Overview of the potential benefits of interconnectors between ERCOTaand WECC networks in a 2050 scenario

Juan Ganzarain, Elias Vignaud

March 2025

1 Abstract

Interconnections play a crucial role in the enhancement of grid flexibility by improving system reliability and reducing operational costs, particularly with high-penetration of renewable energy. This study evaluates the potential benefits of introducing a transmission link between the ERCOT and WECC networks in a 2050 energy landscape. An optimization model is developed to assess the economic and operational impacts of such interconnection. The results demonstrate that a strategically planned interconnection capacity can significantly reduce total system costs by enhancing energy trading opportunities and reducing the need for expensive generation capacity. Additionally, co-optimising generation expansion and interconnection planning leads to substantial cost savings (3.9% of total system cost) compared to a reactive transmission planning approach (0.75%) due to higher installed capacity and a reduced ability to manage renewable integration. Finally, the study provides insights for policymakers and grid planners on the economic viability and optimal design of future interconnection infrastructure in high-renewable power systems.

2 Problem description

The aim of this project is to analyse the impact of inter-connectors between the WECC and ERCOT American power networks through 2 different planning perspectives. This is done in a 2050 scenario to capture the essence of the challenges that will be experienced once renewables have a higher penetration in modern grids. The initial thought was to evaluate their impact on ERCOT, since it is a small network and has an increasing penetration of renewables. This could lead to moments of demand shortage due to their variability and unpredictability, which in turn leads to high prices and system costs as the NSE increases. Nonetheless, the idea of evaluating the value of inter-connectors was expanded to the WECC network, as this will inherently impact both regions.

There are many reasons why inter-connectors between these regions could be essential, whether it is for arbitrage, frequency response support, or more. In this case, USA stakeholders may be willing to engage in financing inter-connectors to make economic profits; this could be generators from a region that might increase their revenue, or customers willing to invest in a long-term price reduction of electricity. Note that there are currently no interconnectors between the ERCOT and WECC networks so the goal of this project is to determine the value of new interconnections between these two. The analysis and discussion will go over the installed capacity, system costs, power flows, nodal prices and line congestion costs.

The main challenges of this project are integrating many concepts seen in class within one program, handling the data, and figuring out if our code is working the way we desire (since we are first timers with Julia). With respect to the concepts, we are integrating a greenfield capacity expansion with an economic dispatch and power flow, and with respect to the data handling, we have had to gather data from different sources and process it in order to simplify our model making assumptions, all of which will be described in the next section.

3 Model description

The following section presents the model used for the analysis in this project. The description includes the model sets, parameters, decision variables, constraints and objective function. As every optimisation model, this analysis includes approximations and has limitations due to lacking constraints, generalisations and more. This does not discredit the validity of the conclusions, but means that the numerical results must be taken as purely indicative.

In reality, the model is split into 3 parts: the first scenario is a greenfield expansion assuming that both regions are separate. In the second scenario the model includes the generation capacity installed in the first scenario as a given (not a decision variable), with a potential interconnection to be added to the system. Finally, scenario 3 is a grienfield expansion, with potential interconnections as a variable to be installed by the optimisation algorithm from the start. Note that the parameter "FLOW" and the decision variable "CAP_FLOW" are not included for the scenario 2. Input data values were mainly collected from the Github repository [1] and from the "Projected Costs of Generating Electricity, 2020 edition" issued by the IEA [2].

3.1 Introduction

The input data consists of predicted demand for the WECC region in 2050, sourced from the "WECC _6zone_2050" folder. However, since 2050 demand projections for ERCOT were unavailable, recent demand data was taken from the "ercot_500kV" folder. To estimate 2050 demand for ERCOT, each demand value was multiplied by 1.9. This assumption is based on GitHub data indicating that WECC demand is projected to increase by a factor of 1.9. Additionally, various sources, including [3], predict that energy demand in Texas will approximately double over the next 25 years, supporting the applied scaling factor. The data was shifted by 2 hours to account for the timezone differences. Note that the data is missing a day, for which there are 8736 datapoints and not 8760.

