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Stochastic optimization model for detailed long-term hydro thermal scheduling using scenario-tree simulation

Geir Warland, Birger Mo*

SINTEF Energy Research, Sem Sælands vei 11, Trondheim 7034,Norway

Abstract

The paper presents a case study comparing two models for hydro-thermal scheduling. Both models are tools that can be applied for forecasting and planning in electricity markets, taking into account inter-connected power markets and using detailed hydro modelling. The first model, which is used as the reference, is in operative use by most market players in the Nordic power market. The second model is a new prototype which is expected to give better utilization in systems with large shares of hydro power because it to a larger extent is based on formal optimization. The case study compares the models with regard to differences in hydropower scheduling, market prices and socio-economic surplus.

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Keywords: Hydro power applications; hydro-thermal scheduling; power market simulator

1. Introduction

Power markets are experiencing increasing quantities of non-storable new renewables such as wind and solar power. This will result in more rapid and unpredictable fluctuations in intermittent generation. Flexible and fast-responding power plants able to produce at peak demand will therefore see a higher revenue potential. Hydropower plants are very flexible and can provide sufficiently fast response to changes in demand. In systems with large amounts of hydropower, it becomes increasingly important to estimate the value of this flexibility correctly and to optimally schedule the use of water.

* Geir Warland. Tel.: +47-73-59-72-00, fax: +47-73-59-72-50.
E-mail address: geir.warland@sintef.no

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Hydro-thermal market optimization and simulation models are crucial decision support tools used for price forecasting, operation planning, analysis of security of supply and investment analysis. The large number of hydro plants and reservoirs in some systems significantly adds to the complexity of these models. The changes caused by new renewables result in more frequent operation at capacity limits which, from a modelling point of view, increase the importance of correct physical modelling at all levels. More short-term price variations will change the operation and increase use of pumped storage plants and open for investment in new pumping capacity. Since existing detailed hydro-thermal models do not properly take into account the connection between short-term variability in e.g. wind power, solar power and prices and pumped-hydro operation, new models are required. The value of such new models will increase as more renewables are being built in the system. In general, for both producers and consumers, better information about future prices and future system utilization give more optimal use of own resources.

A new model for hydro-thermal market optimization and simulation has been developed at SINTEF Energy Research. This paper provides a simple summary of the model concept, and presents a case study where the new model is compared with an existing power market simulation model. A more thorough presentation and discussion of the model concept will be presented in a future paper.

2. Hydro power scheduling

The hydro-thermal system may comprise of tens, hundreds or even thousands of hydro reservoirs and power plants. There are several stochastic optimization techniques that can be applied to solve the problem, but all have a practical upper limit of how many states (or reservoirs) they can handle with a reasonable computation time.

Models for long term scheduling (power market simulation models) are used for hydro scheduling, price forecasting, expansion planning and power system analysis. They also provide boundary conditions for medium and short term scheduling. The long term scheduling normally has a planning horizon of more than one year. The planning horizon depends on hydro system characteristics.

Models for long term scheduling are typically stochastic models and often involve simplifications and approximations in order to give acceptable computation times, e.g. aggregation of hydro representation and few time increments. The stochastic parts in long term optimization are often based on stochastic dynamic programing (SDP) [1, 2] or stochastic dual dynamic programing (SDDP) [3-6]. Due to the complexity given by the large number of hydro plants and the need for stochastic optimization, all models that need to represent large hydropower system use an aggregated representation of the hydro system.

Many models combine aggregated hydro optimization with disaggregation procedures. Disaggregation is used in simulation procedures to verify that decisions from an aggregated model are valid for the detailed physical system. Disaggregation and validation also ensures that the simplifications, and consequently added unrealistic flexibility given by the aggregation, are corrected for in the simulated results. Models that combine simulation techniques with (strategy) optimization at an aggregate level can effectively address non-linear and state dependent constraints that otherwise need to be simplified or even left out in pure formal optimization methods due to problem size and resulting computational burden.

The aggregation technique used in these models introduces simplifications that may give non-optimal model decisions, which in turn may lead to non-optimal operation and utilization of resources, and possibly wrong investment decisions.

3. EMPS

The model that will be used as the reference model in the case study is the EMPS-model developed at SINTEF Energy Research. The EMPS-model is in operative use by many players in the Nordic power market. The model is typically run on a weekly or even daily basis for decision support.

