MEXICO: Analysis of the Electricity Market Operation

Year 2020

Technical Note

February 2021

GLOBAL ENERGY MARKETS CONSULTANTS

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FOREWORD

This document contains an analysis of the electricity market operation in Mexico in the period between January and December 2020.

This period was characterized by the effect of the COVID-19 pandemic on energy consumption, which significantly reduced energy prices in the National Interconnected System (SIN)[1], and by a striking imbalance between supply and demand, which in turn strongly affected normal supply of the demand. For example, (i) a massive blackout occurred on Monday, December 28, with a load cutoff of 8,696 MW which left over 10 million people without supply; and (ii) there were high Local Marginal Prices (LMPs) in the week of November 8.

The opinions expressed in this document are subject to the generally accepted uncertainties associated with the interpretation of engineering and commercial data, and do not reflect the totality of circumstances, scenarios and information that could potentially affect the decisions made by the recipients of the report and/or the actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of the prevailing circumstances.

In line with such accepted standards, this document in no way constitutes or provides a guarantee or prediction of results, and there is no warranty, either implied or express, that the actual result will conform to the results presented herein.

MEXICO: Analysis of the Electricity Market Operation. Year 2020 The SIN does not consider the isolated systems in Baja California peninsula.

[1] The SIN does not consider the isolated systems in Baja California peninsula.

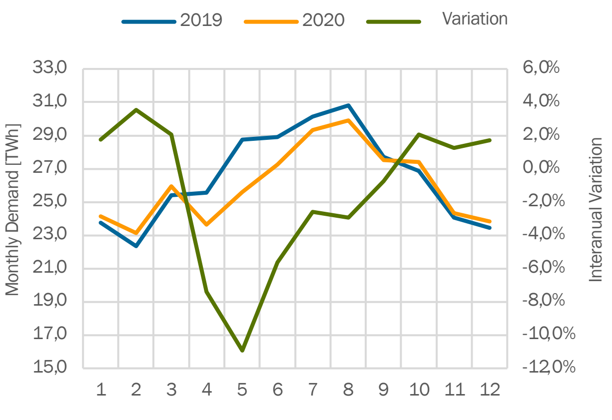
1. DEMAND EVOLUTION

In early December 2019, a new flu epidemic broke out in China and rapidly spread among people. On March 11, 2020, the World Health Organization (WHO) declared COVID-19 (SARS-COV-2) a pandemic while different countries started imposing restrictions on travel and promoting social distancing. Some days later, most governments encouraged self-isolation or, in some cases, mandatory self-isolation. Therefore, there was a considerable decrease in GDP growth expectations that affected the whole world and caused a new global economic crisis along with an important fall in oil prices. In this new context, short-term impacts were observed in the Mexican electricity system (SEN).

As of April 1, 2020, the total demand[2] in the SEN in 2020 was considerably affected by the measures adopted by the government to control the COVID-19 pandemic. Energy demand in 2020 was 312.1 TWh with a Maximum Demand of 45,772 MW.

The following figure shows the monthly demand in 2019 and 2020. We can see a sharp fall from April 2020 onwards. In May there is a maximum 10% decrease compared to the same month in 2019. In the second half of the year, the demand tends to recover, and by the end of the year, the growth is similar to that of the months before the outbreak of the pandemic Demand based on data on settled production. Source: CENACE.

Demand Evolution (Total SEN)



Annual Energy Demand (SEN)

Month	2019 TWh	2020 TWh	Variation
1	23,7	24,2	1,7%
2	22,3	23,1	3,5%
3	25,4	25,9	2,0%
4	25,5	23,7	-7,4%
5	28,7	25,6	-10,9%
6	28,9	27,3	-5,6%
7	30,1	29,3	-2,6%
8	30,8	29,9	-2,9%
9	27,7	27,5	-0,7%
10	26,9	27,4	2,0%
11	24,0	24,3	1,2%
12	23,4	23,8	1,7%
TOTAL	317,7	312,1	-1,75%

	2019 MW	2020 MW	Variation
DMAX	47.368	45.772	-3,37%

[2] Demand based on data on settled production. Source: CENACE.

2. ENERGY PRODUCTION

The following table shows generation installed capacity as of October 2020 by type, owner and system. The values include projects under pre-operative testing. The date when they will start commercial operations has not been informed.

We can see a significant increase in the thermal generation installed capacity of Combined Cycles and that of renewable solar and wind generation..

Installed Capacity by Type [MW]

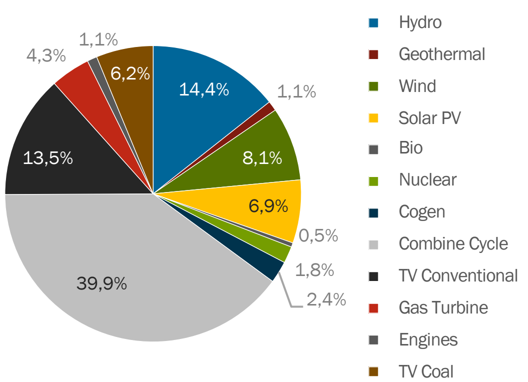
October 2020

	Owner				System			
Technology	CFE	CFE-PIE	PRIVATE	PEMEX	TOTAL	SIN	BC	BCS
Hydro	12,125		489		12,614	12,614	0	0
Geothermal	926		25		951	371	570	10
Wind	86	613	6,378		7,077	7,037	40	0
Solar PV	6		6,059		6,065	5,962	47	56
Bio			408		408	408	0	0
Nuclear	1,608				1,608	1,608	0	0
Cogen			1,738	367	2,105	2,090	15	0
Total Clean	14,751	613	15,097	367	30,828	30,090	672	66
Combine Cycle	10,952	16,076	8,001		35,029	33,208	1,821	0
TV Conventional	10,448		961	422	11,831	11,398	320	113
Gas Turbine	2,858		804	131	3,793	2,842	434	517
Engines	359		590		949	595	2	352
TV Coal	5,463				5,463	5,463	0	0
Total Thermal	30,080	16,076	10,356	553	57,065	53,506	2,577	982
TOTAL	44,831	16,689	25,453	920	87,893	83,596	3,249	1,048

Note: Includes projects in test prior to the start of commercial operation

Source: PRODESEN 2020-2034

Installed Capacity by Type | Total SEN



Installed Capacity by Type | Total SEN [MW]

