NEWSLETTER

Issue 2 December 2001

Editorial

This is the second in a series of semi-annual newsletters on the research project OSCOGEN (Optimisation of Cogeneration Systems in a Competitive Market Environment), which is co-funded by the European Commission (Contract No. ENK5-CT-2000-00094), the Swiss Federal Agency of Education and Science (Contract No. BBW 00.0627), and the Slovenian district heating supplier and project partner Termoelektrarna Toplarna Ljubljana (Contract No. CEU-BS-1/2001). OSCOGEN was launched in November 2000 with an overall project duration of 27 months. The major aim of the research project is the development of a comprehensive and state-of-the-art tool for the optimal operation of cogeneration plants plants in a competitive energy market environment. After providing a brief global introduction on the current state of affairs and project progress, this issue of the OSCOGEN Newsletter describes in a rather non-technical manner how a deterministic model has been built for the CHP system of the German industrial partner BEWAG. Then two ways on how to deal with and incorporate uncertainties in CHP planning are discussed, scenario analysis and stochastic programming, followed by a description of the stylised short-term unit commitment model TEWAG. Next we provide the basic idea behind real option models and report briefly on the real option research approach followed within OSCOGEN. The newsletter concludes with an outlook on the work planned for the coming year 2002 and a list of the OSCOGEN team. For a more detailed account of the project aim and objectives of OSCOGEN, and recently released project reports, please visit the OSCOGEN Website at www.oscogen.ethz.ch, where this newsletter and the previous introductory issue can be downloaded free of charge.

We wish you a Merry Christmas and a Happy New Year 2002. Enjoy!

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Introduction

After a very successful meeting on 12-13 July at BEWAG in Berlin (see Figures 1 and 3), the OSCOGEN team convened again on 8-9 November at the Institute for Advanced Studies (IHS), Vienna. It was the fifth consecutive project meeting, and the common feeling was that the co-operation between the various research teams develops smoothly and that the consortium has indeed continuously built up cohesion. The scientific presentations given in Vienna centred around the following themes:

- deterministic optimisation model for the Slovenian industrial partner TE-TOL;
- genetic algorithm model for TE-TOL;
- inclusion of uncertainties in the stylised demonstration model 'TEWAG';
- progress with the deterministic model for the German industrial partner BEWAG;
- possibilities for the inclusion of heat demand into the real option model; and
- various model specifications for short-term electricity spot price forecasting.

Besides, towards the end of the year several reports (including the first annual Progress Report to the Commission) could be completed. Some of these reports will be made publicly available, so please check out the appropriate sections on our Website.

Figure 1. Fourth OSCOGEN project meeting at BEWAG in Berlin (12-13 July 2001)

Designed by cepe on behalf of OSCOGEN

Deterministic Model for Long-Term Optimisation

For the optimal operation of CHP plants in a competitive energy market environment we have built a deterministic optimisation model as a first step. The model has been applied to the unit commitment and dispatching for a part of the combined heat and power system of BEWAG, consisting of eight CHP turbines, two boilers for heat production and two district heating networks. Extraction condensing steam turbines as well as gas turbines are modelled and coal, oil and gas are considered as input fuels. The operation of the system depends on the electric power load of the utilities' customers and the heat demand in the district heating networks. Market prices on spot and future markets also influence the operation of the system, since electric power can be either self-produced or bought in the market or from take-or-pay (TOP) contracts. The possibility to sell electric power on the market is also taken into account. The model further includes TOP contracts for the fuels. In Figure 2, a simplified reference energy system for the model is shown.

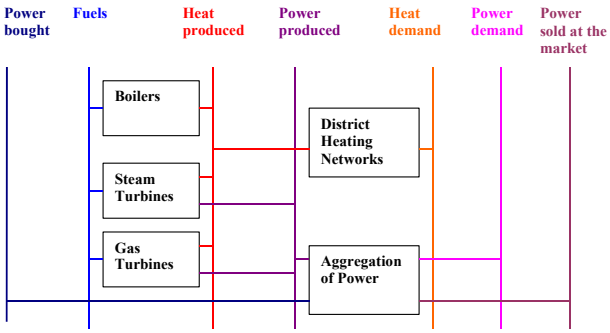

Figure 2. Simplified reference energy system for the optimisation model

The objective of the model is to determine the unit commitment and dispatch of the system yielding the highest profit. To build a realistic model, many technical details of the operation of the different units have to be carefully thought about. Restrictions have to be taken into account for the maximum and minimum power and heat that can be produced by the units at each point in time. The restrictions for the turbines are described with plant-characteristics-maps, so called 'PQ-charts'. There are also restrictions for minimum operating times as well as for minimum down times. Some of the turbines also have grid constraints that must be included in the model. Furthermore, the model also considers the possibility for the system to provide secondary reserve.