The model assumes a greenfield expansion for generation, with four available generation types per region: natural gas with carbon capture and storage, nuclear, wind, and solar. Additionally, the model incorporates battery and hydro storage as potential options in both regions. Recognizing the inevitable role of electric vehicles (EVs) in a 2050 power grid, the model includes EVs as a free resource, with their capacity constrained by the "WECC_6zone_2050" predicted capacity. Given that EVs remain stationary for over 90% of the time and have short driving durations, they are assumed to function as 5-hour batteries within the system. Capital expenditure (CAPEX) values were sourced from the International Energy Agency (IEA) report, while operation and maintenance (O&M) costs were obtained from GitHub data.

Regarding the interconnection costs, the project does not assume a traditional transmission line-type interconnector but rather a converter station-only approach. Project cost estimates for this converter station were based on the Adelanto Converter Station [4] and adjusted for inflation. Finally, the Value of Lost Load (VOLL) was set at $35,000/MWh, using [5] as a reference.

The model has many limitations, but is simplified for the scope and project timeline. Limitations include:
- System represented as one node per network
- Greenfield expansion instead of brownfield expansion
- Potential outdated costs for 2050 and lack of technology development evaluation
- Lack of generation diversity
- Lack of ramping constraints (only for nuclear as it is an essential feature)
- Incorporation of EVs as a 5 hour battery
- Simplified transmission model

3.2 Sets

The following list presents all the sets used in the model to index the parameters and decision variables according to their properties:

G, the set of generator plant IDs [1 : 8],

T, the set of generator types [ng_ccs_new_ERCOT, . . . , nuclear_ERCOT],

STOR, the set of storage plant IDs [1 : 6],

H, the set of hours in a year (excluding one day from GitHub data) [1 : 8736],

N, the set of system nodes [1 : 2].

3.3 Parameters

$\mathbf{CHARGE_{s,h}}$, the charge (in MW) of storage provider s in each hour h,

$\mathbf{DISCHARGE_{s,h}}$, the discharge (in MW) of storage provider s in each hour h,

$\mathbf{SOC_{s,h}}$, the state of charge (MWh) of storage provider s in each hour h,

$\mathbf{FLOW_{l,h}}$, the flow (in MW) of each line l in each hour h,

available_capacity, the thermal limit (in MW) of each line l,

$\mathbf{Fixed\_Cost_g}$, the capital expenditure (in \$/MW) of each generator g,

$\mathbf{c1_g}$, the variable O&M cost (in \$/MW) of each generator g,

$\mathbf{c0_g}$, the fixed O&M cost (in \$) of each generator g,

$\mathbf{Fixed\_Cost_s}$, the capital expenditure (in \$/MW) of each storage provider s,

$\mathbf{c0_s}$, the fixed O&M cost (in \$) of each storage provider s,

Cost, the capital expenditure (in \$/MW) of each line l,

VOLL, the opportunity cost or penalty incurred for involuntary non-served energy (in \$/MWh),

$\mathbf{A_n}$, incidence matrix of all lines, l, and all nodes, n,,

$\mathbf{Demand_{h,n}}$, the demand in each hour h at each node n,

$\mathbf{Eff_s}$, the efficiency in converting energy of storage providers s,

$\mathbf{SOCmax_s}$, the maximum state of charge of storage providers s.

3.4 Decision variables

$\mathbf{CAP_g}$, the capacity (in MW) built for each generator g,

$\mathbf{GEN_{g,h}}$, the generation (in MWh) produced by each generator g in each hour h,

$\mathbf{CAP\_STOR_s}$, the capacity (in MWh) built for each storage provider s,

CAP_FLOW, the capacity (in MW) built for each line l,

$\mathbf{NSE_{h,n}}$, the quantity of involuntarily curtailed demand (in MWh) in each hour h at each node n.

