Decentralization Induced by Power System Flexibility: A Multi-Regional Optimization Framework for Assessing Energy Transition Scenarios

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1 Introduction

1.1 Motivation

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2 Methodology

We develop a multi-regional flexibility optimizer that solves a two-stage Mixed-Integer Linear Program (MILP) to coordinate generation, storage, demand response, and inter-regional power flows. The model accounts for technical constraints and economic costs defined at the regional level, and uses dual analysis to derive marginal price signals.

2.1 Model Formulation

Let $\mathcal{R}$ denote the set of regions and $\mathcal{T}$ the set of hourly time steps. For each $(r, t) \in \mathcal{R} \times \mathcal{T}$:

- C are the costs associated with each flexibility option;

- $g_k^{r,t}$ is the dispatch of technology k in region r at time t;
- $c_s^{r,t}$ and $d_s^{r,t}$ are the charge and discharge from storage unit s;
- $f^{r \to r',t}$ is the power flow from region r to r';
- $dr^{r,t}$ is the net demand response (positive = reduction);
- $soc_s^{r,t}$ is the state of charge of storage unit s;
- binary variables $z^{r,t}$ activate DR flexibility if required.

The primal problem is written:

$$\min_{\mathbf{x},\,\mathbf{y}\in\{0,1\}} \quad \sum_{r,t} \left[\sum_k C_k^r \cdot g_k^{r,t} + \sum_s \left(C_s^{\text{charge}} \cdot c_s^{r,t} + C_s^{\text{discharge}} \cdot d_s^{r,t} \right) + C^{\text{DR}} \cdot |dr^{r,t}| + \sum_{r' \neq r} C_{r \to r'}^{\text{flow}} \cdot f^{r \to r',t} \right] \tag{1}$$

2.2 Constraint Structure

C1. Regional energy balance (per r, t):

$$\sum_k g_k^{r,t} + \sum_s d_s^{r,t} + \sum_{r' \neq r} (1 - \ell_{r' \to r})\, f^{r' \to r,t} = L^{r,t} + \sum_s c_s^{r,t} - dr^{r,t} \tag{2}$$

where $L^{r,t}$ is the exogenous residual demand and $\ell_{r' \to r}$ are distance-based losses.

C2. Generation bounds (per tech k):

$$0 \leq g_k^{r,t} \leq G_k^r \tag{3}$$

C3. Storage dynamics:

$$soc_s^{r,t} = soc_s^{r,t-1} + \eta_s^{\text{charge}} \cdot c_s^{r,t} - \frac{d_s^{r,t}}{\eta_s^{\text{discharge}}} - \gamma_s \cdot soc_s^{r,t-1} \tag{4}$$

with optional cyclical constraint:

$$soc_s^{r,T} = soc_s^{r,0} \tag{5}$$

C4. Storage power and energy limits:

$$0 \le c_s^{r,t} \le C_s^{\max}, \quad 0 \le d_s^{r,t} \le D_s^{\max}, \quad 0 \le soc_s^{r,t} \le SOC_s^{\max} \tag{6}$$

C5. Transport (flow) limits:

$$0 \le f^{r \to r',t} \le F_{r \to r'}^{\max} \tag{7}$$

C6. Demand response:

$$|dr^{r,t}| \le \alpha_r \cdot L^{r,t} \quad \text{(instantaneous limit)} \tag{8}$$

$$\sum_t dr^{r,t} = 0 \quad \text{(net-zero over horizon)} \tag{9}$$

$$dr^{r,t} = dr^{r,t,+} - dr^{r,t,-}, \quad dr^{r,t,+}, dr^{r,t,-} \ge 0 \tag{10}$$

C7. Ramping limits:

$$|g_k^{r,t} - g_k^{r,t-1}| \le \rho_k \cdot G_k^r \tag{11}$$

2.3 Dual Variables and LP Relaxation

After solving the MILP, we freeze $\mathbf{y} = \mathbf{y}^\star$ and relax the integrality constraints to obtain a Linear Program. Solving the LP yields:

- $\boldsymbol{\lambda}_{r,t}$: the shadow price of (2), interpreted as the regional marginal cost of electricity (nodal price);
- $\boldsymbol{\mu}$: duals on capacity constraints, including line flow limits, storage power bounds, and DR ceilings.

These multipliers enable a comparison between actual operational cost and market-based nodal valuation.

2.4 Implementation

The model is implemented in Python using `PuLP`. Constraints and cost parameters are dynamically built from a YAML configuration file, and post-processing scripts (in Jupyter) extract time-series of costs and marginal prices for visualisation and comparison.

2.5 Data Sources

The model relies on empirical data from publicly available platforms and national reports:

- **Electricity demand** profiles are retrieved from the *ODRÉ* platform[1], which provides hourly regional consumption series for mainland France.
- **Renewable generation profiles** (solar and wind) also come from ODRÉ.
- **Installed capacities**, **flexibility parameters**, and **costs assumptions** are informed by official literature, including regional energy planning documents and technical reports from RTE (*Réseau de Transport d'Électricité*), such as the "Panorama régional de l'électricité" series.

All time series are processed and aggregated to half-hourly resolution.

2.6 Parameterization

All technical and economic parameters used in the simulation are loaded from a master configuration file in YAML format. This file defines cost coefficients, technology characteristics, demand response (DR) potentials, storage efficiencies, and grid transfer capacities for each region.

Table 1 summarizes the key values employed in the full-year simulation.