The optimisation problem is formulated as a mixed-integer linear model and the software used to solve the model is GAMS (General Algebraic Modeling System; www.gams.com) with the solver CPLEX. GAMS is a software package that has been designed for linear and non-linear optimisation problems; the CPLEX solver has been developed for large linear mixed-integer problems.

The fuel consumption of the turbines is normally described by a non-linear equation. In the linear model this has been approximated. For the turbines in the model described here, the difference in absolute fuel consumption between the true function and the one-line approximation is up to 2%. The difference in the marginal fuel consumption is up to 10%. The approximation could be improved by making a piece-wise linear approximation consisting of two or more lines. However, the experience gained from the first attempts has shown that the calculation time increases considerably.

So far a model has been formulated for the above-described system, and optimisations with reasonable results have been performed for up to a month. The next step is to improve the model with respect to computational performance, especially for months with low heat load and low electric power load. The goal is to be able to model the unit commitment for up to one year.

Figure 3. The OSCOGEN project team visits the BEWAG trading floor (12-13 July 2001)

CHP Planning and Uncertainty

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. electricity demand, fuel prices and spot market prices), CHP operators have to deal with the uncertainties in heat demand as well. Table 1 shows the main uncertainties relevant for CHP operation.

Table 1. Uncertainties of unit operation

Uncertainty	Influencing factors	Type	Short term relevance (2 weeks)	Long term relevance (1 year)
Heat demand	temperature, wind, seasonality, time of the day, day of the week, ...	quantity risk	medium	high
Steam demand	seasonality, time of the day, day of the week	quantity risk	low	low
Electricity demand	temperature, wind, sun light, seasonality, time of the day, day of the week	quantity risk	high	low, only when reserve power is considered
Plant outages	unknown	quantity risk	medium	medium
Fuel price	economic development	price risk	very low	low
Spot price	seasonality	price risk	medium	high
Forward price	seasonality, expectations	price risk	low	high
Counterparty risk	economic development	other	low	low
Legislative risk		other	low	low

Methods that can be used

One common approach to deal with uncertainties is scenario analysis: the parameters are varied and for a particular scenario the optimal result is determined. However, questions such as which scenario will actually occur and which is the optimal unit commitment for the uncertain parameters cannot be answered by scenario analysis.

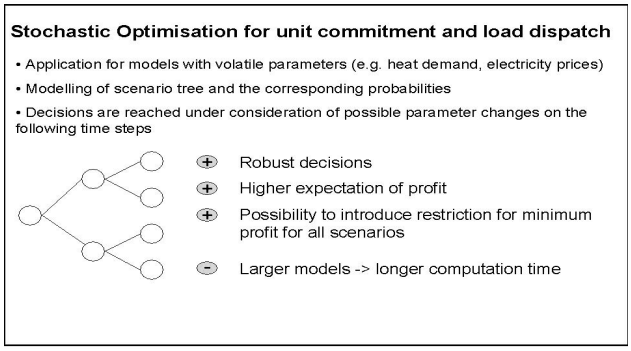

Figure 4. Stochastic optimisation for unit commitment and load dispatch

An extended approach for dealing with uncertainties is stochastic programming (see Fig. 4). Stochastic programming has the advantage that all possible scenarios are taken into account when determining the optimal solution and not only a particular scenario. To apply stochastic programming for the load dispatch and unit commitment problem scenario trees are needed representing all possible realisations of the parameters. But there is a limit to detailed scenario modelling: the size of the scenario tree will rapidly explode if a multitude of combinations of possible values are included for the uncertain parameters. Therefore, in practice, only a selected number of scenarios can be accounted for. Consequently, different uncertain parameters will be modelled with different degrees of detail and the relative importance of uncertainties has to be clearly identified.

