unscheduled downtime is associated with the failure of heat exchangers, pumps, valves, instrumentation and control, utilities, human factors, etc. The choice of rotating equipment and compression strategy has a significant influence on the amount of time that the process is down or operating at partial load. Designers must be aware of the availability implications in the choice of rotating equipment and their arrangement. Initially, one power system design could appear to be more appropriate than others based on equal operating time, but if it implies a lower availability, it might lose such an advantage.

For example, until recently, LNG plants were normally built with two medium sized trains (plants) per project. In this way, one of the trains could keep running, whereas the other was unavailable due to planned or unplanned shutdowns. If, however, only one train was built, there would be no production at all during such downtimes. Consequently, there was a general consensus that two trains were the required minimum for overall availability.[25] Of course, building two 50% trains is more expensive than building a single 100% train, the latter being favored by the economy of scale. However, one must be aware that not only would this imply elements in series for availability, but also large gas turbines, which show worse individual availability and scheduled maintenance time than smaller ones.

The Atlantic LNG Project in Trinidad and Tobago, which began production in 1999, broke the trend of having two trains and set a new benchmark. Given the fact that a significant amount of downtime is due to rotating equipment, they opted for constructing a larger single train but with parallel driver/compressor sets. That is, for each refrigeration cycle, splitting the low-pressure refrigerant stream and feeding two independent compression lines (also with independent drivers and intercoolers). Thanks to this strategy, the project could benefit from the economy of scale while still having an availability comparable to that of a two-train project.[25] In the case when one compressor or driver is down, the plant could keep producing at partial load. Figure 3 illustrates the concept of series and parallel compression.

Sparing Philosophy in Electric Generation. Parallel compression may improve the availability of the system by using redundancy in compressors and drivers. However, it is also important to ensure a reliable electricity supply. If there is only one generator, what would happen if it fails? Most likely, the helper generators or steam turbine generators, if any, would not be able to provide enough electricity to keep the process producing normally or even at reduced capacity. Even if there are two power plants in the process, these problems are likely to remain if they are sized to run at full capacity during normal operation, since one power plant could not boost its capacity significantly in case the other one fails. If there is a connection to an external grid, perhaps importing electricity temporarily could be a solution, but this is not always the case.

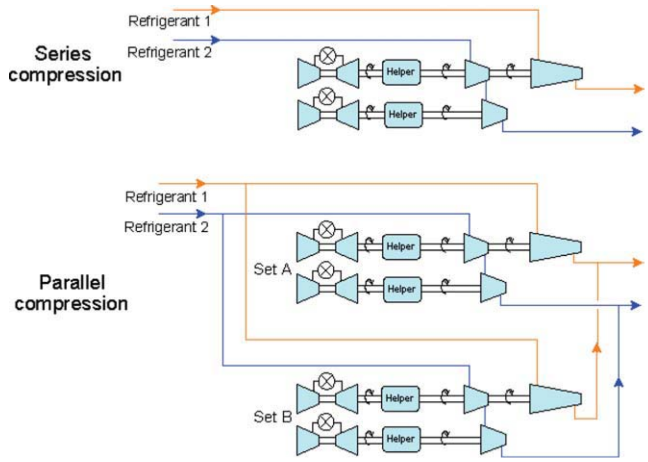


Figure 3. Series and parallel compression.

[Color figure can be viewed in the online issue, which is available at wileyonlinelibrary.com.]

Quite often some sort of redundancy, or sparing philosophy criteria is adopted. For example, the use of several slightly oversized power plants, so that there is immediate spare capacity in case of contingency. An $N + 1$ sparing philosophy is frequently used for electricity generating units. That is, if N generating items are required to supply the normal demand, then one extra unit is installed to cover the deficit left after the potential failure of one of the others. The spare unit may either be kept offline to be used only in case of contingency or be kept online, running simultaneously with the other N units, all at partial load. In both cases, some capital utilization is sacrificed to guarantee a reliable operation.

Synthesis of Power Systems

In very power intensive processes, such as LNG, the heating requirements are relatively minor and therefore a complex cogeneration scheme is not always required. In the approach described below, the heat required by the process can be provided not only via a steam system but also through an alternative thermal fluid circuit so that nonsteam solutions can be obtained whenever optimal. This makes the approach appropriate for a wide range of process power-to-heat ratios.

The problem formulation in this work is the first in providing enough flexibility to produce solutions ranging from no-steam solutions to all-steam solutions. Another major contribution of this work is that availability is allowed to participate in the objective function in the form of lost profit due to planned and unplanned shutdowns. This introduces a new dimension to the problem and allows considering capital/energy/availability trade-offs instead of the classic capital/energy approach. Although the method[12] allowed this type of trade-offs for limited configuration options, this research work was the first in considering this issue as evidenced in Del Nogal et al.[42] Also, sparing philosophy may be considered at designer's request for power plants, steam turbine generators, and boilers.

Similarly, this work is the first synthesis approach considering gas turbine drivers and the possible combination of several mechanical demands (e.g., compression stages) in a single driver shaft, as well as the splitting of a multistage compressor in several casings to be driven by several shafts. Also, the use of starter motors as continuous helpers to gas turbine drivers is exploited at the synthesis stage for the first time.

System components

The main elements involved in the power system are shown in Figure 4. On the demand side, the mechanical power demands are assumed to be compression stages belonging to the different refrigeration cycles in the process. It must be emphasized that this is for illustration purposes only and does not represent a limitation of this work, as the nature of these demands does not actually affect the formulation and equipment other than compressors can be readily included without any difficulty. These demands are known once there is a basic design of the process. In the lumped basic electricity demands, the electricity requirements for running smaller process and utility compressors, air coolers, pumps, instrumentation and control, etc. can be included. These electricity demands are external to the power system and can be estimated once a preliminary design of the process is complete. There could be an additional amount of electricity required internally for the power system itself to support any featured electric motors, air-cooled steam condensers, boiler feed water pumps, water treatment, etc.

On the supply side, gas turbines, steam turbines, and electric motors are the elements available for providing direct mechanical power. The optimal number of DDGTs is unknown, although the designer may have an idea of a practical maximum number. Power plants, either in simple or combined cycle, and steam turbines are the main electricity producers. Again, the optimal number of these is not known, but a practical limit could certainly be set. Helper generators can also produce a limited amount of electricity when the capacity of the gas turbine drivers is in excess of its shaft demands.

Some elements are both a power supply and demand. For example, helper and main motor drivers supply mechanical power and use electricity at the same time. Helper generators act the reverse way. In case these features are selected to be part of the power system, there will be a net additional demand or production of electricity. Unlike the lumped basic demands, this amount of electricity does depend on the characteristics of the power system. Helpers are limited to one per gas turbine driver.

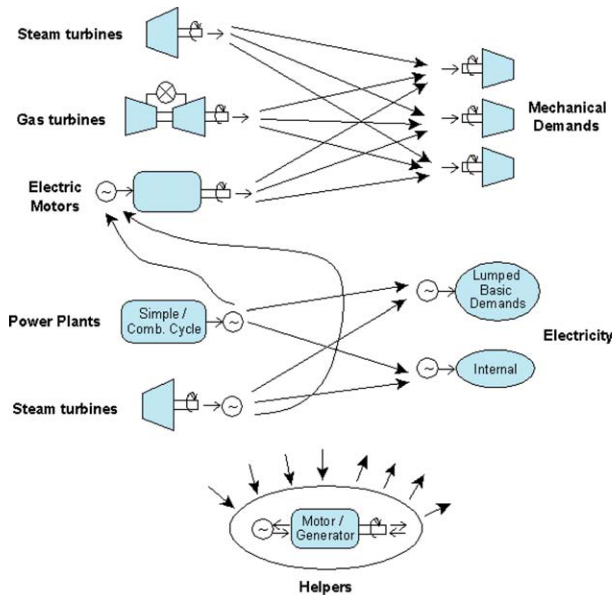


Figure 4. Power sources and demands.

[Color figure can be viewed in the online issue, which is available at wileyonlinelibrary.com.]

Problem formulation

The design of power systems involves discrete decisions, not only because of the discrete options available for gas turbines and power plants, but also because of the discrete power demands and arrangement alternatives of the components in the system. Proper utilization of the installed capacity is also a key issue. The start-up motors of gas turbines are now often used as helper drivers to boost shaft power. The optimal power system must satisfy a set of mechanical, electrical, and heating demands by employing the most cost-effective number, type, and model of mechanical drivers, compressor stage arrangement, helper motors or generators and power plants, either in a simple or combined cycle. A proper optimization model for this problem must allow for the flexible arrangement alternatives of driven equipment on different mechanical shafts to consider the different compressor casing alternatives.

Figure 5 shows, in two parts, the superstructure on which the new optimization model is based. Figure 5a shows all the elements not requiring a customized steam system (steam may still be present in combined cycle power plants). These are gas turbine drivers, electric motors, mechanical demands, power plants, and the relevant electrical connections. Helper motors or generators are allowed on each gas turbine shaft. Each compressor stage is allowed to run on any of the gas turbines or motor shafts, hence allowing each compressor to be split into different casings. Figure 5b shows the steam-based elements and how they are linked to the nonsteam superstructure through potential heat recovery steam generators for each gas turbine driver and simple cycle power plant. This multilevel steam superstructure includes steam generators, such as boilers and supplementary fired HRSGs, which may produce steam at any one of the existing levels, extraction steam turbine drivers and generators, letdown valves, vents, deareator and connections to provide/receive

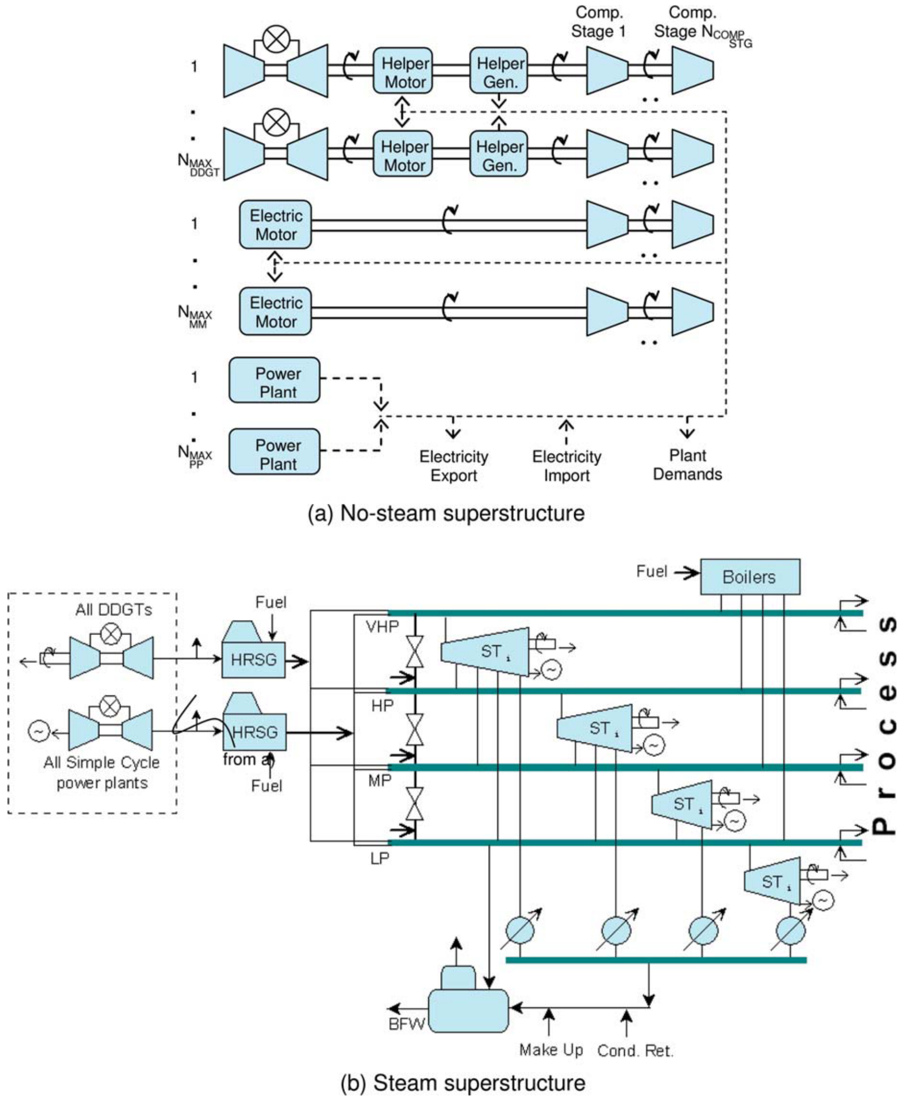


Figure 5. Superstructure for the synthesis of Power Systems.

