NEPR

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GOVERNMENT OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: **REVIEW OF THE PUETO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN**	CASE NO.: CEPR-AP-2018-0001 SUBJECT: Submittal of Redacted AES Coal Plant Conversion Assessment

SUBMITTAL OF REDACTED AES COAL PLANT CONVERSION ASSESEMENT

TO THE PUERTO RICO ENERGY BUREAU:

COMES NOW the Puerto Rico Electric Power Authority through the undersigned legal representation and respectfully submits a redacted version of the AES Coal Plant Conversion Assessment [1].

WHEREFORE, PREPA requests the Puerto Rico Energy Bureau to note the filing of the AES Coal Plant Conversion Assessment.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 23rd day of August, 2019.

<u>/s Katiuska Bolaños</u>
Katiuska Bolaños
kbolanos@diazvaz.law
TSPR 18888

DÍAZ & VÁZQUEZ LAW FIRM, P.S.C.
644 Ave. Fernández Juncos
District View Plaza, Suite 301
San Juan, PR 00907-3122
Tel. (787) 679-7132
Fax. (787) 919-7319

[1] PREPA has requested the Puerto Rico Energy Bureau to grant a confidential designation to the unredacted version.

CERTIFICATE OF SERVICE

We hereby certify that, on this same date we have filed the above motion at the office of the Clerk of the Puerto Rico Energy Bureau; and a courtesy copy of the filling was sent via e-mail to the Puerto Rico Energy Bureau Clerk and internal legal counsel to: secretaria@energia.pr.gov; wcordero@energia.pr.gov; legal@energia.pr.gov; and sugarte@energia.pr.gov.

In addition, the foregoing filing was sent via e-mail to the approved or pending intervenors (Arctas, Caribe GE, League of Cooperatives and AMANESER 2025, OIPC, EcoEléctrica, Empire Gas, Environmental Defense Fund, Local Environmental Organizations, National, "Non Profits", Progression, SESA-PR, Renew, Shell, Sunrun, Wartsila, Windmar Group) and amicus (ACONER, AES-PR, RMI) at the following e-mail addresses: acarbo@edf.org; javier.ruajovet@sunrun.com; pedrosaade5@gmail.com; rstgo2@gmail.com; rmurthy@earthjustice.org; larroyo@earthjustice.org; jluebkemann@earthjustice.org; carlos.reyes@ecoelectrica.com; ccf@tcmrslaw.com; rtorbert@rmi.org; victorluisgonzalez@yahoo.com; mgrpcorp@gmail.com; hrivera@oipc.pr.gov; jrivera@cnslpr.com; manuelgabrielfernandez@gmail.com; axel.colon@aes.com; acasellas@amgprlaw.com; corey.brady@weil.com; maortiz@lvprlaw.com; rnegron@dnlawpr.com; paul.demoudt@shell.com; escott@ferraiuoli.com; aconer.pr@gmail.com; agraitfe@agraitlawpr.com; presidente@ciapr.org; castrodieppalaw@gmail.com; voxpopulix@gmail.com; cfl@mcvpr.com; sierra@arctas.com; tonytorres2366@gmail.com; info@liga.coop; amaneser2020@gmail.com; csanchez@energia.pr.gov; ireyes@energia.pr.gov; asanz@energia.pr.gov; bmulero@energia.pr.gov; nnunez@energia.pr.gov; gmaldonado@energia.pr.gov; viacaron@energia.pr.gov.

In San Juan, Puerto Rico, this 23rd day of August, 2019.

*/s Katiuska Bolaños*___
Katiuska Bolaños

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Siemens PTI Report Number: Report-8/16

AES Coal Plant Conversion Assessment

Draft for the Review of the Puerto Rico Energy Bureau

Prepared for

Puerto Rico Electric Power Authority (PREPA)

Submitted by:
Siemens Industry

Rev. [0]
8/16/2019

Siemens Industry, Inc.

Siemens Power Technologies International

400 State Street • P.O. Box 1058

Schenectady, New York 12301-1058 USA

Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777

www.siemens.com/power-technologies

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Contents

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Section
1

Introduction and Main Findings

The AES Coal Power Plant in Puerto Rico has 2 x 227 MW net coal-fired generating units. Each unit includes a boiler and Steam Turbine Generator (STG) The purpose of the project is to assess, based on dispatch modeling of the PREPA system, the economics of converting the two AES coal units to Natural Gas (NG) To provide approximate power generation unit cost and performance data for study purposes, a brief, high level technical study was performed. Three conversion options were considered:

1. Direct conversion of existing boilers from coal to NG

2. Combined Cycle Repowering by adding GTs and Heat Recovery Steam Generators (HRSGs) to provide steam to the existing STG and abandoning the existing coal-fired boilers

3. Boiler NG conversion plus addition of a Gas Turbine (GT) generator exhausting into the existing boiler (so-called Heavily Fired Combined Cycle or HFCC)

AES did not provide specific design data about the existing plant. A small amount of published technical literature and press releases about the plant were found. So, assumptions were made for study purposes based on typical steam electric plant Rankine cycles and general knowledge of boilers and plant auxiliary systems. This analysis is not a substitute for the detailed studies that would be required to determine technical feasibility, approaches and costs of activities such as boiler fuel conversion, boiler combustion air systems changes, STG modifications, etc.

For the conversion or retirement, the study was done considering the conditions of 2021, that is the plant is required to convert or retire by the end of 2020. This reference year is in line with the Order[1] from the Puerto Rico Energy Bureau and should be considered just representative of conditions (load / generation) at the time of the conversion as in practice it will take significantly longer to implement the conversions, if this was selected.

As will be shown in this report under the assumptions made, none of the conversion options was selected with the exception of Scenario 5 that considered Strategy 1 and hence large generation could be installed in the south. In this case the Combined Cycle Repowering (Option 2) was selected. Instead of the conversion the long term capacity expansion (LTCE)

[1] PREB Resolution and Order CEPR-AP-2018-0001 issued on May 23rd, 2019

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plan elected to extend the operation of other existing units (EcoEléctrica and Costa Sur 5&6) and install a new F-Class combined cycle.

Under all cases there was an increase in the generation revenue requirements as detailed below.

Under Scenario 4 Strategy 2 Base load forecast (S4S2B), AES did not convert and the NPV of the revenue requirements increased from $14.35 billion to $14.93 billion (4.0% increase) with the retirement of AES by the end of 2020 and the average cost of energy from 2019 to 2027 increased from $99.3 / MWh to $104.9 / MWh (5.6% increase).

Under the ESM Base load forecast, AES also did not convert and the impact was the least. The NPV of the revenue requirements increased from $14.431 billion to $14.606 billion (1.2% increase) with the retirement of AES by the end of 2020 and the average cost of energy from 2019 to 2027 increased from $99.0 / MWh to $101.5 / MWh (2.6% increase).

Under Scenario 1 Strategy 2 Base load forecast (S1S2B), AES did not convert and the NPV of the revenue requirements increased from $14.77 billion to $15.24 billion (3.1% increase) with the retirement of AES by the end of 2020 and the average cost of energy from 2019 to 2027 increased from $102.2 / MWh to $106.8 / MWh (2.6% increase).

The Scenario 3 Strategy 2 Base load forecast (S3S2B) was the second least affected by the retirement of AES (the ESM was the least affected) and the NPV of the revenue requirements increased from $13.84 billion to $14.03 billion (1.4% increase) with the retirement of AES by the end of 2020 and the average cost of energy from 2019 to 2027 increased from $96.4 / MWh to $99.7 / MWh (3.5% increase).

The Scenario 5 Strategy 1 Base load forecast (S5S1B) was the only case where AES did convert to a combined cycle (conversion option 2) and only one unit. In this case the NPV of the revenue requirements increased from $14.12 billion to $14.70 billion (4.1% increase) with the conversion of AES by the end of 2022 and the average cost of energy from 2019 to 2027 increased from $98.4 / MWh to $104.2 / MWh (5.9% increase).

No adverse impacts were identified on the transmission system with the retirement of AES Coal or the conversion to a CCGT 585 MW.

Section
2

Input Assumptions

2.1 AES Coal Plant Conversion Options

2.1.1 AES Coal Plant Design

AES Coal (AES PR) uses Circulating Fluidized Bed (CFB) Boilers. This was confirmed by review of the air permit data and industry literature. Also, the plant already has cooling towers, so likely no permit-driven cooling system upgrades would be required in fuel conversion or repowering scenarios.

Quite a few Coal-to-Gas conversions have been performed on US Mainland coal plants in the last 10 years, many driven by Mercury and Air Toxics Standards (MATS) regulations. Most of such plants are more than 40 years old and have conventional pulverized coal (PC) boilers. Some plants saved money by converting existing coal burners to Natural Gas (NG) firing, others installed new NG burners. A CFB boiler is quite different from a PC boiler in its design and operation, though it basically achieves the same objective of burning coal and capturing the heat in the feedwater to make superheated steam. However, the coal burns as glowing hot particles instead of a flame from a conventional burner. So, for AES PR, new NG burners would be needed. Usually there are oil-fired burners to heat the bed for startup, but more burners would be needed for 100% design heat input from NG.

AES PR boiler steam conditions are conventional, subcritical, at 2,400 psig, 1000F superheat and 1000F reheat (2400/1000/1000.) The number of stages of feedwater heating is unknown so a typical 7-heater cycle was assumed. The plant already has Selective Non-Catalytic Reduction (SNCR) for NOx control, (i.e., direct injection of Urea into the combustion gas stream) so this may be helpful in controlling NG NOx. The CFB boiler has limestone injection into the boiler to capture SO2 directly. The AES plant also has a lime scrubber after the boiler to achieve a higher percentage reduction in SO2 than the CFB alone can provide. For NG firing with virtually no fuel sulfur, the lime scrubber probably can be eliminated. The CFB still may require a bed material for heat transfer purposes; if so, possibly this could continue to be limestone or be switched to inert material such as sand. The electrostatic precipitator (ESP) would remain in operation for dust control in the stack gas.

The specifics of fuel conversion always require a boiler-specific study of heat transfer surfaces, fans, burner controls, etc., often performed by the original boiler supplier. This would be especially true for a CFB boiler, as Siemens is not aware of any instances of actual conversion of a coal CFB boiler to NG. Also, if the converted units with higher marginal costs operate in a dispatchable mode instead of baseload, this requires study of the possible effects of frequent starts/stops and load changes on overall plant reliability and maintenance.

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Siemens has assumed that the fuel conversion can be done, and the costs would be similar to a PC boiler conversion.

2.1.2 Fuel Conversion and Repowering Options:

There are 3 main options of Coal-to-Gas conversion that could be considered for AES PR:

1. Convert existing coal boilers to NG firing. This is the most straightforward option.
2. Combined Cycle Repowering using a large new GT and Heat Recovery Steam Generator (HRSG). In this case the existing boiler is abandoned or demolished, while STG and other site facilities are integrated into the Repowered CC.
3. Heavily Fired Combined Cycle (HFCC) using a new gas turbine's (GT) exhaust as preheated combustion air to the existing boiler. This option would increase overall plant output and improve heat rate.

2.1.3 Technical Study Approach

Information was gathered and several calculations were performed to establish a performance baseline for the existing plant. Siemens obtained a typical Colombian El Cerrejon coal specification and a typical "Caribbean" Liquefied Natural Gas (LNG) specification (assumed sourced from US Gulf or East coasts) to represent the current and proposed fuels.

Rough combustion calcs were performed for the existing CFB boilers on coal to establish the Lower Heating Value (LHV) fuel requirements. Steam flows were estimated based on a typical coal Rankine power cycle and correlated with main and reheat steam flows from the air permit and published reports. Fuel requirements also were correlated with the contract heat rate to assume boiler efficiency.

2.1.3.1 Option 1, Boiler NG Conversion

For Option 1, boiler NG conversion, Siemens assumed the LHV heat requirements on NG would be the same as they were on coal. This accounts for heat transferred into the main and reheat steam and boiler losses including stack heat. The ratio of Higher Heating Value (HHV) to LHV for coal is low; Siemens calculated it to be about 1.04 for the selected typical El Cerrejon coal with 3.66% moisture by weight. NG HHV/LHV ratio is substantially higher at 1.107 to 1.110, so this results in a reduced net HHV efficiency for the plant. The NG HHV efficiency determines the NG net heat rate. For study purposes output was assumed to be the same as on coal. In some instances, a boiler NG conversion can require a boiler and plant derating. In the absence of a NG conversion study by the CFB boiler manufacturer (Alstom) no derating was assumed.

A small reduction was made to plant auxiliary loads to reflect lower power consumption by no longer operating coal handling and crushing, dry scrubber, etc. This resulted in a slight credit to heat rate. But overall HHV heat rate is higher on NG due to additional moisture created in NG combustion and lost out the stack.

2.1.3.2 Option 2, Combined Cycle Repowering

This option is similar to repowering of older STGs that has been done at many sites in the US and around the world. The main sizing criterion is to match the steam production and steam conditions of the GT/HRSG trains to the existing STG inlet and reheat. However, as discussed below, the STG extractions are closed off resulting in higher flows to the back end and condenser. So detailed study is required of the STG steam path to accommodate a waste heat cycle vs. a fired boiler cycle.

In a typical steam plant about 1/3 of the STG inlet flow is extracted at 5-7 stages of the STG for feedwater heating, which improves overall cycle efficiency. In a waste heat cycle, feedwater is heated mostly by waste heat including Low Pressure sections of the HRSG, so most STG extractions are not required. When the inlet steam flows all the way through the STG instead of being extracted, the inlet steam rate (in lb/kWh) is reduced, but the STG exhaust flow is increased, which puts more load on the condenser and cooling tower.

Siemens determined that the “Smaller F-Class” (F04) with Duct firing (DF) from the earlier studies was a good match for the existing AES STGs. Each AES unit can be matched with 2 GT/HRSG trains. The AES STGs are somewhat smaller than the F04 CC STGs with full DF, but the amount of DF can be reduced, and the STG can accept more than the Unfired steam output of the HRSGs.

