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*Long-term Unit Commitment Problem with Optimal Zone Configuration:  
a Case Study in Martinique*

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**Disclaimer**

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## **I. Introduction**

Island regions are not interconnected with the mainland and the isolation of these regions has brought challenges to the electric power systems. For instance, the power grids in island regions are more fragile to the rapid variance of the electricity consumption or production than the continental grid. Meanwhile, more intermittent renewable energy, such as wind and solar, has been connected to the power grid. Some of the overseas territories of France are island territories in the Atlantic, Pacific and Indian Oceans.

In this work, we propose a long-term unit commitment (UC) model with simplified network (zone) constraints to apply in these areas.

One of the main purposes of this work is to examine whether a better zonal configuration could help to increase the performance of the long-term UC model. Also, by applying this long-term UC model, we can create a robust generation plan for these territories and would be able to test, for instance, whether a larger amount of renewable energy could be introduced in these areas and whether the performance of the system could be improving by constructing a new transmission line.

## **II. Method**

The method is made of four steps (Fig. 1). The first step is to simulate short-term market outcomes by using an economic dispatch model with a detailed nodal network. We consider different levels of load and renewable generation. This nodal network model considers both the network and economic constraints, therefore, the solution provides price signals to optimally utilize the available resources. The second step is to find the optimal zonal configuration. The price signals given by the first step are used to decide the zonal configurations. The similarity of prices for interconnected nodes implies a lower degree of congestion. We cluster nodes with similar prices into one zone. The third step is to decide the simplified network constraints for the long-term unit commitment. There are two

different sets of simplified network constraints which could be applied in the long-term unit commitment problem, i.e., net transmission capacity (NTC) and flow-based market coupling (FBMC). In this study, we use the NTC network constraints for our study. The simplified network constraints are mainly to limit the power exchange between two zones and reduce the network congestion in real time. The fourth step is to apply the simplified network constraint in the long-term unit commitment problem.

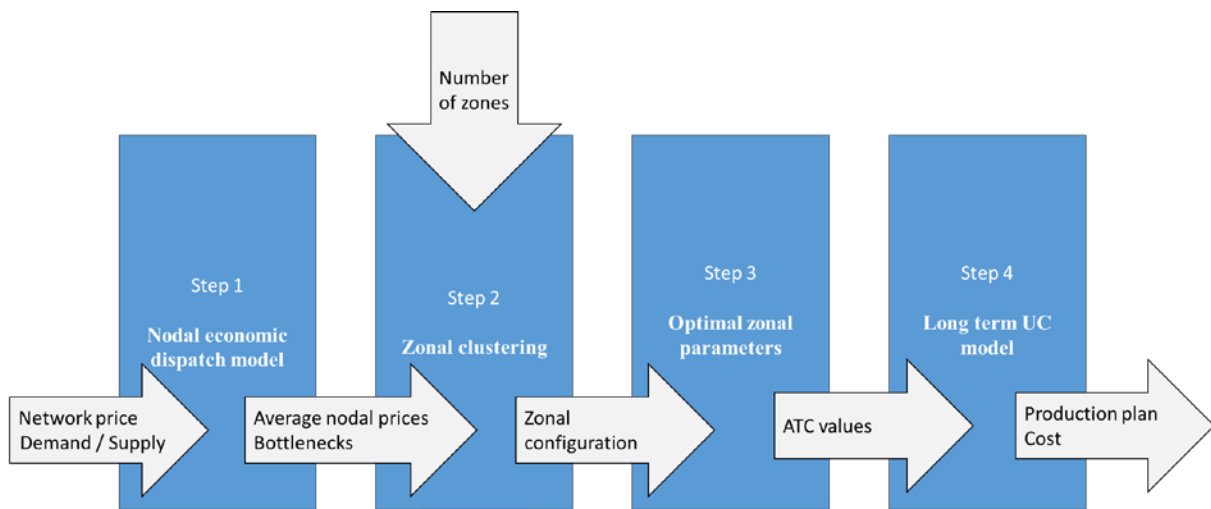


Figure 1: Overview of the method

### 1. Step 1: Nodal economic dispatch model

The nodal economic dispatch model uses an optimal power flow approach, which takes into account the physical and technical constraints [23], to give the price of power for each node. Most power systems are alternating current (AC) and the problem that we ideally would like to solve is an alternating current optimal power flow (AC-OPF) problem. This is a difficult problem to solve, due to non-linearities and non-convexities. Thus, in practice, most of system operators use a lossless direct current (DC) approximation is used. The resulting problem is called direct current optimal power flow (DC-OPF). This approximation has been proved to efficiently approximate the real network [19]. The nodal economic dispatch model is an optimization problem given by,

$$\text{Min} \sum_c c g_c \times G_c \quad (1)$$

Subject to:

$$NI_n = \sum_{c \in C_n} G_c + gwind_n + gsolar_n + gbio_n - Q_n, \forall n \quad (2)$$

$$G_c \leq gmax_c, \forall c \in C \quad (3)$$

$$LF_{n,nn} = bvector_{n,nn} (\Delta_n - \Delta_{nn}), \forall n, nn \quad (4)$$

$$NI_n = \sum_{nn} LF_{n,nn} - \sum_{nn} LF_{nn,n}, \forall n \quad (5)$$

$$-pmax_{n,nn} \times St_{n,nn} \leq LF_{n,nn} \leq pmax_{n,nn} \times St_{n,nn}, \forall n, nn \quad (6)$$

$$\Delta_{n'} = 0, n' = slackbus \quad (7)$$

$$G_c \geq 0, Q_n \geq 0 \quad (8)$$

Where  $G_c$  is the generation of power plant  $c$ ,  $NI_n$  is net injection of node  $n$ , and  $St_{n,nn}$  is the binary variable, 0 indicating the transmission line on an off statue and 1 indicating an on statue.

The objective of the nodal pricing model is to minimize the operation cost (Eq. (1)), considering the various constraints. The areas applying nodal pricing are constrained by the energy balance (Eq. (2)), the maximum generation capacity of thermal power plants (Eq. (3)), and the restrictions on power transmission (Eq. (4)-(6)). The energy balance (Eq. (2)) ensures that at node  $n$ , net input or withdrawal  $NI_n$  is equal to the difference between power generation (including all the conventional power generation  $G_c$  at node  $n$ , wind generation  $gwind_n$ , solar generation  $gsolar_n$  and biomass generation  $gbio_n$ ) and nodal demand  $Q_n$ . The generation of renewable is given exogenously. The dual variables of Eq. (2), which are the marginal costs/benefits of increasing injections in the nodes by one unit, are the nodal prices. Thermal power generation is restricted by the maximum generation requirement  $gmax_c$  (Eq. (3)). The DC approximation (see [6] and [22]) is used to determine the load flows  $LF_{n,nn}$  (Eq. (4)) in each line and the resulting

injection or withdrawal  $NI_n$  (Eq. (5)). Eq. (6) is to ensure that the load flow over a line should not exceed its thermal capacity limit.  $St_{n,nn}$  describes the status of a line (on or off). It is used to enforce the N-1 security constraint. Under this constraint, the failure of a single power line should not cause power outages. Enforcing the N-1 constraint improves security, however, might at a cost. Eq. (7) is to specify the slack bus. Eq. (8) requires the generation and the demand to be positive.

