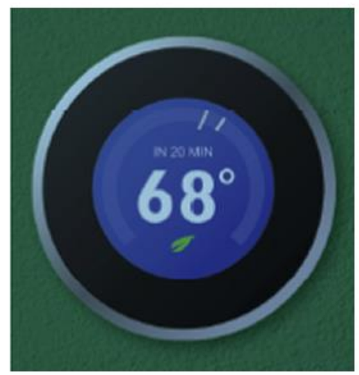
2019 Integrated Resource Plan (IRP) Public Input Meeting
April 25, 2019



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Summary

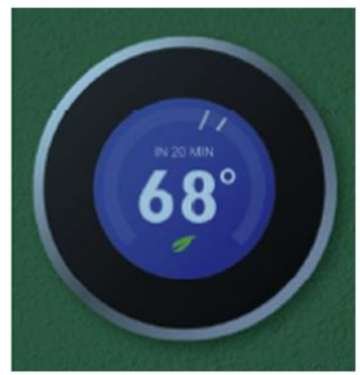
- Updated coal-retirement cases account for incremental resource costs to address reliability issues identified and discussed at the December 2018 public-input meeting.
- The updated analysis shows there are potential customer benefits from accelerating the retirement of certain coal units—the greatest customer benefits are associated with an accelerated retirement of certain units at the Naughton and Jim Bridger power plants.
- The results of these studies do not reflect a final least-cost, least-risk plan.
- Additional resource portfolio analysis will be completed in the coming months before PacifiCorp finalizes the 2019 IRP, which it plans to file with state commissions by August 1, 2019.

Next Steps Analysis

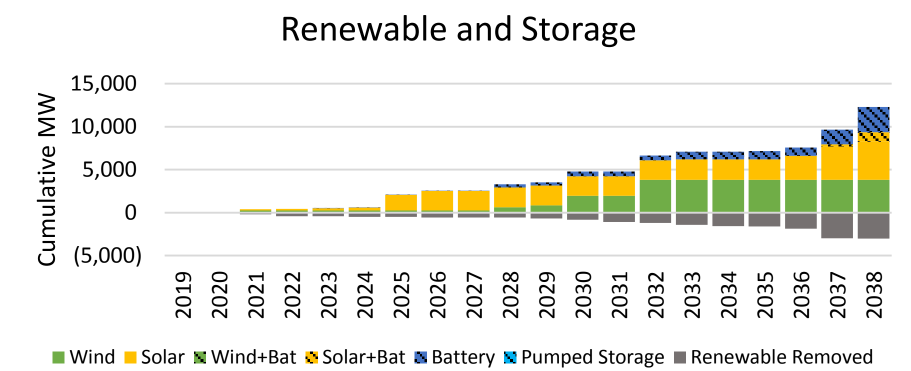
- Additional analysis necessary to establish a preferred portfolio will include, but not limited to:
  - Alternative operational scenarios for existing coal units (*i.e.*, gas conversion, reduced operating minimums, and seasonal operations).
  - Assessment of implementation and resource adequacy risk, employee and community transitions (*i.e.* staging of potential early coal retirements).
  - Risk assessment of near-term replacement resources.
  - Energy Gateway transmission cases.
  - Assessment of expected schedules to implement a request-for-proposals process consistent with new legislation in Wyoming and potential interactions with state-driven new resource procurement rules.
  - Regional haze compliance alternatives.
  - Market price and CO_2 policy scenario risk assessment (price-policy scenarios).

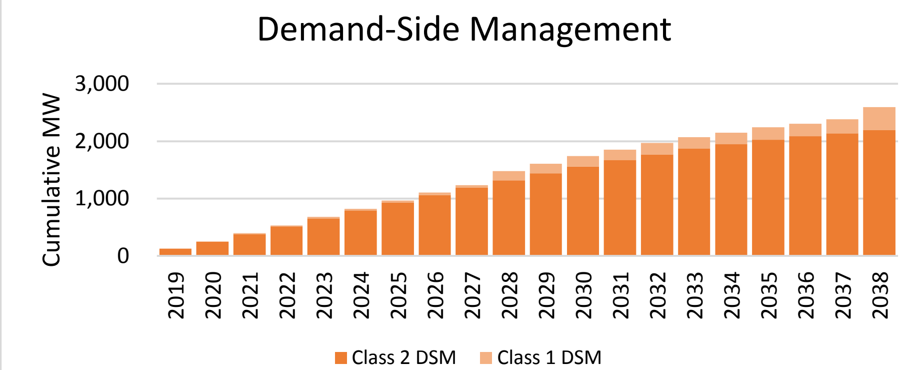
Updated Benchmark Case

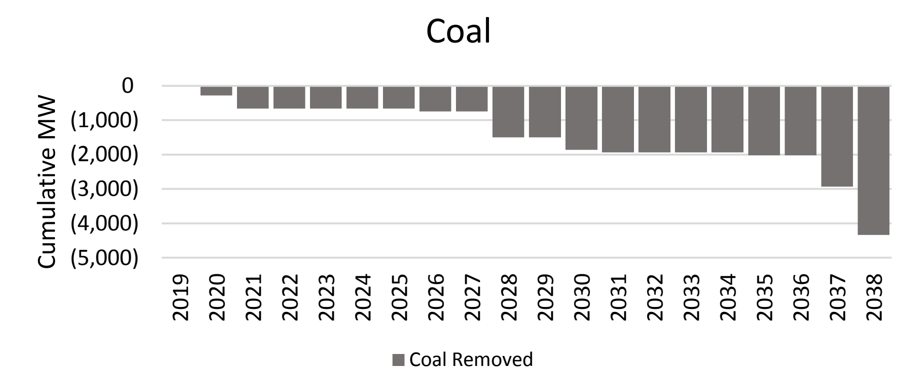


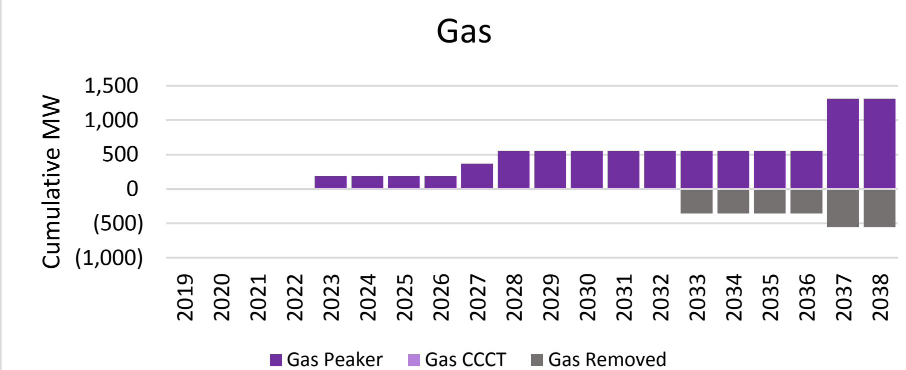



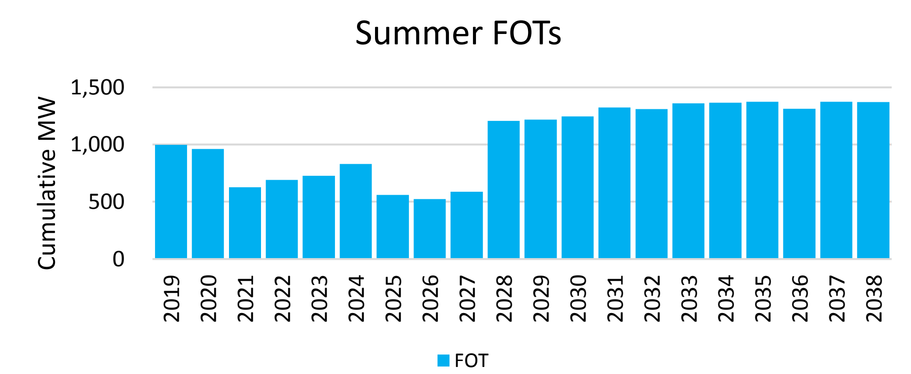
Benchmark Case (C-01) Resource Portfolio











Resource Type	2038 Nameplate Capacity
Net Wind	2,485
Net Solar	3,864
New Battery	3,211
New Class 1 DSM	402
New Class 2 DSM	2,191
Net Gas	757
Net Coal	(4,337)

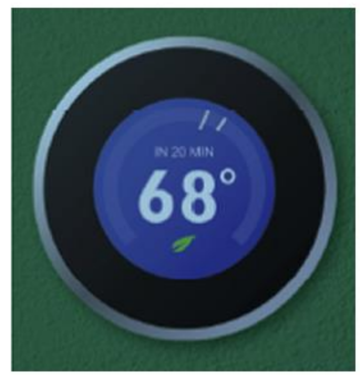
Benchmark Case (C-01) Transmission Upgrades

Year	Resource Location	From	To	ATC	Max Interconnection	Nominal Capital ($m)
2021	UT South	UT South	UT South	0	300	$8.0
2025	Yakima WA	Yakima WA	Yakima WA	0	405	$3.1
2025	Southern OR	Southern OR	Southern OR	0	975	$85.2
2025	SW WY	SW WY	SW WY	0	100	$8.8
2026	UT South	UT South	UT South	0	800	$188.0
2030	Goshen ID	Goshen ID	UT North	800	800	$253.7
2032	Aeolus	Aeolus	UT South	1,500	1500	$2,319.2
2033	Walla Walla WA	Walla Walla WA	Yakima WA	200	450	$74.8
2037	Yakima WA	Yakima WA	Southern OR	450	835	$260.7
2037	UT North	UT North	UT North	0	500	$50.9
2037	SW WY	SW WY	SW WY	0	500	$38.8
					Total	$3,294.6

- Yakima WA to Southern OR in 2037 is an expansion of the Yakima upgrade in 2025

*Note, capital is applied in the model reflecting real-levelized revenue requirement based on 88% of the nominal capital shown in the table above. The 12% reduction to capital is applied to capture assumed third-party revenue credits via the OATT formula rate.

Stacked-Retirement Summary Results



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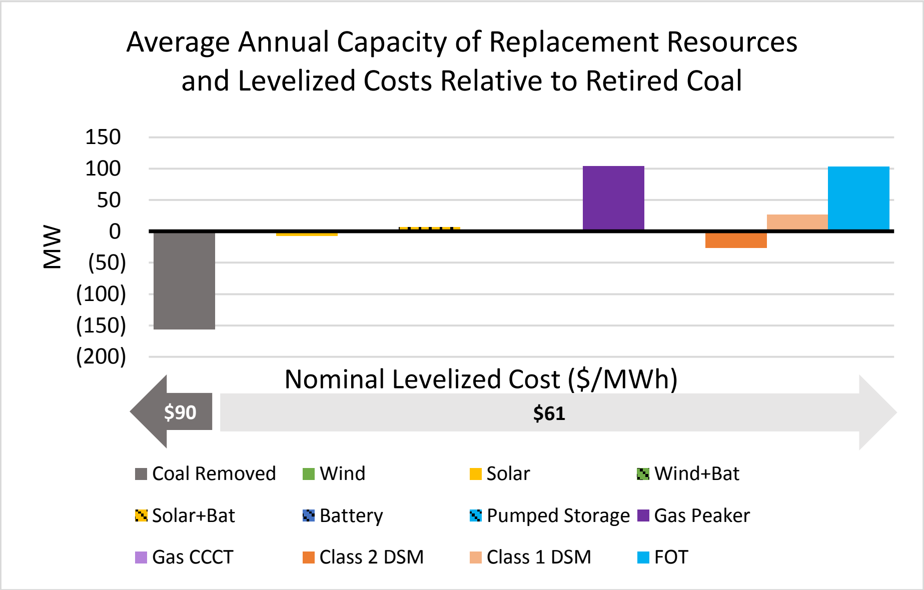
Stacked-Retirement Cases PVRR(d) Results

Case	Inc. Retired Capacity in 2023 (MW)	PVRR(d) (Benefit)/Cost of Early Retirement ($m)	Naughton 1	Naughton 2	Bridger 1	Bridger 2	Hayden 1	Hayden 2	Craig 1	Craig 2	Dave Johnston 3
C-34	357	($123)	✓	✓							
C-35	711	($211)	✓	✓	✓						
C-36	510	($158)	✓		✓						
C-37	554	($143)	✓		✓		✓				
C-38	755	($120)	✓	✓	✓		✓				
C-39	834	($52)	✓	✓	✓		✓			✓	
C-40	1,193	($191)	✓	✓	✓	✓	✓			✓	
C-41	1,529	($12)	✓	✓	✓	✓	✓	✓	✓	✓	✓
C-42	1,063	($248)	✓	✓	✓	✓					
C-43	928	($31)	✓	✓	✓						✓

*Note: in all cases it is assumed that Naughton 3 (280 MW) is retired in 2019 and that Cholla 4 (387 MW) is retired at the end of 2020—however, these units are retired in the benchmark case and therefore not incremental to the stacked-retirement cases listed above.

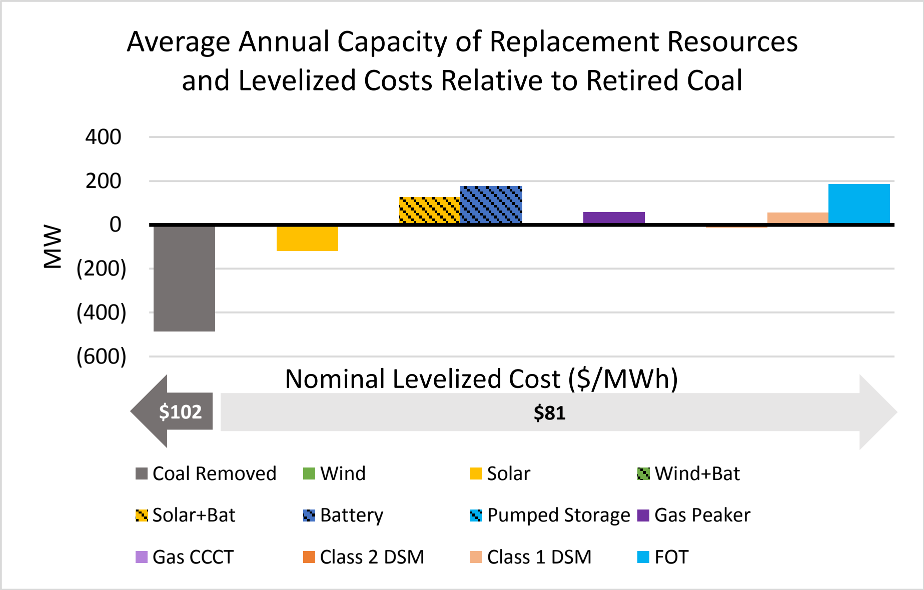
Stacked Cases C-34 and C-35

Case C-34 (NT1-2)



- The nominal levelized cost of the retired coal resources is $29.33/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 18.6% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 59.8% to achieve break-even economics with the replacement portfolio.

