Duke Energy Resource Mix to Meet 70% CO_2 Reduction by 2030 in NC

REVIEW AND ANALYSIS OF DRAFT CARBON PLAN

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- Alternative Portfolios to Achieve 70% CO_2 Reduction
- Benefits of Proactive Transmission Planning

Review of Draft Carbon Plan

Duke Draft Carbon Plan Proposed Portfolios

In its draft Carbon Plan, Duke proposed four portfolios to achieve 70% CO_2 reductions for North Carolina generation facilities in the 2030 to 2034 timeframe

- Proposed portfolios rely on coal plant retirements and a mix of new resources to reduce emissions
- New resources added across portfolios include gas, solar, offshore wind, onshore wind and nuclear generation as well as battery storage and pumped hydro storage
- Portfolios differ depending on which resources are selected and when they achieve compliance

PORTFOLIOS			Grid Edge	Coal Retirements	New Solar	Battery	Onshore Wind	Offshore Wind	New Nuclear	New Pumped Storage	New CC	New CT
2030	P1	70% by 2030	EE 1% of eligible retail sales	(-4.9 GW)	5.4 GW	2.1 GW	0.6 GW	0.8 GW			2.4 GW	1.1 GW
2032	P2	70% 2032 OSW	IVVC growing to 96% (DEC) and 97% (DEP) circuits		5.6 GW	1.7 GW	1.2 GW	1.6 GW				
2034	P3	70% 2034 SMR		(-6.2 GW)	7.7 GW	2.2 GW			0.3 GW	1.7 GW		
2034	P4	70% 2034 OSW + SMR	Winter DR & CPP		6.8 GW	1.8 GW		0.8 GW				0.8 GW

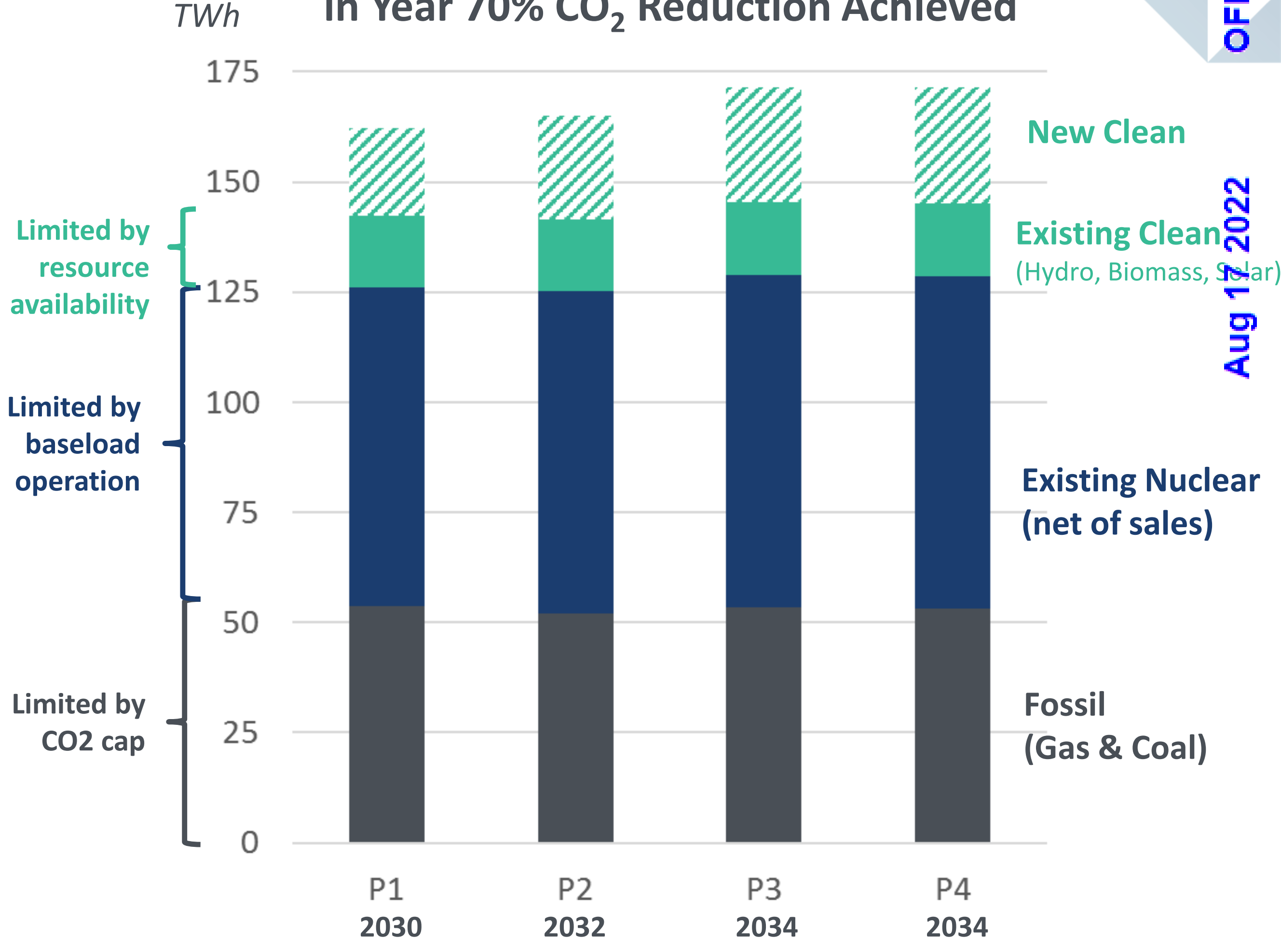
Note 1: Gray blocks denote coal retirements, which are dependent on addition of resources shown.
Note 2: Remaining coal planned to be retired by year end 2035.
Note 3: New Solar includes solar + storage, excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage.
Note 4: Capacities as of beginning of the target year of 70% reduction.
Note 5: IVVC = Integrated Volt/Var Control.
Note 6: CPP = Critical Peak Pricing.
Note 7: Battery includes batteries paired with solar.

Carbon Plan Generation Mix to Achieve 70% Reduction

Duke will need to add new clean energy resources that can produce about 20-27 TWh per year by the compliance year to serve its electricity demand and achieve the Carbon Plan goals:

- Fossil resources are limited to about **52 TWh per year** to remain below the CO_2 cap
- Existing nuclear already operates as baseload, generating about **73 TWh per year**
- Existing clean resources are mostly fixed output, generating about **16 TWh per year**

Total System Generation in Year 70% CO_2 Reduction Achieved



Source: Duke Carbon Plan Results

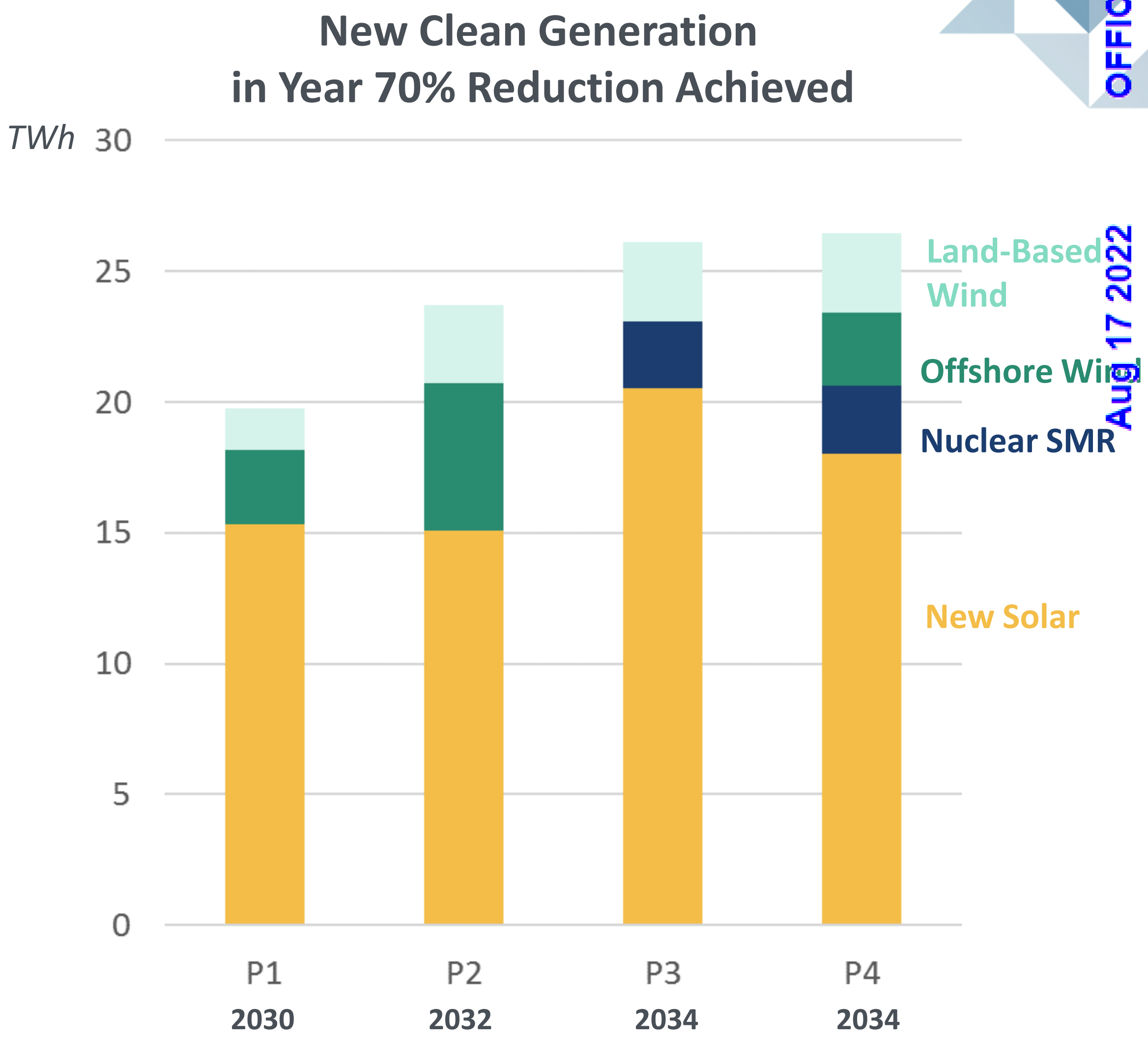
Selected New Clean Generation Resources

To fill the need for clean energy, all of Duke's portfolios rely on significant solar generation capacity as the primary clean energy resource to reduce CO_2 emissions

However, Duke limits how much solar generation can be built each year

Differences in solar generation across portfolios are driven by the assumed solar annual capacity limits and the amount of non-solar clean energy resources selected by Duke to fill the remaining gap

- Onshore Wind: added in all portfolios
- Offshore Wind: added in P1, P2 and P4
- Nuclear SMRs: added in P3 and P4 portfolios

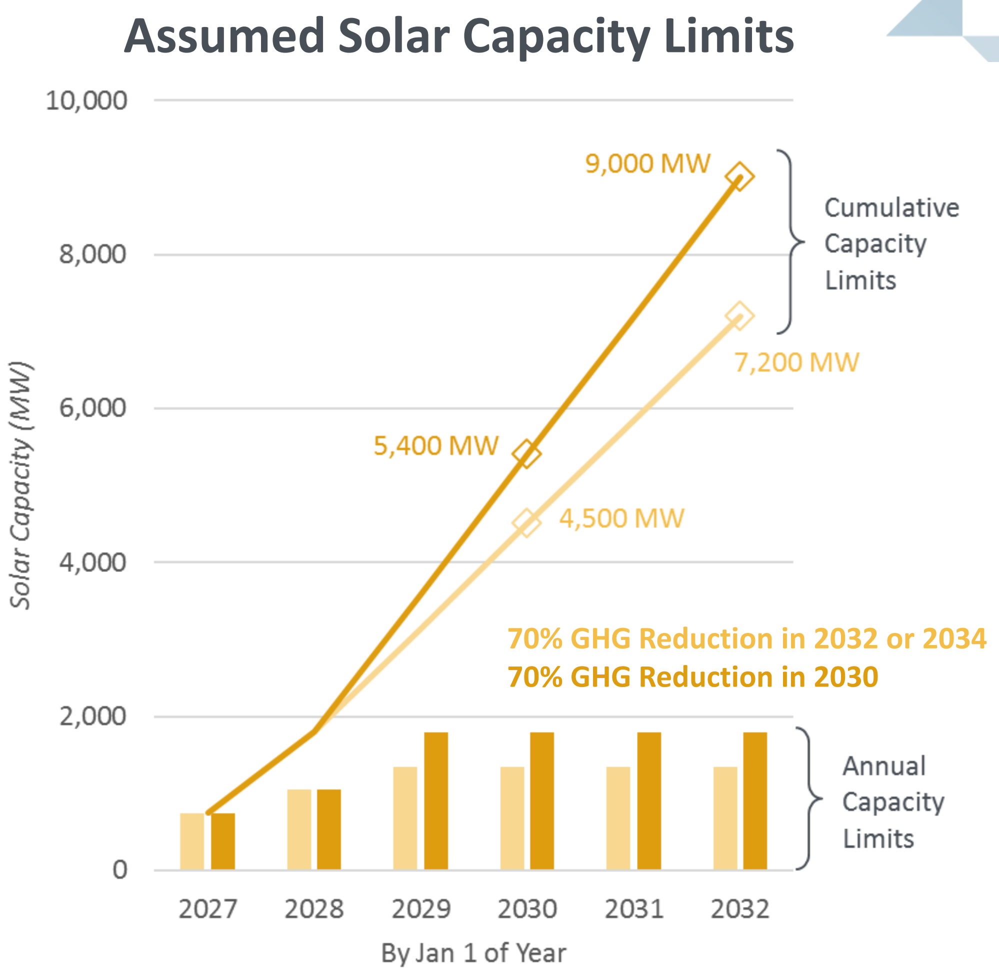


Source: Duke Carbon Plan Results

Carbon Plan Solar Capacity Limits

Draft Carbon Plan limits incremental solar additions on an annual basis, such that 5,400 MW of cumulative solar capacity can be built by 2030 in P1 and 7,200 MW can be built by 2032 in P2-P4*

- Solar capacity limits push back the timeline over which 70% CO_2 reductions are achievable given limited alternatives
- Even if Duke could hit the 2030 CO_2 target with other resources, it would do so at higher cost to ratepayers



* Assumes the Duke system will have 6.7 GW of solar capacity on its system by 2030 following the completion of resource additions required under H589 before the incremental solar additions to achieve the Carbon Plan goals shown above.

