Optimization of CHP Plants in a Liberalised Power System

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Abstract — **The paper presents a comprehensive optimization tool for the operation of combined heat and power (CHP) generating plants in competitive energy markets. Due to the concurrency of the heat and electricity production, the CHP generating plants are an efficient way of energy production, which can help to achieve energy, environmental and climate policy goals. However, the liberalisation of electricity markets introduces new opportunities for power producers and also new risk due to many additional uncertainties. Facing new challenges requires the development of new tools for CHP production optimisation and for decision support when acting on electricity market. The paper presents the scope and latest research findings on the OSCOGEN project (Optimisation of Cogeneration Systems in a Competitive Market Environment).**

Index Terms — **bidding, CHP, cogeneration, deregulation, electricity trading, liberalisation, artificial neural network, stochastic linear programming, real option, evolutionary computation, OSCOGEN, power market.**

I. Introduction

THE importance of combined heat and power (CHP) generating plants has increased over the last years. Due to the concurrency of the heat and electricity production, the CHP generating plants are an efficient way of energy production. Besides, CHP plants are promoted by the EU [1] because their resource effectiveness can help to achieve national environmental and climate policy goals, and particularly the commitments made under the Kyoto Protocol. The aim of the paper is, therefore, to present the requirements and solutions for the development of a comprehensive optimization tool for the operation of cogeneration plants in competitive energy markets.

As many CHP plants in operation across Europe are already fairly productive, it is necessary to have a very close look at the operation of such systems, in order to reduce the costs or increase sales incomes of energy generation and to improve the CO_2-balance of CHP systems. Further, regarding the liberalisation of the energy market, it is absolutely necessary to build realistic CHP operation models that take into account this new situation. Existing optimisation models for CHP plant operation do not account for the increased complexity caused by the energy market liberalisation and, therefore, it is doubtful if their use is still beneficial and thus justified.

The presented approach has three innovative key points:

- solving detailed optimisation models of CHP systems for long and short term unit commitment,
- the explicit modelling of uncertainties, and
- the development of a new tool for computing bid functions for the electricity spot market.

The key task is to build a tool for the optimization of combined heat and power plant operation which will deliver fast and at the same time reasonably accurate planning results for successful competition in liberalized energy markets.

II. CHP Decision Support Tool Architecture

The presented CHP decision support tool essentially comprises of three main parts (Figure 1):

1. modelling CHP uncertainties,
2. optimal CHP production planning, and
3. bidding tool for optimum electricity trading and decision making for long term bilateral contracts for electricity, fuel contracts and risk hedging.

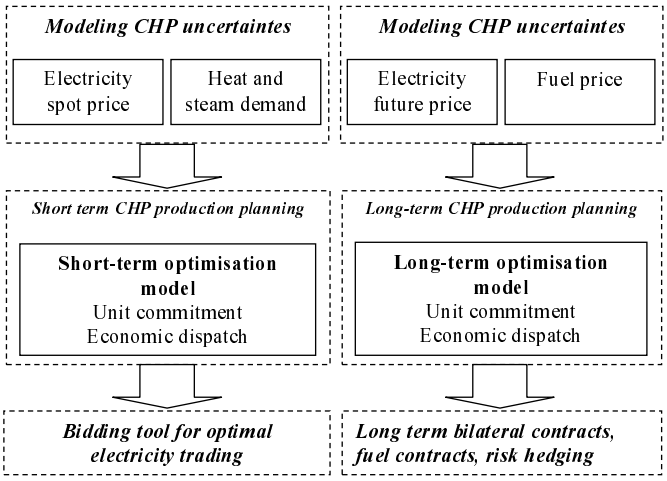

Figure 1: CHP decision support tool

Due to the liberalisation of the energy sector the CHP operation scheduling faces many uncertainties. Both for modelling the unit commitment and for planning the load dispatch, various input parameters are uncertain. In addition to the general uncertainties also faced by power-only plant operators (e.g. regarding electricity demand and spot market prices, fuel prices), CHP operators have to deal with the uncertainties in heat demand as well. The modelling of electricity spot price and heat demand is presented in section III.

