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Short-term hydropower scheduling via an optimization-simulation decomposition approach

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***Abstract*—This paper presents a decomposition approach based on an optimization-simulation approach to short-term hydropower scheduling. The problem is formulated as a mixed-integer nonlinear programming problem where the decision variables are the power output and the number of units committed at each hydro plant and hour of the day or week ahead. The goal consists of maximizing hydropower efficiency while reducing startup/shutdown costs and attaining system load, operational constraints, as well generation targets established by mid-term operation scheduling models. The approach proposed in this paper solves a relaxed version of the original problem in which hydraulic constraints are ignored. Eventual hydraulic infeasibilities are computed by a simulation step in order to either validate the solution or add violated constraints back into the problem. The approach is implemented and tested over the Brazilian power system for a study case comprised of 95 hydro plants, 447 generating units, and an average load of 41 GW for a week long horizon. Results confirm the approach to be very efficient in terms of computational costs, and both unit commitment and generation schedules.**

***Index Terms*—Hydroelectricity, operation scheduling, unit commitment, nonlinear programming, simulation**

I. Introduction

Short-term hydropower scheduling (STHS) aims to determine the power output and the number of generating units dispatched at each hydro plant and hour of the day or week ahead that attains the system load, the generation targets from mid-long term planning, and the plant operational constraints while optimizing a performance criterion. STHS provides operational guidelines to the real time system operation, thus requiring balance between computational costs and sub-optimality of solutions.

Several approaches concerning the STHS problem have been previously proposed, such as dynamic programming [1] and genetic algorithms [2]. A large amount of those approaches [3]–[10], though, consider full constraint sets, including water balance equations for each plant and hour, as well as bounds on storage and discharge variables. Since these constraints are considered throughout the planning horizon, they greatly contribute to the computational burden of the solution techniques. However, since STHS problems usually comprise time horizons of a day or a week, most of these hydraulic constraints will not be active and therefore will not affect the optimal solution, especially for hydro plants with large capacity reservoirs, like the ones found in the Brazilian power system.

Problems with a large number of inactive constraints in the optimal solution are suitable to be efficiently solved by a relaxation approach. Instead of considering all constraints at once, constraints which are likely to be inactive are relaxed in order to efficently solve the problem. A feasibility check over the relaxed constraints is then performed. It will indicate violated constraints that should be added back into the relaxed problem for a new optimization iteration. The procedure ends when the solution of the current relaxed problem satisfies all relaxed constraints.

This paper presents a decomposition approach based on an optimization-simulation approach to short-term hydropower scheduling. The problem is formulated as a mixed-integer nonlinear programming problem where the decision variables are the power output and the number of units committed at each hydro plant and hour of the day or week ahead. The goal consists of maximizing hydropower efficiency while reducing startup/shutdown costs and attaining system load, operational constraints, as well generation targets established by mid-term operation scheduling models. The approach proposed in this paper solves a relaxed version of the original problem in which hydraulic constraints are ignored. Eventual hydraulic infeasibilities are computed by a simulation step in order to either validate the solution or add violated constraints back into the problem. The approach is implemented and tested over the Brazilian power system for a study case comprised of 95 hydro plants, 447 generating units, and an average load of 41 GW for a week long horizon. Results confirm the approach to be very efficient in terms of computational costs, and both unit commitment and generation schedules.

The rest of this paper is organized as follows. Section II formulates the problem. Section III describes the optimization-simulation approach to the STHS problem. Section IV presents numerical results and illustrates the methodology. Finally, Section V draws final conclusions.

