Nodal Pricing – Case Study from Aurora Energy Research

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Context

Nodal pricing, also known as **locational marginal pricing (LMP)**, is used in the context of electricity markets to manage power dispatch efficiently under transmission constraints. Its purpose is to reflect the true cost of delivering electricity to different locations (or *nodes*) in a power grid, accounting for the generation costs and the limitations of the transmission system.

Transmission constraints: In any power system, electricity is transmitted through a network of high-voltage transmission lines. These lines have **capacity limits (also known as line ratings)**, meaning they can only carry a certain amount of electricity safely. When certain parts of the transmission network become congested and line flows reach their capacity limits, it creates a situation where electricity can't always be delivered from the lowest-cost generator to all locations and higher-cost generators have to step in.

Task

Minimize the total dispatch costs under transmission constraints while meeting the hourly power demand.

Here we will be looking at a 7 day horizon at hourly granularity, with hourly power demand given at several nodes in the network. We want to minimize the total cost of dispatching the available generators to meet the power demand, while respecting transmission constraints in the network and respecting dispatch limits for the generators.

Inputs

For the purpose of this case study we will look at an artificial network consisting of 428 nodes, 532 transmission lines and 5 generators with a total capacity of 1450 MW.

- **SHIFT(L, N)** Shift factor matrix: this is an l x n matrix (l: number of lines, n: number of nodes) that specifies how 1 MW of power generation at node n impacts the power flow on line l
  - For example, an entry of shift(l,n) = 0.5 means that when 1 MW of power is generated at node n, it results in 0.5 MW of power flow on line l
- **G** set of Generators
  - **CAP(G)**: capacity (in MW) (i.e. maximum dispatch) for generator g
  - **MC(G)** marginal cost (in £/MWh) of producing 1 MWh of energy for generator g
  - **NODE(G, N)** mapping of generators to nodes
- **N** set of Nodes
  - **DEMAND(N, T)**: (in MW) demand at node n at time t
- **L** set of Transmission Lines
  - **RATE(L)**: (in MW) transmission line rating (i.e. maximum power flow limit) for line l. For some lines we will ignore the limits, these will be marked as 'inf' in the inputs

- **T** set of time (here: hours)
    - Here we will be modelling a 7 day horizon at hourly granularity
- **COST_LOL**: The cost of loss of load (LOL, in £/MWh), I.e. the cost of not meeting demand.
    - Here we assume that COST_LOL = £5000

Optional extension questions:

These questions are completely optional and allow you to dive deeper into the problem.

1. How does the optimal dispatch under transmission constraints differ to the optimal dispatch without transmission constraints? How does the dispatch differ by generator and total cost?
2. What is the hourly nodal price (=locational marginal price)? What are it's components?
3. Can you find what the constraining lines are?
4. Would "upgrading" the constraining lines help to relieve the congestion and reduce the total cost of dispatch? Here we can assume that "upgrading" simply means increasing the line rating.
5. There are many optional extensions you could add to the model to make the dispatch more realistic, such as:
    - Add ramping constraints to generators 3 and 4
    - Add hourly availability to generators 1 and 2 to make them more representative of solar or wind generators