Studying possibilities of hydropower in wind integration

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***Abstract*—Hydropower plants have ideal properties to provide production flexibility for the achievement of renewable targets for variable generation like wind and solar. However, given the typical constraints in the operation of hydro, it is often unclear how much flexibility is left in the dispatch of hydro to assist the system. This is especially true when assessing future system operation with increasing amounts of variable generation (VG). Numerous studies have simulated the operation of electric systems under different levels of VG penetration and found that the integration of renewables is facilitated with a fleet of flexible generators. Yet, due to the complex mix of nontechnical constraints, hydropower representation in these electric sector models is often simplified. This impact leads to under-constrained or over-constrained estimates of the flexibility available in reservoirs. In both cases, the results of the studies are influenced by these assumptions.**

Higher level of details regarding hydro dispatch constraints (detailed cascading hydro systems, detailed watercourses and inflow patterns) might have to be considered in future power system studies and for the calculation of water values. Including more details in a hydrothermal scheduling model leads to more realistic simulation results. However, a high model detail significantly affects computation time, which limits the model complexity in practice when studying larger regions.

Keywords-Hydropower, flexibility, variable renewable eenrgy sources

I. INTRODUCTION

The future electricity system in Europe will be more integrated and will include a larger share of variable renewable generation than what is the case today. This development is, e.g., driven by a stronger transmission grid, environmental targets set by the European Union and decisions on downscaling of nuclear generation capacity. Tighter market couplings and increased contributions from variable renewable energy generation will call for efficient balancing services, and possibly the development of new products to handle system balancing.

The flexibility of hydropower allows for efficient balancing of intermittent production. By fully utilizing this flexibility, hydropower producers can optimize the use and allocation of available capacity in the different electricity markets. Thus, the value of flexible hydropower generation can be enhanced by participating in multiple markets. Large hydropower installations also have various environmental effects [1], which create additional constraints to usage of hydropower resources. In this respect, optimal utilization of hydropower resources should be considered.

Labadie [2] and Rani & Moreira [3] conducted comprehensive reviews on different hydropower scheduling methods. Due to the long-term reservoir storage capability in hydropower-dominated systems, a producer's resource planning should be done in different time horizons in order to deal with computationally complexity of this problem. In order to cope with this issue while modelling a high level of detail, practical hydropower scheduling is normally organized in different time scales, e.g., long-term, medium-term (seasonal) and short-term [4—8]. This span has led to a hierarchy of models starting with long-term models at one end where the scheduling horizon can be several years, the geographical span can be extensive and the level of detail usually coarse. The scope of the models then decrease in scheduling horizon and geographical span and increase in level of detail to models covering a year or several months or weeks in seasonal scheduling. Eventually, in short-term scheduling, the models tend to cover only a small geographical region with a scheduling horizon of only days

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or a few weeks. However, the level of detail is much greater than for the long -term models.

This hierarchy is coupled through information shared between the different models so one model can provide end-value targets to the other model. One example is that a long-term market model produce power price forecasts to seasonal models. These models again provide estimates on, e.g., the value of stored water at a certain time, which again can be used as input to more detailed short-term models [9].

Hydropower systems with large reservoirs in long-term or pumped storage capabilities in short-term provide substantial potential for operational flexibility. On the other hand, correct evaluation of opportunities for deployment of such flexibility is complex and requires detailed analysis. For instance, constraints to keep the river flows and reservoir levels within allowed limits, in order to respect a stack of higher level priorities (e.g., public safety, environmental issues, irrigation, recreation or water sports), than the optimisation of electricity generation play an equally important role when planning/modelling for optimal hydropower scheduling. There are usually costly penalties where river flows or reservoir level regulations are breached. Moreover, spilling water is usually to be avoided, but may be unavoidable during high inflow periods or as a consequence of uncertainty in the inflows.

The issues introduced above become increasingly important when modelling large-scale hydropower systems (e.g., Norwegian, Swedish, Canadian, Austrian and Swiss hydropower systems). Pumped hydropower further increases the importance of uncertainty as the value of pumping assets is decreased by introducing uncertainty leading to suboptimal use. Modelling choices need to be based on a comprehensive understanding of the flexibility possibilities that the given system has to offer. Previous work under IEA Wind (Task24) has summarised national case studies for wind and hydro integration10. The present work is a continuation, under Task 25 on wind integration.