## **2. Step 2: Zonal clustering**

The zonal clustering algorithm groups nodes into a pre-defined number of zones. Generally, it is required that there is not much intra-zonal congestion and that nodes within a zone should have a similar impact on inter-zonal lines. Different clustering algorithms have been proposed in the literature. The two most used are the nodal pricing method [5] - [6] and nodal Power Transfer Distribution Factors (nodal PTDFs) method [16].

The capacity limitation of the transmission network prevents full uses the cheapest energy in the network, i.e., there is no enough capacity to transfer the power from the cheapest places to other places. The price at each node is also decided by the network topology and energy location. Nodal prices differences indicate the level of grid congestion. Less prices differences between nodes mean less congestion. Therefore, the clustering of nodes with similar nodal prices will result in a low intra-zonal congestion zone configuration.

The nodal PTDFs quantifies how the power injection at a given node impacts a given line. The nodal PTDF-values based method takes the congested lines as inter-zonal line, and clusters nodes with similar PTDF-values for the congested lines within the same zone. In this way, a zonal configuration is obtained with low intra-zonal congestion and nodes within the same zone have a similar impact on the interzonal links.

In this work, we apply the nodal pricing method to group the nodes into a zone. However, we also consider the bottlenecks (i.e., the most congested lines) in the systems. That is, we identify the bottlenecks and set them as the inter-zonal lines before we group the nodes with similar prices. The zonal clustering is an optimization problem given by,

Minimize:

$$\text{Min } \sum_n \sum_z (p_n m_{n,z} - c_k m_{n,z})^2 \quad (9)$$

Subject to:

$$\sum_z m_{n,z} = 1 \forall n \quad (10)$$

$$\sum_n m_{n,z} \geq ZN_z \forall z \quad (11)$$

$$c_z \sum_n m_{n,z} = \sum_n (p_n m_{n,z}) \forall z \quad (12)$$

$$aa_{n,z} (\sum_n m_{n,z} - 1) \leq 10000 m_{n,z} (\sum_n m_{n,z} - 1) \forall n, z \quad (13)$$

$$aa_{n,z} (\sum_n m_{n,z} - 1) \geq [1 - 10000(1 - m_{n,z})] (\sum_n m_{n,z} - 1) \forall n, z \quad (14)$$

$$aa_{n,z} = \sum_{nn} \text{link}_{n,nn} \times m_{nn,z} \times m_{n,z}, \forall n \neq nn \quad (15)$$

Where  $m_{n,z}$  is a binary variable.  $m_{n,z} = 1$  indicates that the node  $n$  is within zone  $z$  while  $m_{n,z} = 0$  indicates node  $n$  is not in zone  $z$ .  $aa_{n,z}$  is the total number of connections with the other nodes within the same zone  $z$  for node  $n$ .  $c_z$  is the average price for zone  $z$ .

The objective of the clustering technique is to minimize the price differences within the same zone (Eq. (9)). Eq. (10) is to force each node to only belong to one zone. Eq. (11) is to enforce that each zone has at least  $ZN_z$  node (e.g., 1 or 2 nodes). Eq. (12) defines the average price  $c_k$  in zone  $z$ . Eq. (13) and (14) are to enforce that any node should have at least one connection with another node within the same zone if the number of nodes in a zone is greater than 1. Eq. (15) is to calculate the total number of connections with the other nodes within the

same zone, where  $link_{n,nn}$  is the connecting matrix, which tells if there is a direct connecting between two nodes  $n$  and  $nn$ .

### Step 3: Optimal zonal parameters

This section gives the procedure for implementing the NTC constraints. They are given by,

$$NEX_z = \sum_{zz}(BEX_{z,zz} - BEX_{zz,z}), \forall z \in [1, Z] \quad (16)$$

$$0 \leq BEX_{z,zz} \leq ntc_{z,zz}, \forall z, zz \quad (17)$$

Where  $NEX_z$  is the net position of a zone and  $BEX_{z,zz}$  is total export from zone  $z$  to zone  $zz$ .

$NEX_z$  is defined as the difference of its total export  $BEX_{z,zz}$  and import  $BEX_{zz,z}$  (Eq. (20)). The NTC model does not have specific limitations on specified lines. However, it restricts the total transfer  $BEX_{z,zz}$  between two pricing areas to a pre-defined maximum trading volume  $ntc_{z,zz}$ , (Eq. (21)).

### 3. Step 4: Long-term unit commitment (UC) model

For power system operation, one of the most important issue is to decide for each period which generating units should run to satisfy the demand. In a typical electrical system, there are a variety of resource and power plants available for generating electricity, and each of these units has its own characteristic. For instance, the start-up cost and the variable cost are different. Unit commitment problem is to help to make decisions in such a situation [21][24].

Unit commitment is one of the classic optimization problems in power systems. The goal is to decide the ON/OFF status of all the generating units, which meet the forecasted loads and reserve requirements and provide a least-cost power generation plan. There are two main ways of defining this least-cost objective



function. The first one is used by TSO, which minimize the total cost (i.e., minimizing fuel costs and startup/shutdown cost) or maximize the social welfare while meeting a forecasted hourly load. The second way is used by the generation companies, which maximize the total profit based on their bidding strategy. In this study, we focus on the first type.

Different mathematical formulations of the UC problem exist. One of the most used formulations of UC problems is the mixed integer linear programming (MILP) methods. Due to fact that there could be thousands of generation units and transmission lines existing in a system, the unit commitment problem modeled by MILP could be a computationally challenging problem with many integer variables and constraints. Different optimization techniques including Lagrangian relaxation and branch-and-bound based MILP methods have been used to solve large-scale UC problems [1], [12].

The physical conditions of the operating generators are the main constraints for the UC model, including the generation capacity limits, minimum ON time, minimum OFF time, ramp up/down rate, reserve requirements. In the following, we will illustrate the typical constraints in a UC model used in this project. More UC constraints could be found on [14].

$$\min \sum_c \sum_t (st_c \times V_{ct} + sd_c \times W_{ct}) + \sum_c \sum_t (cg_c \times G_{c,t}) + VOLL \times \sum_c \sum_t LS_{c,t} \quad (18)$$

$$U_{c,t} - U_{c,t-1} \leq U_{c,\tau} \forall c, t, \tau = t, \dots, \min\{t + \text{minion}_c - 1, |T|\} \quad (19)$$

$$U_{c,t-1} - U_{c,t} \leq 1 - U_{c,\tau} \forall c, t, \tau = t, \dots, \min\{t + \text{minioff}_c - 1, |T|\} \quad (20)$$

$$V_{c,t} \geq U_{c,t} - U_{c,t-1} \forall c, t \quad (21)$$

$$W_{c,t} \geq -U_{c,t} + U_{c,t-1} \forall c, t \quad (22)$$

$$gmax_c \times U_{c,t} \leq G_{c,t} \leq gmin_c \times U_{c,t}, \forall g, t \quad (23)$$

$$G_c \geq 0 \quad (24)$$

$$-rdown_c \leq G_{c,t} - G_{c,t-1} \leq rup_c \quad (25)$$

$$0 \leq S_{c,t} \leq s_c^{max} \quad (26)$$

$$\sum_c S_{c,t} \geq rs_{i,t} \quad (27)$$

Where  $U_{c,t}$ ,  $V_{c,t}$ ,  $W_{c,t}$  are binary value.  $U_{c,t}$  is the on/off status of the power plant  $c$  at time  $t$ ,  $V_{c,t}$  is the startup action and  $W_{c,t}$  is the shutdown action.  $G_{c,t}$  is the generation of plant  $c$  at time  $t$ , and  $S_{c,t}$  represents the partial online generating capacity or off-line generation resources.

