Optimal Operation of Hydro-Dominated Power Systems with Environmental Constraints

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***Abstract*—This paper studies the operation of a small renewable and hydro-dominated power system when introducing environmental constraints. The risk of rationing and the local price formation is investigated using a stochastic, cost-minimising optimisation model for long-term operation of a regional renewable power system with reservoir hydropower. The model is applied to a case study based on Norwegian hydropower plants with state-dependent, environmental constraints on reservoir management. The results demonstrate the reduced operational flexibility of the hydropower system and an increased risk of rationing, when the environmental constraint is imposed. In some of the case runs, the long-term management of the constrained reservoir is found to change considerable, but is also shown to be sensitive to the value of lost load, the transmission capacity and the total wind power generation.**

***Index Terms*—Electricity Price, Environmental Constraints, Hydropower, Flexible Power Generation, Security of Electricity Supply**

I. Introduction

The European Green Deal defines ambitious targets for both climate change mitigation and broader environmental sustainability. A sustainable power system must ensure affordable, high quality power supply at the lowest possible environmental and social costs. Environmental requirements are often imposed on power plants to ensure sustainable operation by preserving ecological, social and recreational interests of the surrounding area. Such requirements may reduce the plants' operational flexibility, thereby reducing the plants' capability to adjust production according to the market.

The operation of hydropower plants modify the surrounding ecosystems by altering the flow regime downstream the hydropower outlet and the water levels in the reservoirs. Flow alterations and associated ecological consequences are major environmental concerns [1], [2]. Minimum flows and maximum ramping rates are among the most commonly applied mitigation measures, but a wide range of environmental constraints may be imposed on hydropower plants to limit the negative impacts of operation [3].

While important to preserve ecological and social interests, environmental constraints may in some situations be conflicting with security of power supply. Many existing power systems, such as the Norwegian, rely on hydropower plants to deliver load-following power generation and reserve capacity to avoid blackouts and maintain the power quality in situations of unexpected events [4]. The trade-off between environmental and economic considerations is one of the core challenges when deciding on new terms in revision processes for hydropower licenses in Northern Europe [5]. Furthermore, available flexibility in the power system and concerns for secure power system operations have become more pressing in recently conducted revisions. Because of hydropower plants' importance for security of electricity supply in the whole Nordic region, the consequences of new or adjusted environmental constraints to the power system should be thoroughly assessed on local, regional, and national levels.

Limited research addresses the implications of environmental constraints in competitive power markets dominated by hydropower, and less so the importance of accurate representation of such constraints in the long-term operations of hydropower. Existing research mainly consider environmental constraints in the form of minimum flow requirements and ramping restrictions. Reduced profit for hydropower producers due to such constraints have been assessed using both short- and long-term scheduling models, see e.g. [6]–[8]. A framework to evaluate the cost to the power system has also been suggested [9]. While ramping restrictions have been found to impact strategies for reservoir management under certain conditions [10], such constraints mainly limit the short-term flexibility. Only a few publications consider environmental constraints that include state-dependencies in long-term hydropower scheduling. Such constraints have been found to have a considerable impact on the water value curves used for reservoir management, [11], [12], and may significantly impact the seasonal flexibility.

We evaluate the impacts of environmental requirements for hydropower reservoirs on the risk of scarcity situations and price formation in a competitively operated power system reliant on hydropower. Especially, environmental, state-dependent reservoir constraints that are imposed on Nordic hydropower plants are considered. To the best of our knowledge, this has not been addressed in the research literature previously. A multi-stage stochastic model for operation of small renewable electricity systems is presented and used to investigate the impact on the formation of the electricity price. The modelled part of the power system relies on hydropower, and is only weakly linked to a the larger power system. The model is formulated from a system perspective with an objective to minimise the cost of meeting local electricity demand and is solved using stochastic dynamic programming (SDP) [13]. The main contribution of this work lies in the modelling of the state-dependent environmental constraint, and in the assessment of the impact on the operation of the system and the local electricity price formation for a case study based on a Norwegian hydropower system. The local price formation is directly impacted by the risk of rationing [14] and is a measure of the stress in the local system.

The remainder of this article is structured as follows: the stochastic power system model and the modelling of the environmental constraint is presented in Section II, the case study is presented in Section III, before the results and the final conclusion is presented in Section IV and V accordingly.

