WILMAR Deliverable D6.2 (c):
The WILMAR Long Term Model

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Contents

The Wilmar Long Term Model is part of the Wilmar Planning Tool, developed in the project Wind Power Integration in Liberalised Electricity Markets (WILMAR) supported by EU (Contract No. ENK5-CT-2002-00663).

Preface

The Wilmar Planning Tool is developed in the project Wind Power Integration in Liberalised Electricity Markets (WILMAR) supported by EU (Contract No. ENK5-CT-2002-00663).

A User Shell implemented in an Excel workbook controls the Wilmar Planning Tool. All data are contained in Access databases that communicate with various sub-models through text files that are exported from or imported to the databases. The Long Term Model (LTM) constitutes one of these sub-models as shown in Figure 1.

This report documents the Long Term Model (LTM). The documentation describes:

1. The purpose and idea of the LTM
2. The data
3. The linkage with the Joint Market Model (JMM)
4. Illustration of simulations using the LTM in a stand-alone version.

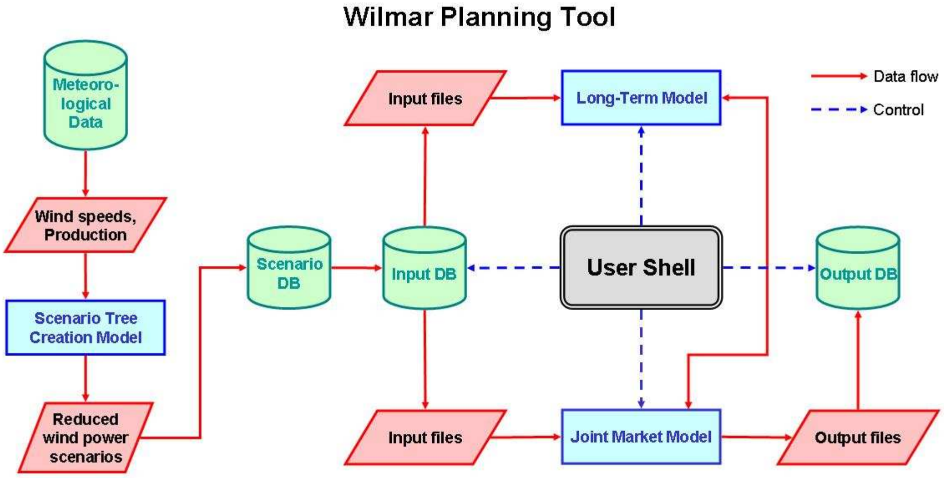

Figure 1 Overview of Wilmar Planning tool. The green cylinders are databases, the red parallelograms indicate exchange of information between submodels or databases, the blue squares are models. The user shell controlling the execution of the Wilmar Planning tool is shown in black.

Table 1: Basic information about the Long Term Model

Authors	Hans F. Ravn
Development period	November 2002 – October 2005
Relation to other programs	See Figure 1
Program language	C++ and GAMS (General Algebraic Modeling System) with a LP solver
Location	http://www.wilmar.risoe.dk

1 Introduction to the Long Term Model (LTM)

1.1 Objectives

The focus of the WILMAR model is the integration of substantial amounts of wind power in a liberalized electricity system. The model analyses the fluctuations and the partial unpredictability in the wind power production, and how other units in the power system have to be operated more flexibly to maintain the stability of the power system. Technically this means that larger amounts of wind power will require increased capacities of spinning and non-spinning power reserves and an increased use of these reserves. Moreover, if wind power is concentrated in certain regions, increased wind power generation may lead to bottlenecks in the transmission networks. Economically, these changes in system operation have certainly cost and consequently price implications. Moreover they may also impact the functioning and the efficiency of certain market designs.

The analysis of wind power emphasises the stochastic behaviour of wind generation and forecast errors; these aspects are mainly of a short term nature (i.e., related to hours or at most a few days ahead). However, in order to operate the system efficiently “now”, it is necessary to incorporate mechanisms that secure that operation “now” is balanced against operation “later”. This is relevant for the operation of hydro power with reservoirs. In the Northern European context there are hydro reservoirs that are designed for holding water throughout a year or more, and with a relative size of energy and power that give them a significant influence on the electricity system in the region. Moreover, due to the relative short term flexibility of hydro power production from reservoir, this is particularly interesting in relation to fluctuating energy sources like wind power.

The purpose of the LTM is to provide the necessary framework in relation to hydro power reservoirs for making decisions at any time in the Joint Market Model (JMM) that are balanced against JMM decisions later. This is done by providing water values, i.e., an evaluation of the value of hydro power from reservoirs. In the JMM, these water values are used as marginal cost for the use of hydro power from reservoirs.

1.2 Main idea and function

Water values represent the value (expressed in monetary terms, such as Euro/MWh) of hydro power from reservoirs (in the sequel called HYRS). HYRS is for the present purpose characterised by three things. First, that the marginal cost of operation is small compared to the average marginal cost in the system under consideration; second, that the energy can be stored on a long terms scale (e.g., one year)); and third, that the energy is limited on a long terms scale (again e.g., one year), although the quantity is stochastic.

The consequence of this is that the value of one MWh additionally of water will be mainly determined by where it can best be used. This will be as a substitute of one MWh of alternative production, which typically will be thermal. So, paradoxically, the value of hydro power can not be determined independently of thermal power. By extending such reasoning it follows that the water value can only be determined by considering the whole system – both in the geographical extension (because any region with HYRS is connected with the other regions through electricity transmission) and in the time extension (because the long term operation consists of a large number of short term operations).

Ideally then, the JMM and the LTM should be solved simultaneously. This is practically impossible due to the size of the problem, and the separation of the whole problem into two models, the JMM and the LTM, is the response to this.

The LTM operates on a simplified version of the whole problem. The simplifications have been done such that the emphasis on the resulting model is the long terms aspects related to operation of HYRS. In particular:

- Combined heat and power (CHP) is represented by equivalent hourly electricity production
- No aspects of unit commitment or ramping limitations for thermal power plants are represented
- Wind power is represented by one hourly time series covering one year (i.e., deterministic)

In all other aspects the data that is common between the LTM and the JMM is identical.

In addition to the data entering the JMM, the LTM receives a time series for hydro inflow to reservoirs. This time series is given on a weekly basis, covering a number of historical years (presently 1980 – 2002). Thus, it is in its origin similar to the time series for unregulated hydro inflow (which enters both the JMM and the LTM, and which is on an hourly basis). These time series are taken as representative of the stochastics of hydro inflow.

The LTM basically operates on a weekly basis, corresponding to the available time series for hydro inflow to reservoirs. However, the variation between the individual hours is represented to some extent, such that the variation in load, forced electricity production (from CHP, wind and unregulated hydro power), marginal electricity costs and exploitation of transmission links are taken into account.

The WILMAR model is a multi-regional model, where a region is characterised by having unlimited electricity transmission capacity internally. Between regions there are transmission possibilities with technical specifications in terms of capacities and costs. Thus, regional differences with respect to HYRS, concentrations of installed wind power, demand and occurring bottlenecks between regions can be considered. This motivates that also the LTM is multiregional.

A classical approach to determining water values uses dynamic programming. This technique permits representation of the technical constraints in the system and exactly reflects the sequential decision structure of the problem. Moreover, it permits handling of stochastic elements (in this case, the hydro inflow), and calculation of water values as expected values.

The weakness of dynamic programming is that, except for special situations (notable the linear-quadratic case) its practical application is dependent on the dimension of the state space (in the LTM context: the number of reservoirs) not being too large (typically meaning no more than two or three).