3.5 Constraints

$$\mathrm{CAP}_g \geq 0, \quad \forall g \in G \tag{1}$$

$$\mathrm{GEN}_{g,h} \geq 0, \quad \forall g \in G, \forall h \in H \tag{2}$$

$$\mathrm{NSE}_{h,n} \geq 0, \quad \forall h \in H, \forall n \in N \tag{3}$$

$$\mathrm{CAP\_STOR}_s \geq 0, \quad \forall s \in \mathrm{STOR} \tag{4}$$

$$\mathrm{DISCHARGE}_{s,h} \geq 0, \quad \forall s \in \mathrm{STOR}, \forall h \in H \tag{5}$$

$$\mathrm{CHARGE}_{s,h} \geq 0, \quad \forall s \in \mathrm{STOR}, \forall h \in H \tag{6}$$

$$\mathrm{SOC}_{s,h} \geq 0, \quad \forall s \in \mathrm{STOR}, \forall h \in H \tag{7}$$

$$0 \leq \mathrm{CAP\_FLOW} \leq \mathrm{available\_capacity}, \quad \forall l \in L \tag{8}$$

$$-\mathrm{CAP\_FLOW} \leq \mathrm{FLOW}_h \leq \mathrm{CAP\_FLOW}, \quad \forall l \in L, h \in H \tag{9}$$

$$\mathrm{GEN}_{g,h} \leq \mathrm{Pmax}_g \cdot \mathrm{cf}_{h,T_g}, \quad \forall g \in G, h \in H \tag{10}$$

$$\mathrm{GEN}_{g,h} = 0.5 \cdot \mathrm{CAP}_g, \quad \forall g \in G, h \in H, \text{ if } \mathrm{type}_g = \mathrm{nuclear} \tag{11}$$

$$0.95 \cdot \mathrm{GEN}_{g,h-1} \leq \mathrm{GEN}_{g,h} \leq 1.05 \cdot \mathrm{GEN}_{g,h-1} \quad \forall g \in G, h \in H, \text{ if } \mathrm{type}_g = \mathrm{nuclear} \tag{12}$$

$$\sum_{g \in G} \mathrm{GEN}_{g,h} + \sum_{s \in \mathrm{STOR}} (\mathrm{DISCHARGE}_{s,h} - \mathrm{CHARGE}_{s,h})$$

$$+ \mathrm{NSE}_{h,n} + A_n \mathrm{FLOW}_h = \mathrm{demand}_{h,n}, \quad \forall h \in H, n \in N \tag{13}$$

$$\mathrm{GEN}_{g,h} \leq \mathrm{CAP}_g \cdot \mathrm{cf}_{h,T_g}, \quad \forall g \in G, h \in H \tag{14}$$

$$\mathrm{SOC}_{s,h} = \mathrm{SOC}_{s,h-1} + \mathrm{Eff}_s \cdot \mathrm{CHARGE}_{s,h} - \frac{\mathrm{DISCHARGE}_{s,h}}{\mathrm{Eff}_s}, \quad \forall s \in \mathrm{STOR}, h \in H \tag{15}$$

$$\mathrm{SOC}_{s,h} \leq \mathrm{CAP\_STOR}_s, \quad \forall s \in \mathrm{STOR}, h \in H \tag{16}$$

$$\mathrm{CHARGE}_{s,1} = 0, \quad \forall s \in \mathrm{STOR} \tag{17}$$

$$\mathrm{DISCHARGE}_{s,1} = 0, \quad \forall s \in \mathrm{STOR} \tag{18}$$

$$\mathrm{CAP\_STOR}_s \leq \mathrm{SOCmax}_s, \quad \forall s \in \mathrm{STOR} \tag{19}$$

$$\mathrm{DISCHARGE}_{s,h} \leq \frac{\mathrm{CAP\_STOR}_s}{5}, \quad \forall s \in \mathrm{STOR}, h \in H \tag{20}$$

$$\mathrm{CHARGE}_{s,h} \leq \frac{\mathrm{CAP\_STOR}_s}{5}, \quad \forall s \in \mathrm{STOR}, h \in H \tag{21}$$