II. Problem formulation

The goal of the STHS problem is to compute the optimal unit commitment and generation schedules for the next day or so up to one week, on an hourly basis. The number of generating units in operation and their respective generation output must be found for every hydro plant and hour of the planning horizon so that a performance criterion is minimized while meeting several constraints. The problem is formulated as a minimization problem of an objective function consisted of the sum of power losses at every plant over the planning horizon. Power losses represent the decrease in hydro generation efficiency due to tailrace elevation, penstock head loss increase, and turbine-generator efficiency decrease, and depends on the number of committed units and their power output. Thus,

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the minimization of losses is equivalent to the maximization problem of power output efficiency. Furthermore, in addition to power losses, startup and shutdown costs [11] are also to be minimized. Finally, for a hydro system composed of I plants and a planning horizon of J hours, the problem can be formulated as the following mixed-integer nonlinear problem:

$$\min_{n,p} \sum_{j=1}^{J} \sum_{i=1}^{I} \alpha f_i(n_{i,j}, p_{i,j}) + \beta c \left| n_{i,j} - n_{i,j-1} \right| \tag{1}$$

subject to the following power generation constraints:

$$\sum_{i=1}^{I} p_{i,j} = d_j \tag{2}$$

$$\sum_{j=1}^{J} p_{i,j} = m_i \tag{3}$$

$$\sum_{i \in \mathcal{R}_{k,j}} (p_{i,j}^{max} - p_{i,j}) \geq r_{k,j} \tag{4}$$

$$\left| \sum_{i \in \mathcal{S}_{k,j}} (p_{i,j} - p_{i,j-1}) \right| \leq s_{k,j} \tag{5}$$

$$p_{i,j}^{min} \leq p_{i,j} \leq p_{i,j}^{max} \tag{6}$$

$$n_{i,j}^{min} \leq n_{i,j} \leq n_{i,j}^{max} \tag{7}$$

and reservoir operation constraints:

$$u_{i,j} - y_{i,j} - \sum_{\forall k \in \Omega_i} u_{k,j-\theta_k} = \frac{x_{i,j} - x_{i,j+1}}{\gamma_j} \tag{8}$$

$$x_{i,j}^{min} \leq x_{i,j} \leq x_{i,j}^{max} \tag{9}$$

$$q_{i,j}^{min} \leq q_{i,j} \leq q_{i,j}^{max} \tag{10}$$

$$0 \leq v_{i,j} \tag{11}$$

$$u_{i,j}^{min} \leq u_{i,j} \tag{12}$$

where

$$u_{i,j} = q_{i,j} + v_{i,j} \tag{13}$$

$$p_{i,j} = g \cdot \rho \cdot \eta_i^t \cdot \eta_i^g \cdot h_{i,j} \cdot q_{i,j} \cdot 10^{-6} \tag{14}$$

$$h_{i,j} = h_{i,j}^f - h_{i,j}^t - h_{i,j}^p \tag{15}$$

Power output $p_{i,j}$ and number of committed units $n_{i,j}$ are problem variables indexed over time. Below is a summary of the symbols used throughout the text:

i	plant index	
j	hour index	
$n_{i,j}$	number of committed units	
$p_{i,j}$	power output	(MW)
g	acceleration of gravity	(m/s^2)
ρ	specific weight of water	(kg/m^3)
η_i^t	turbine efficiency	(%)
η_i^g	generator efficiency	(%)
$h_{i,j}$	water head	(m)
$x_{i,j}$	storage	(hm^3)
$q_{i,j}$	water discharge	(m^3/s)
$v_{i,j}$	water spillage	(m^3/s)
$u_{i,j}$	water release	(m^3/s)
$y_{i,j}$	incremental inflow	(m^3/s)
d_j	load	(MW)
m_i	generation target	(MW)
θ_k	water travel time	(hours)
Ω_i	set of immediately upstream plants	

Water head $h_{i,j}$ for plant i during stage j, as computed in Eq. (15), is a function of forebay $h_{i,j}^f$ and tailrace $h_{i,j}^t$ elevation, which in turn are given by fourth-degree polynomial functions of storage and water release, respectively. Furthermore, penstock head loss $h_{i,j}^p$ is given as a quadratic function of discharge.