[Color figure can be viewed in the online issue, which is available at wileyonlinelibrary.com.]

steam to/from the process at each level. Heat may be provided to the process through steam or through an implicit hot oil system.

There will be a maximum number of potential gas turbines, steam turbines, and main motor shafts that the designer will define to avoid excessive use of binary variables when solving the problem. Later, the optimization will yield their most cost-effective number and type, and therefore which places are to be active. Similarly, the designer can also define a maximum number of potential power plants.

Objective Function. The goal of the optimization is to find a feasible power system with minimum total cost (defined in Eq. 1), which may comprise any combination of capital costs, fuel costs, CO_2 emission penalties, lost profit due to unavailability, boiler water treatment operating costs, and charges for the electricity imported (a credit if exported instead). Taking into account, all these costs will allow the model to trade-off the capital investment against the expected performance of the system. For the sake of a fair trade-off, the capital cost must represent the total installed cost of the equipment and not just the purchased cost. In this way, the real investment is reflected and capital and operating costs are weighted properly in the objective function. Please note that the net present cost is minimized in the current optimization frameworks.

$$\mathrm{TCost} = \mathrm{CCap} + \mathrm{CFuel} + \mathrm{CCO2} + \mathrm{CElec} + \mathrm{CAvail} + \mathrm{COpWT} \quad (1)$$

Equation 2 accounts for all the relevant capital costs. All the equipment cost functions in this article stand for installed cost and on the basis of year 2002. Detailed costs such as piping, instrumentation, etc. are not explicitly considered since they are already covered by the installation factors. The sources of capital costs in this article are obtained from various literature[26,34,43–45] and data obtained directly from

Table 3. Cost Parameters

η_g [−]	0.95	WHMGo (kW)	14,000
WEDo (kW)	446,000	CHMGo (k$)	2372
CEDo (k$)	29,200	WMo (kW)	14,000
FSM [−]	0.15	CMo (k$)	2372
	$\overline{a_{LV}}$	$\overline{b_{LV}}$	$\overline{hexp_{LV}}$ (kJ/kg)
VHP	160.8	2021.1	2400.7
HP	134.8	1691.6	2397.9
MP	100.9	1262.9	2395.4
LP	45.3	559.3	2395.8
$\overline{hret^{CT}}$ (kJ/kg)	251.2	$LMTD^{Cond}$ (°C)	23.6045
U^{Cond} (kW/m^2 C)	0.80912		

Please note that capital cost parameters which is specific to the driver considered are given in Tables 2, 3, 4, and 5 in the Part 2 of this article.

industry sources. Cost parameters used in this work are given in Table 3.

In this formulation, the compressor demands are fixed but nevertheless, their cost has to be a variable since it will depend also on the casing arrangement, which is left as a degree of freedom for the optimizer. The cost of the aftercoolers will be fixed from the beginning as it does not depend on the casing arrangement or any other variables. This cost is also included for the sake of future comparisons, as the resulting solution will be compared with other solutions that feature parallel compression. The aftercooler costs in both situations are different because they are not proportional to size in a linear way as follows:

$$\begin{aligned} CCap = {} & CDDGT + CSTD + CMM + CHelp + CPP + CSTG \\ & + CDist + CHRSG + CB + CDea + CbfwP \\ & + CTFH + CWT + CRC + CAC + CSparePP \\ & + CSpareSTG + CSpareB \end{aligned} \tag{2}$$

$$CDDGT = \sum_{GTD}\sum_{TOP} YTop_{GTD,TOP}\cdot\overline{CT}_{TOP} \tag{3}$$

$$CPP = \sum_{PP}\sum_{PPOP} YPPop_{PP,PPOP}\cdot\overline{CPPop}_{PPOP} \tag{4}$$

$$CSparePP = YSpare_{PPop}\cdot\overline{CPPop}_{PPop} \tag{5}$$

The set of binary variables $YTop_{GTD,TOP}$ indicates whether and which standard gas turbine choice (actual model) has taken the DDGT place *GTD*. Thus, Eq. 3 accounts for the cost of all the actual DDGTs present in the final design and does it in a discrete fashion. The cost of the power plants is calculated in a similar way in Eq. 4.

Some other capital costs are calculated using the six-tenths factor rule to reflect the economy of scale (Eqs. 6 to 21), but more suitable equipment-specific exponents other than 0.6 are used instead (either from correlated data or from Remer and Chai[46]). Electricity distribution costs include the required transformers, lines, etc. and are scaled according to the total electricity produced on site. The cost of aftercoolers can be scaled according to their duty, provided that the reference sizes and costs belong to exchangers of the same type (i.e., water or air-cooled) and used for a similar service (similar physical properties and temperature differences).

$$CDist = \left(\frac{\sum_{PP} WPP_{PP} + \sum_{GTD} WHG_{GTD}\cdot\overline{\eta_g}}{\overline{WEDo}}\right)^{0.70}\cdot\overline{CEDo} \tag{6}$$

$$CAC = \sum_{AC}\left(\frac{\overline{Q}_{AC}}{\overline{Qo}_{AC}}\right)^{0.80}\cdot\overline{CACo}_{AC} \tag{7}$$

$$\begin{aligned} CRC = {} & \sum_{c}\left(\frac{\sum_{CS\in C}\overline{WCS_{CS}}}{\overline{WRCoc}}\right)^{0.82}\cdot\overline{CRCoc} \\ & \times\left(1+\left(NCAS_c-\overline{NCASoc}\right)\cdot\overline{PCAS}\right) \end{aligned} \tag{8}$$

$$\begin{aligned} CHelp = {} & \sum_{GTD}\left(\frac{WGTD_{GTD}\cdot\overline{FSM}+WHMEX+WHGEX}{\overline{WHMGo}}\right)^{0.70} \\ & \times\overline{CHMGo} \end{aligned} \tag{9}$$

$$CMM = \sum_{M}\left(\frac{WM_M}{\overline{WMo}}\right)^{0.70}\cdot\overline{CMo} \tag{10}$$

$$CWT = 136.52\cdot MMkUp^{0.90} \tag{11}$$

$$CB = \sum_{B}\sum_{Lv}\left(\overline{a}_{Lv}\cdot MB_{B,Lv}+\overline{b}_{Lv}\cdot YB_{B,Lv}\right) \tag{12}$$

$$CDea = 2.88\cdot Mbfw + 90\cdot YSteam \tag{13}$$

$$CTFH = 3.032\cdot QTFH^{0.65} \tag{14}$$

$$CbfwP = 240.24\cdot WbfwP^{0.46}\quad\text{(one spare pump assumed)} \tag{15}$$

$$CSTD = \sum_{STD}\left(23.289\cdot WST_{STD}^{0.58}+CCond_{STD}\right) \tag{16}$$

$$CSTG = \sum_{STG}\left(15.066\cdot WST_{STG}^{0.66}+CCond_{STG}\right) \tag{17}$$

$$CSpareSTG = 15.066\cdot WSpareSTG^{0.66} \tag{18}$$

$$CSpareB = \overline{a}_{Lv=VHP}\cdot MStSpareB+\overline{b}_{Lv=VHP}\cdot\overline{YB^{N+1}} \tag{19}$$

$$CCond_{ST} = 0.977\cdot\frac{\sum_{Lv} F^{OUT}_{Lv,\overline{NLv}+1,ST}\cdot\left(\overline{h\,exp}_{Lv,\overline{NLv}+1}-\overline{hret^{CT}}\right)}{\overline{U^{Cond}}\cdot\overline{LMTD^{Cond}}} \tag{20}$$

$$\begin{aligned} CHRSG_{HR} = {} & \sum_{Lv}(8.158\cdot(YHR_{HR,Lv}-YSF_{HR,Lv}) \\ & +1.501\cdot MST^{NOSF}_{HR,Lv})\cdot\overline{AA}_{Lv} \\ & +\sum_{Lv}\left(8.158\cdot YSF_{HR,Lv}+1.501\cdot MST^{SF}_{HR,Lv}\right)\cdot\overline{BB}_{Lv} \\ & +\sum_{Lv}41.955\cdot(1+\overline{BR^{HR}})\cdot MST_{HR,Lv} \\ & +2.335\cdot MExh^{1.2}_{HR}+\frac{QSF_{HR}}{382.9}+76.567\cdot\sum_{Lv}YSF_{HR,Lv} \end{aligned} \tag{21}$$

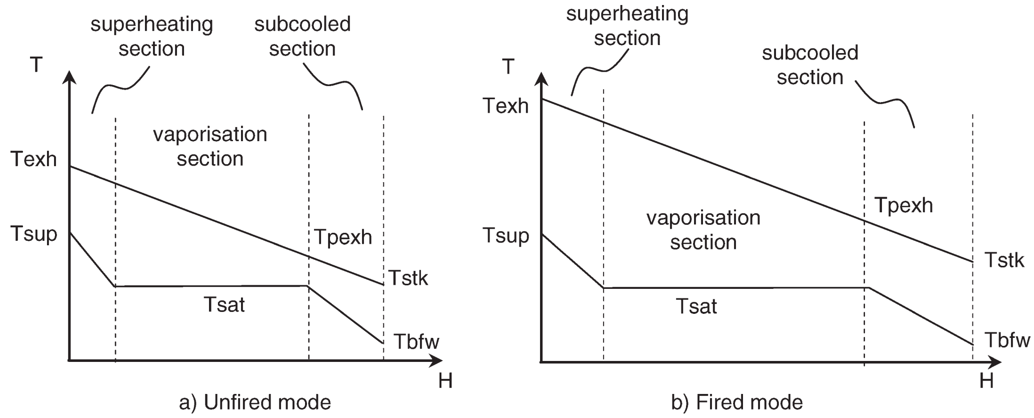


Figure 6. Temperature profiles and nomenclature in a single pressure heat recovery steam generator.

In the case of refrigerant compressors, if they are of the same type and intended for similar service as the cost reference, then two factors affect their cost. The first factor accounts for the total compressor power relative to that of the reference. The second factor considers a fixed fractional penalty per additional casing (or a credit, if a compressor ends up having fewer casings than the reference). This second factor is an estimation and extends the applicability of the six-tenths factor rule to account explicitly for the effect that casing arrangement has on compressor costs.

The cost of helpers and main motors is a function of their power. As stated previously, the sizing of starter motors for gas turbine-driven compression systems is not a trivial task. Nevertheless, for the purposes of this optimization model, it will be assumed that the size of the starter motors is a fixed fraction of the respective gas turbine output (usually around 15%, as seen from existing systems). It is assumed also that there will be one starter motor per gas turbine (i.e., no shared starter motors). Then, when using DDGTs, there will be a fixed charge for the respective starter motors, whether they are intended to be used continuously as helpers or not. If used in a continuous mode, helper power (motor or generator) could be less than or greater than the starting requirements. In the first case, there is no further cost associated. If, however, a helper with a capacity greater than the starting requirements is installed to be operated fully as a helper, but at partial capacity during start up, then of course its cost will be higher than that of a motor sized merely for start up. A maximum limit must exist for the helper power, though relative to the size of the associated gas turbine.

For costing purposes, therefore, the size of starter/helper devices consists of two terms (Eq. 9). The first one ($\mathrm{WT_T} \cdot \overline{\mathrm{FSM}}$) is fixed once a gas turbine is chosen and represents the power required for start up, regardless of its possible continuous use. The second term (WHMEx or WHGEx) becomes active only when the continuous helper contribution (motor or generator) is in excess of the starting requirements and accounts precisely for the amount of excess power. Additional constraints involving these variables are presented later. The cost of motors and generators is calculated using the same equation since they are essentially the same kind of equipment but operating in different modes.