Unclear Basis for Solar Capacity Limit

Duke has provided the following reasons for capping solar additions in the Carbon Plan:

- Time to construct new infrastructure to accommodate increasing levels of renewables
- Increasingly complex interconnections as solar facilities are located farther from existing infrastructure
- Unknown future solar project size and impacts on interconnection
- Finite interconnection resources
- Land availability and community acceptance

However, Duke has not provided technical analysis to support their proposed solar limit based on network upgrades, which will depend on multiple factors that require detailed analysis, or analysis of limits imposed by land availability and community acceptance

Proactive Planning Would Reduce Network Upgrades

Concerns about future network upgrades for solar are caused by the existing transmission planning process, which takes a piecemeal and just-in-time approach to identifying and constructing transmission upgrades via the generation interconnection process

Completing system-wide proactive transmission planning in parallel to the recently reformed generation interconnection process would:

- Identify no-regrets system-level upgrades that can provide multiple benefits regardless of exact locations and types of resources that interconnect
- Reduce costs, complexity, and time required for interconnecting new resources
- Debottleneck the process for the least-cost resources entering the system

Duke could further reduce the challenges to interconnecting sufficient solar capacity by 2030 by adopting a proactive long-term transmission planning process that studies potential resource mixes and the necessary transmission infrastructure to meet future system needs

We provide more insights into the benefits of proactive transmission planning in Section III

Carbon Plan Projects Lower Demand Compared to 2020 IRP

2030 demand included in Duke's Carbon Plan modeling is 1,200 GWh lower than the 2020 IRP

Carbon Plan forecast is primarily lower due to:

- 1,775 GWh lower gross retail sales, based on projections of economic activity in their service territory
- 822 GWh lower due to additional utility EE programs

The lower demand is offset by the following factors that increase demand:

- 902 GWh of less rooftop solar
- 878 GWh of additional EV demand (assuming 5.5% of vehicles on the road are electric by 2035)

Components of Duke 2030 Demand Forecast (GWh)

	Gross Retail Sales	Energy Efficiency	NEM Rooftop Solar	EVs	IVVC	CPP/PTR	Net Retail Sales at Meter
Duke Carbon Plan	132,200	-5,477	-697	1,965	-804	-22	127,164
Duke 2020 IRP	133,975	-4,655	-1,599	1,087	-389	0	128,418
Difference	**-1,775**	**-822**	**902**	**878**	**-415**	**-22**	**-1,254**

Carbon Plan Assumes Conservative Forecast for EV Demand

Duke assumes a conservative outlook for future electric vehicle (EV) sales for 2030-2035

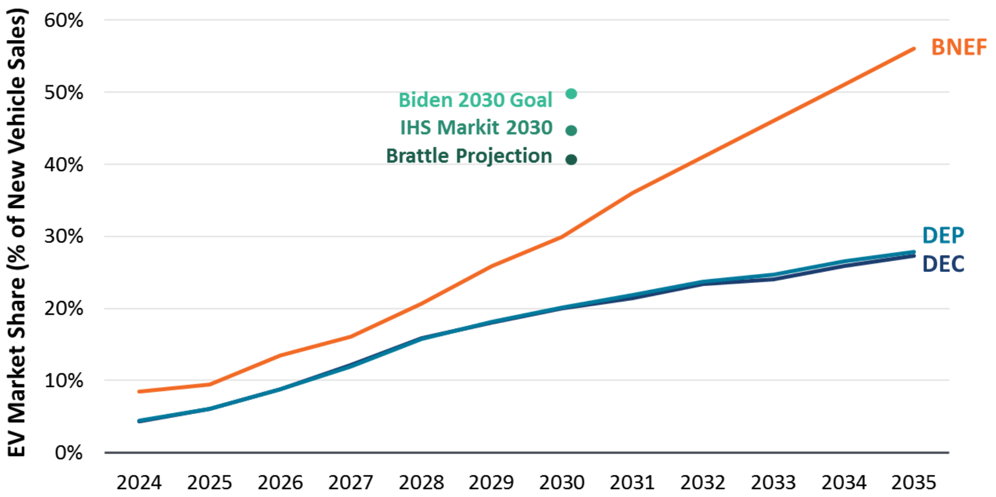
- Duke assumes 310,000 light-duty and nearly 12,000 medium- and heavy-duty vehicles will electrify by 2030
- Duke's EV forecast implies that EVs will make up about 20% of new vehicle sales by 2030
- Their 2030 EV sales outlook is well below recent forecasts and policy goals (30 – 50% of sales by 2030)

Carbon Plan underestimates EV demand by at least 1,050 GWh in 2030 and 3,220 GWh in 2035 based on the conservative BNEF forecast (30% sales in 2030)

- We relied on similar assumptions as Duke for demand per EV and overall vehicle fleet size (see table)

Higher EV demand will need to be matched by additional solar or other clean energy resources to achieve the Carbon Plan CO_2 goals

EV Market Share Forecast



2030 Total EV Electricity Demand

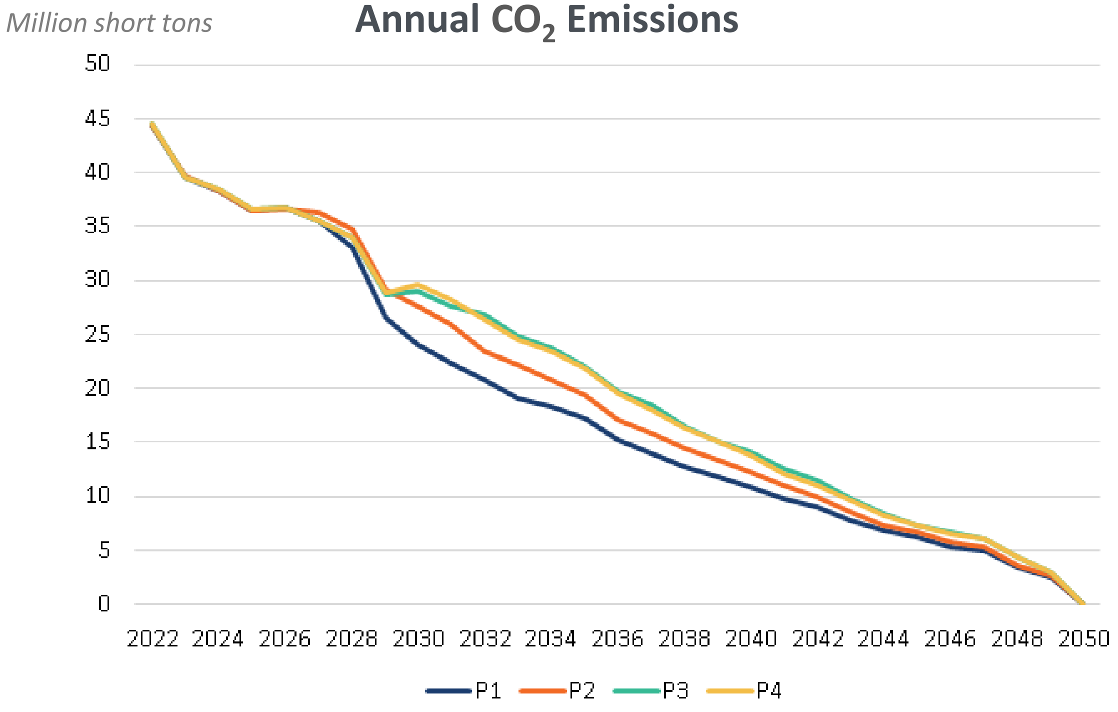
Utility	Estimated Vehicle Fleet	% of Fleet	Total EVs on Road	EV Demand (MWh/EV)	EV Demand (GWh)
DEC	7,410,000	2.5%	188,000	6.4	1,210
DEP	4,580,000	2.9%	134,000	5.6	760
Duke Total	**12,990,000**	**2.7%**	**322,000**	**6.1**	**1,970**
BNEF Total	**12,990,000**	**4.1%**	**494,000**	**6.1**	**3,020**

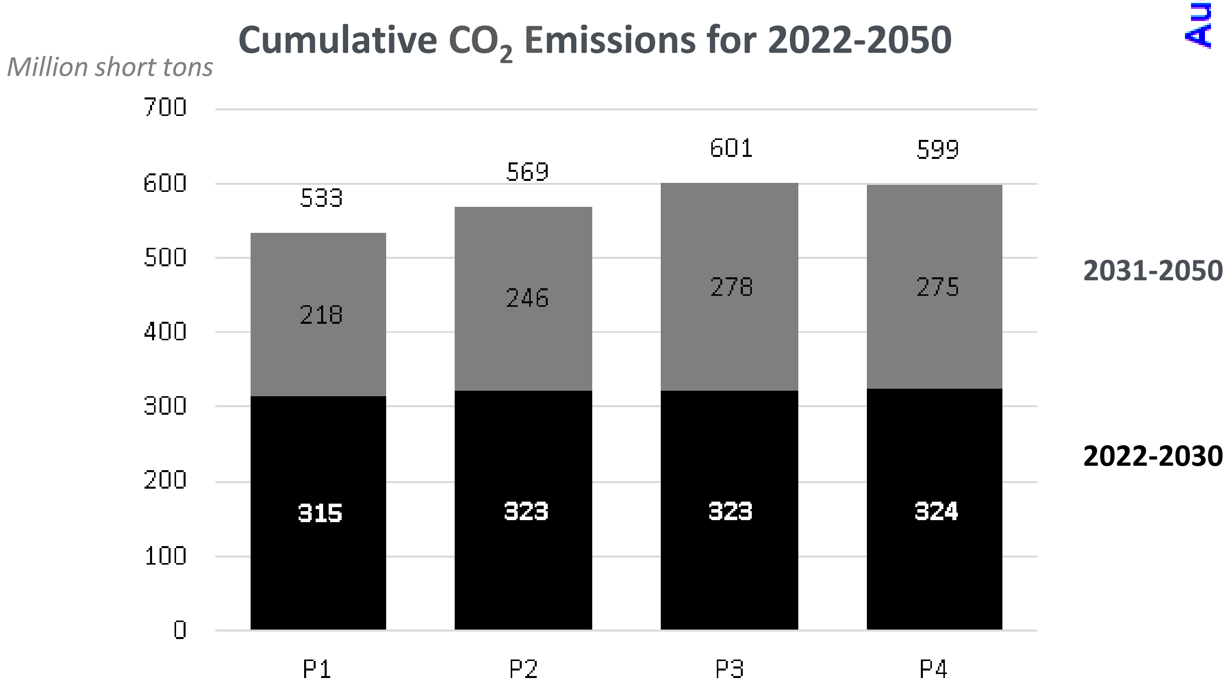
P1 Achieves Lower Cumulative CO_2 Emissions through 2050

Duke set CO_2 limits in the compliance year for each portfolio (2030 to 2034) to achieve the 70% reduction in CO_2 emission and then decreased CO_2 emissions to achieve it 2050 net zero goal

This approach results in significantly lower cumulative CO_2 emissions in the P1 scenario through 2050

- Cumulative P1 CO_2 emission of 533 million short tons are 7% lower than P2 (569 million short tons), 12% lower than P3 (601 million short tons), and 11% lower than P4 (599 million short tons)

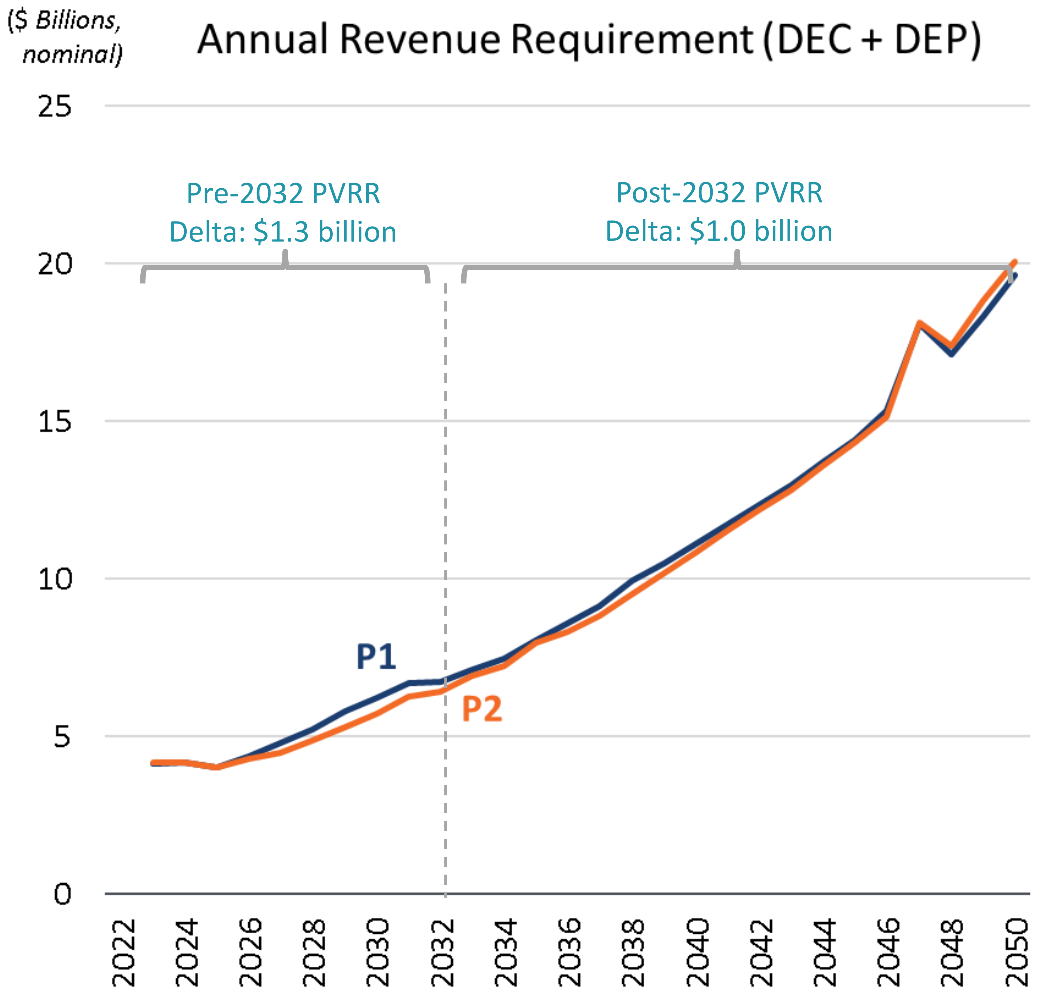




Carbon Plan Overstates the P1 Cost Premium Over P2

Duke's estimate of $2.3 billion higher PVRR in P1 relative to P2 is overstated in part because of greater CO_2 emissions reductions in P1 relative to P2