The dynamic programming approach has therefore been implemented such that it operates on a one reservoir model. This is obtained by aggregating all regions into one region (and hence also only one reservoir).

To represent multiple reservoirs a second approach has been developed. This is based on suboptimal and adaptive control ideas, see[1] Bertsekas (1987) with various adaptations to the problem at hand. The approach uses a certainty equivalent control where the idea may be described as follows.

The available data is mainly that previously described, given as deterministic values: the production system with costs and capacities; electricity demand; forced electricity production (primarily from CHP, wind). Further there are time series for hydro inflow for a number of years. For these time series their mean value time series are calculated, i.e., for hydro with reservoir a time series with weekly values for each reservoir is given, for unregulated hydro a time series with hourly values for each region is given

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[1] Dimitri P. Bertsekas: Dynamic Programming: Deterministic and Stochastic Models, Prentice-Hall, 1987.

Assume that at the beginning of week *w* the following is available: the present hydro reservoir filling and the nominal (i.e., required according to model philosophy, see below) reservoir filling one year ahead. Then formulate and solve the problem consisting in minimising the operations cost over one year, starting in week w, using mean value time series for hydro. The model (called LTM2) may have an approximate representation of the hours of the year (e.g., 1000 hours), while the reservoir filling has a weekly representation. The solution to this problem specifies, among other things, how much regulated hydro power to use during week w.

At the beginning of the following week it is possible to calculate the filling of the hydro reservoir from the calculated use of regulated hydro power and the inflow (which may be taken from a specific historical year, or draw at random from a probability distribution corresponding to the historical values, according to the assumptions taken in the JMM).

The above model, which is a typical example of a rolling horizon idea, uses a fixed end point for reservoir filling, the nominal value. This secures that the reservoirs are not emptied, but kept at sustainable, yet time varying, levels The nominal trajectory for reservoir filling is found as follows. Formulate and solve the problem consisting in minimising the operations cost over one year, using mean value time series for hydro, and requiring a cyclical relation over time (i.e., the reservoir filling at the end of the year must be the same as at the beginning of the year). The model (called LTM1) has the same representation of time as the LTM2 model described above.

Obviously the use of regulated hydro power may deviate from the solution found as described, for instance if wind power deviates much from the assumed value. This is taken care of in the JMM, which handles the time perspective within the week.

The interplay between the LTM and the JMM may then be described as follows:

1. Solve LTM1 to get nominal trajectories for reservoir filling.
2. Select the initial week and initial reservoir filling, pass this information to LTM2.
3. Solve LTM2 to obtain water values, pass water values for the present week to JMM.
4. Solve JMM over one week, using the received water values as marginal costs for use of regulated hydro power.
5. In JMM, calculate the reservoir filling at the beginning of the next week, pass the next week's number and initial reservoir filling to LTM2 and go to step 3.

Various refinements are possible. In particular, the JMM may call LTM2 more frequently that weekly in order to permit timely update of water values. Further, the LTM1 and LTM2 may have additional details, see below.

The lower and upper reservoir capacities are specified as input. Using the mean value implies the risk that the fulfilment of these limits can not be assured in the simulations in LTM2. Using the method described in Jørgensen and Ravn (1996) [2] it is possible to strengthen the probability of attaining a feasible solution as follows.

Consider a week *w*, a region *r* and a given hydro reservoir level. For this situation an optimal use of regulated hydro exists, say, *H*. If this quantity is indeed applied, it is possible to calculate the reservoir level at the beginning of the next week (*w+1*). Recalling that the solution was found using mean weekly

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[2] Claus Jørgensen, and Hans F. Ravn: Optimal Scheduling of Heat Production with Storage and Stochastic Demands, Proceedings, Calorstoch'94, Espoo, 1994, pp 411-418.

inflow, this level will be lower than, equal to or larger than the one assumed on the calculation according to whether the realised stochastic inflow was smaller than, equal to, or larger than the mean value. If the inflow is smaller than the mean value, then the resulting reservoir volume at the beginning of week $w+1$ may be infeasible due to violation of the lower bound of the reservoir level. It therefore makes sense to apply during derivation of the nominal trajectory an artificial lower reservoir level, determined as follows. Take the original lower level, and add to it the maximal difference between the mean inflow and all the instances of the stochastic inflows in week w. This way, all regions' lower reservoir levels in all weeks may be increased. Similar reasoning may be applied around the upper reservoir levels, where the result will be a decrease in the upper level.

This way of correcting the reservoir levels serves as a safeguard against infeasibilities (and hence improvement of expected value). In the case of a one reservoir model the reasoning around the lower level leads to correct results. For the upper reservoir level, and for the case of multiple reservoirs the reasoning is not strictly correct.

A special issue concerns the possible systematic deviation between the price levels in JMM and LTM. As explained, the LTM relies on a simplified representation of the energy system, compared to the JMM. Some of the simplifications might lead to lower prices in the LTM, in particular the omission of unit commitment, ramping constraints and wind power stochastics. On the other hand, some simplifications might lead to higher prices in the LTM, for instance because by converting the CHP production technologies to electricity only technologies some dispatch possibilities related to use of heat storage are missed. For this reason a calibration possibility is built into the interplay between the JMM and LTM models.

2 Data to the LTM

2.1 General

Input data to the LTM is drawn from the WILMAR database. Data to the LTM are simplified data, highlighting the focus on the determination of water values for the hydro dominated parts. In this section the content and the format for the data input to the LTM are described.

From the WILMAR input database the following is provided:
Sets:

- The set of regions.
- The set of hours.
- The set of weeks.
- The set of years.

Numerical data:

- Available electricity generation capacities and costs for dispatchable units.
- Electricity demand.
- Electricity export to 3rd countries.
- Fixed electricity production from:
    - Wind power plants.
    - CHP plants.
    - Unregulated hydro power plants.
- Hydro inflow to regulated hydro power plants.
- Power transmission capacities.
- Hydro reservoir capacities.
- Lower and upper bounds on hydro reservoir fillings.

Further the following information is not used by the LTM, but it may be useful for interpretation of the input files:

- Name of the case.
- The set of fuel types.
- The set of technology types.

The stochastic hydro inflow is assumed to be represented by the time series for regulated and unregulated hydro. The interpretation of the remaining data should be straightforward.

2.2 Data files

Sets and data are organized in text files, one file for each of the above-mentioned sets and data.
Semicolon is used as field separator between data elements. No terminal semicolon is used.
All files have a header of two lines with timestamp and name of the case. The lines start with an asterix.
Example :

```
* TimeStamp : 07/10/2005 20:32:27
* Case Name : 2010_base
```

The input is supposed to consist of characters consistent with the GAMS character set.
The following symbols are used in this paper:

RRR	Region
HHH	Hour
WWW	Week
YYY	Year
FFF	Fuel type
TTT	Name of technology type
GGG	Name of production unit or unit group

2.2.1 OWV_RRR.txt

The set of regions.

The names of all regions, one name per line.
Syntax:

```
RRR
```

Example:

```
DK_E
DK_W
FI_R
```

2.2.2 OWV_HHH.txt

The set of hours.
All hours of a 52-week year, one hour per line.
Hours are indicated by H001, H002, … , H8736.
Syntax:

```
HHH
```

Example :

```
H0001
H0002
….
H8736
```

2.2.3 OWV_WWW.txt

The set of weeks.

