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RISK-AVERSE APPROACH FOR ASSESSMENT OF INVESTMENT IN A RUN-OF-THE-RIVER POWER PLANTS WHILE CONSIDERING REDUCED WATER AVAILABILITY

SUMMARY

Investment in the facility for harnessing a stream of water is usually characterized by long payback period. Hence investment choice not only needs to be optimal, but it also needs to be robust enough to cope with uncertainties which occur during payback period. In this research, a family of flow duration curves is created to model stochastic nature of water availability. The risk-constrained approach for assessment of investments in cascaded hydropower plants is proposed in a form of a mixed-integer linear programming. Proposed approach will manage a risk of large financial losses induced by these uncertainties. The project of run-of-river power plants on the Sava river stretch (Croatia) from border with Slovenia to the city of Sisak is analyzed.

Keywords: Assessment of investment, Small hydropower plant, Mixed-integer linear programming, Conditional value-at-risk, Sava river, Croatia

1 NOMENCLATURE

$c(\cdot)$	Specific investment cost function (€/kW).
$E(i,t)$	Electricity produced for energy market by plant i in period t (MWh).
F_α	Special function used for risk shaping of CVaR (€).
$H_{max}(i)$	Maximal possible head of a pondage i (m).
$H_r(i)$	Rated head of a plant i (m).
$H(i,t)$	Head of pondage i in period t (m).
I	Set of indices of the reservoirs/plants, I={'Podsused','Prečko','Zagreb1','Zagreb2','Zagreb3',Zagreb4'}, $i \in I$.
$I_{>10MW}$	Subset of plants with capacity above 10 MW, $I_{>10MW} \subset I$.
$I_{\leq 10MW}$	Subset of plants with a capacity of 10 MW and under, $I_{\leq 10MW} \subset I$.
i_x	Inflation index.
$Inv(t)$	Investment cost of a cascade in period t (€).
n	Capacity factor.
$\min CVaR(k)$	k^{th} profit tolerance, an i.e. parameter used for risk exposure reduction in risk shaping procedure (€).
$NPV(\omega)$	Net present value of scenario ω (€).
$om(\cdot)$	Specific operating and maintenance cost function (%).
$O\&M(t)$	Operating and maintenance cost of a cascade in period t (€).
$P_{max}(i)$	Capacity of plant i (MW).
$p(\omega)$	Probability of price scenario ω.
$Q_{min}(i)$	Minimum water discharge of plant i (m^3/s).
$Q_{max}(i)$	Maximum water discharge of plant i (m^3/s).
$Q_{res}(i)$	Residual flow of plant i (m^3/s).
$q(i,t)$	Total water discharge of plant i in time step t (m^3/s).
$R(t)$	Revenue of a cascade in time period t (€).
r	Discount rate.
T	Set of indices of the steps of the optimization period, $T=\{1, 2, \ldots, T_{max}\}$, $t \in T$, $T_{max} \in \{20,25,30\}$.
U_i	Set of upstream reservoirs of plant i.
$V_{min}(i)$	Minimal possible utilizable volume of a plant i (m^3).
$V_{max}(i)$	Maximal possible utilizable volume of a plant i (m^3).
$V(i,t)$	Utilizable volume of a plant i in time interval t (m^3).
$W(i,t)$	Forecasted natural water inflow of the reservoir i in time step t (m^3).
$weight(t)$	Distribution of investment cost along y time intervals, $t \in y \subset T$.
$X(i,t)$	Water content of the reservoir i in time step t (m^3).
$X_{avg}(i,t)$	Average water content of the reservoir i in time step t (m^3).
$X_{max}(i)$	Maximal content of the reservoir i (m^3).
$X_{min}(i)$	Minimal content of the reservoir i (m^3).
$X(i,0)$	Initial water content of the reservoir i (m^3).
$X(i,T_{max})$	Final water content of the reservoir i (m^3).
Y	Number of hours in one year, 8760 (h).
$\pi_{fit}(t)$	Feed-in-tariff in time step t (€/MWh).

$\pi_e(t)$	Forecasted price of electricity in time step t (€/MWh).
Greek	
α	Percentile used for the CVaR where 1-α defines the worst events (%).
$\rho_v(blok)$	Slope of the block $blok$ of the utilizable volume function ($m^3/m^3/s$).
$\rho_j(i)$	Slope of the performance curve j of plant i (MWh/m^3).
ζ	The decision variable which defines the Value at Risk (€).
η	Variable used for obtainment of the CVaR (€).
Ω	Set of indices representing future states of knowledge, it is a set of scenarios that can occur, $\Omega = \{1, 2, \dots, \Omega_{\max}\}, \omega \in \Omega,\ \Omega_{\max} \in \mathbb{N}$.