- We estimate that nearly half of the incremental costs of P1 are due to the long-term differences in CO_2 limits
- A more apples-to-apples comparison between P1 and P2 costs would require aligning long-term CO_2 limits beyond the compliance dates
- Accelerating addition of clean energy resources should result in lower long-term costs past the compliance date given the new clean energy assets have already begun depreciating



Key Takeaways from Review of Duke Carbon Plan

- **Duke assumes new solar additions will be limited due to their claimed challenges to building and coordinating network upgrades to support interconnection**
  - The limit on solar capacity additions require Duke to select other clean energy resources to achieve Carbon Plan goals, including higher cost and higher risk offshore wind and nuclear SMRs
  - Replacing lower-cost solar with higher cost resources increases costs to achieve CO_2 goals and challenges timely compliance with the goals given limited availability of other new clean energy resources in Duke's territory through the early 2030s
- **Duke understates future demand due to an overly conservative estimate of EV adoption**
  - Higher electricity demand will increase need for clean energy resources to achieve Carbon Plan goals
- **Duke applies lower CO_2 limits over the long-term in the 2030 compliance scenario (P1)**
  - Results in 7 – 12% less cumulative CO_2 emissions than other scenarios
  - Long-term difference in CO_2 limits accounts for about 50% of the difference in costs across scenarios

Analyzing Alternative Carbon Plan Portfolios

Analysis of Resource Portfolios to Achieve 70% CO_2 Reduction

Objective: Analyze a more complete set of resource portfolios that achieve a 70% reduction of CO_2 emissions from Duke Energy's North Carolina power generation by 2030 or 2032 to inform the Carolinas Carbon Plan

Scope: Model Duke Energy system in North Carolina and South Carolina through 2035 using our internal capacity expansion model, GridSIM

Approach:

- Incorporate updated assumptions for the Duke Energy system into GridSIM
- Identify the least-cost resource mix to meet 2030 or 2032 CO_2 goals
- Estimate annual resource additions to achieve the CO_2 goals

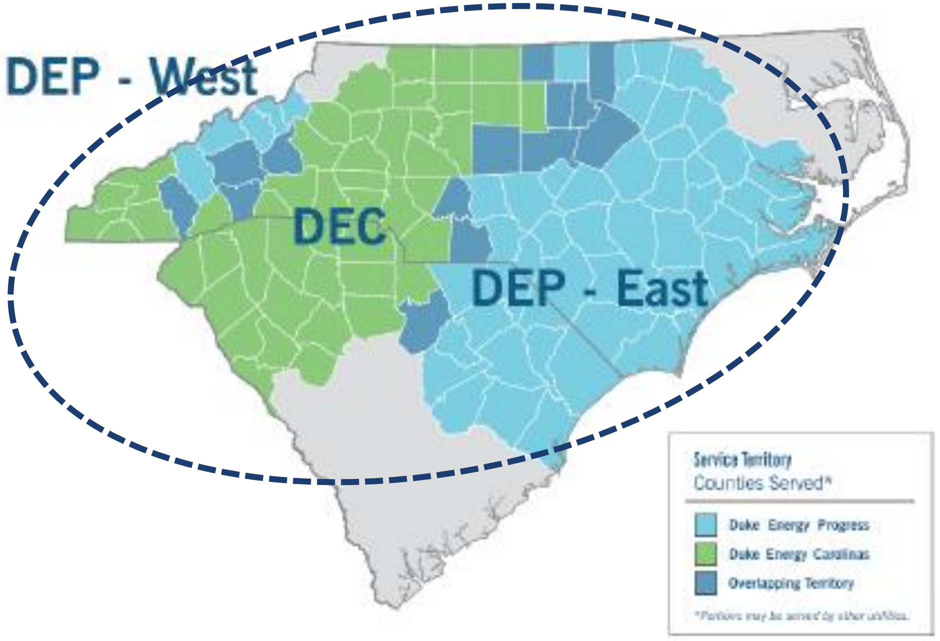
Modeling Approach

Analyzed the combined Duke Energy system using Brattle's internal capacity expansion model GridSIM

- Simulates the dispatch of generation and storage resources to serve demand and the expansion of the resource mix to meet the planning reserve margin and CO_2 emissions goals
- Captures chronological dynamics of a future power system that relies more heavily on renewable resources by analyzing 49 representative days (4 days in each month plus the peak demand day)

Modeled the Duke service territory as an island with limited transactions with neighboring markets, similar to the approach in Duke Carbon Plan

Duke Service Territory Modeled



Source: Duke Carbon Plan, Appendix E, p. 8.

GridSIM Overview

INPUTS

Supply

- Existing resources
- Planned builds and retirements
- Fuel prices
- Investment/fixed costs
- Variable costs (inc. emissions costs)

Demand

- Representative day hourly demand
- Forecasts of annual and peak demand
- Planning reserve margins

Transmission

- Zonal limits
- Intertie limits

Regulations and Policies

- State energy policies and procurement mandates

GridSIM OPTIMIZATION ENGINE

Objective Function

- Minimize NPV of Investment & Operational Costs

gridSIM

Constraints

- Planning Reserve Margin
- Hourly Energy Balance
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints
- GHG Emissions Constraints

OUTPUTS

Builds/Retirements

Carbon Emissions

Market Prices (Energy, Capacity, REC)

Total Resource Costs

Customer Costs

Generator Revenues

GridSIM vs EnCompass

Similar to GridSIM, EnCompass identifies the least-cost portfolio of resources to maintain system reliability, meet 2030 CO_2 limits, and meet hourly demand

- Encompass uses a different modeling approach that optimizes unit commitment decisions and also can simulate dispatch of resources chronologically throughout the year

	GridSIM	EnCompass
Network Representation	Zonal	Zonal
Optimized Capacity Expansion and Retirement	Yes	Yes
Resource Adequacy Requirements	Yes	Yes
CO_2 Emissions Limit	Yes	Yes
Production Cost Simulation	Hourly, 49 representative days	Hourly, chronological
Optimized Unit Commitment	No	Yes

NC and SC CO_2 Emissions Caps

To achieve the Carbon Plan goal, we limit Duke's NC generation plants to 22.6 million short tons in the year of compliance, a 70% reduction from 2005 emissions (75.4 million short tons)

- Estimate 2035 CO_2 limit of 16.9 million short tons by linearly reducing emissions to achieve net zero by 2050, which we apply to all cases

To limit CO_2 emissions leakage into SC, we limited Duke South Carolina generation plant emissions based on the SC plant emissions reported by Duke in its Carbon Plan modeling

Coal Plant Retirement and Conversion Date Assumptions

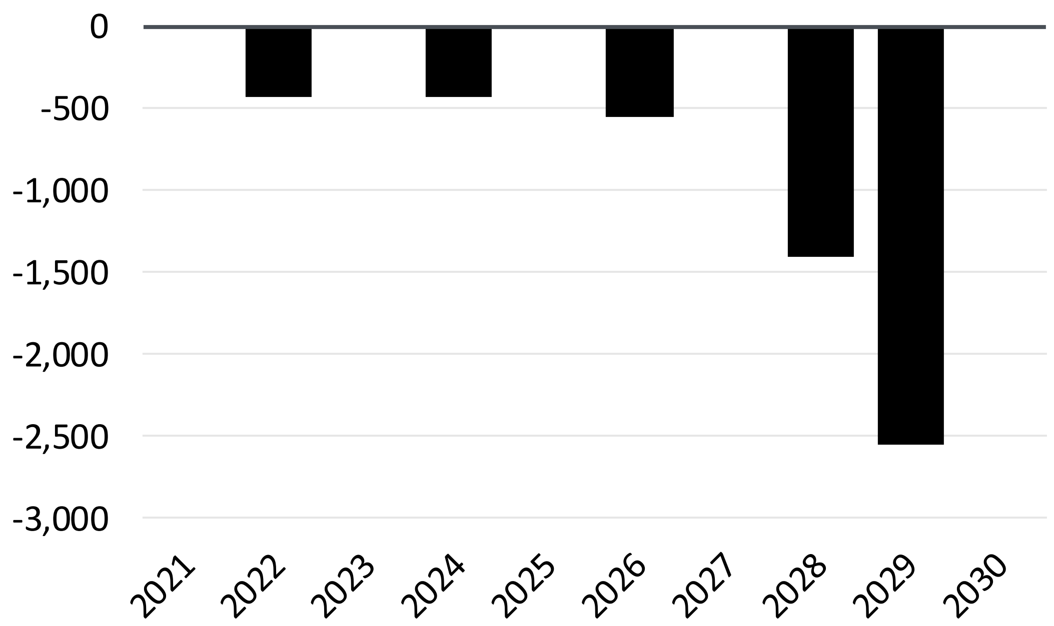
We assume that Duke's coal plants retire based on timing in the Carbon Plan

- Belews Creek 1-2 and Cliffside 6 are converted to operate on natural gas
- Marshal 3-4 remains available to burn coal through its 2033 retirement

Coal Plant Retirement/Conversion Dates

Plant	Owner	Capacity	Modeled Retirement
Allen 2-4	DEC		2022
Allen 1,5	DEC		2024
Cliffside 5	DEC	546 MW	2026
Roxboro 3-4	DEP	1,409 MW	2028
Mayo 1	DEP	746 MW	2029
Marshall 1-2	DEC	760 MW	2029
Roxboro 1-2	DEP	1,053 MW	2029
Marshall 3-4	DEC	1,318 MW	2033
Belews Creek 1-2	**DEC**	**2,200 MW**	**Gas-Only in 2030**
Cliffside 6	**DEC**	**849 MW**	**Gas-Only in 2030**

Total Annual Coal Plant Retirements (MW)

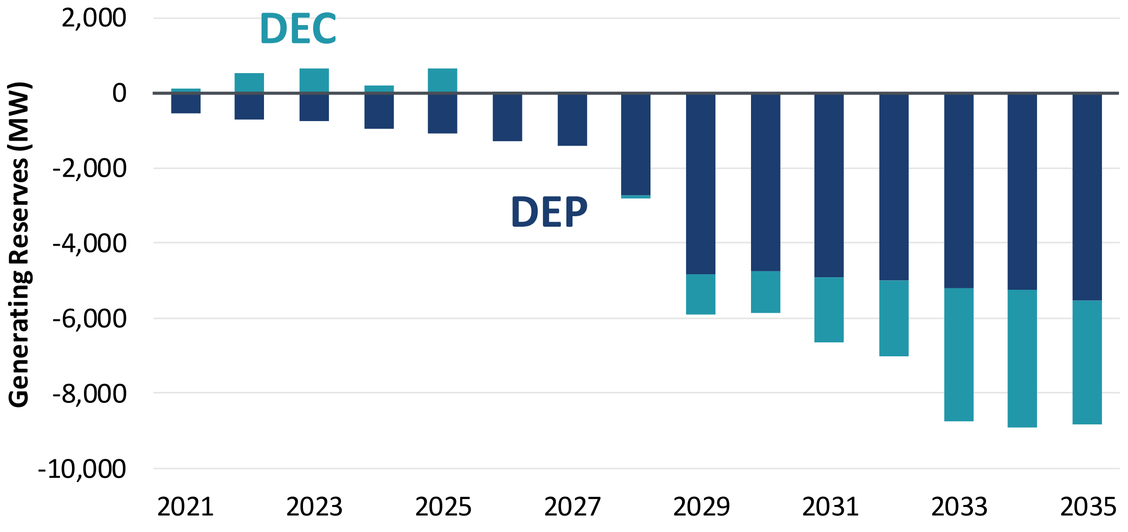


Resource Adequacy

Estimated capacity shortfall for both DEC and DEP to meet the 25% reserve margin achieved in the Carbon Plan

- Started with Carbon Plan winter capacity balance and adjusted reserve margin based on assumed coal plant retirements and new resource additions
- New gas, renewable and battery storage resources added to fill capacity needs

Projected Capacity Shortfall in the Updated Policy Case
(prior to identifying economic new resources)



Available New Generation and Storage Resources

GridSIM identifies new resource additions necessary to meet capacity & energy demand and CO_2 targets at least cost to ratepayers

Resource Type	Capacity Factor	RA Credit (% ICAP)	2032 Capacity Limit	Assumed Life
Gas CC	n.a.	100%	2,400 MW	20 years
Gas CT	n.a.	100%	n.a.	25 years
Solar	28%	2%	*Varies by Case*	30 years
Onshore Wind	30%	40%	600 MW	30 years
Offshore Wind	42%	67%	1,600 MW	30 years
4-Hour BESS	n.a.	95%	n.a.	15 years
4-Hour BESS	n.a.	41%	n.a.	15 years

We did not consider Gas CC with CCS or Nuclear SMR as being feasible to be built by 2030-2032

Note: We assume 6.7 GW of baseline solar additions are online as of 2030.

