Introduction

Anthropogenic climate change demands that we reduce greenhouse gas emissions from energy consumption. This process must begin with the electricity sector, given that it is not only already a major source of carbon emissions across the developed and developing world, but also because clean electricity has the potential to substitute for other polluting fuels in industry and transportation. Thus, managing an efficient and cost-effective transition of the power sector away from fossil fuels is a compelling interest for those looking to mitigate climate change.

A potential resource in that transition is long-distance transmission capacity, Transmission systems deliver energy from where it is produced to where it is consumed with minimal technical losses, which allows economies of scale in generation, which can be sited where land or energy resources are abundant, and also in consumption, by aggregating many consumers with different demand profiles. Transmission may also lower energy costs by enabling potentially distant, lower-cost generators to more reliably be dispatched to meet demand. Long distance transmission, which I consider in this case study, theoretically stands to take advantage of geographic differences in fuel and generation costs, heterogeneous renewable energy potentials, and time-offset demand profiles.

However, in the real world there are significant political and practical barriers to long-distance transmission, including resistance from incumbent utilities, poor or uncoordinated planning, permitting difficulties, and failures at equitable and agreeable cost allocation. Policymakers and institutions interested in lowering these barriers must, then, be informed with more than an inferential description of the actual system value of long-distance transmission capacity. When, and why, is long-distance transmission cost-effective? What impact does it have on the electricity networks that it links, and to whom do benefits accumulate? In an attempt to answer these questions, a case study will be presented of a proposed transmission line between the Pacific Northwest and the Midwest of the United States. GridUnited's $3.2 billion, North Plains Interconnector HVDC project would span the Eastern and Western interconnection between Montana and North Dakota, where it would join existing high-voltage transmission lines which span from Oregon and Washington in the west to Minnesota in the east.[1,2] Here, I study the system implications of transmission capacity which directly interconnects these distant regions, though this is a simplification of actual power system operations.

Methods

To model the power systems in question and the impact of long-distance transmission, this report utilizes GenX, a free open-source capacity expansion model

(CEM). A capacity expansion model is a linear program which determines the theoretical least-cost investment and operational decisions to meet a given demand profile under policy constraints in a simplified power system. These models may be used to calculate the “system value” of an asset by running twin models with the same inputs except for the asset in question, which is present in one but not the other. The difference in the total system costs between the twin models reflects the system value of the asset. By conducting these twin studies with a variety of input scenarios, the robustness of an asset’s value to different economic circumstances - which, in reality, are always uncertain - can be ascertained.

For each case under consideration, I chose to run a five-stage “myopic” model of two zones, spanning 25 years of system evolution, from 2025 to 2050. The choice of a five-stage myopic model is both practical, to improve running time, as well as meant to reflect the relatively short time horizon of many planners and planning mechanisms in the electricity sector. (A single stage model could, for instance, make investments in 2026 which only become economically justified with perfect foresight of specific events in 2049, which does not reflect real-world policy or investment strategy.) Notably, 25 years is significantly shorter than the realistic lifespan of a real transmission asset. However, it becomes significantly more difficult to obtain reasonable, calibrated input data (fuel price, demand forecasts, etc.) beyond the year 2050, while deep uncertainties - “unknown unknowns,” events which occur with an unknown (and often unknowable) frequency - become more important to real world outcomes at long time horizons, limiting the relevance or utility of models which claim to accurately represent the far future.

While the complete mathematical formulation of GenX’s capacity expansion LP is beyond the scope of this report, its central features will be briefly reviewed here. Multistage GenX models minimize annualized system costs, which, for our purposes, consist of investment and fixed O&M costs of generation and storage capacity, the variable costs associated with operating the system, including those such as fuel costs and variable O&M, and the cost of non-served energy. Because GenX models rapidly become computation- and memory-intensive as they grow in size and detail, and because GenX is modular in design and easily configured to exclude certain features, neither unit commitment nor network expansion were modeled in the cases studied for this report. (Cases which include long-distance transmission have this capacity specified exogenously - transmission expansion is not a decision available to the model.) In another attempt to reduce model complexity, generators with similar features (e.g. fuel type, technology) were grouped into idealized “clusters,” such that only each cluster (instead of each generator) must make dispatch decisions. Thus, the decision variables available to the model in each of its stages are a): Investment and retirement decisions for each qualifying resource, and b): 8760 dispatch decisions for each resource “cluster” - one for each hour in a representative year, which repeats identically five times to simulate one planning period, and (in the relevant cases) c): 8760 transmission flow “decisions,” which determine when and how much power is delivered between regions. Energy carried by the transmission connection suffers 5% losses before arriving in another zone.