Stochastic optimisation has some remarkable properties regarding the distribution of gains in all possible scenarios: 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 in comparison with the deterministic case. Stochastic optimisation can even be performed with the additional restriction of a guaranteed minimal gain for each scenario.

For unit commitment models, the electricity prices will in general be the dominant factor of uncertainty. They have a huge influence on the unit commitment and the load dispatch. If only systems without CHP units are considered, the plan for the unit commitment can be made on the basis of the spot market prices. Assuming a totally liberalised market a generating unit will be run, in principle, if the spot market price is above or equal to the variable costs of production; otherwise the unit will not be turned on or be shut down. For the case of CHP systems, heat demand also has a big influence on the optimal unit commitment, making the analysis more complex. Therefore, the construction of a scenario tree with medium size is difficult. In order to prevent the scenario tree from becoming excessively large, in our analysis only the uncertainties of electricity prices have been modelled in a first step.

Short-term demonstration model TEWAG

In order to demonstrate the advantages of stochastic programming, a small demo model for short-term planning (termed 'TEWAG') has been set up (see Fig. 5). It consists of one gas turbine and one extraction condensing turbine. The operator has to ensure that both electricity and heat demand are satisfied. Furthermore, the possibility for buying and selling electricity at the LPX spot market is included in the model.

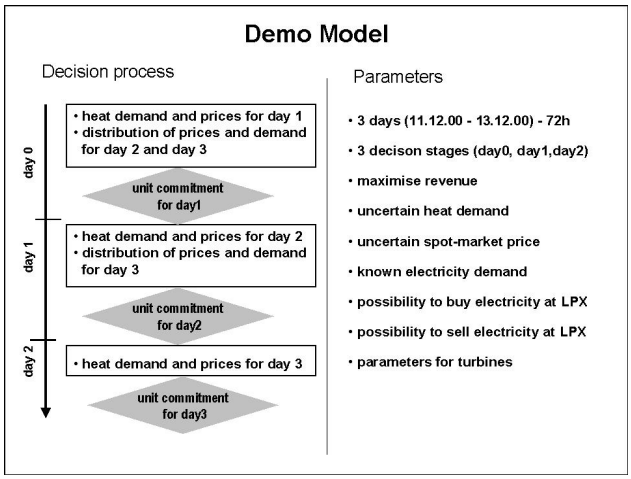

Figure 5. Description of the short-term planning demonstration model TEWAG

In the morning of each day, a plan for the unit commitment for the following day has to be determined. The spot market prices for the following hours and the next two days as well as the heat demand in those days have to be taken into account when taking this decision. The heat demand and the spot market prices for the coming day can be estimated with reasonable accuracy, whereas for the days after tomorrow only a probability distribution can be derived. The decision for the unit commitment and load dispatch for the next day has to be taken considering the known spot market prices and the known heat demand for the following hours, and the estimated distribution for the heat and spot market prices for the following days. As the minimum operation and down times are included in the model, the prices for the following days influence the unit commitment of the first day.

The short-term TEWAG model includes a scenario tree which represents possible scenarios for the spot market prices and the heat demand of the following three days. The electricity market is thereby assumed to be perfectly liquid, so that excess electricity can always be sold, or additionally required electricity bought. After constructing the stochastic optimisation model the results between the deterministic and the stochastic solution were compared. Comparing the deterministic and the stochastic solution we find that on average the stochastic solution will yield about 0.5% -2% better results than the deterministic solution.

Inclusion of uncertainties in a long-term model

For long-term planning in larger CHP systems, it is crucial to reduce the complexity of the stochastic problem. Therefore, an analysis will be done first using a deterministic model for the BEWAG system to calculate the optimal unit commitment and load dispatch for 52 weeks. On the basis of the results for the deterministic long-term model, periods will be identified when production of electricity is possible at costs comparable to the spot market price. In these periods a change in the parameter 'spot market price' will lead to a different schedule for the unit commitment and the load dispatch. In these cases it is thus advantageous to use stochastic programming to find the optimal unit commitment when the real price cannot be estimated with sufficient precision easily. On the other hand situations exist when the uncertainties do not have a high influence on the optimal decisions. For example, if the heat demand in the evening hours is very high, the unit operator faces a surplus of electricity and will sell it at the spot market almost independently of the price at the spot market. This means that in those hours the uncertainty of the prices is of low importance for the optimal schedule.