All weeks of a year, one week per line. All years have 52 weeks!
Weeks are indicated by W01, W02, … , W52
Syntax:

```
WWW
```

Example :

```
W01
W02
….
W52
```

2.2.4 OWV_YYY.txt

The set of years.

The main stochastic element in the model is the inflow of hydro power. This is represented by a time series, indexed by the year.
Syntax:

```
YYY
```

Example:

```
1980
1981
```

2.2.5 OWV_FuelTypes.txt

The set of fuel types.

Syntax:

```
IFuel;FFF;Descr
```

IFuel : Fuel index.
FFF : Fuel name.
Descr : Description of fuel.

Example:

```
1;NUCLEAR;Fuel used to nuclear power stations
2;NAT_GAS;Natural gas
3;COAL;Coal
4;LIGNITE;Lignite
5;FUELOIL;Fuel oil
```

2.2.6 OWV_TechTypes.txt

The set of technology types.

Syntax:

```
ITech;TTT;Descr
```

ITech : Technology index.
TTT : Technology name.
Descr : Description of technology.

Example:

```
1;IGCONDENSING;Condensing thermal units
2;IGBACKPRCHP;Back pressure thermal units
3;IGEXTRACTION;CHP extraction thermal units
```

2.2.7 OWV_CaseName.txt

Name of the case.

Syntax:

Text string

Example:

My_Base_Case

2.2.8 OWV_GDISP.txt

Available electricity generation capacities and costs for dispatchable units.

Syntax:

RRR;WWW;GGG;P;Q;G;F

GGG	Name of the production unit or unit group.
P	Short-term production cost including fuel and emission taxes and tariffs, Money/MWh.
Q	Electricity generation capacity, MW. The capacity is reduced according to GKDERATE. GKDERATE data is given on weekly basis.
G	Number identifying the technology type.

Units included (GGG):

Regulated hydro power, condensing, and extraction (operated at no heat production)

Units not included:

All other units, i.e. back pressure, wind, heat boilers, short term heat and electricity storages.

G	Description
1	Condensing thermal units
2	CHP Back pressure thermal units
3	CHP extraction thermal units
4	Heat-only boilers
5	Heat pumps or electrical heaters
6	Heat storage
7	Electricity storage
8	Hydropower with reservoir
9	Hydropower without storage (run-of-river)
10	Wind power
11	Photovoltaics

F	Description		
1	Nuclear	11	Straw
2	Nat_Gas	12	Wood
3	Coal	13	Wood_Waste
4	Lignite	14	Wind
5	Fueloil	15	Water
6	Lightoil	16	Sun
7	Orimulsion	17	Electric
8	Shale	18	Water_Res
9	Peat	19	Heat
10	Muni_Waste		

Example:

DK_W;W01;DK_W_Rural_ST-E7-NG;217;123.4;3;4

2.2.9 OWV_DE.txt

Electricity demand.

Syntax:

RRR;HHH;Value
Unit: MW

Example:

DK_W;H1234;1234.44
DK_W;H1235;1235.55
DK_W;H1236;1236.66

2.2.10 OWV_X3FX.txt

Electricity export to 3rd countries.

Syntax:

RRR;HHH;Value
Unit: MW

Export : Positive value.
Import : Negative value.

Example:

DE_CS;H1234;1.7100e3
DE_CS;H1235;1.7200e3
DE_CS;H1236;1.7300e3

2.2.11 OWV_WIND.txt

Fixed electricity production from wind power plants.

Syntax:

RRR;HHH;Value
Unit: MW

Example:

DK_W;H1234;134.44
DK_W;H1235;135.55
DK_W;H1236;136.66

2.2.12 OWV_H2EFX.txt

Fixed electricity production from CHP plants.

Syntax:

RRR;HHH;Value
Unit: MW

Example:

DK_W;H1234;234.44
DK_W;H1235;235.55
DK_W;H1236;236.66

2.2.13 OWV_HYRR.txt

Fixed electricity production from unregulated hydro power plants.

Syntax:

YYY;RRR;HHH;Value
Unit: MW

Example:
1980;NO_M;H1234;234.44
1980;NO_M;H1235;235.55
1980;NO_M;H1236;236.66

2.2.14 OWV_HYRS.txt

Water inflow to regulated hydro power plants.

Syntax:
YYY;RRR;WWW;Value
Unit: MW

Example:
1980;NO_M;W01;1234.44
1980;NO_M;W02;1235.55
1980;NO_M;W03;1236.66

2.2.15 OWV_TRANS.txt

Power transmission capacities.

Syntax:
RRR1;RRR2;Value
Unit: MW
The transmission capacity is a one-way capacity.
RRR1;RRR2 indicates transmission from RRR1 to RRR2.

Example:
NO_N;NO_M;900
NO_M;NO_N;900
NO_N;FI_R;120
FI_R;NO_N;120

2.2.16 OWV_HYRSCAP.txt

Hydro reservoir capacities.

Syntax:
RRR;Value
Unit: MWh

Example:
NO_M;1234.56

3 Linkage between LTM and JMM

As described, the LTM actually consists of two sub-models, LTM1 and LTM2. LTM1 generates initially the nominal reservoir trajectories, while LTM2 generates water values corresponding to a specified week and reservoir filling.

LTM1 must be activated before entering the simulation loops in JMM. The LTM1 model is activated from a JMM run by calling the file “base\model\LTM1.gms”.

LTM2 is activated repeatedly during JMM simulation. The JMM model communicates with the LTM through three files placed in folder “Base\Model\LTM\LTMmed”:

- “ResFillWstart.med”
- “WV1reg.med”

- “WVcalib.med”

File “ResFillWstart.med” gives the relative filling of hydro reservoirs for each region and for the week in question. It is written by the JMM each time a day has been simulated, and is used by the JMM to lookup water values in file “WV1reg.med”.

File “WV1reg.med” gives water values as function of hydro reservoir filling and week number, assuming a one region hydro reservoir model. The monetary unit is the same as given in the input files to LTM. The file is recalculated once a week by the LTM.

File “WVcalib.med” holds weekly hydro power production as calculated by the LTM. It is used by the JMM to calibrate water values read from file “WV1reg.med”. Calibration may in principle be done in several ways, but is intended to be done in the JMM interface to LTM. By having available both the weekly average price and the weekly hydro production, these two quantities may be compared with similar values calculated through one week’s JMM simulation. Differences may be exploited to add a mark-up (which in principle may be negative) to the water values received from LTM before application in LTM.

The LTM2 is activated from a JMM run by calling the file “base\model\LTM2.gms”.

4 Illustration of the multi reservoir model

4.1 Simulating several years

As described above, the LTM is intended for use with the JMM. However, in order to illustrate here some basic functionality, a simulation framework has been established that works exclusively on the LTM data. Basically, this means that the calculation done in the JMM is substituted by the calculations done in LTM2. Since the data available for this is the same as the ordinary LTM input, this means that the same type of simplification is made as previously mentioned. In particular the wind power is assumed known with certainty.

With this added functionality it is possible to simulate forwards through the weeks, over a number of years. The LTM1 part of this version is the same as previously described. In the new version the following takes place in a given week.

1. Solve LTM1 to get nominal trajectories for reservoir filling.
2. Select the initial week and initial reservoir filling, pass this information to LTM2.
3. Solve LTM2 to obtain use of regulated hydro.
4. Calculate the reservoir filling at the beginning of the next week, using the hydro inflow according to the year and week in the given time series, pass the next week’s number and initial reservoir filling to LTM2 and go to step 3.