Technology	2017	2018	2019	2020
Hydro	12,612	12,612	12,612	12,614
Geothermal	899	899	899	951
Wind	3,898	4,866	6,050	7,076
Solar PV	171	1,878	3,646	6,065
Bio	374	375	375	408
Nuclear	1,608	1,608	1,608	1,608
Cogen	1,322	1,709	1,710	2,106
Total Clean	20,884	23,947	26,900	30,828
Combine Cycle	25,340	27,393	30,402	35,030
TV Conventional	12,665	12,315	11,831	11,831
Gas Turbine	2,960	2,960	2,960	3,793
Engines	739	880	891	949
TV Coal	5,463	5,463	5,463	5,463
Total Thermal	47,167	49,011	51,547	57,066
TOTAL	68,051	72,958	78,447	87,894

Source: PRODESEN 2020-2034
Note: Includes projects in test prior to the start of commercial operation

Energy production in 2020 continued its trend of previous years:

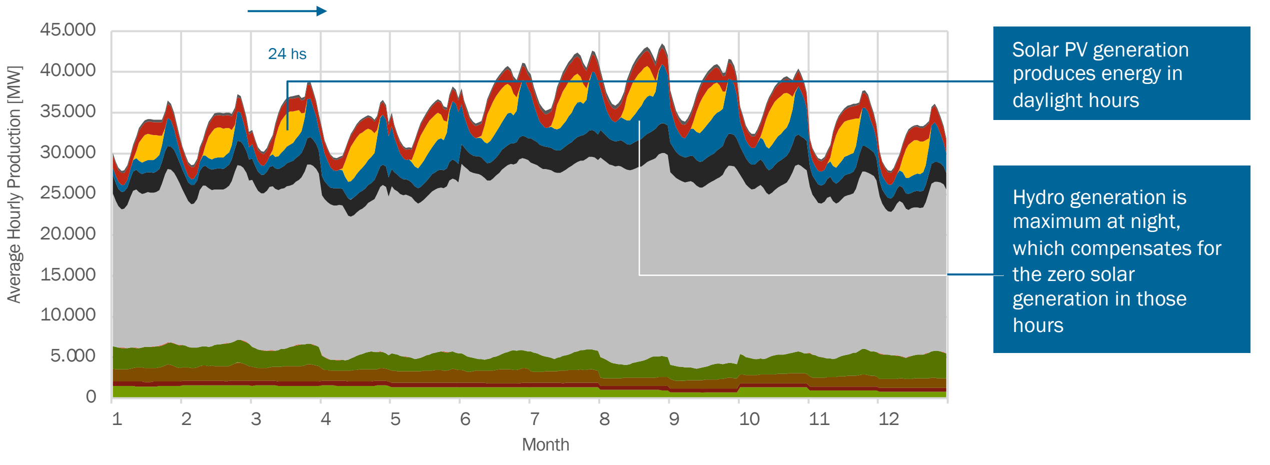
- Growing participation of thermal generation (combined cycles);
- Growing participation of renewable solar and wind generation;
- Downward trend in conventional thermal generation.

The following figure shows the hourly production by type on an average day of each month (matrix 12x24). Accordingly, 24 production values are shown for each month, one for each hour of the day, as the average production in one same hour of every day of the month.

Total production was maximum in the summer months. In April-August, total production fell due to the smaller demand resulting from the measures adopted by the government to control the COVID-19 pandemic. On a typical day, the demand is minimal in the early morning hours and maximum during the night.

Energy Production by Type| Total SEN

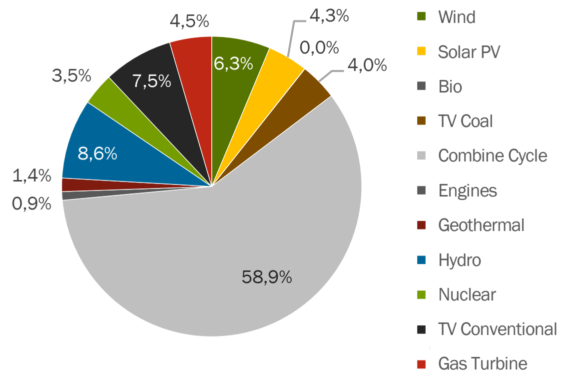
12x24 Matrix



Source: Prepared by the Consultant based on data from CENACE.

The following figure shows the participation of each type of energy produced to meet the demand (2020). We can see a large share of combined cycles (59%). Clean generation (hydro, solar, wind, geothermal, biomass and nuclear) have a 24%[3] share. The rest (13%) of the generation is conventional thermal, coal-fired, internal combustion and gas turbines The objective contained in the Electrical Industry Act is to achieve 35% of clean energy generation by 2030.

Energy Production by Type | 2020



Energy Production by Type (TWh)

Total SEN	2019	2020	Variation
Wind	16.7	19.7	17.7%
Solar PV	8.4	13,5	61.0%
Bio	0.1	0.1	-16.4%
TV Coal	21.6	12.5	-42.0%
Combine Cycle	172.8	183.7	6.3%
Engines	3.2	2.9	-9.3%
Geothermal	5.0	4.5	-9.7%
Hydro	23.6	26.8	13.6%
Nuclear	10.9	10.9	-0.2%
TV Conventional	39.0	23.4	-40.1%
Gas Turbine	16.4	14.1	-13.5%
Total SEN	**317.7**	**312.1**	

Total SEN	2019	2020	Variation
Clean Energy	64.7	75.5	16.7%
Participation	20.4%	24.2%	

The following figures show the historical evolution (monthly values) of the production of wind and solar plants, combined cycles and conventional thermal plants. The production of wind, solar renewable generation and combined cycles thermal plants are rising, which relates to the increase in the installed capacity of this type of technologies. The production of conventional thermal plants, instead, tends to fall due to the lower competitiveness of this technology on account of its low efficiency and high fuel costs.

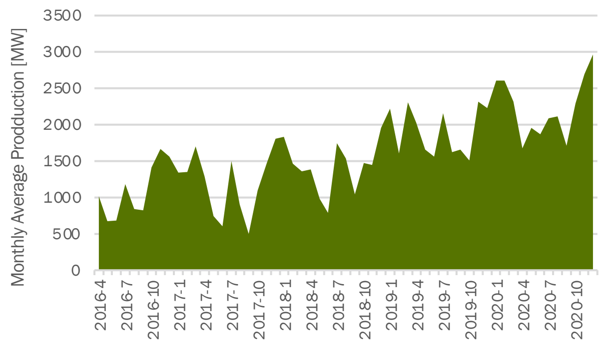
[3] The objective contained in the Electrical Industry Act is to achieve 35% of clean energy generation by 2030.