The cost of steam turbine drivers and generators was correlated as a function of their power and includes air-cooled condensers. The capital cost of water treatment was correlated as a function of the boiler feed water makeup flowrate, assuming a combined ion exchange and reverse osmosis treatment (more details in Beardsley et al., 1995). Heat recovery steam generators are assumed to have a single pressure level (any one of the available levels in the steam superstructure) and to operate in either unfired or 100% supplementary fired mode. Their cost is modeled as an approximation of the correlation presented by Foster-Pegg.[44] Figure 6 illustrates the profiles and nomenclature of a single pressure heat recovery steam generator.

The total fuel consumption of the system is the sum of the fuel consumption, based on low heating value (LHV), of all gas turbine drivers, power plants, heat recovery steam generators, and boilers featured in the system and is calculated using Eq. 22. If there is a source of cheap fuel in the process, such as a tail gas, boil-off, or an end flash gas stream, in case of an LNG process, this would provide a portion of the fuel burned in the process. Any fuel deficit would have to be covered by more expensive feed gas or "fresh" fuel. The optimization will implicitly tend to use as much cheap fuel as possible (e.g., end flash). Equation 23 defines the total fuel as the combination of end flash and fresh fuel streams. The amount of end flash fuel is limited to the maximum available in the process by Eq. 24 (constrain to zero if the stream does not exist). The total present cost of the fuel (through plant lifetime) is calculated in Eq. 25 and different costs for each type of fuel are allowed.

$$\begin{aligned}\mathrm{QFTot} = {} & \sum_{\mathrm{GTD}} \sum_{\mathrm{TOP}} \mathrm{YTOP_{GTD,TOP}} \cdot \overline{\mathrm{HRTOP}}_{\mathrm{TOP}} \cdot \overline{\mathrm{WTOP}}_{\mathrm{TOP}} \\ & + \sum_{\mathrm{PP}} \sum_{\mathrm{PPOP}} \mathrm{YPPOP_{PP,PPOP}} \cdot \overline{\mathrm{HRPPOP}}_{\mathrm{PPOP}} \cdot \overline{\mathrm{WPPOP}}_{\mathrm{PPOP}} \\ & + \sum_{\mathrm{HR}} \mathrm{QSF_{HR}} + \sum_{\mathrm{B}} \mathrm{QB_B} \end{aligned} \tag{22}$$

$$\mathrm{QFTot} = \mathrm{QFEF} + \mathrm{QFF} \tag{23}$$

$$\mathrm{QFEF} \le \overline{\mathrm{MaxQFEF}} \tag{24}$$

$$\text{CFuel} = \left(\text{QFEF} \cdot \overline{\text{CFEF}} + \text{QFF} \cdot \overline{\text{CFF}}\right) \cdot \overline{\text{HYR}} \cdot \frac{\left(1+\overline{\text{IR}}\right)^{\overline{\text{LIFE}}} - 1}{\overline{\text{IR}} \cdot \left(1+\overline{\text{IR}}\right)^{\overline{\text{LIFE}}}} \quad (25)$$

Depending on the environmental legislation that the plant is intended to operate under, or if the plant operator would like to encourage more efficient systems, a penalty for CO_2 emissions might apply. The rate of CO_2 emissions (CO2Em) is calculated in Eq. 26, as a function of the fuel consumption and the present cost of the respective penalties (CCO2) in Eq. 27.

$$\text{CO2Em} = \text{QFTot} \cdot \overline{\text{CO2F}} \quad (26)$$

$$\text{CCO2} = \text{CO2Em} \cdot \overline{\text{PCO2}} \cdot \overline{\text{HYR}} \cdot \frac{\left(1+\overline{\text{IR}}\right)^{\overline{\text{LIFE}}} - 1}{\overline{\text{IR}} \cdot \left(1+\overline{\text{IR}}\right)^{\overline{\text{LIFE}}}} \quad (27)$$

Trading electricity will result in a cost or a benefit, depending on whether it is imported or exported as follows:

$$\text{CElec} = \left(\text{Imp} \cdot \overline{\text{CEImp}} - \text{Exp} \cdot \overline{\text{CEExp}}\right) \times \overline{\text{HYR}} \cdot \frac{\left(1+\overline{\text{IR}}\right)^{\overline{\text{LIFE}}} - 1}{\overline{\text{IR}} \cdot \left(1+\overline{\text{IR}}\right)^{\overline{\text{LIFE}}}} \quad (28)$$

The operating cost of the water treatment plant is estimated in Eq. 29 (derived from Beardsley et al.[45]).

$$\text{COpWT} = 15.776 \cdot \text{MMKUp}^{0.84} \cdot \overline{\text{HYR}} \cdot \frac{\left(1+\overline{\text{IR}}\right)^{\overline{\text{LIFE}}} - 1}{\overline{\text{IR}} \cdot \left(1+\overline{\text{IR}}\right)^{\overline{\text{LIFE}}}} \quad (29)$$

Driver Allocation. Each gas turbine drive position may or may not be taken by an actual unit. As previously stated, binary variables are used to account for the existence or absence of a DDGT in the place *GTD* and for the choice of the actual gas turbine model if the place is active. Equation 30 limits the DDGT assignment to one or none per place and Eq. 31 controls the selection of the DDGT model from the set of available standard options. In Eq. 32, the mechanical demands are assigned to different gas turbine shafts. Full load operation of DDGTs is assumed.

$$\sum_{\text{TOP}} \text{YTOP}_{\text{GTD,TOP}} \leq 1 \quad (30)$$

$$\text{WGTD}_{\text{GTD}} = \sum_{\text{TOP}} \text{YTOP}_{\text{GTD,TOP}} \cdot \overline{\text{WTOP}}_{\text{TOP}} \quad (31)$$

$$\text{WTSD}_{\text{GTD,CS}} = \text{YTCS}_{\text{GTD,CS}} \cdot \overline{\text{WCS}}_{\text{CS}} \quad (32)$$

The shaft balance for a gas turbine driver is as follows:

$$\text{WGTD}_{\text{GTD}} \cdot \left(1 - \overline{\text{MLoss}}\right) - \sum_{\text{CS}} \text{WTSD}_{\text{GTD,CS}} + \text{WHM}_{\text{GTD}} \cdot \left(1 - \overline{\text{MLoss}}\right) - \text{WHG}_{\text{GTD}} = 0 \quad (33)$$

Equation 34 calculates the power required for starting up a gas turbine driver as a function of the respective gas turbine size. Equations 35 and 36 set a maximum limit for the size of the helper devices. The limit is given by the starting power requirements and, if needed, some excess capacity, which is also limited to a maximum in Eqs. 37 and 38. Note that the variables accounting for the excess capacity will be implicitly set to zero when the helper power is not intended to go beyond the starting requirement. Otherwise, the solver would incur unnecessary costs. Equations 39 and 40 ensure the selection of only one type of helper (i.e., either motor or generator) for each gas turbine.

$$\text{WSM}_{\text{GTD}} = \sum_{\text{TOP}} \left(\text{YTOP}_{\text{GTD,TOP}} \cdot \overline{\text{WTOP}}_{\text{TOP}} \cdot \overline{\text{FSM}}_{\text{TOP}}\right) \quad (34)$$

$$\text{WHM}_{\text{GTD}} \leq \text{WSM}_{\text{GTD}} + \text{WHMEx} \quad (35)$$

$$\text{WHG}_{\text{GTD}} \leq \text{WSM}_{\text{GTD}} + \text{WHGEx} \quad (36)$$

$$\text{WHMEx} \leq \text{WGTD}_{\text{GTD}} \cdot \overline{\text{FMaxHM}} - \text{WSM}_{\text{GTD}} \quad (37)$$

$$\text{WHGEx} \leq \text{WGTD}_{\text{GTD}} \cdot \overline{\text{FMaxHG}} - \text{WSM}_{\text{GTD}} \quad (38)$$

$$\text{WHM}_{\text{GTD}} \leq \text{YHM}_{\text{GTD}} \cdot \overline{\Gamma\text{HM}} \quad (39)$$

$$\text{WHG}_{\text{GTD}} \leq (1 - \text{YHM}_{\text{GTD}}) \cdot \overline{\Gamma\text{HG}} \quad (40)$$

In the case of main motors and steam turbine drivers, the shaft balances and the allocation of mechanical demands are similar to the case of gas turbines but without the presence of helpers (Eqs. 41–44). A limit for the steam turbine and motor driver sizes is enforced by Eqs. 45 and 46. Binary variables are used as the number of such drivers must be accounted for in availability calculations afterward. Equation 47 ensures that only one driver is selected to run a particular mechanical demand.

$$\text{WST}_{\text{STD}} \cdot \left(1 - \overline{\text{MLoss}}\right) - \sum_{\text{CS}} \text{WSTSD}_{\text{STD,CS}} = 0 \quad (41)$$

$$\text{WSTSD}_{\text{STD,CS}} = \text{YSTCS}_{\text{STD,CS}} \cdot \overline{\text{WCS}}_{\text{CS}} \quad (42)$$

$$\text{WM}_{\text{M}} \cdot \left(1 - \overline{\text{MLoss}}\right) - \sum_{\text{CS}} \text{WMSD}_{\text{M,CS}} = 0 \quad (43)$$

$$\text{WMSD}_{\text{M,CS}} = \text{YMCS}_{\text{M,CS}} \cdot \overline{\text{WCS}}_{\text{CS}} \quad (44)$$

$$\text{WST}_{\text{STD}} \leq \overline{\text{MaxST}} \cdot \text{YST}_{\text{STD}} \quad (45)$$

$$\text{WM}_{\text{M}} \leq \overline{\text{MaxM}} \cdot \text{YMM}_{\text{M}} \quad (46)$$

$$\sum_{\text{GTD}} \text{YTCS}_{\text{GTD,CS}} + \sum_{\text{STD}} \text{YSTCS}_{\text{STD,CS}} + \sum_{\text{M}} \text{YMCS}_{\text{M,CS}} = 1 \quad (47)$$

Steam Generation. The following set of equations is related to steam generation in the heat recovery boilers. Equations 48 to 50 look after temperature feasibility, whereas Eqs. 51 and 52 state the energy balances around the overall equipment and around the combined superheating and vaporization sections, respectively. These energy balances assume that all the exhaust gas from the gas turbines is sent to the HRSGs, hence they are useful for calculating only the maximum steam production possible, depending on the selected steam level and on the use of supplementary firing. Equation 53 defines an exhaust temperature consistent with the selected gas turbine driver and Eq. 54 limits the actual flowrate of exhaust gas used for heat recovery up to a maximum, again, consistent with the selected gas turbine model. Equations 55 to 60 are logic constraints that ensure only active gas turbine options have a contribution in the HRSG heat balances.