The main part of the decision support tool is the CHP optimization tool for solving the unit commitment problem and the economic dispatch. The latter can be handled at two

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different time scales: short-term and long-term. Short-term planning considers planning horizons up to one week and within intervals ranging from 15 minutes up to one hour and supports pure operation decisions. In contrast, long-term optimization deals with time horizons from one month up to three years, and the operation optimisation is only a sub-problem when optimising long-term contracts.

General requirements of the CHP optimization model for the planning process with respect to the uncertainties of the liberalized market are as follows:

- *efficient:* the economic operation optimum should be identified rapidly;
- *robust:* the crucial restrictions should be fulfilled even if parameters of the stochastic variables are not exactly known;
- *reliable:* when uncertain values change, the optimization results should not show strong oscillations. Even with large changes in the uncertain values, the results should still be acceptable;
- *effective:* the complexity of the model and the increased costs incurred should be compared with the cost reductions achievable due to optimally operating conditions;
- *environmentally benign:* emissions of dangerous substances and impacts on the natural environment and society should also be taken into account in the optimization procedure.

Considering the above requirements, the existing state-of-the-art for CHP plant optimisation models [2, 3] has been integrated in the approach taken or, if necessary, revised and reformulated. For this purpose, the following working steps have been performed:

- for each element of the system the most general model has been built, (for generation units, heat stations, heat storage),
- approximation options for the description of relations in the model have been identified and discussed, compared and selected for a case study,
- different approximations to boiler characteristics have been compared,
- the impacts of heat station limits to the optimal results have been evaluated, and a new approach for modelling heat stations has been used,
- solutions to minimize errors arising from treatment of the end of interval values for dynamic processes have been proposed,
- the inclusion of ancillary services has been tackled,
- handling of special buy/sell contracts (e.g. contracts without flexibility, take-or-pay-contracts, contracts with capacity charges, shut-down contracts).

Methodology and solutions for each module of the CHP decision support tool depicted in Figure 1 are presented next.

III. MODELLING CHP UNCERTAINTIES

A. Forecasting spot market electricity price

Electricity spot prices are the main uncertain factor for both the short-term and long-term optimisation models. Spot prices might significantly influence strategies for the unit commitment and the load dispatch problems. The behaviour of electricity prices differs from the behaviour of other commodity prices. One reason for this is that electricity is a non-storable good, implying that inventories cannot be used to arbitrage prices over time. For example, the behaviour of electricity spot prices of the Leipzig Power Exchange (LPX) [4] can be characterized by the following features:

- strong mean reversion: deviations of the price from the equilibrium level due to random perturbations are corrected at a certain rate.
- time of the day effect
- weekend / weekday effect: prices are on average higher during the week when demand is higher
- seasonal effects
- time varying volatility and volatility clustering
- extreme values
- inverse leverage effect: a positive price shock has a larger impact on price changes relative to negative shocks.