2 INTRODUCTION

Careful planning is a necessity if a goal is a profitable hydropower project. Careful planning assumes precise modelling and simulation which is especially needed when long payback period is assumed, which is the case for the hydropower projects. For that reason, the risk-constrained approach for assessment of investment in run-of-the-river power plants is presented while considering reduced water availability. The methodology will manage the risk of large financial losses. There are many risks induced by many other influences, and this approach can be adapted to them as well, but for formulation clearness, here, only the risk of financial losses induced by declining water availability is considered. Also, only direct benefit of investment is considered, such as selling electricity on the wholesale market. Indirect benefits of improved water management are not considered here such as flood prevention, reduced water stress, and e.g. [1]. The objective of this work is to maximize the net present value from selling electricity on the wholesale market. It is a continuation of the work done in the [2] which is significantly improved here by implementing the family of the flow duration curves (FDC) which represents water availability scenarios, and conditional value-at-risk (CVaR) a risk measure used for risk management. The generated scenarios combined with the risk-constraining approach results in a robust investment plan. The reconnaissance level of detail is warranted, and some basic requirements when considering investing in hydropower plants will be discussed. The usage of the FDC for the economic evaluation of hydropower plants (HPP) is well documented [3], [4] and [5]. The procedure when conducting a hydrologic study is to establish how much water is available to divert through the turbine and at which hydraulic head. Here, the line potential is observed which denotes the theoretical potential of streams and rivers which could be harnessed through a continuous chain of imaginary run-of-river plants as depicted in Fig. 1.

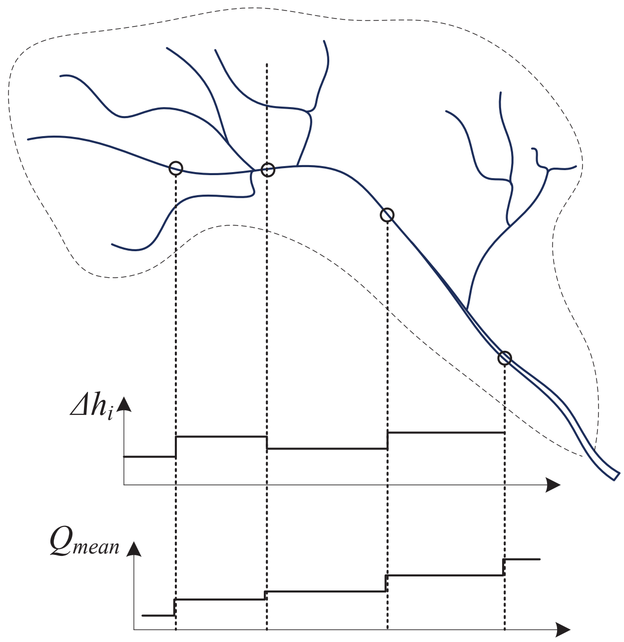

Figure 1. The line potential is a function of a mean annual flow and the head difference Δhi of a reach

The hydro potential is obtained by subdividing a stream or river into reaches along which discharge and longitudinal slope are approximately uniform as illustrated in Fig. 1 and is defined by mean annual discharge and the elevation difference between the beginning and the end of a reach [6]. Additional information on financial aspect of hydropower systems can be found in [7] and technical aspects of small-scale HPP projects in [8]. Approaches how to evaluate potential location for HPP is given in [9], and more detailed insight is given in [10]. Therefore, in section III problem description and mathematical formulation of the model is given, in IV the case study is given of the potential investment in a cascaded run-of-the-river HPPs on the Sava river in Croatia.

3 PROBLEM DESCRIPTION AND FORMULATION

3.1 Flow-Duration Curve

When river line potential is established, the utilizable potential of each river reach is calculated. The utilizable potential is a function of utilizable volume of water and generating unit performance curve. The utilizable (usable) volume, V, is defined by FDC as illustrated in Fig. 2.

When extremely high flows, Q_{ext}, occur, then tail water rises so high that the net power head is so small for the power plant to function. Unless there is an available storage to regulate flows to more favorable discharge rates, or a sluice to divert extreme flows from the main riverbed, then HPP will be inoperable in extremely high flows. The residual flow, Q_{res}, and HPP minimum turbine discharge Q_{min} are taken into account to evaluate utilizable volume correctly. The water availability scenarios are modeled with the four FDCs depicted in Fig. 3.