A rough categorisation of "base" hydropower flexibility can be made by investigating the types of hydropower plants installed in power systems today. National overviews are presented and discussed in the next section. The "effective" hydropower flexibility available to support the integration of variable generation is a far more complex and case specific aspect. It is discussed through national experiences in subsequent parts of the article. The last sections present potential developments that would increase the participation of hydro and discuss the ensuing challenges.

II. Studying possibilities of hydropower in wind integration

Given the typical constraints in the operation of hydro, it is often unclear how much flexibility is left in the dispatch of hydro to assist the system, especially with increasing amounts of variable generation (VG). Numerous studies have simulated the operation of electric systems under different levels of VG penetration [10—14]. All these studies found that the integration of renewables is facilitated with a fleet of flexible generators. Yet, due to the complex mix of non-technical constraints, hydropower representation in these electric sector models is often simplified. This impact leads to under-constrained or over-constrained estimates of the flexibility available in reservoirs. In both cases, the results of the studies are influenced by these assumptions.

A. Hydro-wind studies in the Nordic countries

Studies analysing the operation of the Nordic power system with considerable amounts of VG, mainly wind power, have not reported problems in balancing the system (Jaehnert *et al.* 2013 [15], Farahmand *et al.* 2014 [16], Kiviluoma *et al.* 2012 [17], Holttinen 2004 [18]). However, in these aggregated system models, not all aspects of hydropower plant operation were captured and the flexibility of the Nordic power system might have been overestimated. As a token of existing flexibility, Kiviluoma *et al.* (2012) [17]did not find a favourable cost-benefit analysis for a pumped hydro plant in southern Norway by utilising a unit commitment and dispatch model covering the Nordic countries and Germany.

Solvang *et al.* (2012) [19] also studied cost benefits of adding pumped hydro in South Norway, and the annual system cost savings as seen by the model were not very high in comparison to the annualised investment cost of building pump storage plant. A new transmission line to central Europe from southern Norway did not markedly improve the situation. The benefits remained low because of the existing large flexibility in the Nordic power system, especially as seen by the aggregated model that does not contain the constraints of multiple complex reservoir cascades in the Nordic countries.

Analysing a future system with high penetration of RES and increased interconnection capacity to the continental system displayed better economic performance in [16]. Detailed consideration of grid constraints in southern Norway and between Norway and continental Europe seems to increase the value of flexibility from pumped hydro storage in future scenarios with large-scale offshore wind power deployment [16]. Total wind power in the North European market studied was from 195 to 240 GW, most of it in Germany (78 to 92 GW) [20].

In an Icelandic case study [21], Helseth *et al. (2013)* introduced start-up costs for pumping in the hydro scheduling model considering high share of wind power. Start-up costs have a significant impact for the utilisation of pumped storages, leading to more realistic scheduling and power price in the simulation results. Moreover, by using DC power flow constraints, the estimated balancing potential from hydropower in Iceland is found to be limited based on the case study results.

Modelling of aggregated hydropower can be improved by estimating price steps for the aggregated hydropower plant. One such method was presented by Kiviluoma *et al.* (2006) [22]. All the reservoirs in a given bidding zone were aggregated into one, but the aggregated plant had a ladder of price steps based on the characteristics of hydropower plants in the region. A lower price ladder was used for plants with higher full load hours. Full load hours were based on the inflow and the design flow data. The price was further refined by the ratio between reservoir volume and inflow. Large inflow in comparison to the volume leads to more frequent use of the plant, which in turn requires lower prices for it to happen. A more refined approach would make the price ladder dependent on the inflow history, e.g., during dry periods small reservoirs would have increased prices. Finally, the price spread for aggregated hydropower should be preferably calibrated with empirical data from power markets.

Furthermore, higher level of details regarding hydro dispatch constraints (detailed cascading hydro systems, detailed water courses and inflow patterns) might have to be considered in future power system studies and for the calculation of water values [8]. Including more details in a hydrothermal scheduling model leads to more realistic simulation results, as demonstrated by Helseth *et al.* (2013) [21]. However, a high model detail significantly affects computation time, which limits the model complexity in practice when studying larger regions.