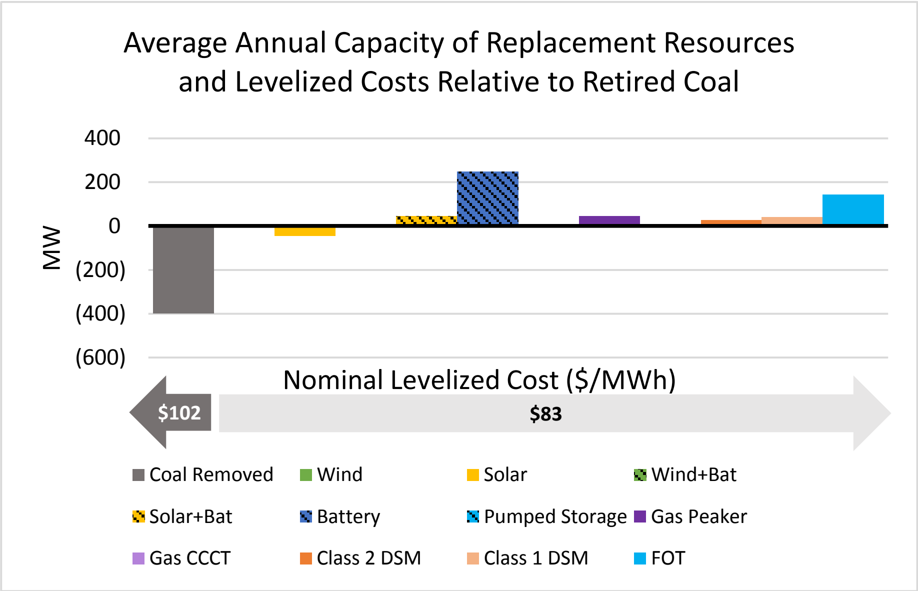
Case C-35 (NT1-2, JB1)



- The nominal levelized cost of retired coal resources is $20.71/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 45.9% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 37.0% to achieve break-even economics with the replacement portfolio.

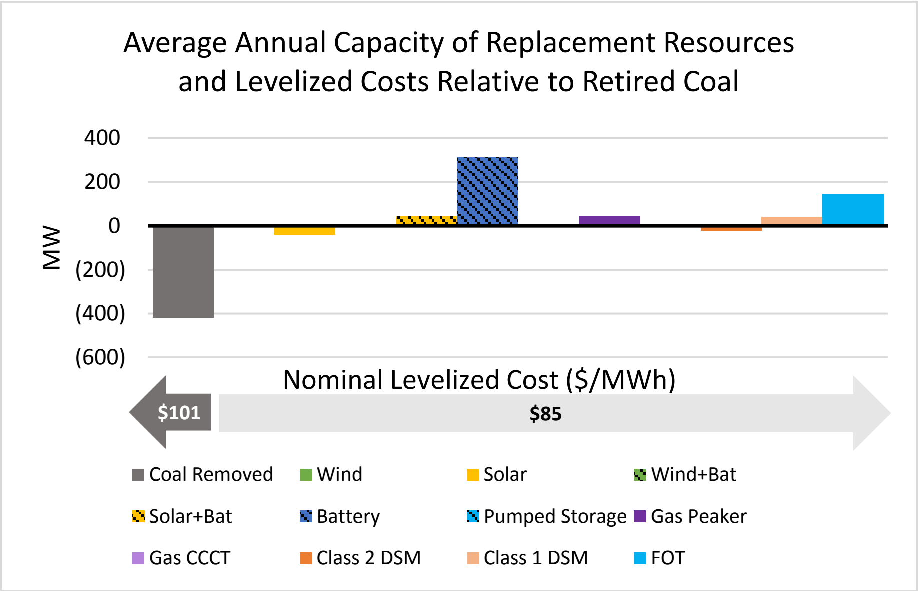
Stacked Cases C-36 and C-37

Case C-36 (NT1, JB1)



- The nominal levelized cost of retired coal resources is $19.15/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 61.9% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 34.2% to achieve break-even economics with the replacement portfolio.

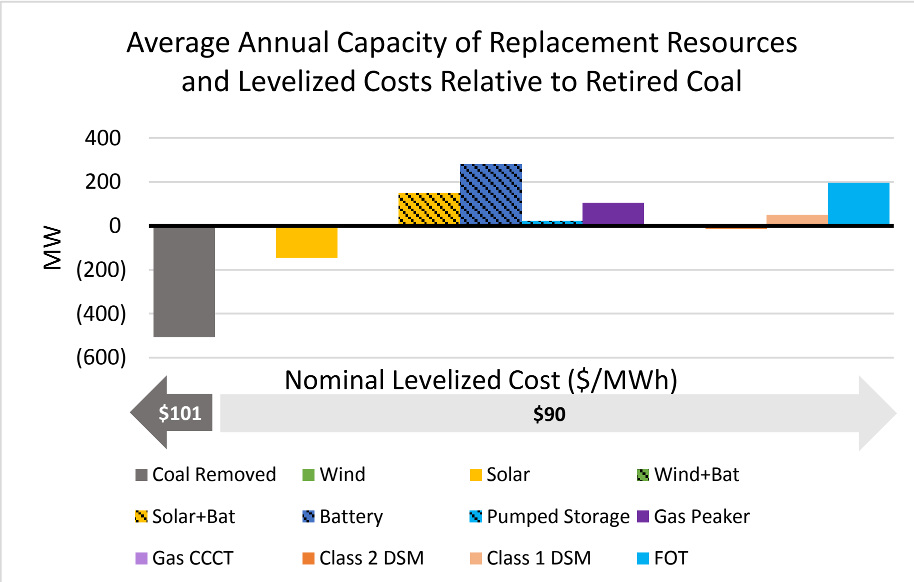
Case C-37 (NT1, JB1, HY1)



- The nominal levelized cost of retired coal resources is $16.00/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 72.4% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 29.1% to achieve break-even economics with the replacement portfolio.

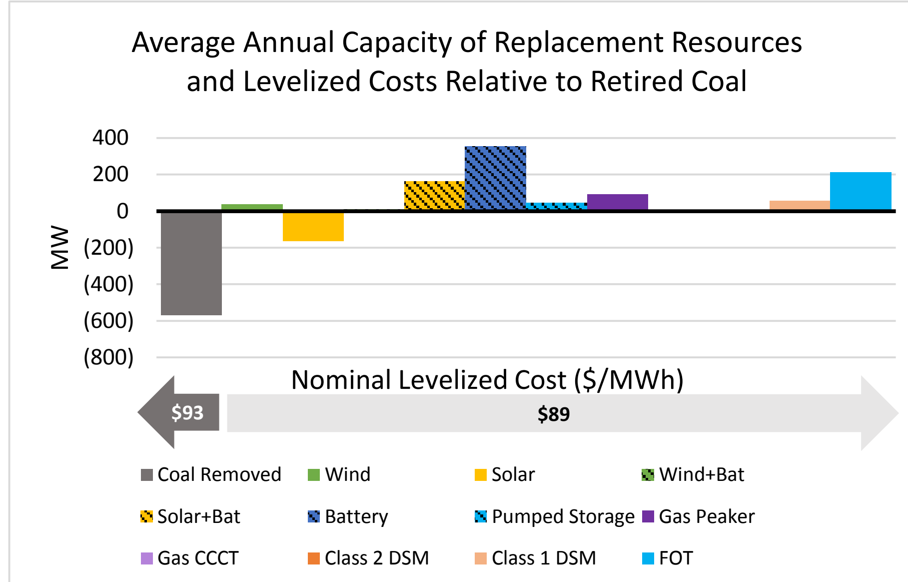
Stacked Cases C-38 and C-39

Case C-38 (NT1-2, JB1, HY1)



- The nominal levelized cost of retired coal resources is $11.03/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 96.0% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 20.0% to achieve break-even economics with the replacement portfolio.

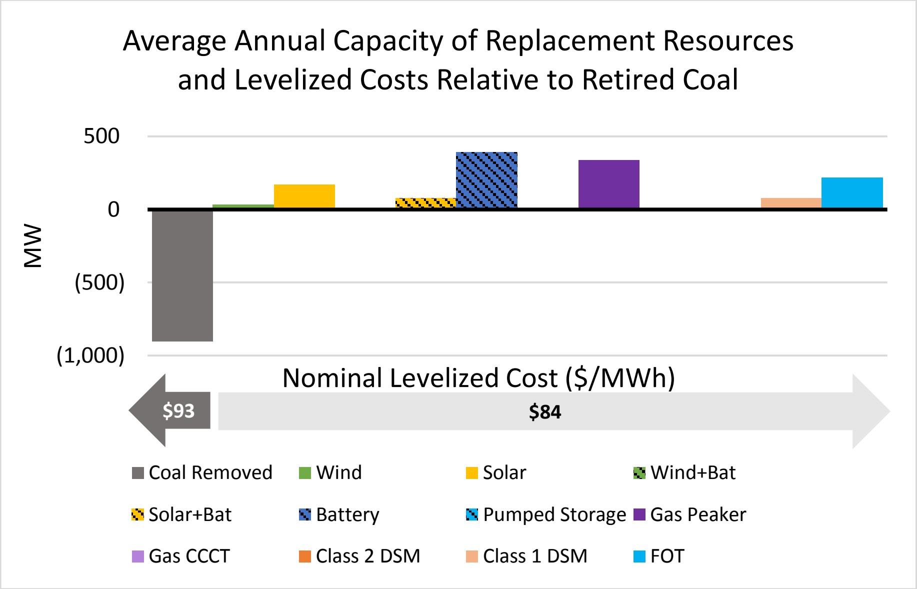
Case C-39 (NT1-2, JB1, HY1, CG2)



- The nominal levelized cost of retired coal resources is $3.67/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 346.9% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 7.6% to achieve break-even economics with the replacement portfolio.

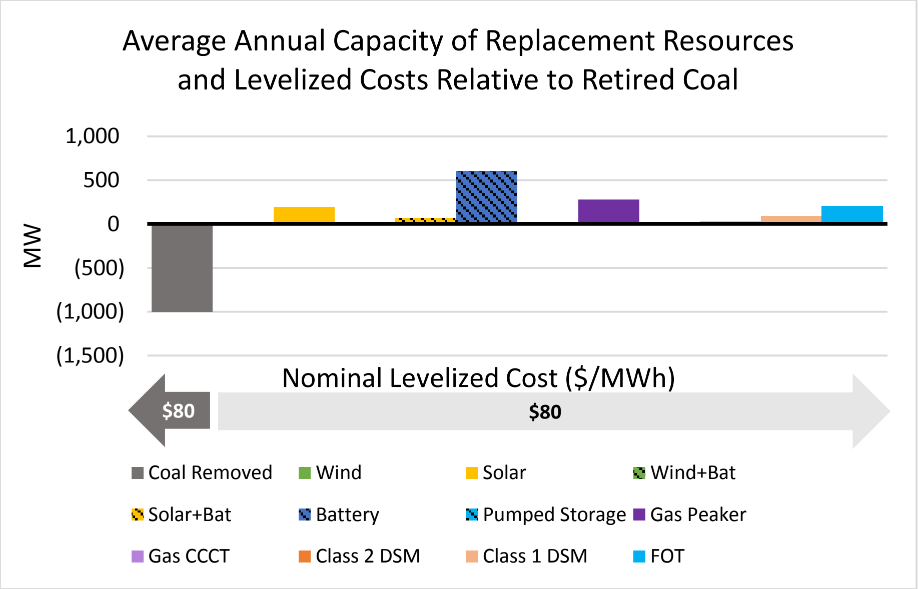
Stacked Cases C-40 and C-41

Case C-40 (NT1-2, JB1-2, HY1, CG2)



- The nominal levelized cost of retired coal resources is \$8.94/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 132.4% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 18.1% to achieve break-even economics with the replacement portfolio.

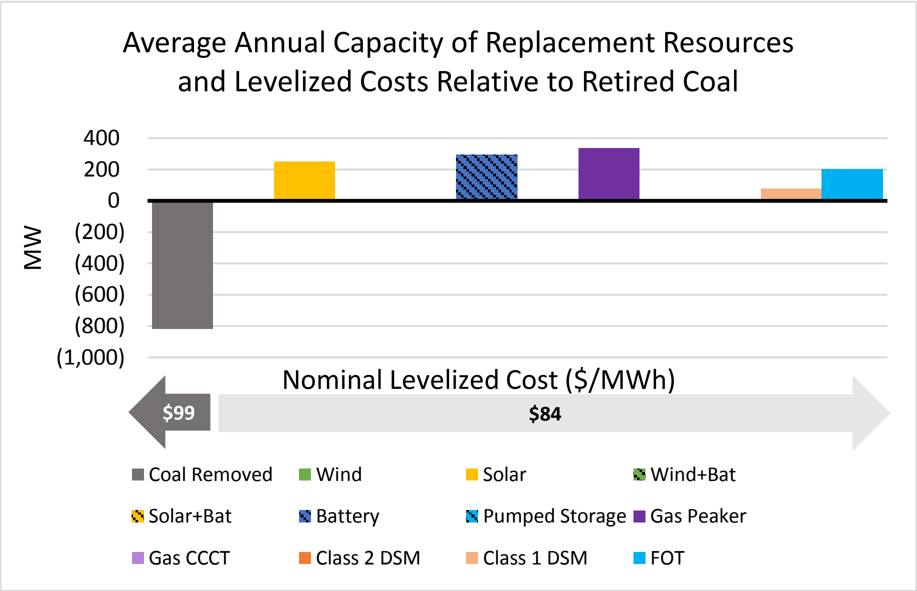
Case C-41 (NT1-2, JB1-2, HY1-2, CG1-2, DJ3)



- The nominal levelized cost of retired coal resources is \$0.43/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 2,525.4% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 1.0% to achieve break-even economics with the replacement portfolio.