II. Power System Model

This section presents the multi-stage, stochastic model used to optimise operation, and determine the corresponding electricity price, of a renewable electricity system dependent on hydropower plants constrained by environmental requirements. A more thorough description of the use of SDP in hydropower scheduling can be found in [12], [15], [16]. We here emphasize on describing the stage-wise (weekly) decision problem.

The defined optimisation problem optimises operation of the system illustrated in Fig. 1, i.e. determines electricity generation, storage of water in the reservoirs, and utilisation of the weak transmission link in order to meet the local electricity demand at the lowest possible cost. The hydropower reservoirs are the only form of energy storage in the system and determine the ability of the hydropower plants to generate electricity during the year. The option to store water in the reservoirs couple the decision variables in time, making the problem dynamic. Furthermore, the problem depends on uncertain weather parameters, making the problem stochastic.

A. Multi-stage, stochastic programming model

To solve the large multi-stage, stochastic problem at hand, we use SDP [13]. SDP is a mature solution method based on decomposing the problem into smaller stage-wise independent problems which can be solved sequentially. The method allows for nonconvex characteristics to be included in the model formulation, but can only be used for smaller or aggregated hydropower systems due to the need to discretise the state variables, making the problem grow exponentially in size with the number of reservoirs considered.

The SDP model solves the problem for a yearly time-horizon, broken down to 52 weekly decision stages ($t \in \mathcal{T}$). In each stage, the model solves the weekly problem for a set of discrete stochastic states ($s_t^u \in \mathcal{S}^u$) and a set of discrete reservoir states ($s^p \in \mathcal{S}^p$). Three stochastic variables are considered; the total weekly inflow to the reservoirs, the weekly average wind power production and a temperature dependent weekly load. The reservoir states give the start filling of the reservoir in each stage. Each time the weekly decision problem is solved, the sum of the immediate cost and the expected future cost is minimised to find the optimal operation of the system.

To account for end-of-horizon-effects, the SDP algorithm iterates until convergence. When the model has converged, the calculated strategy (water values) are used in a final forward simulation of the same system, optimising system operation for a range of scenarios.

B. Weekly decision problem

The weekly decision problem is solved for every discrete system state. The uncertainty is reflected by the stochastic states and corresponding transition probabilities in the SDP algorithm. The weekly decision problems are deterministic as the stochastic variables for each week are known at the beginning of the week. Each problem consist of K time steps, allowing for intra-week variation in weather parameters and load profiles.

The objective of the decision problem (1) is to minimise the sum of the immediate and expected future cost. The immediate cost is determined by the cost of energy import/export at a deterministic market price ($\lambda_k e_k$), and the cost of load rationing ($C^{ls} ls_k$), in each time step k. The expected future cost (α_{t+1}) is a function of the current stochastic state of the system (s_t^u) and the resulting reservoir state at the end of the stage ($v_{t,h\in\mathcal{H},k=K}$).

$$\alpha_t(s^p, s_t^u) = \min \left\{ \sum_{k\in\mathcal{K}} (\lambda_k e_k + C^{ls} ls_k) + \alpha_{t+1}(v_{h\in\mathcal{H},k=K}, s_t^u) \right\} \tag{1}$$

The power balance (2) state that the electricity generation from hydropower ($p_{k,h}$) and net import (e_k) of electricity has to equal the net local electricity demand in all time steps ($k \in K$), i.e. the electricity consumption of households (D_k^C) and industry (D_k^I) minus the wind power generation (W_k). If required, load can be rationed (ls_k) at a high cost (C^{ls}) or wind power can be curtailed (w_k^c) for free.

$$\sum_{h\in\mathcal{H}} p_{k,h} + e_k + ls_k - w_k^c = D_k^C + D_k^I - W_k \quad \forall \quad k \in \mathcal{K} \tag{2}$$

The electricity generation from each of the hydropower plants $h \in \mathcal{H}$ is given by the discharge ($q_{k,h,d}$) from each plant and the efficiency $\eta_{h,d}$ of each discharge segment $d \in \mathcal{D}$, as given in (3). Discharge per segment is restricted by (4). The water level in the reservoir $v_{k,h}$ is restricted by upper and lower limits in (5).

