

A Preliminary System Cost Comparison of Single-Node and Multi-Node Grid Representations of the 2024 Korean Power System Using Posy2

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1. Introduction

Discussions of nuclear economics increasingly depend on system cost, the total cost of operating and expanding the whole power system, rather than the levelized cost of any single plant. Levelized-cost comparisons cannot see the effects that dominate high-renewables and high-nuclear futures alike: balancing, transmission constraints, and the profile of residual demand [1]. Capturing these effects for Korea requires a system model that represents the Korean grid, fleet, and operating rules at sufficient resolution.

This paper uses Posy2, an open-source power-system cost-optimization framework published by the OECD Nuclear Energy Agency [2], and a Korean application of it currently under development within the NEA–KAERI collaboration. As a first demonstration aimed at model transparency rather than scenario results, we ask a deliberately simple question: what does the spatial representation of the grid change in a system-cost model? We reconstruct the 2024 Korean power system and solve it three times at identical data resolution, varying only the network representation, from a single-node copper plate, in which transmission is unlimited and free, through a partially constrained multi-node case, to the fully constrained multi-node network. We find that the grid representation moves the national system-cost total by only about one percent, but moves the locational value of generation several times more: for the nuclear fleet, by more than 1 B USD/yr.

2. Methods and Results

2.1 The Posy2 Model and the 2024 Korean Case

Posy2 minimizes total system cost (fuel, variable and fixed O&M, annualized investment, CO₂, and transaction charges) over a year in hourly resolution, by linear or mixed-integer optimization. The Korean configuration models 11 zones connected by 17 inter-zonal interconnectors, with the 2024 fleet fixed at its actual capacities, actual 2024 hourly zonal demand, and calibrated hourly renewable profiles, built on the Korean input dataset based on the 2024 KPX operating record [3]. Three features matter for nuclear analysis. First, the model accounts for total system cost per zone and technology. Second, nuclear is resolved as three regional

fleets (Busan-Ulsan, Gyeongbuk and Jeonnam) covering 25 of the 26 reactors in the 2024 fleet and 25.4 GW of capacity; Kori-2, out for long-term-operation refurbishment, is excluded. Each fleet carries an hourly availability calendar aggregated from the unit-by-unit 2024 outage and refueling record, so the model follows the actual availability pattern of the fleet rather than an assumed refueling cycle. Third, the zonal grid enforces, alongside individual line ratings, the 12.4 GW limit on combined inflows into the Capital area from the Gangwon, Chungbuk, and Chungnam zones (hereafter the flowgate), a stability-based transfer limit on the metropolitan tie-lines [4].

The three network representations are: (i) single-node (copper plate), where all line limits and the flowgate are removed and the inter-zonal wheeling charge is cut to a nominal 0.01 USD/MWh (1.7 M USD/yr, or 0.003 % of system cost), retained only to pin a unique flow pattern among the cost-equivalent solutions a fee-free network admits, making the case numerically equivalent to a one-node system; (ii) flowgate only (two-node), with the 12.4 GW flowgate into the Capital area enforced, the same nominal charge as in (i), and all else unconstrained; and (iii) full network, with the 17 inter-zonal lines held to the 60 % transfer-capacity availability applied in the Korean dataset (the Jeju HVDC link at full rating), the flowgate, and an assumed 2.5 USD/MWh wheeling charge. The wheeling charge is a fee applied to each inter-zonal transfer, per line crossed, standing in for transmission-usage tariffs; it re-prices flows but does not constrain them. The three cases are solved with binary unit commitment. Because the availability calendars set nuclear available capacity exogenously, in place of an endogenous refueling schedule, the linear relaxation is essentially tight: it reproduces all three objectives to within 0.004 %. Costs, dispatch and flows are therefore reported from the mixed-integer solutions, while zonal prices are the shadow prices of the linear relaxation, which a mixed-integer solve does not provide. A zonal price is the marginal system cost of serving one additional MWh in that zone.