In the following some illustrations will be given for this implementation; the above solution and simulation method will be referred to as LTM3. The data used is a preliminary reference case from the WILMAR database, with relatively low (compared to late 2005) fuel prices and no CO2 emission cost.

4.2 Reservoir filling

The graph in Figure 2 shows the reservoir filling as the result of a simulation for the years 1980 – 2002 with this version. A clear yearly pattern is seen, with high reservoir levels building up during autumn, and then drawing down on the volume during winter and spring.

The differences between the years are due to differences in hydro inflow. For instance 1996 was dry in the Nordic countries, and it is observed from the figure that the peak for NO_S during the autumn 1996 reached only approximately 35 TWh, against typical values between 40 and 50 TWh.

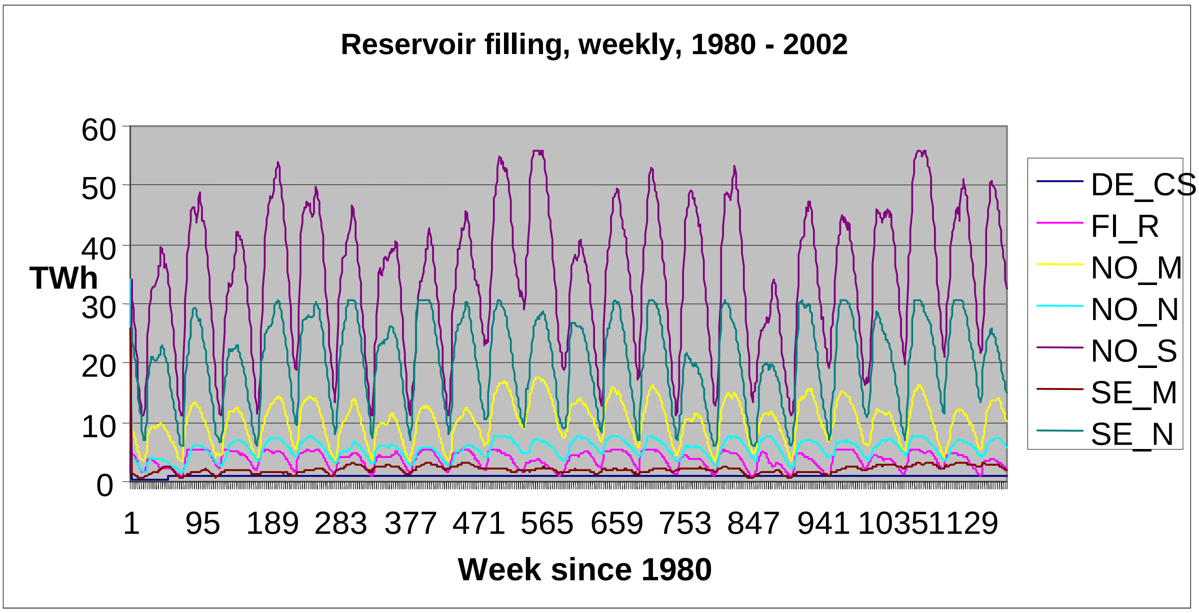

Figure 2 Simulated reservoir filling at the beginning of each week, 1980 – 2002.

Figure 3 presents a different view for NO_S alone. It is observed from Figure 2 that region NO_S has by far the largest filling (because it also has the largest volume), followed by SE_N and then NO_M.

The figure illustrates the reservoir fillings over the weeks, again over the years 1980 – 2002. Figure 4 presents the same, however now based on historical data. Comparing the two figures it is observed that the main characteristics are the same, viz., a cyclical variation over the year, within approximately the same minimum and maximum values.

At a more detailed level, some differences are observed. The minimum value in the simulation is 20%, this is a consequence of taking this as a hard constraint in the simulation. The maximum values in the simulation is 100%, again this is a consequence of taking this as a hard constraint in the simulation.

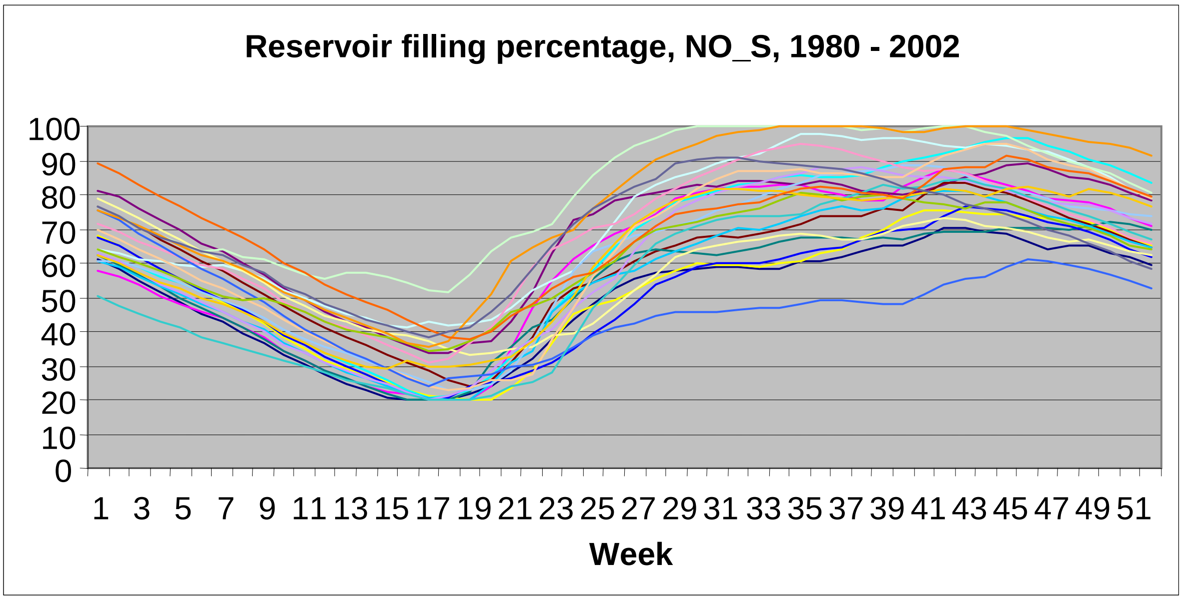

Figure 3 Simulated reservoir filling for NO_S at the beginning of each week, 1980 – 2002.

