Sharing the benefits of a new pipeline in Baja California using the Shapley value

Lilia Garcia Manrique*

Abstract

Baja California is highly dependent on natural gas and electricity imports. A new natural gas pipeline between the US and Mexico can reduce its vulnerability. Using the Shapley value, I calculate how the allocation of profits of the electricity market changes. I also analyse how carbon taxes and a mortality social cost of carbon reallocate profits for producers. Results show that if the cost of a new pipeline is distributed depending on the generator's capacity, there is a unique and fair distribution of benefits. When carbon taxes and mortality SCC are included, geothermal and intermittent producers get more benefits. Combined cycle generators increase their share of the profits during high demand periods even under a high carbon tax scenario.

Keywords: Cooperative markets, Shapley value, Electricity markets, Mexico, Dispatch model.

JEL Classification: C71, F18, H23, Q37, Q41

*University of Calgary. Mailing address: 118 Earth Science, University of Calgary, 2500 University Drive NW, Alberta, Canada, T2N 1N4. Email: l.garciamanrique@ucalgary.ca, phone: +447561737362

1 Introduction

Baja California has two main problems: insufficient electricity production and total dependency on imported natural gas from the US. There are different possible solutions that the government and the independent system operator, the National Centre for Energy Control (Centro Nacional de Control de Energía, CENACE), have proposed. Since the liberalization of the market in 2016, CENACE has been proposing an interconnection with the National Interconnected System (SIN) in Mexico. The proposal never moved to an active state, and the last two annual reports by CENACE no longer mention this project.

On the coast of Ensenada, there is a liquefied natural gas (LNG) terminal. The high demand for natural gas makes it a key player in the market. Since the pipelines are bidirectional, they can import gas from the US or send natural gas from the LNG terminal. Therefore, gas can go from the terminal in Ensenada to Mexicali and Tijuana, cities with the highest demand for gas. During peak energy demand seasons, the LNG terminal sets the gas prices in the market. Although prices at the border can be as low as \$2 USD/million British thermal units (MMBtu) the LNG terminal can set them as high as \$12.50 USD/MMBtu (Lenton, 2023). Figure 1 shows the gas ducts, power generators in Baja California, gas interconnectors, and the LNG terminal.

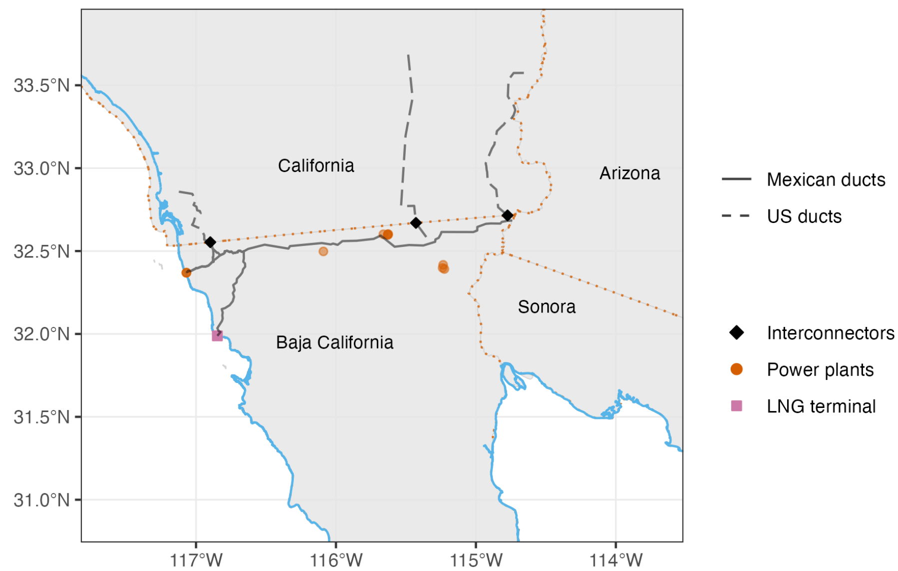
Considering infrastructure costs, it is cheaper to improve the natural gas supply. Compared with the estimated cost of a new interconnection between Baja California and SIN, a new pipeline is considerably less expensive. The calculated cost for the interconnector was \$5,155 million dollars in 2018 (SENER, 2018) whereas the cost of the longest pipeline between US and Rosarito cost \$275 million dollars (SENER, 2019). Although electricity production is the highest natural gas consumer, manufacturers rely highly on natural gas (Lenton, 2023).

IEnova made a joint investment with Sempra for the first part of a pipeline connecting Arizona with the LNG terminal. Given the high demand in Baja California, and the high dependency on electricity production in natural gas, it is natural to assume there will be an interest of the energy generators to invest in the new pipeline connecting with the LNG terminal. In this paper, I explore how a new pipeline can shift market power in the electricity market in Baja California.

Mexico has a commitment to reduce by 2030 22% of its global greenhouse emissions (GHGs). The electricity sector is a major contributor (21.7%) to GHG emissions. Baja California has a proposed carbon tax of \$9.98 USD/tCO2e where 20% of those earnings will be part of the State revenue and 80% will be to foster sustainable policies (Acuña Ramírez, 2022).

Besides, California can also enforce a border carbon adjustment. Although

Figure 1: Energy infrastructure in Baja California and California



Notes: US ducts from East to West are North Baja Pipeline Co, Southern California Gas Co (SoCalGas), and San Diego Gas & Electric. Interconnectors from East to West are Los Algodones, Mexicali, and Tijuana. There are two Mexican ducts, the main one, Gasoducto Rosarito and the small one, non-connected to the rest of the grid. There are 12 power plants plotted; the intensity in the colour of the dots is the density of plants in the area.

since 2014, the California cap and trade programme has considered including electricity imports, there hasn't been strong enforcement; therefore, a border carbon adjustment is foreseen (Pauer, 2018). As part of considering stronger clean energy enforcement, one of the newest energy exporters is a wind farm with a capacity of 157 MW, Energia Sierra Juarez, as outlined in Table 1

The energy sector is also a source of air pollution in the area. Even though a carbon tax accounts for negative externalities, Carleton et al. (2022) discuss how accounting for health costs can increase the cost of a carbon tax. They propose a two-level social cost of carbon, under medium and high GHG emissions scenarios. Gomez-Rios and Galvez-Cruz (2021) explain how including an externality cost to a levelized energy cost can help account for the negative effects of electricity production.

Assessing a new pipeline in Baja California should account for carbon taxes or a more inclusive cost like the mortality social cost of carbon (SCC) (Carleton et al., 2022). The research question is how, under a new pipeline, cost and benefits of the market can be allocated in the fairest possible way. The analysis includes the calculation of scenarios under carbon taxes and a mortality SCC. For this purpose, I calculate the Shapley value, which provides a fair and unique allocation of market benefits. The Shapley value for each energy producer shows the benefits each one receives under each assumption in the market.

Results show that the higher the tax or SCC, combined cycle producers have a lower share of the market's profit. Nevertheless, even when the taxes and SCC are high, combined cycle producers take advantage of their high installed capacity during peak demand periods and get a higher share of benefits. When a pipeline cost is included, the Shapley value is unique, but depending on how the cost is allocated between producers, it can result in a non-optimal solution.

In the next Section 2, I review the electricity market in Mexico and its configuration given the natural gas dependency. In Section 3, I discuss the Shapley value. I present the levelized costs and the merit order curve model in Section 4. Section 5 presents a detailed description and analysis of the results under different scenarios using four days. Finally, in Section 6, I present the conclusions and policy implications of the paper.

2 The electricity and gas market in Mexico

Baja California is an isolated energy market. The electricity and natural gas infrastructure are two independent grids. Both systems are only connected to the Western Electricity Coordinating Council (WECC)[1]. There are two interconnectors for electricity, one in Tijuana and the other in Mexicali. For natural gas, there are three interconnections: Tijuana, Mexicali, and Los Algodones.

The existing gas infrastructure was built in three main sections[2]. The first part was finished in 2000 with a capacity of 300 million cubic feet a day (MMcf/d) and 36 kilometres (km) length by connecting San Diego to Rosarito. In 2002, the longest section of the pipeline was finished with a capacity of 1434 MMcf/d and a length of 302 km; this section runs West to East and is connected to Arizona. (SENER, 2019). Finally, in 2008, a liquefied natural gas (LNG) terminal was built in Ensenada with a capacity for processing and regasifying 1080 MMcf/d (Global Energy Monitor, 2023).

Compared to other projects in Mexico, all the natural gas infrastructure in Baja California is run by private companies and under the regulation of the

[1]WECC covers four main areas: Northwest Power Pool Area (NWPP), Rocky Mountain Power Area (RMPA), Arizona-New Mexico-Southern Nevada Power Area (AZ/NM/SNV), and California-Mexico Power Area (CA/MX)

[2]In 2003, a small connection of 2 km with 9 MMcf/d capacity was built. Conceptos Energeticos owns it and is mainly for supplying gas to Toyota Motors manufacturing plant (Muñoz Andrade et al., 2020).