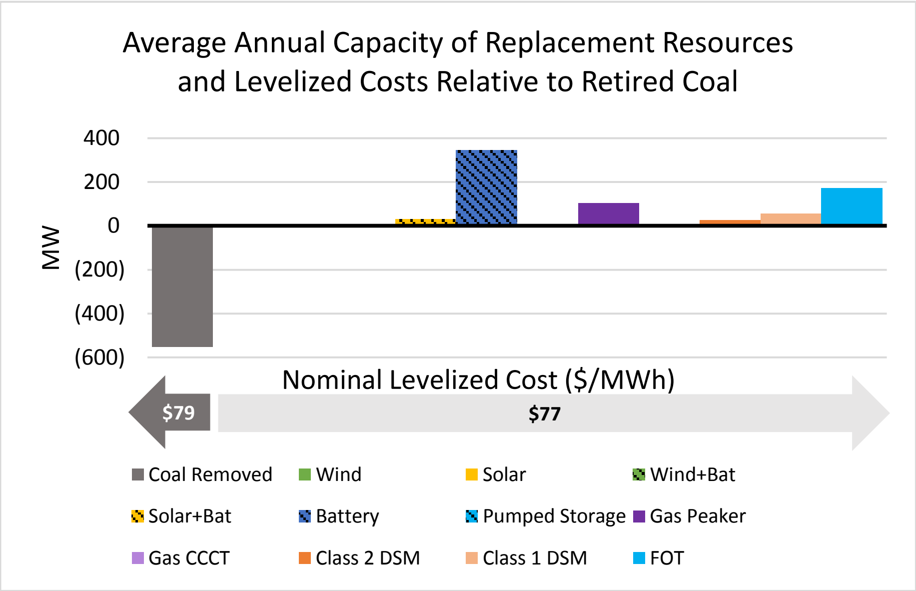
Stacked Cases C-42 and C-43

Case C-42 (NT1-2, JB1-2)



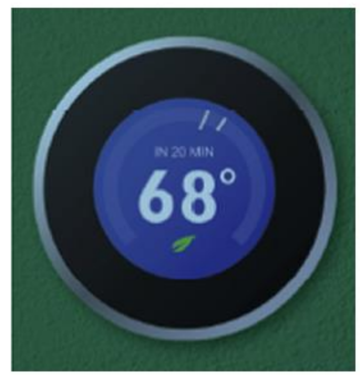
- The nominal levelized cost of retired coal resources is $14.21/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 77.0% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 26.3% to achieve break-even economics with the replacement portfolio.

Case C-43 (NT1-2, JB1, DJ3)

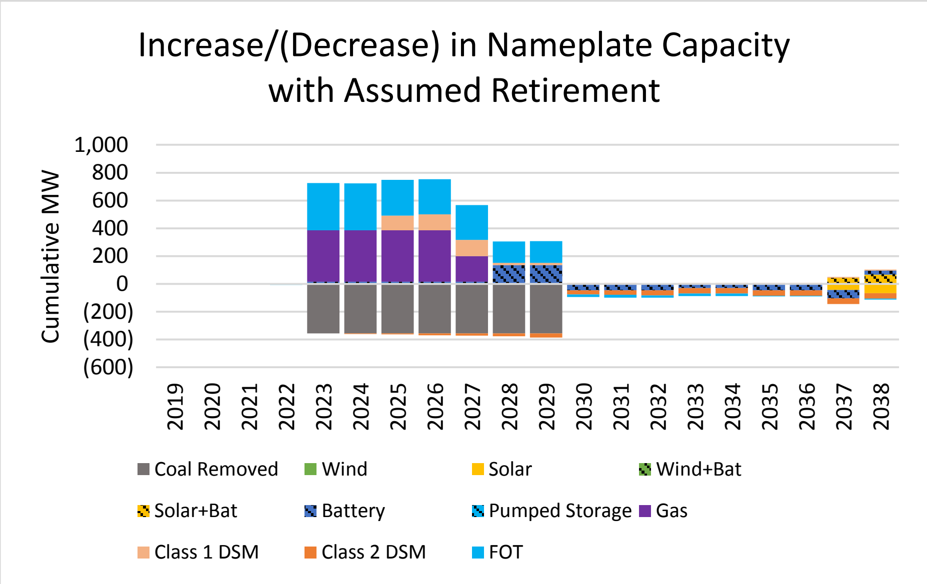


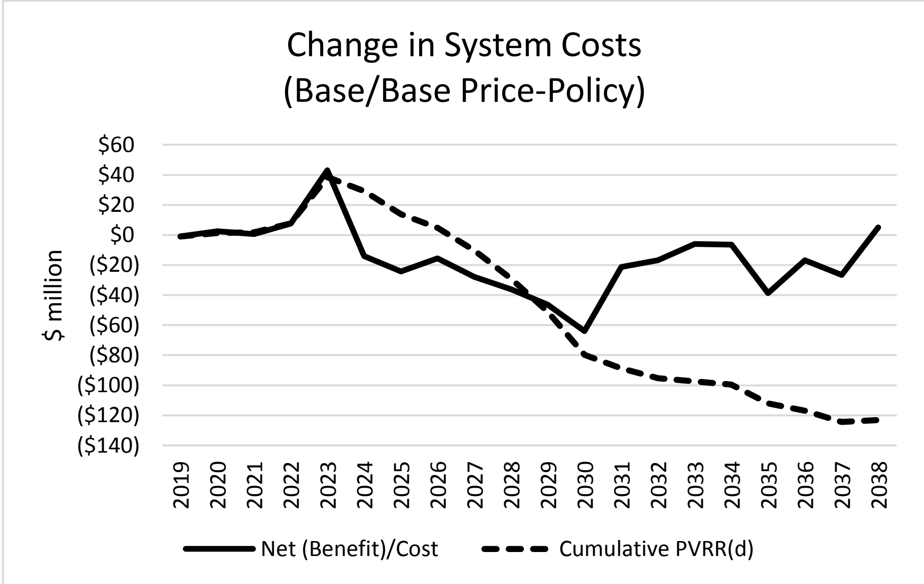
- The nominal levelized cost of retired coal resources is $1.97/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 432.0% of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 4.8% to achieve break-even economics with the replacement portfolio.

Stacked-Retirement Detailed Results



Stacked Case C-34 Overview (NT1-2)



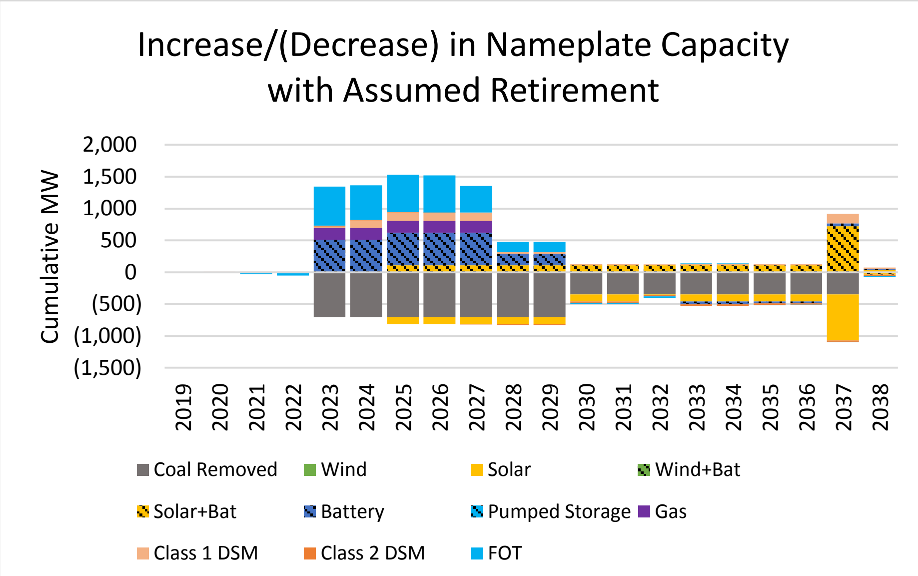


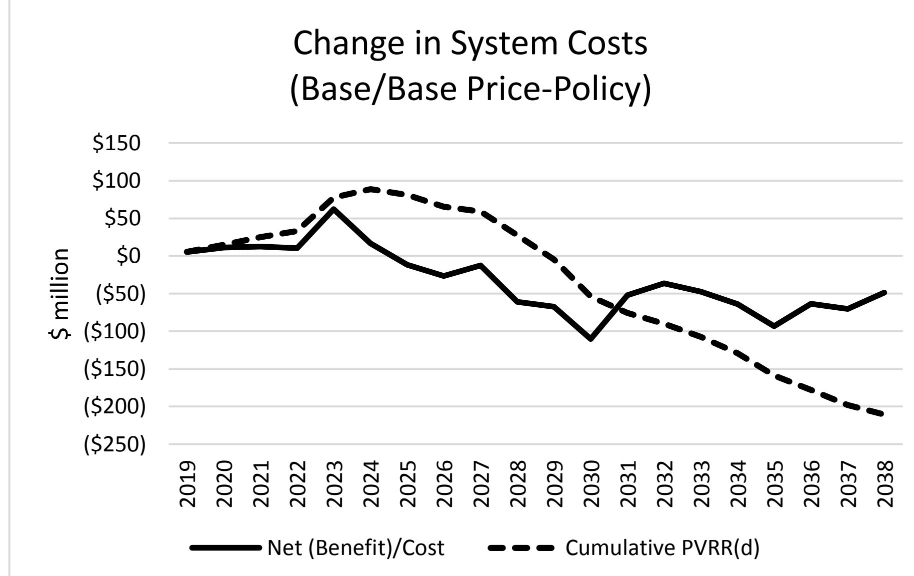
- No change in network transmission upgrades associated with changes to proxy resources in the portfolio relative to the Benchmark Case.

Stacked Case C-34 Detail (NT1-2)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($138)	($32.87)
Inc. Capital Rev. Req. and Fixed O&M	($206)	($49.06)
Variable O&M	$0	$0.00
Emissions	($42)	($9.95)
Decommissioning	$8	$1.82
Total Net Cost Savings from Retired Unit	($378)	($90.07)
Net Replacement Costs		
Fuel	$145	$34.42
Inc. Capital Rev. Req. and Fixed O&M	$124	$29.58
Variable O&M	$18	$4.21
Emissions	$19	$4.49
Demand-Side Management	($71)	($16.82)
Long-Term Contracts	$2	$0.59
Market Purchases	$10	$2.34
Market Sales	$7	$1.76
Reserve/Energy Deficiencies	$1	$0.18
Transmission Upgrades	$0	$0.00
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$255	$60.74
Net (Benefit)/Cost of Assumed Early Retirement	($123)	($29.33)

Stacked Case C-35 Overview (NT1-2, JB1)





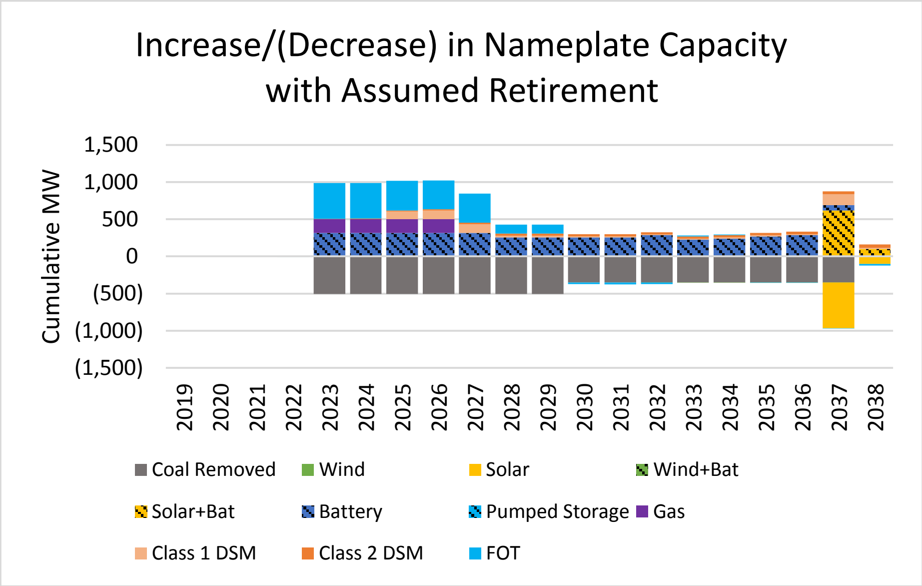
Change in Transmission Upgrades

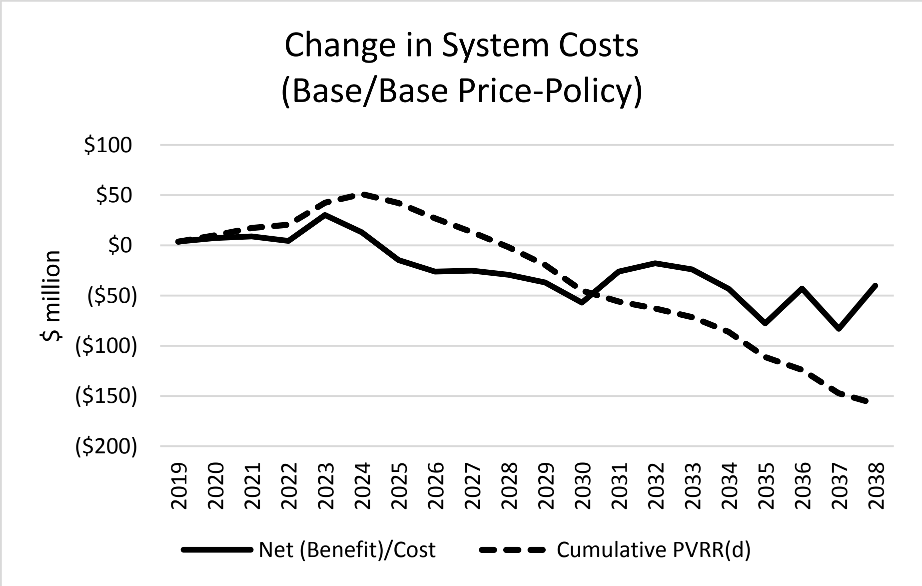
Change in Year	Resource Location	From	To	ATC	Max Interconnection	Change in Nominal Capital ($m)
Accelerated from 2033 to 2032	Walla Walla WA	Walla Walla WA	Yakima WA	200	450	($1.7)
					Total	($1.7)