3.6 Objective Function

$$\begin{aligned} \min \quad & \sum_{g \in G} \Big((\mathrm{Fixed\_Cost}_g + c0_g) \cdot \mathrm{CAP}_g + \sum_{h \in H} c1_g \cdot \mathrm{GEN}_{g,h} \Big) \\ & + \sum_{s \in \mathrm{STOR}} (\mathrm{Fixed\_Cost}_s + c0_s) \cdot \mathrm{CAP\_STOR}_s \\ & + \mathrm{line\_cost} \cdot \mathrm{CAP\_FLOW} \\ & + \sum_{h \in H} \sum_{n \in N} \mathrm{VOLL} \cdot \mathrm{NSE}_{h,n} \end{aligned} \tag{22}$$

4 Results and key findings

4.1 Scenario 1: Separate networks

In the first scenario, the model was run without allowing power flow between WECC and ERCOT (i.e., no interconnectors). Table 1 presents the installed generation capacity for both regions, along with their corresponding annuitized CAPex and annual O&M costs. Since the total Non-Served Energy (NSE) was 0 MWh, it does not contribute to the overall system cost. Consequently, the total cost (ie. representing the objective function) is reported in Table 1 as $128,139 million.

This scheduling serves as a baseline to assess how different interconnection planning approaches impact the system. Table 1 reveals that the model opted not to deploy wind power in WECC likely due to low resource availability. The solar power is only installed in WECC since it is highly correlated to the demand distribution, while it isn't as much in ERCOT (this applies for all 3 scenarios). When comparing "predictable" power sources, the model significantly favors nuclear over natural gas with CCS, primarily due to its lower cost (despite it's ramping constraints).

Type	Installed capacity (MW)	CAPex (M$)	O&M cost (M$)	Total Cost (M$)
ng_ccs_WECC	18,989	4,357	1,693	6,050
nuclear_WECC	137,835	53,360	8,628	61,988
wind_WECC	0	0	0	0
solar_WECC	153,656	13,732	0	13,732
ng_ccs_ERCOT	15,446	3,544	1,395	4,940
wind_ERCOT	16,674	2,628	0	2,628
solar_ERCOT	0	0	0	0
nuclear_ERCOT	86,275	33,400	5,401	38,801
Total	**428,874**	**111,022**	**17,117**	**128,139**

Table 1: Energy generation cost and capacity by type scenario 1.

Table 2 illustrates the storage capacity within the system. As mentioned, EVs were integrated as 5-hour batteries at no cost. Due to their high cost, the model does not install additional batteries or hydro storage, even in scenarios where EVs are removed. Assuming that consumers purchase their own EVs and the O&M cost is negligible, the contribution of storage to the total cost of the system remains zero (and this for all 3 scenarios, for which this table applied for all 3)

Type	Installed capacity (MWh)	CAPex (M$)	O&M cost (M$)	Total Cost (M$)
batteries_WECC	0	0	0	0
hydro_storage_WECC	0	0	0	0
EV_shift_WECC	665,900	0	0	0
batteries_WECC	0	0	0	0
hydro_storage_WECC	0	0	0	0
EV_shift_WECC	266,360	0	0	0

Table 2: Energy storage capacity and costs by type scenario 1,2 and 3.

Figure 1 shows the cumulative distribution functions (CDFs) of nodal prices in both regions. To improve readability, the graph has been truncated at a probability of 0.9786, excluding peaking prices that occur during periods where the inelastic demand is high. The average nodal prices are \$51.852/MWh in WECC and \$51.862/MWh in ERCOT. This close alignment in prices is primarily due to the similarity in the proposed generators across both regions, despite differences in demand curves. Since these generators operate at comparable costs, price variations remain minimal.