EMPS is a tool for forecasting and planning in electricity markets [1, 2]. It has been developed for optimization and simulation of hydro-thermal power systems with a considerable share of hydropower. The model takes into account transmission constraints and hydrological differences between major areas or regional subsystems. The objective is to minimize the expected cost in the whole system subject to all constraints. This can be shown to be equivalent to maximization of socio-economic surplus which again is the solution a perfect market would give. The simulated system can e.g. be the Nordic system or Northern Europe. The basic time step in the EMPS model is one week, with a planning horizon of up to 25 years. Within each week, the time-resolution is 1 hour or longer. The problem is solved in two steps; a strategy part and a simulation part as seen in Fig 1.

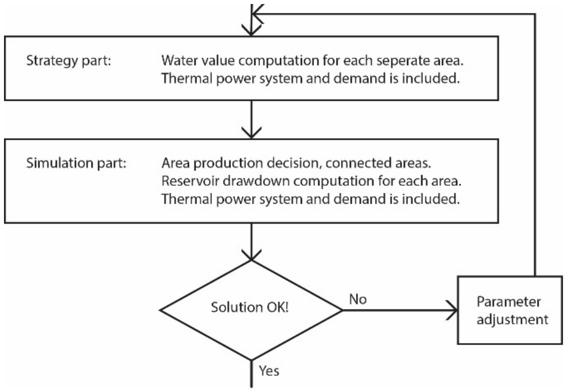

Fig. 1. EMPS logic

3.1. Strategy evaluation

In the strategy part the goal is to find the optimal strategy for use of water. This is done using a combination of SDP and a heuristic approach for treating the interconnection between areas. The heuristic process may also include user calibration. The process is shown in Fig 2.

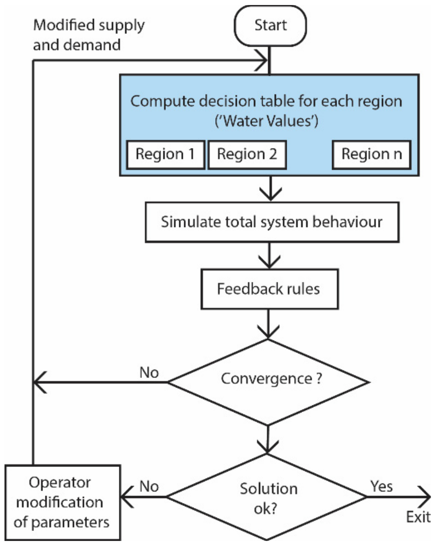

Fig. 2. Strategy evaluation

In the strategy part incremental water values (WV) are computed in an iterative scheme. In each iteration, and for each market area separately, WV's tables are calculated using SDP. The WV calculation for a given area includes a market description representing the local market as well as interconnected power markets. Having found WV-decision tables for all areas, the model simulates the obtained strategy. In the simulation, power system decisions (hydro and thermal generation, price dependent load, etc) are determined week by week in a market clearing process using formal optimization (linear programming; LP) where the WV are used as the marginal costs for hydropower. If the simulated system behavior deviates from the previous iteration, the market description for each area is modified using heuristics, and the process is repeated.

Simulation of system operation in the strategy evaluation is normally based on aggregated hydro models.

3.2. Simulation

In the simulation part a market clearing process equal to what is done in the strategy part is performed based on the incremental water values found in the strategy part. If detailed hydro modelling is used, aggregate hydro production is distributed to individual plants using a rule-based reservoir drawdown model. The rules used to obtain individual target reservoirs for each week, are based on the following main properties:

- Splitting of each year into a filling and a drawdown season
- Equal overflow risk for all reservoirs in the filling season
- Available water as long as possible in all reservoirs throughout the whole drawdown season

The aggregate market clearing problem is updated with information from the detailed drawdown model in an iteration loop. The feedback includes information about marginal plant efficiencies and the actual reservoir fillings compared to the drawdown strategy's target reservoirs.

4. New power market simulation model: SOVN

4.1. Scenario fan simulator

The SOVN model solves the same hydro-thermal market problem, as is solved by the EMPS model. It simulates a sequence of problems referred to as scenario fan problem (SFP) [7,8]. In the SFP problem the first decision stage refers to a given week with a given realization of stochastic variables (inflow, temperature, price etc.). In the second decision stage, covering a part of the remaining planning period, the stochastic variables take values according to predefined scenarios. Only the solution for the first week of the SPF is used. The second stage scenarios are based directly on historical records for all weather related variables. A smoothing procedure, based on individual AR(1) models, is applied to get a smooth transition from the first stage deterministic values to the observed records. The model uses historical records directly as input for stochastic variables; using the same records for the scenario fan as in the main simulation. The SFP structure is illustrated in Fig 3. Each time-stage (and scenario) in the SFP comprise variables and constraints for a detailed representation. That includes reservoir balances for each hydro reservoir, power balances and transmission constraints. As a result the model solves the market clearing process for the whole power market with detailed representation of hydro. Each SFP-problem is, in principle, a large LP.