A hydro-wind dominated power system can cause problems to the functioning of power markets. In the Nordic power market, as in practically all power markets, demand is mostly inelastic. As a result, the marginal generator usually sets the market price for each bid period. Wind power has a very low marginal cost, often assumed to be zero. The marginal cost of reservoir hydropower (water values) is determined based on what it can be expected to replace – whether it is wind or other types of generation. Consequently, in hydro-wind dominated power system, the marginal price may be very low for many hours in the year. The problem of low market prices in such a system was demonstrated in Kiviluoma & Holttinen (2006) [23]. Such prices will not attract investments, and other mechanisms are needed to ensure the adequacy of future electricity supply. Scarcity pricing, increased demand response, pricing of unserved load, and long-term contracts between producers and consumers as well as capacity payments, are possible options to improve the price formation in hydro-wind dominated power systems

1) The Impact of wind power on use of hydropower in Norway

The impact of offshore wind power variability on the Norwegian pumped storage strategies was studied in [24, 16]. The focus is on the interplay between offshore wind farms in the North Sea and the Norwegian hydro pumped storage. Increased production flexibility is required for the operation of a future power system with more uncertainty due to increased share of VG from renewable sources – especially offshore wind power around the North Sea and the Baltic Sea [18]. Introduction of pumped storage in Norway might be able to effectively increase the production flexibility in the power system. While offering the possibility to store excessive power production from large wind power production in the North Sea during high wind production period. Stored energy can be fed back into the grid and support the power system during periods of low wind production.

The study shows that pumped storage increases significantly with increased installed capacity around the North Sea and the Baltic Sea areas. Reference [24] shows the hydropower production and pumping deployment in the two different wind scenarios.

Furthermore, the amount of pumping in Norway depends on the level of grid constraints in the northern European Continental grid. The three grid scenarios considered in [24] are:

i) **IC** (Onshore Grid with today's Internal grid Constraints),

ii) **IGE** (Internal Grid is Expanded according to Ten-Year Network Development Plan (TYNDP), and German, UK and Norwegian national grid development plans)

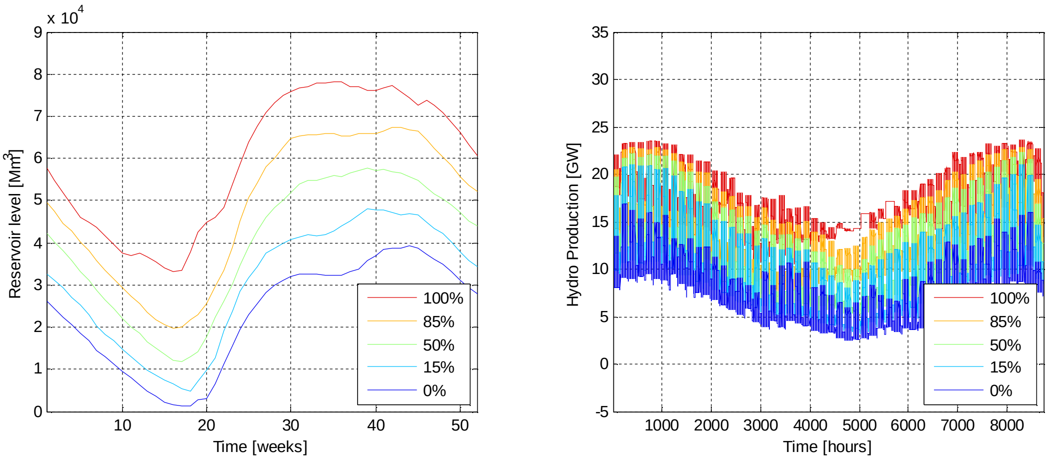
iii) **NC** (No internal Constraints, cross-border constraints only in the form of NTC limiting cross-border transmission capacity).

It is observed that the amount of pumping increases with the amount of constraints in the grid. This reflects the increased need for flexibility in continental Europe due to congestion and wind penetration.