The CC F04 output for a 1x1 was about 250 MW Unfired and about 302 MW with full DF. The CC F04 STG gross output with full DF was 135 MW. Siemens assumed using 2 x GT/HRSG trains into the existing AES STG with a 255 MW gross rating. So the repowered maximum DF output is about 585 MW with Full DF and about 500 MW unfired.

The earlier CC F04 heat balances did not exactly match the AES STG steam conditions of 2400/1000/1000. The CC conditions were about 1800/1070/1070. Siemens assumed that the CC F04 steam cycle could be modified to match the AES STG inlet and reheat temperatures, pressures and flows, or that the AES STG steam path would be modified to match the HRSG conditions, but that the net enthalpy provided in the steam would be about the same as in the earlier CC heat balance.

For the HRSG steam supply, the STG inlet mass flow of High Pressure (HP) steam is reduced from about 1.8 MM pph to 1.5 MM pph. STG exhaust steam flow to the condenser increases about 24%.

The calculated heat rate for the repowered CC is about 0.4% higher than the new CC F04 for full DF and about 1% higher for the Unfired case.

2.1.4 Option 3, HFCC Conversion

For Option 3, HFCC conversion, Siemens started with the CFB boiler as converted to NG. The purpose of HFCC conversion is to improve the overall plant heat rate somewhat when burning a more expensive fuel (NG) without more than doubling the plant output as in a conventional CC Repower (Option 2). The hot GT exhaust at about 1,000F replaces cold ambient air, decreasing the NG fuel requirement in the boiler to produce the same steam flows and temperatures, using the waste heat from the GT, which produces some extra power.

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Rough combustion calcs determined the amount of oxygen required for complete fuel combustion in the NG fired CFB boiler. The AES plant excess air percentage was not known so a typical value of 10% was assumed.

Based on the O2 mass flow required in the boiler, Siemens selected a GT whose exhaust could provide most of the combustion air. The selected unit for study purposes is the Mitsubishi Hitachi Power Systems (MHPS) H-100. Published ISO rating is about 106 MW at a heat rate of 8,930 Btu/kWh LHV.

Siemens used Thermoflow GT Pro software to determine the GT performance at typical site conditions in PR including output, fuel requirements and exhaust flow and composition. Site rating at 85F, 70% RH, 25 ft amsl is about 96 MW net with a heat rate of 9,686 Btu/kWh LHV. This unit provides a little more than 75% of the combustion O2 required by the NG boiler, but the total mass flow is about 45% greater than the original boiler combustion air flow. Without knowing anything specific about the pressures in the existing CFB boilers on coal or when converted to NG, Siemens assumed a somewhat higher backpressure at the GT than for an HRSG that often would be paired with a GT.

Note that the wt % of O2 in air is about 23% and in the GT exhaust is under 15%. So the mass flow of GT exhaust is greater than the original air flow to provide the required O2. Also, at 1,000F, vs. probably 300F-500F for normal preheated combustion air supplied to the boiler, the volume also is much greater. Thus, Siemens included an allowance in the cost for substantial modifications to the air supply ductwork to accommodate combustion gas supply at higher volume and temperature.

Because no boiler manufacturer study was available of the specific changes necessary to accommodate the hotter combustion air, Siemens conservatively assumed that a portion of the GT exhaust heat supplied (above the original combustion air temperature) displaced the LHV value of NG required in the boiler. Siemens calculated the HFCC heat rate based on the converted boiler NG fuel plus the GT fuel, less the exhaust heat fuel credit, and the total net power output from the existing STG plus the GT.

Siemens used Thermoflow's PEACE software that estimates cost for the GT equipment and installation. To this was added the cost of the NG conversion and an allowance of $125 per net kW of the STG for boiler modifications to accept the GT exhaust.

2.1.5 Summary

Approximate project scope, performance and costs were calculated for the 3 NG Conversion Options evaluated. The main results are included in Work Paper 1: AES_Modeling_Assumptions.xls.

Note that many assumptions were made because of lack of site specific information. So, the technical feasibility of Options 1 (NG conversion) and 3 (HFCC) have not been established. Detailed studies based on the actual design of the AES plant are required to confirm the feasibility and performance of these options. Nevertheless, the results provided should be suitable for the purpose of determining whether these options could be attractive for the PR grid. If so, further studies would be advisable.

Because Option 2, CC Repower, uses the existing STG but not the existing boiler, and many other similar projects have been implemented, it can be concluded that this option is technically feasible. However, the economics may change based on detailed studies of conversion cost and performance. Also, because this option would create two 2x1 CC blocks of almost 600 MW each in one grid location where such amount of power are not needed, Option 2 may not be the best solution.

The table below provides a summary of the parameters of each of the conversion options described above including Capital Costs, Heat Rate, Fixed and Variable Operating and Maintenance Costs (FOM & VOM) and other equipment specifications.

Figure 2-1: AES Natural Gas Conversion Options (per generating unit)

	AES Gas ST	AES 2x1 Repower	AES HFCC Repower
Option Number	**1**	**2**	**3**
Manufacturer		GE	Hitachi
Model Turbine		S207F.04	H-100
Type	ST	CC 2x1	CC 1x1
Capacity MW (per unit)	227	585	321
Fuel	NG	NG	NG
VOM (2018 $/MWh)	3.90	1.75	2.61
FOM (2018 $/kW-yr)	60.00	22.09	33.12
Regas Terminal related FOM (2018 $/kw-yr)	76.00	88.16	88.16
Heat Rate at 100% Rated Capacity Btu/kWh	10,164	7,582	9,100
Capital Costs (2018 $/kW)	198.24	854.45	507.79
Capital Investment ($000)	45,000	500,000	163,000

2.1.6 Considerations on Other Fuels

Siemens considered the possibility of using other fuels instead of Natural Gas and in general we found it not feasible. Some details below.

Biomass: Most converted coal plants that have gone to biomass co-firing, have done so with a limit of about 10% biomass to operate without substantial changes. These are mainly Pulverized Coal (PC) boilers. AES has Fluidized Bed Combustion (FBC) boilers and these usually are less suitable for biomass combustion. Many FBC boilers have been built specifically for biomass combustion , but usually they are much smaller at 50-100 MWe, vs. 227 MWe net each for the AES units. One difficulty is biomass boilers usually would be designed with lower steam conditions such as 1,300 psig/750F vs. AES conditions of 2,400 psig/1,000F. Biomass fuels typically have high chlorine and metals levels that cause corrosion and sticky ash that can coat superheater tubes, reducing heat transfer and providing sites for rapid corrosion. Ultimately, a detailed boiler study would be necessary to confirm suitability and cost for biomass conversion.

Another issue is onsite fuel storage. Biomass density is far lower than coal (can be up to 6 times lower on a Btu per unit volume basis) and biomass piles have to be managed even more than coal piles to prevent spontaneous combustion. AES has a long term reserve coal

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pile and it is likely far fewer days of fuel capacity could be stored onsite as reserve for biomass fuel interruption.

It seems that coal ship unloading, and transport systems could be adapted to biomass receiving, but practical difficulties may be identified during detailed analyses.

Bagasse and other agricultural wastes are even more problematic than wood chips, in terms of chlorine and sticky ash levels and material handling issues.

Biofuels are hard to procure in large quantities. This would be primarily biodiesel, but not cheap and it is hard to source.

Of course, the key question is how much biomass of various types reasonably and economically could be sourced on the island or from nearby islands. Note there are some US sources of wood pellets, but these typically are priced similar to light oil on a Btu basis, which is far too expensive as a large boiler fuel.

I summary without detailed studies biomass cannot not considered a viable option.

LPG: This fuel is likely could be burned in similar manner to LNG, but the fuel price likely would make this impractical. Price per MMBTU is significantly higher.

2.2 Natural Gas Supply

Gas was assumed to be delivered to the plant as LNG via a Floating Storage and Regasification Unit (FSRU) LNG.

For the estimated CAPEX for the AES FSRU LNG infrastructure, we based our estimates largely on the same 2017 Oxford Institute for Energy Studies (OIES - Workpaper 2) that we used for the other offshore LNG estimates. The two cost components include the cost to purchase a used LNG carrier and the conversion cost. For the purchase price, we are estimating 65% of the cost in the OIES report to account for a smaller carrier – their estimate is based on a new LNG tanker with a holding capacity of 125,000-140,000 m^3 which would be very large for the AES units – as much as 177 days' worth of fuel). For the conversion cost, we keep the same \$97-122 million cost as used for the other offshore FSRUs for Yabucoa and Mayaguez.

We used the lower range of the OIES report for the smaller Option 1 conversion (2 x 227 MW and 10,164 Btu/kWh) and the upper range for the larger Option 3 conversion (2MW x 321 9,100 Btu/kWh). Option 2 was assumed to be limited to only one unit converted for size reasons and fall in the middle of the above.

The table below shows the CAPEX \$/kW and OPEX \$/kW and are considered adequate, given the estimates being used at this time. Note that the CAPEX and OPEX figures are lower than for the Yabucoa LNG terminal because of the larger capacities for these AES conversions.

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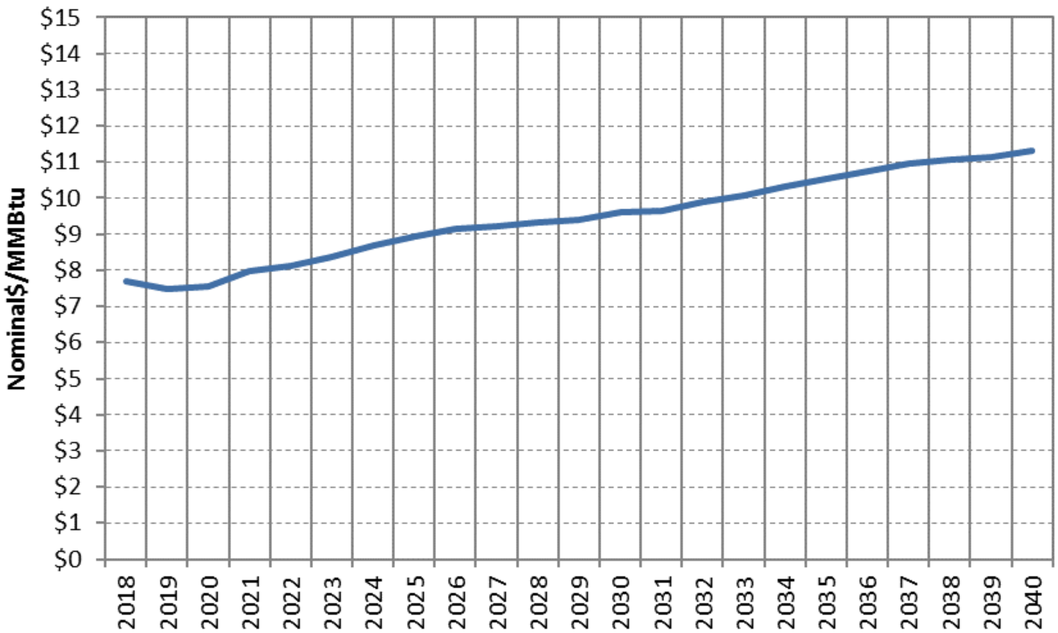
Table 2-1: Fuel Infrastructure Costs

Infrastructure Option	CAPEX $MM (2018$)	Annual OPEX $MM (2018$)	Max Daily Gas Volume (MMcf/d)	Max Capacity MW	CAPEX $/kW (2018$)	OPEX $/kW (2018$)	CAPEX + OPEX
Ship-based LNG (FSRU) at AES (small)	$260.00	$13.52	88.6	454	$58.38	$29.78	$88.16
Ship-based LNG (FSRU) at AES (large)	$317.00	$16.48	128.8	737	$43.83	$22.36	$66.19

For the cost of the delivered gas we used the same projections for the delivered gas at other LNG terminals modeled in the IRP and include the projected cost of the commodity, liquefaction and transportation. This is shown in the figure below.

Figure 2-2: Delivered LNG Projections



2.3 LTCE Screening Analysis

All three conversion options were offered to the LTCE Aurora model. However to form a view on the expected results the figure below shows the LCOE of the three options with the assumptions on CapEx, OpEx and Fuel described above and the same WACC (8.5%), used in the IRP. As can be seen below the most economical is Option 2, the Repower to a 2x1 combined cycle that competes. This option competes with a new F Class Combined Cycle and it is similar to the H-Class. However, its size is relatively large 585 MW and would have problems under Strategy 2 (or 3). The second best option is Option 3 the HFCC repower that more expensive than the F-Class CCGT and most likely capacity factors and the least attractive is the straight conversion to Natural Gas (Option 1).