Eq. (22) is the UC objective function, which is composed of two component costs. The first component cost is determined by the startup  $V_{ct}$  decision and shutdown decision  $W_{ct}$  on each generator ( $st_c$  is the startup cost and  $sd_c$  is the shutdown cost). The second component cost comes is primarily made up of fuel cost  $cg_c$  and possible unserved energy penalty  $VOLL$  (i.e., load loss  $LS_{c,t}$ ). This penalty is usually used to avoid the load-shedding, where scheduled generators are not able to satisfy demands.

Based on two status of a generator  $U_c$ , we can know that when a generator is online and commits to supply capacity, i.e.,  $U_c = 1$  and when the generator commitment status is in an “off” state, i.e.,  $U_c = 0$ , the power dispatch level become zero and has no any operational cost.

Some specific operations are also enforce in the UC constraints, such as the minimum ON time, i.e.,  $minion_c$  and minimum OFF time, i.e.,  $minioff_c$ , and also specify startup action and shutdown action on each unit at a time period  $t$ , respectively. A generator can't be started up or shut down arbitrarily in consecutive hours, Eq (23) and (24) respectively indicate two generator's requirements: the shortest ON duration has to be met before a generator being shut

down and the shortest OFF duration is also required before a generator being restarted up.

The startup action  $V_{c,t}$  and the shutdown action  $W_{c,t}$  are determined by the generator commitment statuses in the previous time period  $t - 1$  and the current time period  $t$ , as in Eq. (25) and (26). Any operational actions can incur start-up or shut-down costs, which are considered in the objective function.

A generator output in an hour is subject to the maximum generation limit  $gmax_c$ , and the minimum generation limit  $gmin_c$ . When a generator is scheduled online ( $U_{c,t} = 1$ ), the generation capacity is active giving bounds on dispatch level, shown in Eq. (27); otherwise, a generator output is forced to zero. The generation must be positive Eq. (28).

In addition, a generator output can be adjusted, increasing  $rup_c$  or decreasing  $rdown_c$  between two successive time periods. The generation difference between two adjacent time periods is called ramping. A basic constraint to address generation ramping is presented in Eq (29).

Operating reserve is one type of ancillary operations to support the power balance on the demand sides. The current operating reserve services being offered in electric energy markets include synchronous or non-synchronous, regulation reserves, spinning reserves, and non-spinning reserves. Generally, the sources of energy provided from different reserve services are different: regulation service mainly supplied from online generators, partial spinning reserve provided from generators already connected to the grid or system resources, and non-spinning reserve provided from quick-start generators, system resources or interruptible loads. The response times of reserve services can vary greatly, depending on the control reserve deployment time. To achieve the optimization of energy and reserve in practice, one can obtain an efficient energy and reserve offering strategy

by Heuristic method [18] or consider the reserve determination on pre-contingency and post-contingency conditions [4].

In our models, if we consider the spinning reserve problem, the spinning reserve  $S_{c,t}$  is generally accounted for partial online generating capacity or off-line generation resources. Their outputs are constrained by predetermined maximum spin reserve  $s_c^{max}$ , shown as Eq. (30).

Meanwhile, the generators that participate in bidding spinning reserve must meet the spin reserve requirements given by TSOs. Eq (31) describes an operating condition that the total spinning reserve at bus  $i$  should not less than the fixed reserve requirement  $rS_{i,t}$ .

### III. Case study

#### 1. Presentation

We apply the method described in the section II to the power network of Martinique. Martinique is an island in the Caribbean Sea and is an overseas department of France. Martinique has a tropical and humid climate with an average temperature of 23 degrees to 29 degrees Celsius. The average monthly temperatures remain remarkably stable, varying by only a few degrees year-round. Therefore, the power demand is also very stable during the year.

In Martinique, the main renewable energy resource is solar energy (about 15 %). They also have little share of biomass and wind energy (less than 5 %) [31]. Currently, the system operator limits that the maximum share of intermittent renewable energies that can be injected into the network at a given time to 35% [31]. Beyond this threshold, disconnections are possible in order to preserve the stability of the electrical system. However, the system operator is considering relaxing this restriction. Figure 1 shows a typical generation curve in Martinique. In a normal day, there are two types of peak hours. The first peak hours are in the daytime (10 h- 14 h) with solar power. The second peak hours are in the nighttime

18 h- 20 h) without solar power. As congestion happens mostly during the peak hours, we mostly focus in these periods in this work, especially in the first two-steps model.

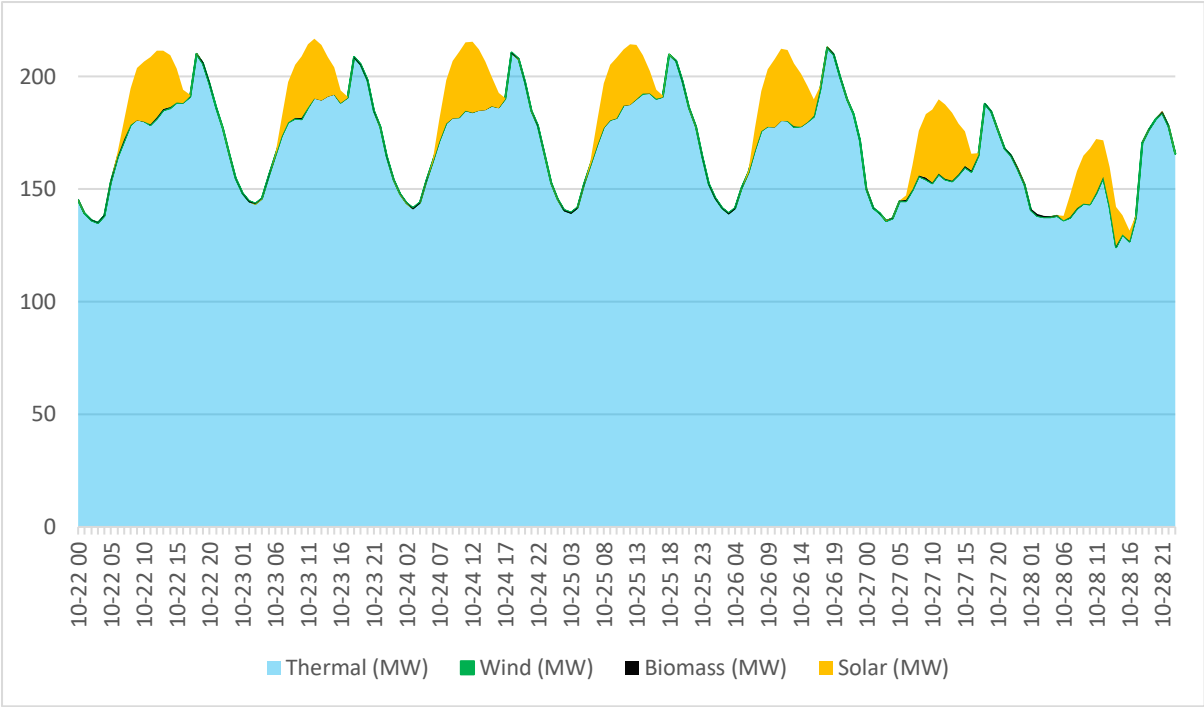


Figure 2: Generation curve from Monday 22nd to Sunday 28th, Oct. 2018. [source: opendata-martinique.edf.fr]

**2. Results of step 1**

We only consider the HTB grid (63 kV) in Martinique, as shown in Figure 3. In total, there are 14 hubs (nodes) and 25 HTB transmission lines. The thermal power plants are located at the nodes “Bellefontaine”, “Hydrobase” and “Galion”.