TABLE I. ANNUAL HYDRO AND PUMPING GENERATION (TWH) VERSUS INSTALLED WIND POWER SCENARIOS (NORTH SEA AND BALTIC SEA)

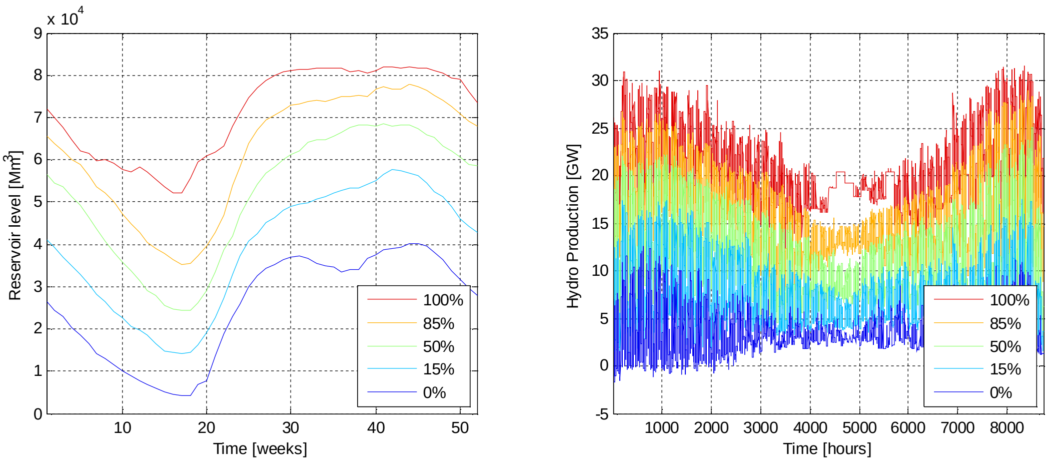
Baseline Wind Scenario						
Grid Scenarios	**Wind**	**Other RES + Solar**	**Hydro**	**Nuclear**	**Thermal**	**Pumping**
NC	1032	370	573	988	1262	29.6
IGE	1031	370	571	988	1265	30.0
IC	1011	359	557	983	1317	32.1
High Wind Scenario						
NC	1196	347	557	979	1151	35.0
IGE	1189	348	559	980	1154	35.2
IC	1153	339	542	975	1222	36.1

In Figure 1 and Figure **2**, reservoir handling and hydro production in Norwegian system are compared in low to high wind penetration scenarios in 2010 and 2030, respectively. The results are based on stochastic dynamic problem taking into account the long-term scheduling of hydropower. 75 hydrological years are simulated in order to find the strategic utilisation of hydropower stored in reservoirs. The diagrams show the percentiles of values based on 75 climatic years. Single percentiles do not refer to the same climatic year in both the Nordic system and Continental Europe. More information about the methodology can be found in [24]. In 2010, the reservoir handling (Figure 1-a) was quite characteristic of the Nordic countries, with a depletion



a) Reservoir handling b) Hydro production

Figure 1 Reservoir handling / Hydro production in Norway 2010 [24]



a) Reservoir handling b) Hydro production

Figure 2 Reservoir handling / Hydro production in Norway 2030 [24]

During the winter and early spring, and a filling during the other time of the year. Assessment of the reservoir handling for the future scenarios in 2030 (Figure 2-a) shows minor differences. It can be observed that the reservoir levels become higher in general, while the long-term reservoir storage capability is utilised less. This means that percentiles of the reservoir handling become more spread and flatter. It also indicates a change of the reservoir utilisation from a long-term perspective to a more short-term perspective [24].

The aggregated hydro production for Norway illustrates the significant changes that can be expected in the hydro production pattern. In 2010 (Figure 1-b) there was a rather stable seasonal production trend, with higher production during winter and lower production during summer, according to changes in the demand. Moreover, there is a diurnal pattern, according to the differences in demand during day-time and night-time as well as the weekend. This stable seasonal pattern vanishes and a more volatile hydropower production occurs in the future scenarios (Figure 2-b). These changes are due to the significant integration of wind power production in the future power system.

As an example, Figure 3 illustrates the correlation between the pumping pattern of one large reservoir, Tonstad, and the German offshore wind production at the offshore wind parks connected to the planned NordLink HVDC cable between Norway and Germany. This result illustrates in detail that pumping strategies in Norway are influenced not only by the seasonal inflow variations but also by the wind production profile in the North Sea in the 2030 future scenarios [24] [16].