Regulatory Energy Commission (Comisión Reguladora de Energía, CRE). All participants in the market are allowed to use the duct capacity, network, and storage since the market operates under open access. IEnova owns the largest duct, and it is mainly for covering the gas supply of the power plant Presidente Juarez. This generator is the main energy supplier to the manufacturing sector in the State (Muñoz Andrade et al., 2020).

In 2019, Baja California consumed 340 million cubic feet a day of natural gas. The main sector demanding natural gas is the electricity market, which consumes 93% of it. In the State, there is no natural gas production; therefore, it relies completely on imports from the United States (Muñoz Andrade et al., 2020). Given that the electricity market demands most of the available natural gas, manufacturing plants are left with a significantly reduced supply. For example, a glass-making plant stated that in 2022, from June 1 to September 30, it didn't receive any gas supply (Lenton, 2023).

When the natural gas market boomed in the early 2000s, gas prices were low, creating an incentive to invest in natural gas power production. The profitability of natural gas created a push-over effect for the geothermal plant Cerro Prieto. It is calculated that since 2011, capacity declined 50% due to a lack of investment (Muñoz Andrade et al., 2020), which was reallocated to gas producers. Although Cerro Prieto relies on geothermal energy that can be accounted as cost-free, its maintenance costs are higher compared to a combined cycle power plant[3].

With no gas production and high electricity demand due to hot summers and a strong manufacturing sector, Baja California is vulnerable. In terms of energy production, there is a high concentration in the market. In 2018, the Herfindahl and Hirschman index[4] (HHI) was $2,330$, and in 2019, there was a new producer that reduced the HHI to 2256 (ESTA International, 2019). In 2020, one of the main generators increased its capacity, which made the HHI increase to $4,548$, an increase of 102% [5] (ESTA International, 2021). As shown in Table 1 producers with the highest capacity are natural gas-reliant, which also increases the vulnerability of the energy system.

For the gas market, the LNG terminal is the main player. Its power is reflected in another aspect of the gas market; for example, in 2016, Baja California had the highest levels of LP gas in storage, with 33% of the total storage of the Mexican Petroleum Company (Petróleos Mexicanos, PEMEX). This was the

[3] A combined cycle plant is a power station that generates energy by two simultaneous processes. There is a combustion process generating energy and steam. The steam is directed to the second process, activating the second stage to generate energy.

[4] A HHI below 100 indicates a highly competitive industry, below 1500 unconcerned status, between 1,500 and 2,500 moderate concentration, and above 2,500 high concentration.

[5] The same is true for the National Interconnected System (Sistema Interconectado Nacional, SIN). Large producers have the strongest swing in the market, and it is hard for the market operator to detect these unbalances due to information asymmetry (McRae, 2019).

biggest PEMEX reservoir in the country (Madrid Ayala et al., 2018).

In Table 1, I list all energy producers in Baja California. Combined cycle plants are those with the highest capacity. In 2018, with a total installed capacity of 3211 megawatts (MW), Baja California imported 265 gigawatts (GW). The month with the highest imports was August, with 137 GW. On Table 1 "La Rosita" and "Termoeléctrica de Mexicali" are identified as only-exports plants, therefore at least 945 MW are produced in the State only for export (ESTA International, 2019).

Table 1: Energy generator in Baja California

Name	Technology	Owner	Capacity (MW)	Location	Regulatory framework
EAX-Gen	Combined cycle	SAAVI	165	Mexicali	Generator
Baja California III	Combined cycle	Iberdrola	324	Ensenada	Generator
Cerro Prieto	Geothermal	CFE	340	Mexicali	Generator
Turbo-gas Tijuana	Turbogas	CFE	345	Tijuana	Generator
La Rosita	Combined cycle	SAAVI	320	Mexicali	Export
La Rosita	Combined cycle	SAAVI	489	Mexicali	Generator
Termoeléctrica de Mexicali	Combined cycle	IEnova	625	Mexicali	Export
Presidente Juárez	Combined cycle	CFE	1063	Rosarito	Generator
Cerro Prieto Solar	Solar photovoltaic	CFE	5	Mexicali	Generator
Parque Eólico Rumorosa	Wind	Government of Baja California	10	Tecate	Selfsupply
Rumorosa Solar	Solar photovoltaic	IEnova	41	Mexicali	Generator
Energia Sierra de Juarez	Wind	IEnova	157	Tecate	Export
CI Cedros	Internal combustion	CFE	1	Ensenada	Generator
Turbo-gas Ciprés	Turbogas	CFE	28	Ensenada	Peaker
Energía Costa Azul	Internal combustion	IEnova	38.5	Ensenada	Selfsupply
Turbo-gas Mexicali	Turbogas	CFE	62	Mexicali	Peaker
EAX-AA	Combined cycle	SAAVI	80	Mexicali	Selfsupply

Notes: With information from Muñoz Andrade et al. (2020)

The LNG terminal started operations in 2008, and its port allows for carrier ships containing up to 220,000 m^3 of LNG. IEnova, the owner of the LNG terminal, announced in 2020 plans to include an exporting terminal. This terminal will be able to export natural gas from the Permian Basin to the Asian market (Global Energy Monitor, 2023). As part of this project, a new pipeline was built near Ehrenberg, Arizona, finishing in Los Algodones. It is a 138 km long project, estimated that by 2025, it will connect to the LNG terminal (TC Energy, 2023). This new pipeline will cross Arizona, California, and Baja California. This will be the longest pipeline in the area. It will supply to all crossing States and the LNG terminal, allowing a higher volume of LNG exports (Lenton, 2023).

2.1 Literature review

Mexico has a high dependency on natural gas imports from the US. In 2021, 70% of the total consumption of natural gas was imported from the US (Estrada et al., 2022). From the whole imported volume 76% was sent by pipelines (Ober

& Dyl, 2021). And even though there has been an increase of 14% in natural gas production in Mexico, on June 2023, imports reached a new historical level of 6.8 billion cubic feet per day (Bcf/d) (EIA, 2023). At the same time, the increase in energy production was one of the main drivers for the increase in imports. From 2000 to 2019, 96% of the increase in gas demand was explained by the increase in demand from energy production (Estrada et al., 2022).

Electricity production is the main driver of natural gas imports. 60.6% of the electricity is produced using natural gas. Mexican gas only covers 30.3% of this demand; the other 69.7% is covered by imports (Estrada et al., 2022). The high dependency on natural gas makes it the main driver of electricity prices; in the short and long run, natural gas determines electricity prices (Bernal et al., 2019). Due to the market configuration, the biggest energy producers are natural-gas-reliant; therefore, the biggest producers are the ones setting prices and having the most market power (McRae, 2019).

The United States-Mexico-Canada Trade Agreement (USMCA)[6] has also fostered the dependency on imported gas. The USMCA considers zero tariffs for energy products among the three countries, and there is an automatic approval for US liquified natural gas exports (Sarmiento et al., 2021).

The configuration of the gas market in Mexico has always been pegged to the US market. Even before the natural gas boom, the gas price in Mexico was determined by the Southwest of the US. It allowed Mexican producer PEMEX, to reduce production or sell it to subsidiaries, increasing domestic prices (Sarmiento et al., 2021).

The changes in the natural gas market have modified the main scope of the market. Meritet and Baltierra (2008) discussed the reduction of cost of using LNG terminals compared with pipelines and how the terminals will help the market to reduce gas prices. Although it correctly forecasted a reduction in pressure for the US gas market, the authors assumed the LNG terminal could have meant lower gas prices in Baja California. As a key player and controlling a considerable market share, the LNG in Baja California had increased prices.

In a competitive market, the costs of electricity generators will change the benefits of the market. Casolino et al. (2015) show for Italy, combined cycle plants get most of the market benefit if they are highly efficient regardless of their output power. Whereas under an oligopoly, producers minimize costs at full power, which means that the global efficiency is at full load. Therefore, under a competitive market, the least pollutant plant will get the highest benefits of the market. Even in a high natural-gas-reliant market such as Mexico, if costs are correctly allocated, the least pollutant producers will get the biggest share of the market.

[6] Formerly known as the North America Free Trade Agreement (NAFTA)

Sarmiento et al. (2021) analyse the effect of changes in natural gas prices in the electricity and gas market in Mexico using an integrated model for low and high-priced scenarios. Under a high natural gas price, there is an increase in coal energy production in the short run. For both price scenarios, there is an increase in renewable production in the mid-to-long term, but the penetration in the lower price scenario is less than in the others. The model also shows a short-term increase of CO_2 in the first periods with a reduction in the long run.

Sarmiento et al. (2019) analyse the commitment to penetration in renewable energies in the Mexican market. The authors use a Global Energy System Model to assess four scenarios: business as usual, national target, climate goals, and 100% renewables. They conclude that the target set by the Mexican government of reaching 30% renewable energy production by 2030 falls short, and it is a similar solution as under the business-as-usual scenario. The model shows that the optimal share of renewables should be 75%. Even though Sarmiento et al. (2019) show that the National target is not optimal, Cruz-Núñez (2023) demonstrates that the National low target will not be reached by 2030.