Stacked Case C-35 Detail (NT1-2, JB1)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($334)	($32.81)
Inc. Capital Rev. Req. and Fixed O&M	($569)	($55.92)
Variable O&M	($3)	($0.28)
Emissions	($143)	($14.01)
Decommissioning	$13	$1.27
Total Net Cost Savings from Retired Unit	($1,035)	($101.76)
Net Replacement Costs		
Fuel	$265	$26.07
Inc. Capital Rev. Req. and Fixed O&M	$353	$34.74
Variable O&M	$17	$1.67
Emissions	$46	$4.51
Demand-Side Management	($39)	($3.88)
Long-Term Contracts	$38	$3.78
Market Purchases	$70	$6.84
Market Sales	$68	$6.64
Reserve/Energy Deficiencies	$5	$0.53
Transmission Upgrades	$2	$0.15
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$824	$81.05
Net (Benefit)/Cost of Assumed Early Retirement	($211)	($20.71)

Stacked Case C-36 Overview (NT1, JB1)



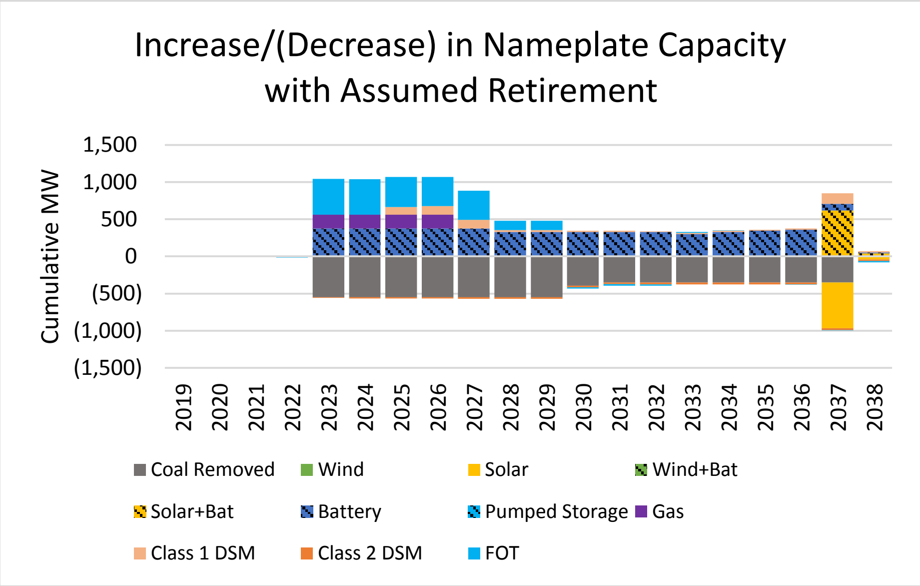


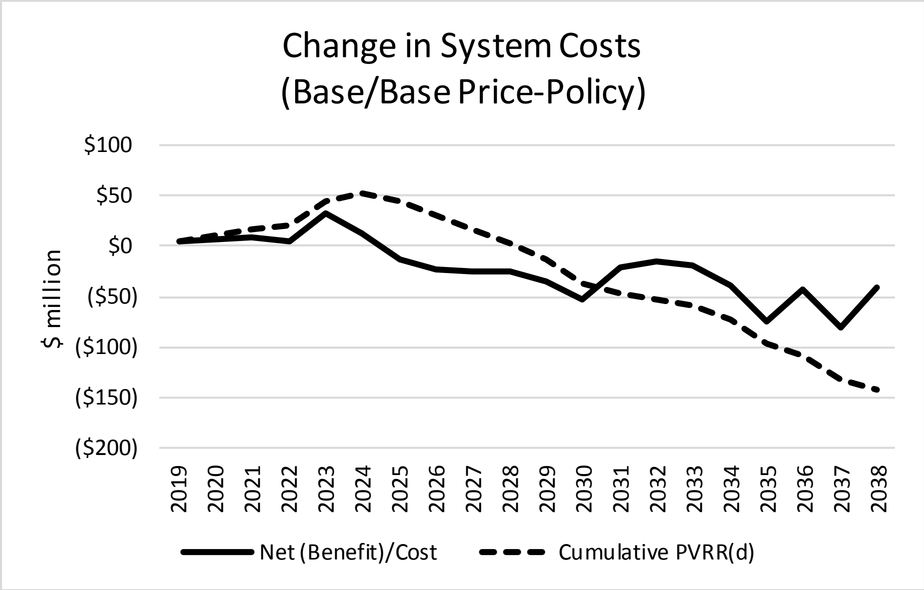
- No change in network transmission upgrades associated with changes to proxy resources in the portfolio relative to the Benchmark Case.

Stacked Case C-36 Detail (NT1, JB1)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($265)	($32.16)
Inc. Capital Rev. Req. and Fixed O&M	($461)	($55.93)
Variable O&M	($3)	($0.35)
Emissions	($122)	($14.80)
Decommissioning	$9	$1.04
Total Net Cost Savings from Retired Unit	($842)	($102.20)
Net Replacement Costs		
Fuel	$166	$20.14
Inc. Capital Rev. Req. and Fixed O&M	$354	$43.00
Variable O&M	$7	$0.85
Emissions	$24	$2.94
Demand-Side Management	($6)	($0.75)
Long-Term Contracts	$37	$4.50
Market Purchases	$50	$6.08
Market Sales	$49	$5.99
Reserve/Energy Deficiencies	$3	$0.31
Transmission Upgrades	$0	$0.00
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$685	$83.05
Net (Benefit)/Cost of Assumed Early Retirement	($158)	($19.15)

Stacked Case C-37 Overview (NT1, JB1, HY1)





- No change in network transmission upgrades associated with changes to proxy resources in the portfolio relative to the Benchmark Case.

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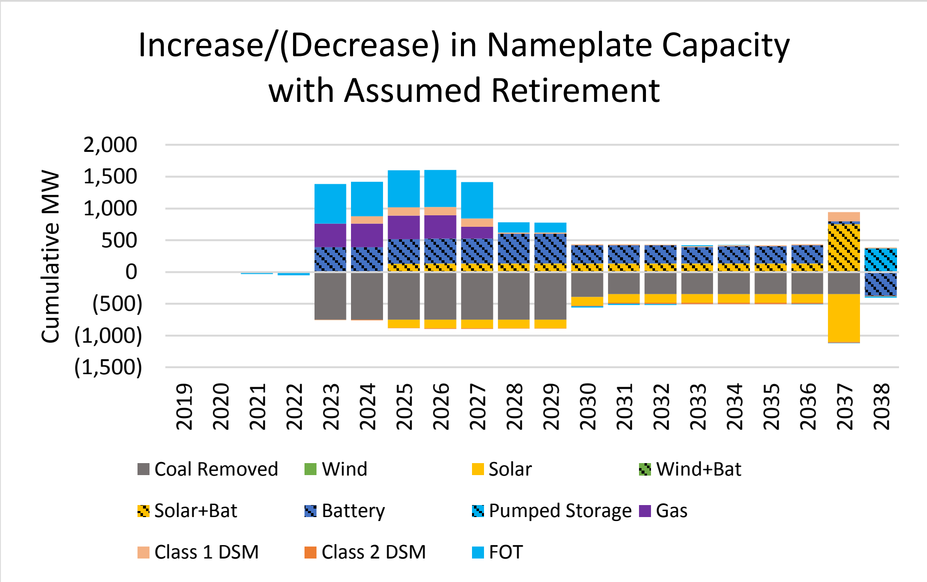
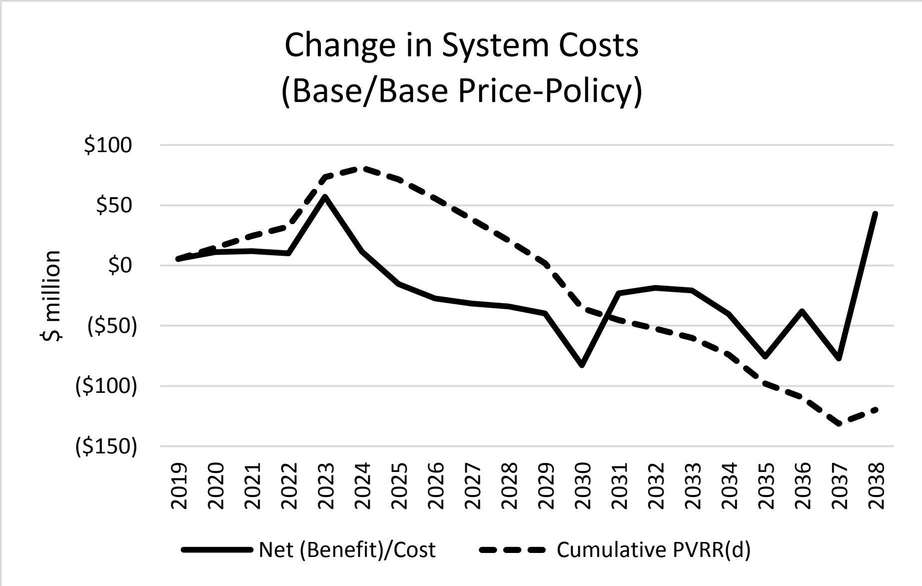
Stacked Case C-37 Detail (NT1, JB1, HY1)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($286)	($32.00)
Inc. Capital Rev. Req. and Fixed O&M	($492)	($55.00)
Variable O&M	($3)	($0.32)
Emissions	($131)	($14.70)
Decommissioning	$9	$0.97
Total Net Cost Savings from Retired Unit	($903)	($101.06)
Net Replacement Costs		
Fuel	$179	$20.04
Inc. Capital Rev. Req. and Fixed O&M	$415	$46.48
Variable O&M	$8	$0.91
Emissions	$28	$3.12
Demand-Side Management	($69)	($7.72)
Long-Term Contracts	$45	$5.04
Market Purchases	$58	$6.49
Market Sales	$92	$10.32
Reserve/Energy Deficiencies	$3	$0.38
Transmission Upgrades	$0	$0.00
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$760	$85.05
Net (Benefit)/Cost of Assumed Early Retirement	($143)	($16.00)

Stacked Case C-38 Overview
(NT1-2, JB1, HY1)



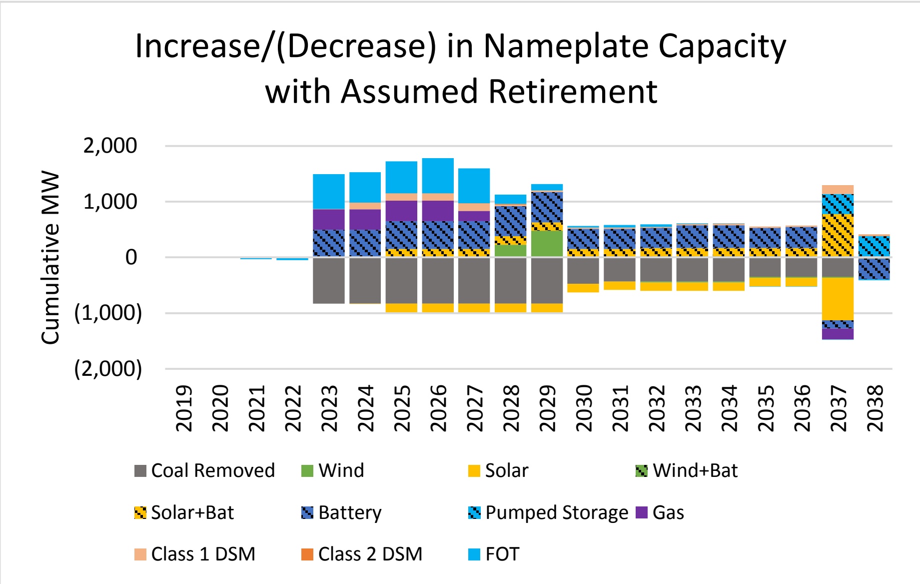


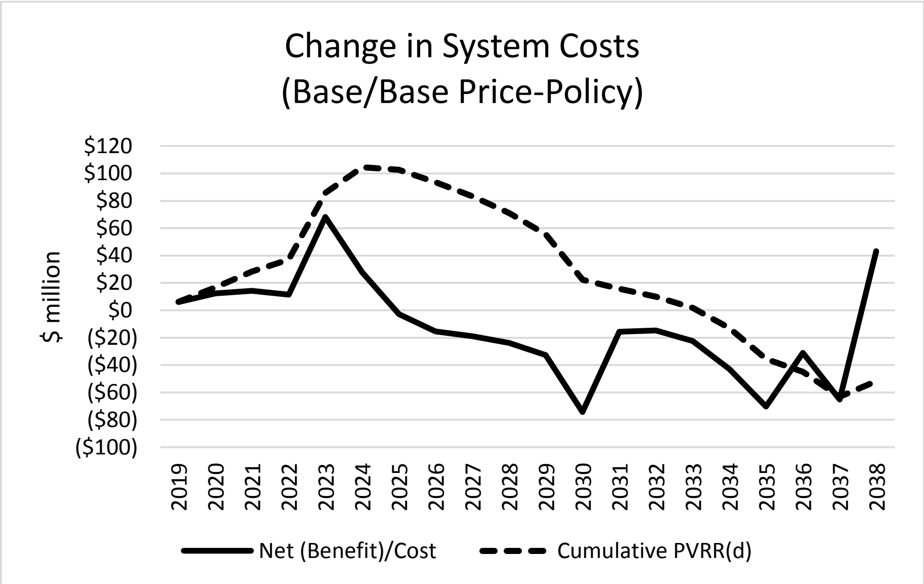
- No change in network transmission upgrades associated with changes to proxy resources in the portfolio relative to the Benchmark Case.