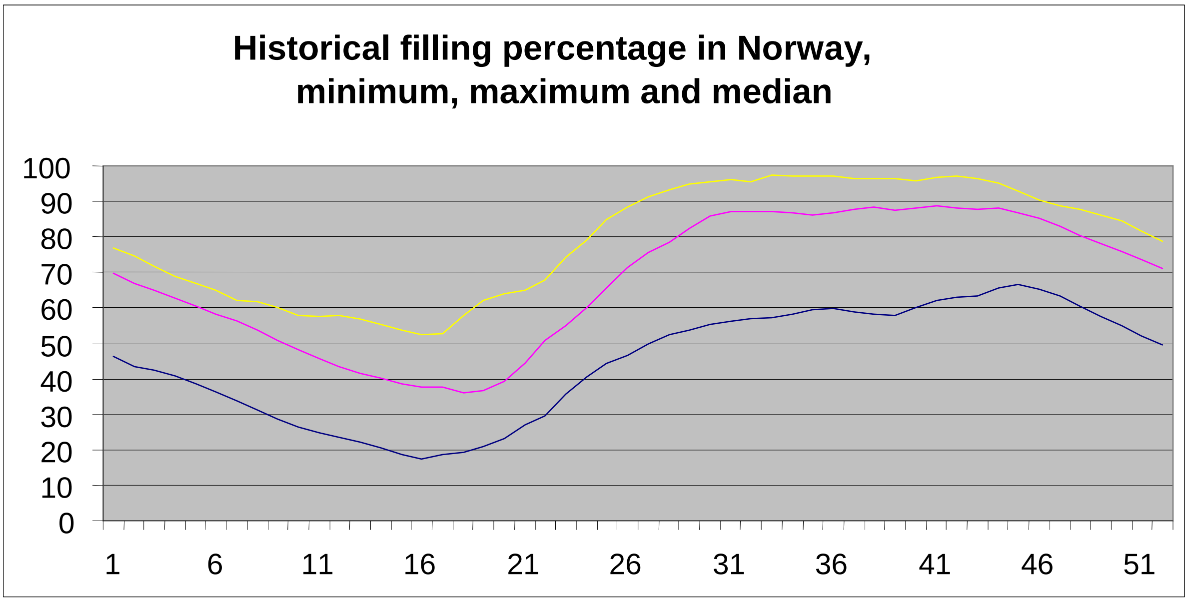

Figure 4. Historical reservoir filling in Norway at the beginning of each week. Source: Norwegian Water Resources and Energy Directorate. The values refer to the years 1990 – 2003.

Similar comparison may be made for Finland, see Figure 5 and Figure 6. In contrast to NO_S which has almost exclusively hydro production, FI_R has a mixed system also containing thermal production.

The same general comments apply to FI_R as to NO_S. Thus, the general pattern between historical and simulated values are the same, with a tendency that the simulated values are higher.

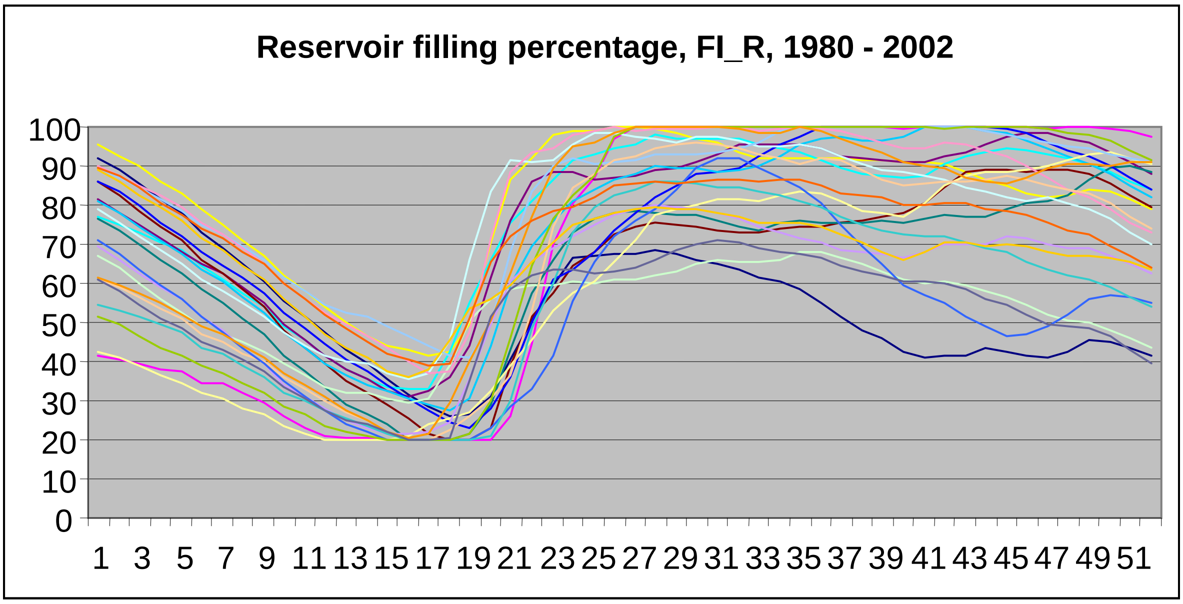

Figure 5 Simulated reservoir filling, FI_R, at the beginning of each week, 1980 – 2002.

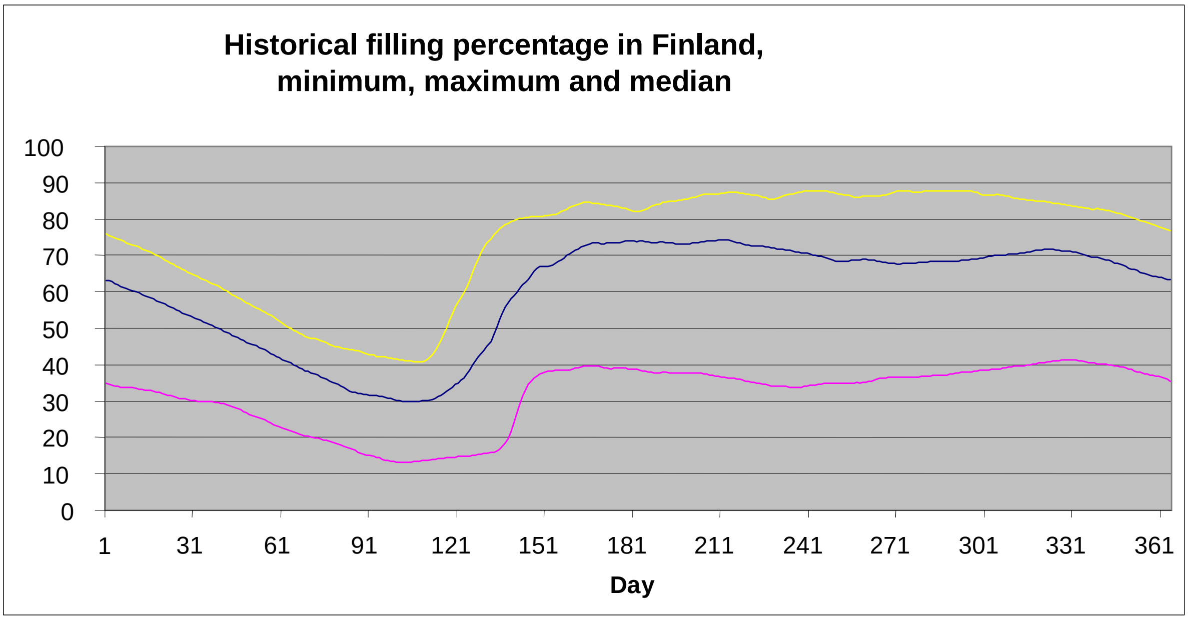

Figure 6 Historical reservoir filling in Finland at the beginning of each week The values refer to the years 1978 – 2001. Source: www.environment.fi.

4.3 Prices

For the simulations described above the resulting weekly average prices will be described here.

Figure 7 shows that there is a clear seasonal pattern. From the figure the prices (all prices are given in Euro/MWh) do not vary very much between the years, nor do they vary much between the regions. A few weeks stand out, though, either due to exceptionally high or low prices. For high prices, the year

1996 is again seen to be significant. The maximum price level is seen to be 80 Euro/MWh, this is a reflection that this price was used as back stop price to ensure feasible solutions.

Comparing with the system spot prices in Figure 10, the general levels of the prices agree fairly well. However, this is mainly attributable to co-incidence; no effort has been done to adjust the fuel price levels (which are very important for this) in the simulation. More interesting is the observation that the high price increase in 1996 seem to agree fairly well between the two figures.