Gomez-Rios and Galvez-Cruz (2021) presents a cost analysis of the Mexican energy market. They consider an externality cost of \$ 14.12 for combined cycle plants. Nevertheless, the cost is assumed as a general levelized cost for CO_2 externalities. Carleton et al. (2022) present an ambitious analysis to calculate a social cost of carbon. They use an integrated assessment model and microdata for various regions of the World. Although there is a lot of variation, there is generally a U-shaped relationship between temperature and mortality risk. Using this calculation, they calculate a mortality cost as a willingness to pay to avoid changes in mortality risk due to additional emissions of CO_2. Therefore, reaching a mortality SCC of \$36.6 USD/tCO2e and \$17.1 USD/tCO2e. Compared to the externality cost proposed by Gomez-Rios and Galvez-Cruz (2021), the mortality SCC is a better calculation of health externality costs of CO_2 emissions.

3 Shapley value and the electricity market

I calculate the Shapley value to estimate the fair allocation of profits in the electricity market. The Shapley value states that each player, in this case, energy generators, should receive shares proportional to their marginal contribution to the market's profit. I use it to analyse the change in the allocation of profits for each producer with a new pipeline and carbon taxes.

Compared to other games, the Shapley value treats every player homogenously. Although this is a strong assumption to hold for heterogeneous producers with different cost functions, I assume the role of the independent system operator (ISO). It will determine the order of the generators according to the price of each bid in the market. The price should reflect the intrinsic cost of the producers; therefore, regardless of the heterogeneity of the players, the ISO will allocate fairly to each of the producers.

The literature shows the suitability of the Shapley value for allocating costs and benefits of new infrastructure. Churkin et al. (2019) use the Shapley value for the cost-benefit analysis of building interconnectors among six countries in Northeast Asia. Kristiansen et al. (2018) present a similar cost-benefit analysis of interconnections between countries in the North Sea. Hubert and Ikonnikova (2011) use it to analyse the gas market and the configuration of market power in the Baltic Sea. Acuña Ramírez (2022) use the Shapley value to analyse co-operation between energy generators and marketers.

For the Shapley value, two axioms are relevant to understanding results in Section 5. Symmetry; for any v, if i and j are interchangeable then $\psi_i(N, v) = \psi_j(N, v)$. If their marginal contribution to the coalition is the same, then each generator will receive the same payment. Dummy player; for any v, if i is a dummy player then $\psi_i(N, v) = 0$. If i joins the coalition, this player doesn't contribute; therefore, generator i receives no profit share. Results show that generators in the market sometimes behave as dummy players, and those with similar costs have symmetry in their share of profits.

In a game with a value function (N, v), and N set of generators, the Shapley value divides the shares of profits among generators according to:

$$\phi_i(N, v) = \frac{1}{N!} \sum_{S \subseteq N \setminus \{i\}} |S|!(|N| - |S| - 1)![v(S \cup \{i\}) - v(S)] \tag{1}$$

Where $\phi_i(N, v)$ is the share of profits for generator i, $[v(S \cup \{i\}) - v(S)]$ is the increment in profits when generator i joins the coalition. There is a total of $|S|!$ ways a coalition is formed before i joins. And the rest of the generators can join the coalition in $(|N| - |S| - 1)!$ different ways. The value function is the merit order curve model that uses LC, and hourly capacity and demand for each producer.

The Shapley value is a fair allocation of share of profits in the grand coalition; that is, all the generators contribute to the market, resulting in the highest possible profit. Nevertheless, there is a possibility of forming smaller coalitions, which can have a similar value to the grand coalition's total profits. This means smaller coalitions can be in the core:

$$\forall S \subseteq N, \sum_{i \in S} x_i \geq v(S) \tag{2}$$

In the core, the sum of the shares of profits in the grand coalition N should always be as high as all other coalitions. Therefore, no set of generators can do better than in the grand coalition, eliminating any incentive to deviate from equilibrium. In Section 5, I present results where smaller coalitions have the same value as the grand coalition, setting all these values in the core.

4 The energy market

This section presents an overview of the Baja California electricity market, the market's levelized costs by producer, and results under different assumptions. I use data for four different days in 2018. For each day, I show capacity by producer, the supply, and the market demand. Then, I show how I calculated the levelized costs, including the cost of a new pipeline. Using these levelized costs, I build a simple merit order curve.

4.1 Supply and demand data

I use data published by CENACE for the year 2018. 2018 was the hottest year since the beginning of the market in 2016 before COVID (ESTA International, 2019). Besides, in 2019, CENACE activated the corrective protocol, a short-term corrective measure when production falls short of covering the demand. In such a scenario, mobile units are provided to cover the deficit. During the peak days when these units were required (during August), they didn't present any offers to CENACE; nevertheless, they supplied energy in the real-time market. Their offers were recorded with zero in the data provided (ESTA International, 2019). Therefore, to avoid these discrepancies with data, I didn't use 2019 data.

I don't use data after 2019 because, in April 2020, there was a reform to the electricity market. The government decided that power plants under state ownership, Federal Commission of Electricity (Comisión Federal de Electricidad, CFE), would be dispatched first. Since then, the merit order curve doesn't follow a strict economic merit dispatch but follows the new legislation (Ramiro et al., 2021).

I use data from four different days for the analysis. One day in August as it was the hottest month, one in December since it was the coldest, one day in March as it reported the lowest average price in the day-ahead market (DAM) and real-time market (RTM), and one day in October as it was the month with a temperature closest to the yearly mean (21 °C). The monthly average prices of the DAM, RTM, and the average monthly temperatures are in Table 2.

I use hourly production data, which is the result of the DAM assigned quantities for each producer[7]. CENACE uses codes for producers. For the four days I report, there are seven different producers. I assume there are five combined

[7]Data is available from `https://www.cenace.gob.mx/Paginas/SIM/Reportes/ResultadosMDA.aspx`

Table 2: Monthly temperature and average prices (DAM and RTM) in Baja California, in Celsius degrees and pesos

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Temperature	16.3	15.5	16.6	20.4	20.5	24.3	28.6	29.6	27.2	21.6	17.1	13.8
DAM	499.95	400.52	329.42	338.54	385.63	639.79	2442.59	3087.83	842.40	514.54	584.96	665.55
RTM	659.58	475.67	392.40	416.93	451.73	595.41	1119.44	1813.02	683.61	573.68	640.08	749.07

Notes: With information from CONAGUA and CENACE

cycles, one geothermal and one intermittent energy producer. I base my assumption upon power plant information, capacity information (SENER, 2018), and factor capacity data (EIA, 2021).

In Table 3, I present the average, maximum, and minimum production capacity per day by the power generator. I take hourly production as the hourly capacity of the power plants. The producer with the higher capacity is CC2, followed by CC4. Capacity is one main driver that allows the producer to capture a bigger share of profits in the market, given the day's demand. For non-gas-reliant producers, the geothermal plant has the highest capacity.

Table 3: Capacity by generator per day in MWh

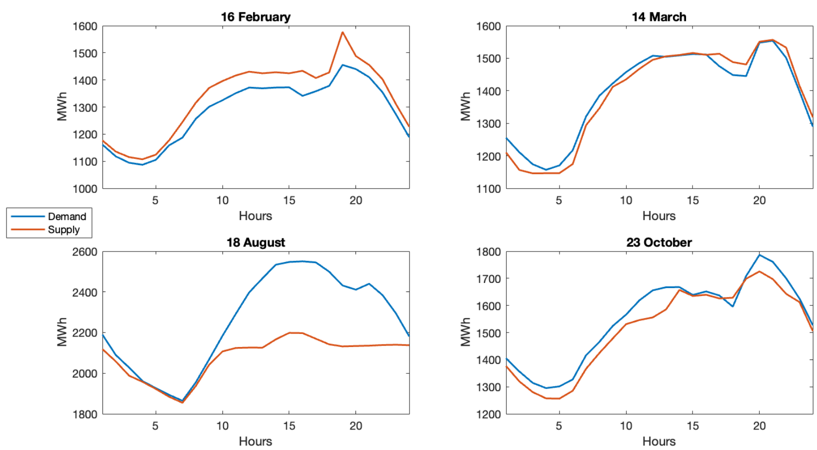
	GT	INT	CC1	CC2	CC3	CC4	CC5
				16 February			
Average	375.88	80.86	12.50	194.37	10.33	503.97	156.04
Max	379.47	82.80	20	213.33	78	646.50	165
Min	371.95	80	0	184	0	345.74	90
				14 March			
Average	370.61	82.45	18.75	234.03	17.92	508.71	156.25
Max	374.67	85.90	30	310.45	70	617.28	165
Min	364.17	80	0	166	0	328.12	130
				18 August			
Average	335.51	81.99	30	778.32	73.33	645.49	136.04
Max	337.89	84.20	30	832	100	675.28	155
Min	331.67	80.40	30	691	20	605.28	90
				23 October			
Average	331.18	80.68	30	412.50	6.67	562.69	90
Max	334.38	81.68	30	516	40	667.28	90
Min	320.85	80	30	339	0	364.95	90

Notes: CC1 to CC5 represents the five combined cycle plants, GT is the geothermal plant, and INT is an intermittent energy producer.

For demand information, I use hourly liquidation of demand[8] of period zero. This demand calculation doesn't include imports. I use it since I don't consider US electricity prices.

