WECC Market Outlook and Modeling

1 Key Takeaways

- Renewables and batteries continue to dramatically drop in cost. The continued deployment of renewables in the Western Electric Coordinating Council (WECC) is putting downward pressure on energy prices, making inflexible thermal resources increasingly uneconomic. At the same time, renewables are driving increased price volatility due to generation intermittency.
- Ascend does not see any evidence to suggest that this trend will reverse itself, therefore we model decreasing average prices (and implied market heat rates) and increasing price volatility in the WECC going forward. We also model a changing price shape, which is now driven by net load (load – renewables). Lower prices and higher volatility will result in a higher valuation for flexible resources over traditional inflexible assets in the PowerSimm construct.

2 General Regulatory Outlook

Current climate regulations in the Unites States have been shifted from federal authority (i.e. the EPA) to the States following the withdrawal from the Paris Climate Accord and the rescinding of the Clean Power Plan (CPP). As the federal government has become less involved in climate policy, many states have introduced their own policies aimed at achieving the goals of the Paris Climate Accord and the CPP. The WECC states have been among the most active in implementing climate policy, with all states in the WECC except Idaho and Utah having renewable portfolio standards, and two of the three founding states in the United States Climate Alliance, a partnership of 19 states working together to maintain the Paris climate accords, being in the west.

Renewable portfolio standards have become a significant part of state environmental policy, and regulation on the energy industry. California has been the leader in the WECC in terms of implementing RPS, with the passage of Senate Bill 100 requiring 100% clean energy by 2045. While California may be the most extreme case of implementing RPS, the rest of the WECC has RPS of at least 15% by 2040, if not larger[1]. These requirements will force states to invest in new renewable generation. As renewable generation is variable, increasing renewable penetration will create the need for fast reacting thermal generation and energy storage options to maintain system reliability. Ascend forecasts that RPS standards will be a lower bound on renewable penetration throughout the west. Utilities are expected to surpass the standards set by state governments, producing more renewable energy than currently expected leading to greater renewable penetration than required under the RPS standards.

[1] http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

Table 1: RPS Standards by State

State	RPS Standard	Energy Use (MWh)[2]
AZ	15% by 2025	77,646,262
CA	100% by 2045	257,267,937
CO	30% by 2020	54,830,186
ID	N/A	23,793,790
MT	15% by 2015	14,709,656
NV	25% by 2025	36,657,786
NM	20% by 2020	23,009,584
OR	50% by 2040	50,043,816
UT	20% by 2025	30,589,021
WA	15% by 2020	91,948,172
WY	N/A	16,778,067
Full WECC	51% by 2045[3]	667,274,227

In addition to renewable portfolio standards, 19 states have joined the US Climate Alliance. The goal of the Climate Alliance is for states to act in partnership to keep up their commitments under the Paris Climate Accords[4]. For the states in the WECC who have joined the Climate Alliance (CA, CO, NM, OR, and WA) there is an extra push toward renewable energy production. The Paris Climate Accord sets the goal of 26-28% reduction in GHG emissions compared to 2005 levels by 2025. The Climate Alliance goals are complementary to the RPS goals that these states have set, providing states accountability outside of their own governments to meet their goals.

Commitments to environmental regulations by individual states in the WECC is leading to the retirement of coal and natural gas power production which is being replaced by renewables, fast ramping natural gas, and increasingly batteries, as they become more economical. With increasing renewable penetration, real time prices are becoming more volatile, creating opportunities for fast reacting generation assets to earn excess profits in sub-hourly energy markets. In the long run, excess profits cannot exist, and competition between fast responding generation will put downward pressure on price volatility limiting profit to normal returns. Internal combustion engines and longer duration batteries will take advantage of increasing volatility to increase their returns on their investment.

3 WECC Market Fundamentals

3.1 Need for New Capacity Mix in the West

A review of current Integrated Resources Plans (IRPs) for WECC utilities outside of California indicates a need for capacity in the region. While preferred least-cost resources differ between utilities, the common element is that Demand Side Management (DSM) will not be sufficient to mitigate load growth over the planning horizon. In each IRP, renewables and peaking resources contribute more toward reserve margins than DSM. As resource

[2] From EIA State Energy Profiles (https://www.eia.gov/electricity/state/)
[3] Calculated as a weighted average of all WECC state RPS standards
[4] https://www.usclimatealliance.org/alliance-principles/

intermittency increases, additional fast-response flexible capacity is needed to respond to changes in supply.[5] Large utilities like PacifiCorp plan to retire 2.7 GW of coal by 2040, while installing approximately 3 GW of new solar and wind energy and about 1 GW of re-powered wind[6]. With these planned retirements, PacifiCorp faces a capacity deficit of 220 MW in 2022 and 2 GW by 2036[7]. Similarly, IdaCorp, Puget Sound Energy, and Arizona Public Services all have significant capacity needs ranging from 200 MW to 1000 MW in 2022. Figure 1 shows the overall planned cumulative capacity with WECC additions and retirements annually by resource type.

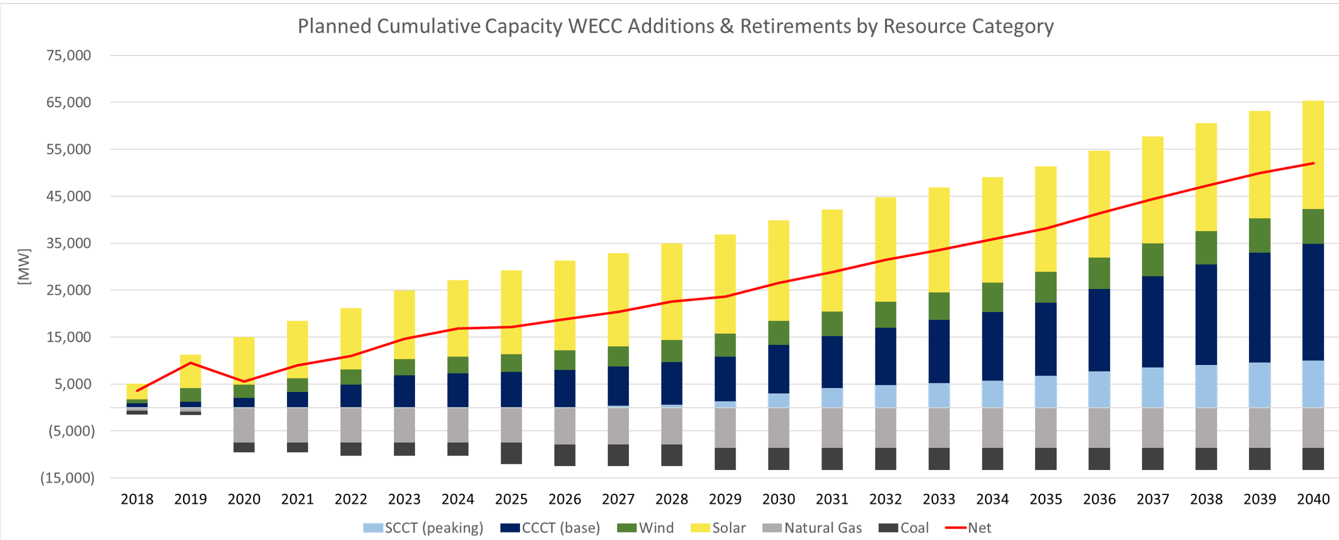


Figure 1 Planned Cumulative Capacity WECC Additions and Retirements by Resource Category

[5] The need for new capacity and for increased flexibility is shown in many of the published IRPs discussed in Appendix B.
[6] Appendix B3
[7] Appendix B4