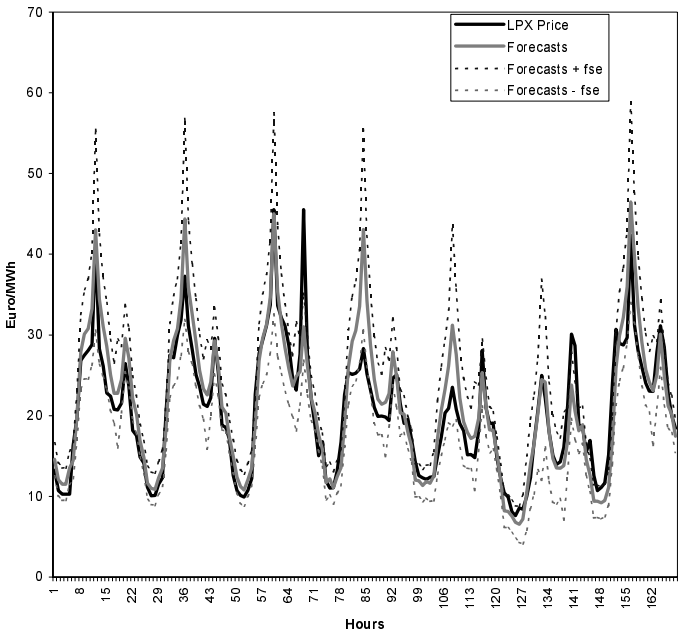

Figure 2: 7-day ahead forecasts

Univariate time series analysis was incorporated to the LPX electricity spot prices of hourly frequency (June 16, 2000 – October 15, 2001) to construct models that describe the behaviour of the prices and give satisfactory forecasts. The forecasting horizon was set to one week and the forecast horizon of models was compared by the root mean square error and the mean absolute error. The following classes of time series models were compared: (i) mean reverting process; (ii) mean reverting process with time-varying mean; (iii) autoregressive moving average (ARMA) models and (iv) exponential generalized autoregressive conditional heteroskedasticity (EGARCH) models. The presence of price spikes was taken into account by constructing the forecasts for *jump models* by adding the jump intensity times the mean of the jump, which were estimated by a recursive filter approach. Two groups of models were considered: (i) global models, which deal with the whole sample and (ii) separate models, which deal with each hour of the day separately. In total, 14 different models were developed, compared and assessed.

Figure 2 presents the actual and forecasted values of LPX electricity spot prices of the best model for the period of October 9, 2001 – October 15, 2001.

B. Forecasting heat demand

Heat demand is a very important factor for both the short-term and long-term production planning models, as its predictions can provide a basis for the optimization of the production process. If the prediction of the heat demand is inaccurate, it may result in non-optimal unit commitment, which has to be corrected afterwards causing higher costs.

Time series analysis for heat demand shows that heat demand can be characterized by the following stylized facts:

- time of the day effect and seasonal effect
- weekday / weekend effect
- time varying volatility
- high negative correlation between heat demand and outside air temperature.

Two basic concepts were used when building short-term heat demand forecasts (STHDF): time series and artificial neural network (ANN) models. The maximum forecast horizon was set to one week in both cases. The total database was divided into a training set (in-sample period) and a test set (out-of-sample period). In real life applications STHDF use forecasted temperature as input data. While temperature forecasts are not yet available, the actual temperature was used in the forecast exercise for all models dealing with the outside air temperature as the explanatory variable. The accuracy of the models was compared by their mean average percentage error (MAPE). Some results are presented later.

1) Time Series Models

Autoregressive integrated moving average (ARIMA) models have been used and in total 24 different models have been developed. The models can be divided into two groups: (i) global models, which deal with the whole sample based on hourly frequency and (ii) separate models, which deal with each hour of the day separately. For some of the global models seasonal differencing is also included (SARIMA models) and sometimes log data transformation has been used to avoid negative heat demand forecasts.

2) Artificial Neural Network (ANN) Models

Application of the ANN technology for forecasting in power systems has received much attention in recent years [5]. The main reason why ANN became so popular lies in its ability to learn complex and non-linear relationships that are difficult to model with conventional techniques. Even for input samples quite different from learning samples neural network methods can yield good results. That capability enables the ANN-based system to model the correlations between the heat demand and factors such as temperature and other climatic conditions, time and type of the day, season, etc. Various architectures of neural networks were analyzed to find the most appropriate solution for this kind of problem, but the *multi-layer perceptron* is found to outperform the other ANNs. In this case the ANN architecture of an existing short-term electricity load forecasting model was used. For the training of the multi-layer perceptron, an enhanced back-propagation algorithm was implemented.