Supply and demand for each day per hour are in Figure 2. For the four days, only on February 16 supply met the demand. For the rest of the days, imports covered the excess of demand. Although 14 March had a similar production level as the 16 February, demand was higher than supply for March in the morning. August shows how the market behaves during the hottest days. At 15:00, the peak of demand, there was a shortage of 353 MW. October shows a shortage of energy before 14:00 and after 19:00.

Figure 2: Supply and demand per day in MWh



4.2 Levelized costs

I assume perfect competition; therefore, the price will equal the marginal cost. To calculate the marginal cost for each megawatt per hour in dollars, I follow the methodology by Gómez Ríos (2008). I use levelized costs (LC) that, as discussed by Gomez-Rios and Galvez-Cruz (2021), are better for assessing different technologies and including externality costs.

I consider a levelized investment cost (LIC), a levelized cost of fuel (LCF), and a levelized operation and maintenance cost (LOMC). The summation of these three levelized costs is my baseline, under a price of $6 USD/MMBtu. I then consider a scenario where the liquified natural gas (LNG) terminal sets the

[8] Data is available from https://www.cenace.gob.mx/Paginas/SIM/Reportes/EstimacionDemandaReal.aspx

price, leading to a scenario of \$ 12 USD/MMBtu. Especially during the summer, the LNG station can set prices similar to those in the spot market (Lenton, 2023). But even during non-peak periods, energy producers and manufacturers had complained about high natural gas prices (Juarez, 2023).

Finally, I consider the scenario where a new pipeline is built. Following the prices reported at SENER (2019) of costs of previous projects, I use a cost of \$65 million USD[9]. This proposed project is a pipeline that connects Rosarito, which is in the South of Baja California, to San Diego, California. It has a longitude of 36 kilometres and a capacity of 300 mmcfd (million cubic feet per day). I assume it will be built in two years with an expected life of thirty years.

I consider a discount rate by the Central Bank in Mexico, which is 12% same as used by Gómez Ríos (2008).

To get the levelized unit costs, I first assign the pipeline investment cost for each energy producer. Since I don't consider storage or a backup power plant for the geothermal and intermittent technology, I assign a zero cost to them. To calculate the share of the cost for each combined cycle plant, I use the following formula:

$$\frac{\sum_{n=1}^{i} HP_i}{TPCC} = \theta_i \tag{3}$$

$$\theta_i * TPP = CP_i \tag{4}$$

Where HP_i is the hourly dispatched production of generator i, $TPCC$ is the total daily dispatched production of combined cycle generators, and θ_i is the shared cost of the pipeline. TPP is the total price of the pipeline, in this case, \$65 million, and CP_i is the cost of the pipeline for generator i. For calculating the shared costs, I only consider combined cycle producers.

Following the methodology by Gómez Ríos (2008) I calculate LIC, LOMC, and LFC for the combined cycle plants. Given the scope of the research question about the natural gas market, I set the levelized cost of the intermittent energy and geothermal plant to zero. I take the LIC and LOMC from Gómez Ríos (2008) and calculate the LIC of a new pipeline using the same methodology. I calculate the LCF using the methodology proposed by the same paper, considering prices of \$ 6 USD/MMBtu and \$ 12 USD/MMBtu, a conversion factor of 3.413 MWh/MMBtu, and a plant efficiency of 51.96%; Table 4 shows the levelized cost per MWh.

[9]Sempra, the company operating the LNG terminal, plans to build a pipeline from the Permian Basin to Ensenada, Baja California. This pipeline will supply natural gas to the only-exporting LNG terminal. This terminal expansion will supply to the Asian market mainly (Global Energy Monitor, 2023).

Table 4: Levelized costs in dollars per MWh

	CC1	CC2	CC3	CC4	CC5	GT	INT
LCI	8.43	8.43	8.43	8.43	8.43	0	0
LCI of duct	0.14	0.82	0.21	1.02	1.07	0	0
LCF at \$6	39.41	39.41	39.41	39.41	39.41	0	0
LCF at \$12	78.82	78.82	78.82	78.82	78.82	0	0
LOMC	4.79	4.79	4.79	4.79	4.79	0	0
Baseline	52.63	52.63	52.63	52.63	52.63	0	0
Baseline + duct	52.77	53.45	52.84	53.66	53.70	0	0
High price	40.55	40.55	40.55	40.55	40.55	0	0
High price + duct	92.19	92.86	92.25	93.07	93.11	0	0

Notes: CC1 to CC5 represents the five combined cycle plants, GT is the geothermal plant, and INT is an intermittent energy producer.

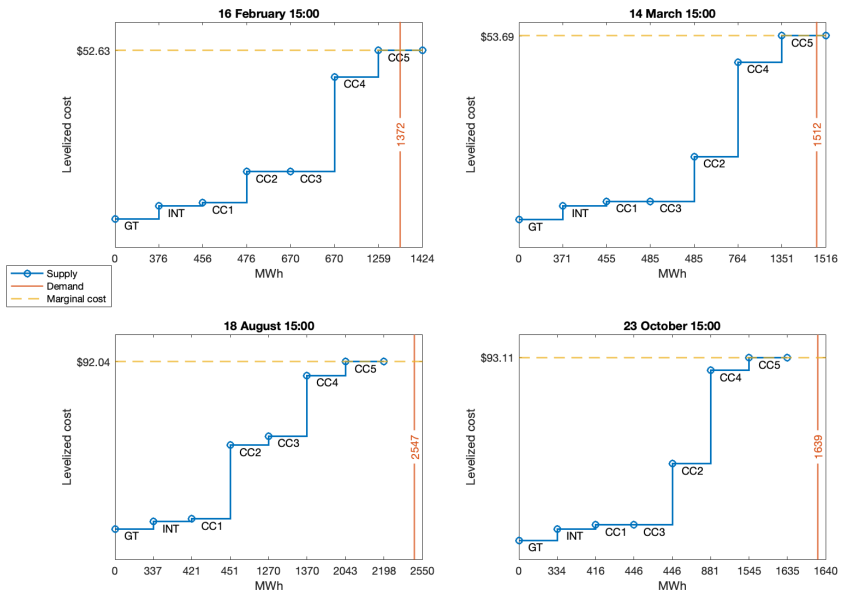
The values calculated for the baseline scenario on Table 4 are similar to those calculated by Gómez Ríos (2008), and just as those levelized costs, the more significant share of the costs is driven by the natural gas price. For the baseline scenario, LFC represents 75% of the cost, similar to previous research, 71%. Nevertheless, for the scenario with high prices, LFC represents 85%.

4.3 Merit order curve

I built a simple merit order curve model that calculates hourly profits for the energy market in Baja California. Similar to Churkin et al. (2019), I use the cost of the generator to calculate $v(S)$. As the authors in the paper discuss, using costs instead of consumer surplus is a better proxy for expansion planning projects. In Figure 3, I present graphically the results of running the merit order curve model under four different cost assumptions. I present the electricity market at $15:00$ for four different days.

For February 16, I consider a gas price of \$6 USD/MMBtu; for March 14, I assume the cost of a new pipeline is split between producers; for August 18, I assume a gas cost of \$12 USD/MMBtu; and for October 23 I consider a gas price of \$12 USD/MMBtu and split costs of a new pipeline. I present Figure 3 as a graphic reference of the hourly result of running the model. The model doesn't include imports, which will be the main resource to cover the excess demand in August and October. I discuss in the next section how the dispatch order of producers changes under different cost assumptions. In Figure 3, the main change is between producer CC2 and CC3, where CC3 is dispatched first when the costs of a new duct are included.

Figure 3: Merit order curve per day at 15:00 under different cost assumptions



Notes: February 16 considers a gas price of \$6 USD/MMBtu, March 14 considers the cost of a new duct split between producers, August 18 considers a gas cost of \$12 USD/MMBtu, and October 23 considers the gas price of \$12 USD/MMBtu and split costs of a new duct.

5 Results

Using the hourly merit order curve model presented in the section before, I calculate the results of the Shapley value under different scenarios: when the natural gas price is \$6 USD/MMBtu, and \$12 USD/MMBtu, and when a new pipeline is built.

I calculate the model with a carbon tax. First, I consider that Baja California's inactive carbon tax is in operation (Acuña Ramírez, 2022). The Baja California tax is \$17/tCO2e (pesos), and in US dollars, it is \$9.98 tCO2e. Then I consider that the Baja California government pegs the carbon tax to the floor price of the California Cap-and-Trade programme, i.e., \$30 tCO2e (World Bank, 2023).

Finally, I present results when there is a mortality social cost of carbon (SCC). I use two SCCs, one under a moderate emissions scenario that is \$ 17.1 per ton of CO_2, and with a high-emissions scenario which is an SCC of \$ 36.6 per ton of CO_2. For all the scenarios listed before, I present the Shapley values per generator in the grand coalition, where they are all at the game's core.