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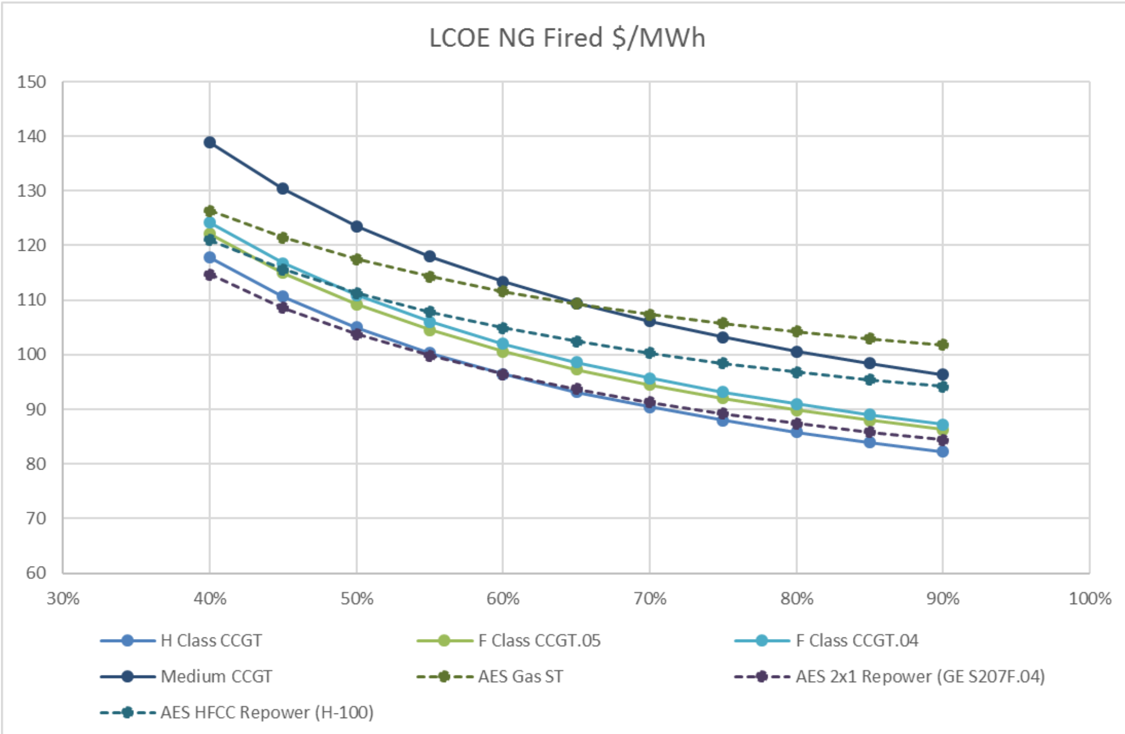
Figure 2-3: LCOE for AES Natural Gas Conversion Options



Section
3

Capacity Expansion Analysis

In this section we present the main results of the long term capacity expansion (LTCE) plan by Scenario and a comparison with the corresponding Base Case (i.e. same scenario but under AES with Coal) is presented.

3.1 Scenario 4 Strategy 2 Base Load Forecast (S4S2B)

In this scenario none of the options offered for repowering were selected and AES retired by the prescribed year the end of 2020.

3.1.1 Resource Additions

Instead of repowering AES the LTCE run elected to accelerate the build of solar PV with respect of the Base Case(S4S2B) by 2025 (27% more see table below). Storage was also increased in consequence (to manage curtailment); 18.2 % increase by 2025. See table below.

Table 3-1: S4S2B Base Case and with AES Retirement Expansion Plan Overview

	Large & Medium CCGTs and Peakers						Renewable and Storage			
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)
S4S2B - BASE	✓	✓	✓	–	–	371	2,220	1,320	2,820	1,640
S4S2B-AES	✓	✓	✓	–	–	371	2,820	1,560	2,940	1,880
Change						*0.0%*	*27.0%*	*18.2%*	*4.3%*	*14.6%*

Over the long term (2038) this case has slightly more PV (2,940 MW versus 2,820 MW or 4.3% more) and storage (1,880 MW versus 1,640 MW or 14.6% more), but other decisions stay the same; new CCGT F-Class at Palo Seco and at Costa Sur. As was the case with S4S2B, this combined cycle can be replaced by EcoEléctrica, that retires in 2024 in this case.

The figures below provide an overview of the additions over time with AES retired and the Base Case. In these figures we observed that that in the AES retirement case, by 2026 the last group of PV generation is added and from that year onwards only storage and some small peaking generation is added (23 MW, 21 and 16 MW by 2033, 2034 and 2037). On the Base Case a large amount of PV, BESS and peaking generation is added in 2028 (after AES retires).

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Figure 3-1: S4S2B AES – Additions

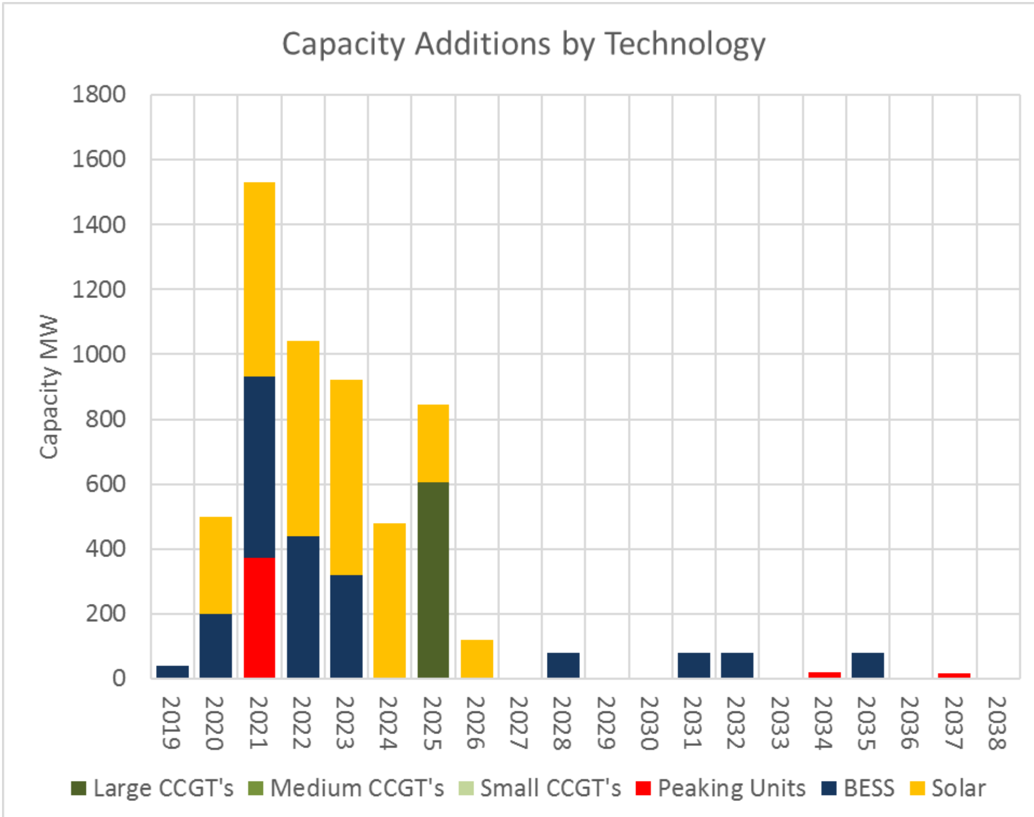
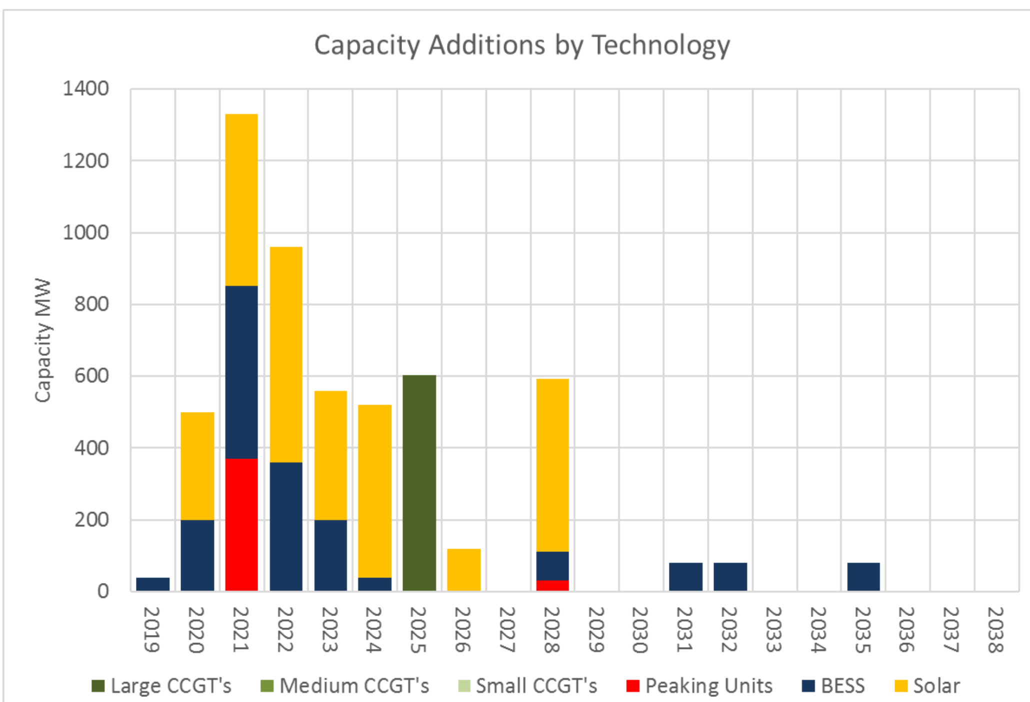


Figure 3-2: S4S2B Base Case – Additions



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3.1.2 Retirements

As an effect of AES being retired by the end of 2020 the main difference with respect of the Base Case is that Costa Sur 6 is extended to the end of 2025 (instead of retiring by the end of 2020). EcoEléctrica is retired in both cases by end of 2024 and one Palo Seco unit is also maintained until the end of that year in both cases. One of the converted San Juan units is retired by end of 2028 and the other by end of 2036. In the Base case only one unit was retired by end of 2034. The figures below provide an overview of retirements.

Figure 3-3: S4S2B AES – Retirements

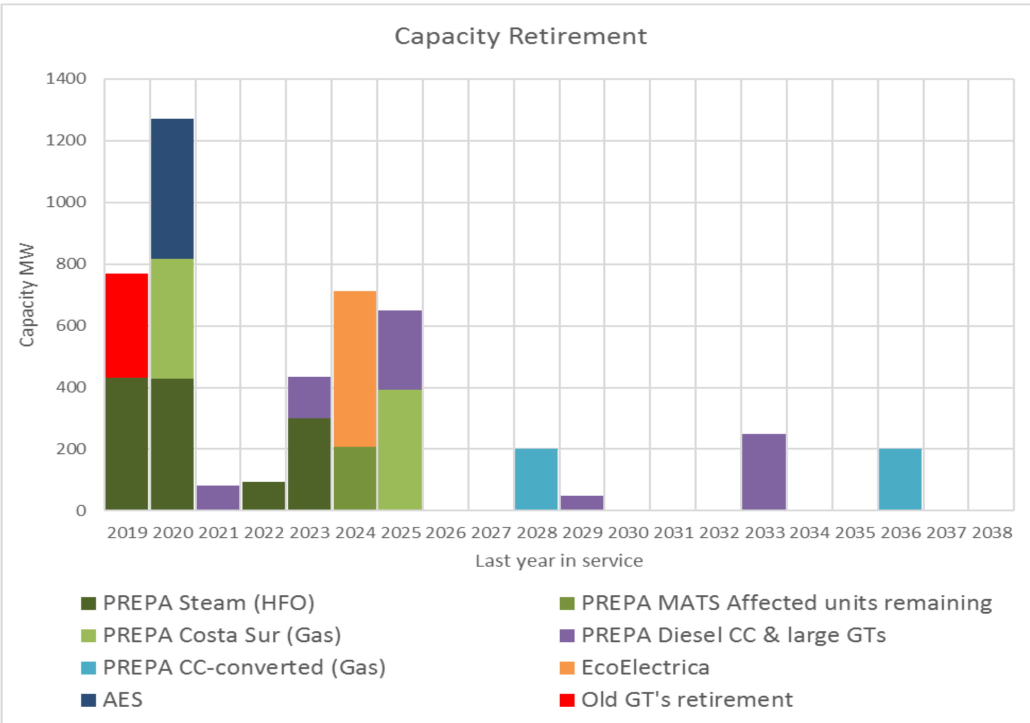

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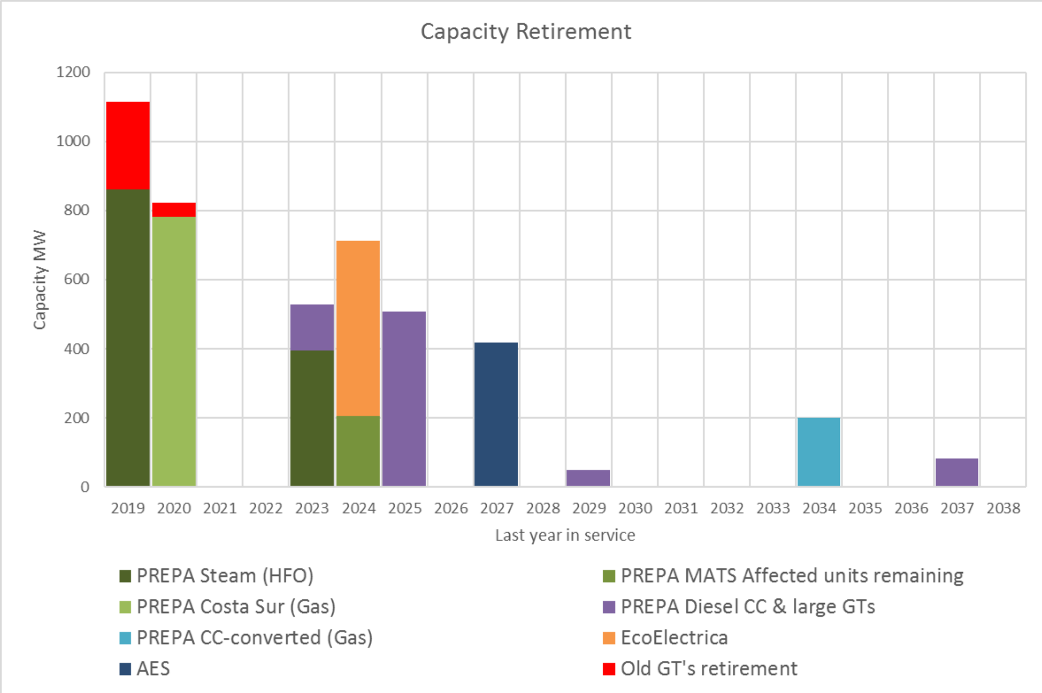
Figure 3-4: S4S2B Base Case – Retirements



3.1.3 Economics

The tables below show a comparison of costs of the S4S2B Base Case with the case where AES is retired. We observe that the NPV of the revenue requirement is expected to be 4.0% higher than the Base Case and the average cost of energy a 5.6% higher for the 2019 to 2028 period. The Capital costs are also higher 4.5% due to the added PV and Storage.