This relates to the power balance constraint, which holds that, for each zone and in every hour of dispatch, the sum of generation, non-served energy, net discharge by storage resources, price-responsive demand, and net transmission flows must equal total demand. In the following experiments, a single idealized transmission line between two zones allows lower-cost supply in one zone to meet demand in the other zone, up to the transmission capacity limit. This is one of the primary mechanisms by which transmission ought to reduce system costs in the model. References to GenX's model and complete documentation are provided in the appendix.

Data

Data inputs were generated for every case considered using the free open-source PowerGenome tool, which programmatically collects, cleans, and packages real-world electricity datasets for their application in electricity models. Notable data sources which I relied on (via PowerGenome) include but are not limited to: the U.S. Energy Information Administration's Annual Energy Outlook "AEO" (2022) for regional fuel prices, the National Lab of the Rockies' (formerly NREL's) Annual Technology Baseline for present and future greenfield generator costs, various NLR and FERC datasets for historical demand data, and miscellaneous data aggregated by the Public Utility Data Liberation (PUDL) project. The only "non-native" (to PowerGenome) data inputs I incorporated were the October 2025 EIA 860 form for a more current list of active U.S. generators, as well as my own specified demand profiles, which were based on a 2025 reference case of the Electrification Futures Study (native to PowerGenome) and load forecasts by the Northwest Power and Conservation Council and the Midcontinent System Operator (MISO).[3,4] References to PowerGenome's documentation and data are provided in the appendix.

Using PowerGenome, I specified my two zones. The "PNW" zone corresponds roughly to the states Washington, Oregon, and Montana, while the "MISONorth" zone corresponds roughly to North Dakota, Wisconsin, Minnesota, and Iowa. These correspondences are rough because they are, in reality, unions of "IPM regions" used by the EIA for their internal modelling and published forecasts. Moreover, I configured a total of 45 cases for consideration, as follows:

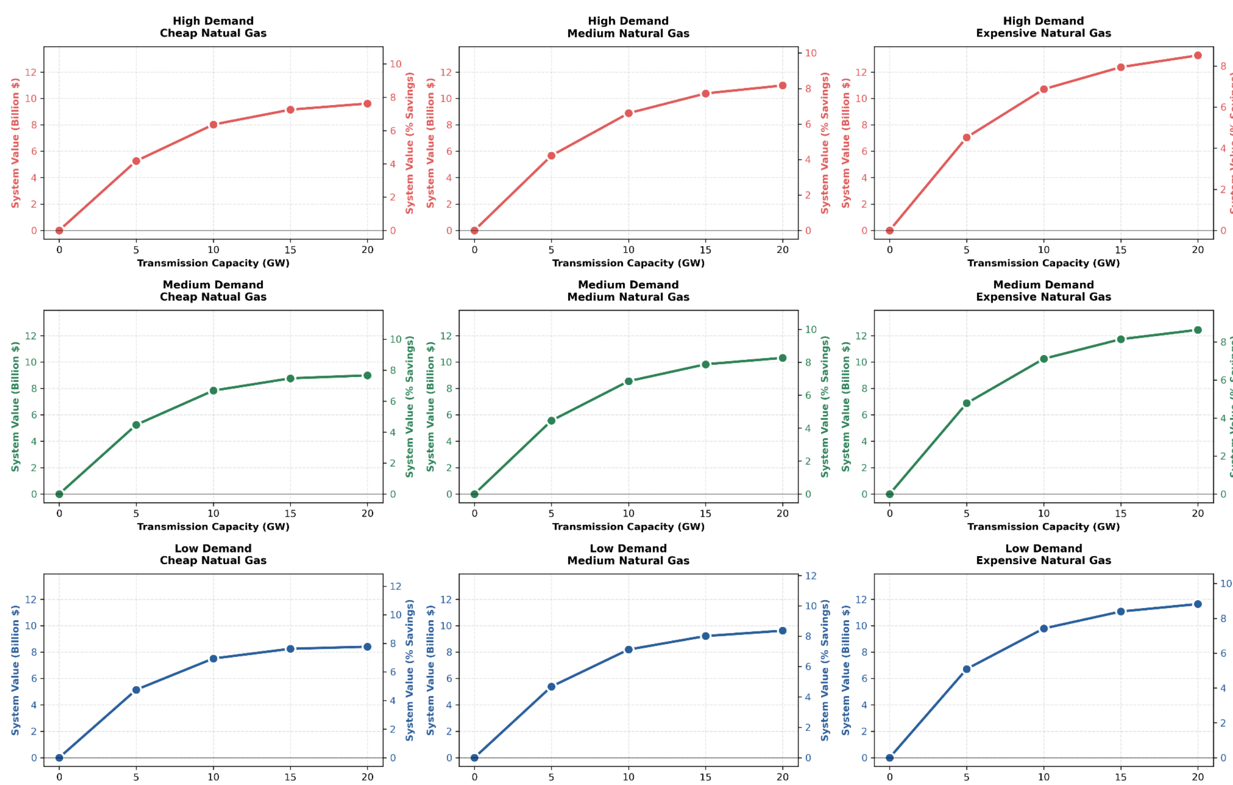
- Three electricity demand growth scenarios, using low, medium, and high annual load growth rates based on forecasts by the Northwest Power and Conservation Council and the Midcontinent Independent System Operator.
- Three fuel (coal, natural gas, and petroleum distillate) price scenarios, using the 2022 AEO's "low oil and gas supply" case as a high price scenario, their reference forecast as a moderate scenario, and their "high oil and gas supply" case as a low price scenario.