We choose four typical hours in the working days for our first two steps analysis as show in Table 1, which includes two peak hours and two off-peak hours with different solar generation.



Figure 3: HTB power network in Martinique [source: opendata-martinique.edf.fr]

	Peak hours		Off-Peak hours	
	With solar	Without solar	With solar	Without solar
<b>Reference load</b>	210 MW		180 MW	
<b>Wind generation</b>	0.5 MW	0.5 MW	0.5 MW	0.5 MW
<b>Solar generation</b>	30 MW	0 MW	30 MW	0 MW
<b>Biomass generation</b>	0.4 MW	0.4 MW	0.4 MW	0.4 MW

Table 1: Reference load and generation for the case study

Note that the N-1 constraint might affect the optimal dispatch. For instance, different prices and quantities of power produced would be given even it is the same reference load and generation profiles. Even more, the bottleneck in the system might also be changed when different transmission lines are disable.

AC lines	Peak hours		Off-Peak hours	
	With solar	Without Solar	With solar	Without Solar
FL_LAMENTIN1	42 %	45 %	39 %	42 %
FL_LAMENTIN2	42 %	45 %	39 %	42 %
BF_SCHOELCHER1	49 %	60 %	47 %	54 %
BF_SCHOELCHER2	49 %	60 %	47 %	54 %
BF_ST_PIERRE	11 %	15 %	9 %	12 %
BF_FOND_LAILLET1	-28 %	-34 %	-26 %	-30 %
BF_FOND_LAILLET2	-28 %	-34 %	-26 %	-30 %
DESBROSSES_DILLON	61%	60%	64%	58%
DESBROSSES_SCHOELCHER	-85%	-84%	-84%	-78%
DILLON_HYDROBASE1	-22%	-23%	-10%	-21%
DILLON_HYDROBASE2	-22%	-23%	-10%	-21%
DILLON_HYDROBASE3	-25%	-27%	-12%	-24%
DILLON_LAMENTIN1	10%	11%	6%	10%
DILLON_LAMENTIN3	21%	23%	12%	22%
DILLON_LAMENTIN4	21%	23%	12%	22%
GALION_LAMENTIN	-47%	-45%	-29%	-53%
GALION_FRANCOIS	-9%	-7%	0%	-17%
GALION_TRINITE1	31%	43%	25%	37%
GALION_TRINITE2	32%	45%	26%	38%
LAMENTIN_FRANCOIS	39%	39%	30%	39%
LAMENTIN_PETIT_BOURG1	40%	40%	34%	35%
LAMENTIN_PETIT_BOURG2	40%	40%	34%	35%
FRANCOIS_MARIN	23%	24%	21%	19%
MARIGOT_TRINITE	-14%	-14%	-12%	-12%
MARIN_PETIT_BOURG	-25%	-26%	-21%	-23%

Table 2: Average utilization rate of the transmission lines

Data for the four study hours are used as input to run the first steps model. The utilization rate (i.e., the actual power flow divided by the line nominal capacity) of the AC transmission line is good indicator to check the bottlenecks in the system. Table 2 gives the average utilization rate under the N-1 constraints for the four different study hours. The transmission line between the “Desbrosses” and “Schoelcher” nodes has the highest utilization rate. The utilization rate for this transmission line is more than 80 % except for the off-peak hour without solar power (78 %). Therefore, we consider this transmission line to be the

bottleneck in the system. For the other transmission lines, the utilization rates generally are less than 60 %, therefore, they are not considered as the bottlenecks in the system for our analysis.

Finally, the average nodal prices given by the economic dispatch model are summarized in Table 3.

Node	Peak hours		Off-Peak hours	
	With solar	Without Solar	With solar	Without Solar
Saint Pierre	148.02	148.01	146.10	154.33
FL	148.06	148.06	146.10	154.33
Bellefontaine	148.02	148.01	146.10	154.33
Schoelcher	146.79	148.21	145.89	155.93
Desbrosses	160.26	162.27	147.39	157.05
Dillon	157.54	159.10	147.22	156.56
Hydrobase	157.54	159.10	147.22	156.56
Lamentin	156.76	158.21	147.18	156.44
Petit Bourg	156.76	158.25	147.18	156.44
Marin	156.76	158.39	147.18	156.44
François	156.76	158.56	147.18	156.44
Galion	156.76	158.67	147.18	156.44
Trinité	156.76	158.67	147.18	156.44
Marigot	156.76	158.67	147.18	156.44

Table 3: Average nodal prices (EUR/MWh)<sup>1</sup>

### 3. Results of Step 2

Here, we cluster the nodes with similar nodal prices into zones, while excluding the bottleneck from them.

For nodes Lamentin, Petit Bourg, Marin, François, Galion, Trinité, Marigot, the nodal price differences for these nodes are less than 1% (Table 3). This means that there is no congestion between these nodes. Therefore, it is reasonable that these nodes are grouped into a zone. The other nodes could be grouped into two

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<sup>1</sup> The average prices here exclude the case when load shedding is enforced in the model. The average prices here are lower than the price in realities. This is because that we don't consider the startup cost in the first step model and assume all the power in the network are available.



or three zones, depending on the clustering criteria, i.e., whether a zone can only include a single node. Figure 4 gives two proposed zonal configurations. The 3-zone configuration requires that there should be at least 2 nodes within the same zone (Eq. (11)), while the 4-zone configuration allows for zones with a single node. The objective value for the clustering model, as showed in *Table 4*, will be improved if we allow there is only one node in a zone, as show on the right hand side of Figure 4. Larger improvement could be found in the cases with high peak hours.

(a) Case I: 3-zone configuration

(b) Case II: 4-zone configuration

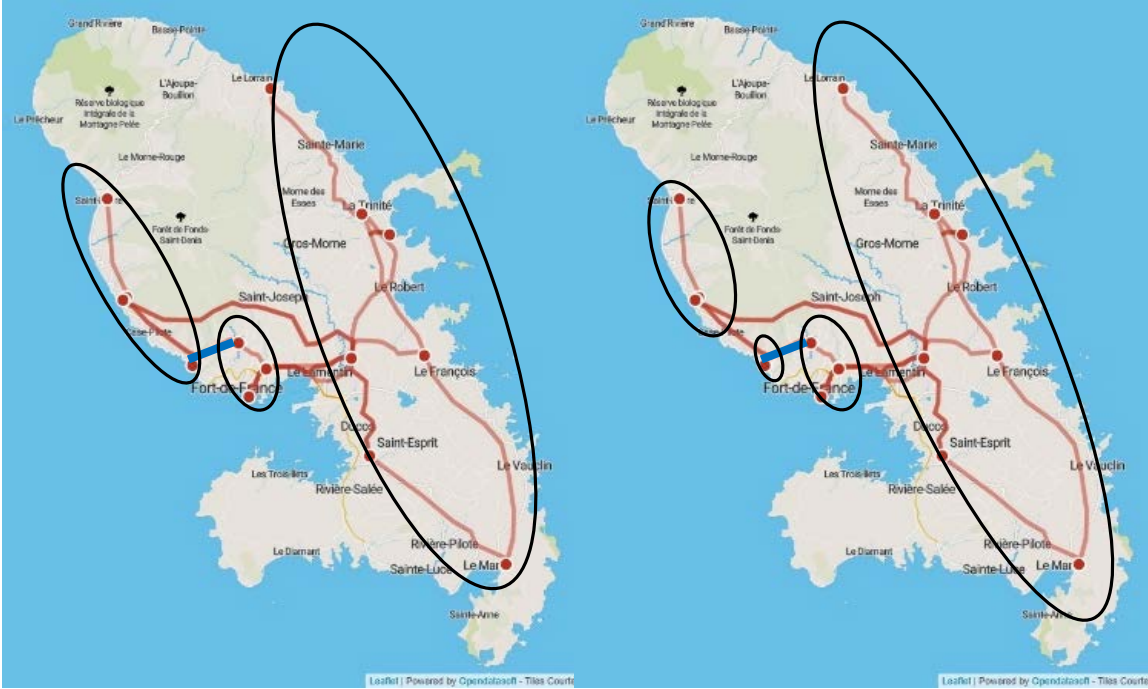


Figure 4: Proposed zonal configurations. The bottleneck is shown in blue.