5.1 Baseline scenarios

Using LC from Table 4, I obtain the Shapley value for each scenario. In Table 4, Baseline is where the price is \$6 USD/MMBtu, Baseline+duct is the scenario under \$6, and when the cost of a new pipeline is distributed between the five combined cycle plants using Equation 4. High price is the scenario under a price of \$12 USD/MMBtu, and High price + duct is the scenario with a price of \$12 where the combined cycle producers share the cost of the new pipeline. Results for each of the four days under the four different scenarios are in Table 5, and the change of shares of profits is in Figure 4.

The results in Table 5 are the Shapley values per player in the grand coalition. This means these are the share of profits when all the players, or producers in this case, agree to join the market. Although some papers report the results for each combination of coalitions in the market, I present only the grand coalition. In a market with seven players, there are 127 combinations of coalitions; therefore presenting all the results makes it challenging, given the number of scenarios I use.

February 16 had the highest total profit for the four scenarios. The day with the lowest total profits is October 23. The results in Table 5 account for the producer surplus; therefore, every cost increase will reflect an increase in total profit, as reported in the column Total. Nevertheless, the increase in cost for combined cycle producers due to natural gas prices and the cost of a new

Table 5: Share of profits by power generator in thousands of dollars per day

	GT	INT	CC1	CC2	CC3	CC4	CC5	Total
				Baseline				
16 Feb	395.66	85.11	19.23	19.23	19.23	19.23	19.23	**576.92**
14 Mar	390.11	86.79	19.08	19.08	19.08	19.08	19.08	**572.27**
18 Aug	353.15	86.30	17.58	17.58	17.58	17.58	17.58	**527.34**
23 Oct	348.60	84.92	17.34	17.34	17.34	17.34	17.34	**520.23**
				Baseline + duct				
16 Feb	402.76	86.64	19.48	20.63	19.47	20.70	21.03	**590.73**
14 Mar	397.12	88.35	19.43	20.64	19.43	20.60	20.96	**586.51**
18 Aug	359.50	87.85	18.11	21.19	18.75	19.67	20.31	**545.37**
23 Oct	354.87	86.45	17.87	19.51	17.52	18.95	19.37	**534.52**
				High prices				
16 Feb	691.93	148.84	33.63	33.63	33.63	33.63	33.63	**1,008.93**
14 Mar	682.23	151.77	33.36	33.36	33.36	33.36	33.36	**1,000.80**
18 Aug	617.60	150.92	30.74	30.74	30.74	30.74	30.74	**922.23**
23 Oct	609.64	148.51	30.33	30.33	30.33	30.33	30.33	**909.78**
				High prices + duct				
16 Feb	699.04	150.37	33.88	35.03	33.87	35.10	35.43	**1,022.74**
14 Mar	689.24	153.33	33.71	34.92	33.71	34.89	35.24	**1,015.05**
18 Aug	623.95	152.47	31.27	34.36	31.91	32.83	33.47	**940.26**
23 Oct	615.91	150.04	30.85	32.49	30.51	31.93	32.35	**924.09**

Notes: CC1 to CC5 represents the five combined cycle plants, GT is the geothermal plant, INT is an intermittent energy producer, and Total is the total profit.

pipeline change the share of profits, which is the interest of this research.

Table 5 shows the shares of profits for each scenario and producer. The four scenarios show a higher allocation of profits for the geothermal plant and the intermittent energy producers. On average, the geothermal plant has an allocation of 64% of the market's profits, the intermittent producer has an average of 14% of total profits, and the combined cycle producers have an average of 3% share of the market's profit. Following the symmetry axiom of the Shapley value, shares for the five combined cycle producers are the same for most of the hours and the four different days. Under the scenario that included a cost for a duct, producer CC3 is preferred to CC2 when dispatching. Under baseline and high-price scenarios, CC2 is dispatched before CC3. The merit order curve for the baseline and high prices is the same as in Figure 5.

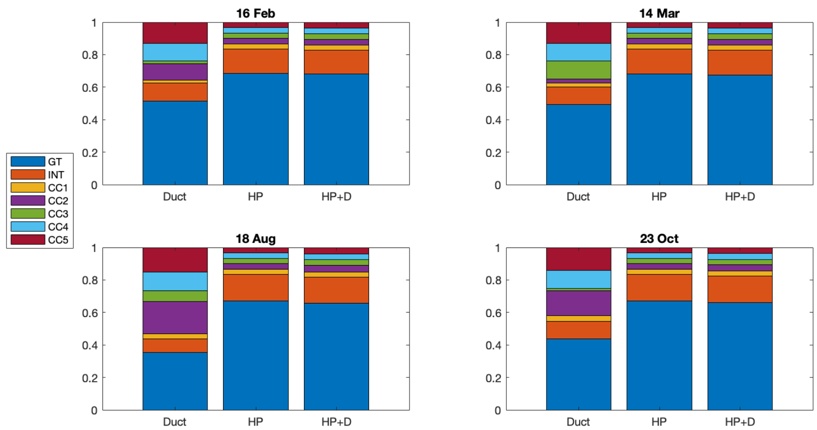
The share of profits reported is at the core of the game. Nevertheless, the scenarios with a unique core are only when a pipeline cost is introduced. There are 31 other solutions in the core for the baseline and high prices. This means there are 31 scenarios where producers can form a coalition and will get the same profit as the one in the grand coalition[10]. This solution is consistent with the behaviour of an electricity market where some days, there will be a producer that is not dispatching energy but will dispatch when the Independent System Operator (ISO) requires it. That is these producers that are off become dummy players.

The cost allocation of the proposed pipeline is not trivial. I use Equation 4 to calculate the costs, but if there is an arbitrary allocation or the producers agree on a different share of costs, the outcomes of the market change. In Table 10 in Appendix A, I show the Shapley value for a different allocation of duct costs. If producers allocate the duct costs using the LC in Table 10 total profits are lower, and the day with the higher profit is March 14. Besides, for March, the grand coalition is not in the core; therefore, there is another coalition that leads to a higher profit. This coalition is when producer CC4 is off, and the other six are active.

The merit order curve, the order in which each producer is dispatched, also changes. Figure 5 shows the merit order curve with duct cost allocation from Table 5 and when the cost allocation changes using LC as in Table 10 in Appendix A. The geothermal and the intermittent energy producers are still the first two dispatched, but the combined cycle producers change in priority. With the original LC, the order is CC1, CC2, CC3, CC4, and CC5. After changing the LC, the dispatch priority of the combined cycle plants is CC1, CC5, CC4, CC2, and CC3. Although I only show results for February 16 for high prices, the results are the same for the other three days and the other three scenarios.

[10]The grand coalition values are those in Table 5.

Figure 4: Share of change of contribution by generator per day



Notes: Duct compares the baseline and the scenario where producers share the duct's cost. HP stands for high price scenario and compares the baseline with a high price scenario. HP+Duct compares scenarios under high prices and when generators share the price of a new duct and the baseline.

By comparing the baseline scenario, that is, a market with a natural gas price of \$ 6, with the other three scenarios, it is possible to see better the change of share of profits per producer by day. In Figure 4, the change from the baseline to the scenario of baseline plus duct shows an increase in the profits of CC2 on 18 August. But the same producer in March had a smaller share of the profits. Another producer that has an important change of share in profits is CC3. The highest share of profits is on March 14, and in October and February, shares are smaller. In March 14 producer CC3 had an increase of 10%, on August 18 it was 6%, and in February and October it was only 1%.

The changes in shares of profits are driven partly by the capacity of each producer. From the information in Table 3, it is clear the advantage CC2 had was its capacity. Therefore, during the peak of demand in August, CC2 produced more energy and had a bigger share of profits. Nevertheless, the share of profits is lower for the same producer under a high-priced scenario.

Although the intermittent technology is always ordered as the second cheapest producer in the merit order curve, it had a lower profit in August than in October. This is the same scenario for geothermal energy, where August shows a decrease in profits for the producer. Looking at the supply and demand curves in Figure 2, it is clear that given the higher demand compared to the supply, combined cycle plants, although expensive, were more active than on other days, which shifted the share of profits.

5.2 Carbon tax scenarios

Using the four scenarios described in Section 5.1 I consider adding a carbon tax. The Baja California tax is considered with a cost of \$9.98 USD/tCO2e, translating into a cost of \$4.32 USD/MWh. For California, the carbon tax considered is \$30 USD/tCO2e, a total of \$12.99 USD/MWh. Therefore, to the four LCs in Table 4, I add the carbon taxes in Dollars per MWh. I assume the geothermal and intermittent generators are not emitting CO_2 since I don't consider backup or storage units for these producers. I calculate the equivalence of tCO2e into CO_2/MWh by using a conversion factor of 4.33×10^{-1}(EPA, 2023).

Using the two carbon taxes, I calculate the Shapley values for the four scenarios. The results of the grand coalitions using the Baja California carbon tax are in Table 6, and results using the California carbon tax are in Table 7.