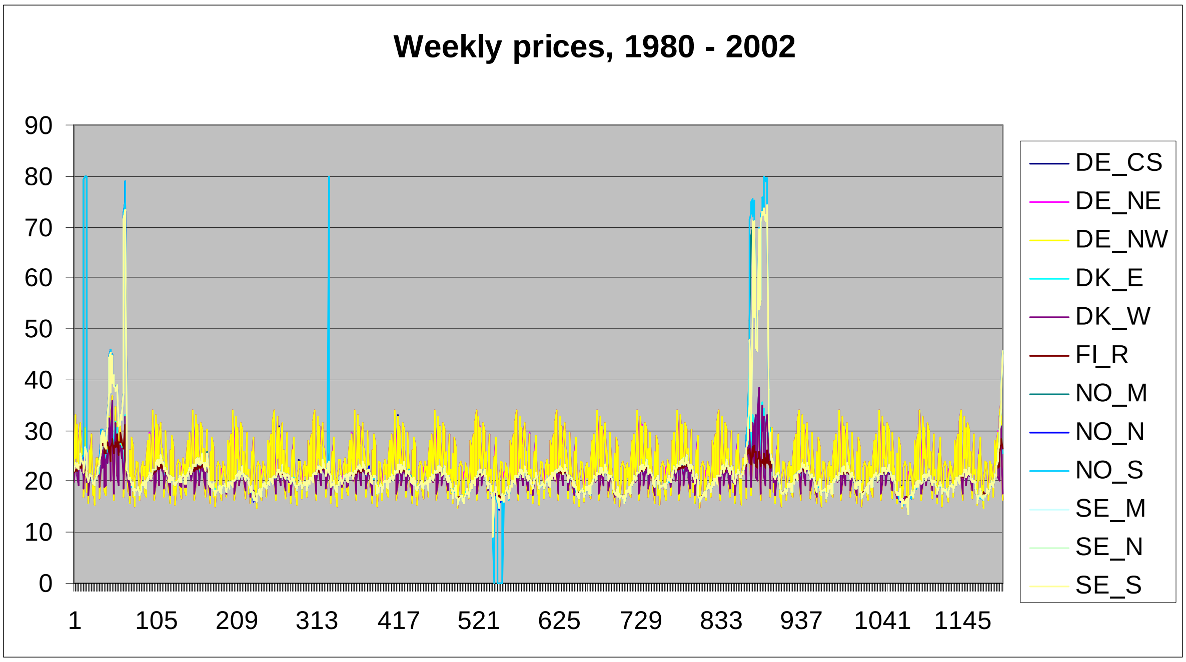

Figure 7 Simulated weekly average prices, 1980 – 2002.

In Figure 8 and Figure 9 a closer look is taken at the same two regions as previously.

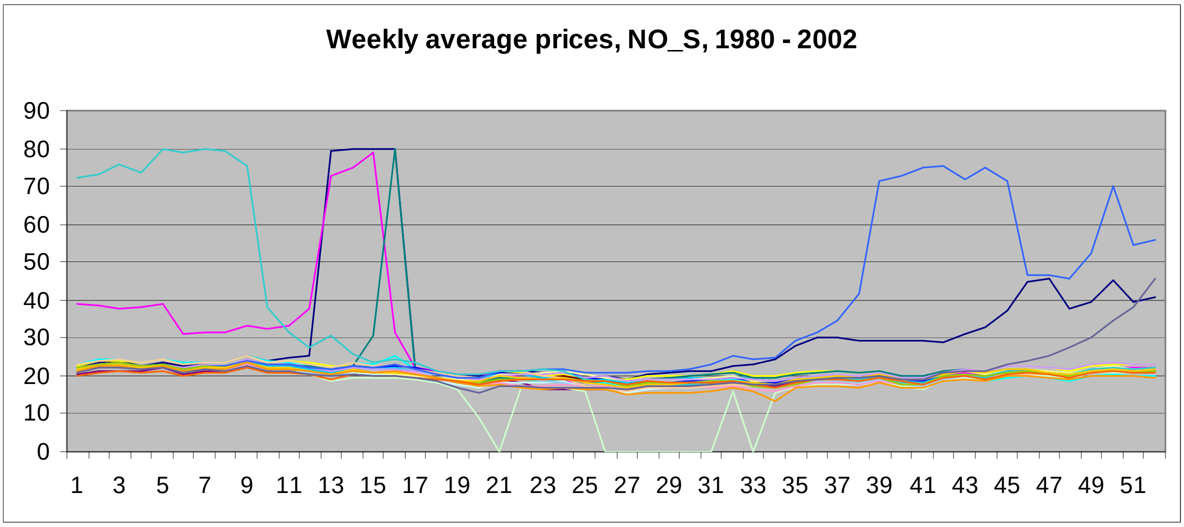

Figure 8 Simulated weekly average prices, NO_S, 1980 – 2002.

Figure 8 relates to NO_S. The high price at the end is for the year 1996. High prices were also seen historically during the second half of 1996, cf. Figure 10. The price which rises smoothly from approximately average in week 43 to approximately 45 in week 52 in Figure 8 is from 2002, where the autumn was also dry, cf. again Figure 10.

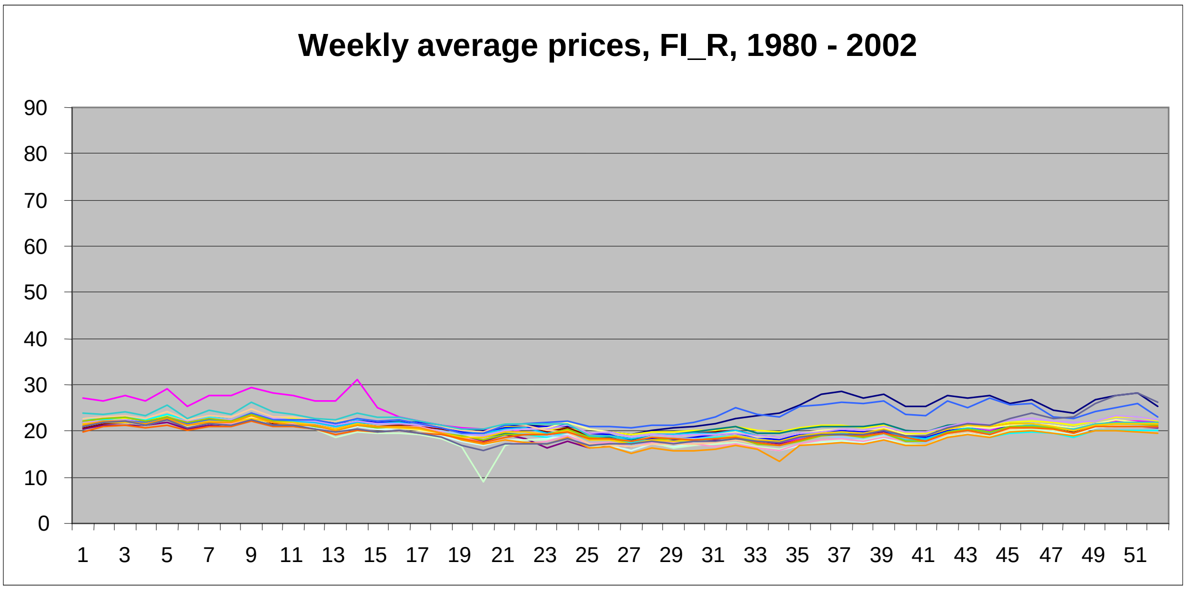

Figure 9 Simulated weekly average prices, FI_R, 1980 – 2002.