- One policy scenario with "energy share requirements" (ESRs) that reflect power-sector decarbonization mandates in various states being modeled. This takes the form of two constraints in the model, so that clean energy credits cannot be traded between zones. These clean energy share requirements are much more stringent in the Pacific Northwest, where Oregon and Washington have pledged to achieve 100% clean power systems before 2050, while, with the exception of Minnesota, no states in the Midwest have ambitious mandates.
- In each case, I run a reference model with no transmission between the two zones, and one model each with 5 GW, 10 GW, 15 GW, and 20 GW of transmission capacity between the two zones to capture the changing marginal return on additional transmission capacity. Thus, for each fuel and growth scenario, there are five cases considered.

Results

We may generate the system value curve of a given fuel price and demand growth scenario by plotting the system value of transmission in that scenario against the amount of transmission, which provides easy insight into the marginal returns of additional investment in transmission. Figure 1 illustrates nine plots of a system value curve for each of nine fuel and growth scenarios:

Figure 1: Transmission System Value - Current ESR Policy



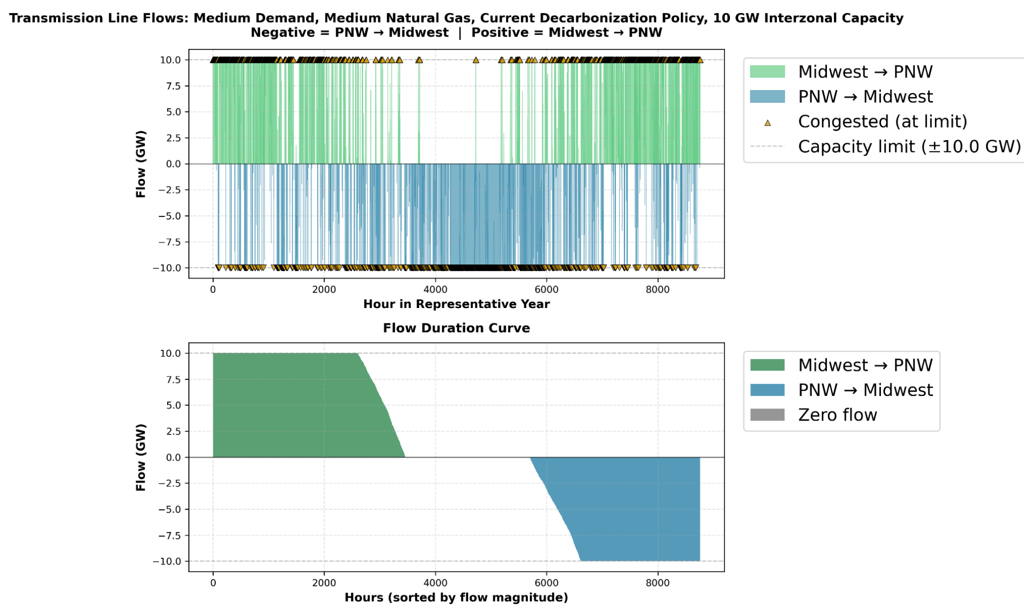
Note that all plots in the figure share a consistent left-hand y-axis indicating absolute system value, while each plot within the figure has its own scaled right-hand y-axis indicating the ratio of the system value to the reference case total system costs.