We therefore plan to identify those periods and to model them more precisely using stochastic programming. The inclusion of the uncertainties of heat demand into the model will be discussed in one of the following newsletters.

Financial vs. Electrical Engineering: Real Option Modelling and the Unit Commitment Problem

The ongoing liberalisation of electricity markets together with the introduction of power exchanges has had a tremendous impact on the electricity production business in Europe. Under the new regime power producers are confronted with volatile spot market prices rather than fixed rates. But this increase in uncertainty also results in increased opportunities and thus potential chances, and here is where the financial industry comes into play. The electricity producer has now the possibility – in finance terms: the 'real' option – either to produce electricity with his/her own generation assets, or to buy electricity in the spot market. The underlying theory of real options has mainly been inspired by the option pricing techniques which revolutionized finance theory in the early 70'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 of the option an electricity producing turbine can be compared to a path-dependent American option (i.e. an option that can be exercised at any time before maturity, in contrast to European options). Path-dependency is caused by inter-temporal operational constraints (e.g. minimum up times – minimum down times), unit capacity constraints, start-up times – start-down times, 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, backward stochastic dynamic programming and a forward Monte Carlo simulation algorithm known from computational finance has been applied in the literature to solve the commitment problem for a single turbine (i.e. in a liquid market it is always optimal to run production capacity against the spot market; it is then not necessary to solve the commitment problem jointly for all production assets).

The solution of such a problem can be represented by so-called *indifference loci* for all periods over the optimisation horizon. Figure 6 shows an example solution. The light (green) 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 dark (red) dotted 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-up times 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 changes in the conditional expectation of spot prices. For example, at night the expected spot price is so low that it requires 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. As part of the OSCOGEN project we have implemented the model using a mean-reverting jump diffusion model with time varying means estimated from LPX spot prices.

Being computationally intensive the advantage of this approach is its flexibility with respect to both the inclusion of additional sources of uncertainty and 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 due to the 'curse' of dimensionality. Further 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.

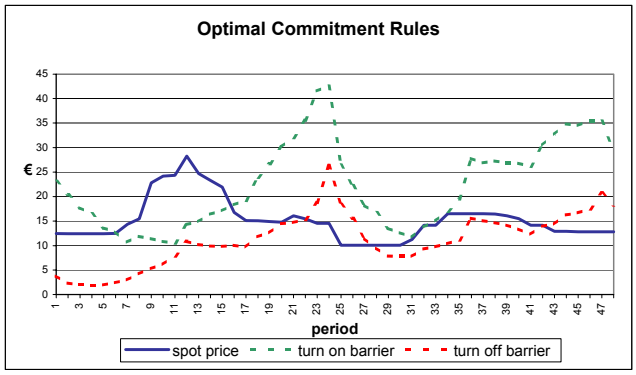

Figure 6: Optimal decision rules for an example turbine given by turn-on/turn-off barriers and the LPX spot price path on 16-17 June 2000.

Planned Work for 2002

In 2002 a suitable short-run forecasting model for heat demand will be fully developed and the forecasting performance studied. The real option model will be extended to include heat production, and the process of studying the CHP operations of the industrial partners will continue. Besides, it is intended to compare the stochastic programming model and the real option model developed with respect to speed, handling, and optimal solutions.

For the solvers based on genetic algorithms the plan is to include uncertainties and to solve both the long-term deterministic and the stochastic model for CHP system operation. This will allow an evaluation and a comparison of the benefits that can be accrued from simultaneously employing stochastic optimisation techniques and genetic algorithms.

Finally, after carefully studying the trading structures and auction mechanisms prevailing in the various European electricity markets, a bidding tool for optimal electricity trading will be developed and evaluated.

The host of the next OSCOGEN partner meeting (28 Feb – 1 March 2002) will be the Centre for Energy Policy and Economics (CEPE) at the Swiss Federal Institute of Technology Zurich (ETHZ).

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