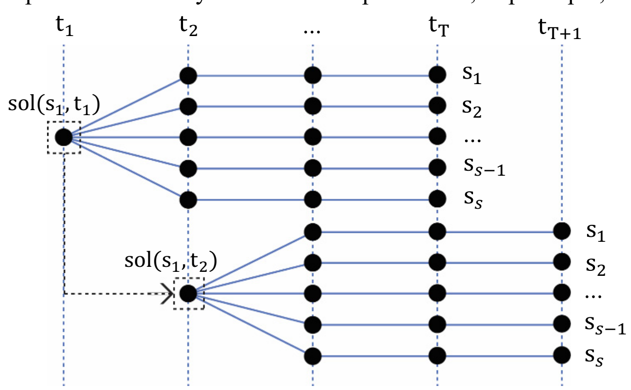

Fig. 3. Illustration of SFS logic

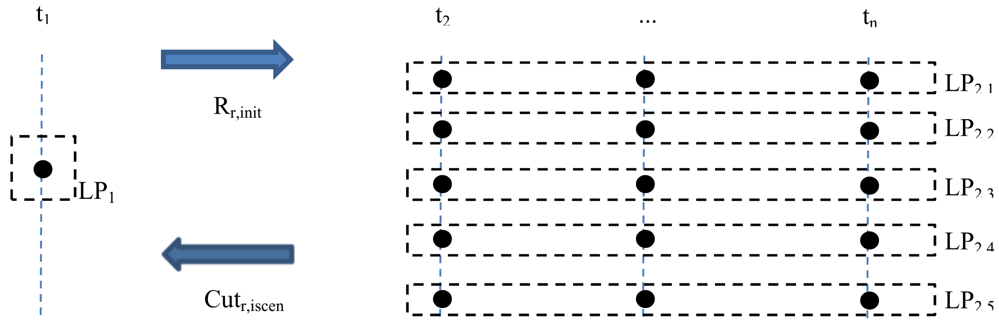

Fig. 4. Solution of SFP

4.2. Scenario fan problem

Each SFP problem, which is a two-stage stochastic LP problem, is solved using Benders decomposition [9]. The first stage represents a given week of the simulation (weather scenario and week). The second step is represented by independent scenarios. The SFP is solved as a sequence of LP-problems, where the first stage (LP_1) is solved first, providing the initial reservoir ($R_{r,init}$) for the independent future scenarios. Each scenario ($LP_{2,i}$) is solved individually LP using the initial reservoirs found in LP_1. In the next iteration the first stage is re-solved with Benders cuts ($Cut_{r,iscen}$) representing the boundary conditions for the future. The iteration process is as follows:

- Solve first stage problem: LP_1 and send $R_{i,init}$ to stage 2.
- Solve second stage problems: $LP_{2,iscen}$ using $R_{i,init}$ and send $Cut_{r,iscen}$ to stage 1.

The process is illustrated in Fig 4.

5. Case study

Results from the SOVN model are compared with the standard EMPS model for a test system.

5.1. Power system

The study case is a fictitious system consisting of 4 interconnected areas, representing 4 coupled power markets. Each area has local power production and demand. Data for demand, transfer capacity and supply for the areas are given in tables 1, 2 and 3.

Table 1. Firm load [values in GWh]

Area	Average / year	Min / week	Average / week	Max / week
Area 1	2925	37,1	56,3	72,9
Area 2	2083	21,0	40,0	57,8
Area 3	2667	24,6	51,3	76,9
Area 4	1000	19,2	19,2	19,2

Table 2. Transfer capacity and aggregate hydro

Line	From	To	Capacity [MW]	P_{max} [MW]	Reservoir [GWh]
1	Area 1	Area 2	200	610	1530
2	Area 2	Area 3	200	535	1610
3	Area 1	Area 3	100	820	2860
4	Area 3	Area 4	100	0	0

Table 3. Price dependent production [values in MW or *GWh/week, prices in øre/kWh]

Area1			Area 2			Area 3			Area 4		
Unit	Capacity	Price	Unit	Capacity	Price	Unit	Capacity	Price	Unit	Capacity	Price
1	0,58	0,0	1	,58*	24,6	1	0,44	1,0	1	,58*	24,0
2	0,64	1,0				2	0,10	4,0	2	50	5,0
3	0,89	9,6				3	0,26	10,0	3	150	15,0
4	0,42	14,3				4	0,17	15,0	4	50	20,0
5	1,32	17,0				5	0,83	17,0			
6	0,26	19,8				6	0,78	40,0			
7	0,90	45,0									

Three of the areas (areas 1 - 3) include hydropower production from the systems shown in Fig. 5, one water course in each area. All the water courses are real physical water courses taken from the Norwegian power system with significant complexity in topology. In total 50 individual hydro power modules are represented. A hydro power module can consist of either a single reservoir, or a reservoir with power plant, and can have separate routes for drawdown, bypass and spillage. This is illustrated in the figure by dotted connection lines.