2.2 Validation Against 2024

Before comparing grid representations, we check that the model reproduces the year it claims to represent. The full-network case is driven by actual 2024 conditions (the hourly demand, the operating fleet, and the recorded

nuclear availability pattern) and its annual outcome is compared against the official 2024 statistics on the KPX metered basis [3]. Total generation agrees to within 0.1 %, and the thermal mix is close: coal and LNG each come out three to four percent above the statistics. Renewable and other non-thermal output cannot be checked against a single official basis. The model's 49.5 TWh lies above the 43.0 TWh the KPX statistic meters, which excludes most behind-the-meter and PPA solar that the model does include, and slightly below the 51.5 TWh implied as a residual. Renewable capacities and hourly profiles are in any case calibrated inputs rather than an independent model result. Curtailment is negligible in both the model, at 0.000 TWh to reporting precision, and the reported statistics for the year, of the order of 0.02 TWh.

One accounting subtlety matters for the nuclear comparison. The model dispatches net generation, the electricity a plant delivers to the grid after supplying its own station service, whereas Korean statistics meter nuclear output gross, at the generator terminals; the two differ by roughly five percent, the station-service share, which is stable across 2023 and 2024. Compared on the same net basis, against the IAEA-PRIS figure of 179.4 TWh [5], the model's 179.5 TWh reproduces the fleet's 2024 generation to within 0.1 %, and its capacity factor to within half a percentage point. The same subtlety also explains most of the small coal and LNG overshoots: because total generation is validated against the gross statistic, the nuclear house-load that the model does not book under nuclear reappears under the other fuels.

2.3 What the Grid Representation Changes

Moving from the single-node representation to the full multi-node network raises the modeled 2024 system cost by about 1.1 % (Table I). The physical difference is concentrated in one corridor: the single-node solution implicitly pushes nearly twice the flowgate's real capability through it (Fig. 1) and overstates its annual deliverable energy accordingly. Just under a third of the difference, +0.33 %, is redispatch forced by the flowgate. The remainder, +0.78 %, is the assumed wheeling charge on inter-zonal transfers, which a single-node model cannot represent at all (Fig. 2). The comparison is robust to both the renewable profile year and the solution mode: repeating the ladder with an alternative annual renewable profile gives +1.14 % in place of +1.12 %, and the binary-commitment solutions reproduce it to three significant figures. Nuclear runs at its calendar availability in all three cases, so its dispatch is identical across them.

Table I: The three grid representations

	Single-node	Flowgate only	Full network
Effective number of nodes	1	2	11
System cost (B USD/yr)	53.81	53.99	54.41

Δ vs single-node (M USD/yr)	—	+176 (+0.33 %)	+601 (+1.12 %)
Flowgate hours at/above 12.4 GW ^a	2,520	2,697	2,336
Capital-area net import (TWh/yr)	94.6	90.1	88.9
CO ₂ (Mt/yr)	201.0	199.3	199.3

^a For the single-node case: hours in which the unconstrained solution exceeds the limit that the real corridor enforces; maximum corridor flow 23.2 GW. Hours are counted within 0.1 % of the limit.

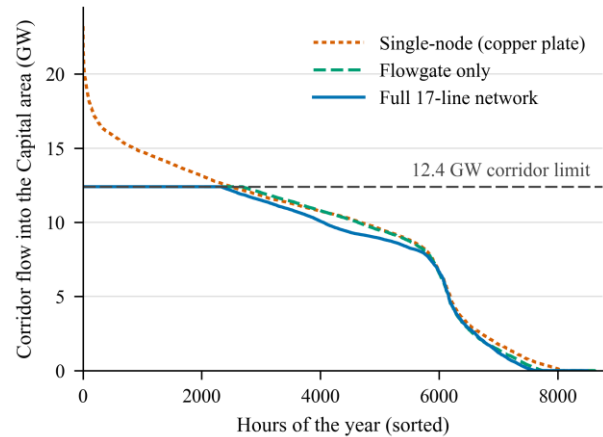


Fig. 1. Duration curve of flowgate flow into the Capital area (net inflow from Gangwon, Chungbuk, and Chungnam) for the three representations, against the 12.4 GW limit; flows from the binary-commitment solutions.