The systems of linear equations in (2)–(7) consist of power generation constraints, where d_j is the system load during the j-th hour, and m_i is the power generation target for hydro plant i over the planning horizon. Equations (4) and (5) refer to spinning reserve and ramp constraints.

On the other hand, water storage, discharge and spillage at every hydro plant and hour are represented by variables $x_{i,j}$, $q_{i,j}$, and $v_{i,j}$, respectively. Water conservation is enforced by (8), where $u_{i,j}$ is the sum of discharge and spillage flows, $y_{i,j}$ is the natural inflow into i, Ω_i is the set of plants immediately upstream from i, θ_k is the water travel time from plant k to plant i discretized in time intervals, and γ_j is a unit conversion factor. Additionally, all problem variables are subject to either lower or upper bounds or both, as depicted in (6)–(12).

A. *Forebay and tailrace elevation*

Forebay elevation plays a major role in the mid/long term operation planning of hydropower systems, but in short term planning, which involves a single day on an hourly basis, little change in forebay elevation is observed so that this variable can be considered constant. However, tailrace elevation can change considerably in daily operation as consequence of variation in discharge necessary to track load.

B. *Loss components*

As the total water discharge of a hydro plant increases, for a given number of generating units in operation, tailrace elevation and penstock head loss also increase and, as a consequence, the net water head decreases. At the same time, due to hill curve, turbine-generator efficiency will initially increase until a maximum efficiency point after which it decreases. An operation out from this optimal efficiency point

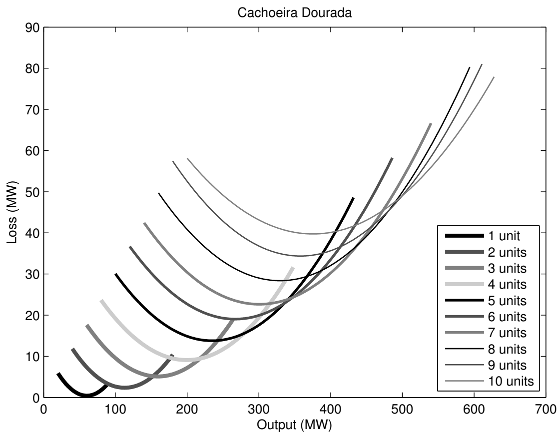

Figure 1. Power loss as a function of output and number of units dispatched.

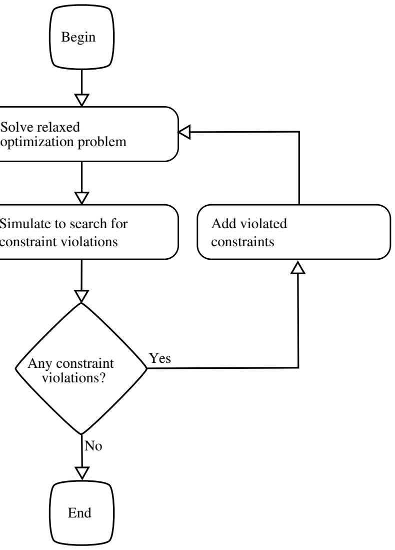

Figure 2. Flowchart for the optimization-simulation decomposition approach.

will result in a loss of efficiency [12]. In the following, these effects on hydro power output are expressed in terms of power loss.

$$p_{tn} = g \cdot \rho \cdot \eta_t \cdot \eta_g \cdot \Delta h \cdot q_n \tag{16}$$

where p_{tn} is the power generation loss for n generating units in operation and Δh is given by

$$\Delta h = h_t(q_n) - h_t(q_{ref}) \tag{17}$$

where q_{ref} is a reference water discharge for the plant, and q_n is the total water discharge for n generating units in operation. Penstock head loss is associated with the friction of water on the penstock and is represented as:

$$p_{pn} = g \cdot \rho \cdot \eta_t \cdot \eta_g \cdot (k \cdot \frac{q_{ref}^2}{n}) \cdot q_n \tag{18}$$

where p_{pn} is the penstock power loss for n generating units in operation, k is a constant that expresses the characteristics of the penstock (s^2/m^5). Finally, efficiency loss can be expressed as

$$p_{\eta n} = g \cdot \rho \cdot (\eta_{ref} - \eta) \cdot \eta_g \cdot h \cdot q_n \tag{19}$$

where $p_{\eta n}$ is the power generation loss associated with the decrease in turbine-generator efficiency and η_{ref} is the reference turbine-generator efficiency, both for n generating units in operation, where η_{ref} relates to water discharge equal to q_{ref}/n.