	Peak hours		Off-Peak hours	
	With solar	Without Solar	With solar	Without Solar
Case I:3-zone	106	114	13	1
Case II:4-zone	5	7	11	0

Table 4: Objective values for Step 2

#### **4. Results of step 3**

It is difficult to decide the NTC value accurately for the long-term UC problem. One possible way is to use the solution provided by the nodal pricing as a benchmark. The NTC constraints are used in the European day-ahead market, which sets a limitation on the commercial power exchanges among countries. An ideal NTC value in this case should allow the maximum utilization of the network. However, due to the loop flow effect, the real time dispatching given by the day-ahead model might overload the lines and therefore, needs to be rescheduled. This rescheduling is also called re-dispatching or counter trading. One of the reasons for re-rescheduling is that the NTC model does not consider the limitation of the network constraints within a zone. It is important to point out that re-dispatching will lead to an extra cost.

However, the purpose of our cases study is not to increase the power exchange among zones, but to increase the efficiency of the whole system. Many studies show that nodal pricing model is consider to give a better result than NTC model. This has been proved by a large stream of literatures [13][15]. Therefore, we use the nodal economic dispatch model solution to calculate the NTC value.

Most congestion happens in the peak hours. NTC can limit the exchange in those hours and therefore could decrease the need for re-dispatching. In the off-peak hours, we could have less restriction because most of time, there is no or less congestion, and therefore the re-dispatching cost is not much.

Table 5 summarizes the power exchanges between zones for different configurations given by the second step model. The amount of power exchange for the hours without solar power is larger than that with solar power. In this case, if we use the result with the solar power, this might reduce the power exchange among zones and increase the total cost.

peak-hour with solar solution (Lower NTC)				peak-hour without solar solution (Higher NTC)			
	zone1	zone2	zone3		zone1	zone2	zone3
zone1		56	55	zone1		67	61
zone2	56		51	zone2	67		63
zone3	55	51		zone3	61	63	

	zone1	zone2	zone3	zone4		zone1	zone2	zone3	zone4
zone1		56		55	zone1		67		61
zone2	56		49		zone2	67		49	
zone3		49		51	zone3		49		63
zone4	55		51		zone4	61		63	

Table 5: Power exchanges based on nodal solution.  
Case I: 3-zonal configuration (Fig. 4a), Case II: 4-zonal configuration (Fig. 4b).

#### Results of step 4

	3 Zone	4 Zone	Full network
Lower NTC	197,300	237,600	198,000
HIGHER NTC	201,600	252,900	

Table 6: Total dispatching cost (1000 EURO)

Table 6 summarizes the total dispatching cost given different zone configuration and 2 different set of NTC value. We compare the number to the model with full network details. We find that the total dispatching cost in the 3-zone case is the one mostly close to the one with the full network. Furthermore, the cases with a higher NTC value have a higher dispatching cost than the case with a lower NTC value. However, the results here cannot sufficiently conclude that one zone configuration is superior to the other one. To fully evaluate it, we much consider the re-dispatching cost given the generation plan.

Another possibility here to evaluate the performance of different zone configuration and NTC value is to check if the generators are on in the “correct” time. Table 7 summarize the total on hours for each generator in different cases. We compare these numbers to the cases with full network model, as show in Table

7. Generally, we could see the cases with a higher NTC model will perform better than the ones with lower NTC model. This is mainly because that the higher NTC value could cover more situation in the peak hours.

Generator	3 zone		4 zone		Full network
	Lower NTC	High NTC	Lower NTC	High NTC	
1	2903	3644	1981	3103	1745
2	8760	8760	8760	8760	8754
3	7061	273	5747	0	698
4	8544	5917	8760	8541	7227
5	8760	8434	8760	7232	4943
6	8760	8760	8760	8039	7782
7	6528	7303	8758	6934	6965
8	127	2334	0	5754	5373
9	0	4379	0	3972	3035
10	368	2569	0	1770	5897
11	0	1465	0	2262	7406
12	2197	6525	8719	4836	5050
13	8757	6480	8760	7769	7563
14	8721	6480	0	6029	7434
15	8760	8756	8723	5519	7991
16	28	261	87	89	732
17	0	5	0	0	77
18	1	0	0	205	62
19	0	21	0	0	46
20	4	14	13	6	53

Table 7: Total on hours for the generators

Generator	3 zone		4 zone	
	Lower NTC	High NTC	Lower NTC	High NTC
1	166%	209%	114%	178%
2	100%	100%	100%	100%
3	1012%	39%	823%	0%
4	118%	82%	121%	118%
5	177%	171%	177%	146%
6	113%	113%	113%	103%
7	94%	105%	126%	100%
8	2%	43%	0%	107%
9	0%	144%	0%	131%
10	6%	44%	0%	30%
11	0%	20%	0%	31%
12	44%	129%	173%	96%
13	116%	86%	116%	103%
14	117%	87%	0%	81%
15	110%	110%	109%	69%
16	4%	36%	12%	12%
17	0%	6%	0%	0%
18	2%	0%	0%	331%
19	0%	46%	0%	0%
20	8%	26%	25%	11%

Table 8: On hours compared to the full network model

#### IV. Future study

At this stage, we still could not conclude which zone configure would be a better choice for the long-term UC model with simplified network constraints. One of the main results is that we must consider the re-dispatching cost given by the generation plans. Another issue is about how to define the NTC values. as we can see from the preliminary results, the NTC values have a large impact on the results. In this study we use the same NTC value for all the hours. However, in the future study, we might need to designate different NTC values to different hours.