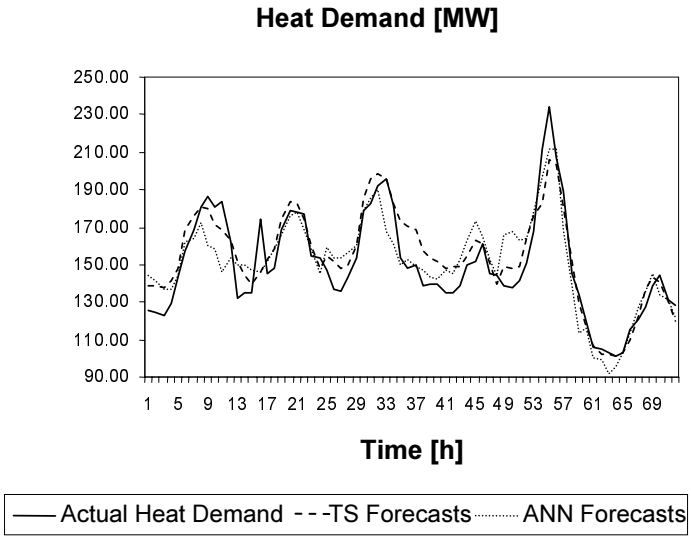

Figure 3: 3-day ahead heat demand forecasts

Figure 3 shows the results for the 3 day-ahead forecasts. It can be observed that the performance of both models is similar.

IV. Optimisation Module

A. Short-term optimisation model for CHP plants

The unit commitment and economic dispatch problem is generally defined as a mixed integer nonlinear optimisation problem. For its solution a number of optimisation techniques have been suggested and implemented [6-8]. However, these methods usually do not allow the inclusion of uncertainties. In the presented work, three stochastic models were developed, which use the spot price model and the heat demand model from section III as input variables. The CHP model was reformulated as a mixed integer linear problem because of two reasons:

1. by comparing the accuracy of the nonlinear and linear CHP model it has been discovered that linear modelling gives similar results;
2. the computational time has to be short enough because of the envisaged future real-life application.

Next, three stochastic models for the short-term CHP optimisation are presented.

1) Stochastic programming model

An extended approach for dealing with uncertainties is stochastic programming [9]. Stochastic programming has become very popular in the field of portfolio optimisation, and in recent years it has also been applied to unit commitment problems. The advantage of stochastic programming is that all possible scenarios are taken into account when determining the optimal decision, in contrast to scenario analysis which calculates the optimal decision only for particular scenarios. To apply stochastic programming for the load dispatch and unit commitment problem scenario trees are needed representing all possible realisations of the parameters. As the size of the scenario tree will rapidly explode if a multitude of combinations of possible values are included for the uncertain

parameters algorithms, scenario reduction techniques have to be applied [10].

Stochastic optimisation has some remarkable properties regarding the distribution of gains in all possible scenarios, and the expected gain is higher than the one of a deterministic optimisation procedure. Moreover, the variance of the distribution of the gains is in general lower compared to the deterministic case. Stochastic optimisation can even be performed with the additional restriction of a guaranteed, minimal gain for each scenario.

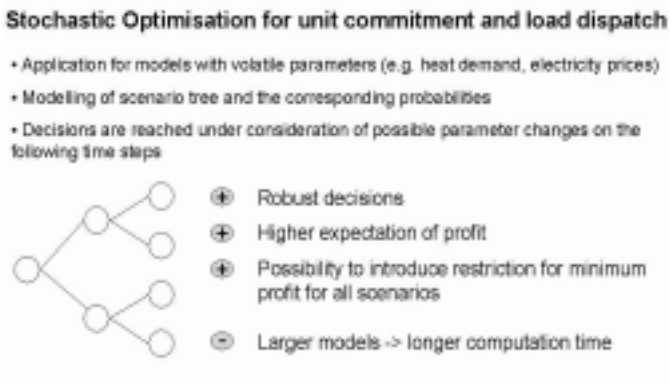

Figure 4: Stochastic optimisation

A stochastic optimisation model has been developed for the short term planning. This model forms the basis for the construction of a tool for creating bid-curves for the spot market.

2) Real option model

Due to liberalisation of electricity markets, power producers are confronted with volatile spot market prices rather than fixed rates. But this increase of uncertainty also results in potential opportunities. The electricity producer has now the possibility - in financial terms: the (real) option - either to produce electricity by using his generation assets or to buy electricity in the spot market. The underlying theory, the theory of real options has mainly been inspired by the option pricing techniques which revolutionized financial theory in the early 1970's. Typical applications of the theory of real options appear in the context of operational decisions, e.g. the unit commitment problem, or in the context of investment decisions, e.g. the decision to extend an existing plant.