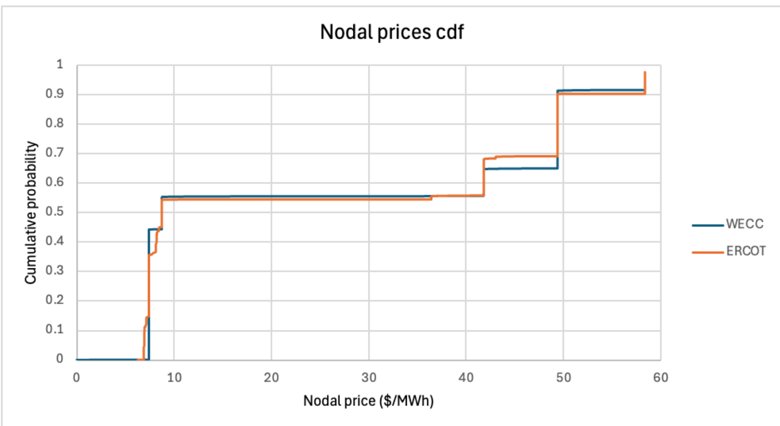

Figure 1: Nodal Price CDF for WECC and ERCOT scenario 1

4.2 Secnario 2: Interconnection proposal after greenfield expansion (reactive approach)

Table 3 shows the new costs for the system now that an interconnection between ERCOT and WECC is allowed. Since this method first optimises the generation, and then considers potential flow as a posterior decision variable, the installed acpacity and CAPex are identical to Table 2. The main differences are the addition of 13.762 GW of transmission between the two systems, costing $266 million; and the reduction in O&M operation costs by $1,219 million (notably due to reduction of natural gas power). In the same fashion as for scenario 1, the NSE and storage costs are null. This yields a total system cost reduction of $955 million (0.75% savings).

Type	Installed Capacity (MW)	CAPex (M$)	O&M Cost (M$)	Total Cost (M$)
ng_ccs_WECC	18,989	4,357	955	5,312
nuclear_WECC	137,835	53,360	8,713	62,073
wind_WECC	0	0	0	0
solar_WECC	153,656	13,732	0	13,732
ng_ccs_ERCOT	15,446	3,544	742	4,286
wind_ERCOT	16,674	2,628	0	2,628
solar_ERCOT	0	0	0	0
nuclear_ERCOT	86,275	33,400	5,488	38,888
Transmission	13,763	266	0	266
Total	**428,874**	**111,288**	**15,898**	**127,186**

Table 3: Energy generation and transmission cost and capacity by type scenario 2.

Figure 2 shows the cumulative distribution function of the nodal prices in both regions. These look quite similar to scenario 1, but in this case no outliers were taken out. This yields an much lower average nodal price (similar to scenario 1 without outliers) of 26.476 $/MWh in WECC and 26.002$/MWh in ERCOT. The issue with these costs is that the only way to set our installed capacity identical to scenario 1, an additional constraint has been added. This makes it impossible for JuMP to retrieve the nodal prices including the fixed costs at peaking prices.

Finally, the total flow through the interconnector is 87.17 GWh; 44.12 GWh from WECC to ERCOT, and 43.05 GWh from ERCOT to WECC. Nonetheless, these flows are sometimes constrained by the maximum capacity of the interconnector, yielding differences in nodal prices between the regions, and a total congestion cost of $266 million.