C. Total power generation loss

The total power generation loss is then computed as the sum of the three losses described above. This function gives the total loss as a function of power output and the number of generating units in operation. Fig. (1) plots total loss functions for Cachoeira Dourada hydro plant for different number of units.

III. Solution Technique

The proposed solution to the mixed-integer nonlinear problem (1)–(14) is based on an optimization-simulation decomposition approach provided by the relaxation of the hydraulic constraints (8)–(14). The relaxed optimization problem is solved and the resulting power generation solution is then checked for feasibility with respect to the hydraulic constraints. This check is performed by using a simulation procedure that determines the discharge decisions necessary for attaining Eq. (14) and the reservoir storage levels resulting from attaining Eq. (8). Note that determining discharge from power generation in Eq. (14) requires an iteractive procedure since water head, calculated as in Eq. (15), depends on discharge, tailrace elevation, and penstock head loss.

During the simulation procedure, bound constraints on discharge, given by Eq. (10), and release, given by Eq. (12), are automatically attained since they are already considered through the bound constraints on power generation, given by Eq. (6). Therefore the only possible violations in the hydraulic constraints are due to bounds on storage. The upper bound on reservoir storage is not enforced so that the reservoir is allowed to exceed its storage capacity (the surplus of water represents spillage, which is not a decision variable but a slack one). When the reservoir runs out of water, the hydro plant may not attain the power generation established by the relaxed optimization problem and, in this case, an energy shortage is verified. Thus, the only possible violations on the hydraulic constraints (8)–(14) are these spillages and energy shortages due to violations on reservoir storage. In order to eliminate these violations, linear constraints are added to the relaxed optimization problem and a new iteration of the decomposition approach is performed. Fig. (2) shows the flowchart for the proposed optimization-simulation approach.

Suppose that a water shortage equal to $\hat{V}$ was detected at hydro plant $\hat{i}$ and stage $\hat{j}$, and the immediately upstream plants are indexed by $\hat{k}$. The corresponding constraint to be included in the relaxed optimization problem in order to eliminate this

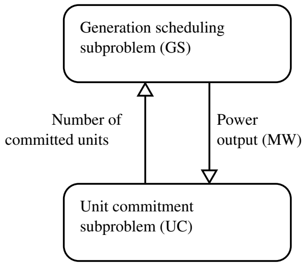

Figure 3. Flowchart for the UC-GS decomposition approach.

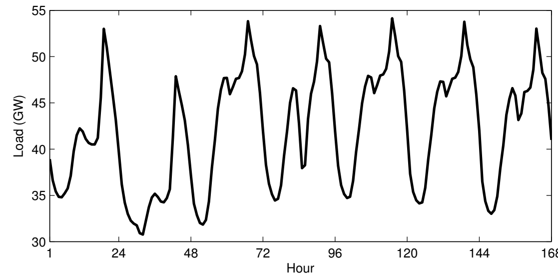

Figure 4. System load.