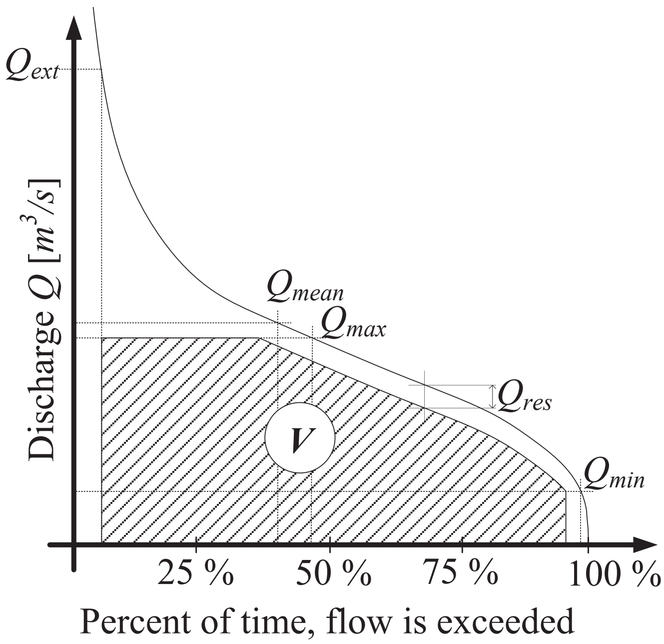

Figure 2. Generic FDC, the dashed area is usable volume V and is always less than ideally possible volume due to the turbine characteristics.

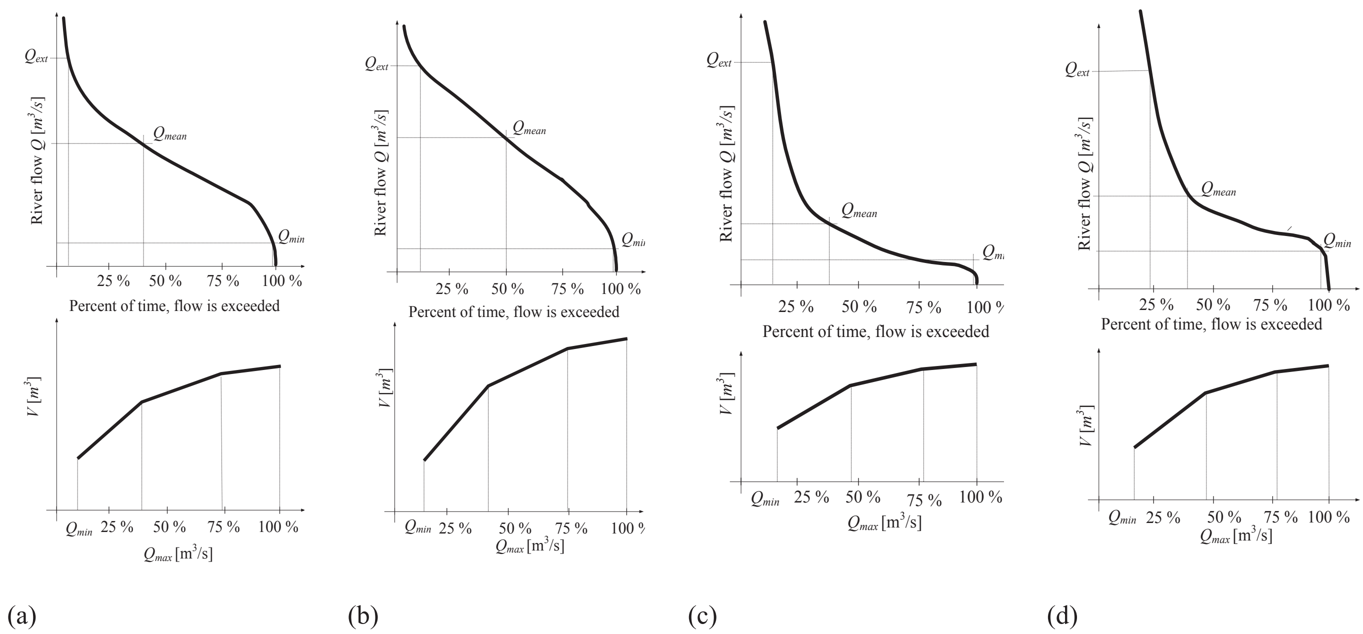

Figure 3. Four FDCs and associated usable volume for (a) average water availability, (b) high water availability and (c) low water availability are generated according to (d) normal distribution of mean flow

4 HEAD

A design head is defined as the head at which the turbine will operate at the best efficiency. Usually, a planner from the power studies determines the head at which best efficiency is desired then provides this value to the hydraulic machinery specialist to select an appropriate turbine design. Also, usually it is desirable to obtain the best efficiency in the head range where the project will operate most of the time, the design head is commonly specified at or near the average head. Additionally, for run-of-river projects, design head can be determined from a head-duration curve by identifying the midpoint of the head range where the project is generating power (Fig. 4). The design head usually is based on the yearly operation. Also, it could be based on operation in the peak demand months when dependable capacity is significant. Contrary, the pondage projects, which operate primarily for peaking, a design head is usually based on the weighted average head (weighted by the amount of electricity produced at each head). The rated head is defined as the head where rated power is obtained with turbine wicket gates fully opened. Thus, it is the minimum head at which rated output can be obtained. The selection of rated head is a compromise based on cost and efficiency. Therefore, a net head versus discharge curve (Fig. 5a) is developed which shows the tail water and forebay elevation dependence with discharge (Fig. 5b). Here the head computation is directly implemented in the performance curve (1).