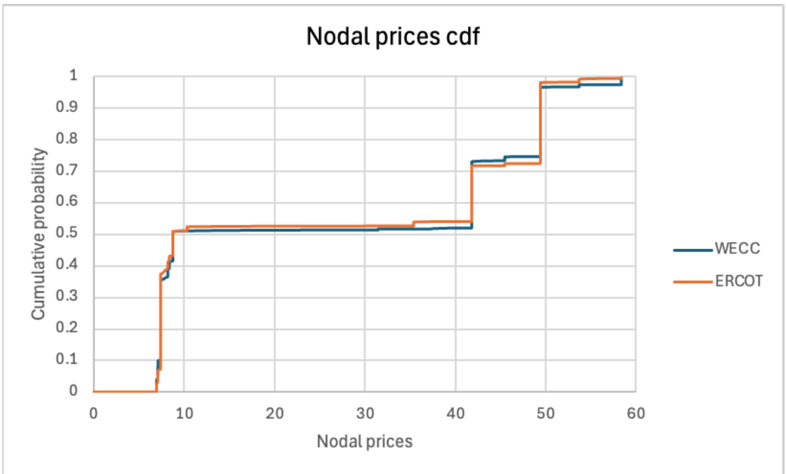

Figure 2: Nodal Price CDF for WECC and ERCOT with 2050 scenario 2

4.3 Scenario 3: Co-optmimising greenfield capacity expansion and interconnection

The system costs for Scenario 3, which introduces co-optimization of both transmission and a greenfield expansion, are presented in Table 4. This new planning approach enables greater transmission capacity between the ERCOT and WECC networks, with 27.7 GW installed (twice the capacity of Scenario 2). Furthermore, while the total installed generation capacity is higher than in Scenario 2, it includes a larger share of renewable sources, which are more cost-effective and partially replace expensive generation sources such as nuclear and natural gas. The most notable difference is the wind power in ERCOT, going from under 17 GW installed to over 83 GW while other generation sources only vary slightly. As a result, total investment expenditures are reduced.

The increased transmission capacity between the two regions enhances the integration of intermittent renewable energy, minimizing curtailment and enabling the deployment of more renewable capacity. Once again, the NSE and storage costs are null. These optimisations lead to a significantly lower overall system cost of $123.183B, yielding savings of $5B compared to scenario 2 (3.9% savings).

Type	Installed Capacity (MW)	CAPex (M$)	O&M Cost (M$)	Total Cost (M$)
ng_ccs_WECC	11,665	2,677	1,069	3,746
nuclear_WECC	128,171	49,619	8,024	57,643
wind_WECC	0	0	0	0
solar_WECC	189,371	16,924	0	16,924
ng_ccs_ERCOT	17,383	3,989	1,678	5,667
wind_ERCOT	83,825	13,214	0	13,214
solar_ERCOT	0	0	0	0
nuclear_new_ERCOT	56,801	21,990	3,466	25,456
Transmission	27,655	534	0	0
Total	**463,529**	**108,946**	**14,238**	**123,183**

Table 4: Energy generation and transmission cost and capacity by type scenario 3.

Figure 3 presents the cumulative distribution function (CDF) of nodal prices in both regions. To enhance clarity, values corresponding to probabilities beyond 0.9812 have been excluded, as they represent peaking prices (at times when the inelastic demand is high). The increase in transmission capacity between the two regions effectively reduces congestion on the interconnector, leading to price convergence across both time zones. As a result, the new average nodal price is $51.852/MWh. Annually, the interconnector facilitates an energy flow of 72.5 GWh from WECC to ERCOT and 88.25 GWh from ERCOT to WECC. However, as the system becomes increasingly reliant on this expanded transmission capacity to maintain supply-demand balance, congestion costs also double, reaching $534 million.