$$\mathrm{Tpexh}_{\mathrm{HR,HROP}} \geq \overline{\mathrm{Tsat}}_{\mathrm{Lv}} \cdot \mathrm{YHR}_{\mathrm{HR,Lv}} + \overline{\Delta \mathrm{T}_{\min}} \tag{48}$$

$$\mathrm{Tstk}_{\mathrm{HR,HROP}} \geq \overline{\mathrm{Tstk}_{\min}} \tag{49}$$

$$\mathrm{Tstk}_{\mathrm{HR,HROP}} \geq \overline{\mathrm{Tbfw}}_{\mathrm{Lv}} \cdot \mathrm{YHR}_{\mathrm{HR,Lv}} + \overline{\Delta \mathrm{T}_{\min}} \tag{50}$$

$$\begin{aligned}\sum_{\mathrm{Lv}} \mathrm{MST}^{\mathrm{MAX}}_{\mathrm{HR,Lv}} \cdot \Big(\overline{\Delta\mathrm{Hvap}}_{\mathrm{Lv}} + \overline{\mathrm{Cpwv}}_{\mathrm{Lv}} \cdot \Big(\overline{\mathrm{Tsup}}_{\mathrm{Lv}} - \overline{\mathrm{Tsat}}_{\mathrm{Lv}}\Big) \\ + \Big(1 + \overline{\mathrm{BR}^{\mathrm{HR}}}\Big) \cdot \overline{\mathrm{Cpwl}}_{\mathrm{Lv}} \cdot \Big(\overline{\mathrm{Tsat}}_{\mathrm{Lv}} - \overline{\mathrm{Tbfw}}_{\mathrm{Lv}}\Big)\Big) \\ = \sum_{\mathrm{HROP}} \overline{\mathrm{Mexh}}_{\mathrm{HROP}} \cdot \overline{\mathrm{Cpexh}} \cdot \Big(\overline{\mathrm{Texh}}_{\mathrm{HROP}} \cdot \Big(1 - \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{HR,Lv}}\Big) \\ + \overline{\mathrm{TSF}^{\mathrm{MAX}}} \cdot \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{HR,Lv}} - \mathrm{Tstk}_{\mathrm{HR,HROP}}\Big)\end{aligned} \tag{51}$$

$$\begin{aligned}\sum_{\mathrm{Lv}} \mathrm{MST}^{\mathrm{MAX}}_{\mathrm{HR,Lv}} \cdot \big(\overline{\Delta\mathrm{Hvap}}_{\mathrm{Lv}} + \overline{\mathrm{Cpwv}}_{\mathrm{Lv}} \cdot \big(\overline{\mathrm{Tsup}}_{\mathrm{Lv}} - \overline{\mathrm{Tsat}}_{\mathrm{Lv}}\big)\big) = \\ \sum_{\mathrm{HROP}} \overline{\mathrm{Mexh}}_{\mathrm{HROP}} \cdot \overline{\mathrm{Cpexh}} \cdot \Big(\overline{\mathrm{Texh}}_{\mathrm{HROP}} \cdot \Big(1 - \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{HR,Lv}}\Big) \\ + \overline{\mathrm{TSF}^{\mathrm{MAX}}} \cdot \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{HR,Lv}} - \mathrm{Tpexh}_{\mathrm{HR,HROP}}\Big)\end{aligned} \tag{52}$$

$$\mathrm{Texh}_{\mathrm{GTD}} = \sum_{\mathrm{TOP}} \mathrm{YTOP}_{\mathrm{GTD,TOP}} \cdot \overline{\mathrm{Texh}}_{\mathrm{TOP}} \tag{53}$$

$$\mathrm{Mexh}_{\mathrm{GTD}} \leq \sum_{\mathrm{TOP}} \mathrm{YTOP}_{\mathrm{GTD,TOP}} \cdot \overline{\mathrm{Mexh}}_{\mathrm{TOP}} \tag{54}$$

$$\begin{aligned}\overline{\mathrm{Texh}}_{\mathrm{TOP}} \cdot \Big(1 - \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{GTD,Lv}}\Big) + \overline{\mathrm{TSF}^{\mathrm{MAX}}} \cdot \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{GTD,Lv}} \\ - \mathrm{Tpexh}_{\mathrm{GTD,TOP}} \leq \mathrm{YTOP}_{\mathrm{GTD,TOP}}.\overline{\Gamma\mathrm{T}}\end{aligned} \tag{55}$$

$$\begin{aligned}\overline{\mathrm{Texh}}_{\mathrm{SCOP}} \cdot \Big(1 - \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{PP,Lv}}\Big) + \overline{\mathrm{TSF}^{\mathrm{MAX}}} \cdot \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{PP,Lv}} \\ - \mathrm{Tpexh}_{\mathrm{PP,SCOP}} \leq \mathrm{YPPOP}_{\mathrm{PP,SCOP}}.\overline{\Gamma\mathrm{T}}\end{aligned} \tag{56}$$

$$\begin{aligned}\overline{\mathrm{Texh}}_{\mathrm{HROP}} \cdot \Big(1 - \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{HR,Lv}}\Big) + \overline{\mathrm{TSF}^{\mathrm{MAX}}} \cdot \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{HR,Lv}} \\ - \mathrm{Tpexh}_{\mathrm{HR,HROP}} \geq 0\end{aligned} \tag{57}$$

$$\begin{aligned}\overline{\mathrm{Texh}}_{\mathrm{TOP}} \cdot \Big(1 - \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{GTD,Lv}}\Big) + \overline{\mathrm{TSF}^{\mathrm{MAX}}} \cdot \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{GTD,Lv}} \\ - \mathrm{Tstk}_{\mathrm{GTD,TOP}} \leq \mathrm{YTOP}_{\mathrm{GTD,TOP}} \cdot \overline{\Gamma\mathrm{T}}\end{aligned} \tag{58}$$

$$\begin{aligned}\overline{\mathrm{Texh}}_{\mathrm{SCOP}} \cdot \Big(1 - \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{PP,Lv}}\Big) + \overline{\mathrm{TSF}^{\mathrm{MAX}}} \cdot \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{PP,Lv}} \\ - \mathrm{Tstk}_{\mathrm{PP,SCOP}} \leq \mathrm{YPPOP}_{\mathrm{PP,SCOP}} \cdot \overline{\Gamma\mathrm{T}}\end{aligned} \tag{59}$$

$$\begin{aligned}\overline{\mathrm{Texh}}_{\mathrm{HROP}} \cdot \Big(1 - \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{HR,Lv}}\Big) + \overline{\mathrm{TSF}^{\mathrm{MAX}}} \cdot \sum_{\mathrm{Lv}} \mathrm{YSF}_{\mathrm{HR,Lv}} \\ - \mathrm{Tstk}_{\mathrm{HR,HROP}} \geq 0\end{aligned} \tag{60}$$

Equations 61 and 62 allow the selection of a steam level in potential HRSGs only in active DDGT and simple cycle power plant places. Equation 63 allows a maximum steam production only in active HRSGs. Equation 64 limits the actual steam production in a given HRSG and steam level to the maximum determined by previous energy balances and constraints.

Supplementary firing is restricted to active HRSG places and selected steam levels only (Eq. 65). To keep linearity in the equations, it is necessary to account for the HRSG steam production in different variables, depending on whether supplementary firing is used or not. This is done by Eqs. 66 to 68. Equations of the linear form are preferred in this formulation to avoid the mathematical difficulties that the optimizers face when nonlinearities are present and the associated risk of being trapped in local optima or not finding a feasible solution at all. More details on linearization are given later.

$$\sum_{\mathrm{Lv}} \mathrm{YHR}_{\mathrm{GTD,Lv}} \leq \sum_{\mathrm{TOP}} \mathrm{YTOP}_{\mathrm{GTD,TOP}} \tag{61}$$

$$\sum_{\mathrm{Lv}} \mathrm{YHR}_{\mathrm{PP,Lv}} \leq \sum_{\mathrm{SCOP}} \mathrm{YPPOP}_{\mathrm{PP,SCOP}} \tag{62}$$

$$\mathrm{MST}^{\mathrm{MAX}}_{\mathrm{HR,Lv}} \leq \mathrm{YHR}_{\mathrm{HR,Lv}} \cdot \overline{\Gamma\mathrm{MST}} \tag{63}$$

$$\mathrm{MST}_{\mathrm{HR,Lv}} \leq \mathrm{MST}^{\mathrm{MAX}}_{\mathrm{HR,Lv}} \tag{64}$$

$$\mathrm{YSF}_{\mathrm{HR,Lv}} \leq \mathrm{YHR}_{\mathrm{HR,Lv}} \tag{65}$$

$$\mathrm{MST}^{\mathrm{SF}}_{\mathrm{HR,Lv}} \leq \mathrm{YSF}_{\mathrm{HR,Lv}} \cdot \overline{\Gamma\mathrm{MST}} \tag{66}$$

$$\mathrm{MST}^{\mathrm{NOSF}}_{\mathrm{HR,Lv}} \leq \big(1 - \mathrm{YSF}_{\mathrm{HR,Lv}}\big) \cdot \overline{\Gamma\mathrm{MST}} \tag{67}$$

$$\mathrm{MST}^{\mathrm{SF}}_{\mathrm{HR,Lv}} + \mathrm{MST}^{\mathrm{NOSF}}_{\mathrm{HR,Lv}} = \mathrm{MST}_{\mathrm{HR,Lv}} \tag{68}$$

The amount of supplementary fuel would be forced to zero by Eq. 69 when supplementary firing is not selected in a given HRSG, since the right hand side of the inequality would be negative and all variables are implicitly positive. This is also possible because the amount of supplementary firing also contributes toward the total cost and the optimizer would implicitly prefer zero supplementary firing in the described situation to avoid unnecessary costs. In case the supplementary firing option is active, the amount of fuel is estimated by using the actual exhaust gas flowrate going through the HRSG and a representative fixed exhaust temperature instead of the actual one to avoid nonlinearities in the equation. The same idea is applied in Eq. 70 for estimating the actual exhaust gas flowrate through each HRSG. This assumption introduces some degree of inaccuracy in the calculated supplementary fuel and exhaust gas flowrate sent for heat recovery. However, such quantities are further required in the problem formulation only for costing purposes. The slight error introduced will eventually end up in the supplementary fuel and HRSG costs. Feasibility conflicts are definitely not introduced by this assumption. Equation 70 also assumes that the pinch point is located at the saturated water point for unfired HRSGs and at the cold end when 100% supplementary firing is used.

Equations 71 to 73 are related to boilers. They account for the selection of up to one steam level, limiting the steam production to active levels only and calculating the fuel required, respectively.

$$\mathrm{QSF_{HR}} \geq \mathrm{Mexh_{HR}} \cdot \overline{\mathrm{Cpexh}} \cdot \left(\overline{\mathrm{TSF^{MAX}}} - \overline{\mathrm{Texh^{AVG}}}\right) - \left(1 - \sum_{\mathrm{Lv}} \mathrm{YSF_{HR,Lv}}\right) \cdot \overline{\Gamma\mathrm{QSF}} \quad (69)$$

$$\mathrm{Mexh_{HR}} \approx \sum_{\mathrm{Lv}} \frac{\mathrm{MST^{NOSF}_{HR,Lv}} \cdot \left(\overline{\mathrm{Cpwv}}_{\mathrm{Lv}} \cdot \left(\overline{\mathrm{Tsup}}_{\mathrm{Lv}} - \overline{\mathrm{Tsat}}_{\mathrm{Lv}}\right) + \overline{\Delta\mathrm{Hvap}}_{\mathrm{Lv}}\right)}{\overline{\mathrm{Cpexh}} \cdot \left(\overline{\mathrm{Texh^{AVG}}} - \left(\overline{\mathrm{Tsat}}_{\mathrm{Lv}} + \overline{\Delta\mathrm{T}_{\mathrm{min}}}\right)\right)} + \sum_{\mathrm{Lv}} \frac{\mathrm{MST^{SF}_{HR,Lv}} \cdot \left(\overline{\mathrm{Cpwv}}_{\mathrm{Lv}} \cdot \left(\overline{\mathrm{Tsup}}_{\mathrm{Lv}} - \overline{\mathrm{Tsat}}_{\mathrm{Lv}}\right) + \overline{\Delta\mathrm{Hvap}}_{\mathrm{Lv}} + \left(1 + \overline{\mathrm{BR^{HR}}}\right) \cdot \overline{\mathrm{Cpwl}}_{\mathrm{Lv}} \cdot \left(\overline{\mathrm{Tsat}}_{\mathrm{Lv}} - \overline{\mathrm{Tbfw}}_{\mathrm{Lv}}\right)\right)}{\overline{\mathrm{Cpexh}} \cdot \left(\overline{\mathrm{TSF^{MAX}}} - \left(\overline{\mathrm{Tbfw}}_{\mathrm{Lv}} + \overline{\Delta\mathrm{T}_{\mathrm{min}}}\right)\right)} \quad (70)$$

$$\sum_{\mathrm{Lv}} \mathrm{YB_{B,Lv}} \leq 1 \quad (71)$$

$$\mathrm{MB_{B,Lv}} \leq \mathrm{YB_{B,Lv}} \cdot \overline{\Gamma\mathrm{MST}} \quad (72)$$

$$\mathrm{QB_B} = \frac{1}{\eta_{\mathrm{B}}} \cdot \sum_{\mathrm{Lv}} \mathrm{MB_{B,Lv}} \cdot \left(\overline{\Delta\mathrm{Hvap}}_{\mathrm{Lv}} + \overline{\mathrm{Cpwv}}_{\mathrm{Lv}} \cdot \left(\overline{\mathrm{Tsup}}_{\mathrm{Lv}} - \overline{\mathrm{Tsat}}_{\mathrm{Lv}}\right) + \overline{\mathrm{Cpwl}}_{\mathrm{Lv}} \cdot \left(\overline{\mathrm{Tsat}}_{\mathrm{Lv}} - \overline{\mathrm{Tbfw}}_{\mathrm{Lv}}\right)\right) \quad (73)$$