Table 3-2: S4S2B Base Case and with AES Retirement Costs

	Central Metrics		
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**Capital Investment Costs ($ Millions)**
S4S2B - BASE	14,350,195	99.3	6,595
S4S2B-AES	14,930,455	104.9	6,889
Change	*4.0%*	*5.6%*	*4.5%*

With respect of the cost components of the NPV as shown below we note that the largest impact as expected is in the fuel costs that is 14.8% higher than the Base Case and it is not off-set by the reduction in fixed and variable costs NPV due to the early retirement of AES-Coal.

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Table 3-3: S4S2B Base Case and with AES Retirement NPV Components ($000 2018)

	S4S2B AES	S4S2B Base	Difference to Base Case	Difference to Base Case
NPV fuel	6,873,855	5,988,757	885,098	14.8%
NPV Var O&M	300,448	390,666	(90,218)	-23.1%
NPV Fixed Costs	7,756,151	7,970,772	(214,620)	-2.7%
Total	14,930,455	14,350,195	580,260	4.0%

Another aspect that is important to take into consideration is that the impact of retiring AES is mitigated by the entry of renewable generation and the combined cycle plants. If these are not in place the impact can be much larger. To illustrate this the table below shows the impact of the retirement of year one (2021), when the mitigating generation is not yet fully in place. In this table we observe that the increased costs can be almost $ 80 million per year.

Table 3-4: S4S2B Base Case and with AES Retirement Year 1 impact ($000 2018)

	S2S2B- AES	S2S2B - BASE	Difference to Base Case	Difference to Base Case
Fuel	1,039,431	825,931	213,500	25.8%
O&M	33,683	52,597	(18,914)	-36.0%
Fixed Costs	701,808	817,631	(115,823)	-14.2%
Total	1,774,921	1,696,159	78,763	4.6%
Total/MWh	114.82	109.44	5.4	4.9%

Finally, the figure below shows the evolution of the average total production costs in $/MWh, where we note that as expected the largest difference is in the years leading to 2027.

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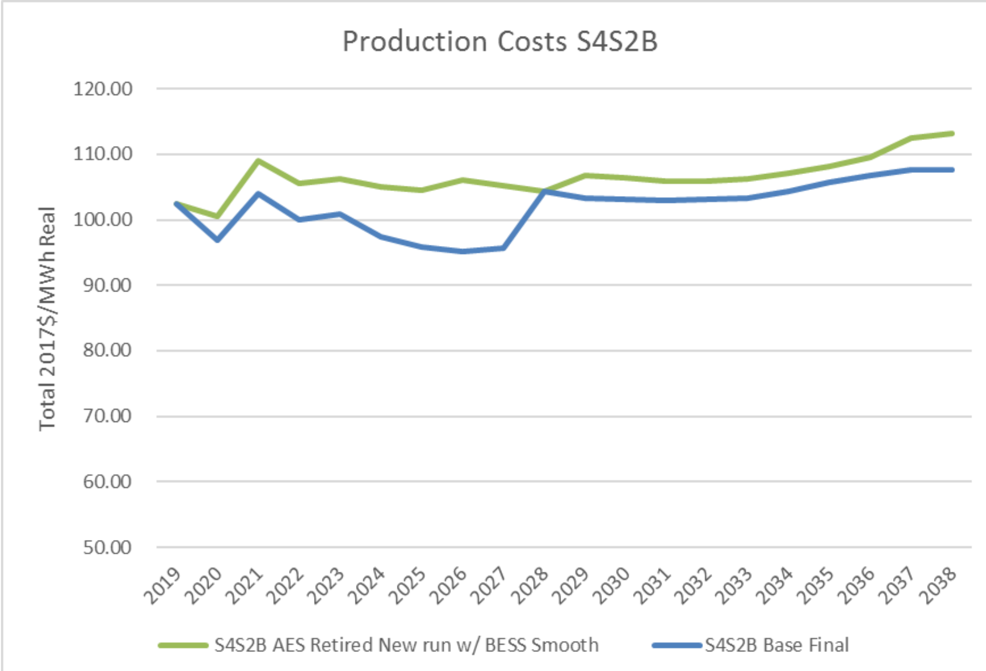
Figure 3-5: S4S2B Production Cost $/MWh



3.2 ESM Case Base Load Forecast

In this scenario as was the case above none of the options offered for repowering were selected and AES retired by the prescribed year the end of 2020.

3.2.1 Resource Additions

Instead of repowering AES the LTCE maintained in service the HFO fired steam generation in the north (Palo Seco 3&4 and San Juan 7&8) until 2024 when the two combined cycle at Yabucoa and Palo Seco entered in service. Interestingly in this case the amount of PV was dropped with respect of the base case with 7.5% less PV by 2025 and 11.6% less total (see table below). The storage was also reduced. We think that the optimization program identified that by keeping the thermal units in the north in service its inflexibility limited the amount of renewable that could be integrated and hence the reduction.

Table 3-5: ESM Base Case and with AES Retirement Expansion Plan Overview

	Large & Medium CCGTs and Peakers						Renewable and Storage			
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)
ESM _BASE	✓	EcoEléctrica Instead	✓	✓	✓	421	2,400	920	2,580	1,640
ESM - AES	✓	EcoEléctrica Instead	✓	✓	✓	421	2,220	800	2,280	1,520
Change						*0.0%*	*-7.5%*	*-13.0%*	*-11.6%*	*-7.3%*

The figures below provide an overview of the additions over time with AES retired and the Base Case. In these figures we observe that the pattern of additions over time is very similar, but with reduced additions of PV and storage from 2022 onwards.

Figure 3-6: ESM AES – Additions

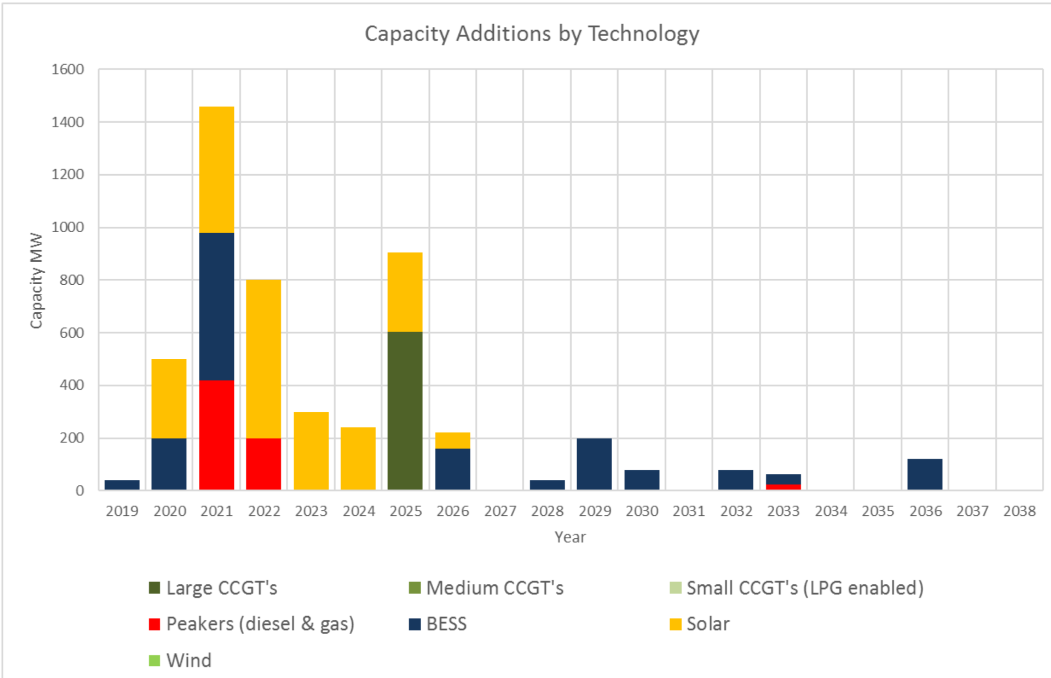
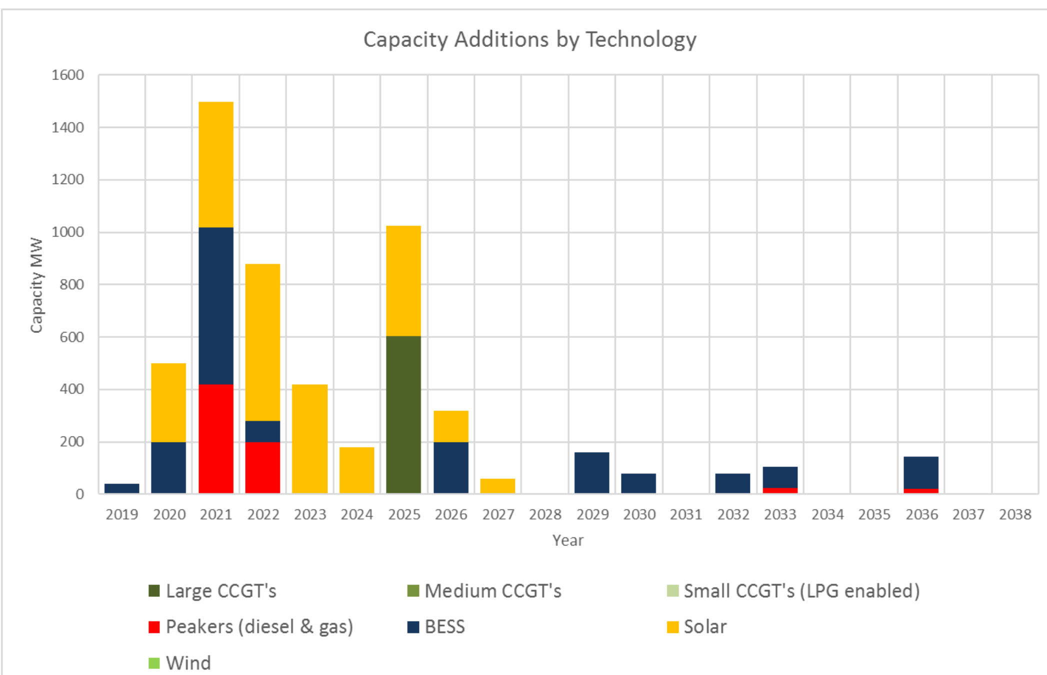


Figure 3-7: ESM Base Case – Additions



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3.2.2 Retirements

As an effect of AES being retired by the end of 2020 the main difference with respect of the Base Case is that the steam units in the north (Palo Seco 3&4 and San Juan 7&8) are extended to the end of 2024 (when they have to retire for MATS compliance) and the converted San Juan 5&6 units as San Juan 6 is retired by end of 2028, instead of 2025 in the ESM-Base and San Juan 6 is not retired instead of by the end of 2034 in the Base Case. The rest of the units have similar retirement patterns. Costa Sur 5&6 are retire by the end 2022 and 2021 respectively, instead of end of 2020. All these retirements postponements are consistent with AES retiring by the end of 2020 and the slight drop in PV.

Figure 3-8: ESM AES – Retirements

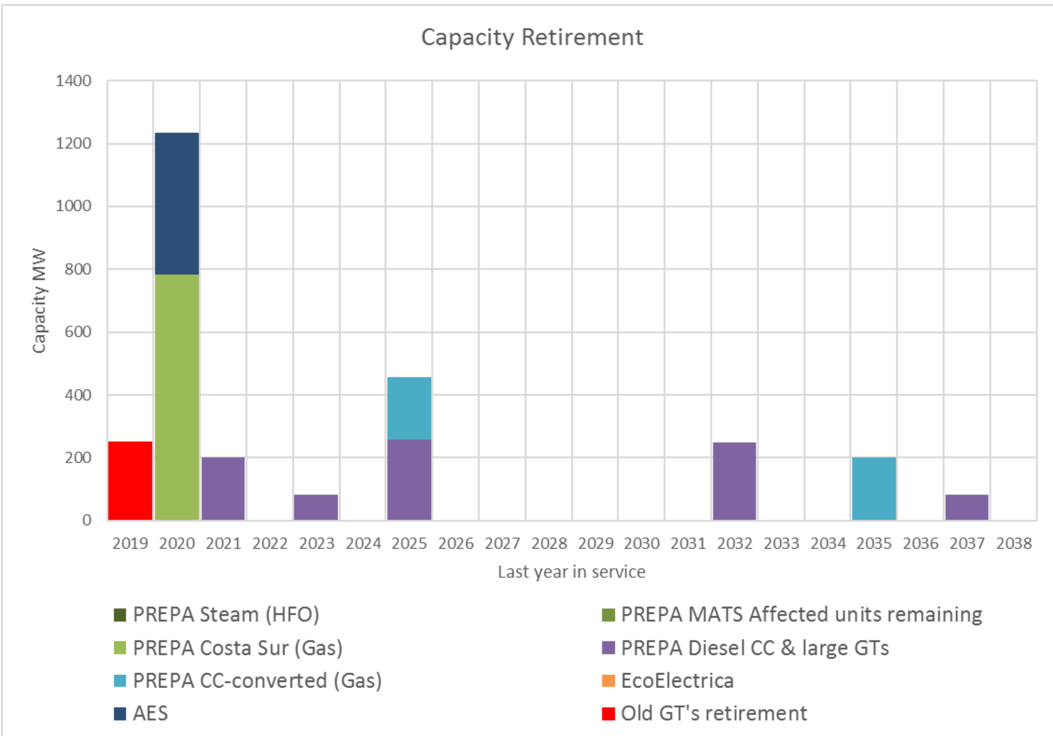
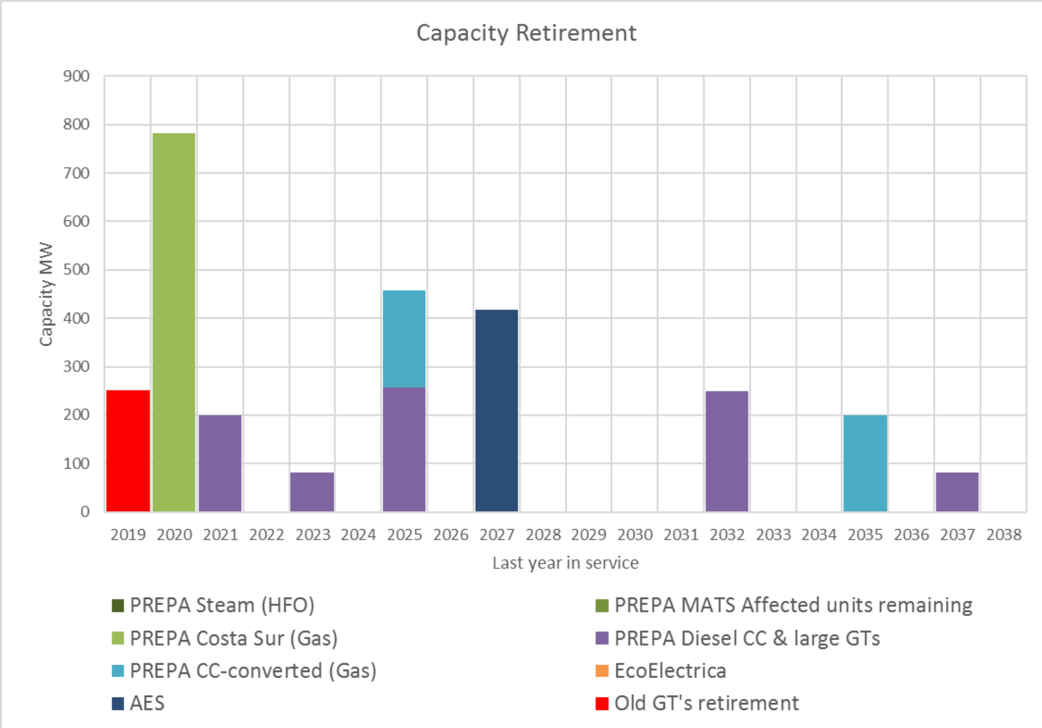