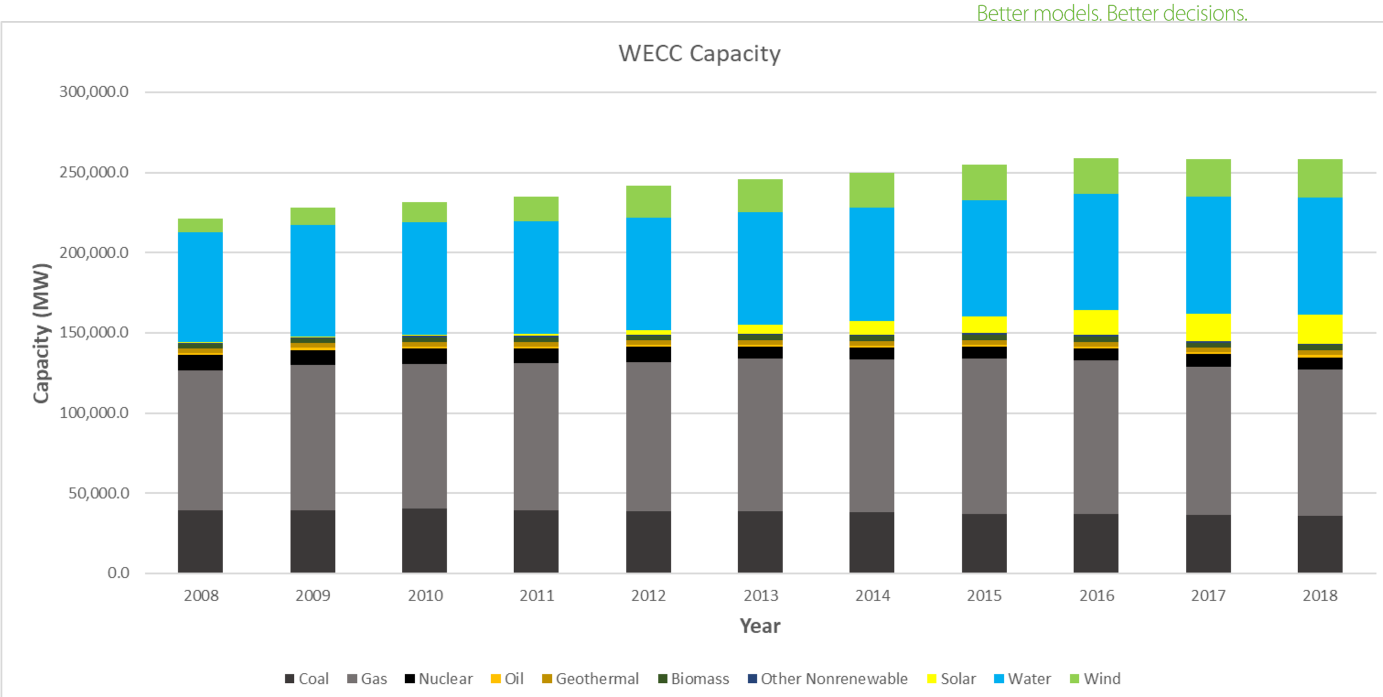


Figure 2 WECC Capacity

3.2 Northwest Supply Fundamentals

In the North West Power Pool (NWPP) generation from coal, hydro, and natural gas have remained relatively constant over the last decade, as seen in figure 3. Hydro and natural gas generation have historically been the main sources of power to the NWPP, with hydro comprising 54% of the current generation capacity while natural gas (baseload and peaking) makes up ~15% of the total capacity mix. Wind installations have been on the rise and currently comprise 14.5% of the total capacity mix in NWPP.

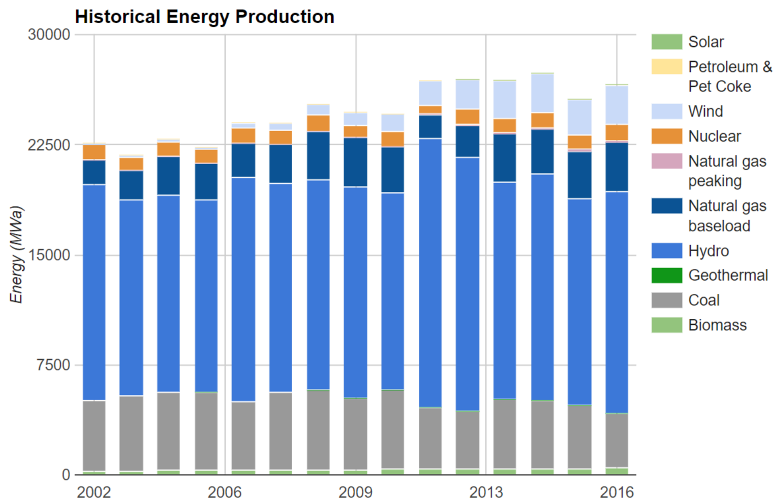


Figure 3 Historical Annual Energy Production in NWPP since 2002

Expected reductions in the capital costs of new renewable resources as well as high renewable portfolio standards implies significant additions of PV solar and onshore wind in the NWPP. Figure 4 shows the slow rise of wind, solar, and hydro assets through 2040. Ascend further predicts 9 GW of nameplate solar and 17 GW of nameplate wind capacity to come online by 2040 due to capacity need in the region from the retirement of coal and rapidly changing renewable energy economics. New renewable generation is likely to come online earlier in the forecast period due to economic incentives in the form on investment tax credits (ITCs) for solar and production tax credits (PTCs) for wind. An effect of phasing out the ITC and PTC is that utilities will build solar and wind assets earlier than they likely otherwise would have to maximize their return on renewable generating assets.

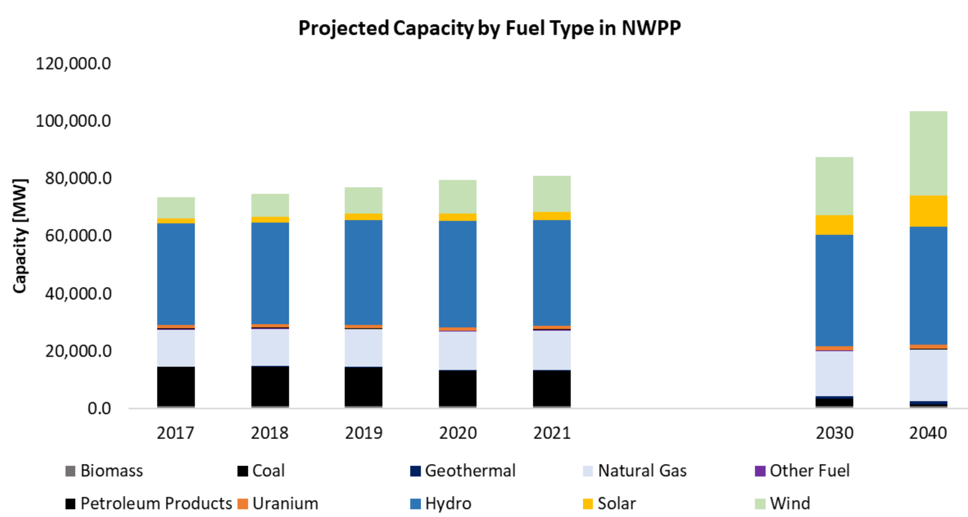


Figure 4 Projected Capacity by Fuel type in NWPP through 2040

Coal generation is expected to fall from accounting for 28% of electricity nationally to 17% by 2050[8]. Coal retirements are expected to be extremely visible in the west. Expected retirements include the 614 MW Colstrip power plant units 1 and 2 in Montana, the 762 MW Dave Johnston power plant in Wyoming, and the 1.3 GW Centralia power plant in Washington, which is expected to transition to natural gas by 2025. Overall, approximately 5 GW of coal is expected to retire in the region by 2030.

Ascend assumes that, in addition to announced retirements, plants will retire at an age of 50 years old or will retire if they are unable to consistently operate in the modern market (i.e. having variable O&M above $25/MWh). On average, the marginal unit can operate with a VOM of ~$18/MWh[9], even with declining power prices, coal will not run at peak demand, therefore Ascend predicts ~11 GW of retirements by 2040[10].

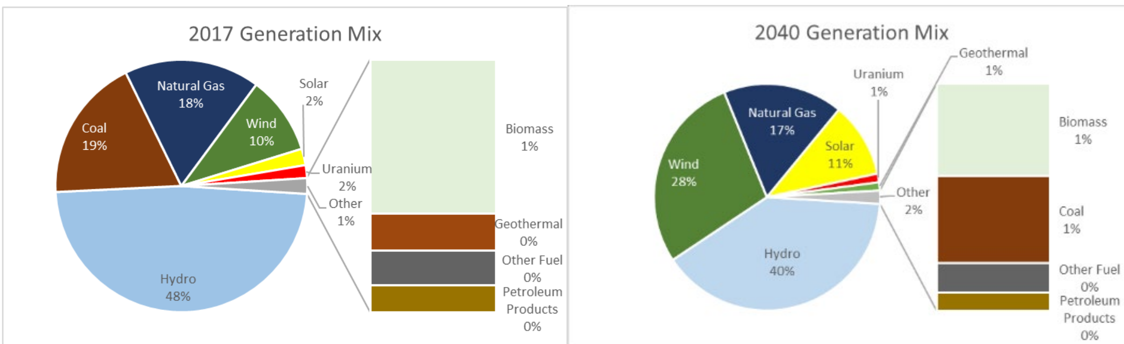


Figure 5 Energy mix in 2017 and projected mix in 2040

With solar projected to increase five times by 2040, and wind installations projected to almost triple, both at zero variable cost, these units will more frequently be the marginal unit, shifting power prices down. Section 3.6 discussed the impact of high renewable integration on power prices.