The remaining equations related to steam generation are the deareator mass and energy balances (Eqs. 74 and 75), the definition of the make up water flowrate as the sum of all water losses in the system (Eq. 76), and the calculation of the boiler feed water pump power (Eq. 77).

$$\mathrm{LPDea} + \mathrm{STCond} + \mathrm{MMkUp} + \sum_{\mathrm{Lv}} \overline{\mathrm{Cret}}_{\mathrm{Lv}} \cdot \overline{\mathrm{PST^{DEM}}}_{\mathrm{Lv}} = \mathrm{Mbfw} + \overline{\mathrm{F^{DEA}}} \cdot \mathrm{LPDea} \quad (74)$$

$$\mathrm{LPDea} \cdot \overline{\mathrm{hLv}}_{\mathrm{Lp}} + \mathrm{STCond} \cdot \overline{\mathrm{hret^{CT}}} + \mathrm{MMkUp} \cdot \mathrm{hMKup} + \sum_{\mathrm{Lv}} \overline{\mathrm{Cret}}_{\mathrm{Lv}} \cdot \overline{\mathrm{PST^{DEM}_{Lv}}} \cdot \mathrm{YSteam} \cdot \overline{\mathrm{hret}}_{\mathrm{Lv}} = \mathrm{Mbfw} \cdot \overline{\mathrm{hl^{DEA}}} + \overline{\mathrm{F^{DEA}}} \cdot \mathrm{LPDea} \cdot \overline{\mathrm{hv^{DEA}}} \quad (75)$$

$$\mathrm{MMkUp} = \left(\overline{\mathrm{BR^{HR}}} + \overline{\mathrm{SLoss}}\right) \cdot \sum_{\mathrm{HR}} \sum_{\mathrm{Lv}} \left(\mathrm{MST_{HR,Lv}}\right) + \left(\overline{\mathrm{BR^{B}}} + \overline{\mathrm{SLoss}}\right) \cdot \sum_{\mathrm{B}} \sum_{\mathrm{Lv}} \left(\mathrm{MB_{B,Lv}}\right) + \overline{\mathrm{F^{DEA}}} \cdot \mathrm{LPDea} + \sum_{\mathrm{Lv}} \left(1 - \overline{\mathrm{CRet}}_{\mathrm{Lv}}\right) \cdot \overline{\mathrm{PST^{DEM}_{Lv}}} \cdot \mathrm{YSteam} + \frac{\overline{\mathrm{BR^{P}}} + \overline{\mathrm{SLoss}}}{1 - \overline{\mathrm{SLoss}}} \cdot \sum_{\mathrm{Lv}} \overline{\mathrm{PST^{GEN}_{Lv}}} + \sum_{\mathrm{Lv}} \mathrm{Vent_{Lv}} \quad (76)$$

$$\mathrm{WbfwP} = \left(\overline{\mathrm{hbfw}} - \overline{\mathrm{hl^{DEA}}}\right) \cdot \sum_{\mathrm{Lv}} \left(\left(\overline{\mathrm{BR^{HR}}} + 1\right) \times \sum_{\mathrm{HR}} \left(\mathrm{MST_{HR,Lv}}\right) + \left(\overline{\mathrm{BR^{B}}} + 1\right) \cdot \sum_{\mathrm{B}} \left(\mathrm{MST_{B,Lv}}\right) + \frac{\overline{\mathrm{BR^{P}}} + 1}{1 - \overline{\mathrm{SLoss}}} \cdot \overline{\mathrm{PST^{GEN}_{Lv}}} + \mathrm{DSPW_{Lv}}\right) \quad (77)$$

Lastly, the master binary variable YSteam controls the activation or ban of boilers and HRSGs as superstructure options (Eq. 77). In case YSteam has a value of zero, Eq. 78 ensures that the process heat demands are satisfied through a thermal fluid heating system (e.g., hot oil).

$$\sum_{\mathrm{HR}} \sum_{\mathrm{Lv}} \left(\mathrm{YHR_{HR,Lv}}\right) + \sum_{\mathrm{B}} \sum_{\mathrm{Lv}} \left(\mathrm{YB_{B,Lv}}\right) \leq \mathrm{YSteam} \times \left(\overline{\mathrm{NPP^{MAX}}} + \overline{\mathrm{NGTD^{MAX}}} + \overline{\mathrm{NB^{MAX}}}\right) \quad (78)$$

$$\mathrm{QTFH} = (1 - \mathrm{YSteam}) \cdot \overline{\mathrm{QP^{DEM}}} \quad (79)$$

Steam Turbines. Figure 7 illustrates a generic extraction steam turbine and the relevant nomenclature adopted. Equations 80 and 81 are the energy balances that calculate the power produced at each stage of a given steam turbine. Note that they feature the product of flowrates and enthalpies. To keep the formulation linear, the enthalpies of the steam mains are made fixed parameters ($\overline{\mathrm{hLv}}_{\mathrm{Lv}}$) by assuming constant predefined header conditions, as they could be calculated before optimization. As a consequence of this assumption, solutions may feature small amounts of steam letdown and/or boiler feed water injection to the steam mains to absorb any deviation from the chosen fixed conditions. Also, the outlet enthalpies from each steam turbine stage would in

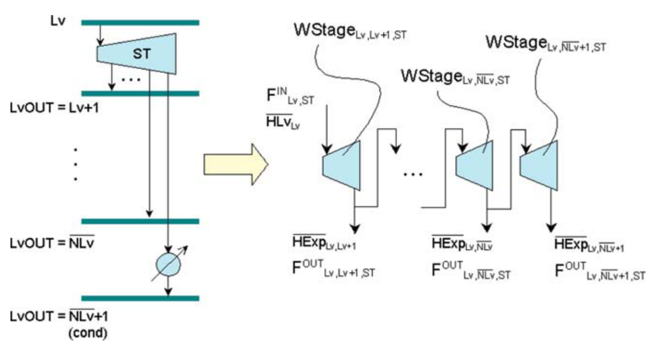


Figure 7. A generic extraction steam turbine.

[Color figure can be viewed in the online issue, which is available at wileyonlinelibrary.com.]

principle be variables since, being rigorous, the performance of steam turbines (e.g., isentropic efficiency) is a function of both the expansion region and the turbine size.[11] However, by neglecting the effect of turbine size, and since the steam levels are known before optimization, the turbine stage efficiencies and the stage outlet enthalpies can be estimated with the model by Varbanov[11] also before optimization (e.g., assuming a moderate steam flowrate). This permit keeping the formulation linear, since the stage outlet enthalpies, now parameters ($\overline{hExp}_{Lv,LvOUT}$), would depend only on the header conditions, which are already fixed. In contrast to the formulations,[11,13] this modeling strategy permits representing multistage steam turbines in a linear fashion and still keeping the relevant energy balances in the formulation to ensure thermodynamic consistency. It has to be emphasized that, although this approximation neglects the impact of stage size on stage efficiency, the effect of stage inlet and outlet conditions is fully considered when predicting these before optimization.

$$\mathrm{WStage}_{Lv,LvOUT,ST} = \left(\overline{hLv}_{Lv} - \overline{hExp}_{Lv,LvOUT}\right) \cdot F^{IN}_{Lv,ST};\quad LvOUT = Lv + 1 \tag{80}$$

$$\mathrm{WStage}_{Lv,LvOUT,ST} = \left(\overline{hExp}_{Lv,LvOUT-1} - \overline{hExp}_{Lv,LvOUT}\right) \times \left(F^{IN}_{Lv,ST} - \sum_{i=Lv+1}^{LvOUT-1} F^{OUT}_{Lv,i,ST}\right); LvOUT \geq Lv + 2 \tag{81}$$

Equation 82 states the mass balance around each steam turbine. Equation 83 defines the total power available from each steam turbine as the sum of the power of all its stages. Equation 84 is a logic statement that allows the selection of only one steam level to feed a particular steam turbine, whereas Eq. 85 limits the inlet flowrate from the active feed steam level to a maximum. Equation 86 is a correlation to estimate the power required by the steam turbine condensers as a function of the heat duty, assuming these are of the air cooled type (derived from Hudson Products Corporation[47]).

$$F^{IN}_{Lv,ST} = \sum_{LvOUT=Lv+1}^{\overline{NLv}+1} F^{OUT}_{Lv,LvOUT,ST} \tag{82}$$

$$\mathrm{WST}_{ST} = \sum_{Lv} \sum_{LvOUT=Lv+1}^{\overline{NLv}+1} \mathrm{WStage}_{Lv,LvOUT,ST} \tag{83}$$

$$\sum_{Lv} \mathrm{YLvST}_{Lv,ST} = \mathrm{YST}_{ST} \tag{84}$$

$$F^{IN}_{Lv,ST} \leq \mathrm{YLvST}_{Lv,ST} \cdot \overline{FIN^{MAX}} \tag{85}$$

$$\mathrm{WCond} = 0.1372 \cdot \sum_{ST} \sum_{Lv} \left(F^{OUT}_{Lv,\overline{NLv}+1,ST} \cdot \left(\overline{h\exp}_{Lv,\overline{NLv}+1} - \overline{hret^{CT}}\right)\right) \tag{86}$$

Steam Mains. Equations 87 and 88 state the mass and energy balances around the steam mains, respectively, except for the first one (VHP), which is taken care of by Eqs. 89 and 90. The letdown from the lowest steam header is used for deareation purposes (Eq. 91). Equation 92 accounts for the total condensate flowrate from steam turbines.

$$\left(1 - \overline{SLoss}\right) \cdot \left(\sum_{HR} \mathrm{MST}_{HR,Lv} + \sum_{B} \mathrm{MB}_{B,Lv}\right) + \overline{PST}^{GEN}_{Lv} + \mathrm{DSPW}_{Lv} + \mathrm{LETD}_{Lv-1} + \sum_{ST} \sum_{i=1}^{Lv-1} F^{OUT}_{i,Lv,ST} = \mathrm{LETD}_{Lv} + \overline{PST}^{DEM}_{Lv} + \sum_{ST} F^{IN}_{Lv,ST} + \mathrm{VENT}_{Lv}; Lv \geq 2 \tag{87}$$

$$\left(1 - \overline{SLoss}\right) \cdot \left(\sum_{HR} \mathrm{MST}_{HR,Lv} + \sum_{B} \mathrm{MB}_{B,Lv}\right) \cdot \overline{hLv}_{Lv} + \overline{PST^{GEN}}_{Lv} \cdot \overline{hPST^{GEN}}_{Lv} + \mathrm{DSPW}_{Lv} \cdot \overline{hbfw} + \mathrm{LetD}_{Lv-1} \cdot \overline{hLv}_{Lv-1} + \sum_{ST} \sum_{i=1}^{Lv-1} F^{OUT}_{i,Lv,ST} \cdot \overline{hExp}_{i,Lv} = \left(\mathrm{LetD}_{Lv} + \overline{PST^{DEM}}_{Lv} \cdot \mathrm{YSteam} + \sum_{ST} F^{IN}_{Lv,ST} + \mathrm{Vent}_{Lv}\right) \times \overline{hLv}_{Lv}; Lv \geq 2 \tag{88}$$

$$\left(1 - \overline{SLoss}\right) \cdot \left(\sum_{HR} \mathrm{MST}_{HR,1} + \sum_{B} \mathrm{MB}_{B,1}\right) + \overline{PST^{GEN}}_{1} + \mathrm{DSPW}_1 = \mathrm{LetD}_1 + \overline{PST^{DEM}}_{1} + \sum_{ST} F^{IN}_{1,ST} + \mathrm{Vent}_1 \tag{89}$$

$$\left(1 - \overline{SLoss}\right) \cdot \left(\sum_{HR} \mathrm{MST}_{HR,1} + \sum_{B} \mathrm{MB}_{B,1}\right) \cdot \overline{hLv}_1 + \overline{PST^{GEN}}_{1} \cdot \overline{hPST^{GEN}}_{1} + \mathrm{DSPW}_1 \cdot \overline{hbfw} = \left(\mathrm{Letd}_1 + \overline{PST^{DEN}}_{1} \cdot \mathrm{YSteam} + \sum_{ST} F^{IN}_{1,ST} + \mathrm{Vent}_1\right) \cdot \overline{hLv}_1 \tag{90}$$

$$\mathrm{Letd}_{\overline{NLv}} = \mathrm{LPDea} \tag{91}$$

$$\mathrm{STCond} = \sum_{ST} \sum_{Lv} F^{OUT}_{Lv,\overline{NLv}+1,ST} \tag{92}$$