Solar+Storage Configurations

GridSIM may select solar paired with battery storage (S+S) in the following four configurations:

- 4-hr BESS at 50% of the solar capacity (60% ELCC)
- 2-hr BESS at 50% of the solar capacity (26% ELCC)
- 4-hr BESS at 25% of the solar capacity (30% ELCC)
- 2-hr BESS at 25% of the solar capacity (13% ELCC)

We estimated BESS costs using ATB projections, similar to standalone BESS, with the following changes:

- We assumed BESS in S+S will be able to receive the same ITC as the solar facility
- We removed network upgrade costs for the BESS as they will share a point of interconnection with the solar generation, similar to Duke's assumption
- We reduced BESS capital costs by 5% to account for lower development costs for hybrid facilities versus two standalone facilities

Capital Costs for New Generation and Storage Resources

Capital cost assumptions based on 2022 ATB cost projections

- We used the Conservative case for solar, onshore wind, and gas CCs and the Moderate case for offshore wind and battery storage
- Based on feedback from Duke, we adopted lower capital costs for Gas CT using recent PJM Cost of New Entry (CONE) study
- For new Gas CC, we added $125/kW for the costs of new gas lateral based on EPA analysis of NC plants

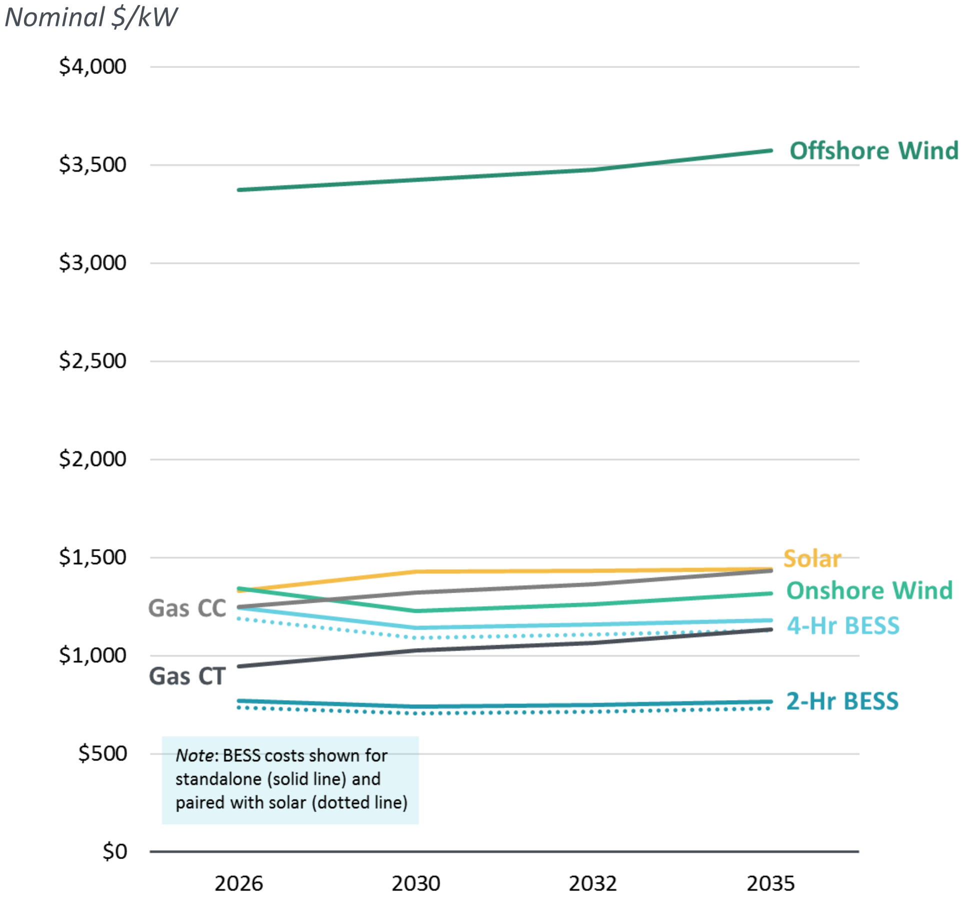
We added estimated transmission upgrades for each resource:

- Offshore wind: $441/kW in 2030 based on NCTPC study
- All other resources: $100/kW
- BESS paired with solar does not incur incremental network upgrade costs

Assume ITC and PTC phase out:

- 30% ITC for solar & storage online by Jan 1, 2023; phased down to 10% for projects online by Jan 1, 2026 or thereafter
- 30% ITC for offshore wind commencing construction by Jan 1, 2026 with ten years to complete (available for 2030 and 2032)
- PTC phases out for onshore wind resources entering after 2025

Overnight Capital Cost Projections

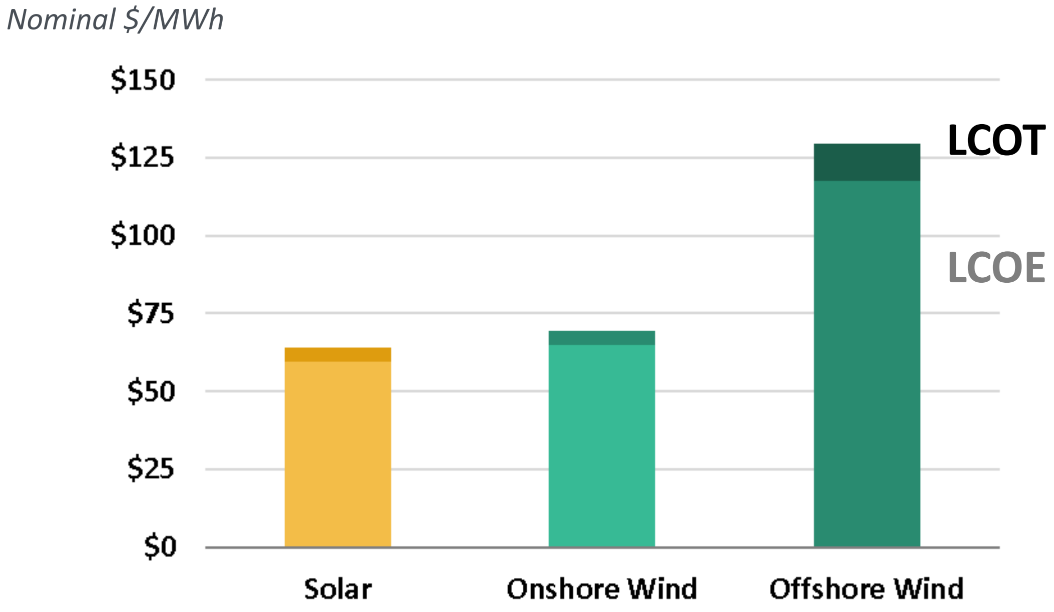


Comparison of Levelized Costs of Renewable Energy

The estimated 2030 LCOE for solar and onshore wind are similar ($60-70/MWh), while offshore wind is nearly 2x higher ($125/MWh)

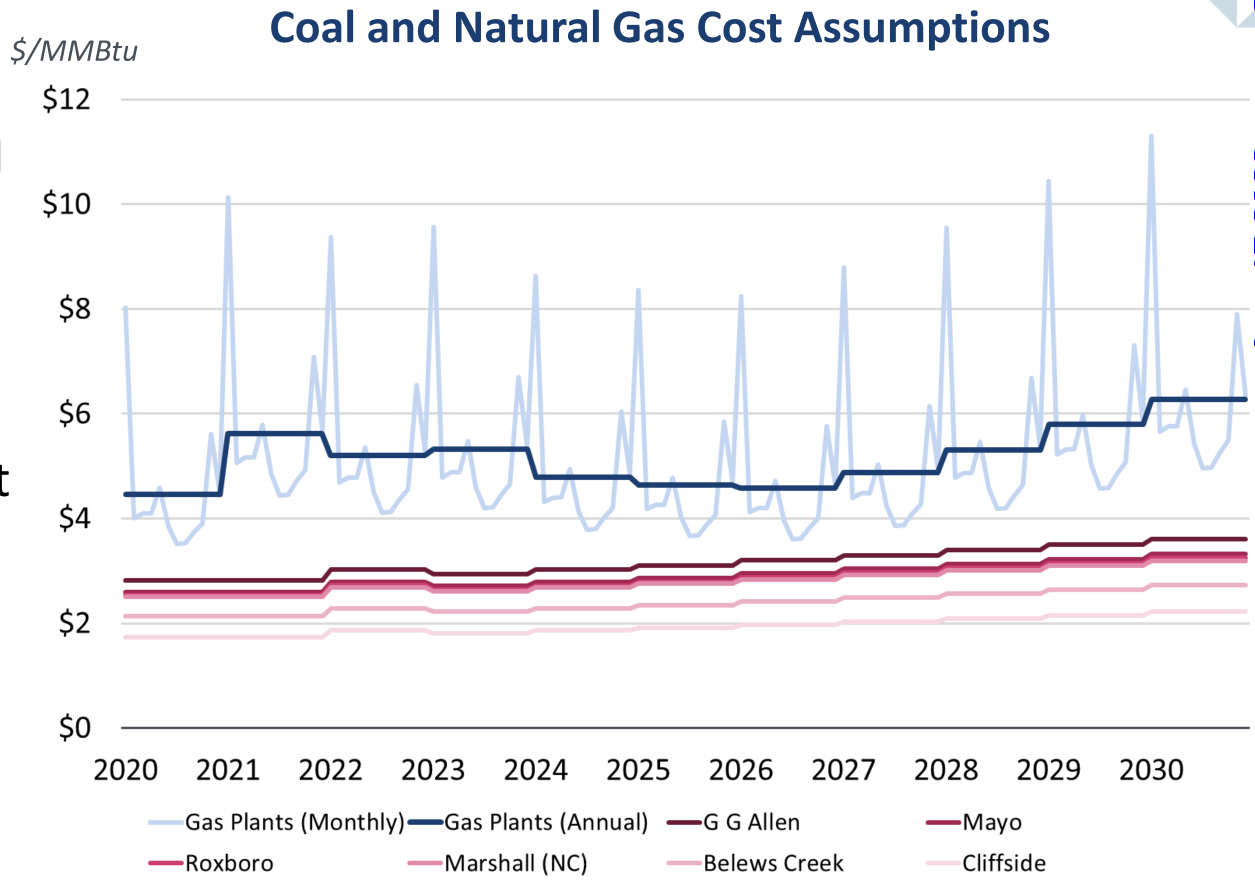
- We estimated the LCOE assuming the levelized costs remain constant in nominal terms over its economic life and assuming Duke's most recent cost of capital of about 6.5% ATWACC
- LCOE values shown here are higher than ATB due to use of nominal 2030 dollars (instead of real 2019 dollars), assumption that levelized costs are constant in nominal terms (instead of real terms), and higher cost of capital

2030 Renewable Generation Levelized Costs



Delivered Fuel Price Projections

- Gas price forecast based on Duke's projected prices for Transco Zone 5
  - Monthly shapes based on average historical shape from 2018-2020 to account for commodity price and variable delivery charges
  - Add firm transportation costs based on Duke's assumptions for new and existing units
- Coal price by plant based on delivered coal prices in 2020 and escalated based on AEO2021 forecast for delivered cost of coal into SRCA region



Summary of Differences in Assumptions with Duke

- **Capacity Expansion Model**: Use our internal capacity expansion model GridSIM
- **Timeframe**: Run through 2035
- **New Resource Costs**: Rely primarily on NREL 2022 Annual Technology Baseline
- **Solar Capacity Limits**: Model cases without and with solar limits included in Duke's analysis
- **CO_2 Emissions Limits**: Assume 2035 CO_2 emissions are consistent across all cases

Alternative Portfolios to Achieve 70% CO_2 Reductions

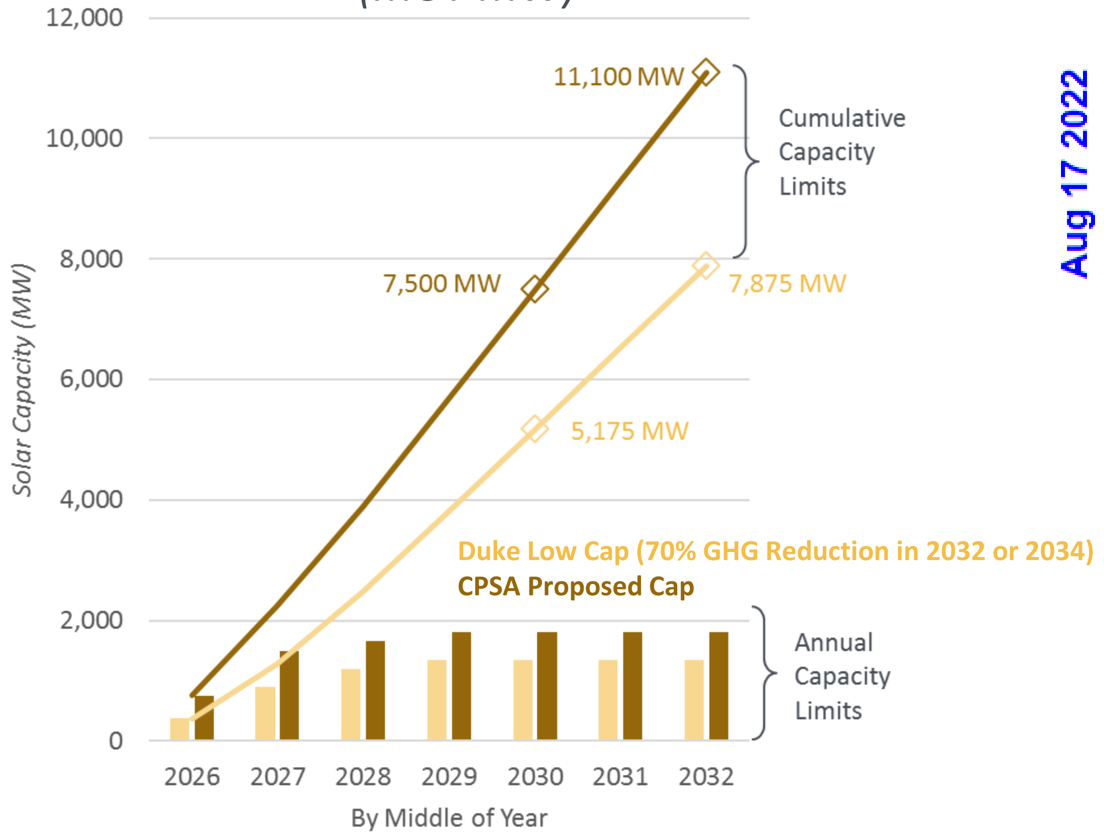
We analyzed 5 scenarios to identify the least-cost resource mix to achieve Duke's CO_2 reduction goals

- Note that we used middle of the year (MOY) capacity limits equivalent to Duke's beginning of year (BOY) limits because GridSIM assumes a constant capacity throughout the year