3.3 California Supply Fundamentals

Over the last five years, renewables have been replacing coal powered energy in California's energy mix, while other thermal generation has remained relatively stable. Renewable portfolio standards and other regulations imposing limits on green-house gas emissions will materially change the generation portfolio in California.

[8] https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf
[9] SNL Generation Supply Curve data
[10] Full table of coal retirement projections in Appendix A

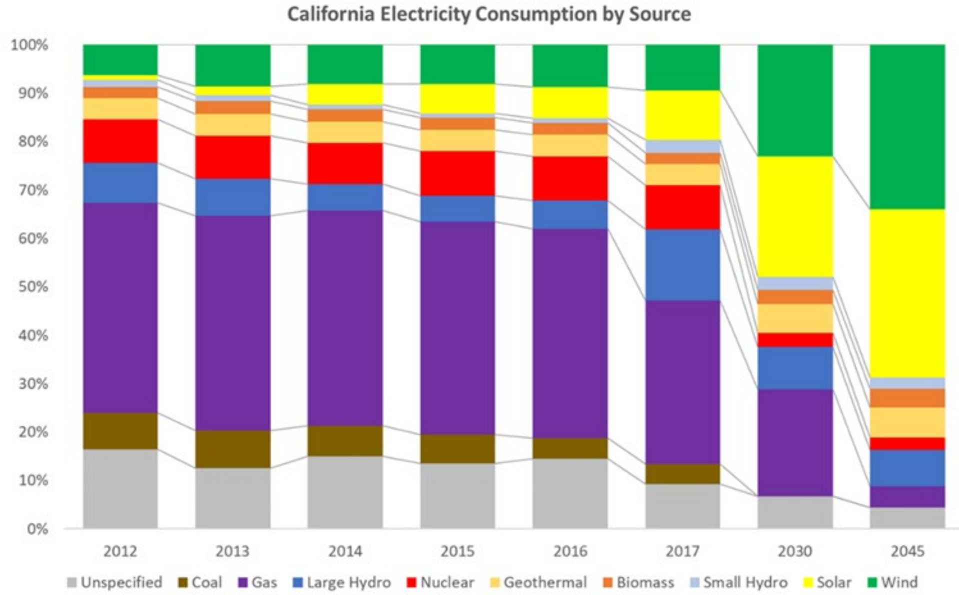


Figure 6 California energy consumption be generation technology

Supply stacks in California have shifted to the right over the past five years mainly due to the installation of additional renewable generation (see figure 7). Increasing renewable capacity puts renewable resources on the margin more often, however, only when they are generating. Without the installation of energy storage in California thermal generation will be on the margin during the high load evening hours. The intermittency of renewable generation paired with the fact that solar energy cannot be produced at night means that there will be a continuing need for thermal generation to maintain system reliability.

Forecasted energy demand in California is set to increase over the next 10 – 20 years. The two main driving forces of demand growth are climate change and the adoption of EVs. Climate change will be responsible for an increased energy demand in the summer months. This will likely increase peak demand, as well as the total amount of energy consumed. EV adoption will increase demand in the off-peak times as EV owners charge cars overnight. Increasing overnight energy demand will change requirements for energy production.

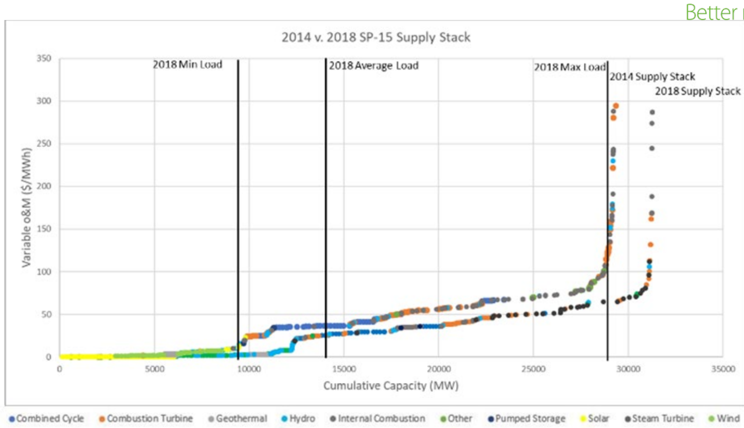


Figure 7 2014 v 2018 SP-15 Supply Stacks

3.4 Southwest Supply Fundamentals

Energy supply in the southwest is likely to change substantially throughout the next 20 years. Large thermal generating assets, such as San Juan Generating Station and Four Corners, are set to retire in the next 15 years as coal and inefficient gas plants are replaces with renewable generation to meet RPS standards. Renewable generation alone will not be sufficient to replace the retirements of power plants like San Juan, and therefore new natural gas flexible generation will be required. The majority of new capacity is likely to come from renewables, mainly in the form of solar and wind, with batteries being built to take advantage of increasing price volatility as renewable penetration increases.

System loads in the southwest are also likely to increase over the next 15 years as the shift to larger renewable penetration is occurring. Cities such as Phoenix and Denver are seeing consistent increases in populations which will drive load increases as more people require energy in population centers. Industry is increasing in the west as well, demanding energy on a second front. Third, climate change will lead to hotter summers, thus increasing demand for electricity on the most extreme weather of the year as energy for cooling homes in the summer and heating homes in the winter is ever more necessary.

3.5 WECC Transmission Expansion

Current Transmission **Currently Planned Transmission**

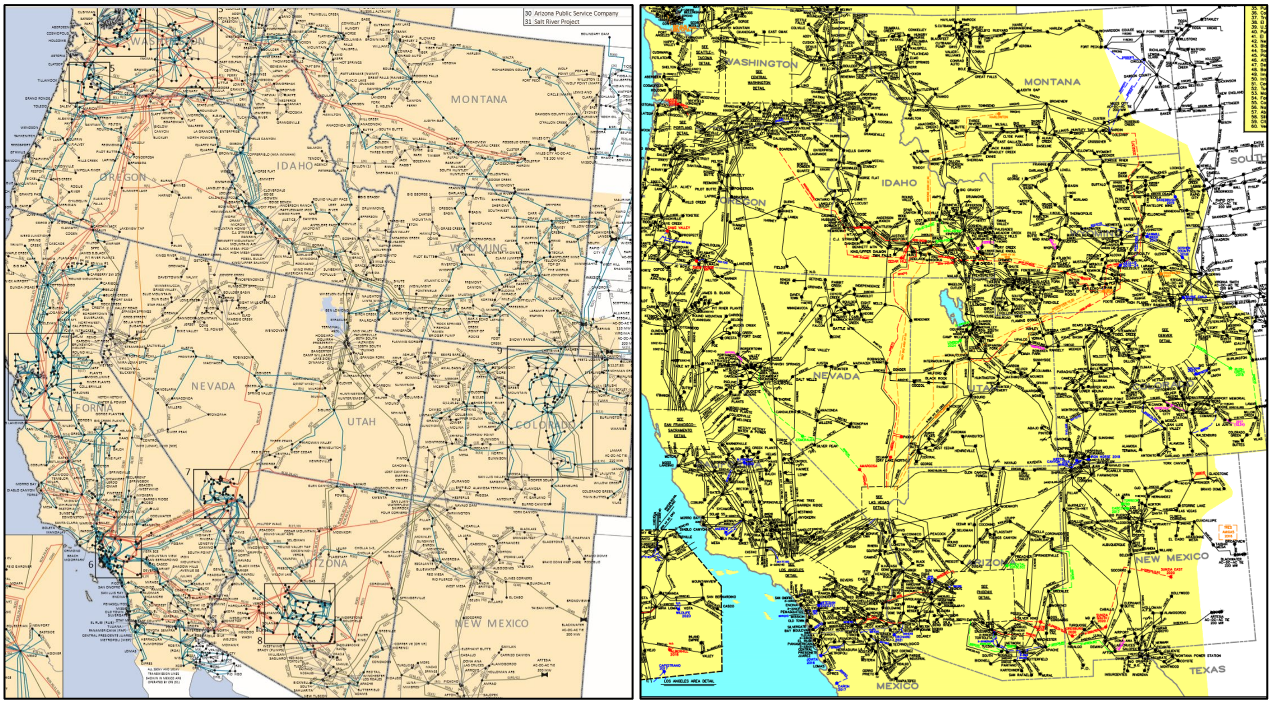


Figure 8 Current and Planned Transmission

The transmission grid in the west was developed to move energy from large thermal generating plants to load centers. The trend in the west is a need for more transmission assets as large thermal generation is replaces with smaller, dispersed, renewable and flexible generation. Renewable generation cannot necessarily be built in the exact location of existing generation; therefore, transmission is necessary to move energy from where it can most efficiently be produced to load centers. Additionally, utilities joining the EIM requires transmission assets to interconnect each network in the EIM.