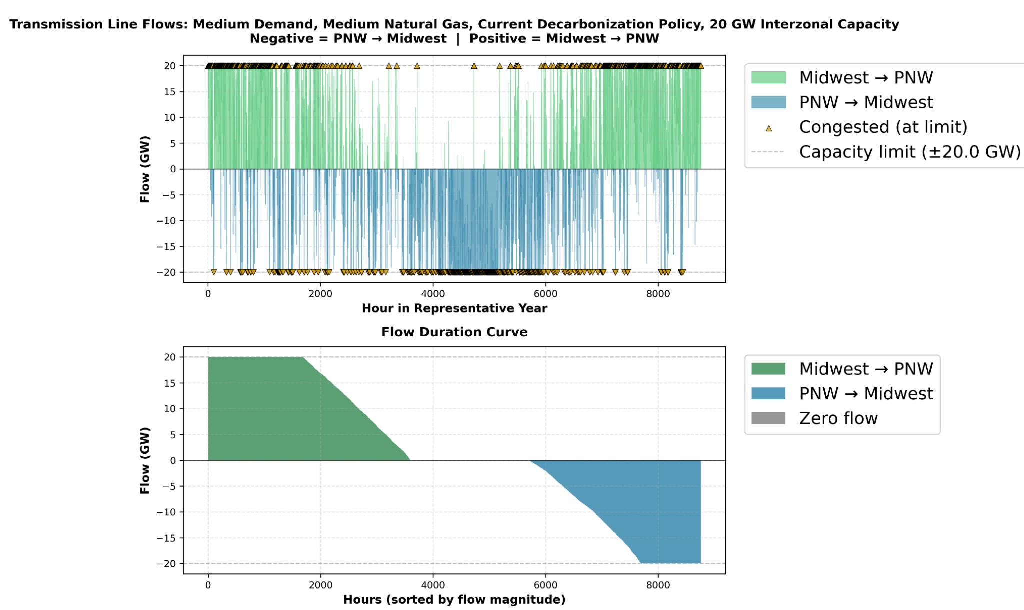
Inspection of these plots reveals several phenomena which merit closer investigation. In all the considered scenarios, there exists a sharply sublinear relationship between transmission capacity and system value. For reference, either zone, across the range of demand scenarios, experiences a peak load between 105 and 132 GW, so 20 GW of transmission does represent a significant fraction of peak load in both systems. Moreover, transmission results in significant, though not revolutionary, system savings. Across all the considered scenarios, a mere 10 GW of interzonal transmission capacity captured most of the potential benefits of larger capacities, resulting in system savings of $7.8-10.7 billion dollars, or 6.5-7.5% of total system savings.

We also observe that absolute and relative system savings only respond to differences in demand growth for larger transmission capacities beyond 10 GW, which reinforces the previous observation that the marginal value of additional interzonal transmission shrinks as it becomes a greater fraction of peak load. (Here, the marginal value of additional transmission increases as it becomes a smaller fraction of peak load under greater demand growth.) Lastly, the system value of transmission is dramatically higher under expensive cost scenarios for natural gas, while it is smaller, but by a much lesser degree, under scenarios with cheaper natural gas costs. This would suggest a major source of interzonal transmission value is in reducing the need for natural gas combustion.

The most direct tool to more deeply understand interzonal transmission's manifold impact on the modeled systems is to examine the flows on that transmission during the operational period, which is one of GenX's data outputs. Table 1 on the next page illustrates some of the key patterns in power flow across the studied transmission lines.