Figure 3-9: ESM Base Case – Retirements



3.2.3 Economics

The tables below show a comparison of costs of the Base Case ESM with the case where AES is retired. We observe that the NPV of the revenue requirement is expected to be 1.2% higher than the Base Case and the average cost of energy is 2.6% higher for the 2019 to 2028 period. The Capital costs however are as expected 8.2% lower as a result of reduced solar and storage additions.

Table 3-6: ESM Base Case and with AES Retirement Costs

	Central Metrics		
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**Capital Investment Costs ($ Millions)**
ESM _BASE	14,431,214	99.0	6,138
ESM - AES	14,605,947	101.5	5,635
Change	*1.2%*	*2.6%*	*-8.2%*

With respect of the cost components of the NPV as shown below we note that the largest impact as before is in the fuel costs that is not off-set by the reduction in fixed and variable costs NPV due to the early retirement of AES-Coal.

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Table 3-7:ESM Base Case and with AES Retirement NPV Components ($000 2018)

	ESM - AES	ESM - BASE	Difference to Base Case	Difference to Base Case
NPV fuel	6,867,211	5,875,910	991,301	16.9%
NPV Var O&M	266,116	358,888	(92,773)	-25.9%
NPV Fixed Costs	7,472,621	8,196,415	(723,795)	-8.8%
Total	14,605,947	14,431,214	174,733	1.2%

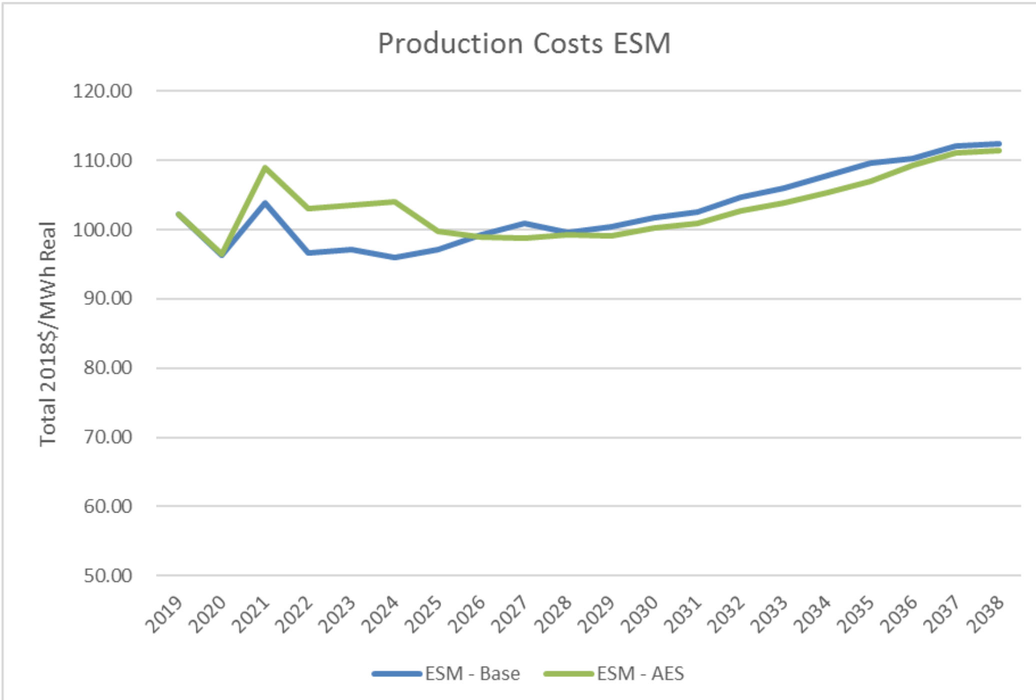
Another aspect that is important to take into consideration is that the impact of retiring AES is mitigated by the entry of renewable generation and the combined cycle plants. If these are not in place the impact can be much larger. To illustrate this the table below shows the impact of the retirement of year one (2021), when the mitigating generation is not yet fully in place. In this table we observe that the increased costs can be almost $ 100.0 million per year.

Table 3-8:ESM Base Case and with AES Retirement Year 1 Impact ($000 2018)

	ESM - AES	ESM - BASE	Difference to Base Case	Difference to Base Case
Fuel	1,058,099	823,443	234,655	28.5%
O&M	31,959	52,662	(20,703)	-39.3%
Fixed Costs	706,838	822,529	(115,691)	-14.1%
Total	1,796,896	1,698,634	98,261	5.8%
Total/MWh	109.34	103.36	6.0	5.8%

Finally, the figure below shows the evolution of the total production costs in $/MWh, where we note that as expected the largest difference is in the years leading to 2027.

Figure 3-10: ESM Production Costs $/MWh



3.3 Scenario 1 Strategy 2 Base Load Forecast (S1S2B)

In this scenario also none of the options offered for repowering were selected and AES retired by the prescribed year the end of 2020.

3.3.1 Resource Additions

Instead of repowering AES the LTCE run elected to accelerate the build of solar PV with respect of the Base Case (S1S2B) by 2025 (18.6% more see table below). Storage remained at the same value by this period.

Table 3-9: S1S2B Base Case and with AES Retirement Expansion Plan Overview

	Large & Medium CCGTs and Peakers						Renewable and Storage			
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)
S1S2B - BASE	–	EcoEléctrica Instead	✓	–	–	559	2,580	1,280	2,700	1,720
S1S2B-AES	–	EcoEléctrica Instead	✓	–	–	484	3,060	1,280	3,060	1,800
Change						*-13.5%*	*18.6%*	*0.0%*	*13.3%*	*4.7%*

Over the long term (2038) this case has more PV (3,060 MW versus 2,700 MW or 13.3% more) and storage (1,800 MW versus 1,720 MW or 4.7% more), other decisions stay the same; as there no new gas EcoEléctrica is maintained in service for the planning period

The figures below provide an overview of the additions over time with AES retired and the Base Case.

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In these figures we observed that that in the AES retirement case, by 2025 the last group of PV generation is added and from that year onwards only storage and some small peaking generation is added (21 MW by 2034). On the Base Case 125 MW of Peaking Generation and 120 MW of PV is added after AES retires. In both cases BESS is added over the long term.

Figure 3-11: S1S2B AES – Additions

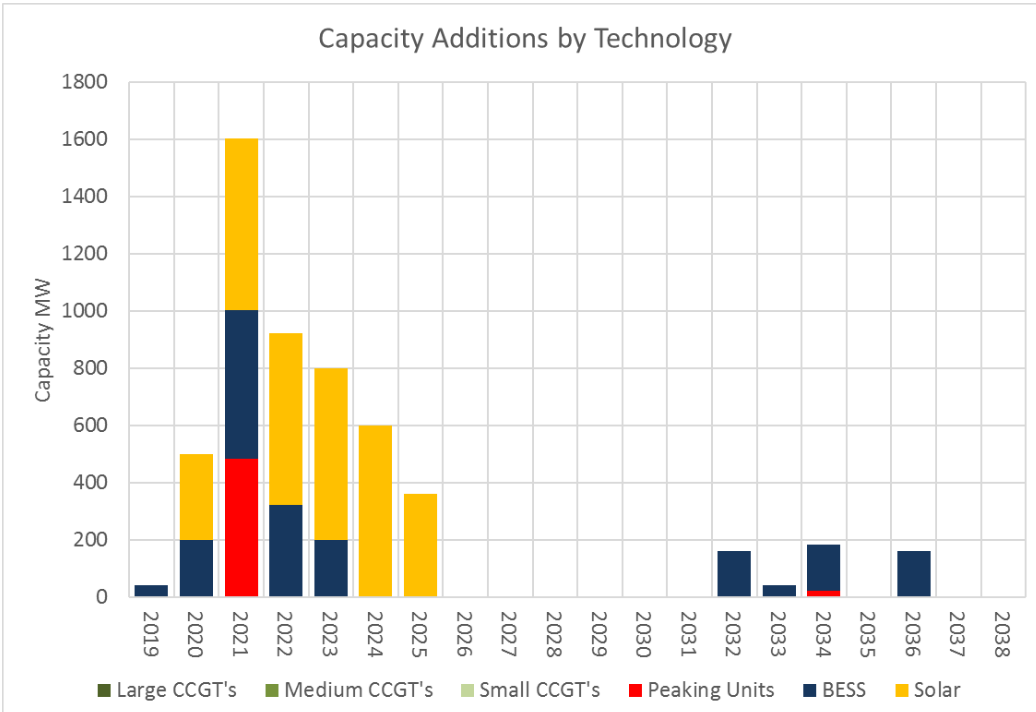
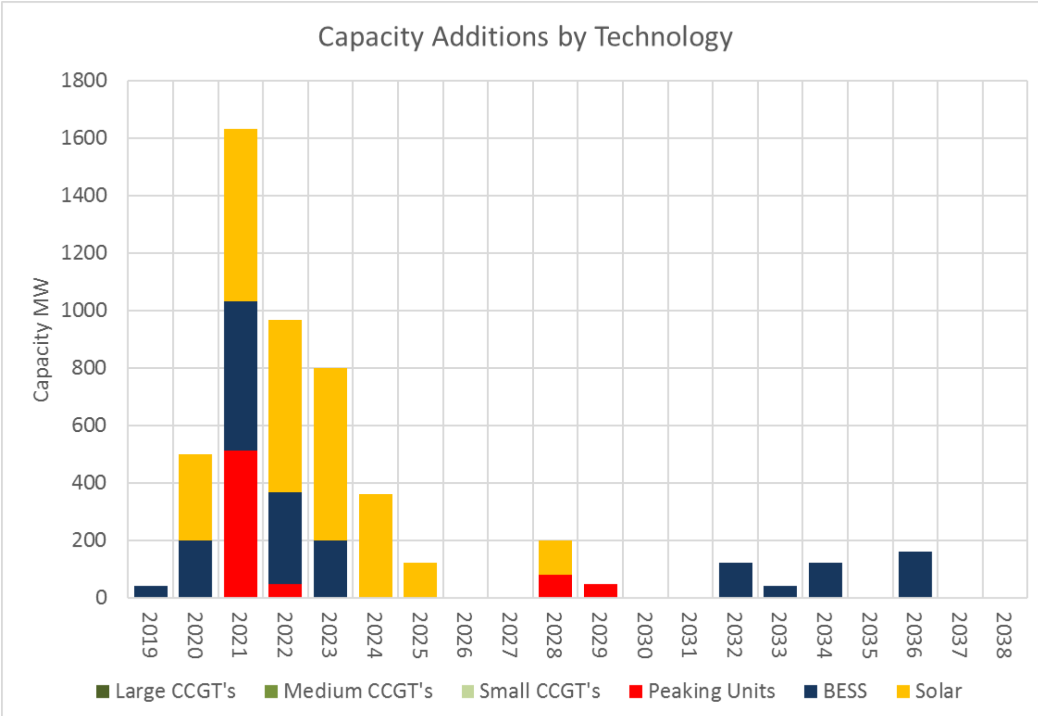


Figure 3-12: S1S2B Base Case – Additions



3.3.2 Retirements

As an effect of AES being retired by the end of 2020 the main difference with respect of the Base Case is that Costa Sur 6 is extended to the end of 2029 and Costa Sur 5 to the end of 2023 (instead of retiring by the end of 2020 and 2022). Peaker generation retires in both cases at deferent times but this is not significant for the case. San Juan converted units retire, but in the long term 2033 (as in the Base Case) and the other by 2037.