## V. Appendix I: nomenclature

### Sets

$c \in C$	Set of conventional power plants
$C_n$	Set of conventional power plants located in node $n$
$C_z$	Set of conventional power plants located in zone $z$
$l$	Set of cluster
$n, nn \in N$	Set of all nodes
$l \in L$	Set of all transmission lines
$z, zz \in Z$	Set of all zones

### Parameters

$bvector_{n,nn}$	Series susceptance of line $n, nn$ [ $1/\Omega$ ]
$cg_c$	The electricity generation cost for power plant $c$ [EUR/MWh]
$gmax_c$	Maximum generation of plant $c$ [MW]
$gsolar_n$	Solar generation at node $n$ [MW]
$gwind_n$	Wind generation at node $n$ [MW]
$gbio_n$	Biomass generation at node $n$ [MW]
$ntc_{z,zz}$	Net transfer capacity between zone $z$ and $zz$ [MW]
$pmax_{n,nn}$	Thermal transmission limit of transmission line $l, n, nn$ [MW]
$St_{n,nn}$	On or off status of transmission line $l, n, nn$
$qda_n$	Contracted demand at node $n$ in the day-ahead market [MW]
$p_n$	Price at node $n$
$link_{n,nn}$	Connecting matrix
$nptdf_{i,i}$	Nodal ptdf matrix
$gsk_{i,z}$	GSK matrix
$zptdf_{l,z}$	Zonal ptdf matrix
$st_c$	Startup cost for generator $c$
$sd_c$	Shutdown cost for generator $c$
$minion_c$	Minimum ON time of generator $c$
$minioff_c$	Minimum Off time of generator $c$
$rdown_c$	Ramp down rate of generator $c$
$rup_c$	Ramp up rate of generator $c$
$s_c^{max}$	Maximum spin reserve of generator $c$
$rs_{i,t}$	Fixed reserve requirement
VOLL	Unserved energy penalty

## Variables

$\Delta_n$	Voltage angle at node n [rad]
$G_c$	Generation of plant c [MW]
$LOADSHED_n$	Load curtailment at node n [MW]
$LF_{n,nn}$	Power flow between nodes n and nn [MW]
$NI_n$	Net input at node n [MW]
$p_n$	Price at node n
$Q_n$	Demand at node n [MW]
$SOLSHED_n$	Solar power curtailment at node n [MW]
$WINDSHED_n$	Wind power curtailment at node n [MW]
$aa_{n,k}$	Number of connections with the other nodes within the same zone
$c_k$	Average price for cluster k
$NEX_z$	Net position of a zone
$BEX_{z,zz}$	Power transfer from zone z to zone zz
$LS_{c,t}$	Load loss of generator c at time t
$S_{c,t}$	spinning reserve

## Binary variable

$m_{n,k}$	Node n belong to cluster k
$V_{ct}$	Startup decision of generator c at time t
$W_{ct}$	Shutdown decision of generator c at time t
$U_{c,t}$	On/off statue of generator c at time t

## VI. Appendix II: GAMS Code for step 1 and 3

\$ontext

Author: Hong Cai

\$offtext

option solprint = on;

set

n

p

map\_pn(p,n)

c(p)

l

i

map\_pi(p,i)

map\_pn(p,n)

map\_ln(l,n,n)

;

alias (n,nn), (c,cc), (l,ll), (i,ii)

;

parameter

lineup

nodeup

genup

techup

fuelup

nodeup

genup

g\_max(p)

g\_min(p)

Q(n)



g\_wind

g\_solar

g\_bio

p\_maxN(n,nn)

react(l)

resis(l)

Voltage(l)

p\_max(l)

circuits(l)

incidence(l,n)

b(n,n)

h(l,n)

bvector(l)

gvector(l)

slack(n)

g\_max(p)

g\_min(p)

circuits(l)

cg(p)

Bin(n,nn)

ptdf(l,n)

;

\$onecho >temp.tmp

set=l	rng=AClines!A2:A836	rdim=1 cdim=0
set=n	rng=nodes!A2:A540	rdim=1 cdim=0
set=p	rng=plants!A2:A412	rdim=1 cdim=0
set=f	rng=fuels!A2:A12	rdim=1 cdim=0
set=i	rng=technologies!A2:A23	rdim=1 cdim=0
set=map_pn	rng=plants!D2:E412	rdim=2 cdim=0
set=map_pi	rng=plants!A2:B412	rdim=2 cdim=0
set=map_ln	rng=AClines!A2:C836	rdim=3 cdim=0
par=lineup	rng=AClines!A1:H836	rdim=1 cdim=1

```
par=nodeup   rng=nodes!A1:L540           rdim=1 cdim=1
par=genup    rng=plants!A1:L412         rdim=1 cdim=1
$offecho
```

```
$onUNDF
```

```
$call "gdxxrw %datadir%%data%.xls MaxDupeErrors=999999999 cmerge=1
squeeze=N @temp.tmp"
$gdxin %data%
```

```
$load l n p map_pn map_ln z zonemember
$load lineup nodeup genup
```

```
$offmulti
```

```
circuits(l) = lineup(l,"Circuits");
p_max(l) = lineup(l,"ThermalLimit")*circuits(l);
voltage(l) = lineup(l,"Voltage");
slack(n) = 1$nodeup(n,'Slack bus');
react(l) = lineup(l,"Reactance")/circuits(l);
resis(l) = lineup(l,"Resistance")/circuits(l);
```

```
incidence(l,n) = 0;
incidence(l,n)$(lineup(l,"From") eq n.val) = 1;
incidence(l,n)$(lineup(l,"To") eq n.val) = -1;
```

```
bvector(l) = (react(l) / (react(l)**2 + resis(l)**2))$(react(l) or resis(l));
gvector(l) = (resis(l) / (react(l)**2 + resis(l)**2))$(react(l) or resis(l));
```

```
h(l,n) = bvector(l) * incidence(l,n);
b(n,nn) = sum(l$incidence(l,n), incidence(l,n) * h(l,nn));
```

```
b(n,nn)$slack(n)=0;
b(n,nn)$slack(nn)=0;
```

```
g_max(p) = genup(p,'Generation capacity');
```

```
g_min(p) = genup(p,'Min Generation');
cg(p) = genup(p,'Cost');
Q(n) = nodeup(n,'Demand share')*210;
g_wind(n) = nodeup(n,'Wind share')*0;
g_solar(n) = nodeup(n,'Solar share')*0;
g_bio(n)= nodeup(n,'Biomass share')*0.4;
```

#### Variable

```
WELFARE
COST_GEN
LINEFLOW
NETINPUT
DELTA
```

```
;
```

#### Positive Variable

```
G
```

```
;
```

#### binary variable

```
STATUS
```

```
;
```

#### Equations

```
OBJ_generation_cost
MKT_lp_1
RES_gmax_1
RES_gmin_1
DEF_lineflow_1
DEF_netinput_1
RES_pmax_1
RES_pmin_1
RES_slack_1
```

```
;
```

OBJ\_generation\_cost..

$$\text{COST\_GEN} =E= \text{SUM}(p\$g\_max(p), \\ \text{cg}(p) * G(p))$$

;

MKT\_lp\_1(n)..

$$\text{NETINPUT}(n) =E= \text{SUM}(p\$(\text{map\_pn}(p,n) \text{ and } g\_max(p)), G(p)) \\ + g\_wind(n) + g\_solar(n) + g\_bio(n) \\ -Q(n)$$

;

RES\_gmax\_1(p)\$g\_max(p)..

$$G(p) =L= g\_max(p)*\text{STATUS}(p)$$

;

RES\_gmin\_1(p)\$g\_max(p)..

$$G(p) =G= g\_min(p)*\text{STATUS}(p)$$

;

DEF\_netinput\_1(n)..

$$\text{NETINPUT}(n) =E= \text{sum}(nn\$b(n,nn), b(n,nn)*\text{DELTA}(nn))$$

;

RES\_pmax\_1(l)..

$$\text{LINEFLOW}(l) =L= 0.95 * p\_max(l)$$

;

RES\_pmin\_1(l)..

$$- \text{LINEFLOW}(l) =L= 0.95 * p\_max(l)$$

;

DEF\_lineflow\_1(l)..

$$\text{LINEFLOW}(l) =E= \text{sum}(n\$h(l,n), h(l,n)*\text{DELTA}(n))$$

;