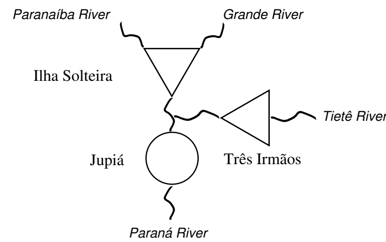

Figure 5. Ilha Solteira, Três Irmãos, and Jupiá hydro plants diagram.

violation is expressed by:

$$\sum_{\forall \hat{k} \in \Omega_{\hat{i}}} \sum_{j=1}^{\hat{j}-\theta_{\hat{k}}} \frac{p_{\hat{k},j}}{k_{\hat{k}} \cdot \hat{h}_{\hat{k},j}} - \sum_{j=1}^{\hat{j}} \frac{p_{\hat{i},j}}{k_i \cdot \hat{h}_{i,j}} = \hat{V} \tag{20}$$

where $\hat{h}$ is the actual head verified during the hydraulic simulation. The meaning of constraint (20) is that the water shortage on reservoir $\hat{i}$ and stage $\hat{j}$ can be eliminated by increasing the generation of the immediately upstream plants $\hat{k}$ during the stages previous to stage $\hat{j} - \theta_{\hat{k}}$ and by decreasing generation of plant $\hat{i}$ during the stages previous to stage $\hat{j}$. Note that the contribution of power generation at each plant and time interval involved in Eq. (20) will depend on the current converson efficiency given by the term $k_i \cdot \hat{h}_{i,j}$. The optimization of the relaxed problem with this additional constraint will provide the elimination of the violation on an optimal way since the objective function remains the same. Note also that as the generation targets remain the same, the changes of generation on plants and hours considered are compensated during the remaining hours of the planning horizon.

The relaxed problem can be solved by a mixed-integer nonlinear programming algorithm. An heuristic approach that provides quite good solutions was proposed in [13]. The methodology presented in this previous work decomposes the relaxed problem into a unit commitment (UC) subproblem that considers a given generation dispatch, and a generation scheduling (GS) subproblem that considers a given number of dispatched generating units. These two subproblems are solved interactively until convergence, which normaly ocurs in a few iterations. The GS subproblem is solved by a Newton method for a given unit commitment setup, and the UC subproblem is solved by a dynamic programming approach for a given power output setup. Fig. (3) depicts the flowchart solution of the relaxed problem.

IV. Numerical Results

The proposed approach was applied to a case study based on the Brazilian power system. The study consisted of 95 hydro plants (out of which 52 were run-off-river plants) to be scheduled for the week of June, 24 2006 with over 41 GW of average load, for a total of 447 generating units. Fig. (4) shows the system load for the problem considered. The study case has resulted in a relaxed problem with 15,960 continuous variables and over 64,000 constraints.

It is important to note, though, that, as expected, most of the relaxed hydraulic constraints are indeed not active on the solution provided by the optimization step. Large reservoirs show virtually constant storage levels over the planning horizon, as it is illustrated on Fig. (6) for Ilha Solteira and Três Irmãos hydro plants, due to their large regulation capacity. On the other hand, if generation targets for run-off-river plants, as stated in Eq. (3), are consistent with the incremental inflow and the generation targets of the immediately upstream plants, no reservoir violations may also be expected, as shown on Fig. (7) for some run-off-river plants located along the Grande river.

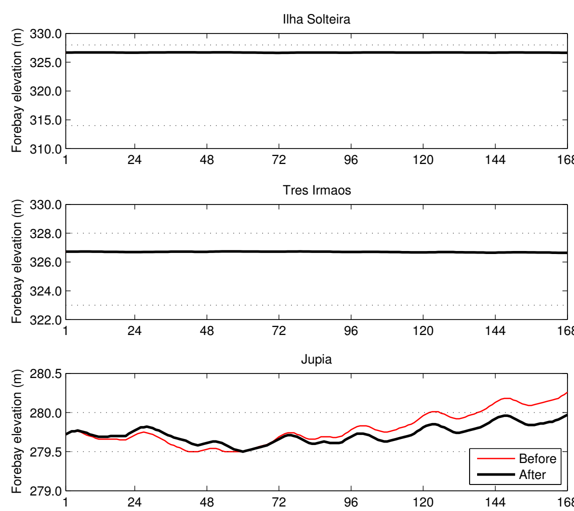

Figure 6. Forebay elevation levels for Ilha Solteira, Três Irmãos, and Jupiá plants before and after the addition of violated constraints back into the problem.