Electricity. In the next two equations, each potential power plant place is allowed to be in use by one actual power plant or none. These are selected from a set of standard models available, including simple and combined cycle models. Full load operation of power plants is assumed.

$$\sum_{PPOP} \mathrm{YPPOP}_{PP,PPOP} \leq 1 \tag{93}$$

$$\mathrm{WPP}_{PP} = \sum_{PPOP} \mathrm{YPPOP}_{PP,PPOP} \cdot \overline{WPPOP}_{PPOP} \tag{94}$$

Equation 95 states the overall electricity balance. The demands included are the lumped basic electricity demands, the helper and main motors, boiler feed water pumps, condensers (air-cooled), and the exported electricity. These are balanced against the electricity supplied by the helper generators, power plants, steam turbine generators, and import. Motor and generator efficiencies are taken into account as well as a factor for the electricity distribution losses. Equations 96 and 97 ensure that only one electricity trade option is active (either import or export) and set a maximum trading limit.

If no electricity trading is allowed, there will be difficulties in closing the overall electricity balance because of the presence of discrete elements operating at full load. For formulation purposes, this can be resolved by setting the electricity import to zero but not constraining the export. In this case, the resulting amount of "exported electricity" would actually represent the surplus capacity of the system. Of course, no value should be given to such an "export" since it does not represent a real profit. In practice, one could operate the power system at partial load and stick to the original plant production rate or, alternatively, redesign the plant for an increased production rate so that the demands and the available power achieve a better match, for the sake of an improved capital utilization. Also, the surplus power could be sold if there is a connection to an external grid and an interested party for purchasing this.

$$\overline{\mathrm{BED}} + \sum_{\mathrm{GTD}} \left(\frac{\mathrm{WHM_{GTD}}}{\overline{\eta_m}} \right) + \sum_{\mathrm{M}} \left(\frac{\mathrm{WM_M}}{\overline{\eta_m}} \right) + \mathrm{Exp} + \mathrm{WbfwP} + \mathrm{WCond} - \left(\sum_{\mathrm{GTD}} \mathrm{WHG_{GTD}} \cdot \overline{\eta_g} + \sum_{\mathrm{PP}} \mathrm{WPP_{PP}} + \sum_{\mathrm{STG}} \mathrm{WST_{STG}} \right) \cdot \left(1 - \overline{\mathrm{ELoss}}\right) - \mathrm{Imp} = 0 \quad (95)$$

$$\mathrm{Exp} \le \mathrm{YEXP} \cdot \overline{\mathrm{MaxExp}} \quad (96)$$

$$\mathrm{Imp} \le (1 - \mathrm{YExp}) \cdot \overline{\mathrm{MaxImp}} \quad (97)$$

Number of Compressor Casings. The purpose of Eqs. 98 to 107 is to calculate the number of casings in which each compressor is arranged. Stages of the same compressor that are to be run by a common shaft, either gas turbine, steam turbine or motor driven, can be merged into one compressor casing provided they are of the same nature (e.g., centrifugal), which is an economic incentive. Equation 98 finds out the number of stages of the compressor C that are driven by each gas turbine and Eq. 99 identifies whether the gas turbine GTD is driving at least one stage of such a compressor or not. Equation 100 is then able to calculate the number of different gas turbine shafts in which the stages of the compressor C are running. Similarly, Eqs. 101 to 103 are able to account for the number of motor shafts servicing the compressor in question and Eqs. 104 to 106 for the number of steam turbine drivers. Last, in Eq. 107, the number of casings for the compressor C is calculated. This is, assuming that those stages belonging to compressor C on the same shaft are merged into one casing.

$$\mathrm{NCST_{C,GTD}} = \sum_{\mathrm{CS} \in \mathrm{C}} \mathrm{YTCS_{GTD,CS}} \quad (98)$$

$$\mathrm{NCST_{C,GTD}} \le \mathrm{YTC_{GTD,C}} \cdot \overline{\mathrm{NCS_C}} \quad (99)$$

$$\mathrm{NTS_C} = \sum_{\mathrm{GTD}} \mathrm{YTC_{GTD,C}} \quad (100)$$

$$\mathrm{NCSM_{C,M}} = \sum_{\mathrm{CS} \in \mathrm{C}} \mathrm{YMCS_{M,CS}} \quad (101)$$

$$\mathrm{NCSM_{C,M}} \le \mathrm{YMC_{M,C}} \cdot \overline{\mathrm{NCS_C}} \quad (102)$$

$$\mathrm{NMS_C} = \sum_{\mathrm{M}} \mathrm{YMC_{M,C}} \quad (103)$$

$$\mathrm{NCSST_{C,ST}} = \sum_{\mathrm{CS} \in \mathrm{C}} \mathrm{YSTCS_{STD,CS}} \quad (104)$$

$$\mathrm{NCSST_{C,ST}} \le \mathrm{YSTC_{STD,C}} \cdot \overline{\mathrm{NCS_C}} \quad (105)$$

$$\mathrm{NSTS_C} = \sum_{\mathrm{STD}} \mathrm{YSTC_{STD,C}} \quad (106)$$

$$\mathrm{NCAS_C} = \mathrm{NTS_C} + \mathrm{NMS_C} + \mathrm{NSTS_C} \quad (107)$$

In case a particular compressor contains stages of different nature (e.g., axial and centrifugal), or they are incompatible in some way, it would be more convenient for formulation purposes to define them as different compressors, each one featuring only compatible stages. Therefore, the solver will implicitly refrain from proposing stages of different types to be merged. Also the compressor costing would be more accurate as the costs of compressors of different nature are calculated separately.

Availability. If all the compressors, drivers, and power plants are assumed in series for availability, the availability of the compression train can be calculated as in Eqs. 108 to 114. Note that inactive driver or power plant places will contribute an availability of 1, which is neutral.

$$\mathrm{AITrain} = \mathrm{AIComp} \cdot \mathrm{AIDDGT} \cdot \mathrm{AIST} \cdot \mathrm{AIMM} \quad (108)$$

$$\mathrm{AIDDGT} = \prod_{\mathrm{GTD}} \mathrm{AIT_{GTD}} \quad (109)$$

$$\mathrm{AIT_{GTD}} = \sum_{\mathrm{TOP}} \left(\mathrm{YTOP_{GTD,TOP}} \cdot \overline{\mathrm{Tai_{TOP}}} \right) + 1 - \sum_{\mathrm{TOP}} \mathrm{YTOP_{GTD,TOP}} \quad (110)$$

$$\mathrm{AIC_C} = \left(\overline{\mathrm{Cai_C}}\right)^{\mathrm{NCAS_C}} \quad (111)$$

$$\mathrm{AIComp} = \prod_{\mathrm{C}} \mathrm{AIC_C} \quad (112)$$

$$\mathrm{AIST} = \left(\overline{\mathrm{STai}}\right)^{\sum_{\mathrm{STD}} \mathrm{YST_{STD}}} \quad (113)$$

$$\mathrm{AIMM} = \left(\overline{\mathrm{MMai}}\right)^{\sum_{\mathrm{M}} \mathrm{YMM_M}} \quad (114)$$

$$\mathrm{SchDT} \ge \overline{\mathrm{SimMnt}} \quad (115)$$

$$\mathrm{SchDT} \ge \mathrm{MntT_T} \quad (116)$$

$$\mathrm{SchDT} \ge \mathrm{MntPP_{PP}} \quad (117)$$

$$\mathrm{MntT_T} = \sum_{\mathrm{TOP}} \mathrm{YTOP_{T,TOP}} \cdot \overline{\mathrm{MntTop}}_{\mathrm{TOP}} \tag{118}$$

$$\mathrm{MntPP_{PP}} = \sum_{\mathrm{PPOP}} \mathrm{YPPOP_{PP,PPOP}} \cdot \overline{\mathrm{MntPPop}}_{\mathrm{PPOP}} \tag{119}$$

The scheduled annual downtime is calculated next as the longest maintenance required among all gas turbine drivers and power plants, although such downtime must have a minimum which is given by the general plant maintenance time (not related to gas turbines or power plants). See Eqs. 115 to 119.

Assuming that the failure of any power plant would lead to a total plant shutdown, the unscheduled annual downtime would be as follows:

$$\mathrm{UnsDT} = (365 - \mathrm{SchDT}) \cdot (1 - \mathrm{AITrain} \cdot \mathrm{AIPP}) \tag{120}$$

where

$$\mathrm{AIPP} = \prod_{\mathrm{PP}} \mathrm{AIPPL_{PP}} \tag{121}$$

$$\mathrm{AIPPL_{PP}} = \sum_{\mathrm{PPOP}} \left(\mathrm{YPPop_{PP,PPOP}} \cdot \overline{\mathrm{PPLai}}_{\mathrm{PPOP}}\right) + 1 - \sum_{\mathrm{PPOP}} \mathrm{YPPop_{PP,PPOP}} \tag{122}$$

The lost profit incurred due to both planned and unplanned shutdowns:

$$\mathrm{CAvail} = \left(\mathrm{SchDT} - \overline{\mathrm{SimMnt}} + \mathrm{UnsDT}\right) \cdot \overline{\mathrm{DCAP}} \cdot \overline{\mathrm{PMar}} \cdot \overline{\mathrm{HYR}} \cdot \frac{\left(1+\overline{\mathrm{IR}}\right)^{\overline{\mathrm{LIFE}}} - 1}{\overline{\mathrm{IR}} \cdot \left(1+\overline{\mathrm{IR}}\right)^{\overline{\mathrm{LIFE}}}} \tag{123}$$

Only the excess downtime over that of the minimum plant maintenance (for equipment other than drivers) is penalized. For instance, if the general plant maintenance is scheduled as 10 days/year (excluding DDGTs and power plants) and the most demanding DDGT and power plant require 13 days/year and 15 days/year for maintenance, respectively, then Eq. 120 will penalize only for the lost profit incurred during (15 − 10) = 5 days/year. That is, assuming simultaneous maintenance and that only gas turbine drivers and power plants are the elements capable of eventually incurring such excess downtime.