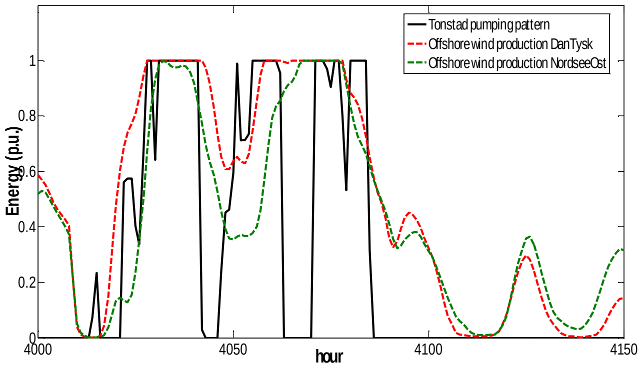


Figure 3 Norwegian pumping strategies versus offshore wind power variations

B. Hydro-wind studies in Sweden

The capacity of Swedish hydropower to balance wind power has been studied in [25]. The hydropower balancing capacity is examined in a model with 256 hydropower plants with a total installed capacity of 15 640 MW. The main aim of the study was to evaluate the flexibility of the hydro system. The Swedish hydropower production is simulated for a total of twelve weeks from the year 2009. The model has a resolution of one hour and considers the existing water permits. Transmission capacity constraints between Sweden and the neighbouring countries, as well as among the four bidding zones in Sweden, are included. Consumption of electricity, other electricity generation, and wind power are in the form of time series. In practice, the hydropower's ability to follow a given variable net-load is simulated. Different levels of installed wind power, load and available export capacity are examined. Simulations are carried out for introduction of 4000 MW, 8000 MW and 12 000 MW installed wind power capacities. 12 000 MW corresponds to 30TWh/year, which is 20% of the Swedish annual consumption. The key finding is that the spillage of water does not increase with increased amount of wind power. Spillage occurs when too much electricity is generated. It can be avoided with modified seasonal planning. There is no seasonal planning in the model since the model only simulates over one week. Export from Sweden is assumed possible with an amount corresponding to the available transmission capacity to other countries. It can be noted that since wind power is added to an existing system where the thermal power is included as time series, the extra energy supplied by wind power is compensated with extra export.

In another study, a future Swedish isolated system with 40% yearly energy contribution from wind and solar power was studied [26]. In this case, the results show that for 860 hours there was a "surplus" of wind and/or solar. This means that during these hours the hydropower was expected to produce at minimum level, assumed 1 875 MW, in order to minimise spillage. Moreover, there was a need of extra power during 765 hours. This means that during this time there is a need to produce as much hydropower as possible, assumed 12 951 MW, in order to reduce the need for other plants. This scheduling of hydropower results in significant change in generation levels and ramps, in comparison with today's smoother generation time series. Two weeks were simulated in details using the method described above in the earlier study. The selected weeks represented one week with high surplus and one week with high need of extra power. The method includes a linear programming approach considering all river couplings and water court decisions. The results show that for the two studied weeks, it was possible to follow the requested profile of the hydropower, i.e., it was possible to operate the hydro system at both low level (1 875 MW) and high level (12 951 MW) during many hours in each week.

C. Hydro-wind studies in Portugal

Regarding the plan for "large renewables" in Portugal (hydro and wind), power system development constraints in Portugal were identified: excess of renewable generation (wind + run-of-river hydro) during the low-load hours (midnight to 6 a.m.). The necessity to provide added flexibility, e.g., through energy storage, after 2011 (Figure 4) was assessed by deterministic parameters: a wet windy day that occurred in 2011 after the installation of 5 700 MW of wind power capacity. The figure illustrates the correlation between pumped-hydropower and wind power for a worst-case day scenario, and assuming a maximum wind generation of 80% of the installed capacity.