Figure 9 relates to Finland. As seen, the simulated price here is more stable over the years than the prices in NO_S, this reflects that Finland is not hydro dominated (as NO_S is), and therefore variations in hydro inflow will not to the same extent imply variations in prices.

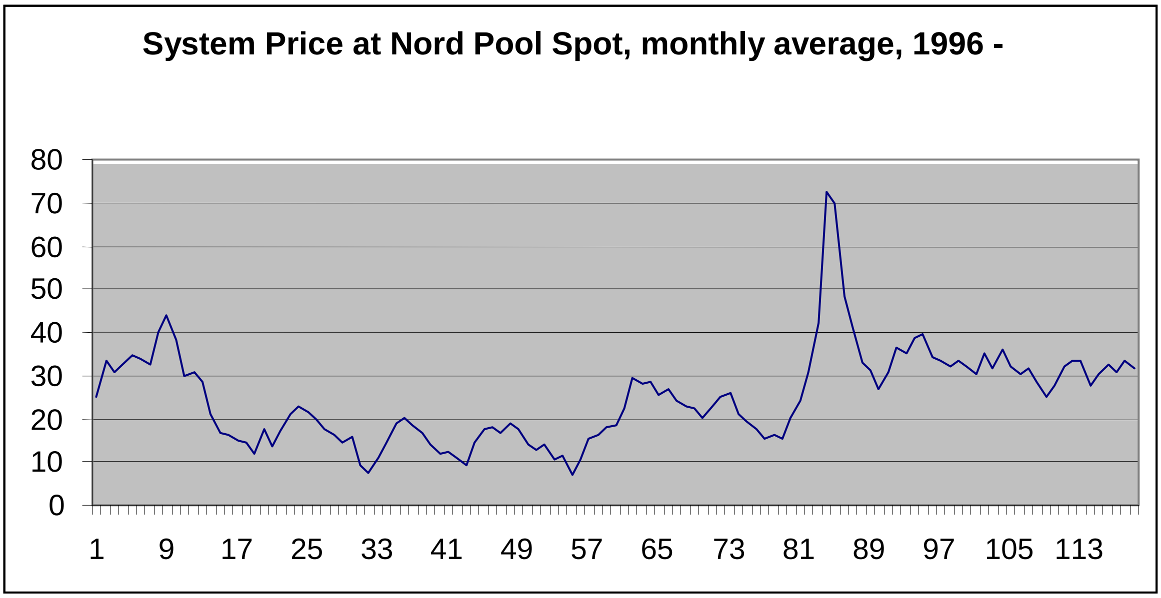

Figure 10 Historical monthly average spot prices at Nord Pool Spot, 1996 - 2005. Source: www.nordpool.com.

5 Illustration of the one reservoir model

As mentioned a stochastic dynamic programming (SDP) code has been made that for a one-reservoir model. The SDP method ideally reflects the information and decision structure of the problem, and therefore in principle provides the true optimal solution (see e.g. the previously mentioned reference Bertsekas (1987)). However, in order to be practically implementable, a discretisation of the state space (i.e., the reservoir volume) is necessary. And as noted, it is not possible to apply SDP directly in the case of the WILMAR model due to the excessive number of regions. The purpose of the SDP code is therefore to serve as a reference point.

Here the application of the SDP method will be illustrated and compared to the solution found with the LTM method described above. The case concerns the situation where Finland is treated in isolation, i.e., without any electrical connections to other countries.

The SDP solution for Finland in isolation is illustrated in Figure 11 and Figure 12. Reservoir filling seems to exploit the available volume more than seen in Figure 5, for instance the volume is close to minimum level (20%) at the end of the year in Figure 12 but not in Figure 5. Similarly the price patterns are different, with some years having low prices during spring in 18Figure 11.

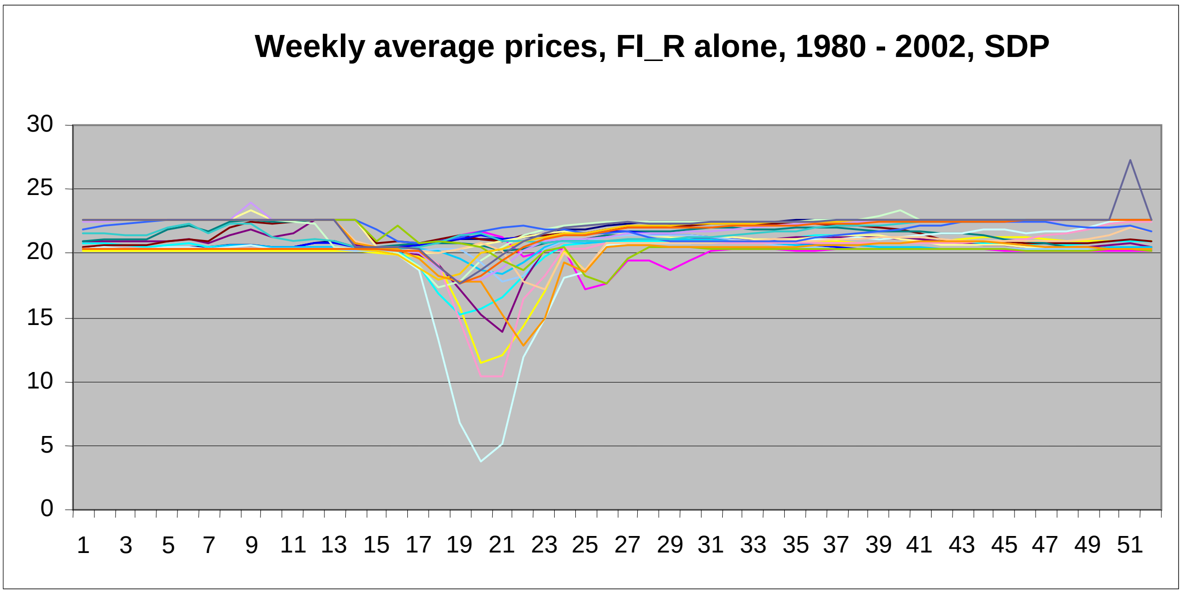

Figure 11 Weekly average prices week for Finland alone, 1980 – 2002, simulated with SDP.