CPSA Carbon Plan Scenarios

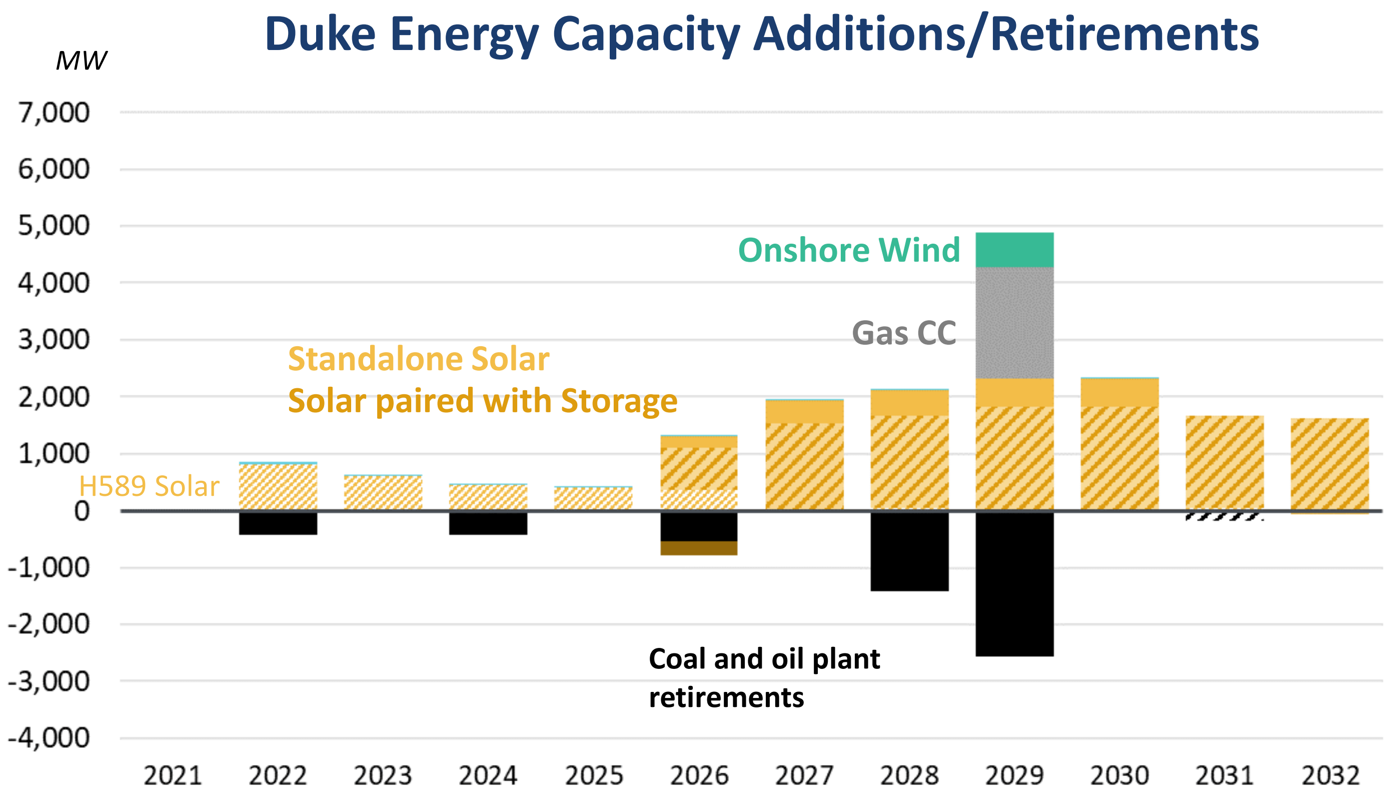
Portfolio	Compliance Year	Solar Cap
CPSA1	2030	No Cap
CPSA2	2030	Duke Low Cap
CPSA3	2030	CPSA Cap
CPSA4	2032	Duke Low Cap
CPSA5	2032	CPSA Cap

Modeled Solar Capacity Limits
(MOY MW)



CPSA1 Generation and Storage Resource Mix

- *2030 Compliance Year with No Solar Cap*



Note: Paired storage is implicitly accounted for by the paired solar capacity additions and not shown above.

Total New Resources by 2030

Utility-Scale Solar: +9,500 MW
- Standalone Solar: +2,100 MW
- Paired with 50% 4-hr BESS: +5,700 MW
- Paired with 25% 4-hr BESS: +1,700 MW

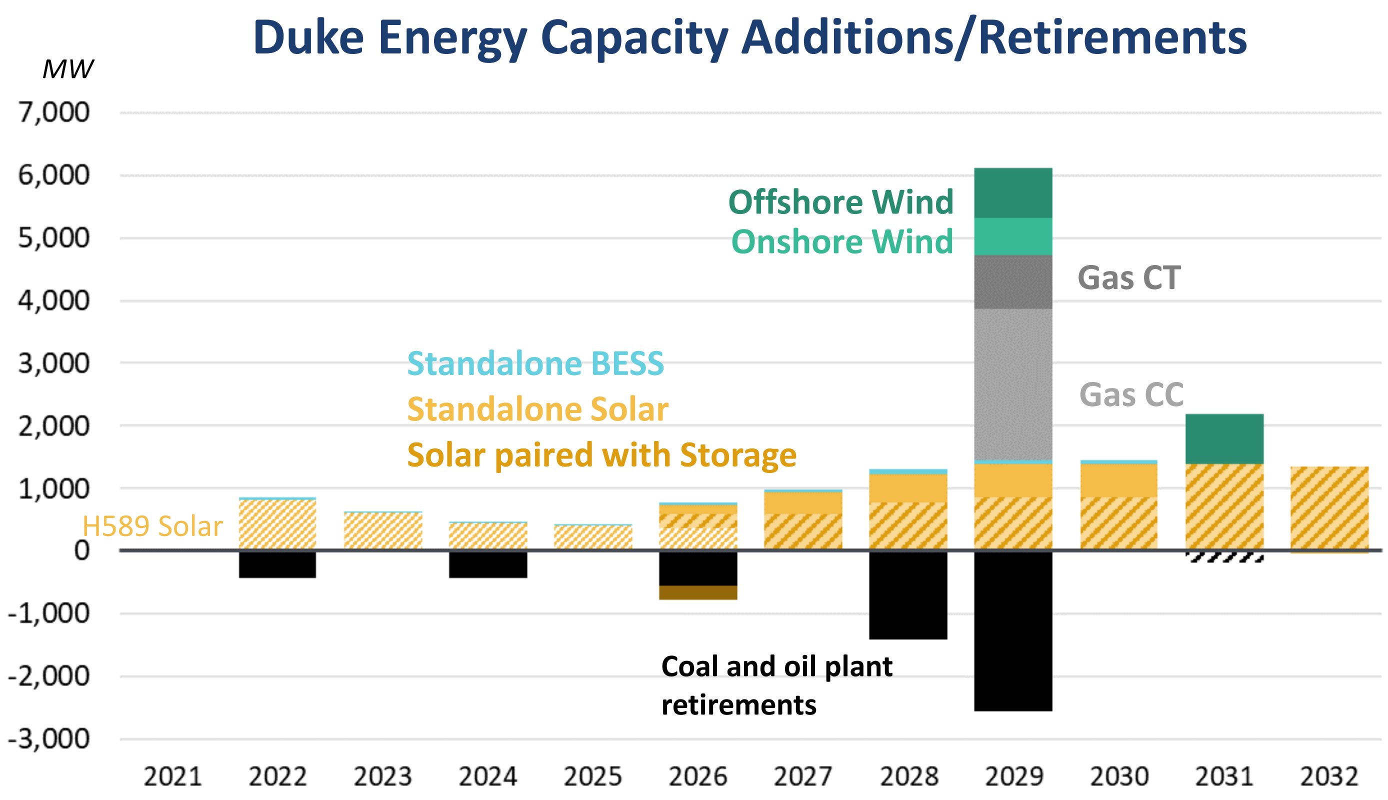
4-hr BESS: +3,300 MW
- Paired with 50% Solar: +2,900 MW
- Paired with 25% Solar: +400 MW

Onshore Wind: +600 MW

Gas CC: +2,000 MW

CPSA2 Generation and Storage Resource Mix

- *2030 Compliance Year with Low Solar Cap*



Note: Paired storage is implicitly accounted for by the paired solar capacity additions and not shown above.

Total New Resources by 2030

Utility-Scale Solar: +5,200 MW
- Standalone Solar: +2,100 MW
- Paired with 50% 4-hr BESS: +3,100 MW

4-hr BESS: +1,800 MW
- Standalone: +200 MW
- Paired with 50% Solar: +1,600 MW

Onshore Wind: +600 MW

Offshore Wind: +800 MW

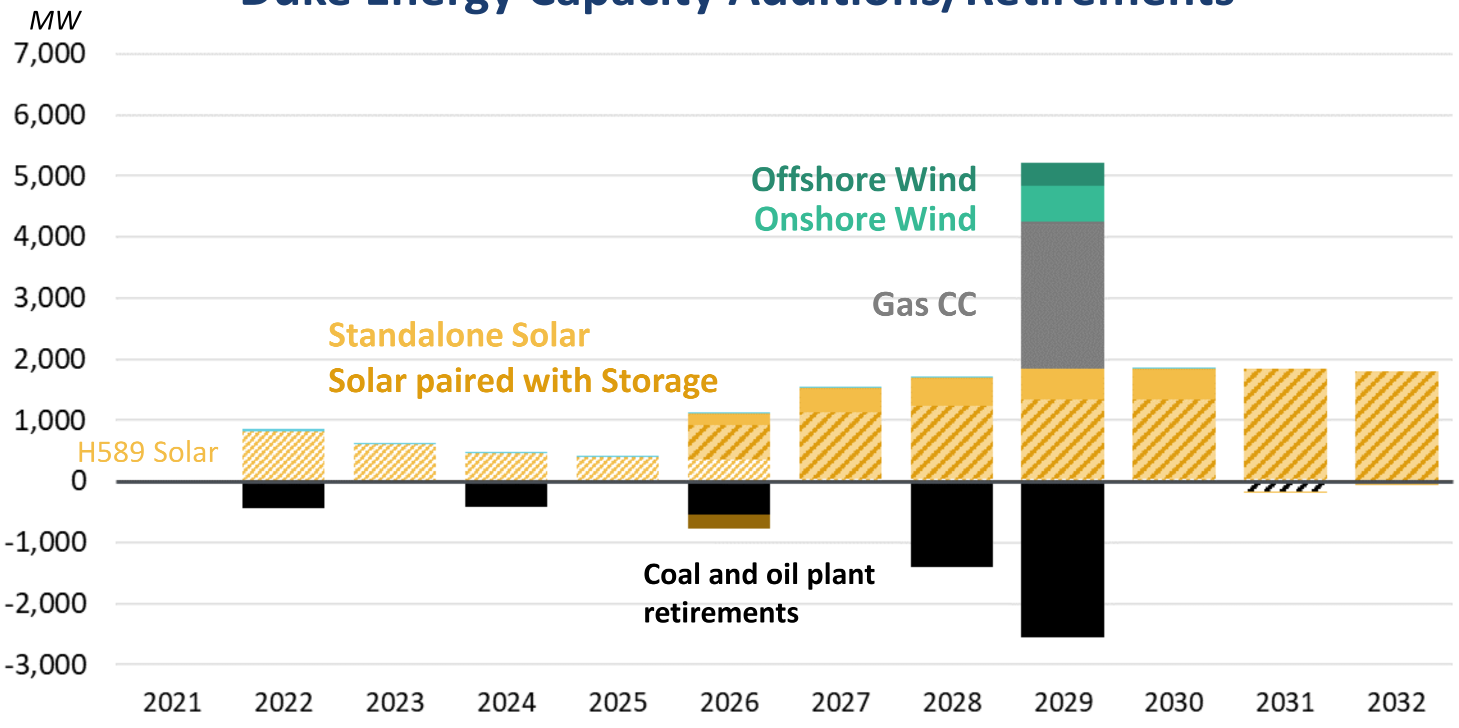
Gas CC: +2,400 MW

Gas CT: +900 MW

CPSA3 Generation and Storage Resource Mix

- *2030 Compliance Year with CPSA Solar Cap*

Duke Energy Capacity Additions/Retirements



Note: Paired storage is implicitly accounted for by the paired solar capacity additions and not shown above.

Total New Resources by 2030

Utility-Scale Solar: +7,500 MW
- Standalone Solar: +2,100 MW
- Paired with 50% 4-hr BESS: +5,400 MW

4-hr BESS: +2,700 MW
- Paired with 50% Solar: +2,700 MW

Onshore Wind: +600 MW

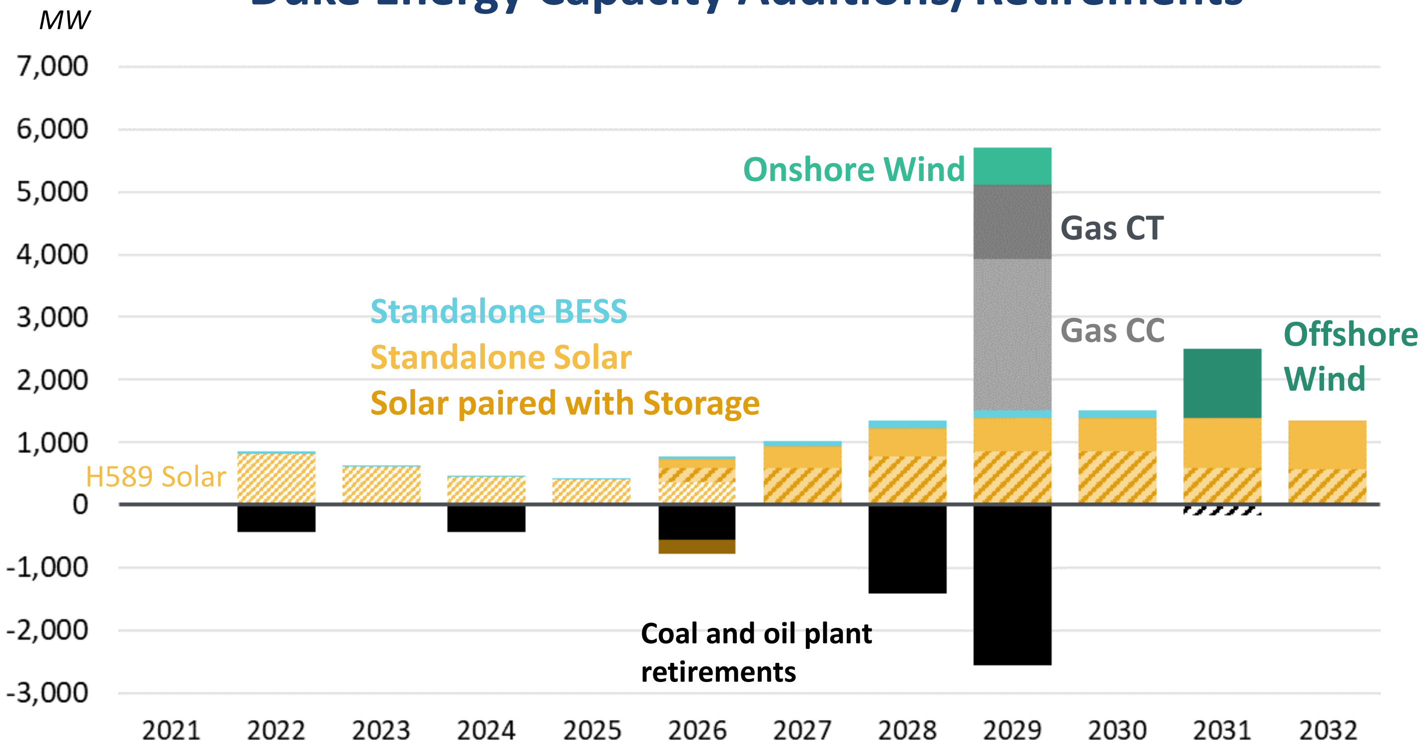
Offshore Wind: +400 MW

Gas CC: +2,400 MW

CPSA4 Generation and Storage Resource Mix

- *2032 Compliance Year with Low Solar Cap*

Duke Energy Capacity Additions/Retirements



Note: Paired storage is implicitly accounted for by the paired solar capacity additions and not shown above.