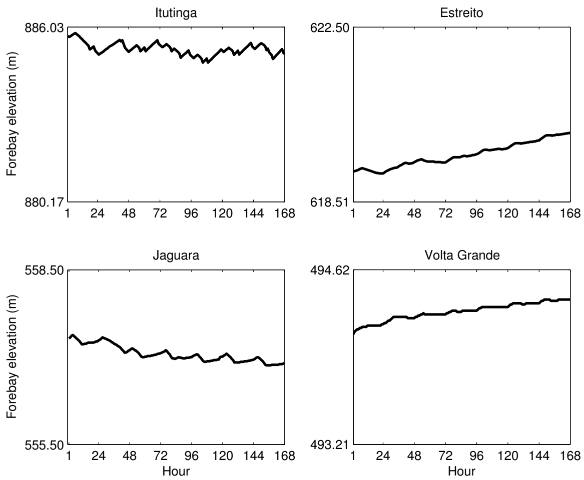

Figure 7. Forebay elevation levels for run-off-river plants on Grande river.

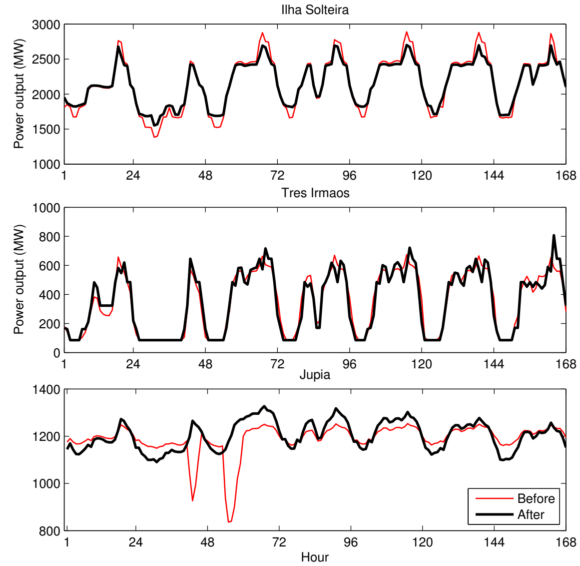

Figure 8. Power output comparison for Ilha Solteira, Três Irmãos, and Jupiá plants before and after the addition of violated constraints back into the problem.

In some cases, however, hydraulic violations may occur in run-off-river plants even if the generation target is coherent, as it was the case of Jupiá, a run-off-river plant in the Paraná river immediately downstream Ilha Solteira and Três Irmãos hydro plants with only half a meter to operate forebay elevation. Fig. (5) shows the diagram for these cascaded plants. On Fig. (6), one can observe that Jupiá storage reaches the minimum in the end of the second day and beginning of the third one, when it was unable to attain power generation established by the relaxed optimization problem during these hours, as can be observed by the sudden output decrease at Jupiá on Fig. (8). Furthermore, storage reaches values above the maximum on the last day of the week, carrying out a waste of energy in the form of water spillage. Once these violations were identified, two additional constraints of the type expressed in Eq. (20) are included in the relaxed problem, yielding a new and hydraulically feasible solution.

In this case, in order to make the hydraulic operation of Jupiá feasible, two constraints were included into the relaxed optimization model. The first, added for stage $j = 60$, aims to eliminate generation shortages occuring from $j = 42$ to $j = 60$, whereas the second, for stage $j = 168$, was added in order to eliminate water spillage occurrences from $j = 140$ up to the end of the week. As a consequence, Ilha Solteira and Três Irmãos hydro plants had their generation increased by 46.8 MW and 18.6 MW in average from the initial stage to stages $j = 57$ and $j = 55$, respectively, while Jupiá had its generation decreased by 16.5 MW in average from the first hour to stage $j = 60$. Such perturbations contributed simultaneously to solve hydraulic unfeasibility on both ends, thus leading to a proper operation.