Area 4 represents a market area without hydro power. The market description in this area only contains firm and price elastic demand, price elastic power production and wind power.

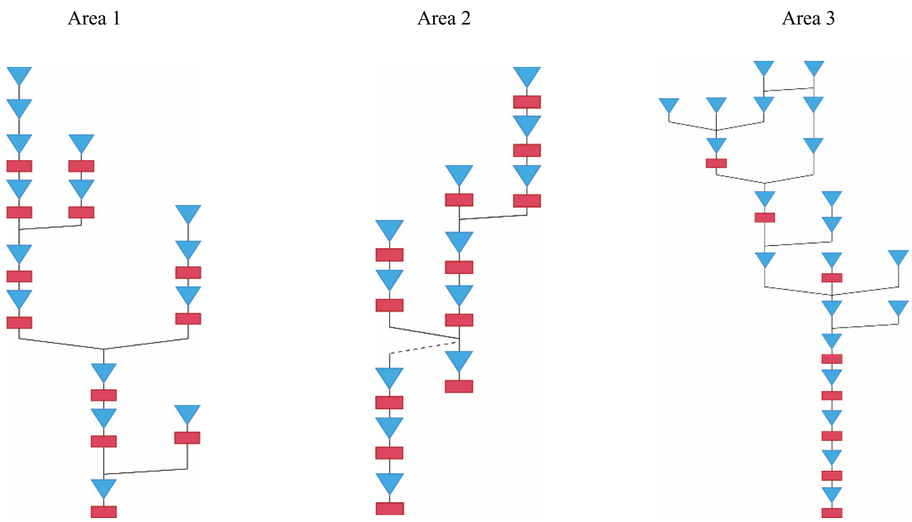

Fig. 5. Water courses in the case study

The system is analyzed using a planning horizon of 3 years (156 weeks) for 38 weather scenarios given by observations for 38 historical years. Each week is divided into 4 accumulated load periods, representing a load duration curve.

5.2. Results

Both models (EMPS and SOVN) give fairly similar aggregate hydro scheduling. This is illustrated in Fig 6, which shows percentiles for simulated sum energy content of the hydro system in area 1. These results indicate that both models have a good utilization of the flexibility in the hydro system, but it is not possible to say from this figure that one is better than the other.

SOVN does, however, give a more optimal us of water compared EMPS, giving higher hydro power production and less spillage. This is shown in Table 4, which shows the difference between results obtained by SOVN and EMPS. The increase in hydro power production replaces thermal production, giving higher socio-economic surplus.

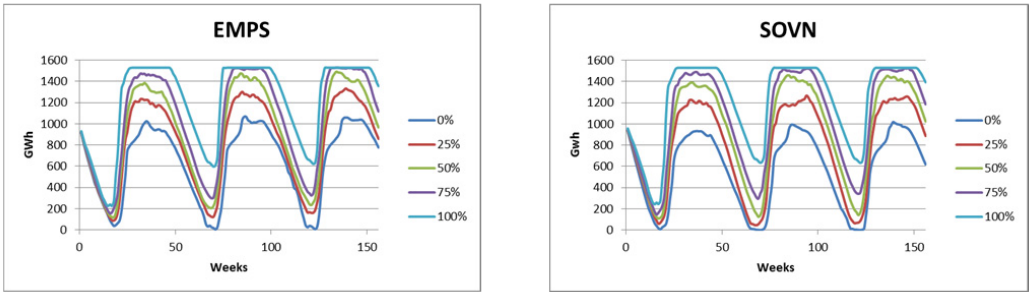

Fig. 6. Percentiles for simulated aggregate reservoir content for area 1

Table 4. Difference between SOVN and EMPS's simulated average values for the 156 week planning period

SOVN – EMPS	Hydro (*GWh*)	Spillage (*GWh*)	Thermal (*GWh*)	Socio-economic surplus (*Mkr*)
Area 1	134	-120	-14	5,7
Area 2	195	-320	0	-18,7
Area 3	458	-165	-4	31,9
Area 4	0	0	-654	22,2
Total	787	-605	-672	41,1