*Total New Resources by 2032**

Utility-Scale Solar: +7,900 MW
- Standalone Solar: +3,600 MW
- Paired with 50% 4-hr BESS: +3,200 MW
- Paired with 25% 4-hr BESS: +1,100 MW

4-hr BESS: +2,300 MW
- Standalone BESS: +500 MW
- Paired with 50% Solar: +1,600 MW
- Paired with 25% Solar: +300 MW

Onshore Wind: +600 MW

Offshore Wind: +1,100 MW

Gas CC: +2,400 MW

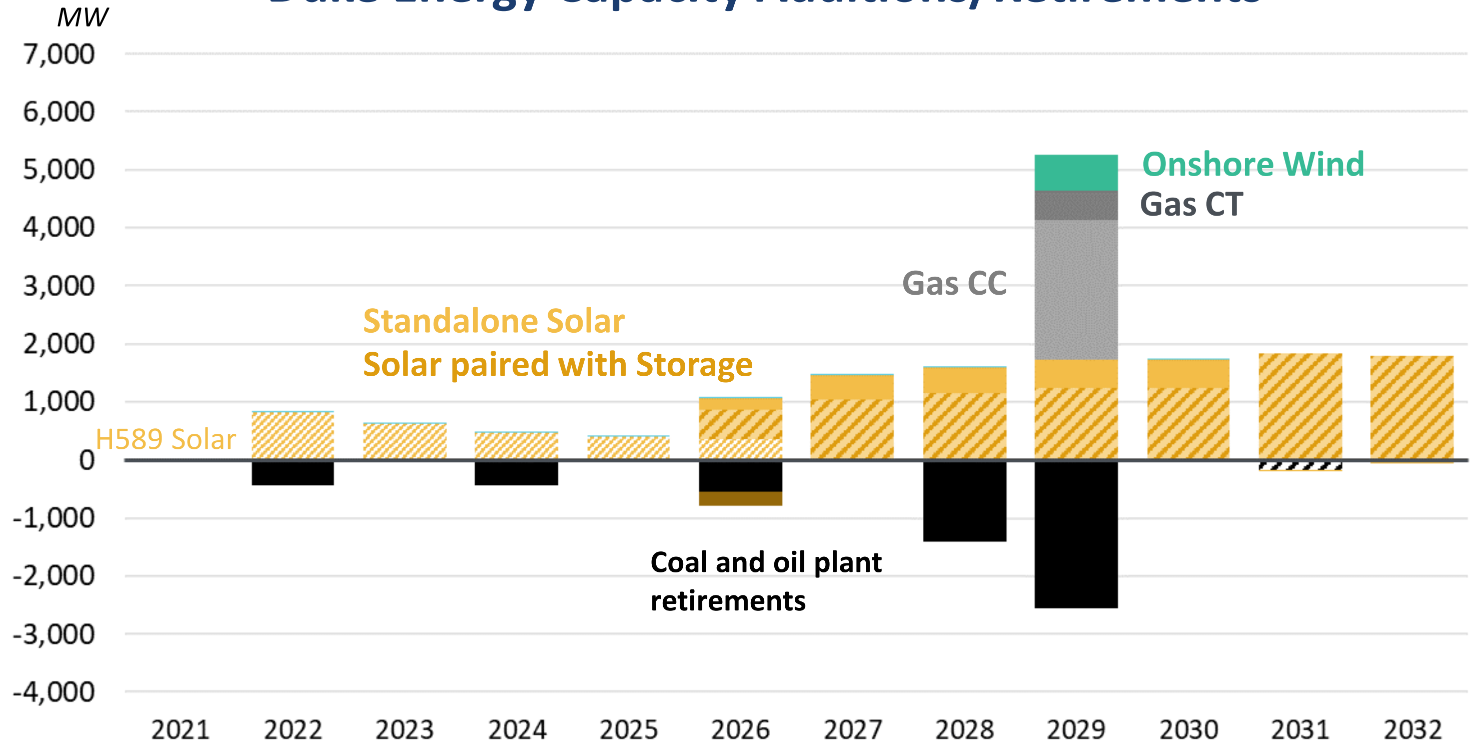
Gas CT: +1,100 MW

* Individual capacity components may not add up to totals due to rounding.

CPSA5 Generation and Storage Resource Mix

- *2032 Compliance Year with CPSA Solar Cap*

Duke Energy Capacity Additions/Retirements



Note: Paired storage is implicitly accounted for by the paired solar capacity additions and not shown above.

Total New Resources by 2032

Utility-Scale Solar: +10,700 MW

- Standalone Solar: +2,100 MW
- Paired with 50% 4-hr BESS: +5,200 MW
- Paired with 25% 4-hr BESS: +3,500 MW

4-hr BESS: +3,500 MW

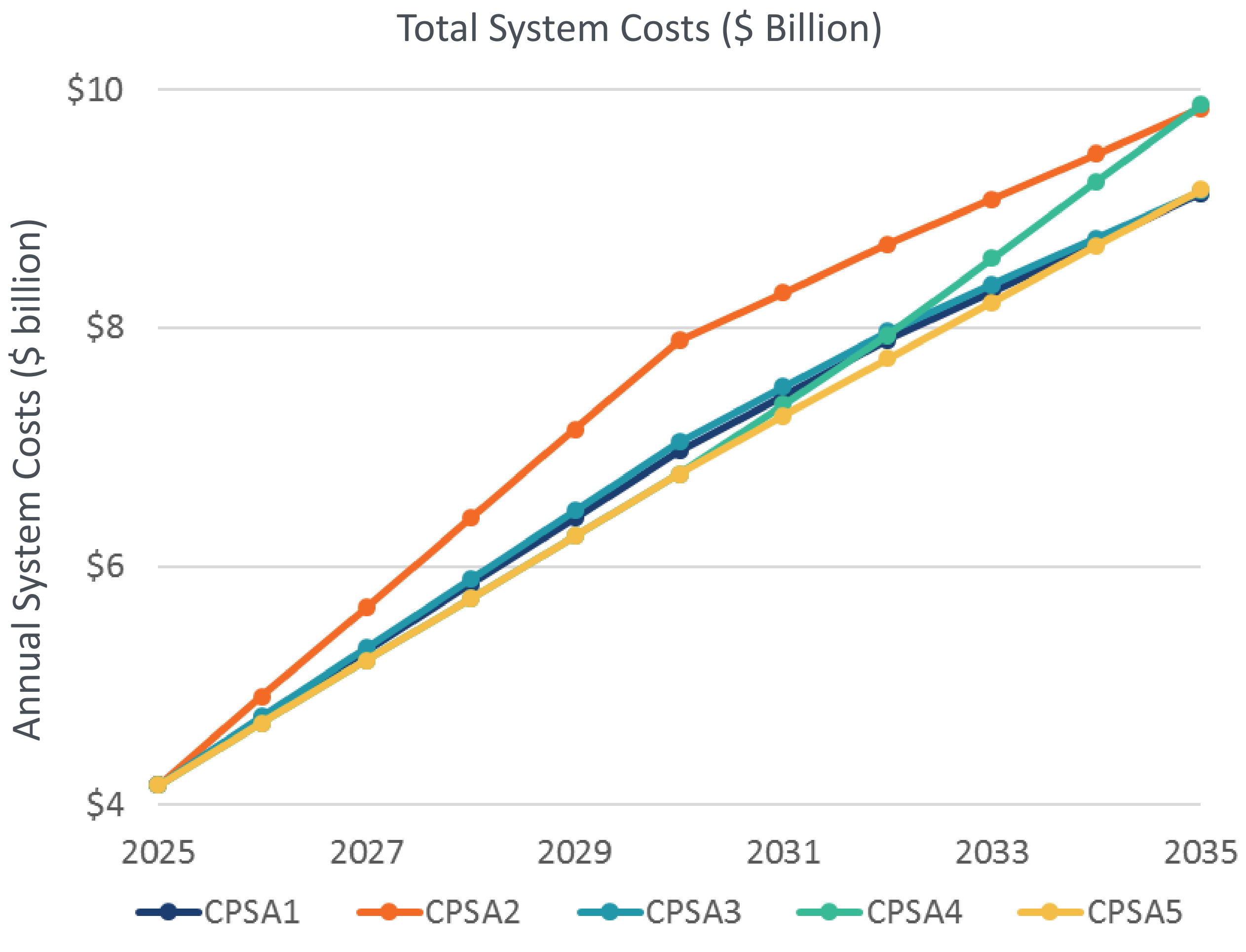
- Paired with 50% Solar: +2,600 MW
- Paired with 25% Solar: +900 MW

Onshore Wind: +600 MW

Gas CC: +2,400 MW

Gas CT: +500 MW

System Costs of Alternative Carbon Plan Portfolios



Benefits of Proactive Transmission Planning

Carbon Plan Should Identify Least-Cost Resource Mix

Identifying the least-cost resource mix to achieve the Carbon Plan must account for both generation and transmission (G&T) costs

The least-cost G&T resource plan can be identified either through:

- A model that can roughly co-optimize generation and transmission expansion
- Or, through running multiple scenarios that consider different transmission expansion options

After potential resource portfolios are identified, Duke should analyze the tradeoffs of each, including a more detailed analysis of transmission system impacts

- Transmission studies will identify upgrades for each portfolio and potential impacts of outages
- Proactively building system-level upgrades will mitigate interconnection challenges

Only if the optimal resource mix either cannot be achieved through transmission planning and interconnection processes or requires significant incremental costs not considered in the capacity expansion modeling, should Duke deviate from the least-cost resource mix

PacifiCorp Integrated Resource Planning

In its 2021 IRP, PacifiCorp accounted for transmission upgrades and costs in two ways:

- Allows model to endogenously select transmission upgrades to achieve optimal resource mix
- Modeled alternative scenarios with and without several major transmission upgrades

IRP identified 14 transmission upgrades necessary to access and integrate resources through 2040

Figure 1.3 – 2021 IRP Preferred Portfolio (All Resources)

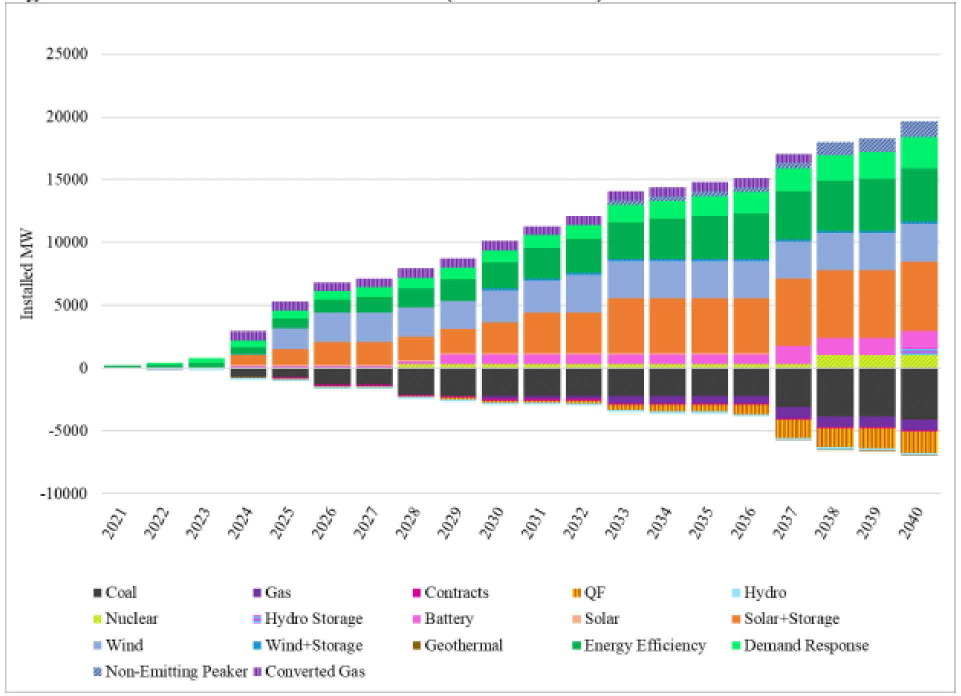


Table 1.1 – Transmission Projects Included in the 2021 IRP Preferred Portfolio[1,2,*]

Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	615 MW Wind (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032) 650 MW Battery (2037)	Portland North Coast	Willamette Valley Southern Oregon	Enables 2080 MW of interconnection with 1950 MW TTC; Portland Coast area reinforcement, Willamette Valley and Southerm Oregon
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	41 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2030	160 MW Solar+Wind+Storage (2030) 20 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 180 MW of interconnection: Yakima local area reinforcement
2031	820 MW Solar+Storage (2031) 206 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2033	400 MW Non-Emitting Peaker (2033) 1100 MW Solar+Storage (2033)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2040	156 MW Solar+Storage (2040) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	549 MW Battery (2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	909 MW Solar+Storage (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	206 MW Non-Emitting Peaker (2040) 60 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

Source: PacifiCorp 2021 IRP.