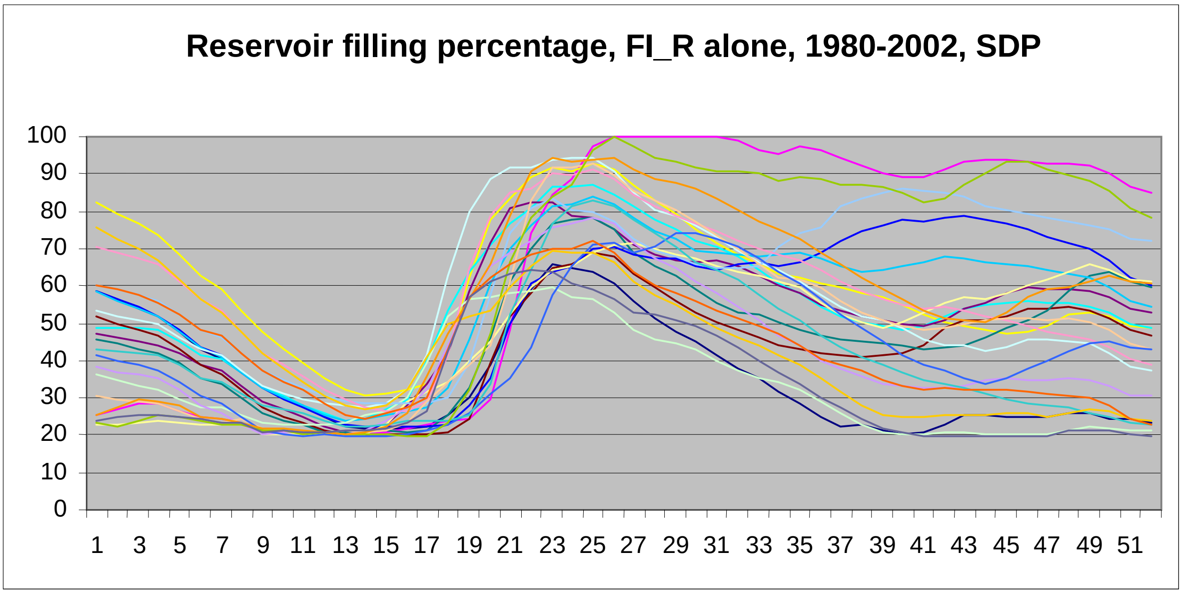

Figure 12 Reservoir filling at the beginning of each week for Finland alone, 1980 – 2002, simulated with SDP.

However, the differences observed between the two solutions may be due to difference in method (LTM and SDP, respectively) as well as to difference in assumptions concerning interactions between Finland and other countries (transmission lines and no transmission lines, respectively). To illustrate this, a further simulation has been made with the LTM3 method on the Finland-alone case.

The LTM3 solution for Finland in isolation is illustrated in Figure 13 and Figure 14.

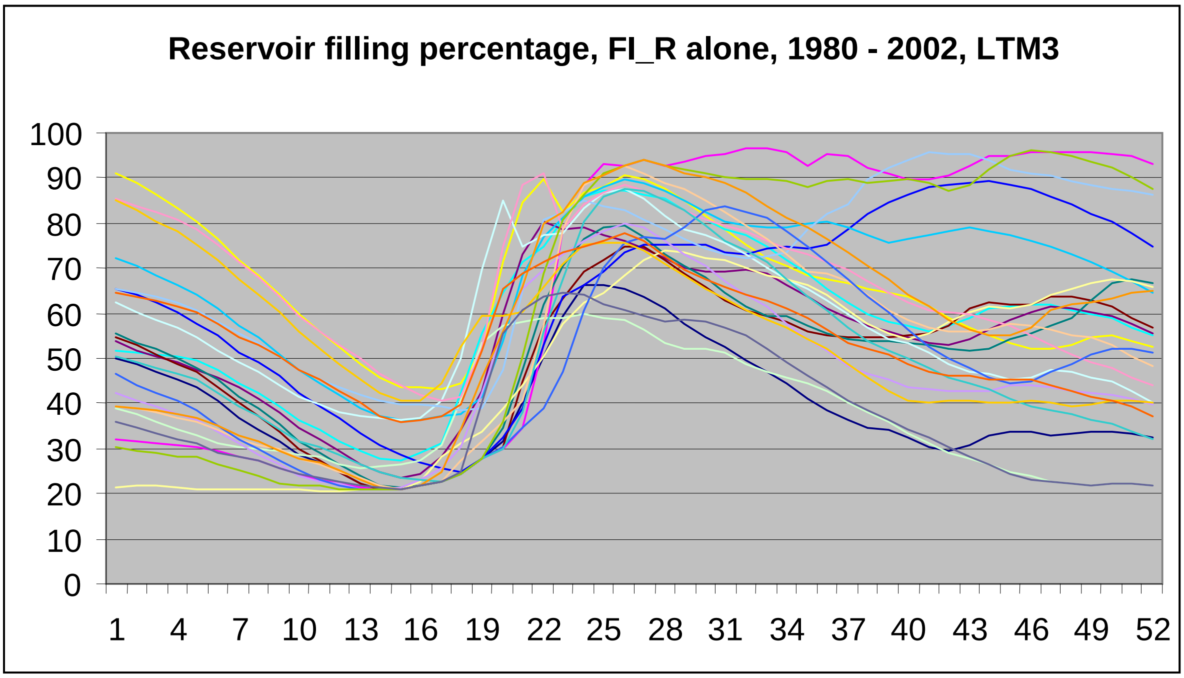

Figure 13 Reservoir filling at the beginning of each week for Finland, 1980 – 2002, simulated with LTM3.

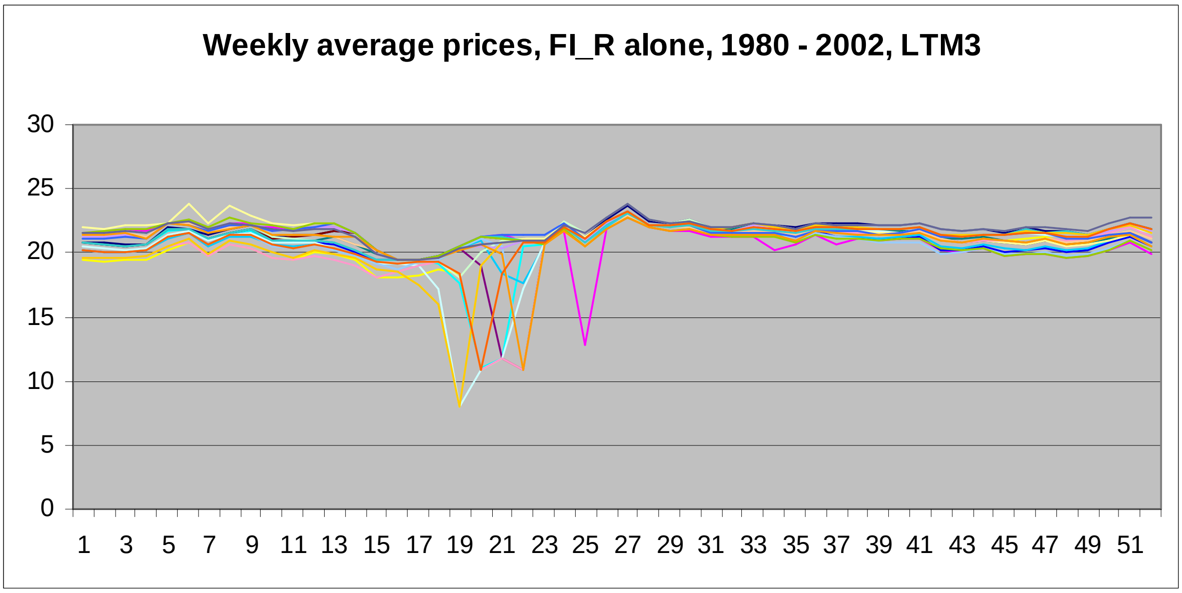

Figure 14 Weekly average prices week for Finland alone, 1980 – 2002, simulated with LTM3.

The solutions are quite similar, although differences are observed. The general impression is that the SDP solution trajectories seem to be slightly more smooth than those of the LTM3 solution.

Since overall the intention is to minimise the expected costs, it may be relevant to compare prices, cf. Figure 11 and Figure 14. The average weekly prices are remarkable close in the two methods, 21.0186 Euro/MWh for the SDP methods against 21.0442 Euro/MWh for the LTM3 method. This indicates that the differences observed in reservoir filling between the two methods are insignificant, and the optimum must therefore be very flat with respect to variations in the reservoir filling. Similarly the differences in the price trajectories observed in the two figures must be insignificant.