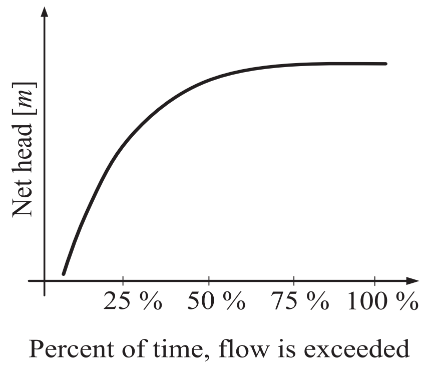

Figure 4. Typical head-duration curve (HDC)

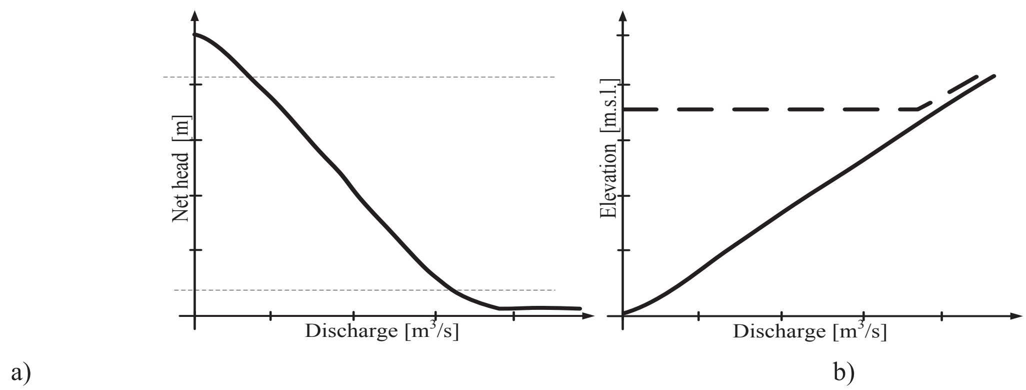

Figure 5. The depiction of a: a) head-discharge curve, b) pool elevation (dashed) and tail water elevation curve (solid). Net head is the forebay elevation minus the tailwater elevation minus the trashrach and penstock head losses.

Using FDC and head discharge curve, head duration curve (HDC) can be constructed (Fig. 4). The FDC and HDC methods are limited to small hydro projects, particular run-of-river projects. To obtain a reasonable estimate of the annual power production performance curves of turbine-generator units are used (Fig. 6). The performance curves account for efficiency characteristics and operating range limitations consistent with the turbine type likely to be installed. More on performance curves in [8].

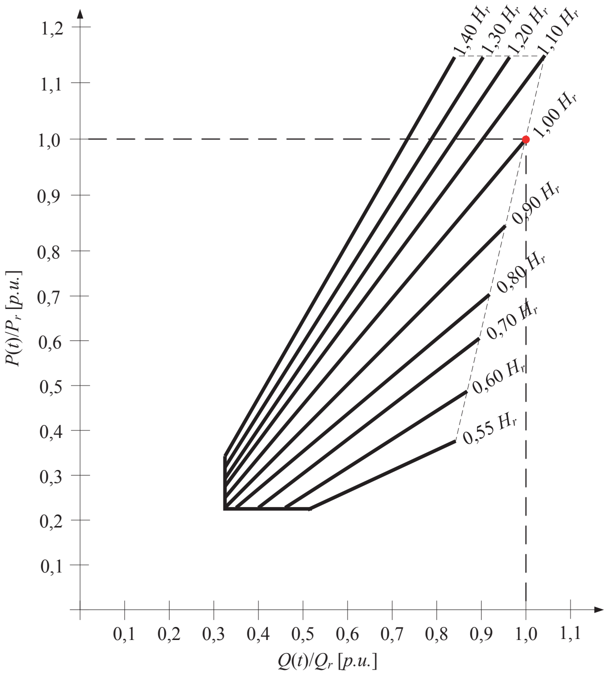

Figure 6. Variable pitch propeller without wicked gates

In this paper performance curves (Figure 6) have been modeled through a piecewise linear formulation of Hill chart [11]. Figure 6 shows linear performance curves with its associated slope ρ which is defined by HPP conversion capabilities (MW/m^3). The Cavitation and vibration problems limit turbines to a minimum discharge of 30 to 50 percent of rated discharge Energy production performance curve (7).