The larger production of renewable plants (wind, solar, hydro) and high-efficiency thermal plants (CC) increases the total efficiency of the system. Consequently, the production of less efficient plants (conventional thermal) is reduced.

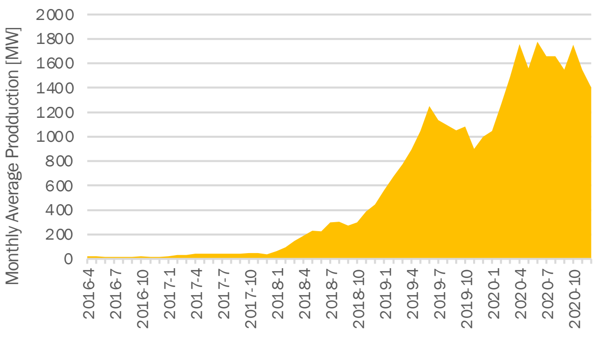
In 2020, there was also a significant drop in fuel oil prices (compared to its typical historical values)[4]. This fuel is mainly used by conventional thermal plants. The drop in prices is due to commercial restrictions affecting PEMEX and associated with the production of fuel oil with high sulfur content.

The smaller demand, greater thermal efficiency and lower fuel prices result in a considerable reduction in LMPs in 2020 compared to the same period in 2019.

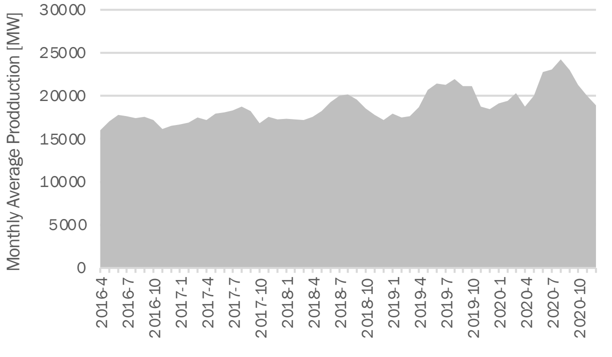
Mexico: Wind Generation



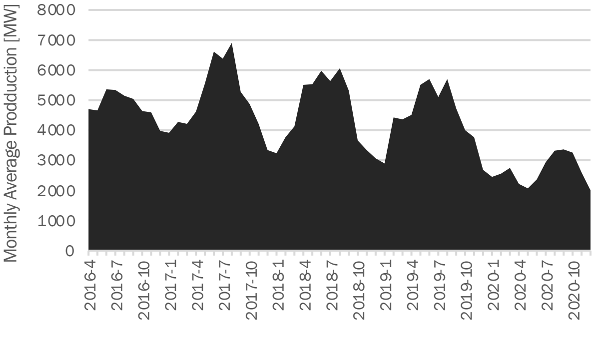
Mexico: Solar PV Generation



Mexico: CC GT Production



Mexico: Conventional Thermal Production



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[4] As a consequence of the global enforcement of maritime regulation IMO-2020 requiring vessels to use clean fuels (under 0.03% sulfur), a large portion of PEMEX's fuel oil production was affected for failing to meet the specifications in the regulation. In the last months of 2019 and particularly after the enforcement of the regulation in January 2020, fuel oil prices in Mexico decreased substantially (they are currently around 6.0 USD/MMBTU) due to the fall in sales. As a result, PEMEX has a production surplus that is sold at very low prices to CFE plants and refineries on the east coast of the United States.

3. FUEL PRICES

The economic generation dispatch seeks to perform the target function of meeting the demand at minimal cost. Generation costs include the cost of the fuel used by thermal generators and the variable O&M cost. The sum of both costs determines the Variable Cost of Production (VCP).

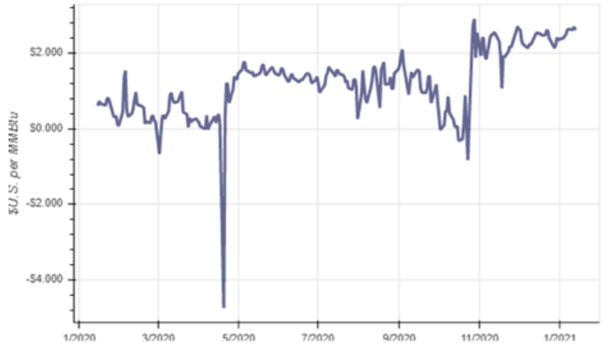
The fuels used by thermal generators in Mexico are mainly natural gas, fuel oil, diesel oil, coal and uranium.

Every hour, LMPs equal the VCP of the generator with the highest VCP that generated (was dispatched) at such hour. To determine the economic dispatch, plants with Bequeathed Contracts, plants dispatched with reliability criteria, and inflexible generation are considered to have VCP=0.0.

As a result, LMPs in the Mexican SIN and the Baja California (BC) system are usually determined by thermal plants using natural gas and, to a lesser degree, fuel oil as fuel. In the Baja California Sur (BCS) system, there is no natural gas availability; therefore, LMPs are mostly determined by fuel oil and, at certain hours with maximum demand (summertime), by diesel oil.

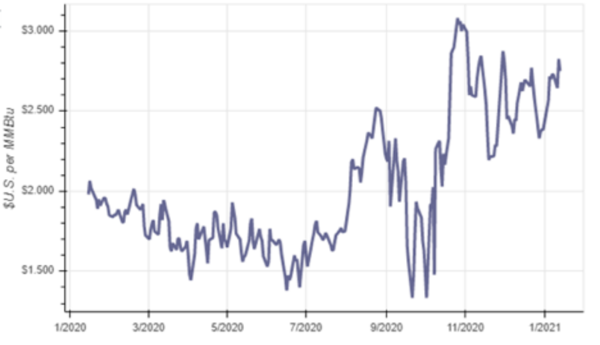
The following figures show the evolution of natural gas and fuel oil prices in 2020.

Daily Waha Prices



Source: NGI

Daily Henry Hub Prices



Source: NGI

Combustoleo (Bunker) Prices USD / MBTU

2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	4.89	6.11	3.87	2.58	3.41	5.12	5.97	6.26	5.70	5.99	6.07	6.00

Source: CRE

As we can see, the price of both fuels increased in the second half of the year and, therefore, LMPs followed the same trend.

[5] Bequathed Contracts are contracts entered into prior to the reform of the power sector in 2014, and the Electrical Industry Act allows them to remain in force without any changes in their contractual conditions.