RES\_slack\_1(n)..

$$\text{DELTA}(n)*\text{slack}(n) =E= 0$$

;

MODEL FIRST\_STEP the hybrid model

```
/
OBJ_generation_cost
MKT_lp_1
RES_gmax_1
RES_gmin_1
DEF_lineflow_1
DEF_netinput_1
RES_pmax_1
RES_pmin_1
RES_slack_1
```

```
/;
```

```
$onecho >cplex.opt
lpmethod 4
threads -1
numeralemphasis 1
scaind 1
EpMrk 0.99999
$offecho
```

```
$onecho >conopt.opt
rtnwma 1.e-6
rtnwmi 1.e-7
$offecho
```

```
SOLVE FIRST_STEP min COST_GEN using minlp;
```

## **VII. Appendix II: GAMS Code for step 2**

```
$ontext
```

```
Author: Hong Cai
```

```
$offtext
```

```
option solprint = on;
```

```
set k/k1*k5/
```

```

n/p1*p14/
ll

;

Alias (n,nn);
Parameter p(n,ll);

$onecho > tasks.txt
dset=ll rng=price!B2      cdim=1
par=p  rng=price!B2  rdim=1 cdim=1
$offecho

$call "gdxxrw %datadir%%data%.xls  MaxDupeErrors=999999999  cmerge=1
squeeze=N @temp.tmp"
$gdxin %data%
$load ll
$LOADDC p

table link(n,nn) conection matrix
      p1  p2  p3  p4  p5  p6  p7  p8  p9  p10  p11  p12  p13  p14
p1  0  0  1  0  0  0  0  0  0  0  0  0  0
p2  0  0  1  0  0  0  0  1  0  0  0  0  0  0
p3  1  1  0  0  1  0  0  0  0  0  0  0  0  0
p4  0  0  1  0  1  0  0  0  0  0  0  0  0  0
p5  0  0  0  1  0  1  0  0  0  0  0  0  0  0
p6  0  0  0  0  1  0  1  1  0  0  0  0  0  0
p7  0  0  0  0  0  1  0  0  0  0  0  0  0  0
p8  0  1  0  0  0  1  0  0  1  0  1  1  0  0
p9  0  0  0  0  0  0  0  1  0  1  0  0  0  0
p10 0  0  0  0  0  0  0  0  1  0  1  0  0  0
p11 0  0  0  0  0  0  0  1  0  1  0  1  0  0
p12 0  0  0  0  0  0  0  1  0  0  1  0  1  0
p13 0  0  0  0  0  0  0  0  0  0  0  1  0  1
p14 0  0  0  0  0  0  0  0  0  0  0  0  1  0

```

;

Variable pri\_dif

price(n,k)

mean

sum\_price(k)

sum\_node(k)

c(k)

num(k)

bb

aa

;

binary variable m(n,k)

;

Equations

Obj\_cluster objective for clustering

assign\_limit1

assign\_limit2

assign\_limit3

assign\_limit4

assign\_limit5

assign\_limit6

assign\_limit7

kluster\_mean

;

Obj\_cluster..

pri\_dif =E= sum((n,k),mean(n,k)\*mean(n,k))

;

assign\_limit1(n)..

sum(k,m(n,k)) =e= 1

```

;

assign_limit2(k)..
    sum(n,m(n,k)) =g= 1
;
kluster_mean(n,k)..
    mean(n,k) =e= p(n)*m(n,k)-c(k)*m(n,k)
;

assign_limit3(k)..
    c(k)* sum(n,m(n,k))=e= sum(n,p(n)*m(n,k))
;

assign_limit4(k)..
    sum(n,m(n,k)) =g= 2
;

assign_limit5(n,k)..
    aa(n,k)=e= sum(nn,link(n,nn)*m(nn,k)*m(n,k));
;

assign_limit6(n,k)..
    aa(n,k) =l= 10000*m(n,k)
;

assign_limit7(n,k)..
    aa(n,k) =g= 1-10000*(1-m(n,k))
;

model kmeans /all/;
option miqcp = COUENNE;
option optcr=0;
solve kmeans minimizing pri_dif using miqcp;

```



parameter cc;

$cc(n,k) = \text{sum}(nn, \text{link}(n, nn) * m.l(nn, k) * m.l(n, k));$

display m.l, cc;

## VIII. Appendix II: GAMS Code for step 4

\$ontext

Author: Hong Cai

\$offtext

set

n

p

map\_pn(p,n)

c(p)

l

i

map\_pi(p,i)

map\_pn(p,n)

map\_ln(l,n,n)

z

zonemember(n,z)

t

char / ch1\*ch2 /

;

alias (n,nn), (c,cc), (l,ll), (i,ii), (z,zz),(t,tt)

;

parameter

lineup

nodeup

genup

techup

infup

nodeup

ntcup

genup

g\_max(p)

g\_min(p)

Q

g\_wind

g\_solar

g\_bio

p\_maxN(n,nn)

react(l)

resis(l)

Voltage(l)

p\_max(l)

circuits(l)

incidence(l,n)

b(n,n)

h(l,n)

bvector(l)

gvector(l)

slack(n)

g\_max(p)

g\_min(p)

circuits(l)

cstart(p)

cdown(p)

cg(p)

zonecap\_fwd(z,zz)

;

\$onecho >temp.tmp

set=l      rng=AClines!A2:A836      rdim=1 cdim=0

set=n      rng=nodes!A2:A540      rdim=1 cdim=0

set=p      rng=plants!A2:A412      rdim=1 cdim=0

```

set=f      rng=fuels!A2:A12          rdim=1 cdim=0
set=i      rng=technologies!A2:A23   rdim=1 cdim=0
set=t      rng=Inf!A2:A10000         rdim=1 cdim=0
set=map_pn rng=plants!D2:E412        rdim=2 cdim=0
set=map_pi rng=plants!A2:B412        rdim=2 cdim=0
set=map_ln rng=AClines!A2:C836       rdim=3 cdim=0
set=z      rng=zone!D2:D100          rdim=1 cdim=0
set=zonemember rng=zone!C2:D100      rdim=2 cdim=0
par=lineup  rng=AClines!A1:H836      rdim=1 cdim=1
par=nodeup  rng=nodes!A1:L540        rdim=1 cdim=1
par=genup   rng=plants!A1:T412       rdim=1 cdim=1
par=infup   rng=Inf!A1:E10000       rdim=1 cdim=1
par=ntcup   rng=NTC!A1:D10           rdim=2 cdim=1
$offecho

```

\$onUNDF

```

$call "gdxxrw %datadir%%data%.xls MaxDupeErrors=999999999 cmerge=1
squeeze=N @temp.tmp"

```

```
$gdxin %data%
```

```
$load l n p t map_pn map_ln z zonemember
```

```
$load lineup nodeup genup infup ntcup
```

\$offmulti

```

circuits(l) = lineup(l,"Circuits");
p_max(l) = lineup(l,"ThermalLimit")*circuits(l);
voltage(l) = lineup(l,"Voltage");
zonecap_fwd(z,zz)=ntcup(z,zz,"cap_fwd");
slack(n) = 1$nodeup(n,'Slack bus');
react(l) = lineup(l,"Reactance")/circuits(l);
resis(l) = lineup(l,"Resistance")/circuits(l);