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Figure 3-13: S1S2B AES – Retirements

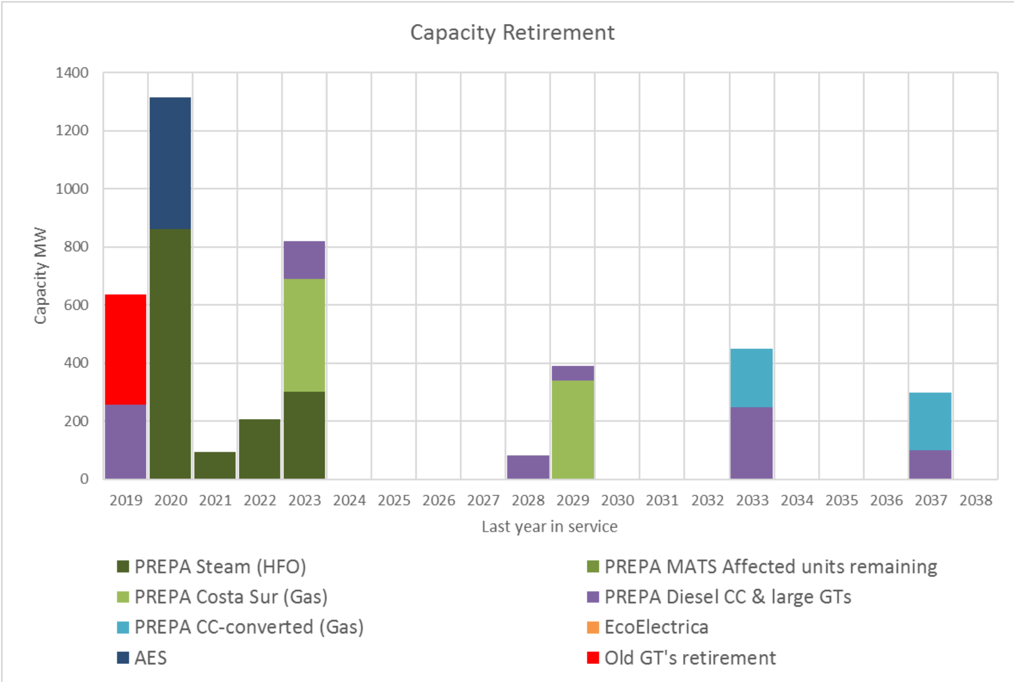
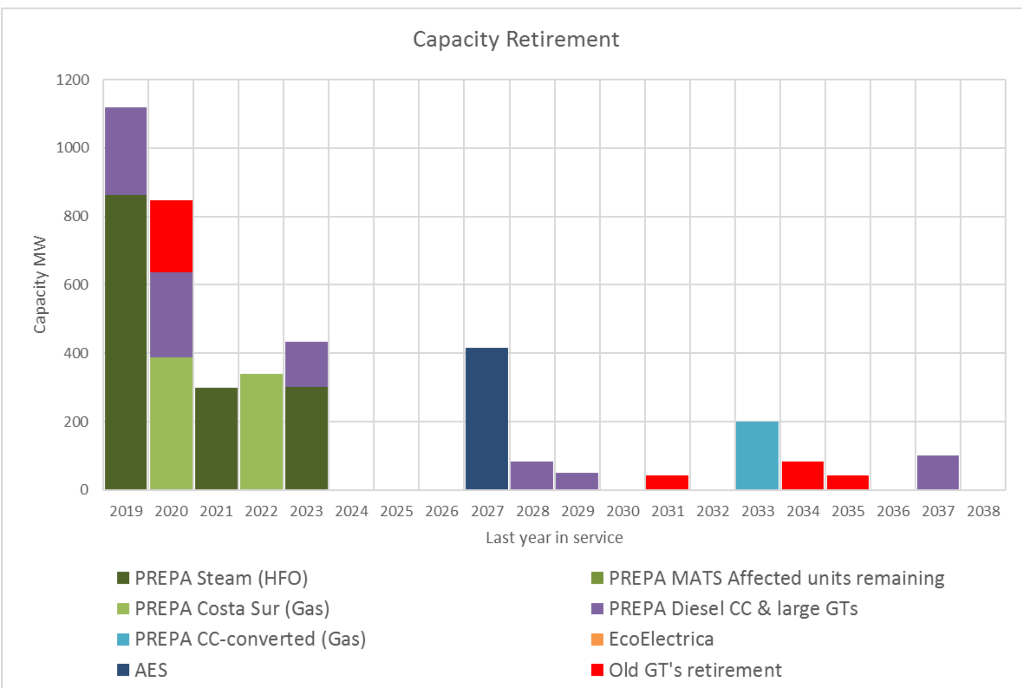


Figure 3-14: S1S2B Base Case – Retirements



3.3.3 Economics

The tables below show a comparison of costs of the Base Case S1S2B with the case where AES is retired. We observe that the NPV of the revenue requirement is expected to be 3.1%

higher than the Base Case and the average cost of energy a 4.5% higher for the 2019 to 2028 period. The Capital costs are also higher 8.5% basically due to the added PV and Storage.

Table 3-10: S1S2B Base Case and with AES Retirement Costs

	Central Metrics		
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**Capital Investment Costs ($ Millions)**
S1S2B - BASE	14,773,629	102.2	5,840
S1S2B-AES	15,238,997	106.8	6,336
Change	*3.1%*	*4.5%*	*8.5%*

With respect of the cost components of the NPV as shown below we note that the largest impact as expected is in the fuel costs that is 12.7% higher than the Base Case and it is not off-set by the reduction in fixed and variable costs NPV due to the early retirement of AES-Coal.

Table 3-11: S1S2B Base Case and with AES Retirement NPV Components ($000 2018)

	S1S2B - AES	**S1S2B - BASE**	**Difference to Base Case**	**Difference to Base Case**
NPV fuel	7,057,769	6,263,314	794,456	12.7%
NPV Var O&M	269,986	368,490	(98,505)	-26.7%
NPV Fixed Costs	7,911,242	8,141,825	(230,583)	-2.8%
Total	15,238,997	14,773,629	465,368	3.1%

Another aspect that is important to take into consideration is that the impact of retiring AES is mitigated by the entry of renewable generation and the combined cycle plants. If these are not in place the impact can be much larger. To illustrate this the table below shows the impact of the retirement of year one (2021), when the mitigating generation is not yet fully in place. In this table we observe that the increased costs can be almost $ 65 million per year in this case.

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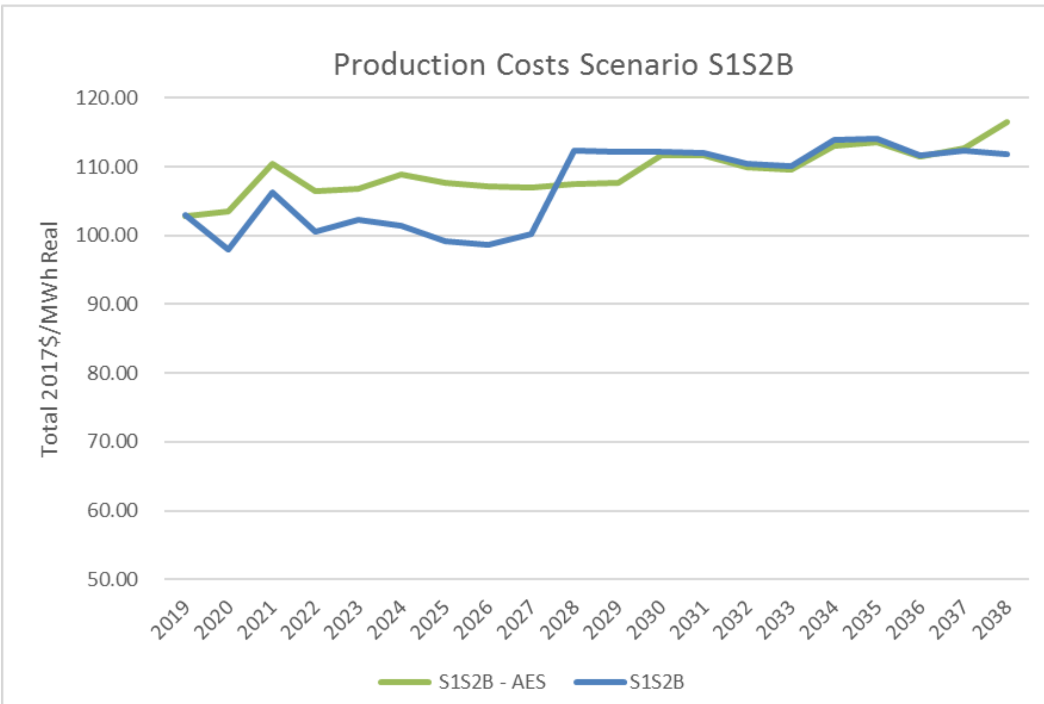
Table 3-12: S1S2B Base Case and with AES Retirement Year 1 impact ($000 2018)

	S1S2B - AES	S1S2B - BASE	Difference to Base Case	Difference to Base Case
Fuel	1,037,155	814,456	222,699	27.3%
O&M	31,936	51,413	(19,477)	-37.9%
Fixed Costs	748,909	887,672	(138,763)	-15.6%
Total	1,818,000	1,753,541	64,459	3.7%
Total/MWh	116.33	111.98	4.3	3.9%

Finally, the figure below shows the evolution of the average total production costs in $/MWh, where we note that as expected the largest difference is in the years leading to 2027.

Figure 3-15: S1S2B Production Cost $/MWh



3.4 Scenario 3 Strategy 2 Base Load Forecast (S3S2B)

In this scenario also none of the options offered for repowering were selected and AES retired by the prescribed year the end of 2020.

3.4.1 Resource Additions

Instead of repowering AES the LTCE run elected to accelerate solar PV with respect of the Base Case (S3S2B) by 2025 (17.0% more see table below). Storage was also increased (3%).

Table 3-13: S3S2B Base Case and with AES Retirement Expansion Plan Overview

	Large & Medium CCGTs and Peakers						Renewable and Storage			
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)
S3S2B -BASE	–	✓	✓	–	–	348	2,820	1,320	4,140	3,040
S3S2B-AES	–	✓	✓	–	–	325	3,300	1,360	3,960	2,960

Over the long term (2038) this case has less PV (3,960 MW versus 4,140 MW or 4.3% less) and less storage (2,960 MW versus 3040 MW or 2.6% less), other decisions stay the same; as EcoEléctrica retired with the entry of the new CCGT at Costa Sur and not CCGT is developed in Palo Seco.

The figures below provide an overview of the additions over time with AES retired and the Base Case. In these figures we observed that as before in the AES retirement case, by 2026 largely all PV has been added and from that year onwards only storage and some small peaking generation is added. On the Base Case important additions of PV continue units 2028. Over the long term in both cases wind generation is added.

Figure 3-16: S3S2B AES – Additions

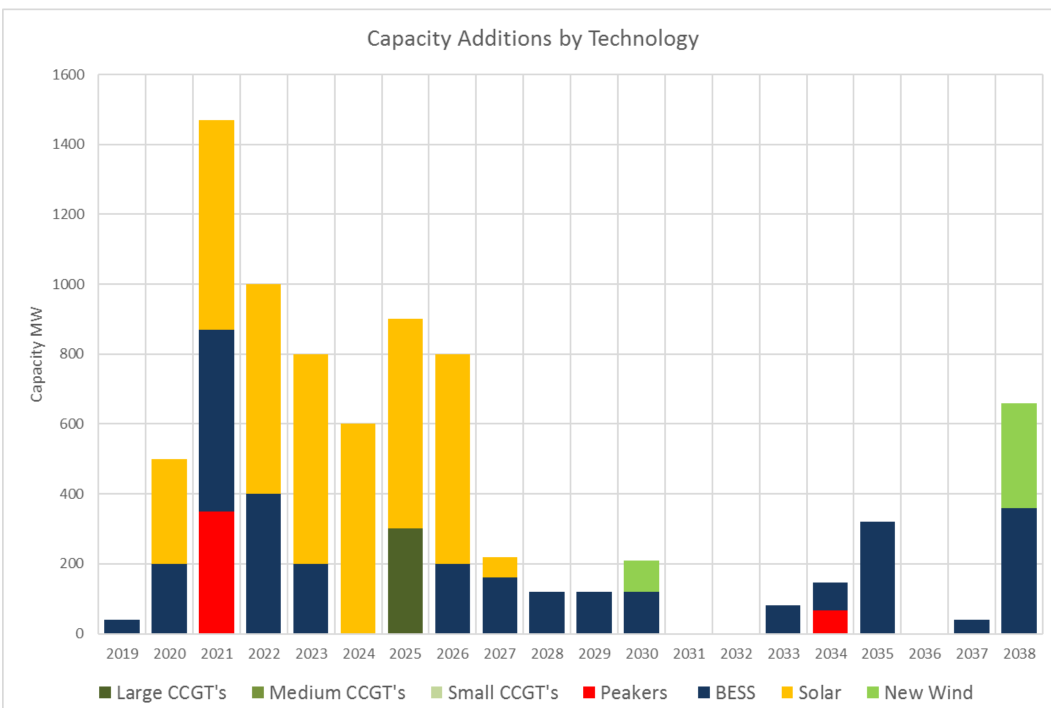


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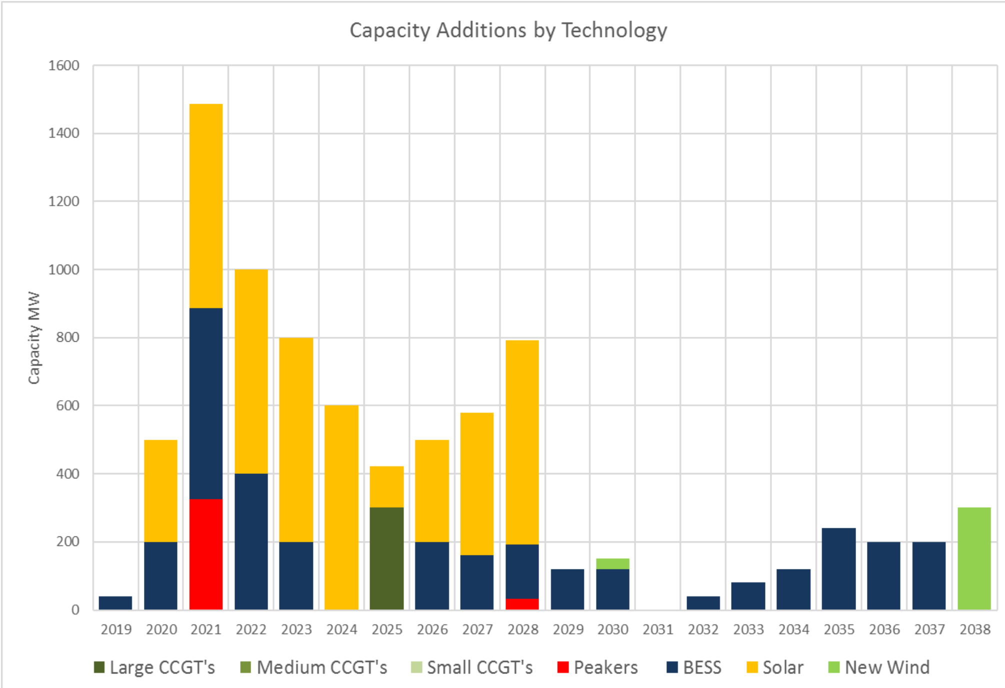
Figure 3-17: S3S2B Base Case – Additions



3.4.2 Retirements

The retirements are similar with respect of both cases, with the exception that in the Base Case Aguirre 1 continues until 2023, while in the AES retirement case Costa Sur 6 continues until 2026. San Juan 5 & 6 retire later in the plan in both cases.