In terms of optimal exercise an electricity producing turbine can be compared to a path-dependent American option. In contrast to European options, American options can be exercised at any time before maturity. Path-dependency is caused by intertemporal operational constraints, e.g. minimum up time – minimum down time, unit capacity constraints, start-up time, start-down time, start-up costs, shut-down costs. The pricing of such instruments, which is the primary interest in case of financial options, requires the solution of the optimal exercise problem. In the case of electricity producers this optimal exercise strategy is interesting in itself since it corresponds to the unit commitment problem. For instance, [11] apply backward stochastic dynamic programming and a forward Monte Carlo simulation algorithm known from computational finance to solve the commitment problem for a single turbine. The solution of the problem is represented by so-called *indifference loci* for all periods over the optimization horizon. Figure 5 shows an example solution. The upper dotted line is the *turn-on barrier*, that is, if the turbine is off and the observed spot price exceeds this line, then it is optimal to turn it on. The red line is the *turn-off barrier*, that is, if the turbine is on and the spot price falls below this line, then it is optimal to turn it off. One should note that, because of start-ups and minimum up times, it is not the observed spot price which determines the profit of the unit, but the conditional expectation of the spot price over the following periods. Therefore the indifference loci move according to the conditional expectation of the spot prices. For example at night, the expected spot price is so low that it takes a very high price to justify turning on. At the same time the turn off barrier is also very high, meaning that if the turbine is on, it does not take much reduction in the spot price to make it optimal to turn it off. The single most important input to the model is a stochastic model for the evolution of electricity spot prices.

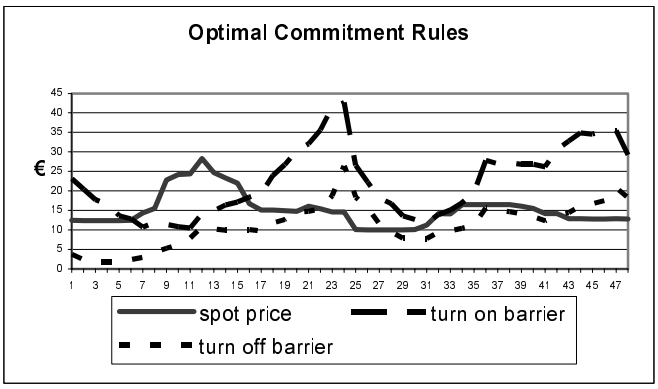

Figure 5: Optimal decision rules for an example turbine given by turn-on and turn-off barriers and the price path of LPX spot prices on June 16 and 17 2000.

Being computationally intensive the advantage of this approach is its flexibility with respect to both the inclusion of additional sources of uncertainty and to the inclusion of additional constraints. Also, the use of Monte Carlo simulation techniques allows for hourly time resolutions, which is in general not possible for scenario trees because of the curse of dimensionality. Furthermore, the approach can be extended to other products that the unit could sell, e.g. ancillary services or emission rights. This allows owners of generation assets to exercise their multi-commodity options across various markets in a consistent and profit maximizing way. In the course of the OSCOGEN project the intention is to extend this approach to heat production, an aspect of particular relevance for CHP plants.

3) GA model

Genetic algorithms (GA) have exhibited significant advantages in finding solutions to non-linear and non-convex problems, and problems with discrete variables, in many different applications [12]. Even though the CHP optimisation problem was defined as a linear mixed-integer problem, the GA can be easily modified for highly non-linear and non-convex problems formulated by detailed CHP model representations.

The CHP optimisation problem has been further divided into two sub-problems: a unit commitment problem (binary variables) and an economic dispatch problem (continuous variables). The unit commitment problem is solved using a genetic algorithm, whereas for the economic dispatch problem the linear programming method was implemented.