4. SHORT TERM MARKET

The Short Term Market is the market where generators/large users can sell their surplus/buy deficits with respect to the amounts committed under their supply contracts. The Short Term Market is an hourly market where only electric power is purchased/sold. The electric power purchased/sold in the Short Term Market is valued at the Local Marginal Prices (LMPs, in Spanish) of the Price Node where the energy purchase/sale is carried out.

There are two Short Term Markets: i) the Day Ahead Market (DAM) and ii) the Real Time Market (RTM). The amounts of energy scheduled for each hour of the following day are purchased/sold in the DAM at the LMPs of each hour resulting from the operation scheduling. The energy differences between the real and the scheduled operation at each hour are purchased/sold in the RTM at the LMPs of each hour resulting from the real operation.

The LMPs in the DAM and the RTM result from the economic generation dispatch, and equal the Variable Cost of Production (VCP) of the generating unit with the highest VCP that was generating in the DAM and RTM, respectively. The LMPs in the DAM and RTM are usually different, although the differences are not significant under normal operating conditions.

The following table and figure show the historical evolution of LMPs (DAM) at the Central Node. Both monthly average values and annual average values are shown. As mentioned above, the LMPs recorded in 2020 are the lowest in the last 10 years.

Local Marginal Prices (Central Node) [USD/MWh]

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
2018	60.62	69.09	66.85	78.61	98.65	103.73	93.79	117.91	90.07	72.97	74.44	71.79	83.3
2019	68.65	83.29	93.59	99.71	99.50	75.89	58.06	73.61	79.58	66.58	57.50	37.69	74.4
2020	27.84	31.12	28.39	23.76	25.66	28.97	27.84	34.34	31.51	34.90	44.09	30.73	30.7

LMPs Central Node

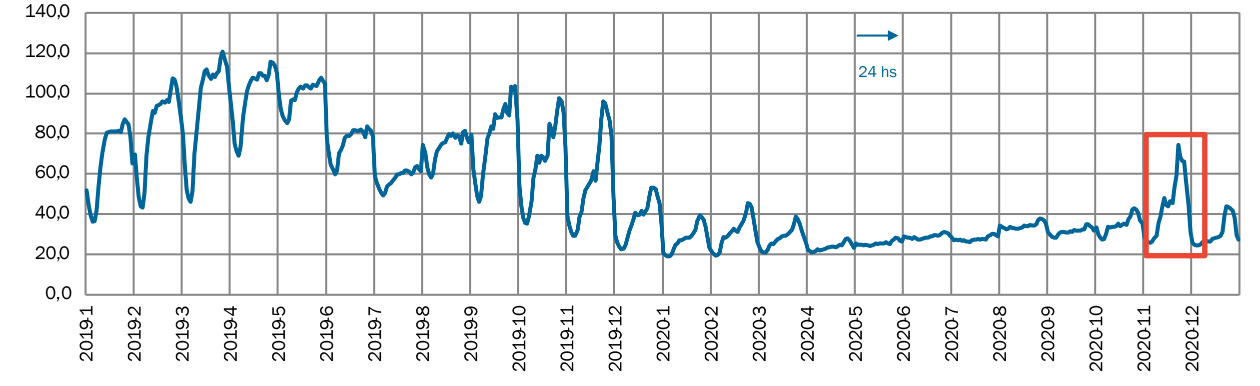
LMPs have intra-day variations related to the supply/demand balance at every hour of the day. In general, they are minimal in the early morning hours when the demand is minimal, and maximum during the night when the demand is maximum. Intra-annual variations mainly arise from seasonal variations in the demand (summer/winter) and from variations in hydro production (wet/dry periods).

The following figure shows the LMPs (DAM) at the Central Node recorded in 2019 and 2020 (Matrix 12x24). Every month, there are 24 LMP values, one for each hour of the day. The LMP of each hour equals the average of the LMPs of all the days of the month at the same hour. In 2020, we can find much lower LMPs than those recorded in 2019. Since the outbreak of the COVID-19 pandemic, LMPs have been very low at every hour of the day. It is only in December that they show the typical intra-day variations of a winter month.

In November 2020, we can find very high LMP values (circled in red) compared to the previous months. These high LMPs were the result of operating with very low operating reserves, which will be commented below.

LMPs Central Node

12x24 Matrix

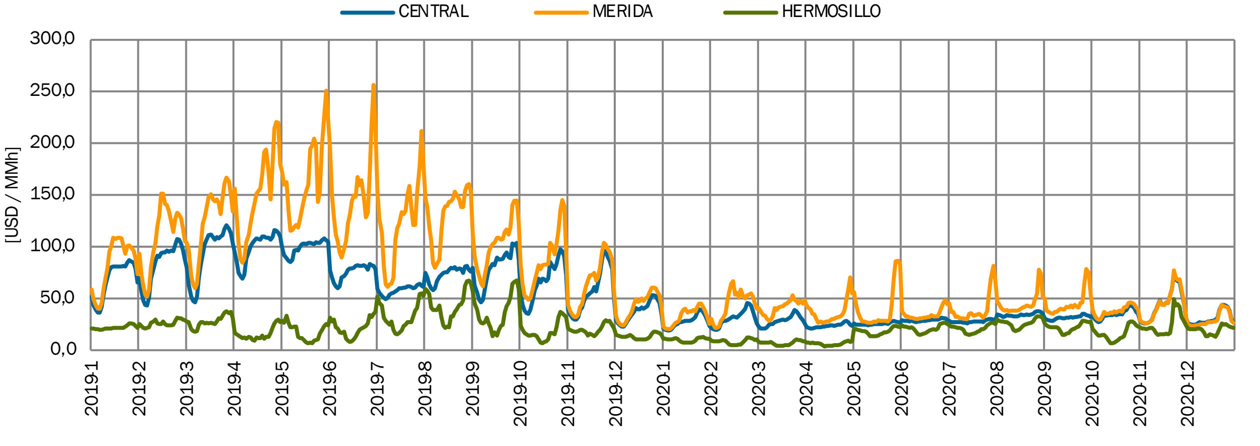


4.1. LMPs in the regions of the SIN

LMPs are different at each node in the power system (price node). The LMPs at each node differ on account of losses and congestion in the transmission system. In energy exporting regions (e.g. the North, Northeast and Northwest regions in Mexico), LMPs tend to be lower than in other regions in the country. For example, the following figure shows the LMPs recorded in 2019 and 2020 at the Hermosillo, Central and Mérida nodes. The Northwest region (Hermosillo) exports energy to the Central region, and the Central region, in turn, exports energy to the Peninsular (Mérida) region; accordingly, the LMPs in Hermosillo are the lowest and those in Mérida are the highest.