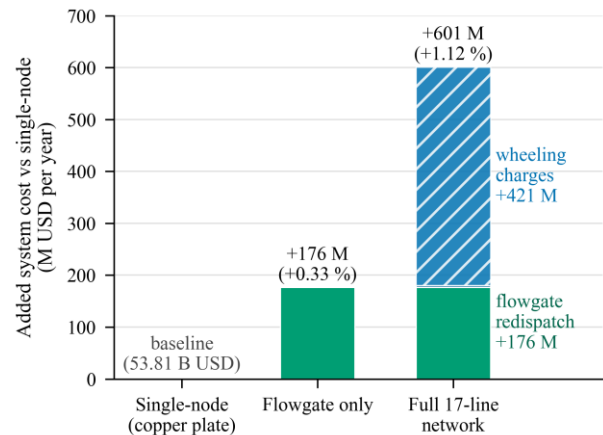


Fig. 2. Increments in modeled 2024 system cost relative to the single-node representation: flowgate redispatch (+176 M USD/yr), the assumed wheeling charge (+421 M USD/yr), and other terms (+4 M USD/yr).

Although national totals barely move (Table II), the constraint relocates generation across the country: about 8 TWh/yr shifts from plants upstream of the flowgate into the Capital area and Incheon, whose tie into the Capital area lies outside the flowgate (Fig. 3). Almost all of it lands on gas: the Capital area has no coal capacity, so its gas fleet is the only local substitute when the flowgate binds. The unconstrained grid also emits slightly more CO₂ since copper-plate modeling lets

remote coal serve demand it physically cannot reach, and it overstates the import share of Capital-area consumption.

Table II: National dispatch by fuel (TWh/yr)

	Single-node	Flowgate only	Full network
Nuclear	179.5	179.5	179.5
Coal	172.5	168.7	168.7
CCGT	122.4	126.2	125.0
CHP	49.8	49.8	50.9
Solar and wind	39.2	39.2	39.2
Total	573.8	573.6	573.6

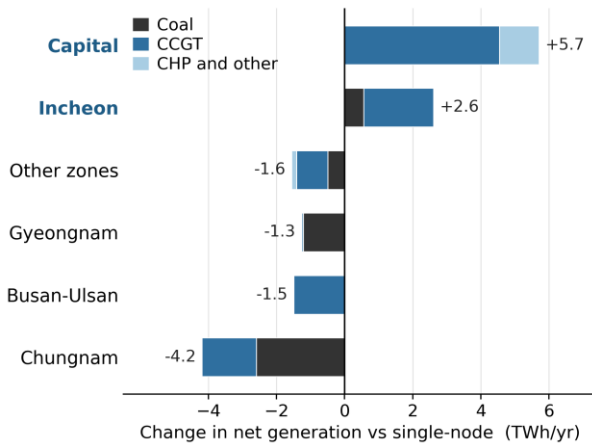


Fig. 3. Change in annual net generation by zone and fuel, full network relative to single-node. The Capital area and Incheon, on the importing side of the flowgate, gain about 8 TWh/yr between them, almost all of it gas-fired, while coal upstream of the flowgate backs down.

The largest differences are distributional. The single-node model has one national price by construction. With the grid represented, zonal prices in the Capital area and Incheon rise above that level, while every other zone falls below it. The flowgate also collects a congestion rent, equal to the zonal price difference across the constraint times the flow through it. That rent is several times larger than the redispatch cost the constraint adds to the total. The nuclear fleet sits on the exporting side of the flowgate, so representing the grid reprices its output downward while leaving its physical generation unchanged: the generation-weighted marginal value of nuclear output falls by 6 to 7 USD/MWh, about six percent. At the fleet's 2024 output that is 1.1 to 1.3 B USD/yr across the two profile years, roughly twice the entire single-node-to-multi-node cost difference. (These are model shadow prices under cost minimization, not forecasts of Korea's uniform-price market outcomes.)

3. Conclusions

Three conclusions follow. First, for national totals, grid representation is a second-order correction at 2024 conditions, and a single flowgate constraint captures nearly all of the physical redispatch, a useful simplification for fast scenario screening. Second, grid

representation is first-order for any quantity with a location attached: where generation runs, what corridors can deliver, and what power costs in each zone. Third, the largest change is not the total system cost. It is the value of generation at each location. Measured by zonal shadow prices under cost minimization, the marginal system value of existing nuclear output is substantially lower than a single-node model implies, while Capital-area capacity and corridor relief are correspondingly more valuable. System-cost analysis of nuclear questions such as new-build siting, corridor reinforcement and outage scheduling therefore requires at minimum the flowgate constraint, and zonal resolution wherever prices, regional mixes, or asset values matter. The demonstrated combination is the foundation for capacity-expansion applications under way, to be reported separately.

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