3.6 Impact of High Renewable Integration

Historic supply curves in the NWPP region show gas or hydro being the marginal unit a significant amount of the time. As the supply stack shifts to the right with added renewable generation, a greater percentage of hours have renewables as the marginal unit. Figure 9 shows a price duration curve for Mid-C Power Prices over the past three years. 2017 is the first year that has negative pricing as the supply has shifted to include more renewable generation.

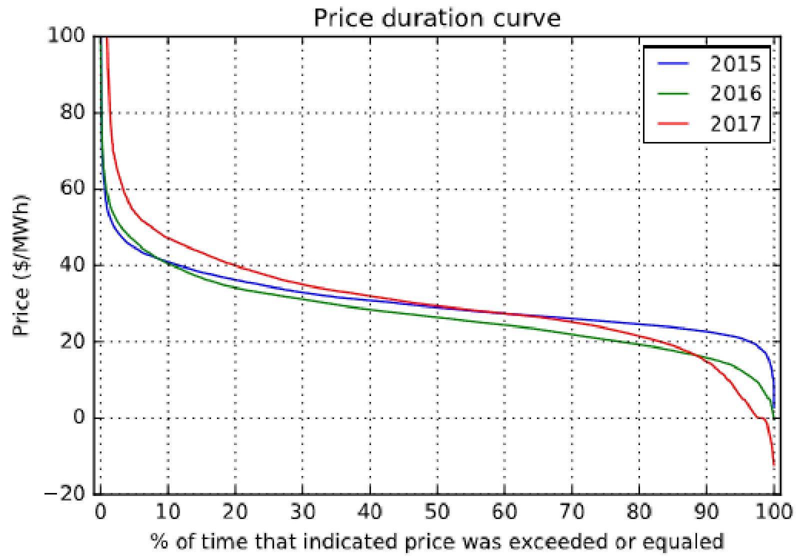


Figure 9 Price Duration Curves for Mid-C 2015-2017

Prices are dropping, to negative values in many hours, due to renewable energy being on the margin in a greater percentage of hours.

Most intermittent renewable power in NWPP is wind, with penetration levels in 2017 reaching 23%. Wind and solar, at effectively zero variable cost, shift the supply stack to the right, reducing power prices. Over the past 3 years, power prices have been negatively correlated with power prices on an hourly level. Figure 10 shows this declining trend in NWPP. In regions like CAISO power prices tend to be negative as renewable penetration increases past approximately 55%, however renewable penetration has not reached this level across the WECC.

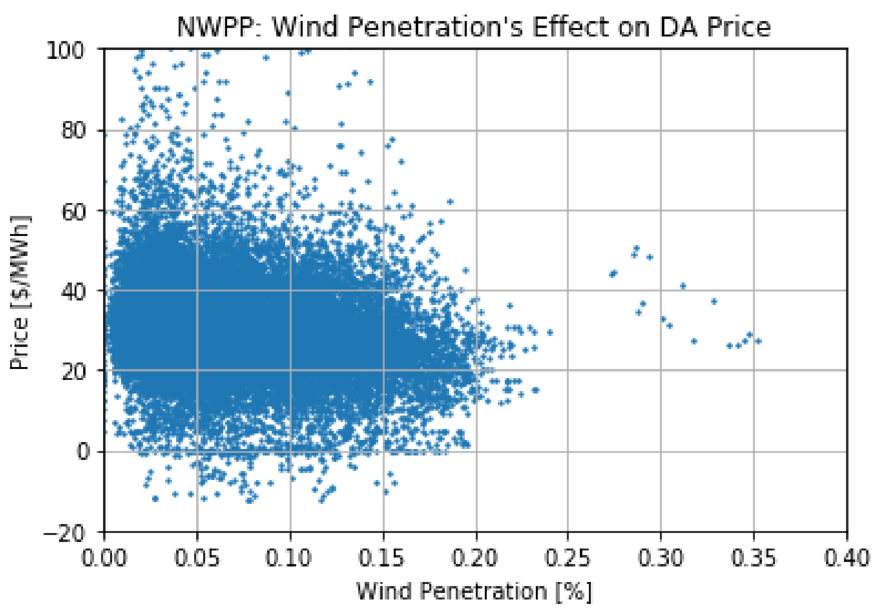


Figure 10 Min., avg., max. wind penetration as a percentage of load in any hour per month

With gas being less on the margin, and renewables being on the margin more frequently, the hourly implied heat rates (Power Price ($/MWh) divided by gas price ($/MMBtu)) will drop in the hours when renewables are on the margin (see figure 11).

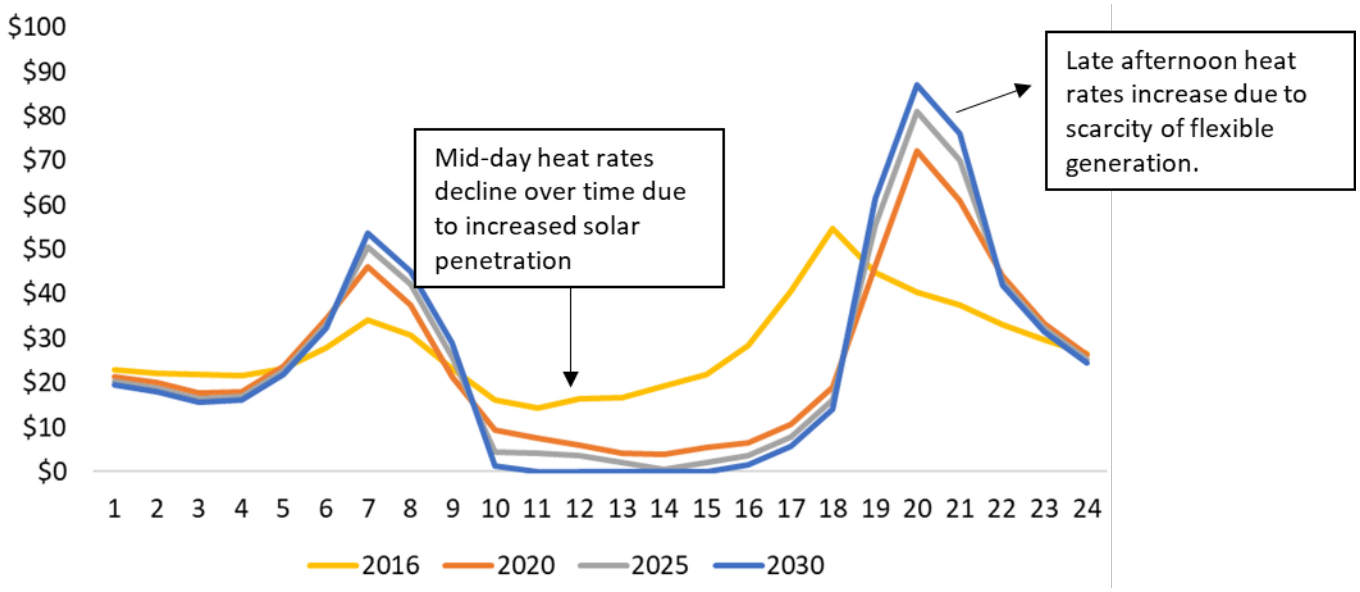


Figure 11 Example Hourly Price Profile Forecasted based on Marginal Unit Analysis

The marginal unit is determined fundamentally by supply/demand economics of the power market from least to greatest cost generation in every hour across the transmission grid in the NWPP region. The graphs below show the hourly supply stacks for the region for four days in 2017 (one day in each season). The load at noon and at 6 pm are shown, where the marginal unit historically was still a gas plant mid-day, and a more expensive generation was marginal in the evening hours when the load is at its peak. Over time, the supply stack shifts to the right as a whole, and the unit that is marginal is of even lower cost, reducing the marginal cost of power. This is especially true in the spring when more solar and wind comes online, and load is expected to remain low. Renewables are expected to be on the margin more frequently than they currently are in the spring, and in the winter/summer, during peak load season, renewables are on the margin more often than currently, but less so than in low load times, with gas and hydro being on the margin at the top peak hours.