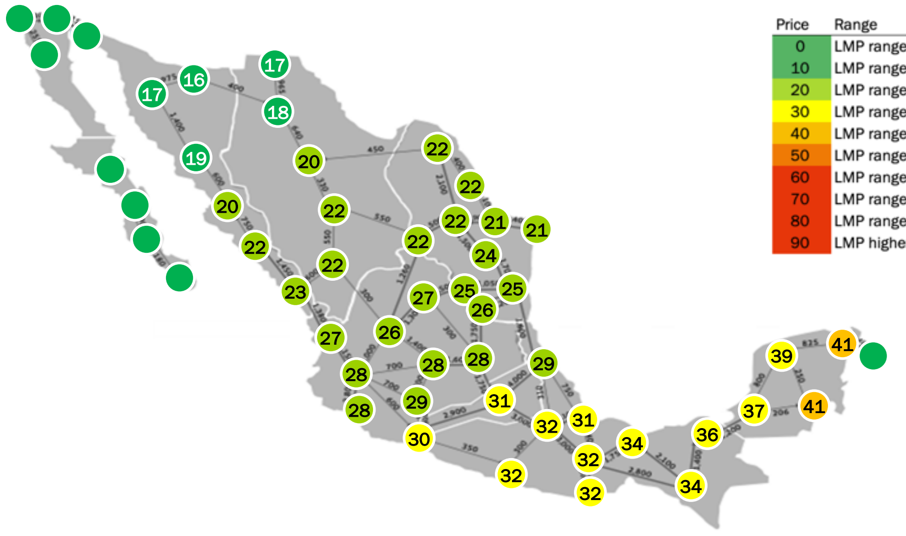
Local Marginal Prices – Year 2020 Hourly Average

12x24 Matrix



Operating conditions (economic dispatch) in 2020 resulted in minimal LMP variations between nodes. The lowest LMPs in the SIN were recorded in the Northwest area, affected by transmission constraints that do not allow exporting the energy available at low marginal cost. Also due to transmission constraints, the Peninsular region had the highest LMPs, as it cannot import energy from the rest of the SIN at low marginal cost and it has no low-cost generation to meet the demand.

LMPs Year 2020 – Annual Average



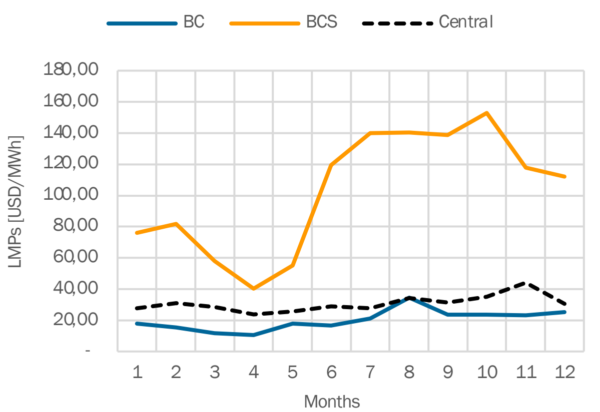
Price	Range
0	LMP range from 0 to 10 USD/MWh
10	LMP range from 10 to 20 USD/MWh
20	LMP range from 20 to 30 USD/MWh
30	LMP range from 30 to 40 USD/MWh
40	LMP range from 40 to 50 USD/MWh
50	LMP range from 50 to 60 USD/MWh
60	LMP range from 60 to 70 USD/MWh
70	LMP range from 70 to 80 USD/MWh
80	LMP range from 80 to 90 USD/MWh
90	LMP higher tha 90 USD/MWh

4.2. LMPs in the BC and BCS regions

The Baja California (BC) and Baja California Sur (BCS) regions are isolated from the rest of the SIN. LMPs in these regions depend on the supply/demand balance in the region, and it is not possible to bring cheaper energy from the SIN or to export any energy surplus from the region to the SIN.

The following table and figure show the LMPs at nodes in the BC and BCS regions in 2020 (monthly average values and annual average values).

LMPs BC, BCS –Year 2020 Monthly Average



LMPs BC, BCS – Year 2020 [USD/MWh]

Month	BC	BCS
	ENSENADA	LA PAZ
1	17.70	75.91
2	15.48	81.83
3	11.76	58.04
4	10.53	40.27
5	18.00	55.01
6	16.66	119.42
7	21.00	139.81
8	34.51	140.17
9	23.72	138.75
10	23.80	152.90
11	23.31	117.72
12	25.08	112.22
Annual	20.18	102.83

LMPs in the BC region are very low (≈20.0 USD/MWh) due to natural gas availability for thermal generation from the Permian Basin (Waha commodity price) and high thermal efficiency due to the availability of natural gas-based generation (Combined Cycles).

The BCS region, instead, has the highest LMP values in all Mexico due to the absence of natural gas for thermal generation. Therefore, thermal generation uses fuel oil and diesel oil as base fuels, resulting in a high Variable Cost of Production and, consequently, high LMPs in the region.

4.3. Congestion / Loss Costs

The differences between the LMPs at the nodes are the reason for the existence of congestion/loss charges when energy is transported from the injection node to the withdrawal node. Congestion/ loss charges are invoiced by CENACE via a Bilateral Financial Transaction (TBF, in Spanish) when there are supply contracts between a generator and a consumer.

The amount invoiced for a TBF at each hour equals the transported energy (ET, in Spanish) times the difference between the LMPs at the withdrawal node (PML(R)) and the injection node (PML(I)).

$$\boxed{\boldsymbol{TBF_h[MXN] = ET_h \times (PML_h(R) - PML_h(I))}}$$

The following table shows the TBF charges in 2020, assuming that 1.0 MWh is transported every hour of the year from the injection node to the withdrawal node.