$$p_{k,h} - \sum_{d\in\mathcal{D}_h} \eta_{h,d} q_{k,h,d} = 0 \qquad \forall \quad k \in \mathcal{K}, h \in \mathcal{H} \tag{3}$$

$$q_{k,h,d} \leq Q_{h,d}^{max} \quad \forall \quad k \in \mathcal{K}, h \in \mathcal{H}, d \in \mathcal{D}_h \tag{4}$$

$$V_h^{min} \leq v_{k,h} \leq V_h^{max} \quad \forall \quad k \in \mathcal{K}, h \in \mathcal{H} \tag{5}$$

Constraint (6) provides a mass balance for the water stored in the reservoirs. Water is drawn from the reservoir as discharge ($q_{k,h,d}$) or spillage ($f_{k,h}$), and can be added to the reservoir as inflow ($\phi_k Z_h$) or through discharge from the reservoirs above. Water that is spilled is lost from the system. The factor ϕ_k distributes the weekly total inflow (Z_h) to the time steps, while F^C is a conversion factor from $\frac{m^3}{s}$ to mm^3.

$$\begin{aligned} & v_{k,h} - v_{k-1,h} + F^C\left(\sum_{d \in \mathcal{D}_h} q_{k,h,d} + f_{k,h}\right) \\ & -F^C \sum_{j \in \mathcal{H}_h^{up}} \sum_{d \in \mathcal{D}_j} q_{k,j,d} = \phi_k Z_h \quad \forall \quad k \in \mathcal{K}, h \in \mathcal{H} \end{aligned} \tag{6}$$

C. Environmental requirements

Many hydropower reservoirs in Norway are also used for recreational purposes in the summer. In this period, low water levels in the reservoirs can make it difficult to access the water surface. In order to meet ecological and recreational needs for high water levels in summer, constraints may be imposed on the operation of selected reservoirs. The purpose of the considered constraint is to enforce rapid filling of the reservoirs ($h \in \hat{H}$) in order to reach a target water level within a given period. Because of large inflow-variations, a hard reservoir constraint may induce high socioeconomic cost in low-inflow years and is therefore not suitable. Instead, a dynamic formulation that restricts discharge from the reservoir is used. The constraint is formulated as a requirement to stop any discharge, except to meet minimum flow obligations, within a certain period $t \in \hat{T}$, if the water level in the reservoir is below a given threshold (V_h^{lim}), as given in (7). If there are no minimum flow obligations $Q^{min} = 0$.

$$\sum_{d \in \mathcal{D}_h} q_{k,h,d} \leq Q^{min} \quad | \quad v_{k,h} < V_h^{lim} \quad \forall \quad k \in \mathcal{K}, h \in \hat{H} \tag{7}$$

If, the water level reach the threshold at any time within the restriction period, the water level in the reservoir has to stay above the threshold for the rest of the period $\hat{T}$, adding (8) to the weekly decision problem (and removing (7)).

$$v_{k,h} \geq V_h^{lim} \quad \forall \quad k \in \mathcal{K}, h \in \hat{H} \tag{8}$$

Since the activation of (7) depends on the reservoir level ($v_{k,h}$), the environmental constraint introduces a state-dependency, making the scheduling problem nonconvex. This type of constraints are imposed on several Nordic hydropower plants and can have a considerable impact on the seasonal reservoir management [12].

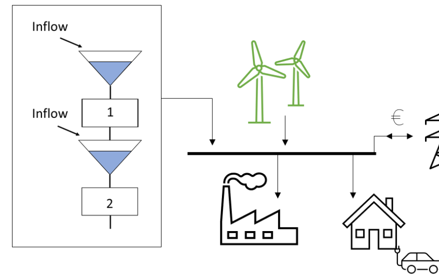

Fig. 1. Illustration of the system used in the case study.

TABLE I
HYDROPOWER SYSTEM

Power Plant	Reservoir Capacity $[Mm^3]$	Generation Capacity $[MW]$	Discharge Capacity $[m^3/s]$	Average Inflow $[Mm^3/yr]$
Upper (1)	195	15.0	26.0	536.0
Lower (2)	179	126.6	37.5	276.3

III. CASE STUDY

The SDP model is applied to a small renewable system, illustrated in Fig. 1, resembling a region that is weakly linked to the rest of the power system. The model is run with 52 weekly stages and an 3-hour resolution within each stage. The electricity demand within the region can be met by wind- and hydropower, and partly by import at a deterministic price. The transmission capacity is not sufficient to meet the power demand at all times.

The wind power generation is represented by weekly energy series, which is evenly distributed between the intra-week time-steps. The total electricity demand is divided into a household consumption and an industry consumption. The household consumption is assumed to follow a weekly load profile, while the industry consumption is constant.

The hydropower system is based on the Gråsjø and Trollheim power plants in Folldalen, Norway. Details are given in Table I. The weekly inflow is assumed to be distributed evenly throughout the week. The environmental reservoir constraint is active from week 18-35 on the lower reservoir, and states that no generation is permitted from the lower reservoir if the filling of the reservoir is below 85% of maximum [1].

Historical inflow data, wind power generation, temperature adjusted load profiles and an exogenous power price for mid-Norway is taken from a 2030 low emission dataset [17] run with the EMPS model [14] [2] . To create a suitable test system, the data was scaled to match the capacity of the chosen hydropower system.

[1]This type of constraint has been suggested for this power plant, but was not imposed in the recently finished revision of the licensing terms.

[2]A market model designed for systems dominated by reservoir hydro, used in the Nordic power market. https://www.sintef.no/en/software/emps-multi-area-power-market-simulator/

TABLE II
CASE DETAILS

Case	Total Load $[GWh]$	Wind Power $[GWh]$	Transmission $[MW]$	VOLL $[€\backslash MWh]$
Base	1 403	474	100	500
HighTrans	1 403	474	300	500
LowTrans	1 403	474	50	500
VOLL 300	1 403	474	100	300
VOLL 100	1 403	474	100	100
HighWind	1 403	949	100	500

A. Representation of uncertainty

Uncertainty is considered for inflow, wind power generation and electricity demand from households (temperature dependent). Serial- and cross-correlations in the stochastic variables are accounted for by the use of a vector auto-regressive model of order one (VAR(1)) to draw scenarios [18]. Each scenario consist of 52 weekly values for each of the stochastic variables. In the SDP-algorithm, the stochastic variables are represented by a Markov-model. The final simulations were conducted for 100 of the originally sampled scenarios.

B. Case runs

In total, 12 case-runs are presented as part of this work. Sensitivities are conducted on the transmission capacity, value of lost load (VOLL) and wind power generation, as given in Table II. In addition, the different configurations of the system is considered both with and without the environmental reservoir constraint.

IV. RESULTS AND DISCUSSION

This section present results from solving the cases described in Table II. We compare results from optimal operation of the Base and HighWind case with and without constraints on operation of the reservoir, and comment on the sensitivity to the value of lost load (VOLL) and the transmission capacity. Finally, we discuss the implications of the reservoir constraint on resource utilisation, local price formation and security of supply.

A. Operational results

The environmental constraint has a considerable impact on the operation of the system. If the reservoir level is below the threshold in the constraint period, the lower hydropower plant is not allowed to produce, which drastically reduce the generation capacity in the system. Combined with unfavorable wind conditions, this can lead to a shortage of generation and rationing of load. Table III presents average yearly results for operation of the system for the different case runs. In general, the operational costs increase when including the environmental constraint, due to higher imports of energy and (in most cases) increased rationing of load. Furthermore, spillages from the hydropower reservoirs increase for all cases when the reservoir constraint is included, reducing the total energy generation from the hydropower plants.

TABLE III
AVERAGE YEARLY RESULTS

Case	Reservoir Constraint	Cost $[10^6\ €]$	Rationing [GWh]	Spillage [Mm3]	Net Import [GWh]
Base	NO	2.16	0.37	11.44	76.85
VOLL300	NO	2.08	0.37	11.44	76.85
VOLL100	NO	2.00	0.43	11.43	76.76
LowTrans	NO	2.70	0.47	12.58	78.12
HighTrans	NO	1.93	0	11.64	77.29
HighWind	NO	-15.83	0.09	16.28	- 387.94
Base	YES	3.61	0.46	28.95	94.59
VOLL300	YES	3.50	0.47	28.87	94.49
VOLL100	YES	2.81	6.53	18.58	77.60
LowTrans	YES	4.80	1.55	35.58	101.12
HighTrans	YES	2.33	0	18.09	83.44
HighWind	YES	-14.98	0.99	23.78	-381.07