Stacked Case C-38 Detail (NT1-2, JB1, HY1)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($354)	($32.64)
Inc. Capital Rev. Req. and Fixed O&M	($599)	($55.18)
Variable O&M	($3)	($0.26)
Emissions	($152)	($13.98)
Decommissioning	$13	$1.19
Total Net Cost Savings from Retired Unit	($1,096)	($100.87)
Net Replacement Costs		
Fuel	$257	$23.70
Inc. Capital Rev. Req. and Fixed O&M	$490	$45.08
Variable O&M	$21	$1.94
Emissions	$37	$3.39
Demand-Side Management	($52)	($4.79)
Long-Term Contracts	$49	$4.55
Market Purchases	$65	$6.01
Market Sales	$102	$9.38
Reserve/Energy Deficiencies	$6	$0.58
Transmission Upgrades	$0	$0.00
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$976	$89.84
Net (Benefit)/Cost of Assumed Early Retirement	($120)	($11.03)

Stacked Case C-39 Overview (NT1-2, JB1, HY1, CG2)





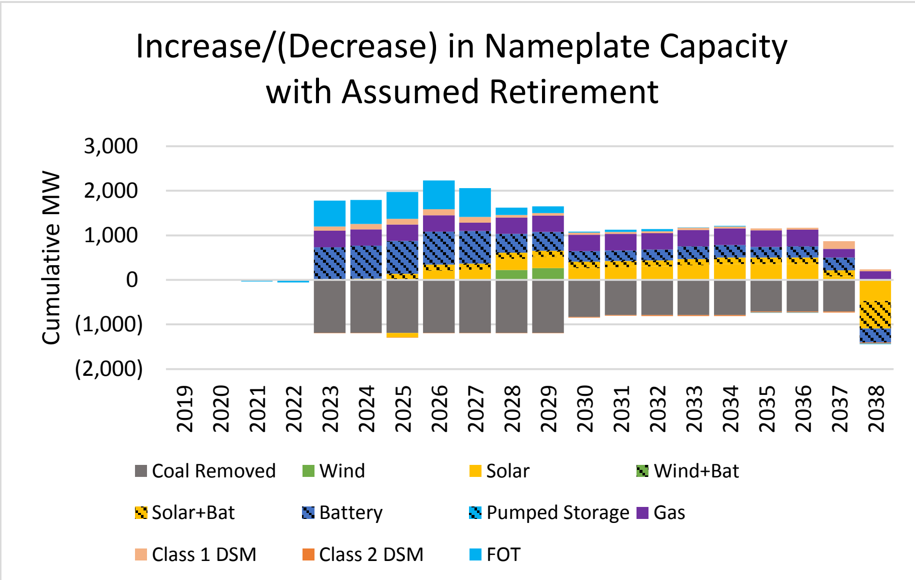
Change in Transmission Upgrades

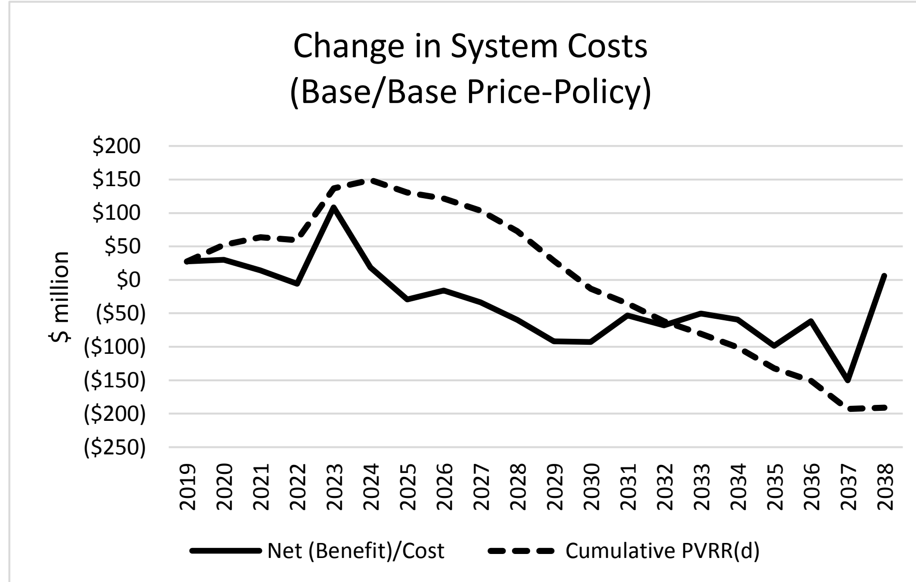
Change in Year	Resource Location	From	To	ATC	Max Interconnection	Change in Nominal Capital ($m)
Accelerated from 2030 to 2029	Goshen ID	Goshen ID	UT North	800	800	($5.7)
					Total	($5.7)

Stacked Case C-39 Detail (NT1-2, JB1, HY1, CG2)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($437)	($30.98)
Inc. Capital Rev. Req. and Fixed O&M	($683)	($48.35)
Variable O&M	($3)	($0.20)
Emissions	($197)	($13.95)
Decommissioning	$13	$0.94
Total Net Cost Savings from Retired Unit	($1,306)	($92.54)
Net Replacement Costs		
Fuel	$203	$14.42
Inc. Capital Rev. Req. and Fixed O&M	$643	$45.59
Variable O&M	$15	$1.06
Emissions	$17	$1.20
Demand-Side Management	($21)	($1.52)
Long-Term Contracts	$64	$4.55
Market Purchases	$58	$4.10
Market Sales	$264	$18.67
Reserve/Energy Deficiencies	$5	$0.36
Transmission Upgrades	$6	$0.44
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$1,254	$88.87
Net (Benefit)/Cost of Assumed Early Retirement	($52)	($3.67)

Stacked Case C-40 Overview (NT1-2, JB1-2, HY1, CG2)





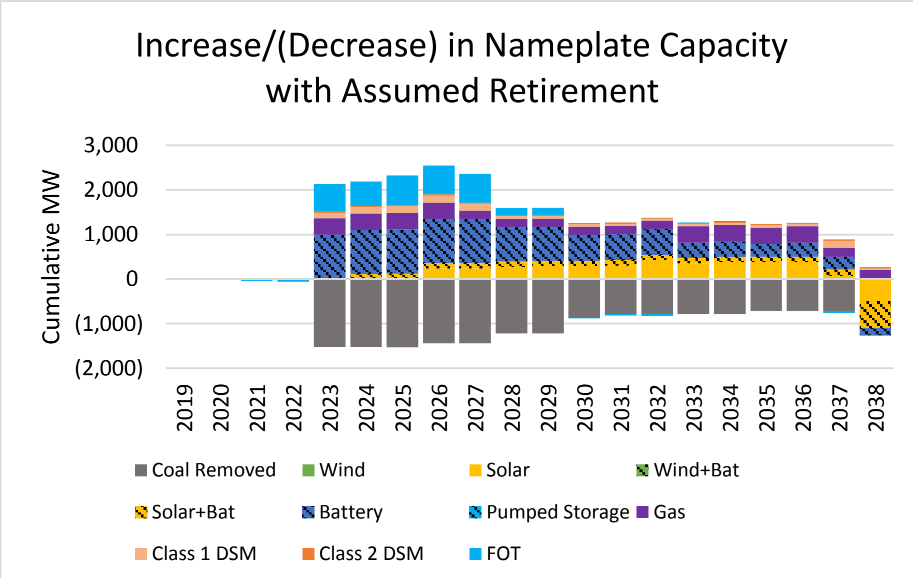
Change in Transmission Upgrades

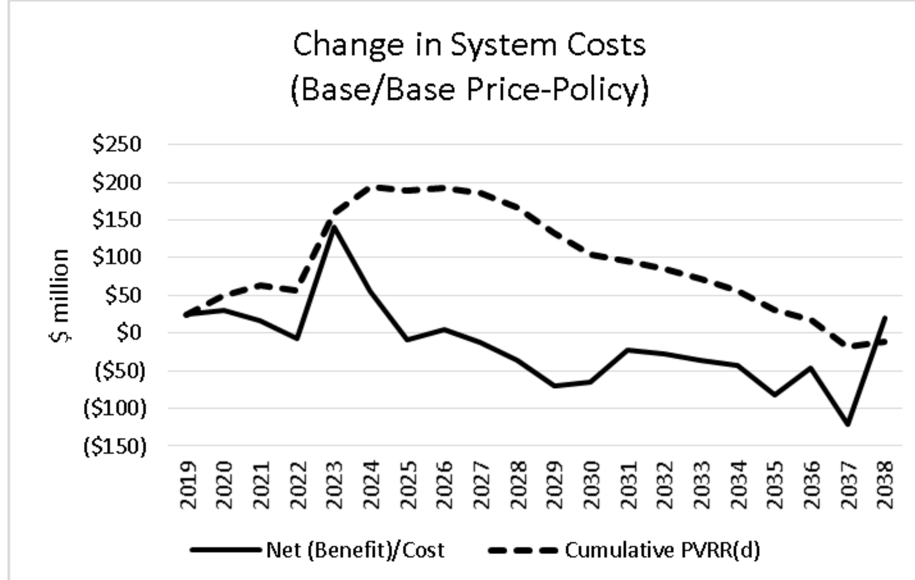
Change in Year	Resource Location	From	To	ATC	Max Interconnection	Change in Nominal Capital ($m)
Accelerated from 2037 to 2028	SW WY	SW WY	SW WY	0	500	($7.2)
Accelerated from 2030 to 2029	Goshen ID	Goshen ID	UT North	800	800	($5.7)
					Total	($12.9)

Stacked Case C-40 Detail (NT1-2, JB1-2, HY1, CG2)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($638)	($29.85)
Inc. Capital Rev. Req. and Fixed O&M	($1,058)	($49.51)
Variable O&M	($6)	($0.30)
Emissions	($308)	($14.43)
Decommissioning	$19	$0.87
Total Net Cost Savings from Retired Unit	($1,992)	($93.23)
Net Replacement Costs		
Fuel	$431	$20.19
Inc. Capital Rev. Req. and Fixed O&M	$845	$39.55
Variable O&M	$50	$2.33
Emissions	$55	$2.59
Demand-Side Management	($51)	($2.38)
Long-Term Contracts	$67	$3.15
Market Purchases	$93	$4.37
Market Sales	$291	$13.61
Reserve/Energy Deficiencies	$6	$0.26
Transmission Upgrades	$13	$0.62
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$1,801	$84.29
Net (Benefit)/Cost of Assumed Early Retirement	($191)	($8.94)

Stacked Case C-41 Overview (NT1-2, JB1-2, HY1-2, CG 1-2, DJ3)





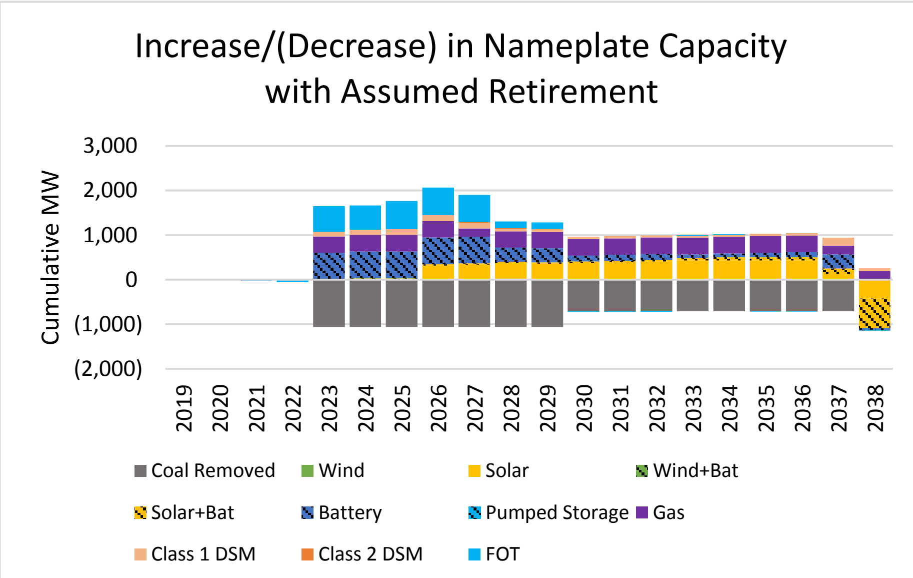
Change in Transmission Upgrades

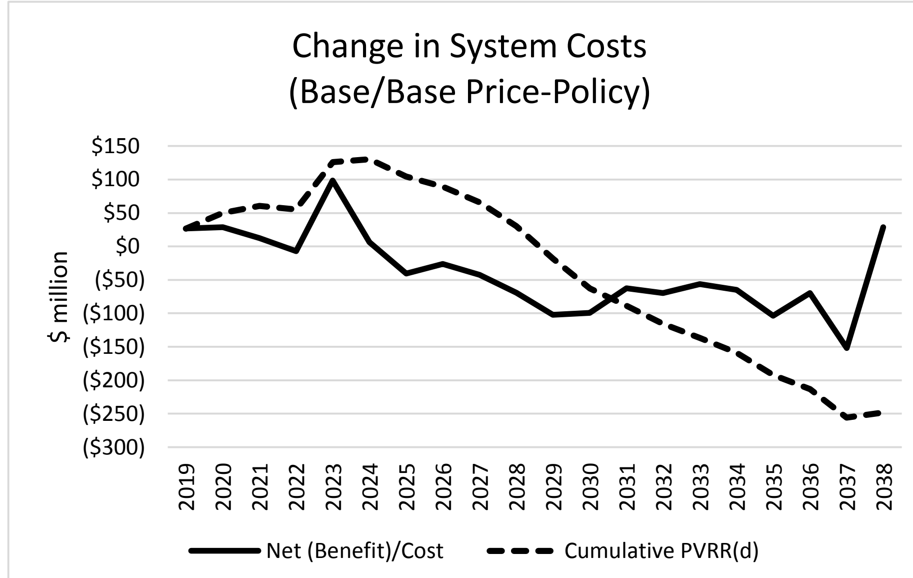
Change in Year	Resource Location	From	To	ATC	Max Interconnection	Change in Nominal Capital ($m)
Accelerated from 2037 to 2028	SW WY	SW WY	SW WY	0	500	($7.2)
Accelerated from 2033 to 2032	Walla Walla WA	Walla Walla WA	Yakima WA	200	450	($1.7)
					Total	($8.9)

Stacked Case C-41 Detail
(NT1-2, JB1-2, HY1-2, CG1-2, DJ3)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($761)	($26.71)
Inc. Capital Rev. Req. and Fixed O&M	($1,180)	($41.43)
Variable O&M	($6)	($0.23)
Emissions	($361)	($12.66)
Decommissioning	$20	$0.70
Total Net Cost Savings from Retired Unit	($2,288)	($80.33)
Net Replacement Costs		
Fuel	$519	$18.24
Inc. Capital Rev. Req. and Fixed O&M	$1,037	$36.41
Variable O&M	$47	$1.65
Emissions	$52	$1.83
Demand-Side Management	($16)	($0.55)
Long-Term Contracts	$77	$2.71
Market Purchases	$129	$4.52
Market Sales	$414	$14.53
Reserve/Energy Deficiencies	$8	$0.28
Transmission Upgrades	$8	$0.30
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$2,276	$79.90
Net (Benefit)/Cost of Assumed Early Retirement	($12)	($0.43)