Despite these corrections, no significant perturbations are observed on the storage levels for Ilha Solteira and Três Irmãos, as it can be seen on Fig. (6). Indeed, changes on power generation are so small that no effect is observed on the storage of the reservoir plants, while for run-off-river Jupiá, hydraulic feasibility is achieved. Fig. (8) shows power generation solutions before and after the addition of the violated constraints into the relaxed problem. Since generation targets are maintained the same, storage correction for Jupiá reservoir levels was made possible with minor changes in power output. This means that hydraulic feasibility was locally achieved by small changes in the generation profile of a plant with hydraulic violations and its immediately upstream reservoirs, with minor changes in the rest of the system.

On the UC subproblem side, Fig. (9) illustrates a comparison on the unit commitment schedules for Ilha Solteira, Três Irmãos, and Jupiá plants before and after the addition of violated constraints. It can be observed that the number of committed units coherently attains to the generation oscillation for Ilha Solteira and Três Irmãos schedules. On the other hand, because generation oscillation at Jupiá is very small, no unit startup or shutdown is required.

Finally, on the computational side, a total of two optimization-simulation iterations were required for a total of 27.2 seconds of computer time. At each procedure iteration, the optimization and simulation steps required 12.5 and 1.12 seconds each, respectively. The optimization and simulation procedures were performed on a desktop personal computer powered by a 32-bit Intel® Core™ Duo T7250 processor with 2 GB RAM.

V. Conclusion

This paper presented an optimization-simulation decomposition approach to the short-term hydropower scheduling problem, formulated as a mixed-integer nonlinear optimization problem, in which hydraulic constraints are relaxed in order to reduce computational burden. This is made possible because the majority of constraints are not active on the optimal solution. This formulation further enables the decomposition of the problem into unit commitment and generation scheduling subproblems, for which a practical and efficient heuristic is

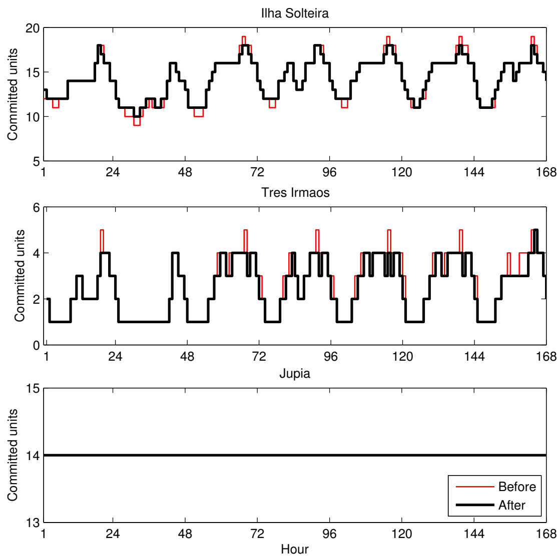

Figure 9. Comparison of unit commitment schedules for Ilha Solteira, Três Irmãos, and Jupiá plants before and after the addition of violated constraints back into the problem.

employed in order to find a unit commitment schedule that attains to the load curve.

The results confirmed the proposed approach to be very efficient in terms of CPU time, as a large number of relaxed constraints were not active. Nevertheless, the resulting solution showed to be smooth in terms of both unit commitment and generation schedules, which is very desirable in realtime systems operation.

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APPENDIX A
PLANT DATA

This Appendix presents plant data for the 95 hydro plants studied in this paper. These plants are distributed among four systems: North, Northeast, South, and Southeast. They are listed on Tab. (I), (II), , (III), and (IV), respectively. Storage, output capacity, and maximum discharge information are provided.