1) Base case: Fig. 2 (upper) shows the operation of the lower reservoir (where the constraint is imposed). The reservoir management throughout the year changes completely when considering the environmental constraint, in order to keep both hydropower plants in operation. With high reservoir fillings throughout the year, spillage would be expected to increase, reducing the total generation from hydropower. The average spillage increase from 1.4% to 3.5% percent of the average total inflow when the constraint is included. There is no curtailment of wind power.

2) High wind case: In this case, the total wind generation is doubled, resulting in a net export of energy and a negative total system cost, as given in Table III. The system still has some rationing of load, but less than in the Base case. In some hours curtailment of wind power occur, but on average less than 0.5% of the total wind generation is curtailed. The high share of wind gives a high variation in total energy availability between the scenarios, increasing the spread in the operation of the hydropower plants. This can be seen comparing the High Wind case Fig. 2 (lower) to the Base case in Fig. 2 (upper). Due to the increased availability of energy, rationing is lower than in the Base case when the environmental constraint is not included, while the spillage of water is higher. When the environmental constraint is included, we find that the seasonal reservoir operation of the reservoirs are less changed than in the Base case. As a result, there is more rationing and less spillage.

3) Value of lost load: The results are sensitive to the expected cost of rationing, which is impacted by two factors: VOLL (EUR/MWh) and the amount of rationing (MWh). The VOLL can be seen as a calibration parameter, and the optimal value used in this type of models is not easily defined. Ideally, it should vary with type of consumption and duration of the rationing of load [19]. From Table III we see that a low VOLL (VOLL100) gives more rationing of load, but equal or less spillage of water from the reservoirs than in the Base case. More rationing is accepted in the VOLL 100 case, as the system cost of rationing in this case is quite low. Fig. 3 shows that the reservoir management is more similar to the operation without the reservoir constraint for VOLL 100, giving lower spillage than in the Base and VOLL 300 cases. VOLL up to

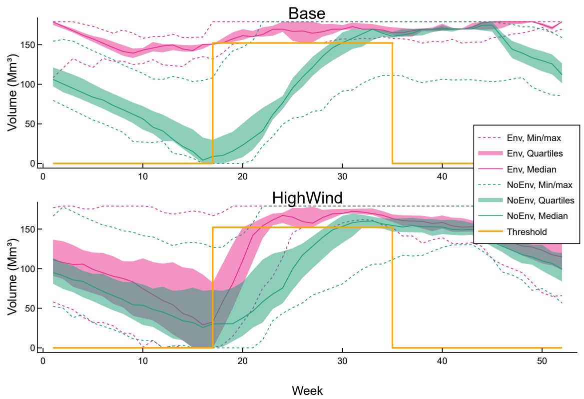

Fig. 2. Water filling in the lower reservoir for the Base case (upper) and Highwind case (lower) for all scenarios.

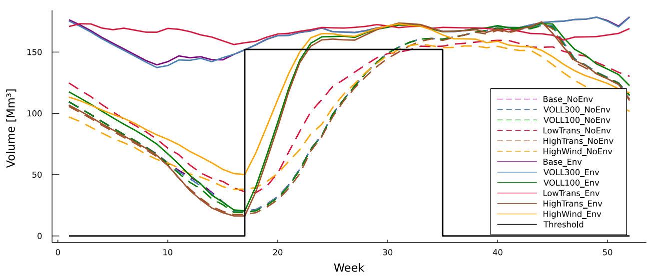

Fig. 3. Average water filling in the lower reservoir for all cases.

4000 EUR/MWh was also tested, but gave similar results to the Base and VOLL 300 cases.

4) Transmission capacity: The transmission capacity to the larger system is vital for security of supply. If the transmission capacity is reduced (LowTrans), the system becomes more vulnerable to uncertainty and variation, which again increase the probability of rationing. This is reflected in the operation of the reservoirs by that the water level in the reservoirs are kept higher, as shown in Fig. 3 for the lower reservoir. The differences in operation are particular apparent for the cases with the environmental constraint, having higher rationing and spillage compared to the Base case. This is due to the restrictions on operation combined with low import capacity and high reservoir levels, accordingly.