Stacked Case C-42 Overview (NT1-2, JB1-2)





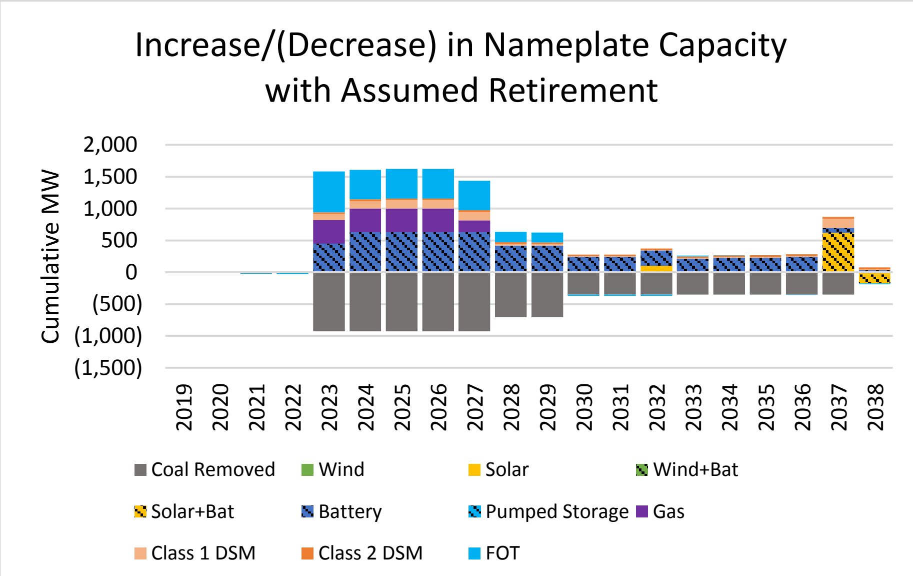
Change in Transmission Upgrades

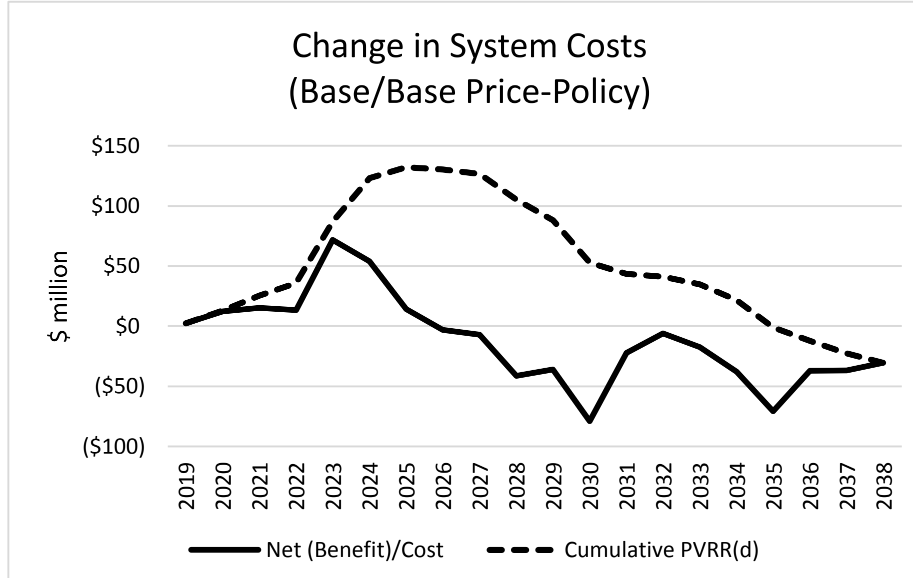
Change in Year	Resource Location	From	To	ATC	Max Interconnection	Change in Nominal Capital ($m)
Accelerated from 2037 to 2028	SW WY	SW WY	SW WY	0	500	($7.2)
					Total	($7.2)

Stacked Case C-42 Detail (NT1-2, JB1-2)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($535)	($30.65)
Inc. Capital Rev. Req. and Fixed O&M	($944)	($54.07)
Variable O&M	($6)	($0.37)
Emissions	($254)	($14.55)
Decommissioning	$18	$1.04
Total Net Cost Savings from Retired Unit	($1,722)	($98.59)
Net Replacement Costs		
Fuel	$452	$25.88
Inc. Capital Rev. Req. and Fixed O&M	$705	$40.34
Variable O&M	$52	$2.96
Emissions	$63	$3.60
Demand-Side Management	($26)	($1.48)
Long-Term Contracts	$49	$2.78
Market Purchases	$89	$5.09
Market Sales	$80	$4.60
Reserve/Energy Deficiencies	$4	$0.20
Transmission Upgrades	$7	$0.40
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$1,474	$84.38
Net (Benefit)/Cost of Assumed Early Retirement	($248)	($14.21)

Stacked Case C-43 Overview (NT1-2, JB1, DJ3)





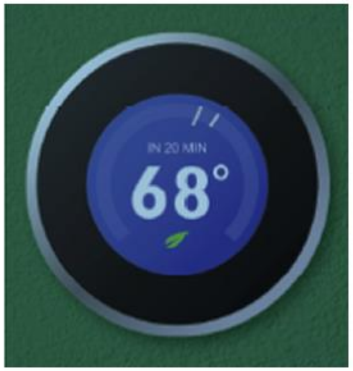
Change in Transmission Upgrades

Change in Year	Resource Location	From	To	ATC	Max Interconnection	Change in Nominal Capital ($m)
Accelerated from 2033 to 2032	Walla Walla WA	Walla Walla WA	Yakima WA	200	450	($1.7)
					Total	($1.7)

Stacked Case C-43 Detail (NT1-2, JB1, DJ3)

Study	PVRR(d) (Benefit)/Cost of 2022 Retirement ($m)	Nom. Lev. (Benefit)/Cost of 2022 Retirement per MWh of Retired Generation ($/MWh)
Cost Savings from Retired Unit		
Fuel	($411)	($26.48)
Inc. Capital Rev. Req. and Fixed O&M	($640)	($41.30)
Variable O&M	($3)	($0.18)
Emissions	($183)	($11.82)
Decommissioning	$14	$0.91
Total Net Cost Savings from Retired Unit	($1,223)	($78.87)
Net Replacement Costs		
Fuel	$352	$22.72
Inc. Capital Rev. Req. and Fixed O&M	$572	$36.91
Variable O&M	$27	$1.71
Emissions	$51	$3.32
Demand-Side Management	$3	$0.19
Long-Term Contracts	$36	$2.32
Market Purchases	$74	$4.76
Market Sales	$70	$4.53
Reserve/Energy Deficiencies	$5	$0.33
Transmission Upgrades	$2	$0.10
Transmission Reinforcements	$0	$0.00
Total Net Replacement Cost	$1,193	$76.90
Net (Benefit)/Cost of Assumed Early Retirement	($31)	($1.97)

Reliability Assessment



Incremental Capacity from Deterministic Analyses

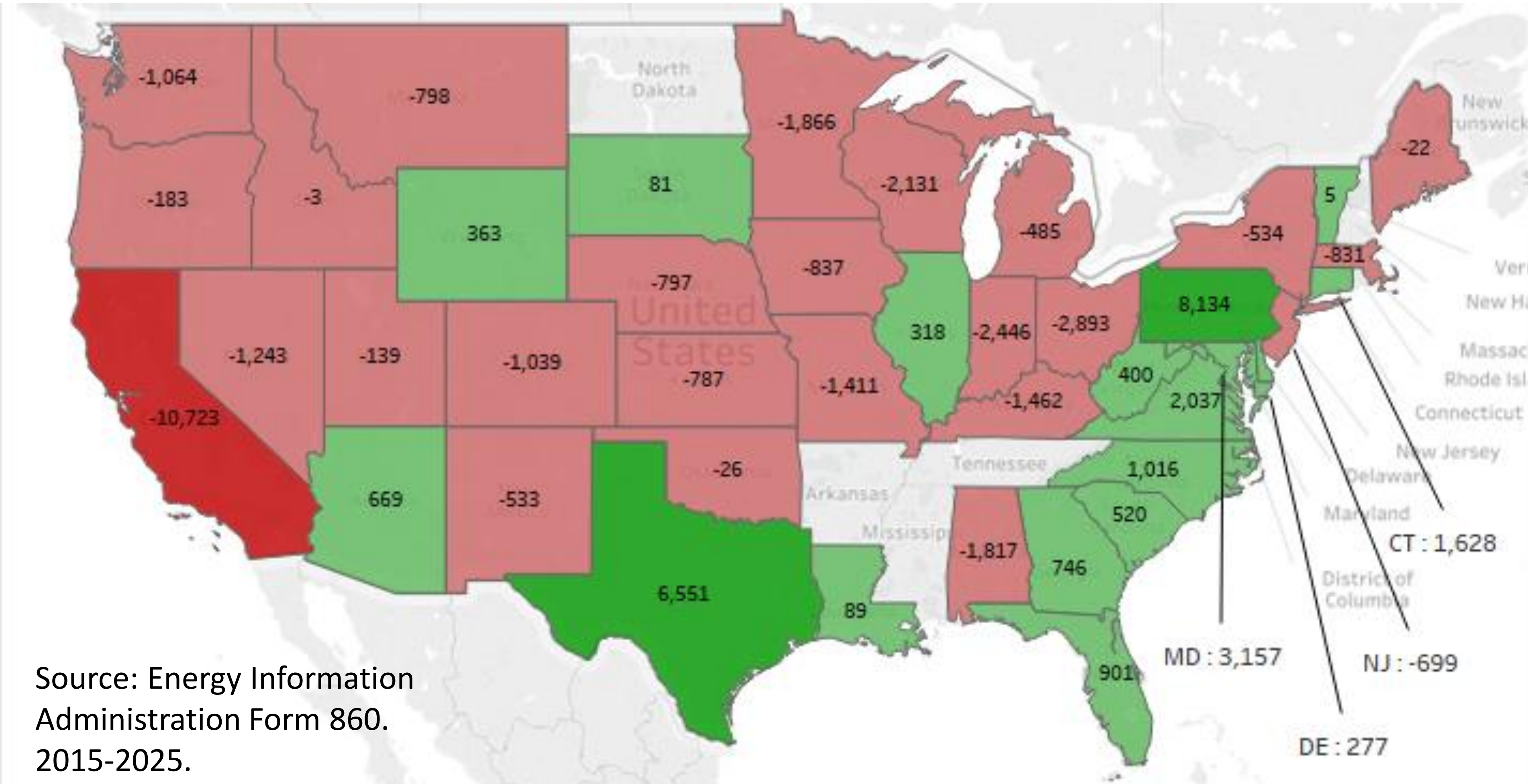
- Hourly, deterministic reliability assessment for 2023, 2030, and 2038 for each case.
- Deterministic studies reflect "perfect foresight" for the following assumptions:
    - Normal load (1-in-2 exceedance)
    - Average thermal outages in all hours
    - Average hydro conditions
    - Fixed variable energy resource generation profiles, and
    - Average market prices without electric or natural gas price volatility and physical supply risks
- Additional flexible capacity is required beyond the capacity needed to "cure" hourly shortfalls to reliably serve customers considering that the above factors vary from day to day and hour to hour and are not known in advance.

Variable Energy Resource Uncertainty

- Variable energy resources are modeled with fixed hourly generation profiles and always produce as scheduled in the model, however, in reality, there is significant uncertainty on a day-ahead, hour-ahead and real-time basis.
- The estimated total day-ahead reserve requirement, including day-ahead uncertainty for load, wind, and solar, as a percentage of load:
  - 2018 historical: carried average reserves amounting to 18% of load.
  - 2023 forecast: will need average reserves at 19% of load.
  - *These values are higher than the current planning reserve margin*.
- Short-term solutions:
  - Larger firm market purchases.
  - More thermal unit commitment and fuel nominations.
- Long-term solutions:
  - Incremental flexible capacity additions.

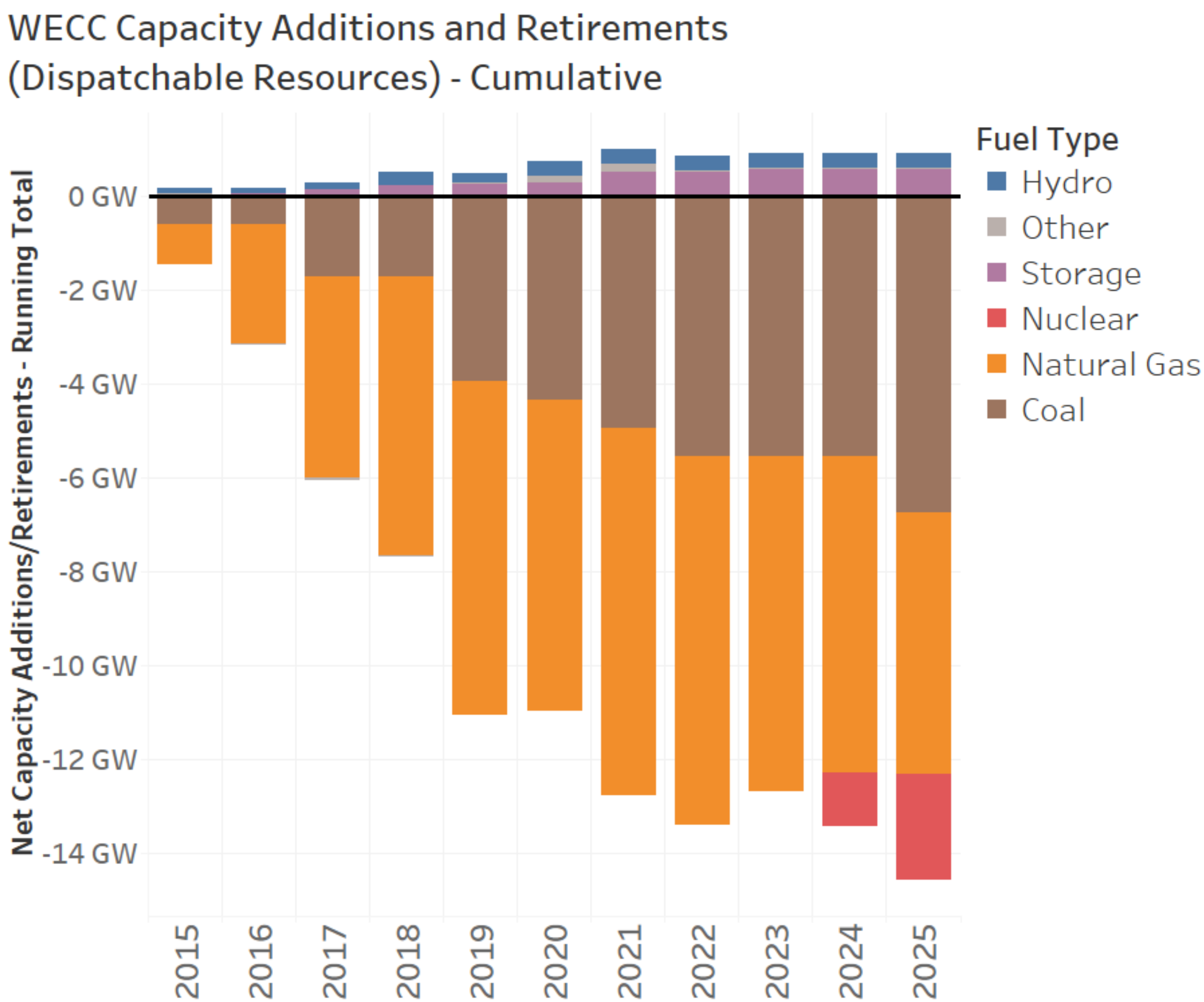
Market Supply Uncertainty

Net Capacity Additions/Retirements, excluding Wind and Solar



Source: Energy Information Administration Form 860. 2015-2025.