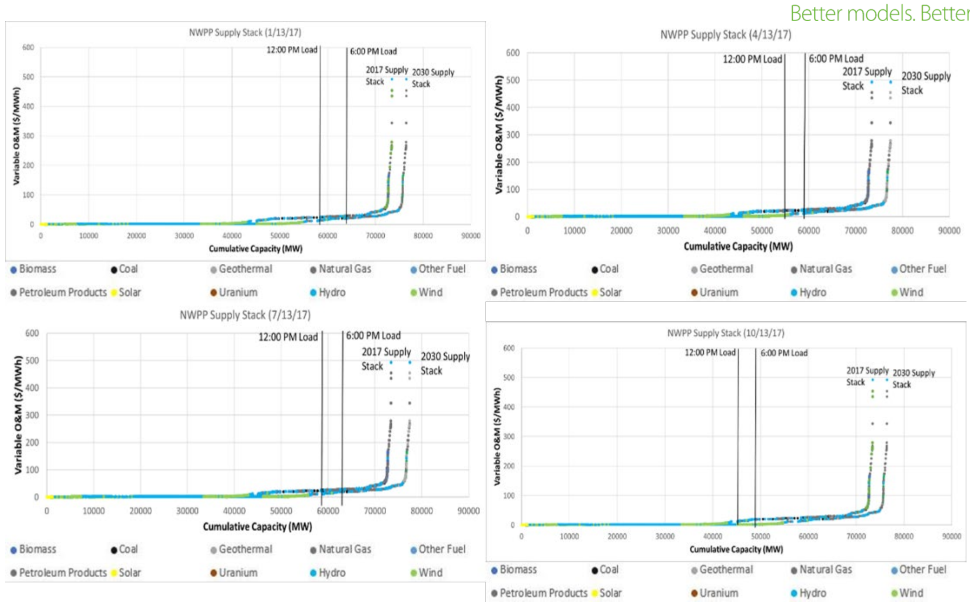


Figure 12 NWPP Seasonal Supply Stacks

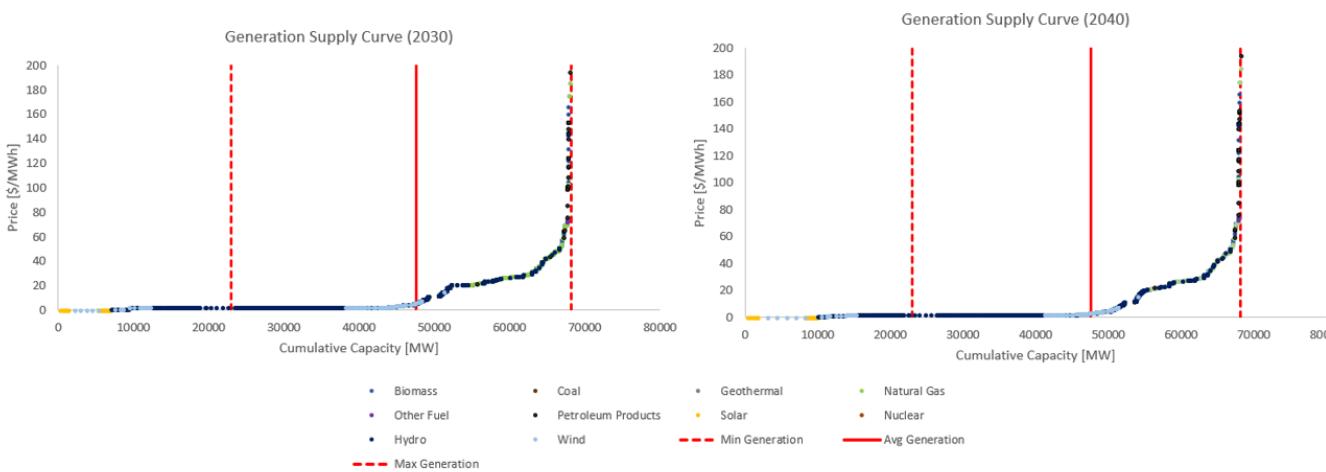


Figure 13 NWPP Predicted Supply Stacks

Implied heat rates vary by hour of day within a given season. Figure 14 shows how the implied heat rates in the future are projected to change during the course of that year for the NWPP region. With greater solar and wind, the power price profile gets duckier in the spring months when renewables are high, and load is low. When peakers run in the summer and winter due to higher load, the implied heat rate is higher due to gas being on the margin more frequently.

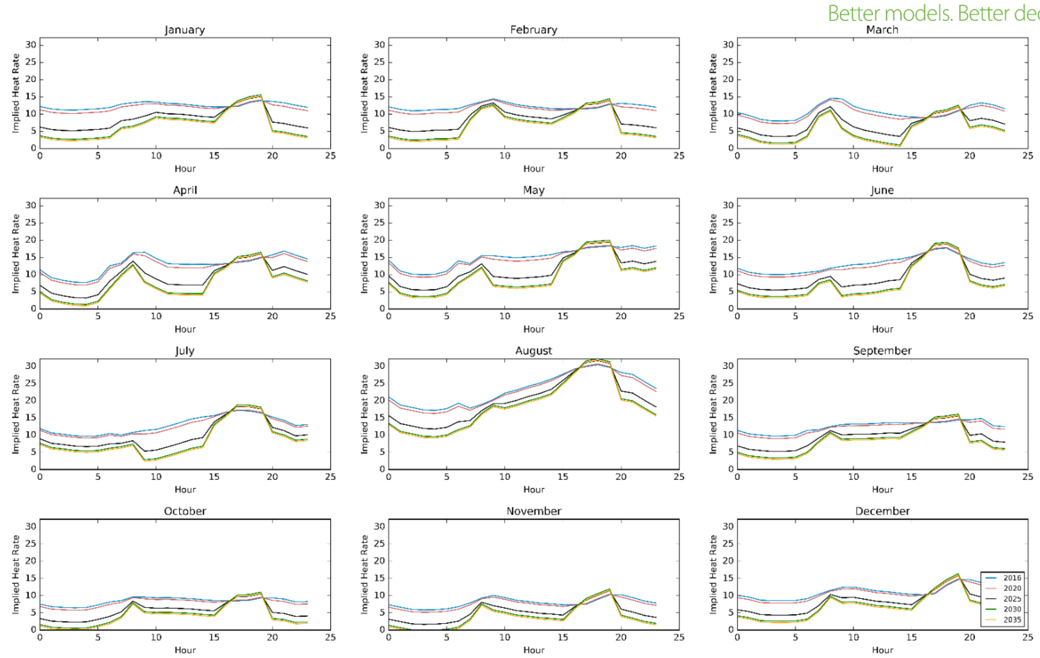


Figure 14 Implied Heat Rate forecast by season

Figure 15 below shows the correlation between increased renewable penetration in the system and volatility in SP15 power prices, from 2015-2017 in the CAISO market. In both the Real-Time (RT) and the Day-Ahead (DA) market, price volatility tends to follow renewable generation more closely when renewable penetration in the system increases from 10% to 20%. Currently, the northwest region sees renewable penetration as high as 23% in a given hour which is increasing. As intermittent renewables grow, volatility will grow accordingly as well.