If the transmission capacity is unconstrained (higher than peak demand), scarcity will never be a problem (no rationing), and the power generation can be optimised towards the larger system. Comparing the HighTrans cases with and without the environmental constraint, we see only small differences in the operation of the hydropower reservoirs in the weeks before the environmental constraint is activated, as illustrated in Fig. 3. We have assumed a constant transmission capacity, the actual capacity can vary with the operation and state of the system.

B. Local price formation

The dual value of the power balance gives the marginal cost of covering one more unit of load, and represents the

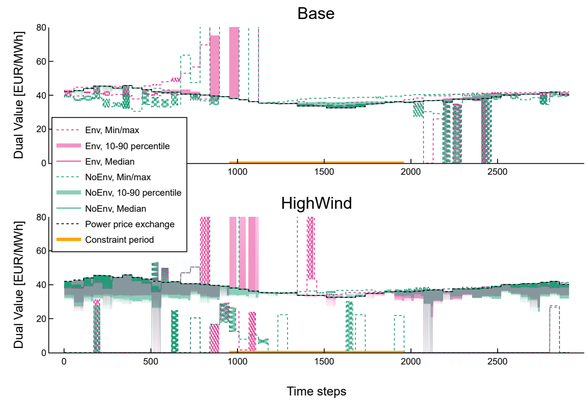

Fig. 4. The dual value (local price) in the Base Case (upper) and HighWind case (lower) plotted over one year for all scenarios. The highest dual values reach (500 EUR/MWh), but for readability the y-axis is capped in the plots.

theoretical power price in competitive power markets. In the defined system, one additional unit of load would in most hours either be covered by increasing the hydropower generation or adjusting the import/export. If the local system is not constrained, the local price is equal to the exogenous market price on the other side of the transmission cable. However, when there is an increased risk of load rationing, spillage of water or curtailment of wind power, the local price formation will increase or decrease accordingly. The resulting local price for the Base and HighWind case are given in Fig. 4. For both cases, there are more hours with high local prices when including the environmental constraint.

In the Base case, the highest local prices can be found before and in the beginning of the constraint period (before time-step 1000) when including the environmental constraint. Since the water level in the lower reservoir is below the threshold for some scenarios (week 18 in Fig. 2), rationing of load becomes necessary, resulting in local prices up to the VOLL (i.e. 500 EUR/MWh). The higher local prices before the constraint becomes active is due to the increased risk of rationing, which gives higher marginal costs of using water. In the HighWind case, the high local prices occur later than in the Base case. This is because the water level in the lower reservoir stays below the threshold for a longer period for many of the scenarios (see Fig. 2). Still, due to the relatively high wind power generation there are only a few scenarios where rationing is required. Furthermore, the local price falls to zero in more periods, due to curtailment of wind power or spillage from the reservoirs.

V. Conclusion and Further Work

An SDP-model for long-term scheduling of small hydro-dominated systems is presented and applied to a case study based on two Norwegian hydropower plants. The small test model is found to be useful to evaluate area-specific aspects of power system operation, such as the conducted case study. The case study results demonstrate how operation of the system is restricted when an environmental reservoir constraint is included, increasing the risk of rationing in certain periods. The magnitude and frequency of rationing strongly depend on the configuration of the system and the assumptions of VOLL used in the operational planning. Furthermore, both increased transmission capacity and higher wind power generation are found to reduce the impact of the constraint on the reservoir management.

The results, in the form of price formation and rationing, show that the system becomes more stressed when the environmental constraint is added. The local price is found to be higher within the constraint period in many of the scenarios. In some of the scenarios, the increased risk of rationing also lifts the local price in the weeks leading up to constraint period. To dampen the negative impacts, the operations of the hydropower resources are adjusted, significantly changing the reservoir management. The sensitivity to the VOLL demonstrates the importance of correctly pricing this parameter and alternative flexibility resources in the system, such as demand flexibility.

Further work should include demand side flexibility, short-term variations in wind generation and reserve capacity requirements. In addition, impacts on local flexibility of different types of environmental constraints could be considered.

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