To assure that best choice of rated head H_r, rated turbine discharge Q_{max} and number of units N is selected, all combinations of scenarios H_r, Q_{max} and N should be calculated, a procedure for determining optimal rated flow, number of units, and a head is shown in Fig. 8 of [2]. The general procedure is to calculate and compare energy produced of turbines having a higher and a lower rated flow. Following establishment of the rated flow it needs to be checked if power is being lost because turbine discharge is consistently below lower boundaries, then HPP maximal capacity P_{max} is lowered, and more units are added. If energy production $E(i,t)$ increase is substantial, cost of the alternatives may be determined from the HPP specific investment cost function (Fig. 7) and O&M specific costs function (Fig. 8). Also, the first selection of the number of turbines needs to be compared with the lesser number of units. The rated head of the turbine can be further refined by optimization in a similar manner. The annual power production is computed for higher and lower heads with the same capacity rating. The rated head yielding the highest annual output should be used. The greater the chosen value of the maximal turbine discharge, the smaller proportion the year that the system will be operating at full power, i.e., it will have a lower capacity factor n [2].

To calculate annual energy production it is necessary to calculate annual utilizable volume V correctly. To do that V needs to be expressed as a function of HPP maximum water discharge Q_{max} as explained in Eq. (11)-(15) in [2]. Essential characteristic of used function is its concave nature necessary to ensure convexity in optimization problems and to assure strong duality.

5 REVENUES AND EXPENSES

The largest share of investment cost for large hydropower plant is typically taken up by civil works for the construction of the hydropower plant (such as a dam, tunnels, canal and construction of powerhouse, etc.). Electrical and mechanical equipment usually contributes less to the cost. However, for hydropower projects where the installed capacity is less than 5 MW, the costs of electro-mechanical equipment may dominate total cost due to a high specific cost of small-scale equipment [7]. The specific cost of investment in HPP is depicted in Fig. 7 and is a piecewise linear function. HPP usually require little maintenance, and operation costs will be low. When in cascade along a river, centralized control can reduce O&M costs to low levels. In this study O&M specific costs are depicted on Fig. 8 according to [7].

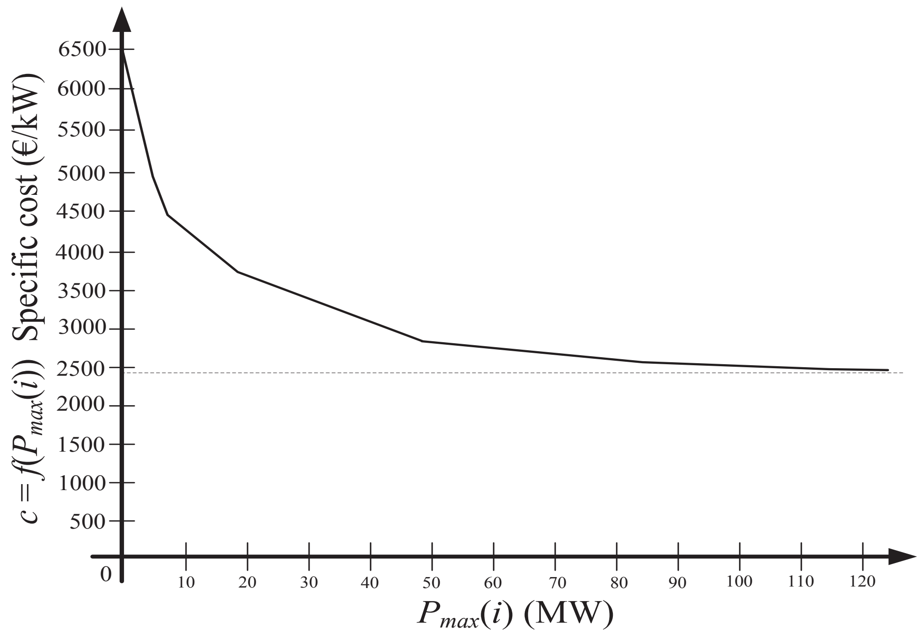

Figure 7. The specific investment cost of an HPP as a function of installed capacity.

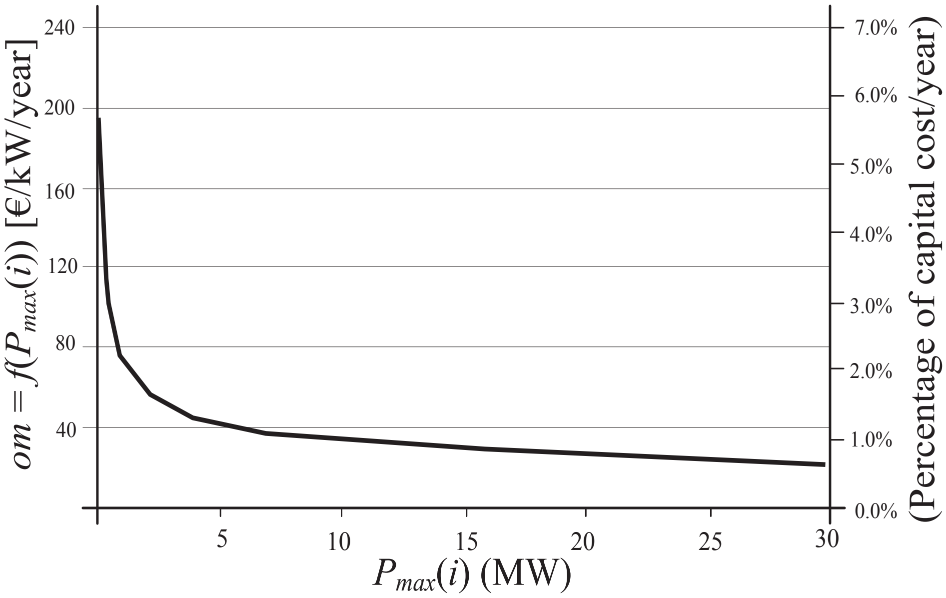

Figure 8. Specific O&M costs as a function of installed capacity.