Table 6: Share of profits by power generator under Baja California carbon tax in thousands of dollars per day

	GT	INT	CC1	CC2	CC3	CC4	CC5	Total
				Baseline + tax				
16 Feb	428.14	92.10	20.81	20.81	20.81	20.81	20.81	**624.29**
14 Mar	422.14	93.91	20.64	20.64	20.64	20.64	20.64	**619.26**
18 Aug	382.15	93.39	19.02	19.02	19.02	19.02	19.02	**570.64**
23 Oct	377.23	91.89	18.76	18.76	18.76	18.76	18.76	**562.94**
				Baseline + duct + tax				
16 Feb	435.25	93.63	21.06	22.21	21.05	22.28	22.61	**638.10**
14 Mar	429.15	95.47	20.99	22.20	21.00	22.17	22.52	**633.50**
18 Aug	388.49	94.94	19.55	22.64	20.19	21.11	21.75	**588.67**
23 Oct	383.49	93.42	19.29	20.93	18.94	20.37	20.79	**577.24**
				High prices + tax				
16 Feb	724.41	155.83	35.21	35.21	35.21	35.21	35.21	**1,056.30**
14 Mar	714.26	158.90	34.93	34.93	34.93	34.93	34.93	**1,047.79**
18 Aug	646.60	158.01	32.18	32.18	32.18	32.18	32.18	**965.53**
23 Oct	638.26	155.48	31.75	31.75	31.75	31.75	31.75	**952.50**
				High prices + duct + tax				
16 Feb	731.53	157.36	35.46	36.61	35.45	36.68	37.01	**1,070.11**
14 Mar	721.27	160.46	35.28	36.49	35.28	36.45	36.81	**1,062.04**
18 Aug	652.95	159.56	32.71	35.80	33.35	34.27	34.91	**983.56**
23 Oct	644.53	157.01	32.28	33.92	31.93	33.35	33.78	**966.80**

Notes: CC1 to CC5 represents the five combined cycle plants, GT is the geothermal plant, INT is an intermittent energy producer, and Total is the total profit.

The day with the highest profits for both carbon taxes was February 16.

Table 7: Share of profits by power generator under California carbon tax in thousands of dollars per day

	GT	INT	CC1	CC2	CC3	CC4	CC5	Total
				Baseline + tax				
16 Feb	493.31	106.12	23.98	23.98	23.98	23.98	23.98	**719.31**
14 Mar	486.39	108.21	23.78	23.78	23.78	23.78	23.78	**713.52**
18 Aug	440.32	107.60	21.92	21.92	21.92	21.92	21.92	**657.50**
23 Oct	434.64	105.88	21.62	21.62	21.62	21.62	21.62	**648.63**
				Baseline + duct + tax				
16 Feb	500.42	107.65	24.23	25.38	24.22	25.45	25.78	**733.12**
14 Mar	493.40	109.77	24.14	25.34	24.14	25.31	25.67	**727.76**
18 Aug	446.66	109.15	22.45	25.53	23.08	24.01	24.64	**675.52**
23 Oct	440.91	107.41	22.15	23.79	21.80	23.23	23.65	**662.93**
				High prices + tax				
16 Feb	789.58	169.85	38.38	38.38	38.38	38.38	38.38	**1,151.32**
14 Mar	778.51	173.19	38.07	38.07	38.07	38.07	38.07	**1,142.05**
18 Aug	704.76	172.22	35.08	35.08	35.08	35.08	35.08	**1,052.38**
23 Oct	695.68	169.47	34.61	34.61	34.61	34.61	34.61	**1,038.18**
				High prices + duct + tax				
16 Feb	796.70	171.38	38.63	39.78	38.62	39.85	40.18	**1,165.14**
14 Mar	785.53	174.76	38.42	39.63	38.42	39.59	39.95	**1,156.30**
18 Aug	711.12	173.78	35.61	38.70	36.25	37.17	37.81	**1,070.42**
23 Oct	701.95	171.00	35.13	36.77	34.79	36.21	36.63	**1,052.49**

Notes: CC1 to CC5 represents the five combined cycle plants, GT is the geothermal plant, INT is an intermittent energy producer, and Total is the total profit.

On average, the geothermal plant has an allocation of profits of 67% and the intermittent producer an allocation of 16%. For the combined cycle producers, the average allocation of profits is 3%. Similar to the previous scenarios without carbon taxes, the symmetry property of the Shapley value allocates the same share of profits for the five producers during most days. Compared with the scenarios in Section 5.1, the geothermal and intermittent producers have a higher share of profits with both carbon taxes. This shift in profits reflects the cost increase of the most pollutant producers. Similar to previous scenarios, producer CC3 has a higher preference over CC2 for dispatching when the cost of a duct is included. Under the baseline plus taxes CC2 is preferred to CC3

Nevertheless, for the baseline scenario plus duct costs and taxes, producers CC2, CC4, and CC5 increased their shares of profits by 1% during August and October. The higher share of profits is a response to higher demand. These three producers have a higher capacity, as reported in Table 3, compared to CC1 and CC5. Therefore, they could produce more to get a bigger profit share.

On August 18, the increase in the share of profits for the combined cycle plants came with a reduction in the share of profits from the geothermal plants. This is because the capacity of this plant is not as much as the one for the combined cycle plants. The intermittent energy plant also increased as much as possible its production, which is reflected in the higher share of profits. Still, the capacity of the combined cycle plants was the main driver of the higher allocation in the share of profits for these plants.

Similar to the results in Table 5, the grand coalitions of the scenarios that included duct costs are the only ones where the core is unique. The baseline + tax and high prices + tax have non-unique cores, but the grand coalition is the highest possible value of the game; therefore, it is a fair and optimal allocation of share of profits.

The California carbon tax results in higher profits for the market. The geothermal and intermittent energy producers benefit the most from it. Although, proportionally, the share of profits is the same with the California and Baja California carbon taxes.

5.3 Mortality Social Cost of Carbon

Besides analysing the effects of a carbon tax on the share of profits in the market, I also analyse the mortality social cost of carbon (SCC). As suggested by Carleton et al. (2022), the mortality SCC is the excess mortality of emitting a marginal ton of CO_2. The authors argue that this is a better instrument to account for the negative effects on the health of producing an extra ton of CO_2 compared to a carbon tax. They discuss the uncertainty of the proposed cost; nevertheless, they propose two main SCC. Under a high-emissions scenario, the cost is \$36.6 per ton of CO_2, and with a moderate-emissions scenario, it is \$17.1[11]

Using the two mortality SCCs, I calculate the four scenarios for the market. I use the same conversion rate for the carbon tax, which is 4.33×10^{-1}. Therefore, the SCC of \$36.6 USD/tCO2e becomes a \$15.85 USD/MWh, and \$17.1 USD/tCO2e is a total of \$7.4 USD/MWh. I add these two costs to each LC of the four scenarios described in Table 5. I don't overlap the analysis of carbon taxes and mortality SCC since Carleton et al. (2022) argue that the mortality SCC is a fairer cost for the negative impacts of CO_2 emissions.

The results of calculating the Shapley value using these two SCCs are in Table 8 for the scenario with \$7.4 USD/MWh and in Table 9 for the LC plus an SCC of \$15.85 USD/MWh. As in the other results, both tables show the grand coalition for each scenario. These results show the fair and optimal allocation of the share of profits.

The grand coalition reported for each scenario follows the same behaviour as the carbon tax coalition. The scenarios where the cost of the new duct is allocated result in a unique core, and the baseline and the high-priced scenario have 31 coalitions in the core. Nevertheless, as before, the total profit reported under the grand coalition is the highest possible value for all the scenarios.

Similar to the scenarios under a carbon tax, geothermal and intermittent energy producers have an average share of profits of 67% and 16%, respectively. Similarly, the combined cycle producers have a share of profits of 3% each. In terms of dispatch, as before, the scenarios considering the costs of a duct give preference to producer CC3 over producer CC2 as ordered under the baseline.

Under a low mortality SCC producers CC3, CC4, and CC5 have a higher share of profits under the baseline and duct cost scenario. This allocation happened on August 18 and October 23, meaning that the geothermal producer had a smaller profit share. The intermittent energy producer had the same allocation with a 16% share of the total profits. It is clear that regardless of the cost accounted for CO_2 emissions, on the days when there's peak demand, the most pollutant producers can take advantage of the situation to get a higher share of profits.

Although combined cycle producers have a bigger share of the market with a low mortality SCC, the producer with the highest capacity[12], that is, CC2 doesn't increase its share of profits. For the scenario with high mortality SCC, these shifts in shares of profits don't happen. Although producers have the capacity available, the cost increase makes it less likely to be dispatched first and,

[11] The uncertainty interquartile range for the SCC of \$36.6 is [-\$7.8, \$73] and for the SCC of \$17.1 is [-\$24.7, \$53.6].