[1] `https://opendata.reseaux-energies.fr`

Table 1: Selected parameters used in the model

Parameter	**Value / Description**
Generation costs	Hydro: €30/MWh, Nuclear: €40/MWh, Gas: €80/MWh, Coal: €90/MWh, Biofuel: €70/MWh
Demand response cost	€120/MWh (penalty for activation)
Storage costs	Charge: €35/MWh, Discharge: €50/MWh
Flow cost	€35/MWh (for inter-regional exchange)
Slack	Slack penalty: €50,000/MWh
Storage efficiencies	Charge: 90%, Discharge: Batteries: 85%, STEP: 90%, self-discharge (batteries): 19.2% per 30min
DR limits	Max shift: 5% of load, max energy shifted: up to 10,000 MWh depending on region
Ramp rates	Nuclear: 5%, Hydro: 90%, Gas: 80%, Coal: 30%, Biofuel: 15% (per 30min step)
Min nuclear share	15% of total generation capacity per timestep
Flow loss factor	0.025% per km between regions
Storage initialisation	Initial SOC = 50%
Transport capacity	Up to 5000 MW between regions

Formal proof: market payments exceed operational cost

Notation.

$\mathbf{x}$	continuous decision variables: dispatch, (dis)charging, DR, flows, ...
$\mathbf{y} \in \{0,1\}$	non-convex variables (unit commitment, DR flags)
$\mathbf{c}^\top \mathbf{x}$	linear cost function (regional tariffs from `config_master.yaml`)
$\mathbf{A}\mathbf{x} = \mathbf{b}$, $\mathbf{G}\mathbf{x} \le \mathbf{h}$	balance, capacity and loss constraints
$\boldsymbol{\lambda}$	Lagrange multipliers of regional balance equations — *nodal prices*
$\boldsymbol{\mu} \ge \mathbf{0}$	multipliers of capacity constraints (lines, DR, storage, ...)
Z_{MILP}	optimal value of the original MILP ("operational cost")
$P = \sum_{t,r} \lambda_{t,r} D_{t,r}$	market payment, with $D_{t,r}$ the exogenous net demand.

1. From the MILP to a "fixed" LP

Solve the MILP

$$\min_{\mathbf{x},\, \mathbf{y} \in \{0,1\}} \mathbf{c}^\top \mathbf{x} \quad \text{s.t. } \mathbf{A}\mathbf{x} = \mathbf{b},\ \mathbf{G}\mathbf{x} \le \mathbf{h},$$

obtaining $(\mathbf{x}^\star, \mathbf{y}^\star)$ and Z_{MILP}.

Freeze $\mathbf{y} = \mathbf{y}^\star$ and drop integrality; the problem becomes a linear programme

$$\boxed{(\text{LP}_{\text{fix}})}\ \min_{\mathbf{x}} \mathbf{c}^\top \mathbf{x} \quad \text{s.t. } \mathbf{A}\mathbf{x} = \mathbf{b},\ \mathbf{G}\mathbf{x} \le \mathbf{h}.$$

Because $(\mathbf{x}^\star, \mathbf{y}^\star)$ is feasible,

$$Z_{\text{LP}} \ \le\ Z_{\text{MILP}}.$$

2. Strong duality for (LP_{fix})

The dual reads

$$\max_{\boldsymbol{\lambda},\, \boldsymbol{\mu} \ge \mathbf{0}} \boldsymbol{\lambda}^\top \mathbf{b} + \boldsymbol{\mu}^\top \mathbf{h} \quad \text{s.t. } \mathbf{A}^\top \boldsymbol{\lambda} + \mathbf{G}^\top \boldsymbol{\mu} \ = \ \mathbf{c}.$$

Strong duality gives

$$Z_{\text{LP}} \;=\; \boldsymbol{\lambda}^\top \mathbf{b} \;+\; \boldsymbol{\mu}^\top \mathbf{h}. \tag{1}$$

3. Link with market payment

By definition $P = \boldsymbol{\lambda}^\top \mathbf{b}$, so (1) becomes

$$Z_{\text{LP}} \;=\; P \;-\; \boldsymbol{\mu}^\top \mathbf{h}. \tag{2}$$

Since $\boldsymbol{\mu} \geq \mathbf{0}$ and $\mathbf{h} - \mathbf{G}\mathbf{x} \geq \mathbf{0}$, we have $\boldsymbol{\mu}^\top \mathbf{h} \geq 0$.

4. Fundamental inequality

Combining $Z_{\text{LP}} \leq Z_{\text{MILP}}$ with (2),

$$\boxed{Z_{\text{MILP}} \;\leq\; P \;-\; \boldsymbol{\mu}^\top \mathbf{h} \;<\; P}.$$

Hence the market payment is *always* at least as large as the true operational cost. The gap decomposes as

$$P - Z_{\text{MILP}} \;=\; \underbrace{\boldsymbol{\mu}^\top \mathbf{h}}_{\text{congestion \& flexibility rents}} \;+\; \underbrace{(Z_{\text{LP}} - Z_{\text{MILP}})}_{\text{non-convexity penalty}},$$

which is strictly positive whenever at least one capacity constraint binds ($\boldsymbol{\mu}^\top \mathbf{h} > 0$) *or* non-convexities are present ($Z_{\text{LP}} < Z_{\text{MILP}}$).

Q.E.D. This establishes rigorously that the operational (co-optimised) approach yields lower total costs than the price-based market settlement in our model.