For example, transporting 1.0 MWh during every hour of 2020 had the following unit costs:

- from Hermosillo node to Mérida node: + 22.66 USD/MWh
- from Monterrey node to Guadalajara node: + 6.31 USD/MWh
- from Grijalva node to Mérida node: + 4.94 USD/MWh
- from Veracruz node to Durango node: - 8.22 USD/MWh

Congestion and Losses Costs 2020 [USD/MWh]

	Withdrawal											
Inyection	HERMOSILLO	MONTERREY	CHIHUAHUA	DURANGO	AGUASCALIENTES	GUADALAJARA	CENTRAL	PUEBLA	VERACRUZ	GRIJALVA	LERMA	MERIDA
HERMOSILLO	-	5.13	3.56	5.69	9.74	11.43	14.11	15.17	13.90	17.73	20.39	22.66
MONTERREY	-5.13	-	-1.56	0.56	4.62	6.31	8.99	10.04	8.78	12.60	15.26	17.54
CHIHUAHUA	-3.56	1.56	-	2.12	6.18	7.87	10.55	11.60	10.34	14.16	16.82	19.10
DURANGO	-5.69	-0.56	-2.12	-	4.06	5.75	8.43	9.48	8.22	12.04	14.70	16.98
AGUASCALIENTES	-9.74	-4.62	-6.18	-4.06	-	1.69	4.37	5.42	4.16	7.98	10.64	12.92
GUADALAJARA	-11.43	-6.31	-7.87	-5.75	-1.69	-	2.68	3.73	2.47	6.29	8.95	11.23
CENTRAL	-14.11	-8.99	-10.55	-8.43	-4.37	-2.68	-	1.05	-0.21	3.62	6.28	8.55
PUEBLA	-15.17	-10.04	-11.60	-9.48	-5.42	-3.73	-1.05	-	-1.26	2.56	5.22	7.50
VERACRUZ	-13.90	-8.78	-10.34	-8.22	-4.16	-2.47	0.21	1.26	-	3.83	6.49	8.76
GRIJALVA	-17.73	-12.60	-14.16	-12.04	-7.98	-6.29	-3.62	-2.56	-3.83	-	2.66	4.94
LERMA	-20.39	-15.26	-16.82	-14.70	-10.64	-8.95	-6.28	-5.22	-6.49	-2.66	-	2.27
MERIDA	-22.66	-17.54	-19.10	-16.98	-12.92	-11.23	-8.55	-7.50	-8.76	-4.94	-2.27	-

Even though the LMPs recorded in 2020 were low, we can find high congestion/loss cost values that reach maximum values of 22.66 USD/MWh. These costs are therefore very relevant when entering into supply contracts under the current Electrical Industry Act (LIE, in Spanish).

It is important to mention that the costs mentioned above are only reference values, since the real costs will depend on the characteristics of each supply contract (injection/withdrawal nodes, hourly demand under contract).

4.4. Prices captured by solar projects

As mentioned above, LMPs have hourly variations. As a result, the price captured by renewable projects, mainly solar, is different from the mean prices mentioned above.

The following table shows the relation between captured prices and mean prices determined for typical solar projects located at Central, Monterrey, Hermosillo and Chihuahua nodes.

Some captured prices can be 10% lower than the mean prices at the node. The effect is more significant in the Northwest and North regions.

Captured Prices Ratio (2020)

CENTRAL	MONTERREY	HERMOSILLO	CHIHUAHUA
1,022	0,979	0,892	0,905

5. CAPACITY BALANCE MARKET

5.1. Capacity Price

The Capacity Prices in the Capacity Balance Market are determined by CENACE every year in the month of February of the following year. The Capacity Prices are determined for the SIN and for the isolated BC and BCS systems (Capacity Zones).

In each Capacity Zone, CENACE establishes the Reference Generation Technology (TGR, in Spanish) and the annuity of the fixed costs of said generating unit (Levelized Fixed Cost), so that they can recover their investment costs and fixed O&M costs. The following table shows the TGR and the related Levelized Fixed Costs for the three capacity zones.

Selected Technology for Suppling Peak Demand

Capacity Zone	Selected Technology	Capacity [MW]	Levelized Cost (Fix) [USD/MW-Year]
SIN	Gas Turbine (GT) Industrial Type	210.0	118,088.95
BC		210.0	103,506.96
BCS		47.5	209,588.43

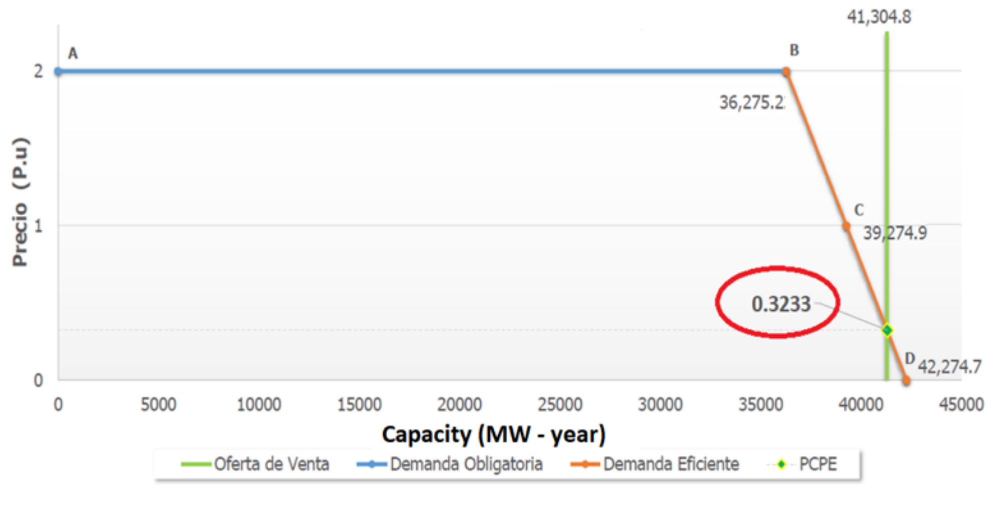
Source: CENACE

Based on the capacity demand and sale offers, CENACE determines a FACTOR that multiplies the Levelized fixed cost. The following figure shows the procedure used. The FACTOR is a value between 0.0 and 2.0. The FACTOR equals 0.0 when the generation reserve of the system is higher than twice the optimal reserve. The FACTOR equals 2.0 when the generation reserve of the system is lower than the minimum. The FACTOR equals 2.0 when the generation reserve is optimal.

Between the maximum and minimum reserve values, the FACTOR is linearly reduced (in orange). The FACTOR equals 1.0 when the generation reserve of the system is optimal (7.7%).

The value of the FACTOR estimated for the SIN in 2020 is 0.3233. This shows that there is generation oversupply (higher reserve than the optimal one), which will tend to reduce the Capacity Price.

SIN – Capacity Balance Curves



CENACE determines the marginal revenue from energy sales in the short term market (IMTGR [MXN/MW]) of the plant selected as TGR. The revenue from energy equals the sum – for all the hours of the year when the plant is dispatched – of the difference between the LMPs and the Variable Cost of Production (VCP) of the plant. The hours when the plant is dispatched are those when the LMPs are higher than or equal to the VCP of the plant. The LMPs are those of the node in the SIN where CENACE considers that the plant is located (typically, a node in the Northeast region). The LMPs are those of each hour of 2020.

$$\boldsymbol{IMTGR[MXN/MW]} = \sum_{h=1}^{h=8760} \boldsymbol{MAX(0; PML_h - CVP)}$$

The following table shows the values estimated by CENACE as IMTGR for each capacity zone in 2020. The low LMPs recorded in 2020 result in low IMTGR values compared to those recorded in previous years.