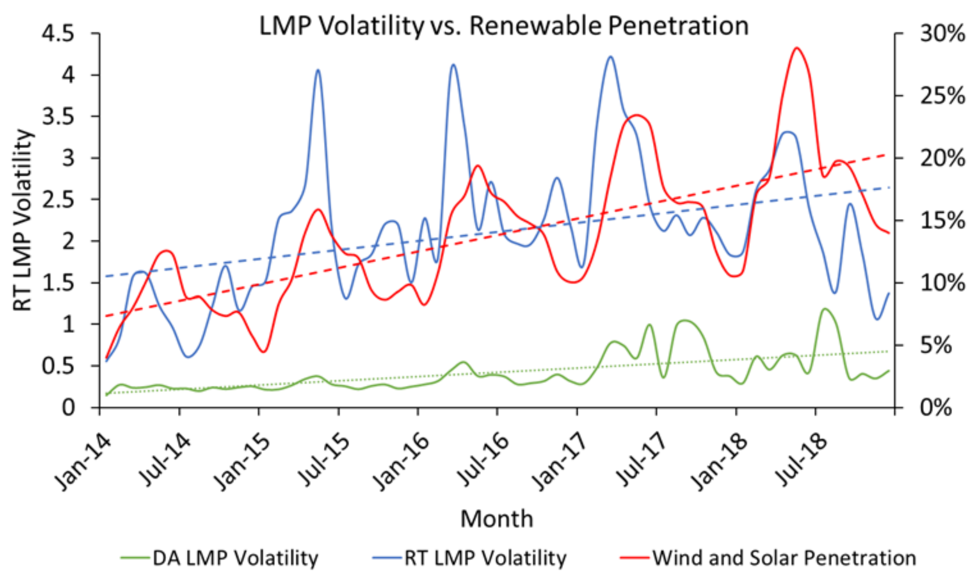


Figure 15 Volatility in RT Prices (2015-2017)

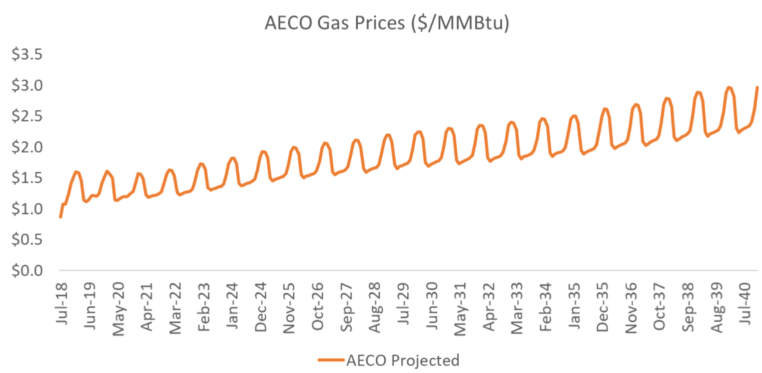
4 Appendix

4.1 Inputs into MT

The figures below show the inputs into PowerSimm modeling given energy market fundamentals. The main inputs into spot price modeling are Ascend's projections of hourly price shapes, hourly spot volatility, and the forward power price projections that spot prices will converge to. Gas prices are projections by Northwestern.

Gas prices projected below are shown in Figure 4.1.1. AECO prices have historically been low due to excess supply and storage, falling below $1.50/MMBtu. The first few years of the forecast are gas curves from the futures market (through 2022). After 2022, the futures market is illiquid, and the prices are escalated by EIA's rate of inflation of 3% through the remainder of the forecast.

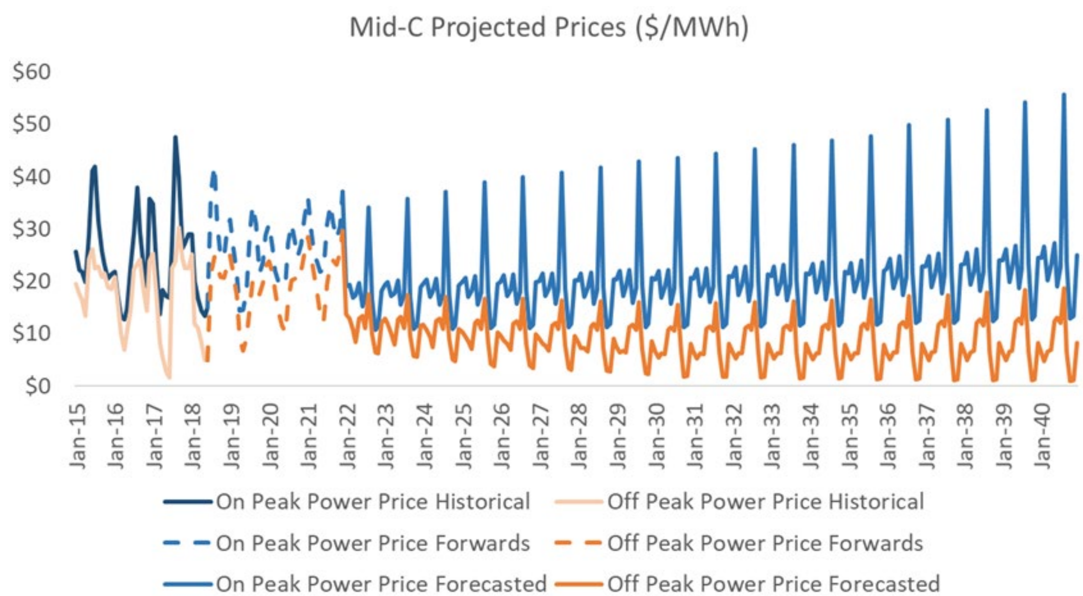
Figure 4.1.1: AECO Gas Price Forecast



In Ascend's current methodology, power prices projections are calculated as a product of implied heat rate forecasts (MMBtu/MWh) and gas price forecasts ($/MMBtu). The implied heat rates are predicted based on renewable penetration in the system shown in Figure 4.1.2. This figure shows the power price profile, or implied heat rate, in 2016, and select projected years, by month and hour. The implied heat rate is expected to decline overall in most hours due to increased penetration of wind and additions of solar. Mid-day and nighttime hours will see suppressed prices due to solar and wind/hydro, respectively. The late afternoon hours will see an increase in heat rates as more inflexible thermal comes online when the sun sets. Forecasts are based on a typical hydro year. A drought year would see an increase in the implied heat rate with thermal assets replacing hydro on the margin more frequently.

The implied heat rates are forecasted seasonally, by day of week, and hourly. Projected implied heat rates in 2022 and after are multiplied by the monthly gas prices to forecast out power prices in 2022 onwards, seen in Figure 4.1.3 below. ICE forward curves are used for the first few years (through 2021), until the market is illiquid.

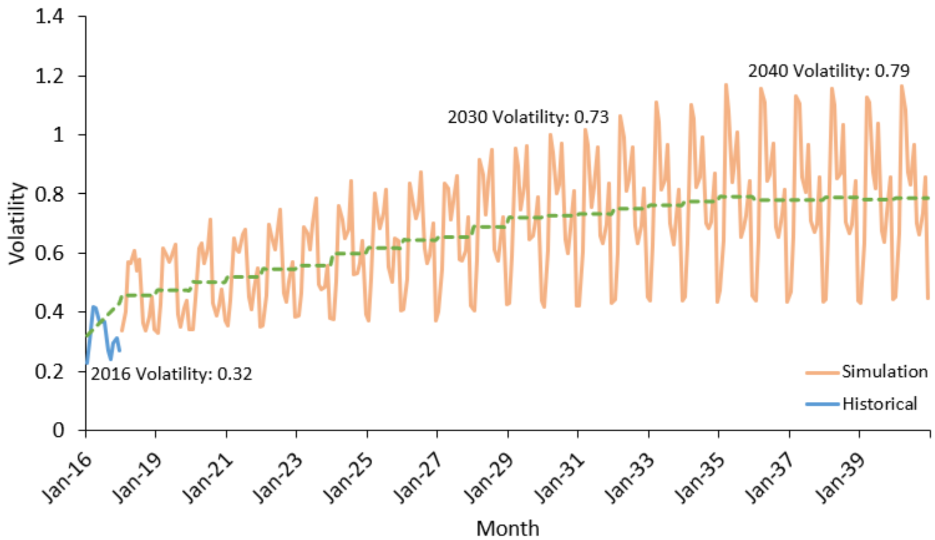
Figure 4.1.3: Mid-C Projected DA Prices ($/MWh)



The volatility of hourly prices increases in strong correlation with increase in intermittent renewable penetration. That is, after about 20% renewable penetration in the grid, volatility of DA prices follows closely at approximately 0.9 correlation. About ~2.4 GW of derated wind and solar is projected to be online by 2021 in NWPP[11], causing the supply curve to shift right. Coal plants retiring will shift the curve slightly left, and price volatility will increase further. Figure 4.1.4 shows the monthly volatility of hourly prices in 2016 and forecasted through 2040. 2017 was omitted due to it being an outlier drought year. Volatility, as measured by the coefficient of variation, is approximately 0.32 as of 2016, and is expected to more than double by 2030 as wind and solar more than double in the grid. Ascend takes a conservative approach by more slowly increasing the rate of volatility increase after 2030, as resources such as batteries can dampen volatility by arbitraging between peaks and valleys in the real-time prices.

Figure 4.1.4: Projected DA Price Volatility Mid-C

[11] SNL Generation Supply Curve



NorthWestern's PowerSimm portfolio and Northwestern's assets are optimally dispatched to these power prices. The dispatch of existing and future assets will be impacted by this new market outlook.