6 OBJECTIVE FUNCTION

Maximize the net present value (NPV) of the project:

$$NPV = \sum_{t=y+1}^{t=T} \frac{(1+i_x)^t (R(t) - O\&M(t))}{(1+r)^t} - \sum_{t=1}^{t=y} \frac{(1+i_x)^t Inv(t)}{(1+r)^t} \#(1)$$

Expression (1) assumes that the project will be developed in y years (time intervals). At the end of y^{th} year the whole development is finished and paid. The electricity revenues and O&M costs are made effective at the end of each year and begin at the end of the y^{th} year [10]. All variables and parameters are defined in the nomenclature.

Revenue part of (13):

$$R(t) = \pi_e(t) \cdot \sum_{i \in I_{>10MW}} E(i,t) + \pi_{fit} \cdot \sum_{i \in I_{\leq 10MW}} E(i,t) \;\; \forall i \in I, \forall t \in T \;\; \#(2)$$

where the first part of (2) denotes revenues from wholesale electricity market and the second part, revenues of eligible units (under 10 MW) from feed-in-tariff (FIT).

Operating and maintenance part:

$$OM(t) = \frac{\sum_{i \in I} om\big(P_{max}(i)\big)}{100} \cdot \sum_{t=1}^{t=y} \frac{(1+i)^t Inv(t)}{(1+r)^t} \quad \forall i \in I, \forall t \in T \;\#(3)$$

Investment cost:

$$\boldsymbol{Inv}(t) = weight(t) \cdot \sum_{i \in I} c\big(P_{max}(i)\big) \cdot P_{max}(i) \quad \forall i \in I, \forall t \in T \;\#(4)$$

The (5) defines how investment cost is distributed over y years.

$$\sum_{t=1}^{y} weight(t) = 1 \;\#(5)$$

7 RISK MEASURE

An easy way to incorporate risk into linear model is to use CVaR [12] as a measure of risk. The α-CVaR in Fig. 9 is an average profit in worst 1-α (i.e., 15%) scenarios and α-VaR is minimal profit which company can expect in rest α (i.e. 85%) scenarios.

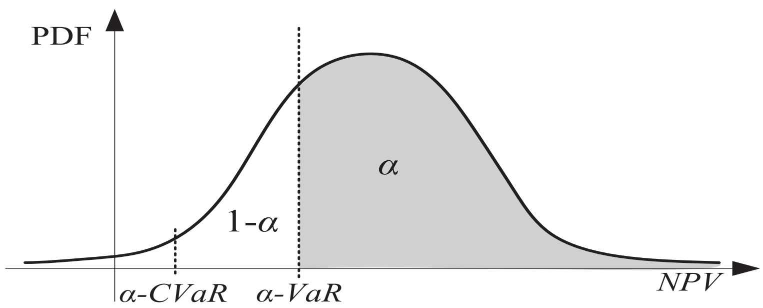

Figure 9. Hypothetical PDF of an NPV.

In the next section α-VaR and α-CVaR are formulated using the profit probability distribution function (PDF) as depicted in Fig. 9. Both α-VaR and α-CVaR can be calculated by solving a simple optimization problem of a convex type in one dimension. For this purpose, the function (6) is formulated.

$$F_\alpha(Variables, \zeta) = \zeta - \frac{1}{1-\alpha} \sum_{\omega=1}^{\Omega_{max}} p(\omega) \cdot [\zeta - NPV(\omega)]^+ \;(6)$$

where $[\zeta - NPV(\omega)]^+ = \max\{0, \zeta - NPV(\omega)\}$, and ω denotes one water availability scenario, i.e., one FDC as depicted in Fig. 3 for which the NPV is calculated.