```

```
incidence(l,n) = 0;
```

```
incidence(l,n)$(lineup(l,"From") eq n.val) = 1;
```

incidence(l,n)\$(lineup(l,"To") eq n.val) = -1;

bvector(l) = (react(l) / (react(l)\*\*2 + resis(l)\*\*2))\$(react(l) or resis(l));

gvector(l) = (resis(l) / (react(l)\*\*2 + resis(l)\*\*2))\$(react(l) or resis(l));

h(l,n) = bvector(l) \* incidence(l,n);

b(n,nn) = sum(l\$incidence(l,n), incidence(l,n) \* h(l,nn));

g\_max(p) = genup(p,'Pmax');

g\_min(p) = genup(p,'Pmin');

cg(p) = genup(p,'Cost');

Parameter unit(p,char);

unit(p,'ch1') = 8760;

unit(p,'ch2') =(genup(p,'UT') - genup(p,'U0'))\*genup(p,'Uini');

Parameter unit2(p,char),check1;

unit2(p,'ch1') = 8760;

unit2(p,'ch2') =(genup(p,'DT') - genup(p,'S0'))\*(1 - genup(p,'Uini'));

genup(p,'Lj') = smin(char,unit(p,char));

genup(p,'Fj') = smin(char,unit2(p,char));

Q(n,t) = nodeup(n,'Demand share')\*infup(t,'supply');

g\_wind(n,t) = nodeup(n,'Wind share')\*infup(t,'wind');

g\_solar(n,t) = nodeup(n,'Solar share')\*infup(t,'solar');

g\_bio(n,t)= nodeup(n,'Biomass share')\*infup(t,'bio');

\*\*\*\*\*  
\*\*\*\*\*

Variable

COST\_GEN

LINEFLOW

NETINPUT

DELTA

StC

SDC  
G  
NEX(z,t)

;

#### Positive Variable

G  
StC  
SDC  
BEX(z,zz,t)

;

#### binary variable

u(p,t)  
y(p,t)  
sz(p,t)

;

#### Equations

OBJ\_generation\_cost generation cost definition (for the first step model)  
MKT\_lp\_1 market clearing equation (for the first step model)  
RES\_gmax\_1 maximum generation restriction (for the first step model)  
RES\_gmin\_1 minimum generation restriction (for the first step model)  
DEF\_lineflow\_1 lineflow definition (for the first step model)  
DEF\_netinput\_1 netinput definition (for the first step model)  
RES\_pmax\_1 maximum transmission restriction (for the first step model)  
RES\_pmin\_1 minimum transmission restriction (for the first step model)  
RES\_slack\_1 slack bus restriction (for the first step model)  
Uptime1  
Uptime2  
Uptime3  
Dntime1  
Dntime2  
Dntime3

```

startc
shdnrc
Genconst2
export
sdbl
capforward_aggr(z,zz,t)
intertrading(z,t)

;

OBJ_generation_cost..
    COST_GEN    =E=  SUM((p,t),
                    cg(p)$g_max(p)*  G(p,t))+  sum((p,t),  StC(p,t)$g_max(p)  +
SDC(p,t)$g_max(p))
;

MKT_lp_1(n,t)..
    NETINPUT(n,t)  =E=  SUM(p$(map_pn(p,n) and g_max(p)), G(p,t))
                    + g_wind(n,t) + g_solar(n,t) + g_bio(n,t)
                    -Q(n,t)
;

RES_gmax_1(p,t)$g_max(p)..
    G(p,t)    =L=  g_max(p)*u(p,t)
;

RES_gmin_1(p,t)$g_max(p)..
    G(p,t)    =G=  g_min(p)*u(p,t)
;

DEF_netinput_1(n,t)..
    NETINPUT(n,t) =E=  sum(nn$b(n,nn), b(n,nn)*DELTA(nn,t))
;

RES_pmax_1(l,t)..
    LINEFLOW(l,t) =L=  10000000
*    LINEFLOW(l,t) =L=  p_max(l)
;

RES_pmin_1(l,t)..

```

```

- LINEFLOW(l,t) =L= 1000000
* - LINEFLOW(l,t) =L= p_max(l)
;
DEF_lineflow_1(l,t)..
    LINEFLOW(l,t) =E= sum(n$h(l,n), h(l,n)*DELTA(n,t))
;
RES_slack_1(n,t)..
    DELTA(n,t)*slack(n) =E= 0
;
Genconst2(p,tt)$(ord(tt)>0)..
    U(p,tt) =e= U(p,tt-1)$(ord(tt)>1) + genup(p,"Uini")$(ord(tt)=1) + y(p,tt) - sz(p,tt);

Uptime1(p)$(genup(p,"Lj")>0)..
    sum(t$(ord(t)<(genup(p,"Lj")+1)), 1 - u(p,t)) =e= 0;

Uptime2(p)$(genup(p,"UT")>1)..
    sum(t$(ord(t)>24-genup(p,"UT")+1), u(p,t) - y(p,t)) =g= 0;

Uptime3(p,t)$(ord(t)>genup(p,"Lj") and ord(t)<24-genup(p,"UT")+2 and
not(genup(p,"Lj")>24-genup(p,"UT")))..
    sum(tt$((ord(tt)>ord(t)-1) and (ord(tt)<ord(t)+genup(p,"UT"))), u(p,tt)) =g=
genup(p,"UT")*y(p,t);

Dntime1(p)$(genup(p,"Fj")>0)..
    sum(t$(ord(t)<(genup(p,"Fj")+1)), u(p,t)) =e= 0;

Dntime2(p)$(genup(p,"DT")>1)..
    sum(t$(ord(t)>24-genup(p,"DT")+1), 1 - u(p,t) - sz(p,t)) =g= 0;

Dntime3(p,t)$(ord(t)>genup(p,"Fj") and ord(t)<24-genup(p,"DT")+2 and
not(genup(p,"Fj")>24-genup(p,"DT")))..
    sum(tt$((ord(tt)>ord(t)-1) and (ord(tt)<ord(t)+genup(p,"DT"))), 1-u(p,tt)) =g=
genup(p,"DT")*sz(p,t);

startc(p,t).. StC(p,t) =g= genup(p,"costst")*y(p,t);

```



shtdnc(p,t).. SDC(p,t) =g= genup(p,"CostsD")\*sz(p,t);

export(z,t)..

NEX(z,t) =e= sum(n\$zonemember(n,z),NETINPUT(n,t));

sdbl(t)..

sum(z,NEX(z,t))=e= 0;

capforward\_aggr(z,zz,t)..

BEX(z,zz,t) =l= zonecap\_fwd(z,zz);

intertrading(z,t)..

NEX(z,t) =e= sum(zz,(BEX(z,zz,t)-BEX(zz,z,t)));

MODEL FIRST\_STEP uc

/

OBJ\_generation\_cost

MKT\_lp\_1

RES\_gmax\_1

RES\_gmin\_1

DEF\_lineflow\_1

DEF\_netinput\_1

RES\_pmax\_1

RES\_pmin\_1

RES\_slack\_1

Uptime1

Uptime2

Uptime3

Dntime1

Dntime2

Dntime3

```
startc  
shtdnc  
Genconst2  
export  
sdbl  
capforward_aggr  
intertrading
```

```
/;
```

```
$onecho >cplex.opt  
lpmethod 4  
threads -1  
numeralemphasis 1  
scaind 1  
EpMrk 0.99999  
$offecho
```

```
$onecho >conopt.opt  
rtnwma 1.e-6  
rtnwmi 1.e-7  
$offecho
```

```
SOLVE FIRST_STEP min COST_GEN using mip;
```

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