Table I
LIST OF PLANTS LOCATED IN THE NORTH SYSTEM

Name	**Storage** (hm^3)	**Output** (MW)	**Max. discharge** (m^3/s)
Cana Brava	–	472	404
Lajeado	–	903	680
Tucuruí	38982	8365	1277

Table II
LIST OF PLANTS LOCATED IN THE NORTHEAST SYSTEM

Name	**Storage** (hm^3)	**Output** (MW)	**Max. discharge** (m^3/s)
Boa Esperança	1912	225	296
Itaparica	3549	1500	551
Itapebi	–	475	254
Moxotó	–	400	550
Paulo Afonso 123	–	1423	670
Paulo Afonso 4	–	2460	400
Pedra do Cavalo	379	160	90
Sobradinho	28669	1050	713
Xingó	–	3162	496

Table III
LIST OF PLANTS LOCATED IN THE SOUTH SYSTEM

Name	**Storage** (hm^3)	**Output** (MW)	**Max. discharge** (m^3/s)
Capivari/Cachoeira	156	260	10
Dona Francisca	–	125	188
Foz do Areia	3805	1676	344
Itaúba	–	500	155
Itá	–	1450	318
Jacuí	–	180	39
Machadinho	1056	1140	437
Manso	2951	210	100
Monte Claro	–	130	186
Passo Fundo	1405	226	52
Passo Real	3357	158	206
Quebra Queixo	26	120	38
Salto Caxias	–	1240	525
Salto Osório	–	1078	591
Salto Santiago	4113	1420	394
Santa Clara	262	120	78
Segredo	384	1260	317

Table IV
LIST OF PLANTS LOCATED IN THE SOUTHEAST SYSTEM

Name	Storage (hm^3)	Output (MW)	Max. discharge (m^3/s)
Água Vermelha	5169	1396	493
Aimorés	–	330	456
Bariri	–	144	257
Barra Bonita	2567	140	189
Cachoeira Dourada	–	658	1013
Camargos	672	46	110
Candonga	–	140	106
Canoas I	–	83	189
Canoas II	–	70	182
Capivara	5729	640	436
Chavantes	3041	414	162
Corumbá I	1025	375	190
Emborcação	13056	1192	262
Estreito	–	1104	338
Euclides da Cunha	–	109	37
Fontes Nova	–	132	34
Funil	602	222	126
Funil Grande	–	180	195
Furnas	17217	1312	424
Graminha	504	80	94
Guilman Amorim	–	140	34
Ibitinga	–	131	235
Igarapava	–	210	296
Ilha Solteira	12807	3444	1419
Ilha dos Pombos	–	183	600
Itaipu 50	–	7000	657
Itaipu 60	–	7000	657
Itiquira I	–	61	40
Itiquira II	–	95	41
Itumbiara	12454	2280	537
Itutinga	–	52	179
Jaguara	–	424	269
Jaguari	792	28	33
Jauru	–	118	85
Jupiá	–	1551	596
Jurumirim	3168	98	178
Limoeiro	–	32	89
Marimbondo	5260	1488	368
Mascarenhas	–	181	981
Miranda	146	408	225
Nilo Peçanha	–	380	45
Nova Avanhandava	–	347	477
Nova Ponte	10380	510	199
Ourinhos	–	44	162
Paraibuna	2636	85	63
Peixoto	2500	478	522
Pirajú	–	80	181
Ponte Coberta	–	100	160
Ponte de Pedra	–	176	27
Porto Colômbia	–	328	497
Porto Estrela	33	112	124
Porto Primavera	4294	1540	636
Promissão	2128	264	431
Queimado	389	105	24
Rosal	–	55	16
Rosana	–	372	707
Salto Grande	–	72	141
Santa Branca	307	58	63
Serra da Mesa	43250	1275	405
Sobragi	–	60	30
Sá Carvalho	–	78	67
São Simão	5540	1710	445
Taquaruçu	–	554	574
Três Irmãos	3448	808	441
Três Marias	15278	396	154
Volta Grande	–	380	396

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