Figure 3-18: S3S2B AES – Retirements

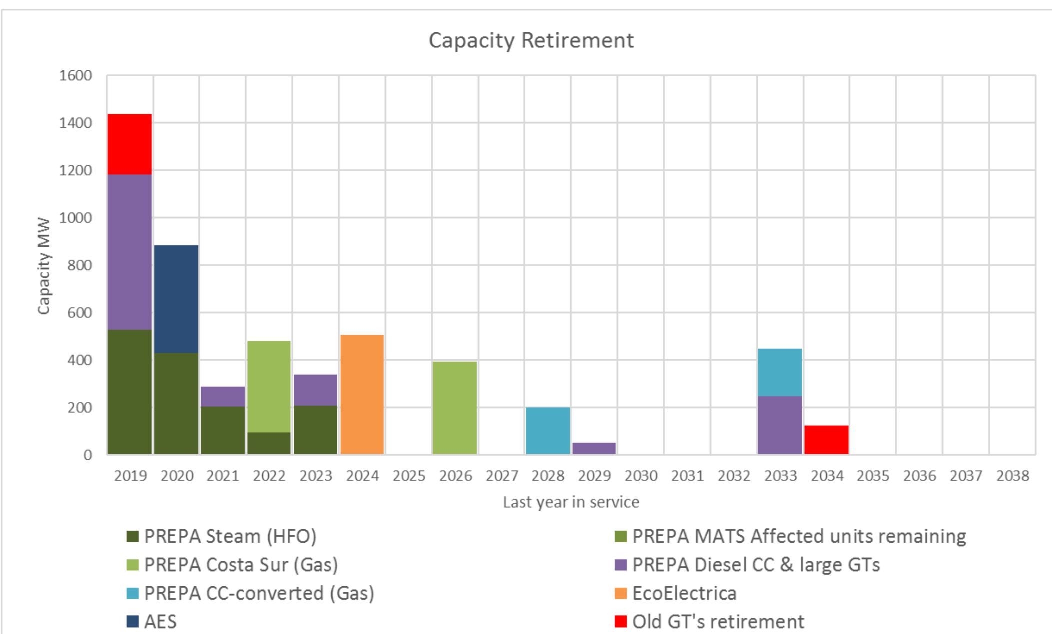
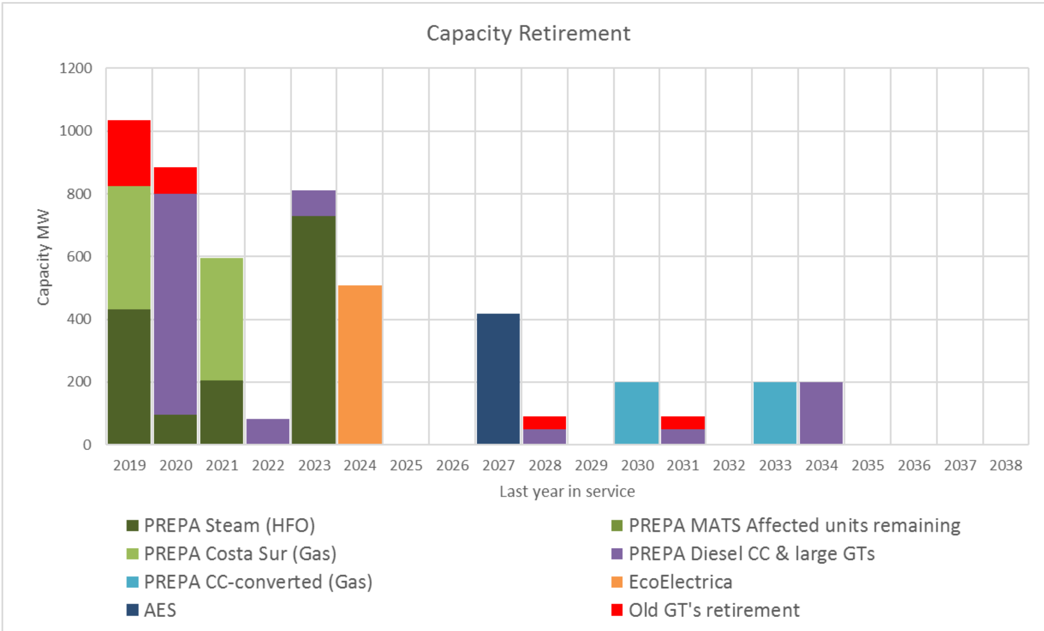


Figure 3-19: S3S2B Base Case – Retirements



3.4.3 Economics

The tables below show a comparison of costs of the Base Case S3S2B with the case where AES is retired. We observe that the NPV of the revenue requirement is expected to be only 1.4% higher than the Base Case and the average cost of energy is 3.5% higher for the 2019 to 2028 period. This Scenario is the best capable of dealing with the retirement due to the lower cost of renewable. The capital costs are also lower basically due to the fact that this case makes better use of the ITC by advancing the PV and storage.

Table 3-14: S3S2B Base Case and with AES Retirement Costs

	Central Metrics		
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**Capital Investment Costs ($ Millions)**
S3S2B -BASE	13,843,500	96.4	8,474
S3S2B-AES	14,030,670	99.7	7,459
Change	*1.4%*	*3.5%*	*-12.0%*

With respect of the cost components of the NPV as shown below we note that the largest impact as expected is in the fuel costs that is 14.8% higher than the Base Case and it largely off-set by the reduction in fixed and variable costs NPV due to the early retirement of AES-Coal.

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Table 3-15: S3S2B Base Case and with AES Retirement NPV Components ($000 2018)

	S3S2B - AES	S3S2B - BASE	Difference to Base Case	Difference to Base Case
NPV fuel	6,193,330	5,393,422	799,908	14.8%
NPV Var O&M	295,410	385,413	(90,003)	-23.4%
NPV Fixed Costs	7,541,930	8,064,665	(522,735)	-6.5%
Total	14,030,670	13,843,500	187,170	1.4%

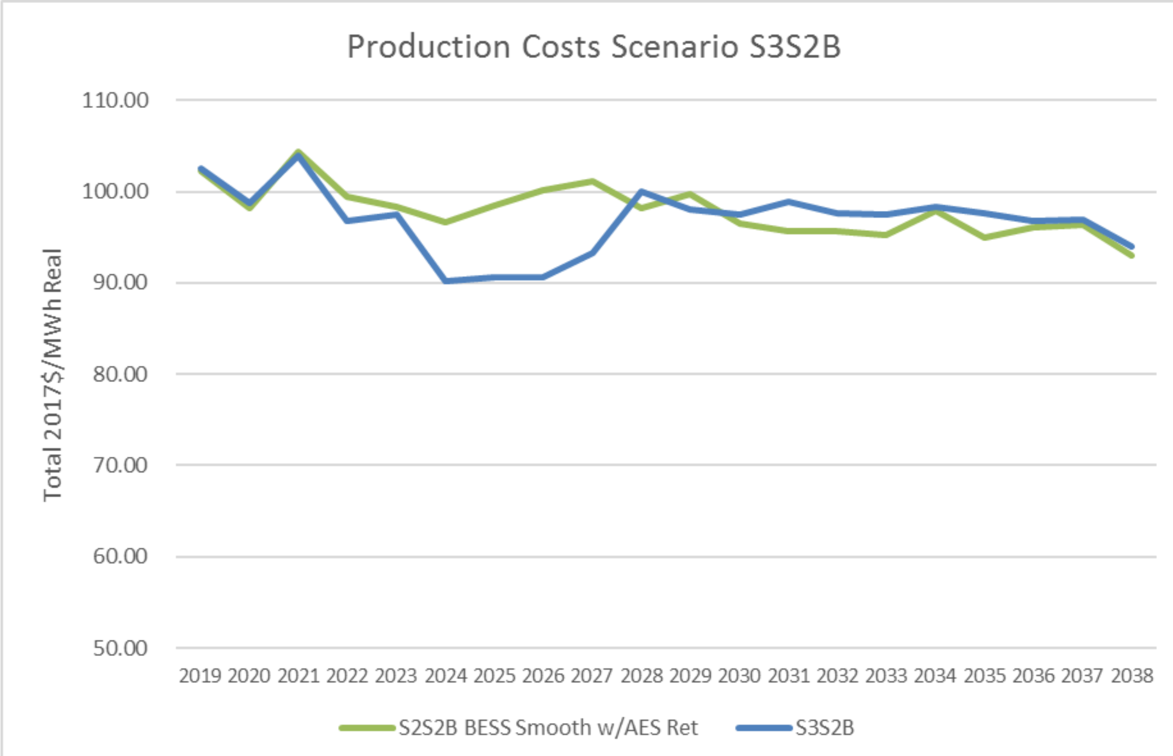
Also the year 1 impact is much lower in this case due to the reduction in fixed costs.

Table 3-16: S3S2B Base Case and with AES Retirement Year 1 impact ($000 2018)

	S3S2B - AES	S3S2B - BASE	Difference to Base Case	Difference to Base Case
Fuel	1,021,554	845,709	175,845	20.8%
O&M	31,621	51,163	(19,542)	-38.2%
Fixed Costs	664,883	819,021	(154,138)	-18.8%
Total	1,718,058	1,715,894	2,164	0.1%
Total/MWh	109.87	109.36	0.5	0.5%

Finally, the figure below shows the evolution of the average total production costs in $/MWh, where we note that as expected the largest difference is in the years leading to 2027.

Figure 3-20: S3S2B Production Cost $/MWh



3.5 Scenario 5 Strategy 1 Base Load Forecast (S5S1B)

In this scenario one AES is converted to a CCGT 585 MW (Option 2) by start of 2023 and the other unit is forced to be retired by the prescribed year the end of 2020. Note that the time elapsed from the time the first unit retires and the time the new CCGT is brought online reflects the minimum construction time required on site.

3.5.1 Resource Additions

As indicated above the LTCE elected Option 2 (585 MW CCGT) by 2023. In addition, this cased built more PV (16.3%) and slightly more BESS (3.3%) with respect of the Base Case (S5S1B) by 2025.

Table 3-17: S5S1B Base Case and with AES Retirement Expansion Plan Overview

	Large & Medium CCGTs and Peakers						Renewable and Storage			
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)
S5S1B -BASE	–	369 MW (2025&2028)	✓	–	–	371	2,580	1,200	2,580	1,480
S5S1B-AES	–	585 CCGT at AES instead	✓	–	–	348	3,000	1,240	3,000	1,560
Change						*-6.3%*	*16.3%*	*3.3%*	*16.3%*	*5.4%*

Over the long term (2038) the only new additions are Storage with the AES conversion case having more storage (1,560 MW versus 1,480 MW or 5.4% more).

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The figures below provide an overview of the additions over time with AES converted and the Base Case.

In these figures we observe that that in the AES conversion case the only New CCGT is this plant conversion (2023) and the last entry of PV occurs in 2025. From that year onwards, only storage is added.

On the Base Case there are two F-Class units at Costa Sur but one in 2025 and the other in 2028. The rest of the patterns are similar.