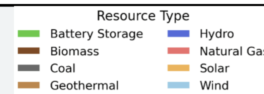
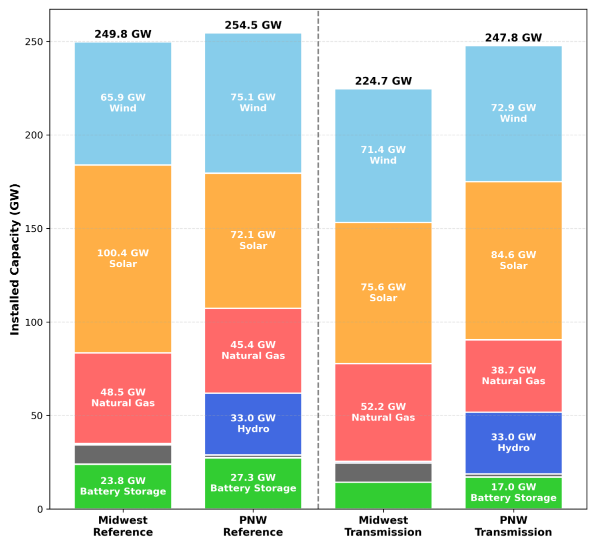
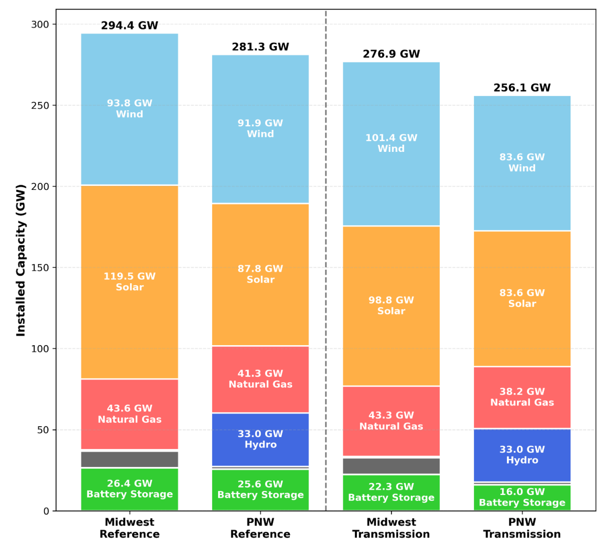
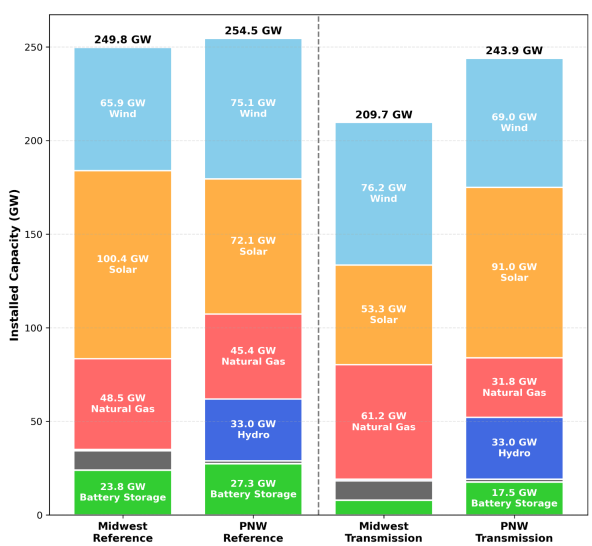
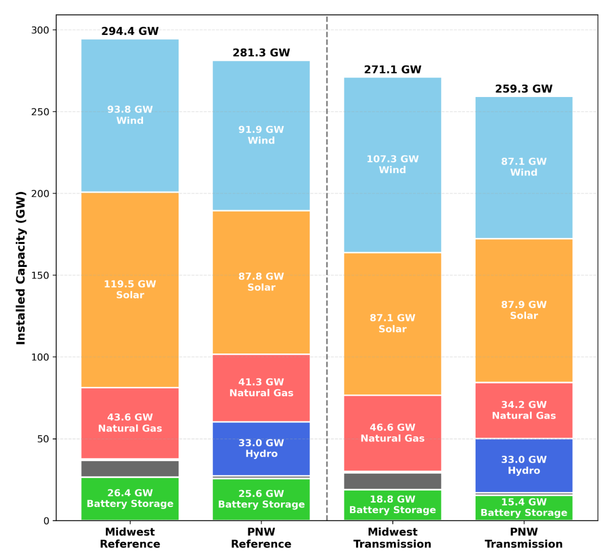
There is a visually obvious seasonality to the transmission flows between the Pacific Northwest and the Midwest. In the middle of the year, i.e. the summer, power flows almost uniformly eastward, and, in the remainder of the year, power flows westward. A compelling argument for why that might be the case is simply that the Midwestern states which have been modeled - Minnesota, Wisconsin, Iowa, North Dakota - are home to some of the finest wind energy resources in the United States, and wind farms are less productive in the summer than in the winter. Thus, the transmission line enables a sort of seasonal compensation; the windy plains send their abundant power westward in the winter, and when their wind farms are less productive in summer, they receive instead of taking power. What is remarkable is how *evenly* this utilizes the transmission line. It is not necessary that this seasonality results in a net energy exchange so close to zero, and yet it does.