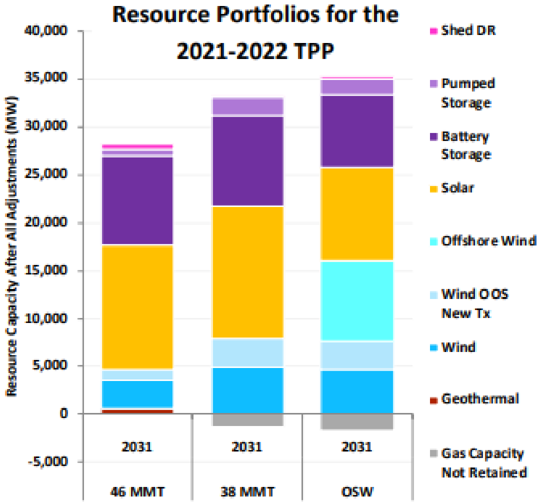
California IRP and Transmission Planning Process

During each IRP cycle, CPUC identifies optimal resource portfolios needed to meet state policy goals over next 10 years, including resource type and zone

- Capacity expansion model accounts for transmission limits, total resource potential, and estimated transmission costs of alternative resources
- Identify substations within each renewable zone for placing new resources for transmission planning studies

CAISO then studies whether there are reliability, economic, and/or policy needs for new transmission under each portfolio

- 2021-22 process identified 23 reliability, policy, and economic projects, estimated to cost $2,964 million
- Stakeholders play a key role in reviewing assumptions and preliminary results, and submitting transmission upgrades for CAISO to study



		2031		
Resource Category	*Unit*	**46 MMT**	**38 MMT**	**OSW**
Gas	*MW*	-	-	-
Biomass	*MW*	-	-	-
Geothermal	*MW*	651	-	-
Hydro (Small)	*MW*	-	-	-
Wind	*MW*	2,943	4,955	4,689
Wind OOS New Tx	*MW*	1,062	3,000	3,000
Offshore Wind	*MW*	-	-	8,351
Solar	*MW*	13,043	13,816	9,807
Customer Solar	*MW*	-	-	-
Battery Storage	*MW*	9,368	9,447	7,604
Pumped Storage	*MW*	627	1,843	1,613
Shed DR	*MW*	608	222	222
Gas Capacity Not Retained	*MW*	-	(1,319)	(1,718)
In-State Renewables	*MW*	**16,638**	**18,876**	**22,847**
Out-Of-State Renewables	*MW*	**1,062**	**3,000**	**3,000**

Table 8.2-2: New Policy-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project	SCE	2023	$17.3M
2	Reconductor Delevan-Cortina 230kV line	PG&E	2028	$17.7M–$35.4 M
3	New Collinsville 500 kV substation	PG&E	2028	$475M-$675M
4	Reconductor Rio Oso–SPI Jct–Lincoln 115kV line	PG&E	2028	$10.6M - $21.2M
5	New Manning 500 kV substation	PG&E	2028	$325M - $485M
6	GLW/VEA area upgrades	GLW/VEA	TBD	$278M

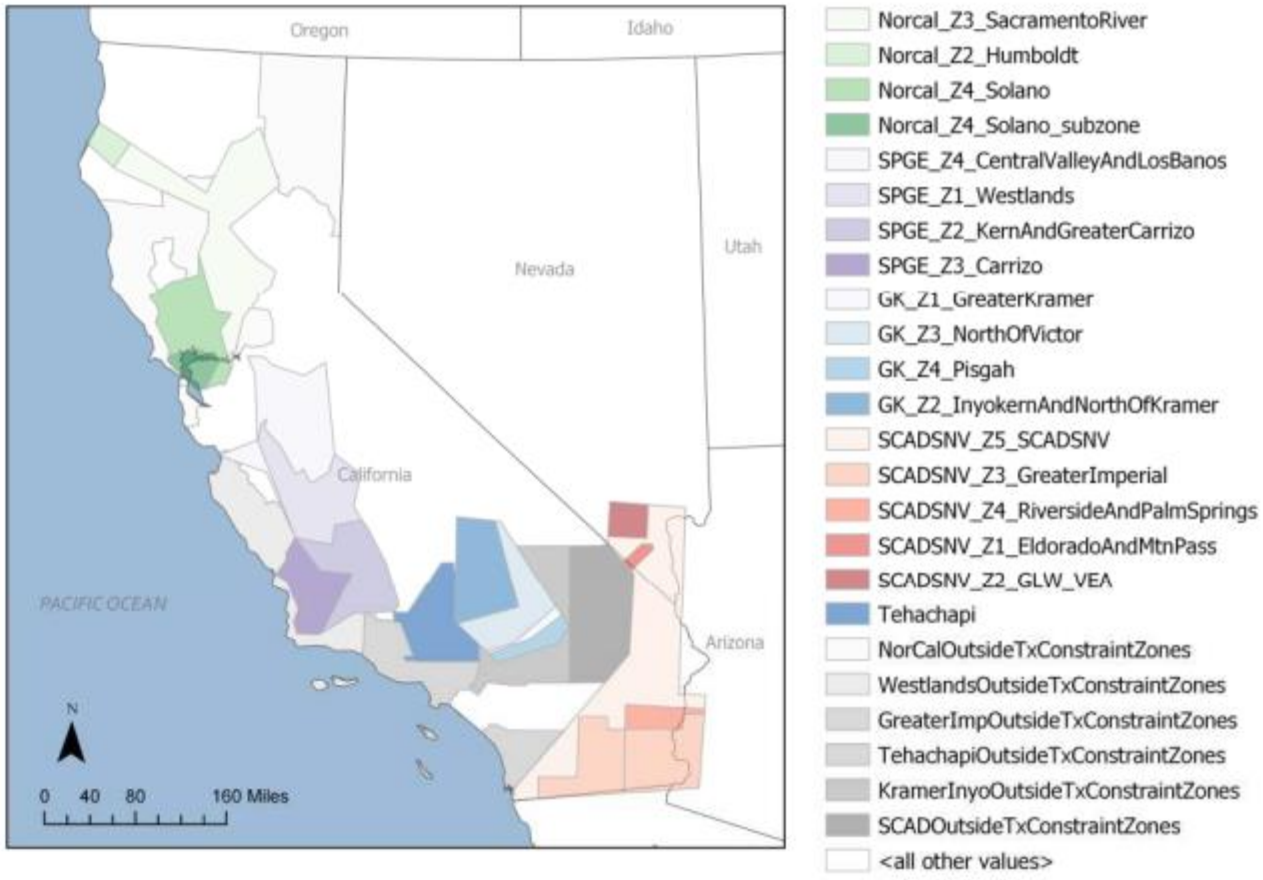
Table 8.2-3: New Economic-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Installing 10 ohms series reactors on the PG&E's Moss Landing – Las Aguilas 230 kV line	PG&E	2026	$30-40M

PROACTIVE TRANSMISSION PLANNING

CPUC IRP Transmission Capacity and Cost Assumptions

In-State Transmission Zones



Available Capacity and Incremental Deliverability Costs by Transmission Zone

Transmission Zone or Subzone	Incremental Deliverability Cost ($/kW-yr)	FCDS Availability on Existing Transmission, Net of Post-2018 COD Baseline Capacity (MW) ***	Energy-Only Availability on Existing Transmission (MW, Default) ***	Energy-Only Availability (MW, Sensitivity) ****
Carrizo	$10	187	0	700
Central_Valley_North_Los_Banos	$36	791	0	500
GLW_VEA	$14	596	0	1470
Greater_Imperial	$221	919	1900	1900
Greater_Kramer	$48	597	0	0
Humboldt	$999**	0	100	100
Inyokern_North_Kramer	$161	97	0	0
Kern_Greater_Carrizo	$21	784	700	3680
Kramer_Inyokern_Ex*	$999**	0	0	0
Mountain_Pass_El_Dorado	$7	250	2150	3790
None	$0	0	0	0
North_Victor	$161	300	0	0
Northern_California_Ex*	$999**	866	0	0
Riverside_Palm_Springs	$88	2665	2550	3100
OffshoreWind_UnknownCost	$999**	0	0	0
Sacramento_River	$19	1995	2600	2600
SCADSNV	$102	2434	6600	10260
Solano	$21	599	700	700
Solano_subzone	$999**	0	0	0
Southern_California_Desert_Ex*	$999**	862	0	0
SPGE	$7	675	700	4080
Tehachapi	$13	3677	800	1800
Tehachapi_Ex*	$999**	0	0	0
Westlands_Ex*	$999**	1779	0	0

* Resources that end in “Ex” refers to areas outside of the CAISO transmission cost and availability estimates

Source: CPUC IRP Assumptions.

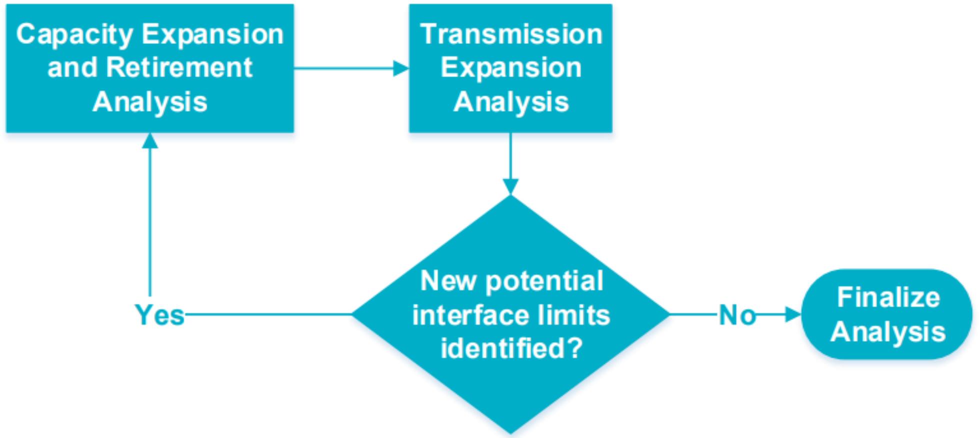
ERCOT Long-Term System Assessment of Transmission Needs

ERCOT develops 10-year forward projections of the resource mix under alternative scenarios and then studies the transmission system needs for each scenario

- ERCOT will adjust capacity expansion analysis if new transmission system limits identified
- LTSA results inform nearer-term needs for upgrades through the Regional Transmission Plan

Currently analyzing need for West Texas upgrades to support growing solar development based on identification of need in previous LTSA studies

ERCOT's Iterative Transmission Planning Process



Industry Experience in Implementing Proactive Transmission Planning

Resource planning is a proactive generation planning effort that needs to be combined with proactive transmission planning to be the most effective

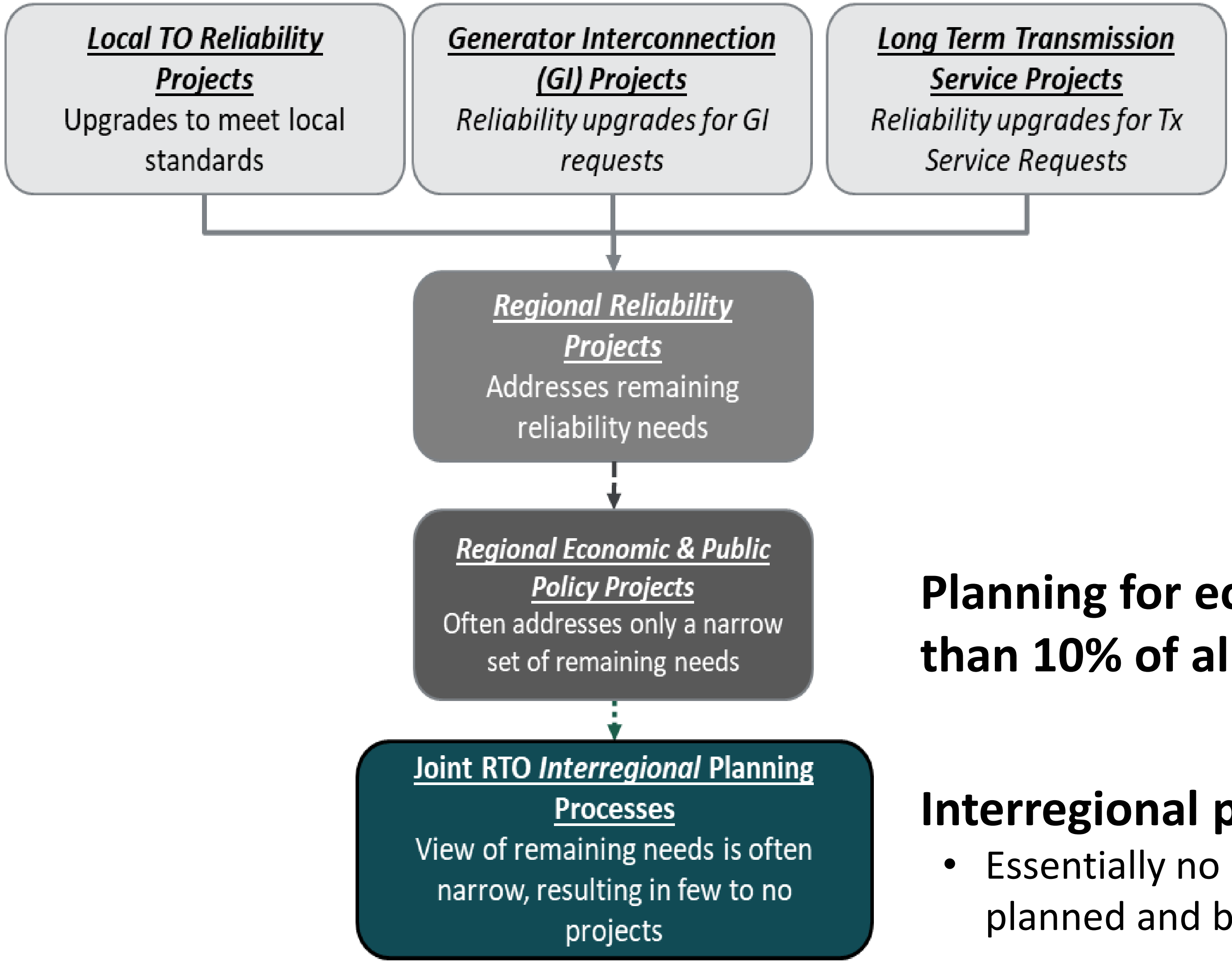
RTOs and utilities across the country have implemented proactive transmission planning approaches that identify cost effective upgrades for their changing resource mix

- Duke Energy can take advantage of this broad experience to identify an effective approach to planning for the future needs of its system
- Transmission planning will not identify all the upgrades necessary for new resources seeking interconnection, but will identify more cost-effective system upgrades in advance of the needs

Regional projects from proactive planning will speed up the generation interconnection process because fewer deep network upgrades will be triggered by GI requests

The parallel proactive transmission planning process can also identify upgrades that provide a wider range of benefits and address unexpected emerging network needs, such as rising congestion and curtailments

Current U.S. Transmission Planning Processes for…



These solely reliability-driven processes account for > 90% of all transmission investments

- None involve any assessments of economic benefits (i.e., cost savings offered by the new transmission)
- Which also means these investments are not made with the objective to find the most cost-effective solutions
- Will yield higher system-wide costs and electricity rates

Planning for economic and public-policy projects: less than 10% of all transmission investments

Interregional planning processes are largely ineffective

- Essentially no major interregional transmission projects have been planned and built in the last decade

Duke Can Look to Other Regions for Planning Best Practices

Available experience points to proven planning practices that reduce total system costs and risks:

Most relevant to Duke's Carbon Plan

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, policy mandates, load levels, and load profiles over lifespan of the transmission investment
2. **Account for the full range of transmission projects' benefits** and **use multi-value planning** to comprehensively identify investments that cost-effectively address all categories of needs and benefits
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events
4. **Use comprehensive transmission network portfolios** to address system needs and **cost allocation** more efficiently and less contentiously than a project-by-project approach
5. **Jointly plan inter-regionally across neighboring systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits

* Brattle & Grid Strategies Report: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

Experience with Proactive Transmission Planning Processes

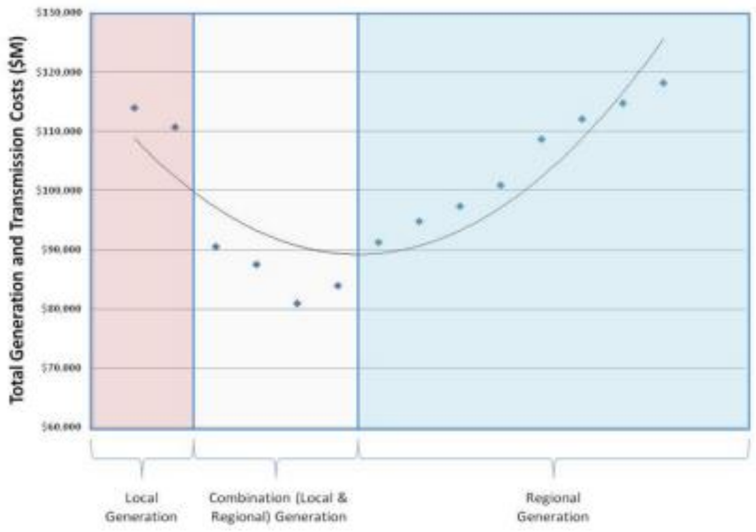
Significant experience exists with successful proactive, multi-value, scenario- and portfolio-based transmission planning efforts:

	Proactive Planning	Multi-Benefit	Scenario-Based	Portfolio-Based	Interregional Transmission
CAISO TEAM (2004)[146]	✓	✓	✓		
ATC Paddock-Rockdale (2007)[147]	✓	✓	✓		
ERCOT CREZ (2008)[148]	✓			✓	
MISO RGOS (2010)[149]	✓	✓		✓	
EIPC (2010-2013)[150]	✓		✓	✓	✓
PJM renewable integration study (2014)[151]	✓		✓	✓	
NYISO PPTPP (2019)[152]	✓	✓	✓	✓	
ERCOT LTSA (2020)[153]	✓		✓		
SPP ITP Process (2020)[154]		✓		✓	
PJM Offshore Tx Study (2021)[155]	✓		✓	✓	
MISO RIIA (2021)[156]	✓	✓	✓	✓	
Australian Examples:					
- AEMO ISP (2020)[157]	✓	✓	✓	✓	✓
- Transgrid Energy Vision (2021)[158]	✓	✓	✓	✓	✓

Source: Brattle & Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

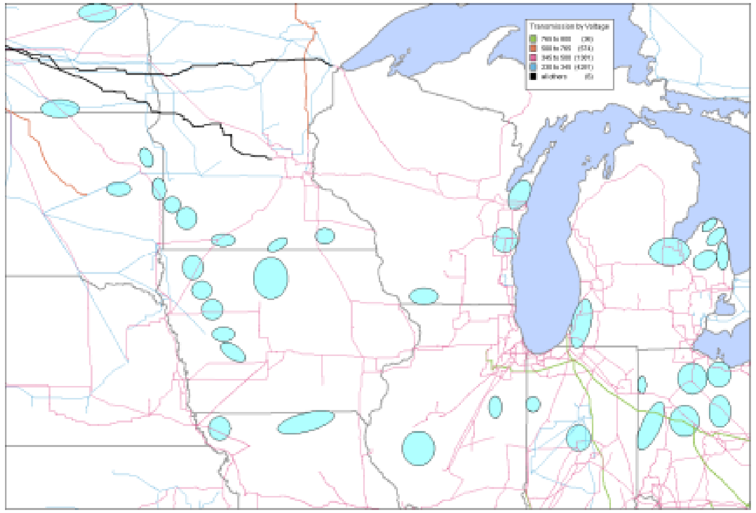
MISO Renewable Generation Outlet Study (RGOS) and MVP Projects

G&T Cost of Local vs Regional Generation



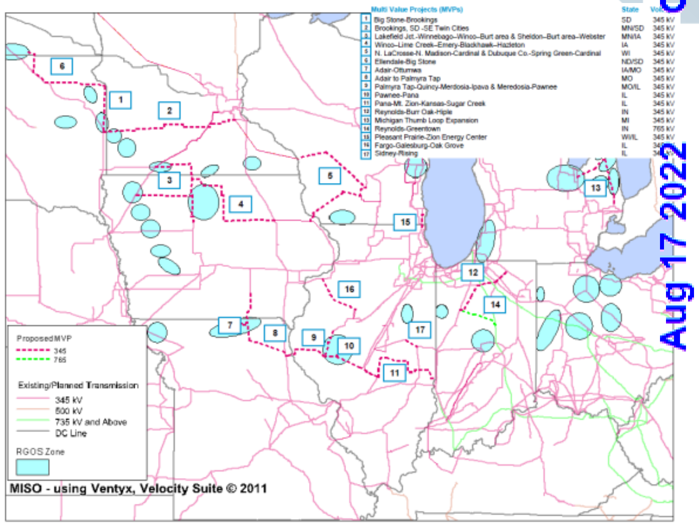
MISO and its stakeholders identified total capital costs associated with generation capacity and indicative transmission to deliver the energy to the system

RGOS Energy Zones



MISO sought input from regulatory bodies and various state agencies to identify energy zones; zone selection was based on a number of potential locations developed by MISO using NREL wind data

MVP Transmission Projects



Transmission upgrades were identified by MISO and its stakeholders over a series of planning studies that resulted in the MVP portfolio

Source: MISO MVP Portfolio Analysis

Decade of Experience with Identifying and Quantifying Benefits

SPP 2016 RCAR, 2013 MTF

Quantified
1. **production cost savings***
   - value of reduced emissions
   - reduced ancillary service costs
2. avoided transmission project costs
3. reduced transmission losses*
   - capacity benefit
   - energy cost benefit
4. lower transmission outage costs
5. value of reliability projects
6. value of mtg public policy goals
7. Increased wheeling revenues

Not quantified

8. reduced cost of extreme events
9. reduced reserve margin
10. reduced loss of load probability
11. increased competition/liquidity
12. improved congestion hedging
13. mitigation of uncertainty
14. reduced plant cycling costs
15. societal economic benefits

(SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.)

MISO MVP Analysis

Quantified
1. **production cost savings** *
2. reduced operating reserves
3. reduced planning reserves
4. reduced transmission losses*
5. reduced renewable generation investment costs
6. reduced future transmission investment costs

Not quantified

7. enhanced generation policy flexibility
8. increased system robustness
9. decreased natural gas price risk
10. decreased CO_2 emissions output
11. decreased wind generation volatility
12. increased local investment and job creation

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

CAISO TEAM Analysis
(DPV2 example)

Quantified
1. **production cost savings*** and reduced energy prices from both a societal and customer perspective
2. mitigation of market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation investment costs
5. operational benefits (RMR)
6. reduced transmission losses*
7. emissions benefit

Not quantified

8. facilitation of the retirement of aging power plants
9. encouraging fuel diversity
10. improved reserve sharing
11. increased voltage support

(CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity)

NYISO PPTN Analysis
(AC Upgrades)

Quantified
1. **production cost savings*** (includes savings not captured by normalized simulations)
2. capacity resource cost savings
3. reduced refurbishment costs for aging transmission
4. reduced costs of achieving renewable and climate policy goals

Not quantified

5. protection against extreme market conditions
6. increased competition and liquidity
7. storm hardening and resilience
8. expandability benefits

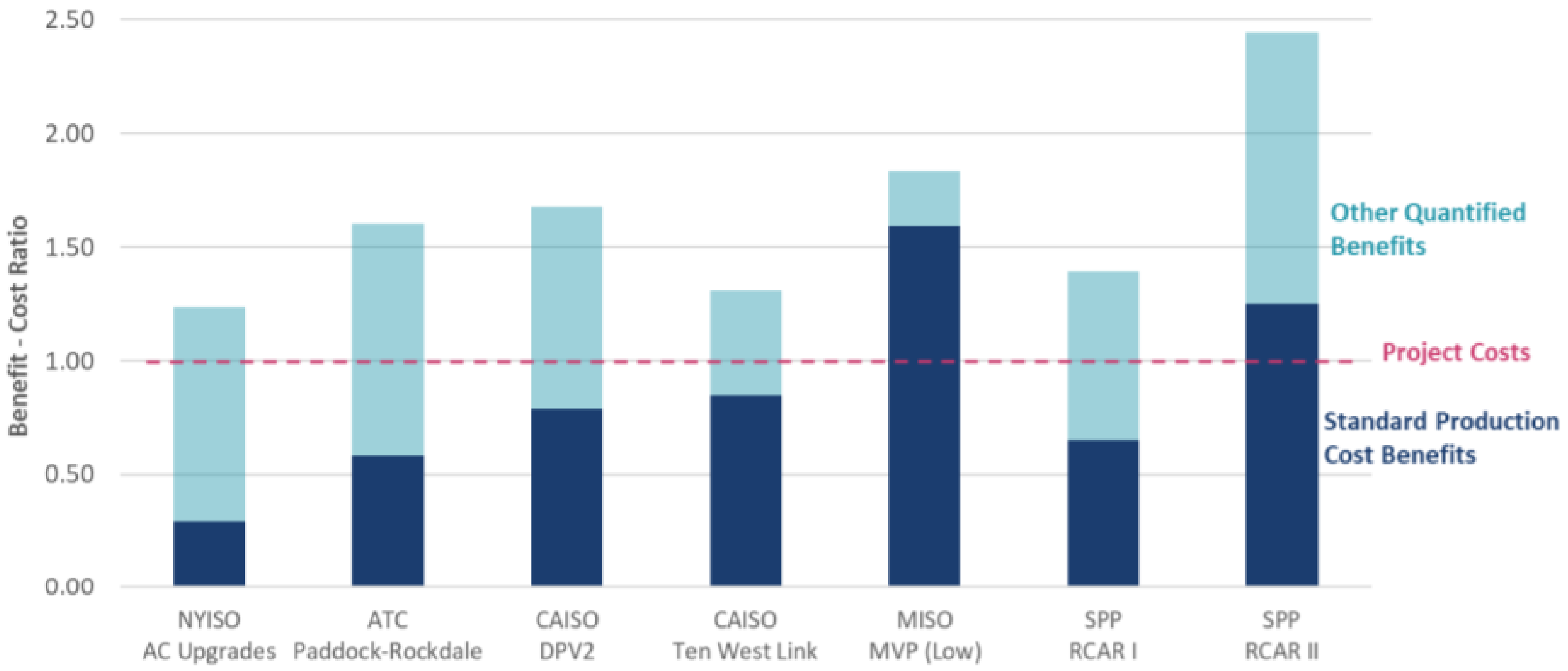
(Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015)

* Fairly consistent across RTOs

Quantifying Benefits Beyond “Production Cost” Savings

Relying on solely on traditionally-quantified Adjusted Production Cost (APC) Savings results in the rejection of beneficial transmission projects:

FIGURE 5. BENEFIT-COST RATIOS OF TRANSMISSION PROJECTS WITH AND WITHOUT A BROAD SCOPE OF BENEFITS



Source: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (brattle.com)

Proactive Transmission Planning for Changing Resource Mix

- **ERCOT**: CREZ lines unlocked over 11 GW of wind and solar capacity based on detailed review of ideal locations; currently considering additional upgrades to expand West Texas capacity
- **SPP**: Priority Projects developed to access 3 GW of wind; later replaced by Integrated Transmission Planning process for identifying upgrades to provide broad range of benefits
- **MISO**: Identified least-cost mix of regional & local renewable resources through RGOS that resulted in market-wide Multi-Value Project upgrades to access 14 GW of wind resources
- **PJM**: In recent study, identified much lower cost portfolio of upgrades to interconnect 75 GW of renewable resources across its system compared to doing so through GI process
- **PacifiCorp**: Gateway West projects proposed to access 1,500 MW of low-cost wind in WY
- **NV Energy**: Building Greenlink projects to access 4,000 MW of low-cost solar resources in NV

Proactive Planning Will Improve Interconnection Process

Proactive planning efforts will provide the roadmap to the most cost-effective solutions for interconnection-related and other transmission needs over the next 10-20 years

These planning efforts usually run in parallel with the regular interconnection process

- Each planning study may take 1-2 years to complete and be done only every few years, but that does not hold up anything else

At the same time, Duke should consider approaches to continuing to improve the interconnection process:

- Identify network upgrades based on a level of output that more closely reflects its ELCC instead of its nameplate capacity
- Allow solar resources to request non-firm/energy-only service
- Allow solar to begin operating as an energy-only resource after building its attachment facilities and then become a full network resource once network upgrades completed

Substantial Differences in Generation Interconnection Processes

Interconnection processes and study criteria differ substantially across the regions:

- ERCOT's generation interconnection process is generally seen as more effective
  - Efficient handoff of study roles by ERCOT and Transmission Owners limits restudy needs
  - Projects can be developed and interconnected within 2-3 years; in other regions, the interconnection study process itself takes longer than that
  - Upgrades focused more on local needs (similar to ERIS) and are recovered through postage stamp
  - Network constraints managed through market dispatch – which imposes higher congestion and curtailment risks on interconnecting generators but yields more efficient outcomes and risk sharing
  - See working-paper.pdf (enelgreenpower.com) [Note: Brattle was not involved]
- Attractive: UK "Connect and Manage" (replaced prior "Invest and Connect")
  - Similar to ERIS; reduced lead times by 5 years; network constraints addressed later (e.g., with congestion management) https://www.gov.uk/guidance/electricity-network-delivery-and-access#connect-and-manage
- Generation interconnection study criteria matter, yet differ substantially across RTOs
  - For example, PJM's stringent study criteria tend to trigger more "deep network" upgrades, which increases churn and restudy requirements; will often be less cost effective than congestion management

Recommendations for Carbon Plan

- Develop least-cost resource mixes to achieve 70% CO_2 reductions without the proposed limit on incremental solar additions
- Instead, either include estimates of transmission costs in the simulations (which may increase with additions) or simulate alternative transmission buildout scenarios
- Identify likely locations of new resources in least-cost resource mix, including input from stakeholders on renewable energy zones, transmission constraints, and costs
- Perform proactive transmission planning studies for identified resource mixes that consider a broad range of system benefits
- Review generation interconnection process to identify opportunities to align with best practices across the industry

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Appendix

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