Market Incomes

System	Technology	Capacity [MW]	IMTGR [USD/MW-Year]
SIN	TG Ind	210	6,849.8
BC	TG Ind	210	64,914.9
BCS	TG Ind	47.5	401.7

The capacity price for each Capacity Zone is the result of the following expression:

$$\boldsymbol{Capacity\ Price} \left[\frac{\boldsymbol{USD}}{\boldsymbol{MW}}\right] = \boldsymbol{FACTOR} \times \boldsymbol{Levelized\ Cost} - \boldsymbol{IMTGR}$$

The following table shows the values of the Capacity Price for the three Capacity Zones. The resulting PPOT for the SIN is high compared to the values recorded in previous years. The reason for this is the low LMPs recorded in 2020, which reduced the Market Revenues of the plant selected as TGR to a minimum.

Capacity Prices| Year 2020

Exchange Rate [$MX/USD] 19.97

System	Technology	Capacity	Factor	Levelized Cost	IMTGR	Price	
		[MW]		[USD/MW-Year]	[USD/MW-Year]	[USD/MW-Year]	[USD/kW-Month]
SIN	TG Ind	210	0.3233	118,538.9	6849.8	31,473.9	2.6
BC	TG Ind	210	2.00	103,744.4	64,914.9	142,573.9	11.9
BCS	TG Ind	47.5	2.00	210,046.9	401.7	419,692.2	35.0

SIN | Historic Capacity Prices

Year	Levelized Cost	Factor	IMTGR	Prices	
	[USD/MW-Year]		[USD/MW-Year]	[USD/MW-Year]	[USD/kW-Month]
2016	109,430	1.18	65,364	63,544.5	5.3
2017	102,620	1.62	128,587	37,349.5	3.1
2018	103,260	2.00	200,336	6,184.0	0.5
2019	120,401	1.51	170,473	11,332.5	0.9
2020	118,089	0.3233	**6,849.8**	31,473.9	**2.6**

The high capacity prices in the BC and BCS regions are worth mentioning. They are an economic signal associated with a generation reserve that is lower than the minimum, which implies supply risks due to insufficient generation capacity in such regions.

As high capacity prices remain over time in the BC and BCS regions (PPOT values in 2019 are similar), this indicates that the economic signal associated with the Capacity Balance Market is not attracting new investment in generation in these regions.

5.2. 100 critical hours in the SIN

The Electricity Market Regulation defines the hours of a year with minimum generation reserve in the power system as 100 critical hours. The reserve is the difference between the capacity available at every hour and the demand to be supplied at such hour. The 100 critical hours are used to determine capacity purchase/sale transactions in the Capacity Balance Market.

Typically, the 100 critical hours occur in the summer months, when the demand is maximum. In 2020, the smaller demand in the summer months mentioned above and due to COVID-19 resulted in the shift of the 100 critical hours to the last 4 months of the year, when 21% of them occurred during daylight hours (9:00 – 19:00).

SIN | 100 Critical Hours (2020)

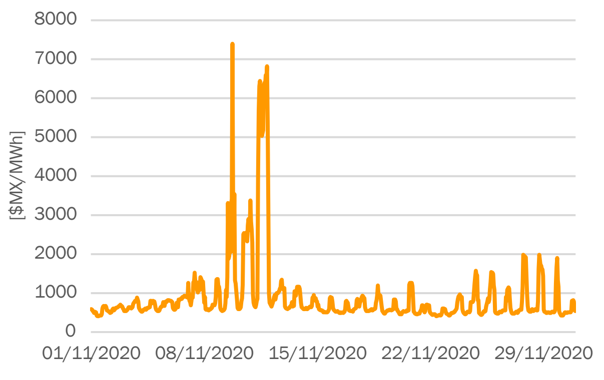
	Hour																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	3	1	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	6	5	5	0
10	1	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	3	4	5	10	15	10	9	4
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	5	3	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

6. RELIABILITY IN THE OPERATION OF THE SIN

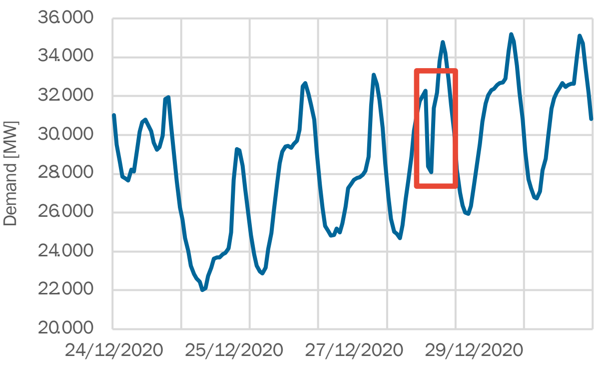
In 2020, two events affected the reliable operation of the Mexican SIN and, therefore, normal supply.

- In the week of Nov. 8, high LMPs were recorded (> 6,000 MXN/MWh, 300 USD/MWh). They are unprecedented values in operation and were not repeated in the remaining days of the year.
- In the afternoon of Dec. 28, there was strong instability in the power system operation (SIN), which resulted in a severe blackout affecting over 10 million people, with a load cutoff of 8,696 MW (Source: CENACE[6]).

LMPs Central Node



SIN | Hourly Total Demand

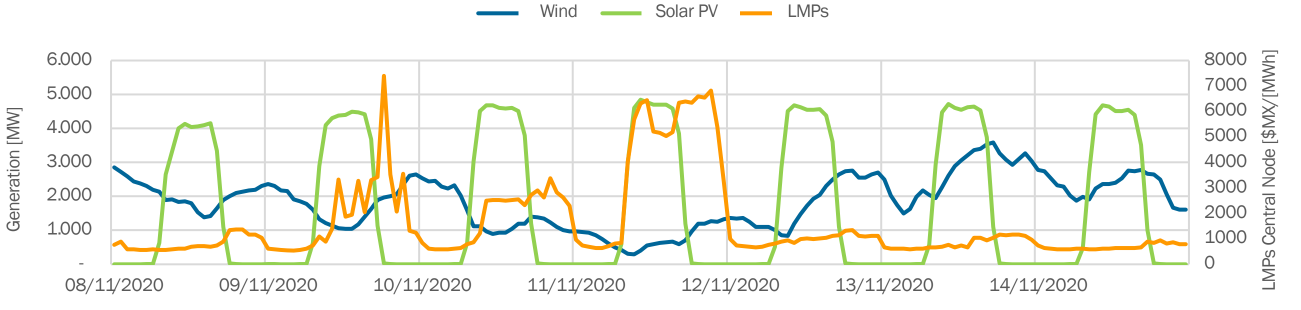


6.1. Event of Nov. 8

The high LMP values recorded in the week of Nov. 8, 2020 are explained by a very low generation reserve, which resulted in the need to dispatch generation units that use Diesel as fuel and are characterized by their very high variable cost of production.