When maximizing (6) over all variables defined in model, (8) and (9) are obtained.

$$\max_{(Variables,\zeta)\in \mathbb{R}^{No.of\ var}\times\mathbb{R}} F_\alpha(Variables,\zeta) \tag{7}$$

$$\alpha - CVaR = F_\alpha(Variables^*,\zeta^*) \tag{8}$$

$$\alpha - VaR = \zeta^* \tag{9}$$

where $Variables$ denotes all variables defined in nomenclature. ζ is shown separately only to point out its importance. In (7)-(9) risk measure is expressed as a daily value which manages risk occurred during a whole day. Since this model already has defined an objective function, special function is thus brought in the optimization problem in the form of a constraint (10).

$$F_\alpha(Variables,\zeta) \geq minCVaR \ \#10$$

When implementing constraint (10), risk is "shaped" using profit tolerance $minCVaR$. When set of profit tolerances $minCVaR(k), \forall k \in N$ is introduced in optimization model and requirement (11) is valid, then α-CVaR can be heuristically obtained using algorithm described in Fig. 10.

$$minCVaR(k-1) < minCVaR(k) < minCVaR(k+1) \ \#(11)$$

Linear formulation of CVaR as implemented is shown in (12)-(14).

$$\eta(\omega) \geq 0 \quad \forall\omega \in \Omega \tag{12}$$

$$\eta(\omega) \geq NPV(\omega) - \zeta \quad \forall\omega \in \Omega \tag{13}$$

$$\zeta - \frac{1}{1-\alpha}\sum_{\omega=1}^{\Omega_{max}} p(\omega)\cdot\eta(\omega) \geq minCVaR(k) \tag{14}$$

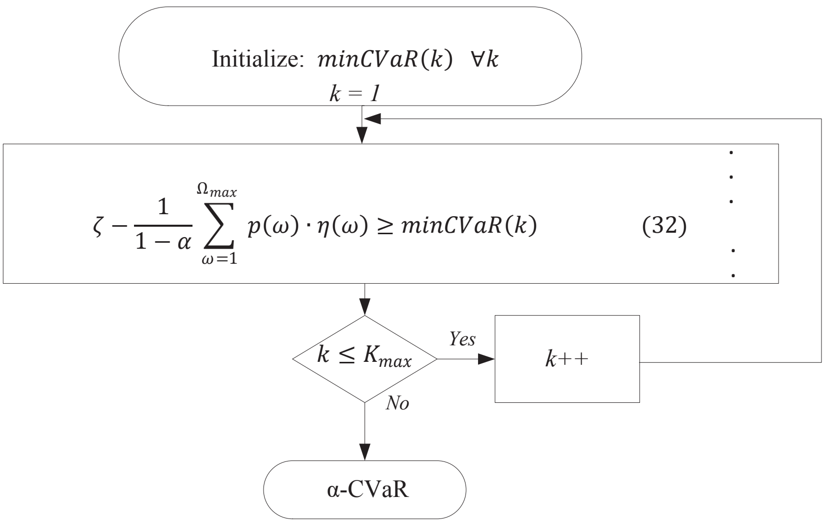

Figure 11. Simple heuristic algorithm for obtaining α-CVaR

Model is defined as a mixed-integer linear program using indexed assignments [13]. The presented results were obtained on 3.4 GHz based processor with 8 GB RAM using CPLEX under General Algebraic Modeling System (GAMS).

8 RESULTS AND DISCUSSION

Virtual hydropower system (HPS) Sava (Croatia) is modelled as illustrated in Fig. 9. The observed six river reaches consists of six pondages, six run-of-river HPP and a sluice. Tributary line potential is not considered.

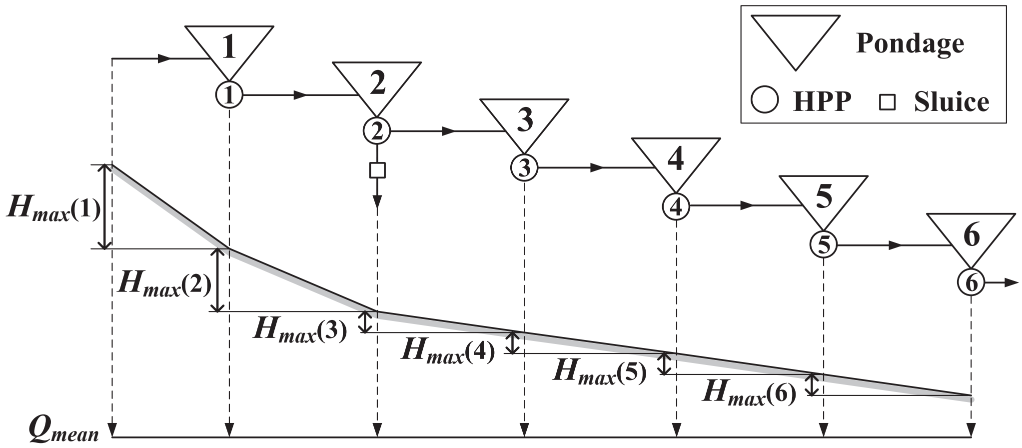

Figure 11. Heuristic algorithm for assessment of investment in cascaded run-of-river HPPs.