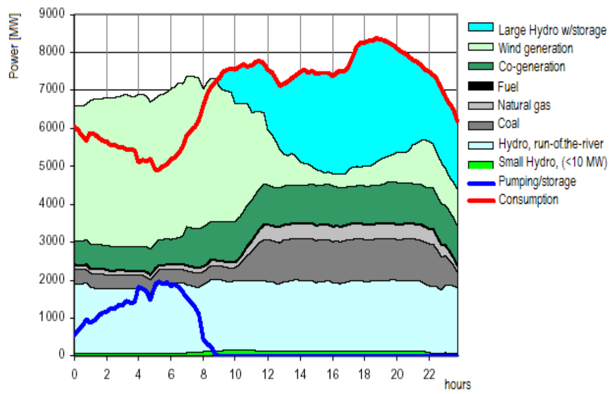


Figure 4 The scenario of generation profile for a wet windy day in 2011 [27,28]

\\home.ansatt.ntnu.no\farahman\Papers\WIW\National - _ENREF_35The plan to expand hydropower in Portugal defined ten hydroelectric power plants for the deployment/upgrading of approximately 1 054 MW and having an estimated annual production of 1 519 GWh/year. Seven of these have potential for reversible capability with a capacity of 807 MW. Most of the hydro projects were implemented to refurbish aging power plants built in the 1950s and 1960s. Thus, it would be possible to start the project of upgrading and the construction phase in a short time. In the ongoing first phase, construction of two hydropower plants with reversible turbines was already anticipated. This phase can support the existing high wind penetration that reached 20% of annual consumption in 2013. The necessary pumping equivalent capacity, estimated at 220 MW, is already available and was deployed directly (and bilaterally) with wind parks through (Distribution System Operator) DSO/wind cluster management arrangements.

D. Hydro-wind studies in United States

A recent study [29] examined the effect of having a more accurate representation of hydro operations utilising RiverWare [30], a dedicated model of cascading hydro systems. RiverWare uses a rule-based optimisation that allows for a detailed specification of the various constraints. RiverWare was coupled with PLEXOS [31] (a power systems production cost model) to better represent the interactions between the power system and the hydro dispatch. The model was applied to the “Big Ten” reservoirs, managed by the BPA in coordination with the Bureau of Reclamation and the U.S. Army Corps of Engineers (Figure 5).

Figure 5 BPA Big Ten (Inset: Pacific Northwest Region).

A significant portion (85%) of the hydro in the region was modelled in RiverWare with realistic power and non-power objectives for a week in spring. This operation was compared to the typical simplified assumptions that are included in power system modelling with PLEXOS. There was a significant benefit to the power system because of the increased flexibility in the hydro system as represented by RiverWare. More specifically,

- Under a business-as-usual scenario (BAU), total productions costs were reduced by 2%.
- A high-wind scenario saw a reduction of 16% in the amount of VG curtailed and a 0.6% decrease in total production costs.
- In both BAU and high-wind cases, extreme marginal price spikes were reduced.

III. SIMULATION CHALLENGES

Modelling a flow-based hydro system is a complex exercise, as is modelling the power system. The combined complexity that would arise by a combined "hydro system and power system model" has been out of reach. This will be the case until the characteristics of both these complex systems can be included into a combined model in a detailed enough but computationally reasonable way. However, there may be opportunities to improve the power system models’ representation of the hydro system. This can be achieved by undertaking studies that can capture the hydro limitations and parameterising the behaviour into electricity production simulation modelling. Especially important is the correct assessment of hydropower flexibility to support power systems with large share of variable generation and its value for storage. Studies show that a simplistic and aggregated modelling of hydropower limitations and capabilities in electricity production simulation modelling can severely overestimate [22] or underestimate [29] the real value and opportunity that hydropower flexibility might offer.

With increasing uncertainty and variability, a stochastic scheduling approach should yield lower costs [32, 23, 33]. There are limitations in a deterministic approach as it can produce suboptimal results since low-probability events are not taken into account [32—35]. Stochastic approaches have also been applied to hydro-wind systems [23, 33], but the benefit over deterministic approaches was not studied. The benefits should be weighed against the additional computational burden, since stochastic optimisation is computationally very demanding. In many cases, nonlinearities such as reservoir head variation would not be possible to model, and important detail would be lost [36]. Available computing power has increased in the recent years very rapidly, which means that methods previously computationally infeasible might become usable. There remains room for a methodological development for stochastic scheduling in systems with large amounts of wind and hydropower.