PowerSimm simulates forward prices based on the forecasts that are input into the system, and scales hourly spot prices to those forwards. PowerSimm also takes the asset's physical heat rate curve as an input, and the assets will only be dispatched in a given hour if it is less than the implied market heat rate. Given our price projections, PowerSimm will dispatch traditional assets far less frequently than current operations, which is consistent with Ascend's understanding of the direction of the electricity market.

Increasing hourly spot volatility will also have a detrimental impact on traditional inflexible assets in PowerSimm. These assets, such as coal plants and combined cycle gas plants, will not be able to ramp quickly enough to provide reliability to the grid nor capture high prices on a more granular time scale. PowerSimm incorporates the physical start-up attributes of each asset to accurately model future dispatch schedules. The dispatch optimization module will naturally select assets with flexible ramping capabilities due to their lower start-up costs and lesser physical constraints. In addition, higher cost assets may not recover costs from the energy market as they used to if high price periods are not sustained due to increased volatility. Assets with long start-up times and high start-up costs may miss the high price period and would be "out-of-the-money" before they fully come on line. These economic considerations are included in PowerSimm's optimization logic and the effects are shown in the dispatch results.

Table 4.1.1

Cumulative Capacity Additions in Studied IRPs [MW]																					
	Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Puget Sound Energy																					
	Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Peaking	-	-	-	-	-	-	-	-	-	717	717	717	717	717	717	717	717	717	717	1,195
	Wind (de-rated)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar (de-rated)	-	-	-	-	-	40	40	40	40	57	57	57	57	57	57	57	57	57	57	73
Idaho Power																					
	Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300	300		
	Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	36	72	72	126	180		
	Wind (de-rated)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
	Solar (de-rated)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Pacificorp																					
	Base																				
	Peaking												200	636	636	636	677	1,313	1,313	1,313	
	Wind (de-rated)	-	-	-	220	220	220	220	220	220	220	220	220	220	237	237	237	237	237	402	
	Solar (de-rated)	-	-	-	-	-	-	-	-	-	-	2	17	17	35	71	105	112	156	158	
Portland General																					
	Base	290	317	317	370																
	Peaking	8	12	16	20	Outside IRP Forecast Horizon															
	Wind (de-rated)	-	103	103	103																
	Solar (de-rated)	-	-	-	-																
Arizona Public Services																					
	Base	-	-	-	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	4,090					
	Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-					
	Renewable	-	-	-	9	9	9	9	9	9	9	9	9	9	9	27					

4.2 Coal Plant Predictions in the NWPP

In order, the following criteria were used to determine whether each coal plant would retire by 2030 and 2040:

1. Is the retirement date known, officially or unofficially?
2. Will the coal plant be at least 50 years old?
3. Is the coal plant's variable cost $25/MWh or greater?

Table 4.2.1: 2030, 2040 Retiring Coal Plant Predictions

Plant Name	Summer Capacity (MW)	Reason for Retirement by 2030	Reason for Retirement by 2040
Dry Fork Station	88	N/A	N/A
Amalgamated Sugar	5	N/A	50+ years old
Laramie River Station	182	N/A	50+ years old
Amalgamated Sugar	2	50+ years old	50+ years old
Dave Johnson	330	Retirement date unknown	Retirement date unknown
Antelope Valley	112	N/A	50+ years old
Kennecott Utah Copper	35	N/A	N/A
Antelope Valley	113	Retirement date unknown	Retirement date unknown
Dave Johnson	210	Retirement date unknown	Retirement date unknown
Wygen 3	37	N/A	N/A

Leland Olds	167	50+ years old	50+ years old
Wyodak	332	50+ years old	50+ years old
Bonanza	458	Retirement date unknown	Retirement date unknown
Hunter	460	50+ years old	50+ years old
San Juan	36	N/A	N/A
Colstrip	740	N/A	N/A
Hunter	901	50+ years old	50+ years old
Colstrip	629	N/A	N/A
Colstrip	614	Retirement date unknown	Retirement date unknown
FMC Westvaco ST	47	50+ years old	50+ years old
Hardin Generator Project	107	N/A	N/A
Colstrip Energy LP	35	N/A	N/A
Thompson River	12	N/A	N/A
George Neal South	20	N/A	N/A
TS Power Plant	218	N/A	N/A
Huntington	909	50+ years old	50+ years old
Centralia	1340	Retirement date unknown	Retirement date unknown
Yellowstone Energy Cogen (Billings Generation Inc)	68	N/A	N/A
Intermountain	225	N/A	50+ years old
General Chemical - Wyoming	30	N/A	N/A
Intermountain	225	Above $25/MWh variable cost	50+ years old
Naughton	687	50+ years old	50+ years old
Craig (Yampa)	83	Retirement date unknown	Retirement date unknown
Craig (Yampa)	83	Above $25/MWh variable cost	Above $25/MWh variable cost
Big Stone	54	Above $25/MWh variable cost	Above $25/MWh variable cost
Hayden	33	Above $25/MWh variable cost	Above $25/MWh variable cost
Cholla	380	Above $25/MWh variable cost	Above $25/MWh variable cost
Jim Bridger	1058	50+ years old	50+ years old
Hayden	44	50+ years old	50+ years old
Sunnyside Cogeneration	51	Above $25/MWh variable cost	Above $25/MWh variable cost
Jim Bridger	1053	50+ years old	50+ years old

Boardman	527	Retirement date unknown	Retirement date unknown
R.M. Haskett Generation Station	52	Above $25/MWh variable cost	Above $25/MWh variable cost
North Valmy Station	522	Retirement date unknown	Retirement date unknown

4.3 Capacity Evolution in the WECC

Existing IRPs demonstrate a need for capacity in the WECC. Least-cost resources differ between utilities; however, the common element is still that DSM is not enough to mitigate load growth over the planning horizon. Furthermore, as resource intermittency increases, additional peaking capacity is needed to respond to changes in supply. Almost all studies IRPs predict that there will be an inflection point in the early 2020s, where between 2020 and 2023, utilities plan to install large quantities of energy in those years to correspond with forecasted coal generation shutdowns. A second round of coal station shutdowns is forecasted to occur in the early 2030s, and this is also reflected in the IRPs with a corresponding plan to install new, predominantly renewable generation in those years. The following sub-appendices detail resource plans by utility.

4.3.1 Puget Sound Energy[12]

Peak load in PGE service territory is projected to grow by over 1400MW by 2037. Using DSM PGE plans to shave the peak to 5664MW. The balance of this peak demand is predominantly filled by peaking resources and renewables.

Figure 4.3.1.1

Cumulative Nameplate Capacity of Resource Additions

	2023	2027	2037
Conservation (MW)	374	521	714
Demand Response (MW)	103	139	148
Solar (MW)	265	377	486
Energy Storage (MW)	50	75	75
Redirected Transmission (MW)	188	188	188
Baseload Gas (MW)	0	0	0
Peaker (MW)	0	717	1,195

4.3.2 Idaho Power[13]

Idaho Power forecasts that without the installation of new capacity, they will begin to have capacity deficits by 2029, with mean power deficits growing to the over 600MW in 2036. Peak deficits are projected to occur by 2026 and grow to almost 1000MW by 2036. To resolve this, Idaho Power is proposing to add peaking capacity in the form of reciprocating engines as well as generic generation in combined cycle combustion turbines. They also plan to install additional capacity to allow for increased transactional supply of power.

[12] PGE IRP - https://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx
[13] Idaho Power IRP - https://www.idahopower.com/energy/planning/integrated-resource-plan/

Figure 4.3.2.1

Date	Resource	Installed Capacity
2026	B2H	500 MW transfer capacity, Apr–Sep 200 MW transfer capacity, Oct–Mar
2031	Reciprocating engines	36 MW
2032	Reciprocating engines	36 MW
2033	CCCT (1x1)	300 MW
2035	Reciprocating engines	54 MW
2036	Reciprocating engines	54 MW

4.3.3 PacifiCorp[14]

PacifiCorp does not face large capacity deficits over the planning horizon, in part due to their acquisition of energy through long term bi-lateral contract. Despite their lack of demand driven development, they are still choosing to overhaul their portfolio for economic reasons. They are steering away from thermal generation and toward renewable resources. In In total, they plan to put almost 3GW of new/repowered wind online and 1GW of new solar online by 2036. Over the same period, coal generation will be decreased by 2.7GW and a net of about 1GW of natural gas generation will be installed. This new capacity allows them to easily hit their load demand targets and to maintain their 13+% reserve margin.