Because of computational efficiency, it should be noted that time periods of 1 year are considered. Since there is a sluice in pondage 2, extreme water flows will not reduce utilizable volume by extreme tail water rise. The conventional propeller and very low head (VLH) Kaplan turbines are considered which are operated at power outputs with flows from 40 to 100 percent of rated flow $Q_{max}(i)$. Performance curves (Figure 6) and pondage (Figure 11) parameters are shown in Table 1.

Table I HPP performance curves and associated pondage parameters

HPP	ρ_1	X_{min}	X_{max}	H_{max}
1	2,207E-5	3E6	4.078E6	9
2	1,839 E-5	4.6E6	6.75E6	7,5
3	9,197E-6	1.2E6	1.903E6	3,75
4	9,197E-6	1.2E6	1.9406E6	3,75
5	9,197E-6	0.4E6	0.7875E6	3,75
6	9,197E-6	1.7E6	2.718E6	3,75

Since there is no significant tributary in observed river reaches, one FDC is constructed and is assigned to all six river reaches for each scenario. The four FDC based on daily flows of periods from time intervals: 1997 to 1987, 1988 to 1993, 1988 to 1998 and 1994 to 1999 are used. Resulting FDCs are linearized and are depicted in Figure 12. For confidentiality reasons only the averaged data of four FDC will be shown in the paper, therefore: Mean annual discharge Q_{mean} for each river reach is 320 m³/s. Residual water flow Q_{res} is 20 m³/s. Maximal flow Q_{ext} of each river reach is 800 m³/s. Electric energy price π_e is 43.6 €/MWh and is an average price of base load power at EPEX Spot (EEX, 2012) for 2003 to 2012 period. Feed-in-tariff π_{fit} is set at 56 €/MWh. Discount rate r is 8.2 %. Inflation index i is 2%, a number of investment years y is 1 and utilizable volume function slopes ρ_1 and ρ_2 are 0.8616 and 0.3618 respectively (Fig. 12). The number of units is set to $N(i)$ = 1 for all plants. Stabilizing head $H(i,t)$ of each river reach is one of the major concerns in this study where maximal possible head $H_{max}(i)$ is predetermined by geographical and urbanization constraints, thus rated head $H_r(i)$ won't be optimized. Results are obtained for the period T_{max}= 30 years with scenario matrix.

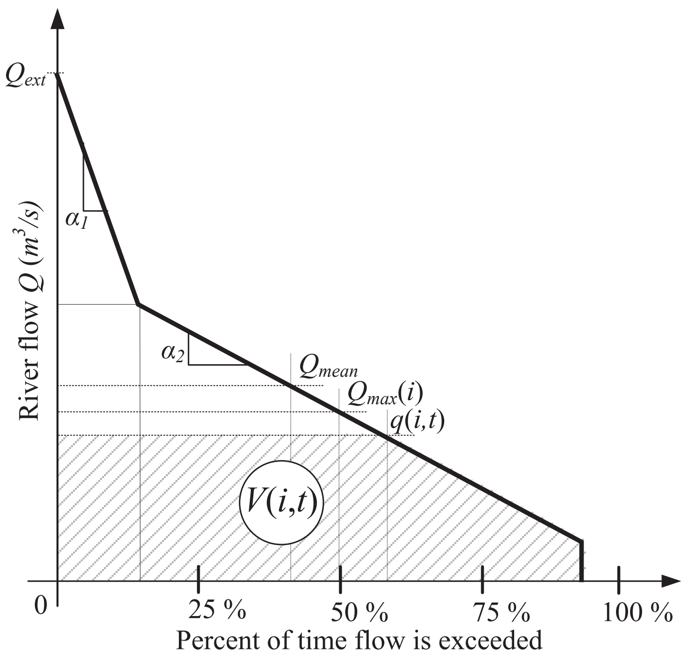

Figure 12. Linearized FDC less residual flow and extreme flows

Table II Averaged Results of Four Scenarios With and Without CVaR

	Without	With
Q_{max}/Q_{mean}	**0,75**	**0,70**
n	**0,8616**	**0,82**
NPV (mil. €)	**16,1**	**13,5**
IRR (%)	**8,7891**	**7,532**
W (GWh)	**461,22**	**403,3**
I (mil. €)	**259**	**239**
$P_{max}(1)$ (MW)	**17,879**	**17,455**
$P_{max}(2)$ (MW)	**14,899**	**14,321**
$P_{max}(3)$ (MW)	**7,45**	**7,12**

	Without	With
$P_{max}(4)$ (MW)	**7,45**	**7,12**
$P_{max}(5)$ (MW)	**7,45**	**7,12**
$P_{max}(6)$ (MW)	**7,45**	**7,12**

9 CONCLUSION

Simulation showed favorable NPV and IRR which means that the HPS Sava project is economically sound. Additional simulations should be conducted for wide range of possible future scenarios. Additionally, adjusting model to desired accuracy and detail will result in computational intensive simulation and will provide valuable data on run-of-river cascade long-term schedule.

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