<table>
<tr><th colspan="2">Table 1: Example Transmission Flows (Medium Demand, NG Price)</th></tr>
<tr><td>10 GW</td><td>


</td></tr>
<tr><td>20 GW</td><td>


</td></tr>
</table>

It is traditionally difficult to reason about the *cause* of these flows, since they are, matter-of-factly, just a part of the least-cost solution to meet demand. To better understand how these flows - which are operational outcomes - result from and result in differentiated capacity decisions, we can directly compare the investment decisions made in the transmission and reference cases from the scenarios above:

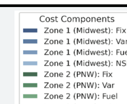
<table>
<tr><td colspan="3">Table 2: Capacity Impacts of Transmission (Medium Demand)

</td></tr>
<tr><td></td><td>Medium Natural Gas Price</td><td>Expensive Natural Gas Price</td></tr>
<tr><td>10 GW</td><td>
</td><td>
</td></tr>
<tr><td>20 GW</td><td>
</td><td>
</td></tr>
</table>

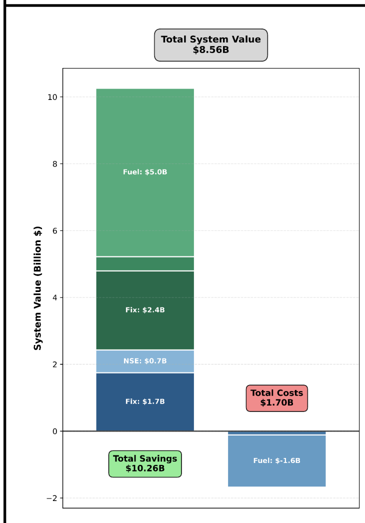
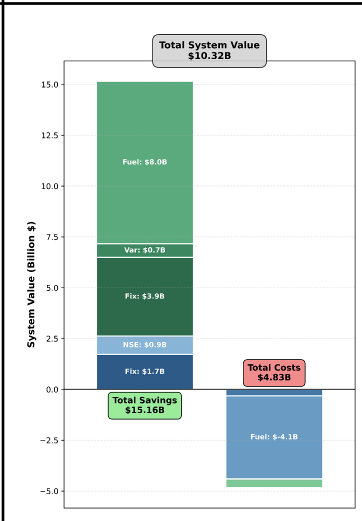
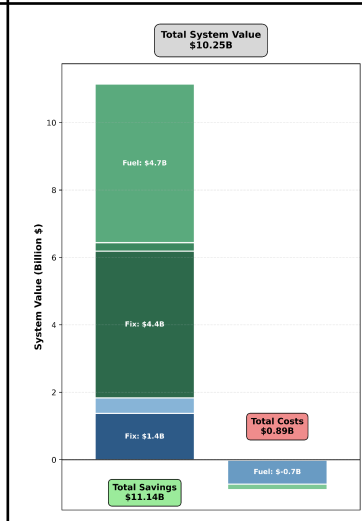
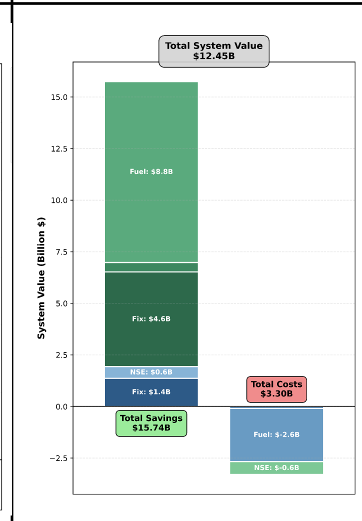
We observe that, as interzonal transmission capacity is introduced between the two systems, the necessary generation capacity *in both zones* also falls, sometimes by more than the capacity of the transmission itself! This implies that the interzonal transmission, if treated myopically in one zone as a “generator,” delivers a much greater capacity value - the quality of being able to reliably meet (near-)peak demand - than the variable resources which it displaces. This basic observation also contributes to our understanding of transmission’s system value: reductions in capacity investment.