Figure 3-21: S5S1B AES – Additions

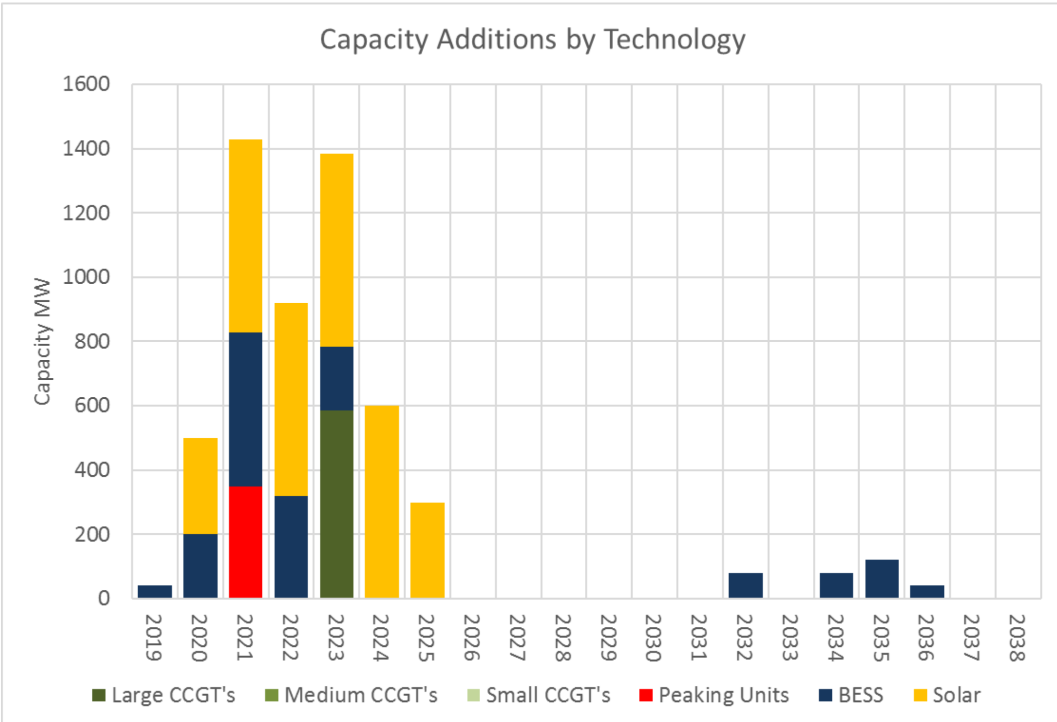

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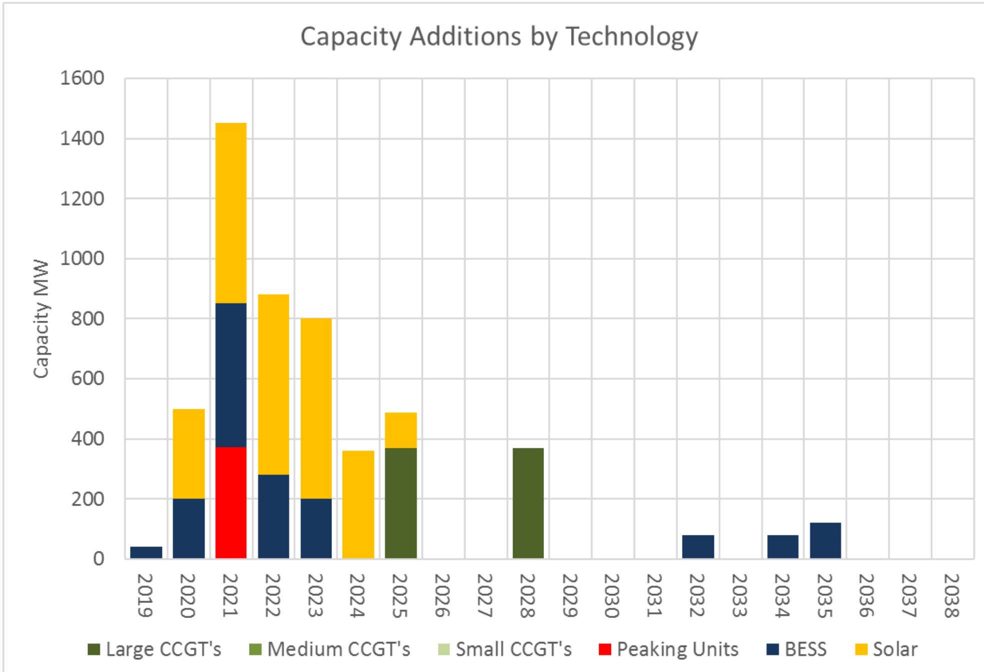
Figure 3-22: S5S1B Base Case – Additions



3.5.2 Retirements

As an effect of one unit AES being converted (2023) and the other retiring in by the end of 2020 the main difference with respect of the Base Case is that in this case Costa Sur 5 retires by the end of 2022. San Juan 5 is retired by 2033 (2031 in the Base Case) and 6 by 2030 (2025 in the Base Case).

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Figure 3-23: S5S1B AES – Retirements

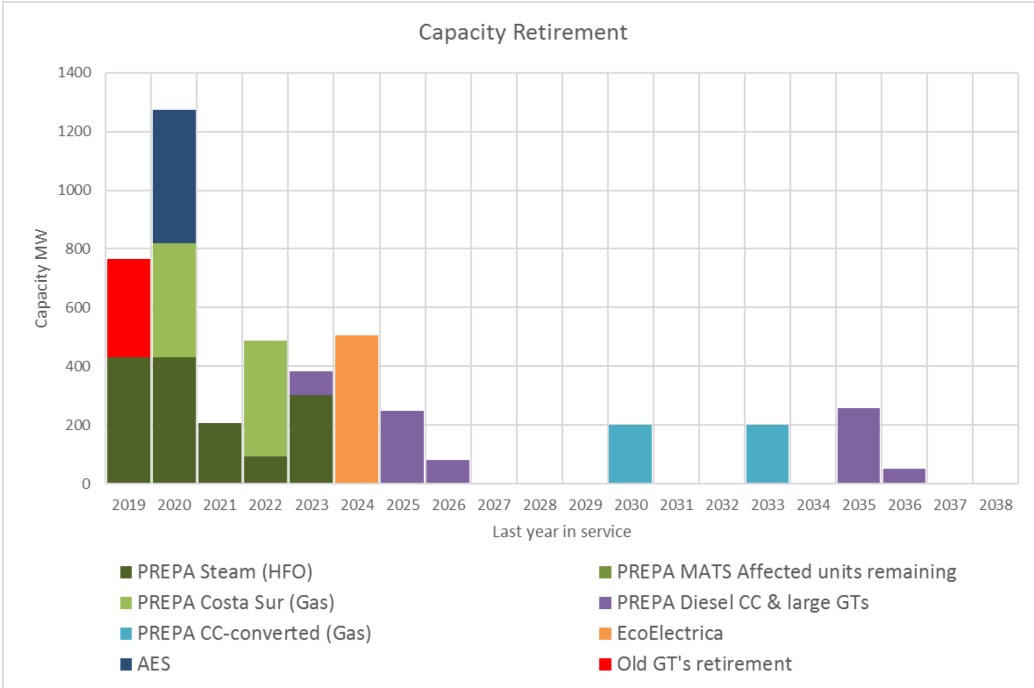
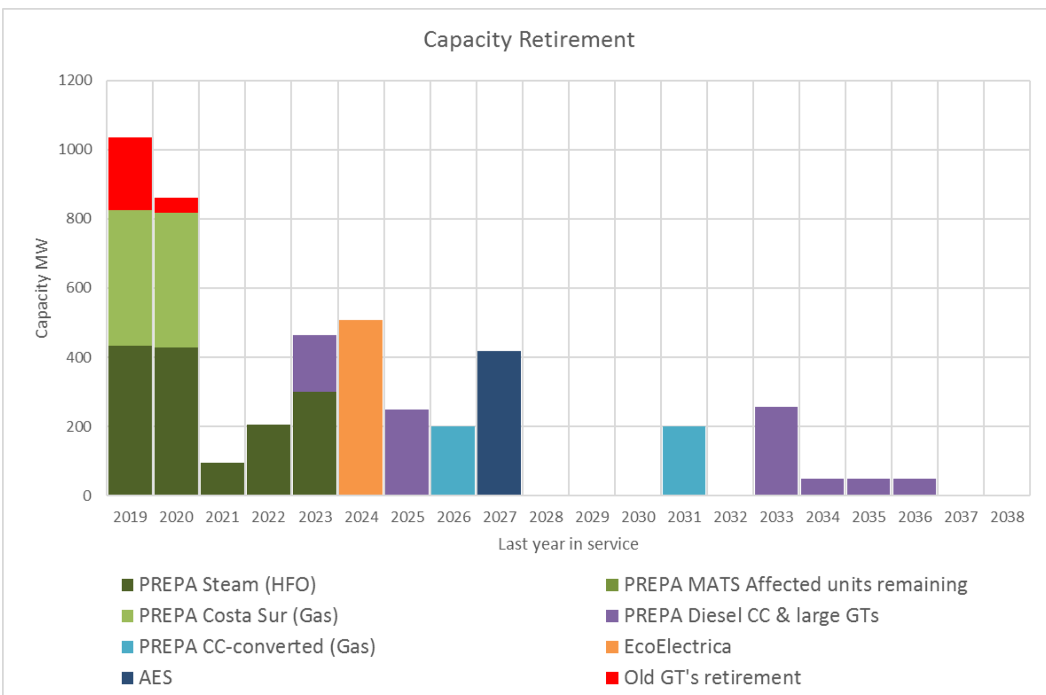


Figure 3-24: S5S1B Base Case – Retirements



3.5.3 Economics

The tables below show a comparison of costs of the Base Case S5S1B with the case where one AES unit is converted and the other retired. We observe that the NPV of the revenue requirement is expected to be 4.1% higher than the Base Case and the average cost of energy is 5.9% higher for the 2019 to 2028 period. The Capital costs are also higher 11.1 %. In all this case shows the overall worse performance as compared with the Base Case

Table 3-18: S5S1B Base Case and with AES Retirement Costs

	Central Metrics		
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**Capital Investment Costs ($ Millions)**
S5S1B -BASE	14,122,690	98.4	6,201
S5S1B-AES	14,700,856	104.2	6,890
Change	*4.1%*	*5.9%*	*11.1%*

With respect of the cost components of the NPV as shown below we note that the largest impact as expected is in the fuel costs that is 12.0% higher than the Base Case and it is not off-set by the reduction in fixed and variable costs NPV due to the early retirement of AES-Coal.

Table 3-19: S5S1B Base Case and with AES Retirement NPV Components ($000 2018)

	S5S1B - AES Smooth	**S5S1B - BASE**	**Difference to Base Case**	**Difference to Base Case**
NPV fuel	6,983,557	6,233,610	749,947	12.0%
NPV Var O&M	293,167	387,870	(94,704)	-24.4%
NPV Fixed Costs	7,424,132.32	7,501,210	(77,078)	-1.0%
Total	14,700,856	14,122,690	578,166	4.1%

As before, another aspect that is important to take into consideration is that while the mitigations are not in place the impact of the retirement can be much larger. To illustrate this the table below shows the impact of the retirement of year one (2021), when the mitigating generation is not yet fully in place. In this table we observe that the increased costs can be almost $ 76 million per year, in line with previous results.

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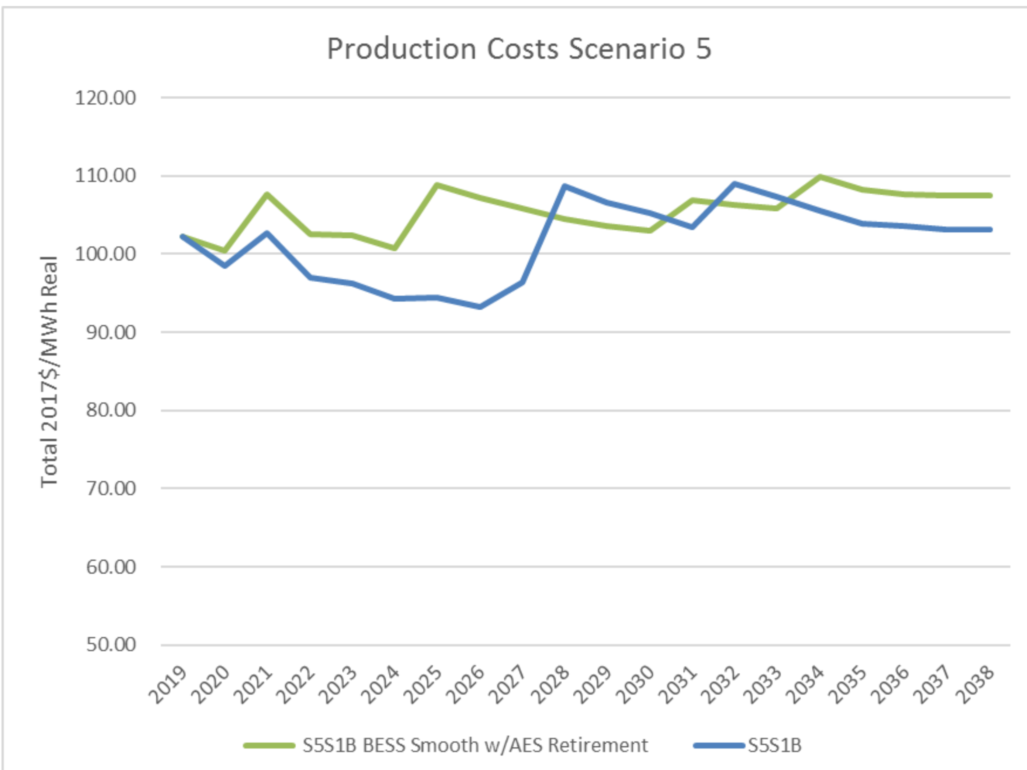
Table 3-20: S5S1B Base Case and with AES Retirement Year 1 impact ($000 2018)

	S5S1B - AES	S5S1B - BASE	Difference to Base Case	Difference to Base Case
Fuel	1,042,485	806,024	236,461	29.3%
O&M	33,392	52,009	(18,617)	-35.8%
Fixed Costs	677,964	819,617	(141,654)	-17.3%
Total	1,753,840	1,677,651	76,190	4.5%
Total/MWh	113.37	108.08	5.3	4.9%

Finally, the figure below shows the evolution of the average total production costs in $/MWh, where we note that as expected the largest difference is in the years leading to 2027.

Figure 3-25: S5S1B Production Cost $/MWh



Section
4

AES Steady State Assessment

Confidential - CEII

Section

5

Conclusions

Siemens PTI conducted an analysis of the impact of AES Coal Plant being either converted to burn natural gas or retire by the end of 2020 (reference year). Three options were assessed; direct conversion to NG keeping the existing boilers (Steam), Repowering to a Combined Cycle (2x1 with F-Class GTs) or a Heavy Fired Combined Cycle where a CT is used to provide heated air to the boilers.

With the exception of Scenario 5 Strategy 1 (Centralized development of generation), in all cases the Long Term Capacity Expansion Plan resulted in the plant not being converted to natural gas, but rater being retired. On Scenario 5 the option to repower to a combined cycle 585 MW was selected.

The least impact of AES retiring occurs in Scenario 3 that has low cost of renewable (1.4% increase in the NPV or $ 187 million increase in the NPV) and the ESM that has more thermal generating options available (1.2% increase in the NPV or $ 174 million increase in the NPV). Scenario 4 (4.0%) and Scenario 5 (4.1%) have similar cost increases and in the order of $ 580 million. Finally, Scenario 1 experience $ 461 million increase in the NPV (3.1%).

From a transmission point of view, no issues were identified.

Siemens Industry, Inc.

Siemens Power Technologies International

400 State Street • P.O. Box 1058

Schenectady, New York 12301-1058 USA

Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777

www.siemens.com/power-technologies