[12] Capacity is reported in Table 3

Table 8: Share of profits by power generator under low mortality SCC in thousands of dollars per day

	GT	INT	CC1	CC2	CC3	CC4	CC5	Total
				Baseline + SCC				
16 Feb	451.32	97.09	21.94	21.94	21.94	21.94	21.94	**658.09**
14 Mar	444.99	99.00	21.76	21.76	21.76	21.76	21.76	**652.78**
18 Aug	402.84	98.44	20.05	20.05	20.05	20.05	20.05	**601.53**
23 Oct	397.65	96.87	19.78	19.78	19.78	19.78	19.78	**593.42**
				Baseline + duct + SCC				
16 Feb	458.43	98.61	22.19	22.18	23.34	23.41	23.74	**671.89**
14 Mar	452.00	100.56	22.11	22.11	23.32	23.28	23.64	**667.02**
18 Aug	409.18	99.99	20.58	21.22	23.67	22.14	22.78	**619.56**
23 Oct	403.91	98.39	20.31	19.96	21.95	21.38	21.81	**607.71**
				High prices + SCC				
16 Feb	747.59	160.82	36.34	36.34	36.34	36.34	36.34	**1,090.09**
14 Mar	737.11	163.98	36.04	36.04	36.04	36.04	36.04	**1,081.31**
18 Aug	667.28	163.06	33.21	33.21	33.21	33.21	33.21	**996.42**
23 Oct	658.69	160.46	32.77	32.77	32.77	32.77	32.77	**982.97**
				High prices + duct + SCC				
16 Feb	754.71	162.35	36.59	36.58	37.74	37.81	38.14	**1,103.91**
14 Mar	744.12	165.54	36.40	36.40	37.60	37.57	37.93	**1,095.56**
18 Aug	673.64	164.62	33.74	34.38	36.83	35.30	35.94	**1,014.45**
23 Oct	664.95	161.99	33.29	32.95	34.93	34.37	34.79	**997.28**

Notes: CC1 to CC5 represents the five combined cycle plants, GT is the geothermal plant, INT is an intermittent energy producer, and Total is the total profit.

Table 9: Share of profits by power generator under high mortality SCC in thousands of dollars per day

	GT	INT	CC1	CC2	CC3	CC4	CC5	Total
				Baseline + SCC				
16 Feb	514.79	110.74	25.02	25.02	25.02	25.02	25.02	**750.64**
14 Mar	507.58	112.92	24.82	24.82	24.82	24.82	24.82	**744.59**
18 Aug	459.49	112.29	22.87	22.87	22.87	22.87	22.87	**686.14**
23 Oct	453.57	110.49	22.56	22.56	22.56	22.56	22.56	**676.88**
				Baseline + duct + SCC				
16 Feb	521.90	112.27	25.27	25.26	26.42	26.49	26.82	**764.45**
14 Mar	514.58	114.48	25.17	25.17	26.38	26.34	26.70	**758.84**
18 Aug	465.84	113.84	23.40	24.04	26.49	24.96	25.60	**704.16**
23 Oct	459.84	112.02	23.09	22.74	24.73	24.17	24.59	**691.17**
				High prices + SCC				
16 Feb	811.07	174.47	39.42	39.42	39.42	39.42	39.42	**1,182.65**
14 Mar	799.69	177.91	39.10	39.10	39.10	39.10	39.10	**1,173.12**
18 Aug	723.94	176.91	36.03	36.03	36.03	36.03	36.03	**1,081.02**
23 Oct	714.61	174.08	35.55	35.55	35.55	35.55	35.55	**1,066.43**
				High prices + duct + SCC				
16 Feb	818.18	176.00	39.68	39.66	40.82	40.89	41.22	**1,196.46**
14 Mar	806.71	179.47	39.46	39.46	40.67	40.63	40.99	**1,187.37**
18 Aug	730.29	178.46	36.56	37.20	39.65	38.12	38.76	**1,099.05**
23 Oct	720.88	175.61	36.08	35.73	37.71	37.15	37.58	**1,080.74**

Notes: CC1 to CC5 represents the five combined cycle plants, GT is the geothermal plant, INT is an intermittent energy producer, and Total is the total profit.

therefore, to have a higher share of profits.

The higher mortality SCC allows for a higher profit; under a fair and optimal allocation, the geothermal producer receives the bigger share of the profits. The intermittent energy producer is the player with the second highest share of profits, and, as before, on the days the demand peaks, the intermittent producer receives a higher share of the profits. Although profits are higher under the high mortality SCC, in proportion, the share of profits under the two SCCs stays the same.

6 Conclusion

The Baja California electricity market is an isolated system highly dependent on natural gas imports from the US. This intertwined relationship sets the scenario for joint cross-border infrastructure, a new pipeline. Given the cost and benefits that such a project represents, it is needed a tool that can allocate the cost and benefits of the market fairly. I run a simple merit order curve and calculate the Shapley value for each power generator in Baja California.

I run it under different scenarios like high prices, as set by the LNG terminal, carbon taxes considering those proposed by Baja California, and the cap-and-trade programme in California. I also consider a mortality SCC, which accounts for the negative impacts of energy production. Results show that carbon taxes and mortality SCC deter combined cycle producers from getting a higher share of profits. Nevertheless, as these natural-gas-reliant producers have a bigger capacity than no-fossil fuel generators, they get a higher share of profits during high-demand days.

The costs of the new pipeline are assumed to be allocated accordingly to the energy production of each generator. Nevertheless, this allocation is not trivial, and if the generators agree on a different share of costs, the equilibrium in the market can be neither unique nor fair. Although the literature uses the Shapley value to allocate the costs of trans-border infrastructure (Hubert & Ikonnikova, 2011) calculating the Shapley value to calculate it again to understand the reconfiguration in the market results in a recursive exercise. Therefore, the cost allocation followed a levelized cost procedure.

Building a new pipeline will provide more energy security to Baja California but will also increase a carbon lock-in for at least another thirty years. Even under the assumed scenario of a Baja California carbon tax or compliance with the cap-and-trade programme in California, combined cycle producers will have incentives to stay in operation in the market. With a weakened geothermal production and only 56 MW of installed renewable energy, the State will hardly become less fossil fuel dependent.

Although Federal plans to increase interconnections with the SIN have disappeared in recent years, this project could break the fossil-fuel dependency in the area. Wang et al. (2023) show that in China, an electricity interconnection between regions increased renewable energy penetration and reduced CO_2 emissions. By allowing isolated markets to connect with inland China and high energy capacity, small markets benefited from this connection.

If the Mexican electricity market keeps fostering big fossil-fuel producers, the market will keep its dependency on natural gas and imports from the US. This dependency only creates vulnerability in the market and deters the country from reaching its emissions reduction targets. Besides, the volatility of fossil fuels in recent years has demonstrated the urgency of a greener energy production matrix. The shift in the market will only be possible with a suitable and strong infrastructure.

References

Acuña Ramírez, G. (2022). *Impuestos al carbono en México: desarrollo y tendencias.* UK Pact Mexico CO2.

Bernal, B., Molero, J. C., & Perez De Gracia, F. (2019). Impact of fossil fuel prices on electricity prices in Mexico. *Journal of Economic Studies*, *46*(2), 356–371. Retrieved 2023-08-07, from https://doi.org/10.1108/JES-07-2017-0198 (Publisher: Emerald Publishing Limited) doi: 10.1108/JES-07-2017-0198

Carleton, T., Jina, A., Delgado, M., Greenstone, M., Houser, T., Hsiang, S., ... Zhang, A. T. (2022). Valuing the global mortality consequences of climate change accounting for adaption costs and benefits. *The Quarterly Journal of Economics*, *137*.

Casolino, G., Liuzzi, G., & Losi, A. (2015). Combined cycle unit commitment in a changing electricity market scenario. *International Journal of Electrical Power & Energy Systems*, *73*, 114–123. Retrieved 2023-08-08, from https://linkinghub.elsevier.com/retrieve/pii/S0142061515001994 doi: 10.1016/j.ijepes.2015.04.017

Churkin, A., Pozo, D., Bialek, J., Korgin, N., & Sauma, E. (2019). Can cross-border transmission expansion lead to fair and stable cooperation? Northeast Asia case analysis. *Energy Economics*, *84*, 104498. Retrieved 2023-07-31, from https://www.sciencedirect.com/science/article/pii/S0140988319302798 doi: 10.1016/j.eneco.2019.104498

Cruz-Núñez, X. (2023). Will Mexico meet its climate commitments? *Atmósfera*, *37*, 445–454. Retrieved 2023-08-08, from https://www.revistascca.unam.mx/atm/index.php/atm/article/view/53174 doi: 10.20937/ATM.53174

EIA. (2021). *Natural gas combined-cycle plant use varies by region and age.* Retrieved 2023-07-15, from https://www.eia.gov/todayinenergy/detail.php?id=48036

EIA. (2023). *Natural Gas Weekly Update.* Retrieved 2023-08-07, from https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2023/08_03/

EPA. (2023). *Greenhouse Gases Equivalencies Calculator - Calculations and References* [US Environmental Protection Agency]. Retrieved 2023-07-28, from https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

ESTA International. (2019). *Reporte Anual del Mercado Eléctrico Mayorista 2019.* ESTA International LCC.

ESTA International. (2021). *Reporte Anual del Mercado Eléctrico Mayorista 2020.* ESTA International LCC.

Estrada, J., Rodríguez, V., & Ventura, V. H. (2022). *El gas natural en México Impacto de la política de autosuficiencia, seguridad y soberanía en la transición y la integración energética regional.* CEPAL.