We see that, universally, interzonal transmission allows the Midwest to build less solar and more wind, and it substitutes for battery storage in both zones. These are perhaps unsurprising. The geographic arbitrage allowed by transmission - producing energy elsewhere, where it's more abundant - is a close relative of the temporal arbitrage allowed by a battery - producing energy another time, when it's more abundant - and only so much arbitrage is needed to meet demand in the two systems. A less easily explained effect is the stubborn fixity or expansion of Midwestern natural gas capacity when interzonal transmission is introduced, while in the PNW natural gas capacity falls in each case. One contributing factor must be that regional fuel cost multipliers from the EIA are also parameters in these models, and natural gas is approximately 10% cheaper in the Midwest than in the Pacific region. This argument is clearest at its extreme; ceteris paribus, if there were unlimited interzonal transmission, then costs would be minimized by moving all Pacific natural gas capacity to the Midwest and transmitting the power back, as long as the fuel savings outweigh the transmission losses. Given the relatively tame transmission constraints, the fact that the line is not nearly fully utilized during the year, and the modest differences in fuel price, this cannot fully explain the phenomenon of expanding Midwestern gas capacity. Appendix 2 contains some semi-related discussion of Pacific natural gas capacity.

However, we do not need to wonder how transmission contributes to system savings. GenX isolates fixed, variable, and fuel contributions to total system costs, and we may compare these values against reference cases by the same method that we calculated system value. Table 3 contains the system savings breakdown of each case considered in the previous section.

Table 3: System Savings Contributions of Transmission (Medium Demand)



Medium Natural Gas Price, 10 GW	Medium Natural Gas Price, 20 GW	Expensive Natural Gas Price, 10 GW	Expensive Natural Gas Price 20 GW
			

Thus, we need not speculate as to whether or how Midwestern natural gas capacity increases, since, clearly, Midwestern natural gas combustion increases. The size of fuel costs is roughly on the order of the savings on fixed investment and O&M and non-served energy (which, here, is really price-responsive demand). This has especially nasty political implications because, in deregulated power markets, ratepayers will assume the burden of fuel costs via their energy bills, but they won't accumulate the benefits of foregone capacity investment, which will be diffuse and opaque, if they ever even reach the ratepayer. An orthodox economist's solution to this problem of positive but uneven surplus would be a transfer payment from one zone to the other, which could prove another difficult political challenge. This is arguably the origin of the "beneficiaries pay" school of cost allocation in transmission expansion. An actual line such as this one would need to be paid for by some party, who will be compensated in part with the savings that their investment created. To avoid the need for unpalatable ex-post transfer payments, the costs of the investment (which are zero in the model to identify system value, but nonzero in the real world) should be borne by those who will anyway receive the surplus it creates, especially if they're positioned to continually collect that surplus over a long period of time. Thus, this example of long-distance transmission proves to also conceal, under an apparently balanced trade in energy, a lurking cost-allocation problem where nearly all the benefits of the transmission resource accumulate solely to the Pacific zone.

Conclusion

In our analysis of the system impacts of long-distance transmission between the Pacific Northwest and the Midwest, we make several major findings:

- **Significant system value, diminishing returns:** the system-wide returns on interzonal transmission capacity are promising, shaving several billion dollars off of total system costs, but there are quickly diminishing returns as transmission capacity grows as a fraction of peak load. High demand growth improves the case for larger transmission capacities
- **A well-utilized, seasonal transmission asset:** linking the Pacific and Midwestern zones allows for a predictable trade in energy, where the Midwest draws power in the summer and the Pacific draws excess wind power in the winter, which coincidentally results in a strikingly balanced net exchange in energy
- **Capacity reductions, savings on fixed costs:** the remarkably balanced seasonal trade in power enabled by the interzonal transmission capacity allows both zones to significantly decrease their total generation and storage capacities, creating savings for both systems on investment and fixed O&M costs
- **Cost allocation woes:** the lion's share of system value created by the transmission accumulates to the Pacific Northwest, while the net value created

for the Midwest is even negative in some cases due to the increased fuel costs they shoulder. As a practical matter, this information could guide the allocation of transmission costs between the parties involved, suggesting that, ultimately, the Pacific Northwest should bear almost all, and the Midwest almost none, of the cost of the transmission.

There are also several *limitations* to this analysis, which will close out this report:

- **Parametric & Deep Uncertainty:** we ought to be uncertain as to the parameters of these models, even if several demand and fuel forecasts have been considered; consider how quickly power demand forecasts have been revised upwards over the previous handful of years. On that subject, the root causes of a sharp increase in power demand were (and remain) *deeply* uncertain, i.e. that large language models could provoke such a wave of infrastructure investment to bolster sector-wide electricity demand. We should be conscious when reading results that equally unforeseeable events may also radically reshape the value of a given asset
- **Structural Uncertainty and Nature of the Model:** we should be wary of taking capacity expansion model outputs as gospel in determining the costs or benefits of an asset. One glaring simplification at play is that of these "zones" at all, within each of which power flows freely, without losses, across state lines to balance supply and demand, when in reality these regions are also highly fragmented. Another is their isolation; we shouldn't assume that the simple, seasonal patterns we observe hold up when, for instance, a solar-rich zone is also included in the analysis. We should also only expect the central-planner outcomes of a CEM to be literally reproduced if markets are perfectly efficient, without transaction costs or information asymmetries, which is not an accurate description of modern electricity markets. Policymakers should carefully consider how real markets diverge from ideal ones, and how that affects modeled outcomes.
- **Limited Sensitivity Analysis and Modelling Ability:** limited by both the available data inputs and the challenge of controlling uncertainty in the far future, this analysis extended only until 2050, far shorter than the realistic lifespan of a transmission asset built today, which leaves open the question of how to robustly model transmission value far into the future. Additionally, due to my own time constraints, technical issues, and talent for mis-parametrizing models, the scope of the sensitivity analysis in this report was far narrower than even it could have been. With more advanced methodology to identify worthy cases, more compute, and more time, future sensitivity analyses could vary the cost of clean firm resources and long-duration storage, or the timing of the transmission investment and how "well planned" (i.e., how not-myopic) it was, or they could discover entirely new parameters of interest!

Appendix 1: Models and Data

GenX's public GitHub repository can be found here: https://github.com/GenXProject/GenX.jl

And its documentation, including its detailed formulation, can be found here: https://genxproject.github.io/GenX.jl/dev/

See especially:

- Objective function: https://genxproject.github.io/GenX.jl/dev/Model_Concept_Overview/objective_function/
- Multi-stage models: https://genxproject.github.io/GenX.jl/dev/User_Guide/multi_stage_input/
- Power balance constraint: https://genxproject.github.io/GenX.jl/dev/Model_Concept_Overview/power_balance/

PowerGenome's public GitHub repository, which includes its documentation and wiki, as well as all of its data sources, can be found here: github.com/PowerGenome/PowerGenome

I used a completely unmodified form of GenX 0.4.5 to run all cases analyzed in this report.

Appendix 2: Parameters and Repository

To generate my own demand scenarios, I began by having PowerGenome generate sample demand inputs to the model's regional aggregations for the year of 2025, so that it generated a demand profile for both custom regions in 2025 according to the Electrification Futures Study. Then, I created three growth scenarios for each region: drawing on the NWPCC report, I chose a lower value of 1.8%, an upper value of 3.1%, and a middle value as their arithmetic mean, 2.45% as cases for load growth in the Pacific Northwest. Using the MISO forecast, I took the energy growth rates from Figure 7, Page 11 to an exponent of 0.05 to extract annual growth rates of 1.5%, 2.3%, and 2.9% for the portion of the Midwest which was modeled. In both cases, I simply multiplied the entire base demand profile by the appropriate growth rate, and I did not distinguish between energy demand growth and peak load growth.

The clean energy share requirements for both zones in the model were as follows:

	Midwest	PNW
2030	0.17	0.73
2035	0.20	0.81
2040	0.216	0.90
2045	0.233	0.95
2050	0.25	1

For which I initially queried Claude Sonnet 4.5 for information on binding decarbonization policies and deadlines in the states being modeled, and then I chose (somewhat arbitrarily) how to implement these as region-wide clean energy share requirements.

(The reason, as best as I can tell, that the PNW retains natural gas capacity despite having a binding 100% clean energy share is that the constraint is implemented such that clean energy generated within a zone is a fraction of *energy demand* - not generation - within a zone, which creates two loopholes. First, by exporting energy, a region could actually exceed such a clean energy share of 1, for instance by generating 110% of its own demand with 5% from fossil generation, then exporting the additional 10%. Second, which I actually believe to be occurring in this case, is that natural gas can be dispatched to charge batteries, which, when *they* are dispatched, count as clean generation, with a similar ultimate effect.)

The vast majority of the code and scripts for *data visualization, as well as manipulating and modifying PowerGenome outputs* were written by Claude Sonnet 4.5, with my own minor tweaks or bug fixes when necessary. All the conceptualization, experimental design, case generation and evaluation, and analysis of results (except visualization) was performed on my own.

Finally, you can find all my inputs, data, and results and some instructions to reproduce my work at this GitHub Repository: https://github.com/JesseAngrist/MAE573

References

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This paper represents my own work in *accordance* with *University regulations*

Jesse Angrist