The production of solar and wind plants in the week of Nov. 8 is shown in the following figure. We can see high LMP values even though there was maximum solar production. The increase in LMPs is not associated with a sudden (unpredicted) variation in renewable generation.

Renewvable Generation (Wind, Solar PV)



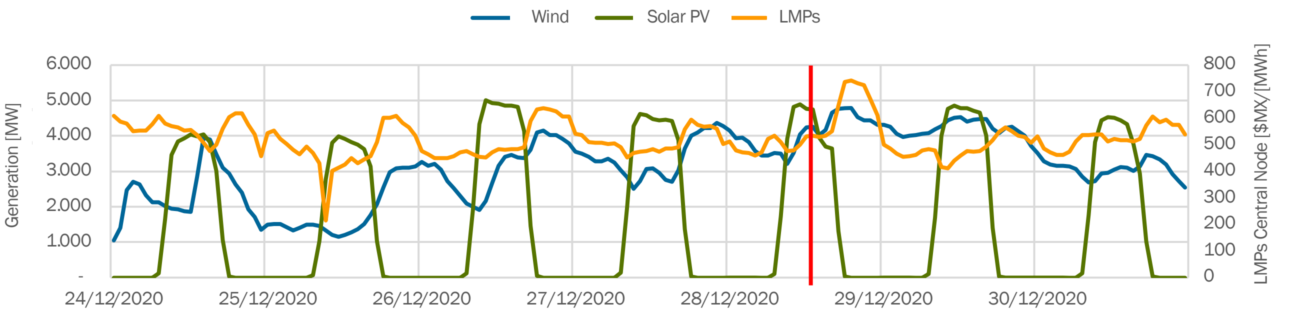
6.2. Event of Dec. 28

As mentioned above, in the afternoon of Dec. 28, there was strong instability in the operation of the SIN, which resulted in a significant load cutoff (8,696 MW).

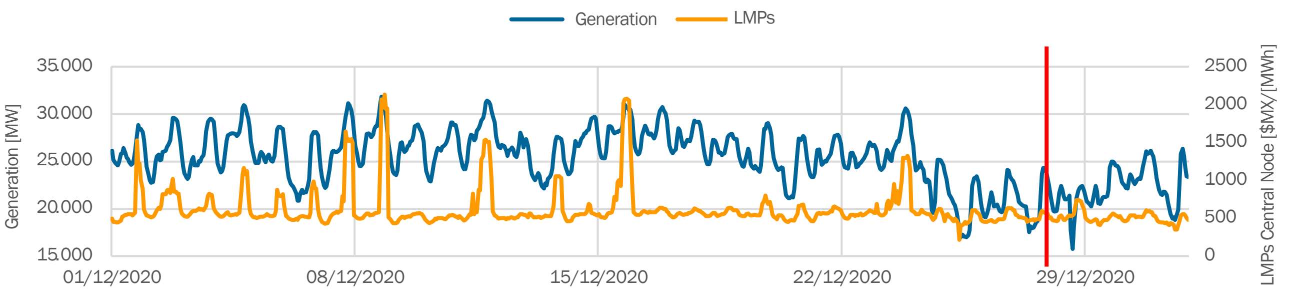
[6] *Press release 04/2020.- The National Energy Control Center* (CENACE) reported that a load of 8,696 MW was affected in the National Interconnected System at 14:28. This represented 26% of the demand at that moment. At the time of the event, the demand was 31,789 MW.

The following figures show the renewable generation dispatch (wind, solar) and the total thermal generation dispatch in the week when the analyzed disturbance occurred. The red line indicates the moment when the instability occurred. We can see that the renewable production had similar levels to those of the previous days and, at the time of the fault, there was no significant intermittence. Total thermal generation was considerably lower than the maximum recorded in the month of December.

Renewable Generation (Wind, Solar PV)



Thermal Generation



The above comments allow us to conclude once again that the instability recorded in the power system on Dec. 28 was due to the lower availability of thermal generation, as a result of which, upon a fault in the transmission system, the power system had not enough generation capacity in the SIN (reserve), which led to a frequency drop in the system with the subsequent load loss to restore the dynamic balance of the power system.

We can also find low reserve levels on other days of the month of December when, even with low demand (winter), the dispatch of CT plants was required, with consequent LMPs over 2,000 MXN/MWh.

7. FORECAST FOR 2021

1	Demand growth recovery, resulting in higher values than those recorded in 2019 and 2020. Monthly demand is estimated to grow by 2.5% on the values recorded in 2019.
2	The addition of new plants (CC, wind, solar) will continue, increasing the thermal efficiency of the system with lower production from conventional thermal plants..
3	Similar fuel prices to the current ones (December 2020)
4	Higher LMPs than those of 2020, mainly because of the higher demand and higher fuel prices than the average ones in 2020.
5	As long as thermal generation availability does not improve, more instability events similar to the ones mentioned above are expected to occur in the power system, both in the SIN and in the isolated BC and BCS systems.
6	No significant enhancements are expected in the trunk transmission grid. The expected low LMPs will reduce congestion costs and favor energy exchanges between electrical regions.

ABOUT GME

At GME we have been providing strategic advice to companies and institutions in the global energy market for nearly three decades. Our interdisciplinary platform implements comprehensive solutions tailored to each type of client, at each link in the value chain.

With a team of more than 70 consultants specialized in technical, economic and regulatory aspects, we operate from five companies with strategically located offices in Argentina, Brazil, Chile, Mexico, Peru, Uruguay and South Africa. This allows us to manage more than 300 projects per year for the electricity, oil and gas, and water and sanitation sectors.

We were pioneers in global energy consulting, with the first market reforms in the 90s, and it is thanks to our expertise, our vocation for excellence, and our vision for the future that today we continue to be a strategic partner for all our clients

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