An exhaustive state-of-the-art review in the field of genetic algorithms for the unit commitment problem was conducted, concentrating on the encoding scheme and realization of special operators [13-17]. Up to now in most algorithms matrix binary coding was preferred, where one bit is representing the state of one unit in one hour. However, because of minimum up and down time, the search space has a large number of infeasible solutions, thus making it hard for the genetic algorithm to find optimal solutions. Some attempts have been made in finding such coding that only feasible solutions are mapped, but until now no good solution has been reported. In our case two GA were developed: one with direct representation and one with indirect representation. In the first approach each solution is represented by an NxM binary matrix, where N is the number of units and M the number of time intervals [15]. In the indirect approach only the feasible solutions referring to the minimum up and down constraints are encoded. First, N_{Fi} the total number of feasible solutions for each unit i is calculated. The chromosome for one individual is then represented with N integer variables [n_{F2}, n_{F1}... n_{Fi} ... n_{FN}], where $n_{Fi} \in [1 \ldots N_{Fi}]$. A coding/decoding algorithm was developed in such a way that the difference between similar solutions (e.g. same number of start-ups) is small.

The computational effort in a genetic algorithm usually resides in the evaluation of the initial and new individuals. In our case, the evaluation of each individual is solving the economic dispatch problem. Because of the linearity of the CHP model, the linear programming method was implemented.

One of the major issues when solving the optimisation problem with GA is the treatment of unfeasible solutions. Generally, there are two approaches for how to deal with them: (i) penalizing unfeasible solutions using penalty functions, and (ii) encoding only feasible solutions. The second approach is preferable, but not always applicable. In case of the CHP unit commitment problem, the unfeasibility is on one hand due to minimum up and down constraints and, on the other hand, due to heat and steam demand that has to be satisfied (the former is the inter-hour constraint, the latter the intra-hour constraint). In the indirect coding approach, the inter-hour constraint is eliminated. However, for the intra-hour constraint a penalty function was developed, that calculates the distance from the space of feasible solutions.

The convergence of the algorithm and the computational time can be speeded up significantly by implementing special genetic algorithm operators that are tailored to the CHP optimisation problem. As a result, a special mutation operator that considers heuristic rules and the course of the electricity price was developed.

At present the deterministic genetic algorithm is being modified to solve the stochastic optimisation problem. Two uncertain variables are being implemented: the heat demand and the electricity price at the day-ahead market.

B. Long-term optimisation model for CHP plants

For the long-term model, which creates a unit commitment plan for the whole year, it is not possible to have such a detailed description of the system as for the short-term model. In order to reduce the model's complexity approximations have been made. The restrictions for the turbines are described with plant-characteristics-maps, so-called *PQ-charts*. Instead of an hourly time resolution, the model summarises special hours of a day into 7 time slices.

Emphasis lies on the support of decision makers within contract negotiations: therefore, long-term contracts (such as take-or-pay contracts) were included into the optimisation model.

The linear optimisation problem is solved with *Langrangian relaxation* [18]. Lagrangian relaxation algorithms are efficient in speeding up the solving of linear and non-linear optimisation problems. The idea is to decompose the problem, called the primal problem, to several smaller problems that are easier to solve.

V. BIDDING TOOL FOR OPTIMUM ELECTRICITY TRADING

In liberalised electricity markets, participants may either trade bilaterally on the *over-the-counter (OTC) market*, where the bulk of transactions is still being settled, or they may trade on the *exchange market*. Electricity exchanges usually provide at least a *day-ahead market*, where electricity is traded a day in advance, and which helps the system operator to develop an optimal power supply schedule. In order to allow for short term deviations of the supply-demand structure, often an *intra-day market* (hour-ahead market, adjustment market) is also established [19].