Large-scale variable generation has impact on all time scales of hydropower scheduling as indicated in hydro-wind studies in Norway. Different time scales are often handled in separate modelling tools. It is challenging for the simulation models to take into account the uncertainty in different time scales. Generally, in the models that are specifically made for hydro scheduling purposes, the long-term uncertainties are taken into account instead of short-term uncertainties. On the other hand, the other models that consider the short-term uncertainty do not have proper water value calculation. Therefore, a comprehensive modelling approach should combine all levels in an integrated manner.

- Investment decisions (long-term) are sensitive to hour-to-hour operation since the value of storage is highly influenced by the increasing variability in these time scales [15]. It is also influenced by the seasonal or annual correlation in the variability of wind and hydropower, which is still not well studied and could be further influenced by climate change. The cost-benefit of new hydropower with storage is naturally very site-specific. For example, storage schemes might be economical in isolated systems, but not in large systems with other sources of flexibility [37] – at least until increasing VG makes the storage more beneficial.

- In the medium-term, stochastic nature of variable generation has to be taken into account in addition to the classical inflow stochastic. This requires multivariate stochastic optimisation and scenario creation; examples of methods used currently are stochastic dual dynamic programming [4, 37] and stochastic model predictive control [38]. In a future power system with considerable amounts of variable renewable generation, a proper simulation should be preferred over simplified methods such as the use of historical records for reservoir reference levels [39]. An open issue is how to combine the auto- correlated and cross-correlated stochastic analyses while retaining the impact of all relevant stochastic elements.

- In the short-term, unpredicted changes in VG availability could be likely be balanced by reservoir hydropower in hydro-dominated power systems. Complicated hydrological networks might prevent the maximal use of resources. Other limiting factors are the use of reservoir water for irrigation or community drinking water, and navigational and ecological constraints. Some of the current power market simulation tools (e.g., WILMAR JMM [40, 41], PSST [42], SHOP [43]) have an aggregated hydropower description and should incorporate a more detailed hydropower to make simulations more realistic.

A modelling tool combing all these time scales should give more realistic results when simulating a hydro-dominated power system with large scale VG. Commercial software packages might have these features already. However, they often lack proper scientific documentation or are not publicly available at all. This suggests that further work in this area may result in advances in the economic use of hydro system to help maintain system balance with high levels of VG. Power system production cost model may not do a good job representing hydro conditions, and hydro models use a simplified version of the power system. This suggests incorporating the following issues in these models:

- Models correctly assessing strategies for hydropower dispatch and pumped storage need to be based not only on seasonal inflow variations but also on variable RES production. This is especially a case in scenarios with large-scale deployment of renewable energy production.

- Geographically detailed description of hydropower systems, cascading river systems, reservoirs, grid connection and congestion is needed to properly assess the real flexibility potential of hydropower and its value for storage.

- The time scales in large reservoir hydropower variability (seasonal) are different from those in wind and solar power generation variability (days to weeks). To bridge the gap, models operating in multiple time scales need to be refined.

IV. CONCLUSIONS

Hydropower is one of the most flexible sources of electricity. Power systems with considerable amounts of hydropower offer easier integration of variable generation like wind and solar. Assessment of the available and future hydropower flexibility in different countries with large hydropower capacity shows that there are considerable opportunities in many countries and the flexibility can be offered to neighbouring countries as well.

Despite a large potential for flexibility and storage possibilities, constraints may exist during some times of year or day in order to keep river flows and reservoirs levels within allowed limits. A review of the state-of-the-art modelling, its limitations and need for improvements for both hydro systems models and techno-economic models of hydropower dominated power systems has been presented with a focus on modelling of hydro systems in power system operation with large share of variable renewables.

Recommendations for further improvement of models are that a combined model should include sufficient amount of details regarding i) transmission constraints, ii) hydrological details between major areas or regional subsystems with large hydropower installed capacity, and iii) treatment of the uncertainty and variability of variable generation (wind and solar). These details are essential to correctly assess the real flexibility potential of hydropower and its value for storage to support power systems with increased variable generation. Main ingredients to capture and parameterise the behaviour and limitations of hydro systems are: i) correct marginal costs of hydro power generation (water values), ii) incorporation of reasonable geographical details of hydropower reservoirs, river coupling of power plants, and detailed representation of transmission grids.

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