Market Supply Uncertainty



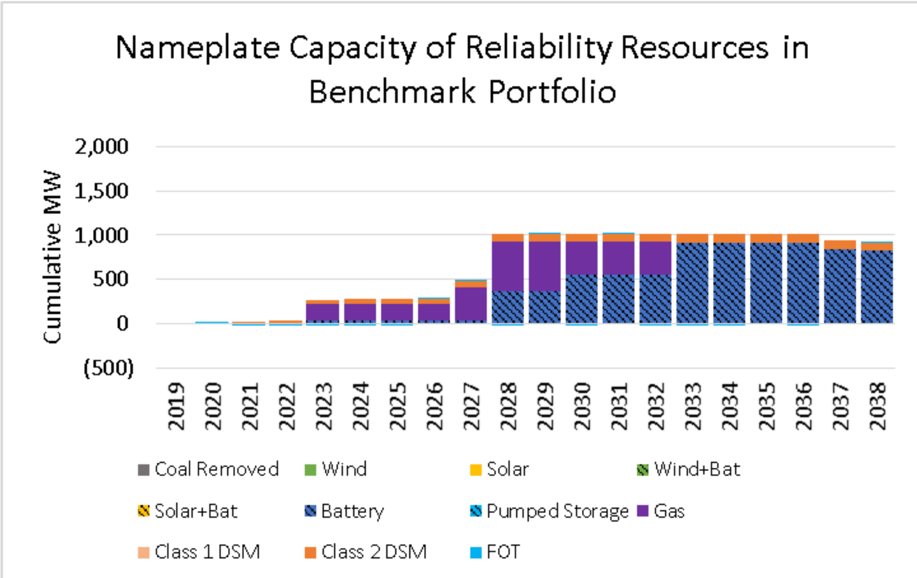
Source: Energy Information Administration Form 860.

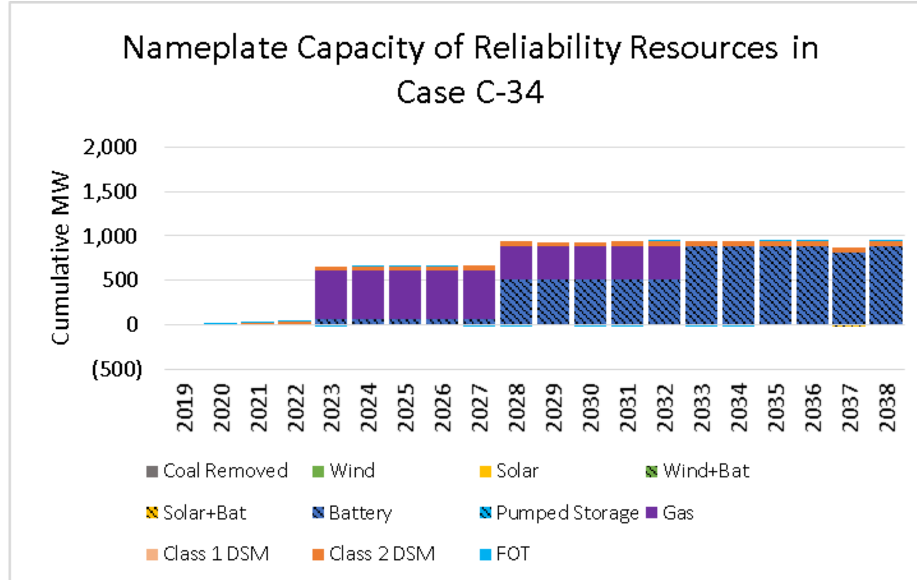
- Potential PacifiCorp retirements are not included.
- Recent events have highlighted natural gas pipeline delivery risk.
- Additional flexible capacity is required to address this market supply uncertainty.

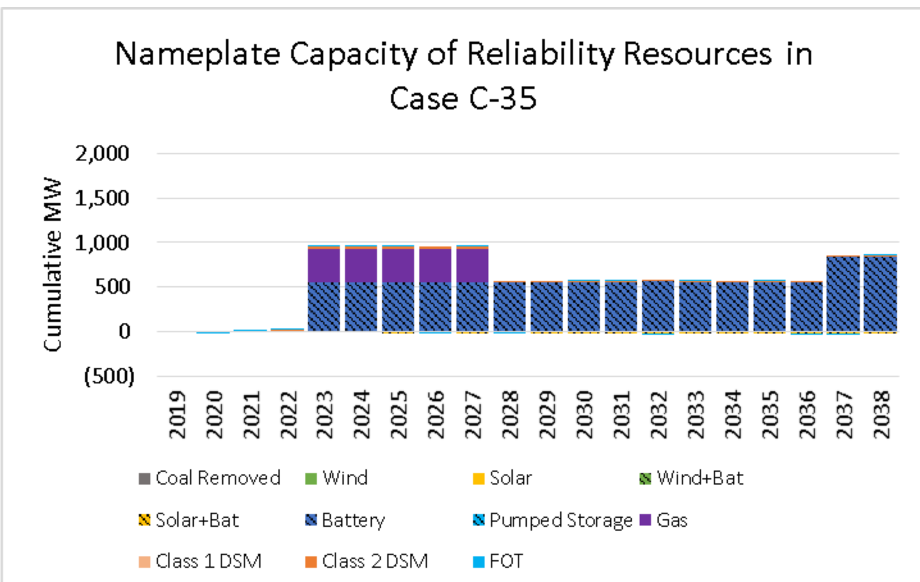
Calculating the Capacity Need from Deterministic Analyses

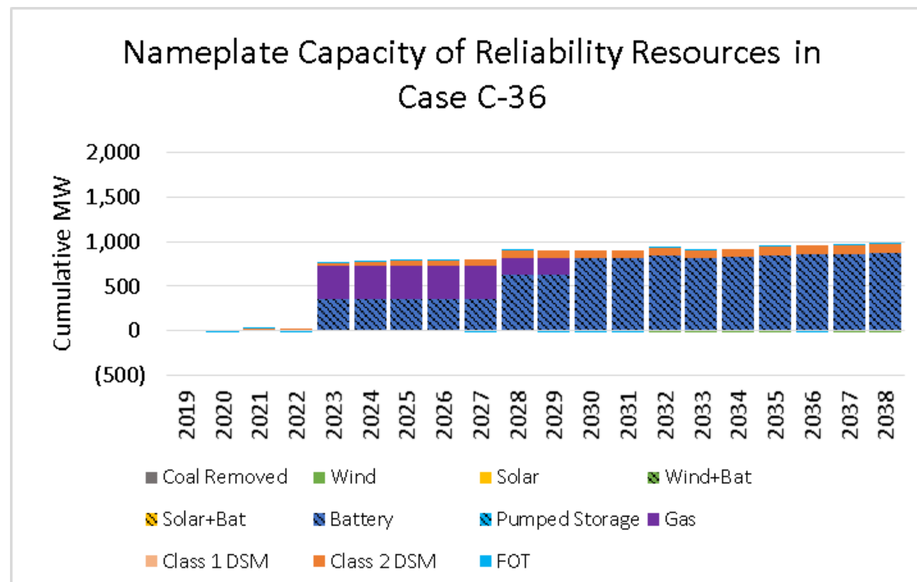
- Portfolios must meet four hourly requirements:
  - Energy, non-spinning reserve, spinning reserve, and regulation reserve
- Separate requirements for East and West, but transfers allowed up to transmission limits.
- Shortfall or unused available capacity is calculated for each hour.
- Maximum hourly shortfall (or minimum available) is identified by season.
- Given aforementioned risk factors, 500 MW of capacity in excess of hourly shortfalls identified in the deterministic studies was required.
- Allocated between East and West based on peak load by season:
  - Example 1: 200 MW required – 100 MW available = 100 MW incremental
  - Example 2: 200 MW required + 50 MW shortfall = 250 MW incremental
- Incremental requirements applied: 2023-2027 based on the 2023 deterministic study, 2028-2036 based on the 2030 deterministic study, and 2037-2038 based on the 2038 deterministic study.
- The SO model adds or accelerates the following resource types relative to the pre-reliability portfolio to meet East and West incremental requirements:
  - Batteries, Energy Efficiency, Gas Peakers, Pumped Storage
- Other resource types are locked at levels in pre-reliability portfolio.