In Europe quite a number of electricity exchange markets have been put into operation in recent years, such as APX (The Netherlands), APX UK / UKPX (United Kingdom), EXAA (Austria), Borzen (Slovenia), EEX/LPX[1] (Germany), Nord Pool (Norway, Sweden, Finland), OMEL (Spain), and Powernext (France). Typically, these electricity exchanges provide some form of bidding-based trading in contracts for physical power delivery during a particular hour of the next day (*spot market*). The most common trading system is a *daily double-sided auction* for every hour of the (next) day, where transactions are matched at a single price and at a fixed point in time.[2] By submitting sales (purchase) bids, participants indicate how much they are prepared to sell (buy) at what prices. Sometimes the possible price range is capped (e.g. LPX, Powernext), and sometimes *limits to price volatility* are being imposed in order to improve price continuity (e.g. EEX, Borzen). Typically bidders may attach *special execution orders* to their bids, and very often they are allowed to offer, or ask for, the same quantity of electricity for a period of consecutive hours (*block bids*). In a typical power exchange auction (figure 6) all submitted bids are collected in a *sealed order book* (i.e. participants only know their own bids). Bids can be changed any time until the closure of the call phase. Then, after expiry of the call phase, all sales and purchase bids

[1] In October 2001 the merger of the two German power exchanges EEX (Frankfurt) and LPX (Leipzig) into EEX Leipzig was announced.

[2] The electricity market in England and Wales differs in at least two respects: first, only half-hour contracts are being traded and, second, trading only takes the form of continuous trading.

are collected and sorted by price in ascending order to construct the market demand and supply curve for every hour (figure 7) [19].

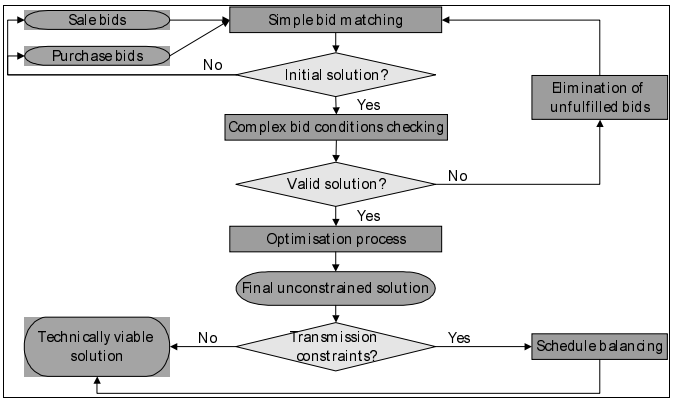

Figure 6: Basic structure of a power exchange bidding mechanism

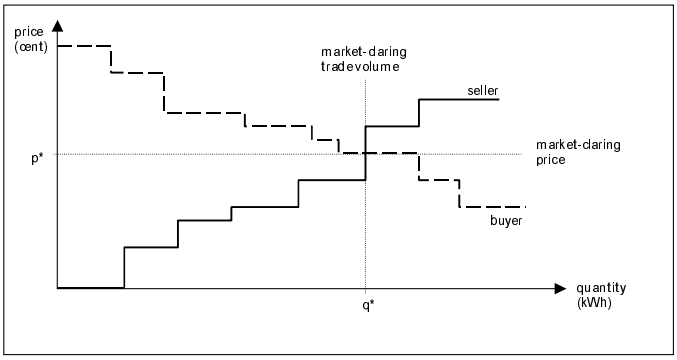

Figure 7: Simple bid matching

The simple bid matching ignores any execution conditions or grid capacity constraints, and results in an initial *market clearing (or auction) price* for every hour and trade volumes for every bid. The market clearing price (price level at the intersection of the aggregated demand and supply curves) maximizes the trade volume.

Ideally, a bid generation tool needs to (i) deliver bids that can actually be used straightforwardly at a particular power exchange market; (ii) automatically generate bid functions that are based on an optimal unit commitment plan; and (ii) take the large spot price volatility appropriately into account.

Since for CHP systems minimum operation and minimum up/down times are important restrictions, the offer curve for each hour cannot be calculated independently. This makes optimisation rather complex. In the OSCOGEN project the actual status of the units and the heat and electricity demand forecasts are used in the model, and an optimal unit commitment plan for the next 24 hours is calculated by means of stochastic optimisation. Based on this optimisation procedure, hourly bidding curves are generated for further use by the CHP plant operator. For the development of the prototype model, data from the German power exchange LPX have been used [4].