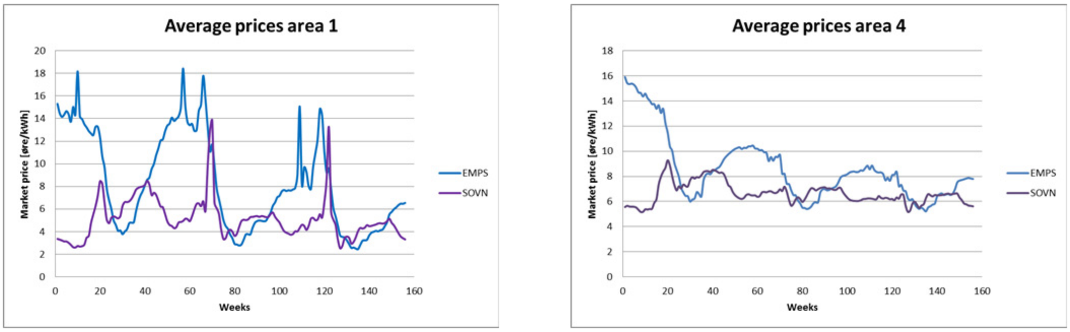

Fig. 7. Simulated average prices in area 1 and 4 from SOVN and EMPS

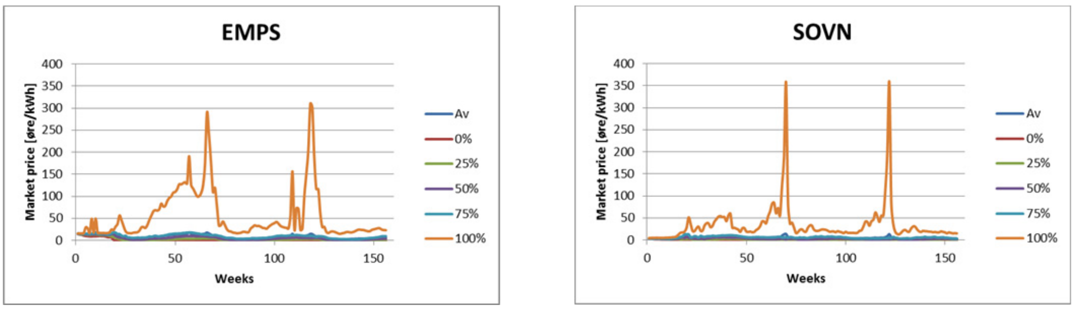

Fig. 8. Percentiles of prices in area 1 from SOVN and EMPS

Fig. 7 shows the average simulated prices from EMPS and SOVN for areas 1 and 4. The prices in area 2 and 3 are similar to the prices in area 1. Fig. 8 shows percentiles for the simulated prices in area 1 for both models. SOVN clearly gives lower prices than the EMPS. This has several reasons. The demand is predominantly firm load, with a yearly and weekly profile. Price dependent supply is dominated by 3 large thermal units in area 4. SOVN gives more optimal utilization of the hydro; higher hydro production and lower spillage. Higher hydro production replaces thermal production in area 4, and thus gives lower prices. Due to the few, large thermal units in area 4, relatively small changes in thermal production may give large changes in prices. Another reason for the price difference is because EMPS has more curtailment, as is seen in Fig. 8. This also contributes to higher average prices in EMPS.

EMPS gives especially higher prices than SOVN for the first 20 weeks. One reason is that EMPS uses less hydro production in area 3, and instead imports from area 4, while SOVN has higher production in area 3 in this period, avoiding large imports from area 4.

6. Conclusion

The case study in this paper indicates that replacing aggregate hydro description and heuristics with a more formal optimization may give a model better suited for power systems analysis. A model with formal optimization gives better utilization of the hydro resources as is shown in the example. It is also believed that this model will be better suited e.g. for investment analysis models because the model that uses a combination of aggregation and heuristics may lead to inconsistencies.

In our example the prototype model gave better simulated operation of the system than the traditional model. This is as expected as the SOVN model is based on formal optimization, while EMPS uses a heuristic approach. Some differences may be caused by special hydro system constraints not yet included in the SOVN-model. It is, however, still expected that SOVN will give better results also for more realistic cases (real power systems) but more testing is needed to very this.

7. Future work

The SOVN – model will be further developed, e.g. by including more detailed hydro constraints such as ramping constraints and time delays. Future research development will also include representation of detailed transmission constraints.

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