Sparing Philosophy. Another way of looking after availability issues, particularly for electricity and steam generation, is the consideration of sparing philosophy as discussed before. At the designer's request (through binary parameters $\overline{\mathrm{YPP}}^{N+1}$, $\overline{\mathrm{YSTG}}^{N+1}$ and $\overline{\mathrm{YB}}^{N+1}$), the formulation is able to consider automatically the investment on a spare power plant, spare steam turbine generator, and/or an auxiliary boiler, covering for the failure of any one of their respective units in the system. This is considered by Eqs. 124 to 127. The spare boiler would also cover the failure of any one of the HRSGs in the system. It is assumed that the spare boiler will be designed to produce steam at the highest pressure level.

$$\sum_{\mathrm{PPop}} \mathrm{YSpare_{PPop}} \le \overline{\mathrm{YPP}^{N+1}} \tag{124}$$

$$\sum_{\mathrm{PPop}} \mathrm{YSpare_{PPop}} \cdot \overline{\mathrm{WPPop}}_{\mathrm{PPop}} \le \overline{\mathrm{YPP}^{N+1}} \cdot \mathrm{WPP_{PP}} \tag{125}$$

$$\mathrm{YSpare_{PPop}} \le \sum_{\mathrm{PPop}} \mathrm{YPPop_{PP,PPop}} \tag{126}$$

$$\mathrm{WSpareSTG} \ge \overline{\mathrm{YSTG}^{N+1}} \cdot \mathrm{WST_{STG}} \tag{127}$$

$$\mathrm{MStSpareB} \ge \overline{\mathrm{YB}^{N+1}} \cdot \sum_{\mathrm{Lv}} \mathrm{MB_{B,Lv}} \tag{128}$$

$$\mathrm{MStSpareB} \ge \overline{\mathrm{YB}^{N+1}} \cdot \sum_{\mathrm{Lv}} \mathrm{MST_{HR,Lv}} \tag{129}$$

Parallel Compression. With few modifications, the optimization model can also be used to find optimal power systems that employ parallel compression strategy. Assuming identical compression sets in parallel (identical drivers, compressors, and aftercoolers), there is no need to add more variables to the model, as the user would simply duplicate the driver/compressor arrangement obtained as result. The input data to the optimization would be the same as before, just that the set of compressor demands must be consistent with the fact that they now handle half the refrigerant flowrate.

The contribution of drivers, compressors, aftercoolers, and HRSGs to capital costs, steam, electricity, and fuel has to be doubled because duplicates of these items exist in the implicitly-modeled parallel driver/compressor set. To incorporate these changes, only minor modifications are required in some equations throughout the formulation. Regarding availability, it has to be considered that, although the failure of any item in a compression train still causes the failure of such train, there is another independent train still running and allowing the plant to keep producing at partial capacity. Production at 50% capacity will be assumed for such scenarios, although sometimes it could be more than that. Equation 120 has to be replaced by the following two equations:

$$\mathrm{UnsTot} = (365 - \mathrm{SchDT}) \times \left((1 - \mathrm{AlTrain})^2 \cdot \mathrm{AIPP} + (1 - \mathrm{AIPP})\right) \tag{120a}$$

$$\mathrm{UnsPart} = 2 \cdot (365 - \mathrm{SchDT}) \cdot (1 - \mathrm{AlTrain}) \cdot \mathrm{AlTrain} \cdot \mathrm{AIPP} \tag{120b}$$

The lost profit incurred now becomes as follows:

$$\mathrm{CAvail} = \left(\mathrm{SchDT} - \overline{\mathrm{SimMnt}} + \mathrm{UnsTot} + 0.5 \cdot \mathrm{UnsPart}\right) \times \overline{\mathrm{DCap}} \cdot \overline{\mathrm{PMar}} \cdot \overline{\mathrm{HYR}} \cdot \frac{\left(1+\overline{\mathrm{IR}}\right)^{\overline{\mathrm{LIFE}}} - 1}{\overline{\mathrm{IR}} \cdot \left(1+\overline{\mathrm{IR}}\right)^{\overline{\mathrm{LIFE}}}} \tag{123a}$$

Solving the problem

To obtain the optimal solution, the total cost given in Eq. 1 must be minimized subject to the constraints described by

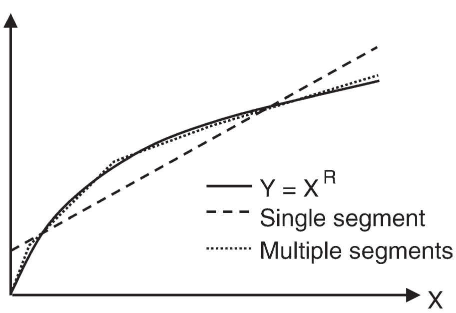


Figure 8. Approximation of a function of the type $Y = X^R$ with $0 < R < 1$.

Eqs. 2 to 129 (general formulation), which still involve several nonlinearities. Additional constraints are given by nonnegative values for the continuous variables (i.e., each continuous variables greater than or equal to zero) and values of {0,1} for the binary variables. The problem is, in principle, of the MINLP type.

Note that a 100% availability subformulation, defined by Eq. 1 as the objective functions and subject to constraints 2 to 106 plus 124 to 129 (i.e., omitting the availability constraints), is also a valid and consistent subproblem that does not consider plant availability. Another way of neglecting plant availability would be to use the general formulation with the inherent availabilities of all components set to 1 and their maintenance time set to 0 days/year or any value below that given to the minimum plant maintenance time.

Linearization. Nonlinearities in the general formulation arise from equations dealing with cost estimation and plant availability. Linearizing the latter could result a very lengthy and complex task, if possible at all, due to the mathematical nature of the expressions (e.g., a variable to the power of another variable) but certainly the nonlinear cost equations can be linearized with a fair effort and some extra equations. By so doing, the 100% availability subformulation could be transformed into an equivalent MILP problem, thereby being much easier to solve. Furthermore, global optima would be guaranteed. Also, the solver robustness would be significantly enhanced when solving the general formulation, even when availability-related nonlinearities force the problem to remain MINLP. This is because firstly the nonlinearities would be kept to a minimum and secondly because the linear, 100% availability formulation could be solved in advance of the nonlinear, variable availability formulation to provide a feasible initial solution for the MINLP solver.

Most cost equations contain factors of the type X^R, where X is a variable and R a constant. Replacing each of these functions by a single straight line would result in a significant loss of accuracy. Instead, a more precise approximation, yet linear, can be implemented by combining several straight lines, each one valid over a given interval. That is, a piecewise linearization. Figure 8 shows clearly that this is a better approximation. Four linear segments are used in the illustration. Depending on how broad the expected range of equipment sizes is, it could be appropriate to use a larger or a lesser number of linear segments. The more segments the more precise the approximation. Nevertheless, it must be kept in mind that these cost models are an approximation themselves and that using an excessive number of segments will just bring extra complexity without a significant improvement in the accuracy of the calculations.

There are various ways of implementing piecewise linearization in practice. Perhaps the most compact way will be employing SOS2 variables (special ordered sets of Type 2). Within an SOS2 set of variables at most two can have positive, nonzero values, and these two variables must be adjacent in the ordering given to the set.[48]

With the purpose of illustrating the application of SOS2 variables to piecewise linearization, let $Y = f(X)$ be the function to be approximated and let the set of N data points (X_i, Y_i) define the $N - 1$ linear segments for the approximation. That is, each segment being defined by each pair of consecutive (X_i, Y_i) points. Let also $\lambda = (\lambda_1 \ldots \lambda_N)$ be the SOS2 variable set. The linearization is then performed by substituting $Y = f(X)$ for the following three equations:

$$Y = \sum_{i}^{N} \lambda_i \cdot Y_i \tag{130}$$

$$X = \sum_{i}^{N} \lambda_i \cdot X_i \tag{131}$$

$$\sum_{i}^{N} \lambda_i = 1 \tag{132}$$

Conclusions

In Part 1 of this article, a systematic methodology has been described for the systematic driver and power plant selection in power-demanding industrial processes using mathematical programming. The discrete nature of gas turbines is fully considered and gas turbine drivers and pre-engineered power plants are selected from a group of candidates. A superstructure-based optimization model has been proposed which is able to obtain the best power system for a given economic scenario and the designer is able to influence the final design by modifying the system constraints, equipment choices, and economic parameters. When neglecting availability considerations, the problem can also be formulated as an MILP problem by linearizing some of the constraints in several intervals. This does, without sacrificing significant accuracy, avoid the convergence problems usually associated with nonlinearities. Although it is not practical to linearize the constraints dealing with plant availability, by linearizing the remaining equations the solving difficulties are kept to a minimum. By carrying out either the full or the maximum practical linearization, one can have more confidence in the optimality of the resulting solutions. The proposed optimization framework is applied to an LNG case study, which is presented in the second part of this article.

Notation

Indices

B = boiler
C = refrigerant compressor
CS = compressor stage

- Lv = steam level (e.g., 1 = VHP, 2 = HP, …, $\overline{\mathrm{NLv}}$ = Cond)
- HR = heat recovery steam generator place (GTD ∪ PP)
- HROP = gas turbine option for HRSG (TOP ∪ SCOP)
- M = electric motor driver place
- PP = power plant place
- PPOP = power plant option (actual model)
- SCOP = simple cycle power plant option (actual model) (SCOP ∈ PPOP)
- ST = steam turbine place
- STD = steam turbine driver place (STD ∈ ST)
- STG = steam turbine generator place (STG ∈ ST)
- GTD = gas turbine driver place
- TOP = gas turbine driver option (actual model)