Global Energy Monitor. (2023). *Costa Azul LNG Terminal.* Retrieved 2023-07-15, from https://www.gem.wiki/Costa_Azul_LNG_Terminal

Gomez-Rios, M. d. C., & Galvez-Cruz, D. C. (2021). Simulation of Levelized Costs of Electricity Considering Externalities. *Revista Mexicana de Economía y Finanzas Nueva Época REMEF*, *16*(4), 621. Retrieved 2023-07-15, from https://www.remef.org.mx/index.php/remef/article/view/621 (Number: 4) doi: 10.21919/remef.v16i4.621

Gómez Ríos, M. d. C. (2008). *La energía nuclear una alternativa de generación de energía eléctrica de carga base en México* (Unpublished doctoral dissertation). Tesis Universidad Anáhuac México Norte. Facultad de Ingeniería.

Hubert, F., & Ikonnikova, S. (2011). Investment Options and Bargaining Power: The Eurasian Supply Chain for Natural Gas. *The Journal of Industrial Economics*, *59*(1), 85–116. Retrieved 2023-07-31, from https://www.jstor.org/stable/41289444 (Publisher: Wiley)

Juarez, U. (2023). *Reclama Canacintra Mexicali a Sempra por precio del gas.* Retrieved 2023-07-15, from https://energiaadebate.com/reclama-canacintra-mexicali-a-sempra-por-precio-del-gas/

Kristiansen, M., Muñoz, F. D., Oren, S., & Korpås, M. (2018). A Mechanism for Allocating Benefits and Costs from Transmission Interconnections under Cooperation: A Case Study of the North Sea Offshore Grid. *The Energy Journal*, *39*(6), 209–234. Retrieved 2023-07-31, from https://www.jstor.org/stable/26606251 (Publisher: International Association for Energy Economics)

Lenton, C. (2023). *North American Natural Gas Futures Still Lifeless; Baja California Seeks Supply Relief – Mexico Spotlight - Natural Gas Intelligence.* Retrieved 2023-07-15, from https://www.naturalgasintel.com/north-american-natural-gas-futures-still-lifeless-baja-california-seeks-supply-relief-mexico-spotlight/

Madrid Ayala, V. M., Gómez, M., Aguilar, C., Márquez, J. A., & Figueroa, D. (2018). *Transición hacia Mercados Competidos de Energía: Gas LP.*

COFECE.

McRae, S. D. (2019). Market power in cost-based wholesale electricity markets: Evidence from Mexico..

Meritet, S., & Baltierra, A. E. (2008). Developing LNG in North America: Impact on prices of natural gas..

Muñoz Andrade, D., Sweedler, A., Martin, J. M., Prieto, A., Kristin, R., & Gruenwald, T. (2020). *Baja California Energy Outlook 2020-2025.* Institute of the Americas.

Ober, M., & Dyl, K. (2021). *U.S. natural gas exports to Mexico established a new monthly record in June 2021.* Retrieved 2023-08-07, from `https://www.eia.gov/todayinenergy/detail.php?id=48836`

Pauer, S. U. (2018). Including electricity imports in California's cap-and-trade program: A case study of a border carbon adjustment in practice. *The Electricity Journal*, *31*(10), 39–45. Retrieved 2023-08-07, from `https://www.sciencedirect.com/science/article/pii/S1040619018302549` doi: 10.1016/j.tej.2018.11.005

Ramiro, M., Díaz, D., Mendiola, V., & Ocampo, O. (2021). *Los cambios al sector eléctrico: todos pierden.* Instituto Mexicano para la Competitivdada A.C.

Sarmiento, L., Burandt, T., Löffler, K., & Oei, P.-Y. (2019). Analyzing Scenarios for the Integration of Renewable Energy Sources in the Mexican Energy System—An Application of the Global Energy System Model (GENeSYS-MOD). *Energies*, *12*(17), 3270. Retrieved 2023-08-08, from `https://www.mdpi.com/1996-1073/12/17/3270` (Number: 17 Publisher: Multidisciplinary Digital Publishing Institute) doi: 10.3390/en12173270

Sarmiento, L., Molar-Cruz, A., Avraam, C., Brown, M., Rosellón, J., Siddiqui, S., & Rodríguez, B. S. (2021). Mexico and U.S. power systems under variations in natural gas prices. *Energy Policy*, *156*, 112378. Retrieved 2023-08-07, from `https://www.sciencedirect.com/science/article/pii/S0301421521002482` doi: 10.1016/j.enpol.2021.112378

SENER. (2018). *Programa de desarrollo del sistema eléctrico nacional, PRODESEN.*

SENER. (2019). *Estatus de la infraestructura de gas natural.*

TC Energy. (2023). *TC Energy — North Baja Pipeline System.* Retrieved 2023-08-04, from `https://www.tcenergy.com/operations/natural-gas/north-baja-pipeline-system/`

Wang, H., Zhang, Y., Lin, W., & Wei, W. (2023). Transregional electricity transmission and carbon emissions: Evidence from ultra-high voltage transmission projects in China. *Energy Economics*, *123*, 106751. Retrieved 2023-08-08, from `https://www.sciencedirect.com/science/article/pii/S0140988323002499` doi: 10.1016/j.eneco.2023.106751

World Bank. (2023). *Carbon Pricing Dashboard | Up-to-date overview of carbon pricing initiatives.* Retrieved 2023-07-15, from `https://carbonpricingdashboard.worldbank.org/map_data`

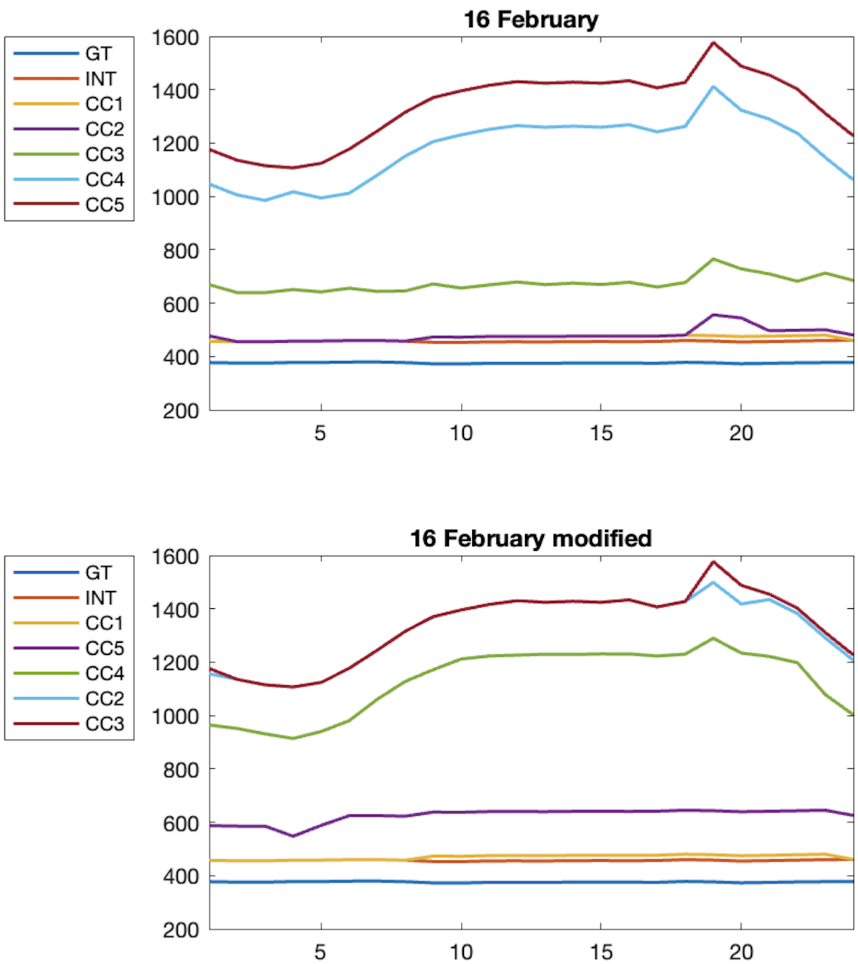
A Appendix

Table 10: Share of profits by power generator changing duct cost allocation, thousand of dollar per day

	GT	INT	CC1	CC2	CC3	CC4	CC5	Total
16 Feb	690.07	153.21	33.56	34.29	36.48	34.97	34.52	**982.59**
14 Mar	701.92	152.31	34.19	36.51	38.69	37.26	36.82	**1000.88**
18 Aug	625.07	152.75	31.28	33.09	35.46	33.07	32.12	**910.72**
23 Oct	616.97	150.26	30.86	31.87	33.98	32.36	31.29	**896.31**
LC	0	0	92.52	93.11	93.27	93.06	92.76	

Notes: CC1 to CC5 represents the five different combine cycle plants, GT is the geothermal plant, INT is an intermittent energy producer, Total is total profit, and LC are the levelized cost under a different allocation of cost from Table 4. The results show the Shapley value for a scenario of high prices ($ 12) and including the cost of a duct.

Figure 5: Merit order curve for 16 February with different duct cost allocations



Notes: 16 February shows the merit order curve of the market with a price of \$12 and the duct costs in Table 4. 16 February modified is the merit order curve for the market with prices of \$12 and the allocation of duct prices as in Table 10