Reliability Resources

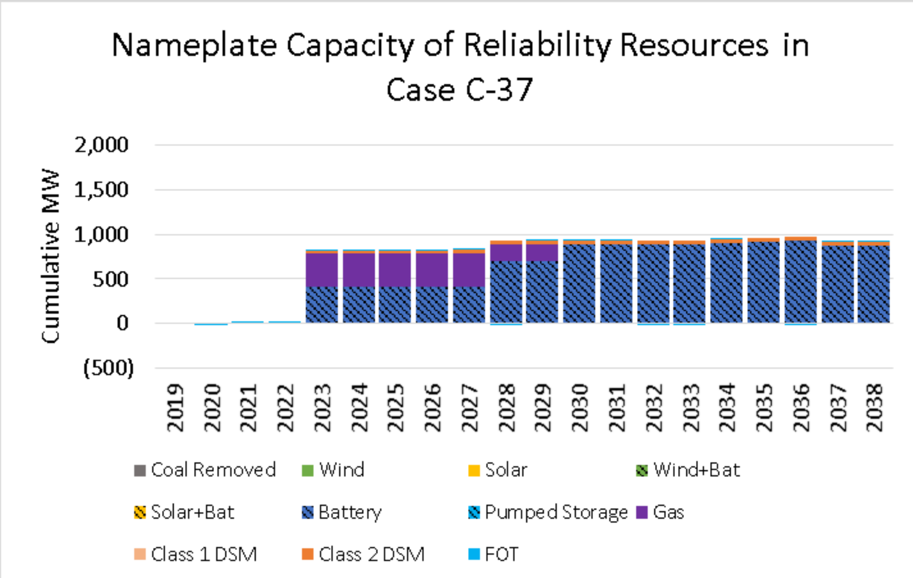


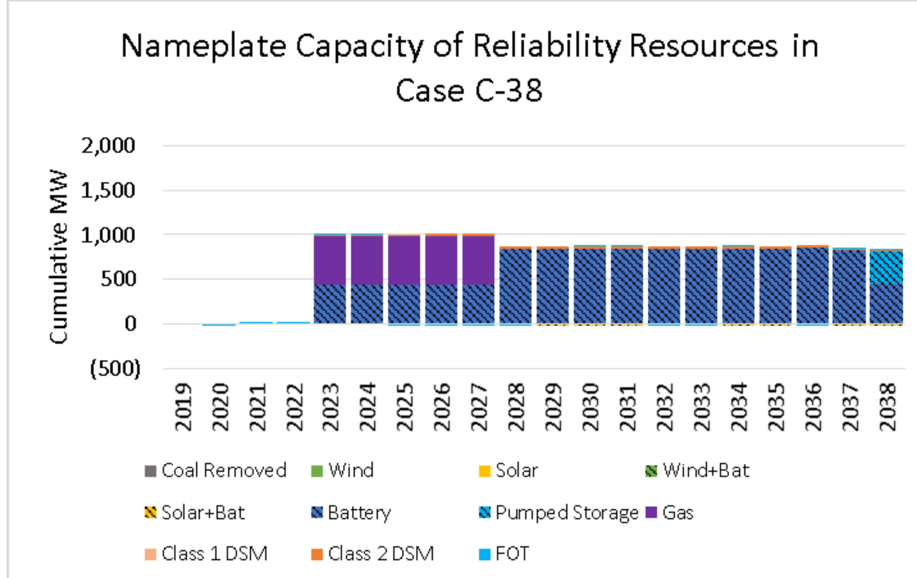


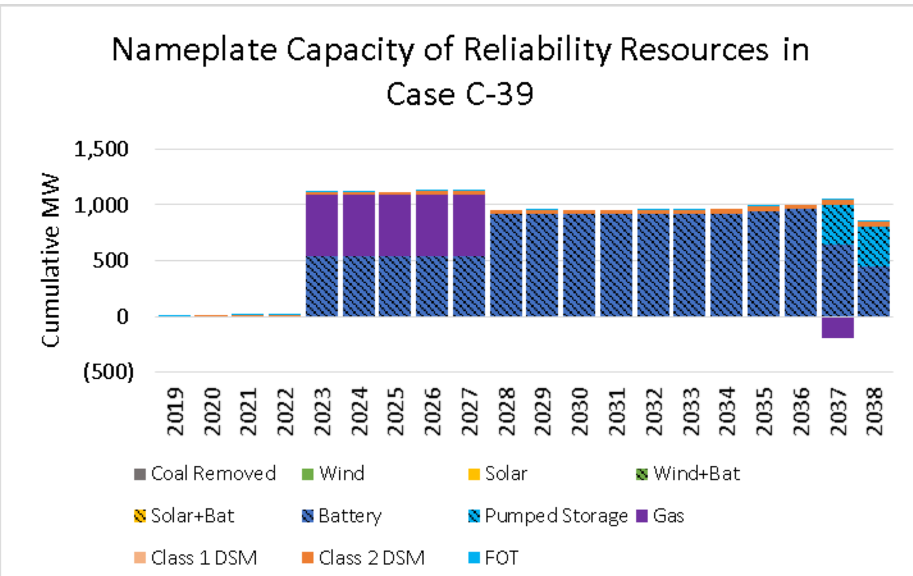


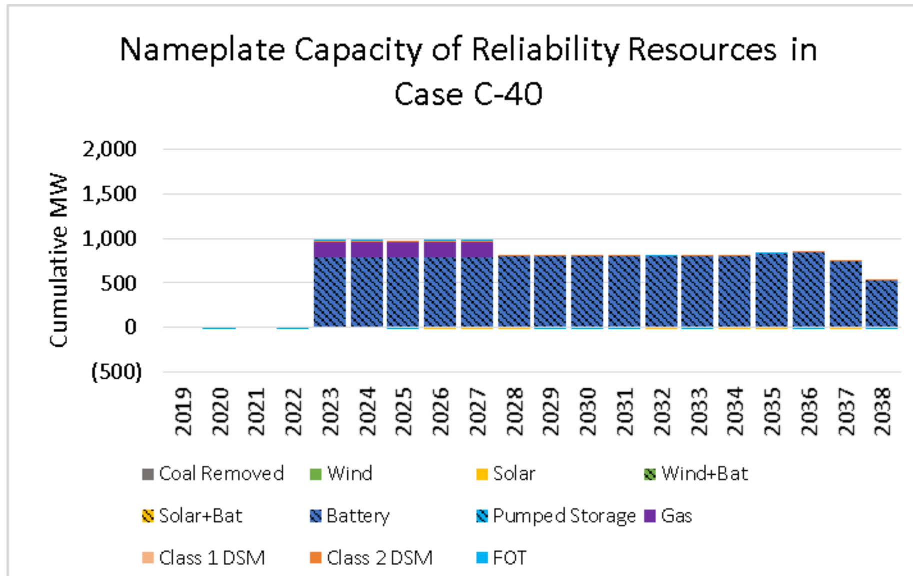


Reliability Resources (Continued)

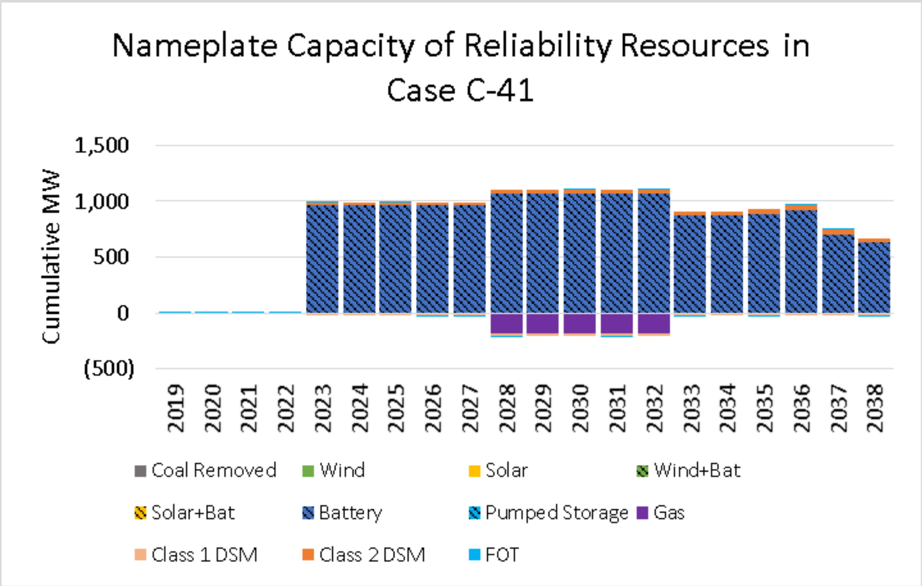


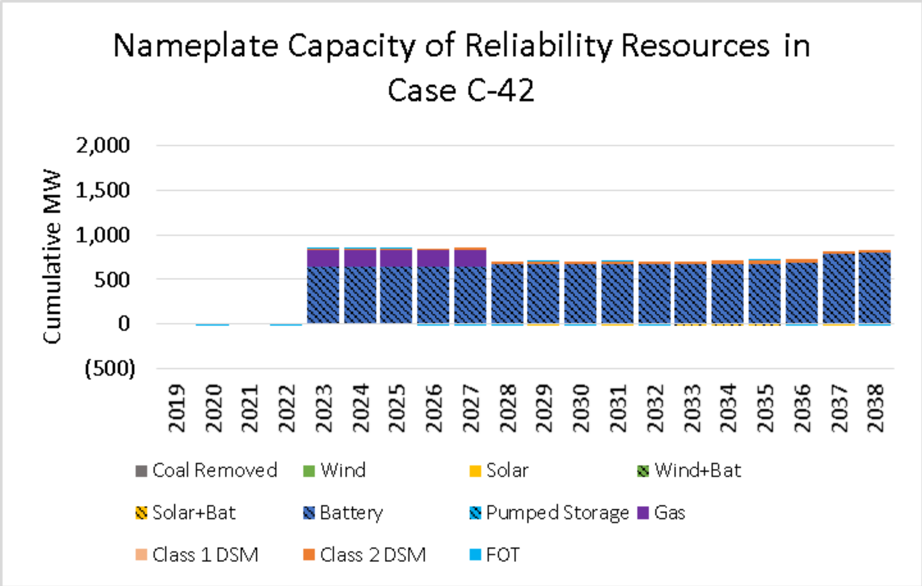


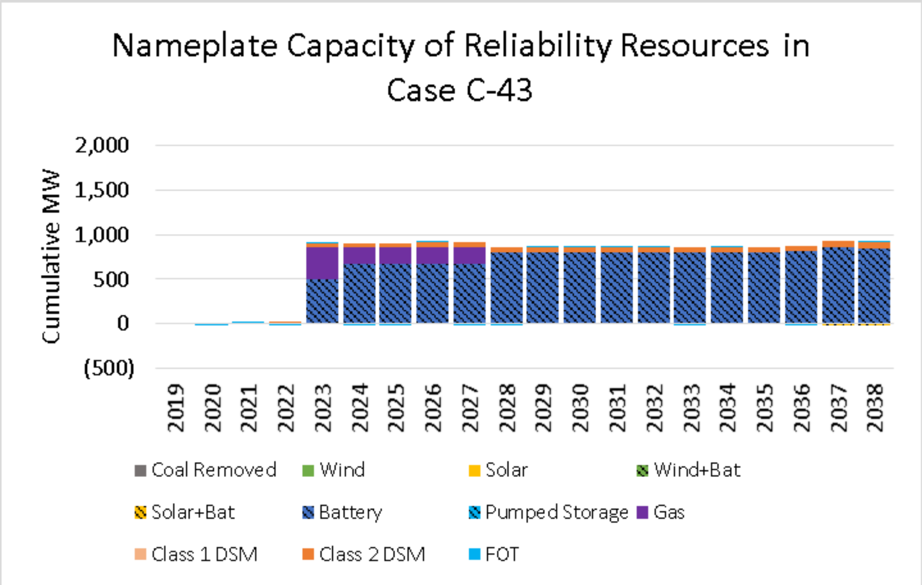




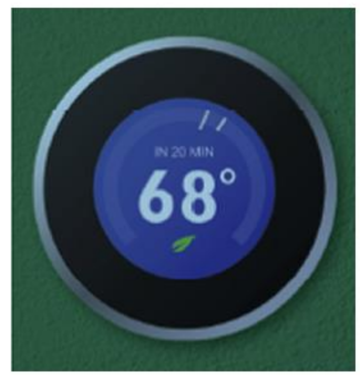
Reliability Resources (Continued)







Stakeholder Feedback Form Recap



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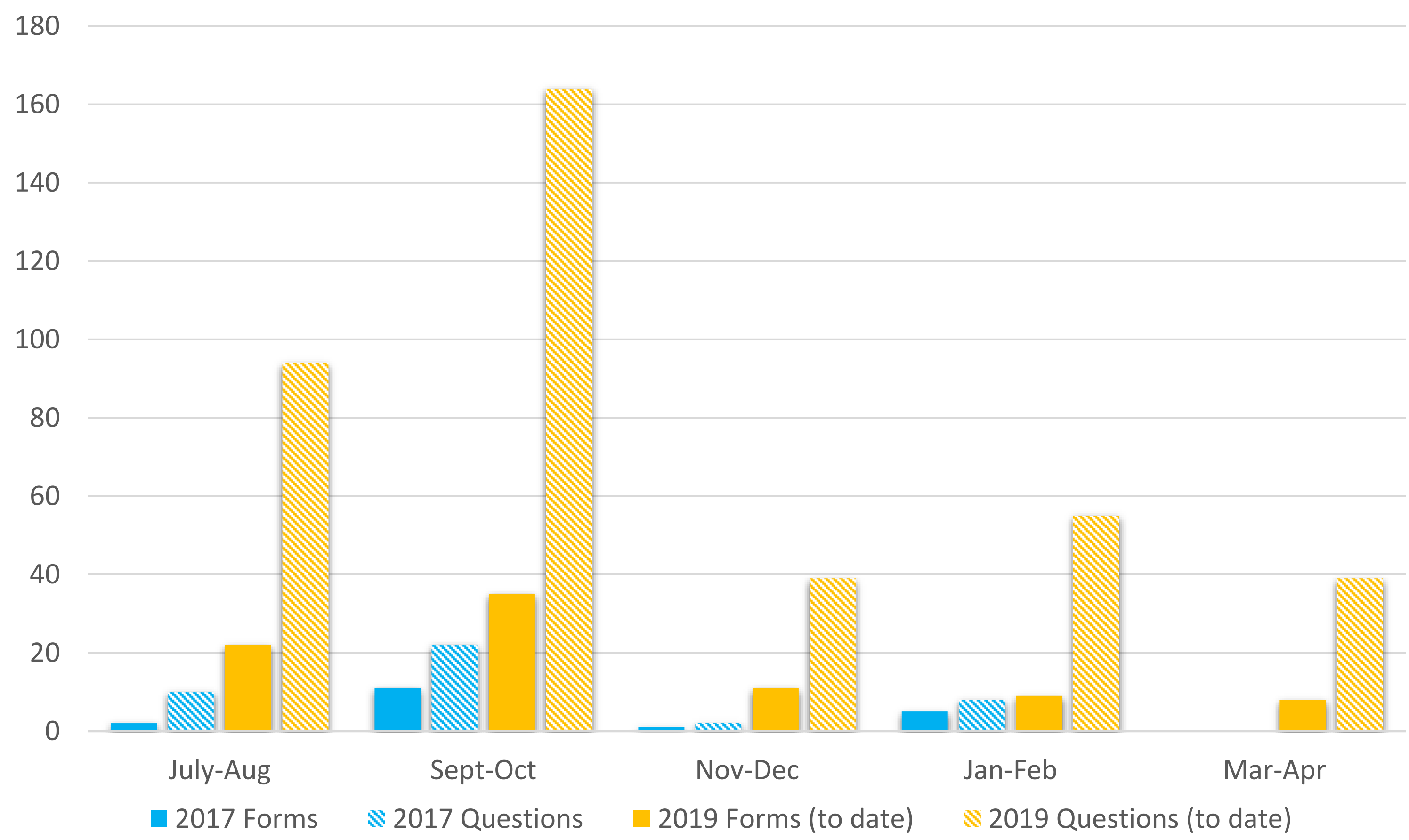
2019 IRP vs. 2017 IRP Stakeholder Feedback Form Activity to Date



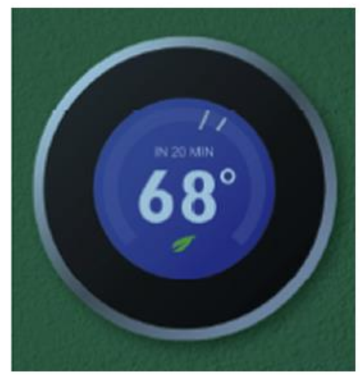
Stakeholder Feedback Forms

- 85 stakeholder feedback forms submitted to date.
- Stakeholder feedback forms and responses can be located at: www.pacificorp.com/es/irp/irpcomments.html.
- Depending on the type and complexity of the stakeholder feedback received responses may be provided in a variety of ways including, but not limited to, a written response, a follow-up conversation, or incorporation into subsequent public input meeting material.
- Stakeholder feedback following the most recent public input meeting is summarized on the following slides for reference.

Summary - Recent Stakeholder Feedback Forms

Stakeholder	Date	Topic	Brief Summary (complete form available online)	Response (posted online when available)
WUTC	Mar 22	General	Feedback and questions from March public input meeting.	Target response week of April 29.
UCE	Mar 22	Private Generation	Request for clarification and explanation on inputs regarding Navigant's 2018 Private Generation Long-Term Resource Assessment.	Provided clarification and explanation on data inputs.
UCE	Apr 3	DSM Modeling	Request for additional DSM modeling.	Target response week of April 29.
UCE	Apr 4	Coal Analysis	Request for CO_2 price data inputs, explanation of calculation of decommissioning costs, and specific unit and contract information.	Target response week of April 29.

Additional Information and Next Steps



Draft Topics for Upcoming PIMs*

May 20-21, 2019 PIM*

- Regional Haze Cases
- Portfolio Development Cases
- Stakeholder Feedback Form Recap

June-July, 2019*

- Portfolio Development Cases
- Sensitivity Studies
- Portfolio Selection Process
- Draft Preferred Portfolio
- Draft Action Plan
- Stakeholder Feedback Form Recap

** Topics and timing are tentative and subject to change*

Additional Information and Next Steps

- Public Input Meeting Presentation and Materials:
  - pacificorp.com/es/irp.html
- 2019 IRP Stakeholder Feedback Forms:
  - pacificorp.com/es/irp/irpcomments.html
- IRP Email / Distribution List Contact Information:
  - IRP@PacifiCorp.com
- Upcoming Public Input Meeting Dates:
  - May 20-21, 2019
  - June 20-21, 2019
  - July 18-19, 2019 *(as needed)*
  - August 1, 2019 – 2019 IRP File Date