In contrast to methods based on heuristic procedures, the stochastic optimisation outcome has the advantage that all possible value combinations of the uncertain model parameters ('scenarios') are taken into account, weighted by their expected probability of realisation. The result is an offer curve that yields the highest profit on average.

VI. THE OSCOGEN PROJECT

The research project OSCOGEN (Optimisation of Cogeneration Systems in a Competitive Market Environment; www.oscogen.ethz.ch), which is partially funded by the - European Commission (5th Framework Programme/EESD), the Swiss Federal Agency of Education and Science, and the Slovenian district heating supplier and project partner Termoelektrarna Toplarna Ljubljana d.o.o., was launched in November 2000 with an overall project duration of 27 months. The consortium consists of five academic research and education organisations, combining competence in the fields of energy modelling, energy economics and market analysis, genetic algorithms, optimisation models for CHP systems, and stochastic optimisation, and two industrial companies with considerable CHP capacities:

- IER - Institute of Energy Economics and the Rational Use of Energy, University of Stuttgart, Stuttgart (Germany)
- IHS - Institute for Advanced Studies and Scientific Research, Vienna (Austria)
- IJS – Energy Efficiency Centre, Institute "Jozef Stefan", Ljubljana (Slovenia)
- FE – Faculty of Electrical Engineering, University of Ljubljana, Ljubljana (Slovenia)
- CEPE - Centre for Energy Policy and Economics, Swiss Federal Institutes of Technology, Zurich (Switzerland)
- TE-TOL - Termoelektrarna toplarna Ljubljana, Ljubljana (Slovenia)
- BEWAG - BEWAG Aktiengesellschaft, Berlin (Germany)

The project will provide prototype tools for the short-term and long-term optimisation of CHP system operation which can then be used by the industrial project partners involved (BEWAG, Berlin, and TE-TOL, Ljubljana) as well as others. If successful, the prototype model may be developed further by the research partners to become a commercially available tool for CHP operation. Finally, due to the expected operation cost reductions that accrue from using the CHP optimisation tool developed, the competitiveness of such plants under liberalised energy market conditions will be enhanced. Hence, an additional benefit of the OSCOGEN project is its contribution to the environmental goals of the European Community, and in particular to reduce CO_2 and other emissions. Overall, this allows strengthening the competitive edge of cleaner energy supply systems in the European countries.

VII. SUMMARY

The objectives, scope, and results of the research project OSCOGEN have been presented in the paper. The overall aim of the research project is the development of a comprehensive and state-of-the-art tool for the optimal operation of cogeneration plants in a competitive energy market. The architecture of the CHP decision support tool for short-term and long-term planning is presented and each sub module is explained.

Due to the liberalisation of the energy sector the CHP

operation scheduling faces many uncertainties. In addition to the general uncertainties also faced by power-only plant operators (e.g. electricity demand, fuel prices and spot and future market prices), CHP operators have to deal with the uncertainties in heat demand as well. The paper presents modelling of electricity price on a day-ahead market. Several classes of time series models were compared: mean reverting process, mean reverting process with time-varying mean, ARMA models, and EGARCH models. Similarly, a short-term heat demand forecasting tool was developed. Apart from time series models, an artificial neural network forecasting tool was constructed.

In the short-term production optimisation module three different methods for solving the stochastic optimisation problem were considered: linear stochastic programming, real option modelling, and genetic algorithms. For the long-term optimisation problem the Lagrangian relaxation was preferred.

Results from the short-term optimisation module form the basis in the bidding tool. The stochastic optimisation outcome has the advantage that all possible value combinations of the uncertain model parameters are taken into account. As a result, the bidding tool developed produces an offer curve that yields the highest profit on average.

The OSCOGEN project will provide prototype tools for the short-term and long-term optimisation of CHP system operation which will be implemented and tested by the industrial project partners involved.

VIII. Acknowledgment

The authors wish to thank M. Kaufmann (CEPE) and A. Schnabl (IHS) for their valuable contribution on the OSCOGEN project. The authors also gratefully acknowledge the support and real-life experiences from A. Hoffmann (Bewag) as also J. Rupar and M. Pavlin (TE-TOL) during the research on the project.

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