Parameters

- $\overline{\Gamma \mathrm{HG}}$ = upper limit for helper generator power (kW)
- $\overline{\Gamma \mathrm{HM}}$ = upper limit for helper motor power (kW)
- $\overline{\Gamma \mathrm{MST}}$ = upper limit for steam flowrate (kW)
- $\overline{\Gamma \mathrm{QSF}}$ = upper limit for supplementary firing fuel (kW)
- $\overline{\Gamma \mathrm{T}}$ = upper limit for temperature (kW)
- $\overline{\eta_{\mathrm{B}}}$ = boiler efficiency
- $\overline{\eta_{\mathrm{g}}}$ = helper generator efficiency
- $\overline{\eta_{\mathrm{m}}}$ = motor efficiency
- $\overline{\Delta \mathrm{Hvap}}$ = enthalpy of vaporization of water (kJ/kg)
- $\overline{\Delta \mathrm{Tmin}}$ = minimum temperature difference (°C)
- $\overline{\mathrm{a}}$ = parameter for boiler costing
- $\overline{\mathrm{AA}}$ = parameter for HRSG costing
- $\overline{\mathrm{b}}$ = parameter for boiler costing
- $\overline{\mathrm{BB}}$ = parameter for HRSG costing
- $\overline{\mathrm{BED}}$ = basic electricity demand. Internal power system demands are not included (kW)
- $\overline{\mathrm{BR}^{\mathrm{B}}}$ = boiler blowdown ratio (blowdown rate/steam produced)
- $\overline{\mathrm{BR}^{\mathrm{HR}}}$ = HRSG blowdown ratio (blowdown rate/steam produced)
- $\overline{\mathrm{BR}^{\mathrm{P}}}$ = process blowdown ratio (blowdown rate/steam produced)
- $\overline{\mathrm{CACo}_{\mathrm{AC}}}$ = reference cost of aftercooler (k$)
- $\overline{\mathrm{Cai}}$ = inherent availability of a compressor casing
- $\overline{\mathrm{CEDo}}$ = reference cost of electricity distribution equipment (k$)
- $\overline{\mathrm{CEEXP}}$ = price of exported electricity (k$/kW h)
- $\overline{\mathrm{CEIMP}}$ = cost of imported electricity (k$/kW h)
- $\overline{\mathrm{CFEF}}$ = cost of end flash fuel (k$/kW h)
- $\overline{\mathrm{CFF}}$ = cost of fresh fuel (k$/kW h)
- $\overline{\mathrm{CHMGo}}$ = reference cost of helper motor or generator (k$)
- $\overline{\mathrm{CMo}}$ = reference cost of electric motor driver (k$)
- $\overline{\mathrm{CO2F}}$ = specific CO_2 emissions (kg CO_2/kW h of fuel − LHV)
- $\overline{\mathrm{Cpexh}}$ = mean heat capacity of gas turbine exhaust (kJ/kg C)
- $\overline{\mathrm{CPPOP}}$ = cost of power plant option (model) (k$)
- $\overline{\mathrm{Cpwl}}$ = mean heat capacity of liquid water. (kJ/kg C)
- $\overline{\mathrm{Cpwv}}$ = mean heat capacity of steam. (kJ/kg C)
- $\overline{\mathrm{CRCo}_{\mathrm{C}}}$ = reference cost of refrigerant compressor (k$)
- $\overline{\mathrm{Cret}}$ = fraction of condensate return from process
- $\overline{\mathrm{CT}_{\mathrm{TOP}}}$ = cost of DDGT option (model) (k$)
- $\overline{\mathrm{DCAP}}$ = plant capacity (metric ton/day)
- $\overline{\mathrm{ELoss}}$ = fraction of electricity lost in distribution
- $\overline{\mathrm{F}^{\mathrm{DEA}}}$ = deareator vent (fraction of deareating LP steam)
- $\overline{\mathrm{FIN}^{\mathrm{MAX}}}$ = maximum steam flowrate to steam turbines (kg/s)
- $\overline{\mathrm{FMaxHG}}$ = maximum helper generator size (fraction of the gas turbine output)
- $\overline{\mathrm{FMaxHM}}$ = maximum helper motor size (fraction of the gas turbine output)
- $\overline{\mathrm{FSM}}$ = starter motor size (fraction of the gas turbine output)
- $\overline{\mathrm{hexp}}$ = enthalpy of steam after expansion (kJ/kg)
- $\overline{\mathrm{hbfw}}$ = enthalpy of boiler feed water (kJ/kg)
- $\overline{\mathrm{hl}^{\mathrm{DEA}}}$ = enthalpy of liquid water from deareator (kJ/kg)
- $\overline{\mathrm{hLv}}$ = enthalpy of steam in header (kJ/kg)
- $\overline{\mathrm{hMKUp}}$ = enthalpy of water make-up (kJ/kg)
- $\overline{\mathrm{hPST}^{\mathrm{GEN}}}$ = enthalpy of process steam generation (kJ/kg)
- $\overline{\mathrm{hret}}$ = enthalpy of condensate return from process (kJ/kg)
- $\overline{\mathrm{hret}^{\mathrm{CT}}}$ = enthalpy of condensate return from condensing turbines (kJ/kg)
- $\overline{\mathrm{HRPPOP}}$ = fuel consumption of power plant option (kW fuel/kW power − LHV)
- $\overline{\mathrm{HRTOP}}$ = fuel consumption of DDGT option (kW fuel/kW power − LHV)
- $\overline{\mathrm{hv}^{\mathrm{DEA}}}$ = enthalpy of vapor water from deareator (kJ/kg)
- $\overline{\mathrm{HYR}}$ = annual operating time (h)
- $\overline{\mathrm{LMTD}^{\mathrm{Cond}}}$ = Logarithmic mean temperature difference in steam condensers (°C)
- $\overline{\mathrm{MaxExp}}$ = maximum electricity export (kW)
- $\overline{\mathrm{MaxImp}}$ = maximum electricity import (kW)
- $\overline{\mathrm{MaxM}}$ = maximum electric motor driver power (kW)
- $\overline{\mathrm{MaxQFEF}}$ = maximum end flash fuel available. (kW − LHV)
- $\overline{\mathrm{MaxST}}$ = maximum steam turbine driver power (kW)
- $\overline{\mathrm{Mexh}}$ = exhaust gas flowrate (kg/s)
- $\overline{\mathrm{MLoss}}$ = mechanical loss fraction
- $\overline{\mathrm{MMai}}$ = inherent availability of variable speed electric motor driver
- $\overline{\mathrm{MntPPop}}$ = scheduled maintenance time of power plant option (model) (days/year)
- $\overline{\mathrm{MntTop}}$ = scheduled maintenance time of DDGT option (model) (days/year)
- $\overline{\mathrm{NCASo}_{\mathrm{C}}}$ = reference number of compressor casings
- $\overline{\mathrm{NCS}}$ = number of stages for a compressor
- $\overline{\mathrm{NB}^{\mathrm{MAX}}}$ = maximum number of boilers
- $\overline{\mathrm{NGTD}^{\mathrm{MAX}}}$ = maximum number of gas turbine drivers
- $\overline{\mathrm{NPP}^{\mathrm{MAX}}}$ = maximum number of power plants
- $\overline{\mathrm{PCAS}}$ = penalty per extra compressor casing
- $\overline{\mathrm{PCO2}}$ = penalty for CO_2 emissions (k$/kg CO_2)
- $\overline{\mathrm{PMar}}$ = profit margin (k$/metric ton)
- $\overline{\mathrm{PST}^{\mathrm{DEM}}}$ = process steam demand for heating (kg/s)
- $\overline{\mathrm{PST}^{\mathrm{GEN}}}$ = process steam generation (kg/s)
- $\overline{\mathrm{QP}^{\mathrm{DEM}}}$ = total process heat demand (kW)
- $\overline{\mathrm{SimMnt}}$ = plant scheduled maintenance excluding DDGTs and power plants (days/year)
- $\overline{\mathrm{SLoss}}$ = steam losses (fraction of steam produced)
- $\overline{\mathrm{Tai}}$ = inherent availability of gas turbine driver option (model)
- $\overline{\mathrm{Tbfw}}$ = boiler feed water temperature (°C)
- $\overline{\mathrm{Texh}}$ = temperature of exhaust gas (°C)
- $\overline{\mathrm{Texh}^{\mathrm{AVG}}}$ = average temperature of exhaust gas (°C)
- $\overline{\mathrm{Tsat}}$ = saturated steam temperature (°C)
- $\overline{\mathrm{TSF}^{\mathrm{MAX}}}$ = maximum temperature with supplementary firing (°C)
- $\overline{\mathrm{Tstkmin}}$ = minimum stack temperature (°C)
- $\overline{\mathrm{Tsup}}$ = superheated steam temperature (°C)
- $\overline{\mathrm{U}^{\mathrm{Cond}}}$ = heat transfer coefficient in steam condensers (kW/m^2 C)
- $\overline{\mathrm{Q}_{\mathrm{AC}}}$ = aftercooler heat duty (kW)
- $\overline{\mathrm{Qo}_{\mathrm{AC}}}$ = reference aftercooler heat duty (kW)
- $\overline{\mathrm{STai}}$ = inherent availability of steam turbine driver
- $\overline{\mathrm{WCS}}$ = compressor stage mechanical power demand (kW)
- $\overline{\mathrm{WEDo}}$ = reference electricity distribution (kW)
- $\overline{\mathrm{WHMGo}}$ = reference helper motor or generator size (kW)
- $\overline{\mathrm{WMo}}$ = reference electric motor driver size (kW)
- $\overline{\mathrm{WPPOP}}$ = power output of power plant option (model) (kW)
- $\overline{\mathrm{WRCo}_{\mathrm{C}}}$ = reference compressor mechanical power demand (kW)
- $\overline{\mathrm{WTOP}}$ = power output of DDGT option (model) (kW)
- $\overline{\mathrm{YB}^{\mathrm{N+1}}}$ = activation of sparing philosophy for boilers
- $\overline{\mathrm{YPP}^{\mathrm{N+1}}}$ = activation of sparing philosophy for power plants
- $\overline{\mathrm{YSTG}^{\mathrm{N+1}}}$ = activation of sparing philosophy for steam turbine generators

Continuous, non-negative variables

- AITrain = inherent availability of compression train
- AIComp = inherent availability of all compressors
- AIC = inherent availability of a compressor
- AIDDGT = inherent availability of all gas turbine drivers
- AIMM = inherent availability of all electric motor drivers
- AIST = inherent availability of all steam turbine drivers
- AIT = inherent availability of a gas turbine driver
- CAC = cost of aftercoolers (k$)
- CAvail = present value of losses due to scheduled and unscheduled shutdowns (k$)
- CB = cost of boilers (k$)
- CbfwP = cost of boiler feed water pump (k$)
- CCap = total capital costs (k$)
- CCO2 = present value of penalties for CO_2 emissions (k$)
- CCond = cost of steam condenser (k$)
- CDea = cost of deareator (k$)
- CDDGT = cost of direct drive gas turbines (k$)
- CDist = cost of equipment for electricity distribution (k$)

CElec = present value of exported or imported electricity (k$)
CFuel = present value of fuel consumption (k$)
CHelp = cost of DDGT starter/helper motors and generators (k$)
CHRSG = cost of HRSGs (k$)
CMM = cost of variable speed electric motor drivers (k$)
CO2Em = CO_2 emissions (kg/h)
COpWt = present value of water treatment operating costs (k$)
CPP = cost of power plants (k$)
CspareB = cost of spare boiler (k$)
CSparePP = cost of spare power plant (k$)
CSpareSTG = cost of spare steam turbine generator (k$)
CSTD = cost of steam turbine drivers (k$)
CSTG = cost of steam turbine generators (k$)
CTFH = cost of thermal fluid heater (k$)
CRC = cost of refrigerant compressors (k$)
CWT = cost of water treatment facilities (k$)
DSPW = desuperheating water flowrate (kg/s)
Exp = electricity export (kW)
F^{IN} = steam flowrate to steam turbine (kg/s)
F^{OUT} = steam flowrate from steam turbine (kg/s)
Imp = electricity import (kW)
LetD = steam letdown flowrate (kg/s)
LPDea = low pressure steam flowrate to deareator (kg/s)
MB = boiler steam flowrate (kg/s)
Mbfw = boiler feed water flowrate (kg/s)
Mexh = exhaust gas flowrate (kg/s)
MMkUp = make-up water flowrate (kg/s)
MntT = scheduled maintenance time for a DDGT (days/year)
MntPP = scheduled maintenance time for a power plant (days/year)
MST = steam produced in HRSG (kg/s)
MST^{MAX} = maximum possible steam flowrate from HRSG (kg/s)
MST^{NOSF} = steam produced in HRSG without supplementary firing (kg/s)
MST^{SF} = steam produced in HRSG with supplementary firing (kg/s)
MStSpareB = capacity of auxiliary boiler (kg/s)
NCAS = number of casings for a compressor
NCSM = number of stages of a compressor attached to an electric motor
NCST = number of stages of a compressor attached to a DDGT
NCSST = number of stages of a compressor attached to a steam turbine driver
NMS = number of electric motors running a compressor
NSTS = number of steam turbine drivers running a compressor
NTS = number of DDGTs shafts running a compressor
QB = boiler fuel consumption (kW)
QFEF = end flash fuel consumption (kW − LHV)
QFF = fresh fuel consumption (kW − LHV)
QFTot = total fuel consumption (kW − LHV)
QSF = supplementary firing heat (kW)
QTFH = heat duty of thermal fluid heating system (kW)
SchDT = scheduled maintenance time (days/year)
STCond = total condensate from steam turbines (kg/s)
TCost = total cost (k$)
Texh = exhaust gas temperature (°C)
Tpexh = exhaust gas pinch temperature in HRSG (°C)
Tstk = exhaust gas stack temperature (°C)
UnsDT = unscheduled downtime (days/year)
UnsPart = unscheduled downtime − partial shutdown (days/year)
UnsTot = unscheduled downtime − total shutdown (days/year)
Vent = steam vent flowrate (kg/s)
WbfwP = power of boiler feed water pump (kW)
WCond = power demand of steam condensers (kW)
WHG = helper generator size (kW)
WHGEx = helper generator excess power above starting requirements (kW)
WHM = helper motor size (kW)
WHMEx = helper motor excess power above starting requirements (kW)
WM = electric motor driver power (kW)
WMSD = power delivered to compressor stage by motor (kW)
WPP = power plant output (kW)
WSpareSTG = power of spare steam turbine generator (kW)
WStage = power of steam turbine stage (kW)
WSM = power required for starter motor (kW)
WST = steam turbine driver power (kW)
WSTSD = power delivered to compressor stage by steam turbine driver (kW)
WGTD = power of gas turbine driver (kW)
WTSD = power delivered to compressor stage by a gas turbine driver (kW)

Binary variables

YB = activation of boiler and steam level selection
YExp = activation of electricity export
YHM = activation of helper motor on gas turbine drivers
YHR = activation of HRSG place
YMC = indicates whether an electric motor is running at least one stage of a compressor
YMCS = indicates whether a motor driver is attached to a compressor stage
YMM = activation of motor driver
YPPop = selection of power plant option (model)
YSF = activation of supplementary firing in HRSG
YSpare = selection of spare power plant option (model)
YLvST = inlet steam level selection for steam turbine
YST = activation of steam turbine driver
YSTC = indicates whether a steam turbine driver is running at least one stage of a compressor
YSTCS = indicates whether a steam turbine driver is attached to a compressor stage
YSteam = presence of steam system
YTC = indicates whether a DDGT is running at least one stage of a compressor
YTCS = indicates whether a DDGT is attached to a compressor stage
YTop = selection of gas turbine driver option (model)

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