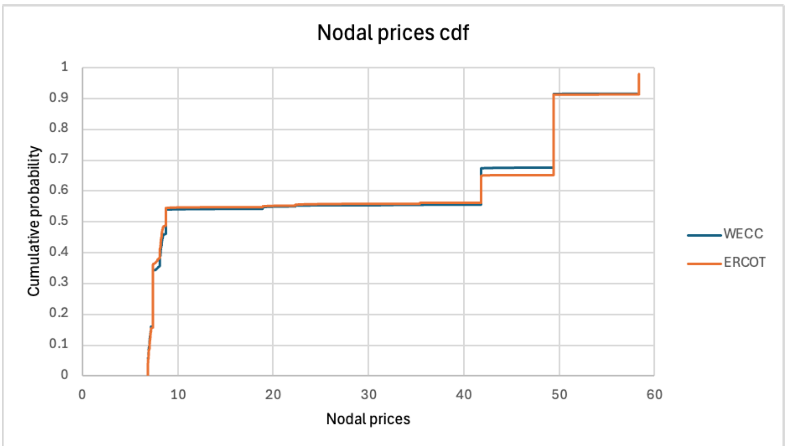

Figure 3: Nodal Price CDF for WECC and ERCOT with 2050 scenario 3

5 Conclusion

Table 5 shows the comparison of the metric for Scenarios 1,2 and 3. As expected, the case without any proposed transmission is the most expensive. Although there are no transmission costs, the CAPex is higher than in Scenario 3, and the O&M costs are the highest due to the reduced ability to exploit cheap sources from the neighboring region at any given point. Scenario 2 (reactive transmission proposal after the optimisation of generation) saves $955 million (0.75%) of the total cost. This is because the model decides to install transmission and exploit the cheaper generating sources better through the system. This results in O&M cost savings, and the resultant total system cost reduction. Finally, scenario 3 (co-optimisation of generation and transmission) yields the cheapest cost. This is because the model anticipates different potential generation mixes for the future together with potential transmission. This not only saves in O&M costs, but also resuts in a considerable reduction in CAPex. This yields a cost reduction of $5 billion (3.9%).

These system costs lead to two key conclusions. First, incorporating transmission between ERCOT and WECC can significantly reduce total system costs, ultimately enhancing social welfare. Second, considering transmission at the early stages of the planning process leads to substantially lower costs compared to introducing it at later stages.

Scenario	Gen. CAPex (M$)	O&M (M$)	Transmission/Congestion (M$)	Total cost (M$)
Scenario 1	111,022	17,117	0	128,139
Scenario 2	111,022	15,897	266	127,186
Scenario 3	108,412	14,238	534	123,183

Table 5: Comparison of costs across different scenarios.

Another notable point is that Transmission and Congestion costs are presented in the same column because they are identical in all scenarios. This suggests that the optimization algorithm installs transmission capacity up to the point where the congestion cost equals the investment cost. When the marginal congestion cost is lower than the transmission cost, the algorithm chooses to invest in additional capacity. Conversely, when the congestion cost exceeds the transmission cost, further investment is not economically justified. As a result, the optimization process naturally stops when these two costs are equal.

Table 6 presents the payments per regions and system costs for scenarios 1 and 3. Note that scenario 2 was excluded from this analysis since the separate optimisation of generation and transmission required additional constraints, impeding the return of accurate nodal prices on Julia (investment costs are not taken into account). The first thing to note is that in the eyes of the consumer, both ERCOT and WECC will reduce their payments in the case that an interconnection is built. The second thing is the difference in total payments and system costs. The difference in payments between both scenarios yield $4.59 billion, while the reduction in system costs is of $4.95 billion. The difference between the two is explained by the congestion costs; $534 million (minus differences due to numerical precision - this accounts for less than 0.1% of the total system cost).

Scenario	WECC payments (M$)	ERCOT payments (M$)	Total payments (M$)	System cost (M$)
Scenario 1	83,801	47,218	131,019	128,139
Scenario 3	82,734	43,692	126,428	123,184
Difference	-1,067	-3,526	-4,591	-4,955

Table 6: Comparison of Payments and System Costs Across Scenarios

Having observed the financial benefits of a potential interconnection between these two regions, the question remains: who would be willing to pay for it?

From a generator's perspective, a high-level analysis suggests that generators in both regions would be reluctant to fund this transmission line. The total installed capacity would decrease, and their total revenues would be reduced by $4.6 billion. For consumers, however, the interconnection might be an attractive investment. The reduction in total payments directly benefits them, as it lowers their electricity costs. Finally, the system operator should see a strong incentive to support this investment. The operator's primary responsibility is to maintain a functional and cost-efficient system. In this case, since the system integrates a large fleet of EVs, the NSE remains null in both scenarios, indicating a highly functional system. Moreover, the interconnection helps reduce overall costs, making it a beneficial investment from a system-wide perspective.

6 Sources

[1] https://github.com/Power-Systems-Optimization-Course/power-systems-optimization/tree/master/Project

[2] https://iea.blob.core.windows.net/assets/ae17da3d-e8a5-4163-a3ec-2e6fb0b5677d/Projected-Costs-of-Generating-Electricity-2020.pdf

[3] https://texas2036.org/posts/a-first-look-at-our-new-future-of-texas-energy-dashboard/

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[5] https://www.brattle.com/wp-content/uploads/2024/09/Value-of-Lost-Load-Study-for-the-ERCOT-Region.pdf