[14] PacifiCorp IRP - https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf

Table 4.3.3.1 2017 IRP Perferred Portfolio Summary (Nameplate MW)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
New Resources																					
Summer FOT	500	521	878	807	799	916	844	885	1,042	978	1,040	1,575	1,575	1,566	1,575	1,575	1,575	1,575	1,575	1,539	n/a
Winter FOT	281	332	273	307	319	308	306	287	348	351	297	412	551	516	490	451	437	477	479	766	n/a
DSM - Energy Efficiency	154	128	131	122	123	114	118	118	112	111	109	102	96	95	96	83	75	65	63	63	2,077
DSM - Load Control	0	0	0	0	0	0	0	0	0	0	0	193	140	5	3	3	3	4	3	12	365
Wind	0	0	0	0	1,100	0	0	0	0	0	0	0	0	0	85	0	0	0	0	774	1,959
Solar	0	0	0	0	0	0	0	0	0	0	0	11	97	0	118	237	226	48	291	13	1,040
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	30	0	0	0	0	0	0	0	30
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	200	436	0	0	677	0	0	0	1,313
Existing Resources																					
Reduced Coal Capacity	0	0	(280)	0	(387)	0	0	0	0	(82)	0	(762)	(354)	(357)	(78)	0	(359)	0	(82)	0	(2,741)
Reduced Gas Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(358)	0	0	0	(358)
Repowered Wind Capacity	0	0	794	111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	905

* Note: Energy efficiency resource capacity reflects projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource. FOTs are short-term firm market purchases delivered only in the year shown. Reductions in existing coal and natural gas capacity are shown in the year after the assumed year-end retirement date (909 MW of existing coal capacity is assumed to retire year-end 2036, which would be reflected beginning 2037). Repowered wind capacity reports the amount of existing wind capacity assumed to be repowered in the preferred portfolio.

4.3.4 Portland General Electric[15]

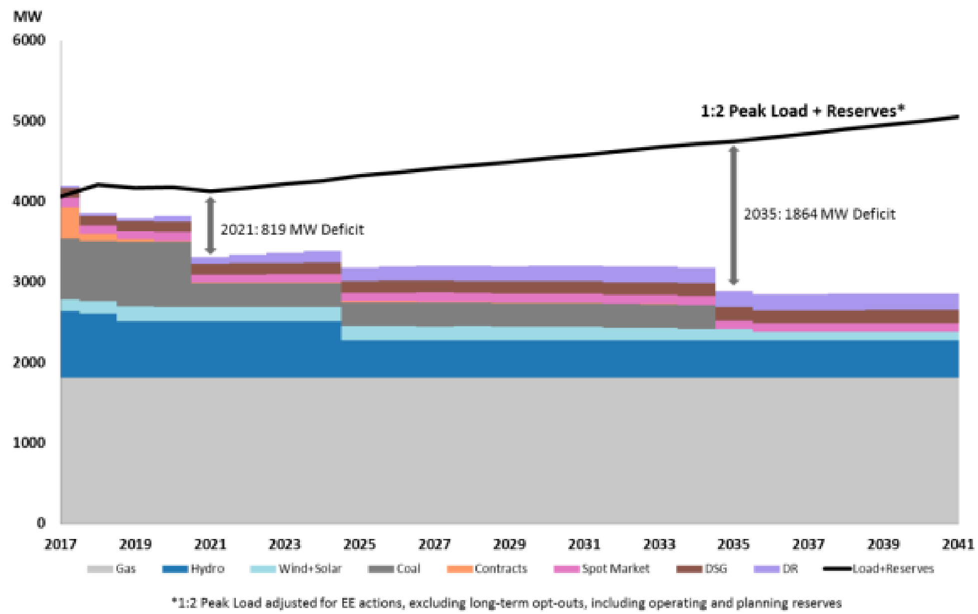
PGE forecasts that due to demand increases, retirement of coal resources, contract expiration, and decreasing availability of hydro resources, a demand deficit will emerge in the near future, growing to 819MW by 2021 and to 1864MW by 2035. The short-term actions to address this forecasted deficit focus primarily on installation of renewable and efficient capacity as well as demand side actions with reductions through DSM and energy efficiency programs.

Figure 4.3.4.1

Preferred Portfolio Cumulative Resources* *Efficient Capacity 2021* (Nameplate Capacity, MW)	Action Plan Time Horizon 2017	2018	2019	2020	2021
Energy Efficiency (EE)	45	89	131	168	202
Demand Response (DR)	26	29	32	70	78
Conservation Voltage Reduction (CVR)	-	0.43	0.86	1.29	1.74
PNW Wind	-	515	515	515	515
Generic Capacity	-	290	317	317	370
Efficient Capacity	-	-	-	-	389
Dispatchable Standby Generation (DSG)	4	8	12	16	20

15 PGE IRP - https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp

Figure 4.3.4.2



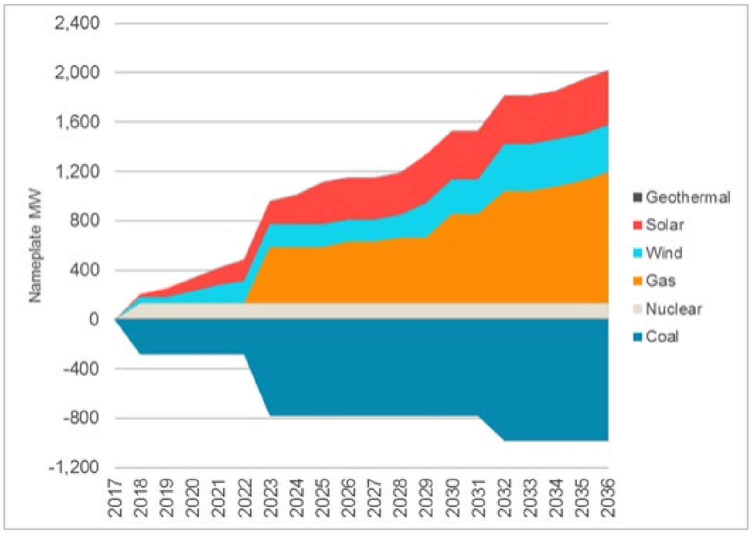
4.3.5 Public Service Company of New Mexico[16, 17]

PNM's IRP calls for a significant elimination of coal from the generation portfolio in 2022 and following that a complete elimination of coal resources in 2031 when an existing supply contract expires. Absent that contract it would be economically preferable to transition away before that date. To replace this energy and to meet future load demands PNM found that the most economic option was to install a combination of solar and flexible natural gas peaking CTs. PNM considers battery storage to be an option, but it is contingent on the economics of proposals received over the next four years.

[16]PNM IRP Executive Summary - https://www.pnm.com/documents/396023/396193/PNM+2017+IRP_Executive+Summary.pdf/992f1578-8eb1-4454-a51e-7ea19cf39833

[17]PNM IRP- https://www.pnm.com/documents/396023/396193/PNM+2017+IRP+Final.pdf/eae4efd7-3de5-47b4-b686-1ab37641b4ed

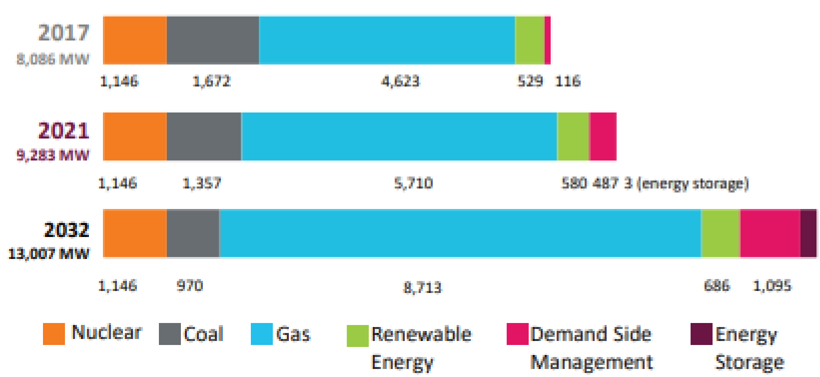
Figure 4.3.5.1



4.3.6 Arizona Public Services[18]

APS is forecasting a large demand increase over their planning window with demand forecasted to grow from 8,086MW in 2018 by 4,921MW to 13,007 by 2032. To accomplish this, APS plans to install over 4GW of gas generation and to implement almost 1GW of DSM. APS also uniquely plans to install a large amount of energy storage. The chosen portfolio was configured to maximize the flexibility of the resources to respond to an increasingly dynamic supply and demand. In addition, the flexible as well as to give APS the ability to interface better with the rest of the WECC, and in particular to interface with CAISO's EIM.

Figure 4.3.5.1



[18] APS IRP - https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf