NS POWER 2020 IRP MODELING RESULTS RELEASE

JUNE 26, 2020

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PROCESS UPDATE & WORK COMPLETED

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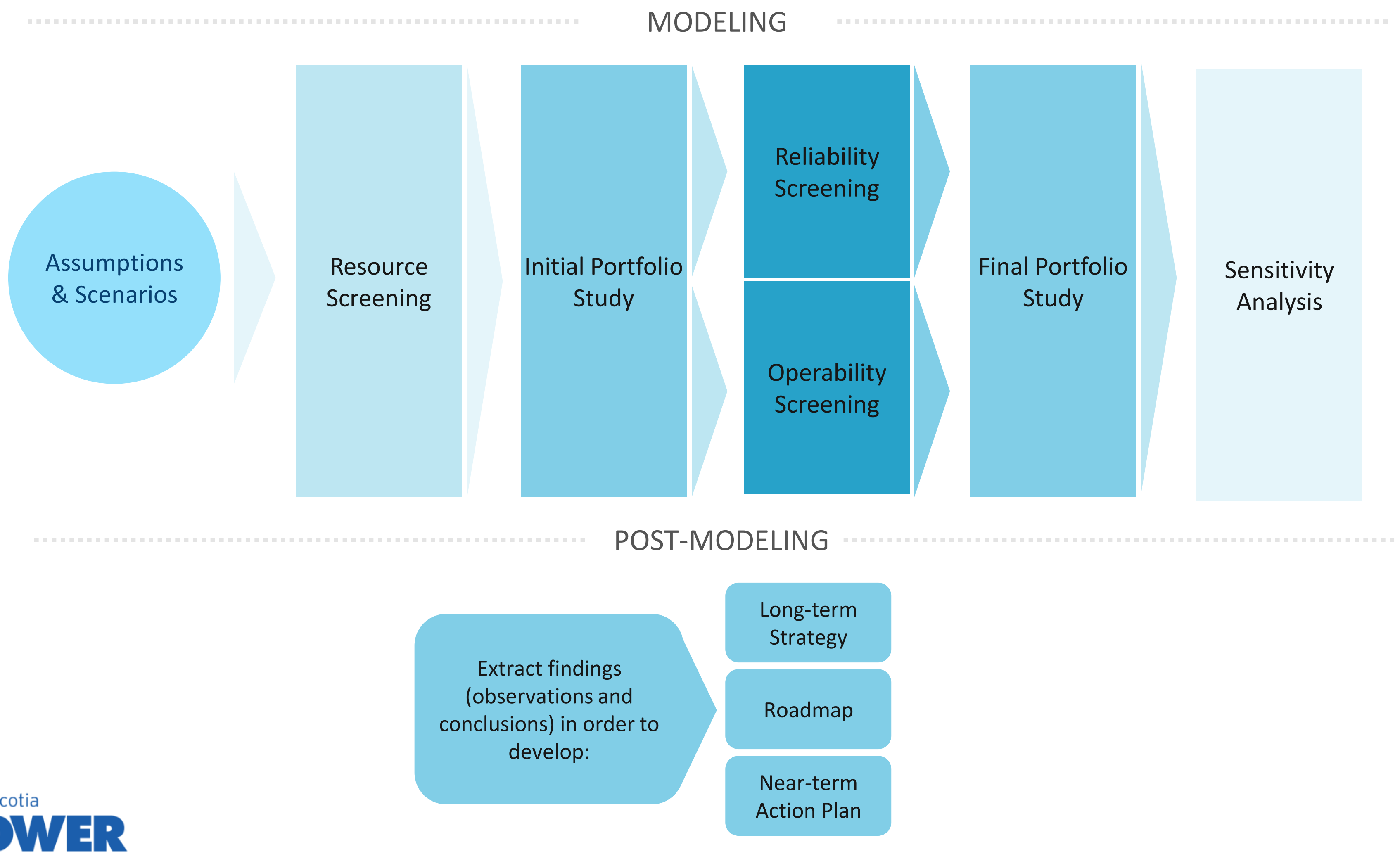
resulting in Final Report

Sept 2020

- Terms of Reference
- Scenario Development
- Modeling Plan
- Assumptions
- Modeling
- Analysis/Conclusions
- Report, Roadmap, & Action Plan

- Previously completed
- Completed since last update
- In Progress

IRP MODELING PLAN



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ASSUMPTION & KEY SCENARIO UPDATES

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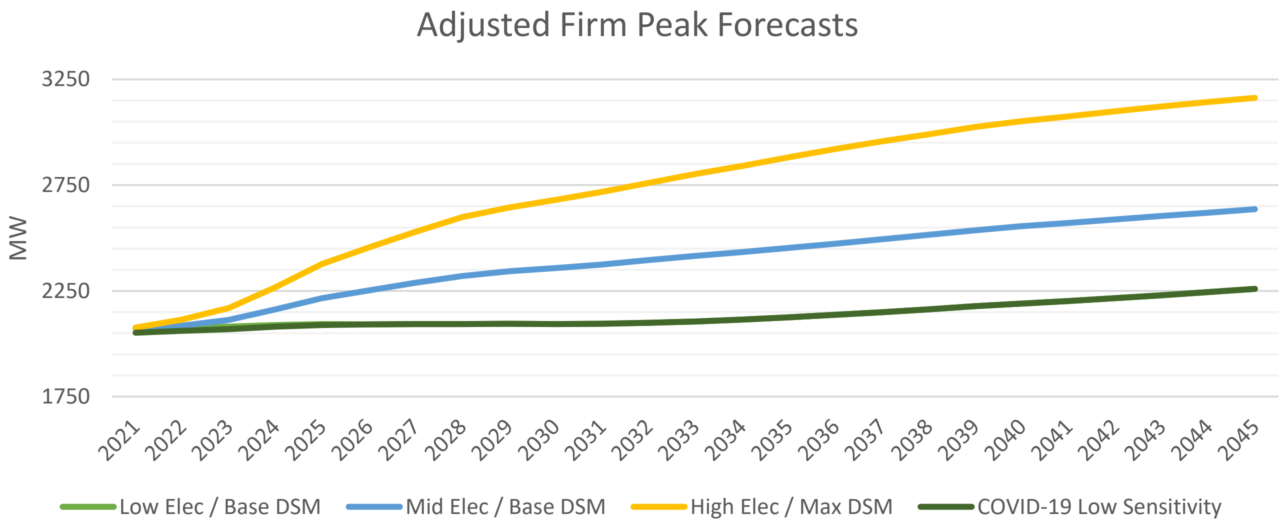
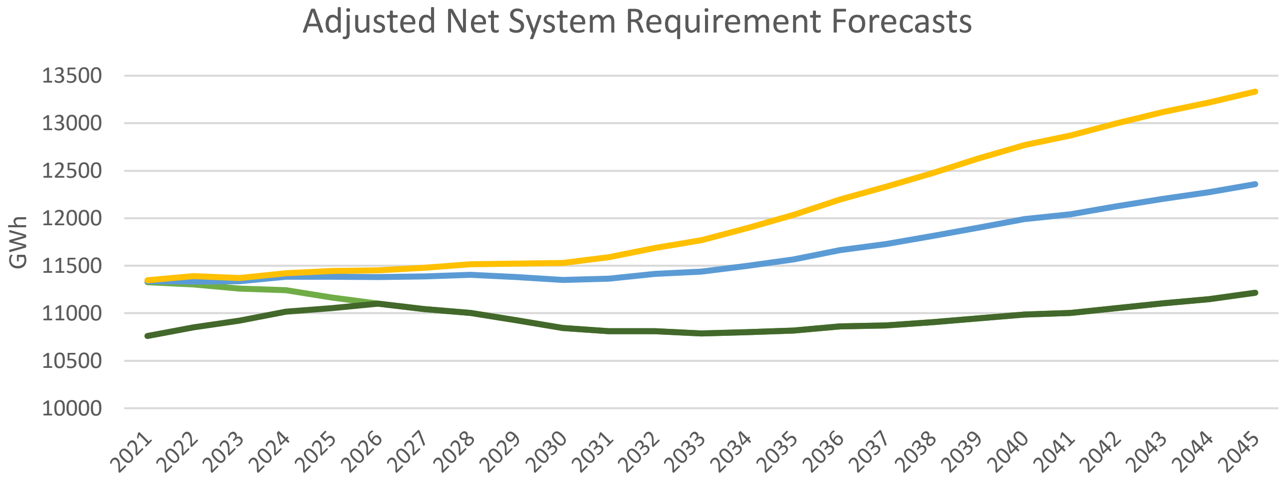
ADJUSTMENTS TO IRP LOAD FORECASTS

Based feedback from some stakeholders and observations from the modeling runs completed to date, NS Power has made the following adjustments to reflect potential impacts of the COVID-19 pandemic:

- The Low Electrification forecast remains unchanged at all DSM levels
- The Mid and High Electrification forecasts are adjusted to moderate the original steep ramp up in electrification over the first 10 years of the forecast; the end points remain unchanged as they are consistent with the established SDGA goals (as modeled in the PATHWAYS study)
- The added COVID-19 Low forecast will test the robustness of certain resource plans to potential pandemic load impacts in the first 5 years (a reduction of 1% in firm peak and 5% in net system requirement in year one, returning to the base Low Electrification forecast by 2026)

The resulting load forecasts continue to explore a wide range of potential scenarios, which will allow the IRP to continue to appropriately test the robustness of potential resource strategies to these various loads.





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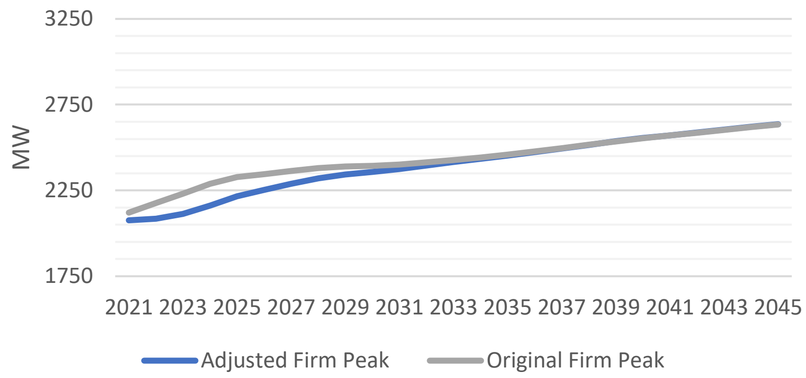
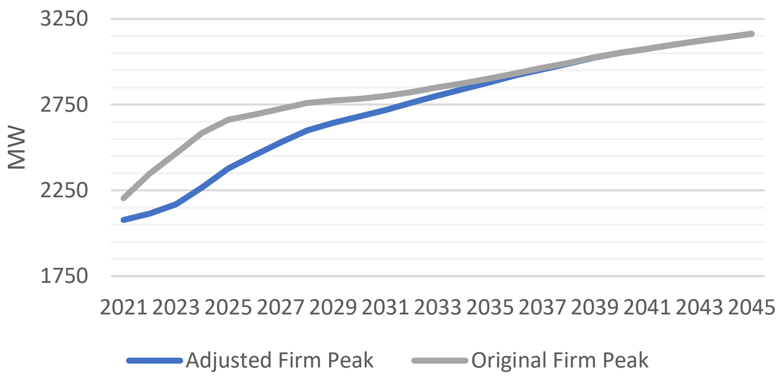
ADJUSTED LOAD FORECAST - COMPARISONS

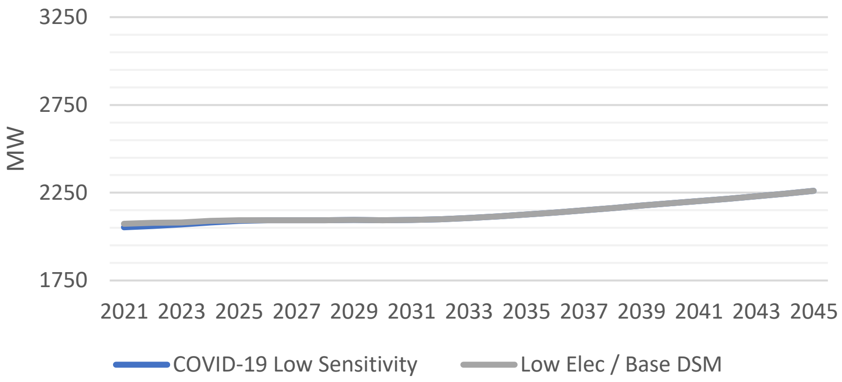
Firm Peak
Mid Elec / Base DSM



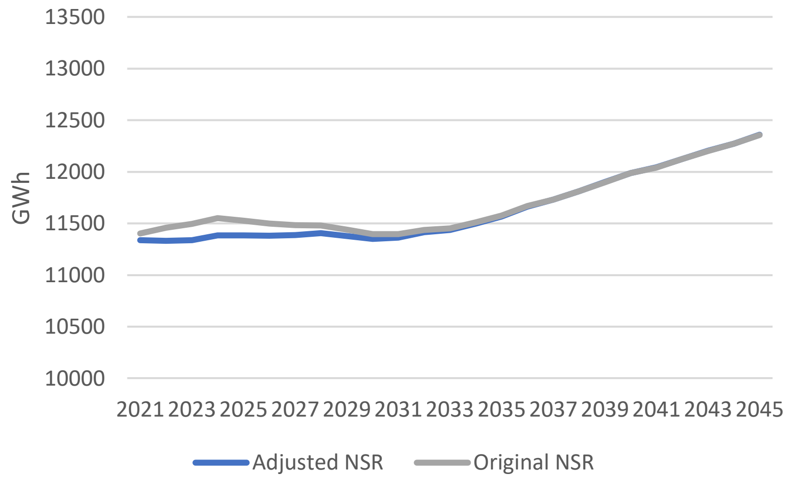
Firm Peak
High Elec / Max DSM



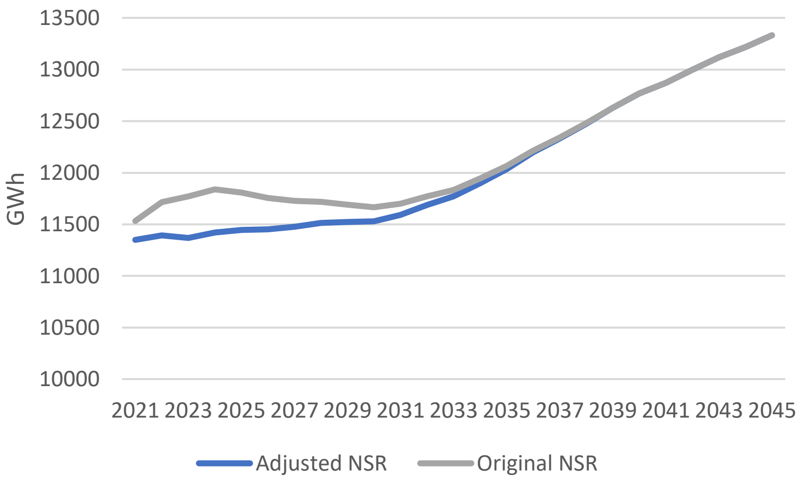
Firm Peak
Low Elec / Base DSM, COVID-19 Low Forecast



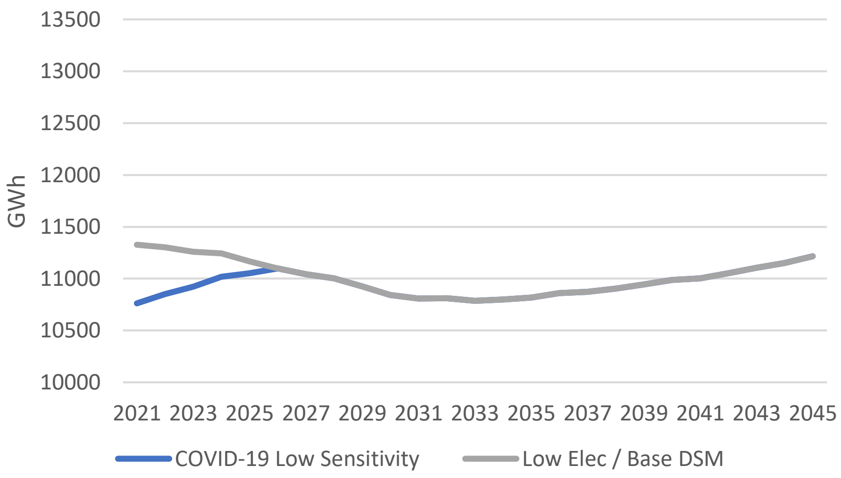
Annual Net System Requirement
Mid Elec / Base DSM



Annual Net System Requirement
High Elec / Max DSM



Annual Net System Requirement
Low Elec / Base DSM, COVID-19 Low Forecast



ELCC FACTORS FOR EXISTING RESOURCES

- NS Power has adopted the ELCC methodology for both existing and new generation resources which is used in calculating unit contributions to Planning Reserve Margins
- ELCC Factors for existing resources have been calculated as follows, using the most recent 3-year average DAFOR rates

ELCC Factors

	Net Operating Cap. (MW)	ELCC Factor	UCAP Firm Cap. (MW)	Notes
Coal	1081	90%	976	No LIN-2
HFO/Gas	318	73%	232	
Gas CTs	144	93%	133	
LFO CTs	231	77%	178	
Biomass	43	95%	41	
Hydro	374	95%	355	
Wind	595	19%	113	
Other IPPs	34	95%	32	No Wind
ML Base	153	98%	150	
Total	2972		2211	

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INERTIA CONSTRAINT

- The kinetic inertia constraint is modeled at 3266 MW.sec minimum online requirement
  - This is derived as allowing an approximate contingency of 500 MW.sec (~1 unit) above the level of 2766 MW.sec that was found to be required for stability in the 2019 PSC Study
- Unit provisions are shown in the table on the right for existing and new resource types available to the model

Source	Inertia Contribution (MW.sec)
Generators (01 - Lingan 1)	814
Generators (02 - Lingan 2)	814
Generators (03 - Lingan 3)	797
Generators (04 - Lingan 4)	797
Generators (05 - Point Aconi)	933
Generators (06 - Point Tupper)	777
Generators (07 - Trenton 5)	620
Generators (08 - Trenton 6)	771
Generators (11 - Tufts Cove 1)	403
Generators (12 - Tufts Cove 2)	412
Generators (13 - Tufts Cove 3)	768
Generators (14 - Tufts Cove 4)	245
Generators (15 - Tufts Cove 5)	245
Generators (16 - Tufts Cove 6)	245
Generators (270 - New_50MW Pump Strg)	100
Generators (320 - New_Tre 5 NGas)	620
Generators (321 - New_Tre 6 NGas)	771
Generators (322 - New_TUP NGas)	777
Generators (040 - New_RECIP - 9.3 MW)	45
Generators (050 - New_ CT 50 MW Aero)	250
Generators (052 - New_CC 145 MW)	750
Generators (054 - New_CC 253 MW)	1265
Generators (056 - New_CT 34 MW Aero)	170
Generators (058 - New_CT 33 MW Frame)	165
Generators (059 - New_CT 50 MW Frame)	250
Generators (CAES_Air Component)	100
Generators (H01 - Wreck Cove)	424
Generators (Sync Cond _1)	5 (per MVA of SC)
Lines (670-NB 2nd 345kV Intertie_Basic)	3266

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KEY MODELING SCENARIOS

Scenario	Features	Load Drivers	Coal Retires	Resource Strategies Tested	Key Sensitivities
1.0 **Comparator**	Equivalency GHG	Low Elec. Base DSM	2040	A - Current Landscape C – Regional Integration*	
2.0 **Net Zero 2050** **Low Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Low Elec. Base DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels
2.1 **Net Zero 2050** **Mid Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Mid Elec. Base DSM	2040	A - Current Landscape B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
2.2 **Net Zero 2050** **High Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	High Elec. Max DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels • No New Emitting
3.1 **Accelerated Net Zero 2045 Mid Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	Mid Elec. Base DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
3.2 **Accelerated Net Zero 2045 High Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	High Elec. Max DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels

*Based on stakeholder feedback, the scenario highlighted in blue was added to the set of key scenario runs

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RESOURCE SCREENING RESULTS
DIESEL COMBUSTION TURBINES

RESOURCE SCREENING – DIESEL COMBUSTION TURBINES

- Screening of existing Diesel CTs was conducted by E3 using RESOLVE
- During screening the model was free to re-optimize the resource portfolio and to select any available supply options to replace the CT capacity (e.g. new gas CTs/CCGTs, batteries, firm imports, etc.)
- Analysis was completed on two key scenarios (1.0A and 2.1C)
- Screening results showed that sustaining the existing diesel CT fleet is economic vs. replacement alternatives; Diesel CTs will be assumed "in" in the Initial Portfolio Study runs
- This result was robust to testing with a lower Planning Reserve Margin (PRM) and to testing a single unit retirement

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Approach to Screening Diesel CTs

- **The diesel CT screening analysis evaluates the system value of NSP's diesel CT assets**
- **E3 performed capacity expansion optimization of NSP's IRP scenarios in RESOLVE, with diesel CTs "in" and "out"**
  - The "in" cases reflect the NSP system, including all existing diesel CTs within the model
  - The "out" cases remove the diesel CTs from NSP's existing portfolio and allow the system to perform capacity expansion without the units
- **The difference in costs reflects the net system value (or cost) of the diesel CTs**

1. **Run the "In" Case:** Run RESOLVE with all existing units in the model to identify optimal future resource portfolio that meets reliability and GHG goals while minimizing customer costs
Outputs: System Costs (RR), Capacity Additions, Energy Generation, Retirements, etc.

2. **Run the "Out" Case:** Run RESOLVE with existing units except the diesel CTs in the model to identify optimal future resource portfolio that meets reliability and GHG goals while minimizing customer costs, but without the diesel CTs available
Outputs: System Costs (RR), Capacity Additions, Energy Generation, Retirements, etc.

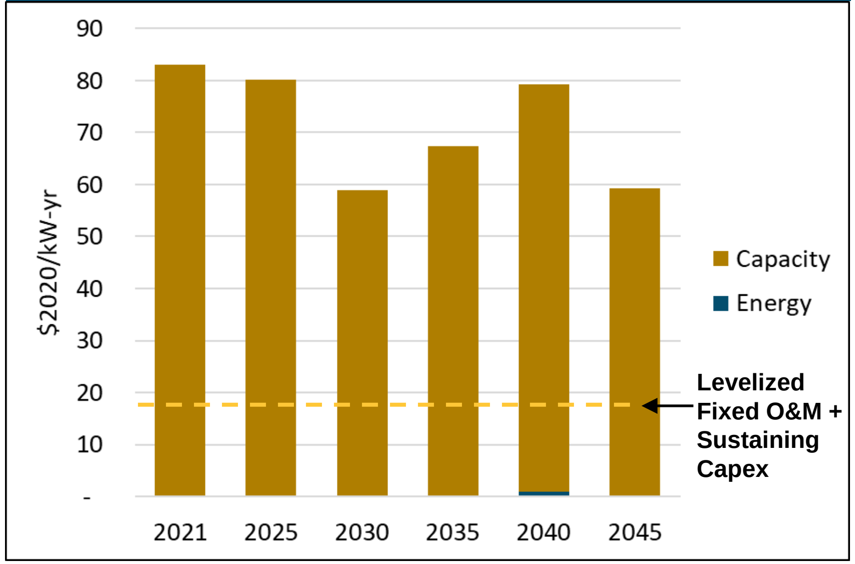
3. ***The incremental cost of the portfolio (or savings) reflects the net system benefit (or cost) associated with the diesel CTs****

* Assuming all major system costs and benefits associated with the diesel CTs are within the model.

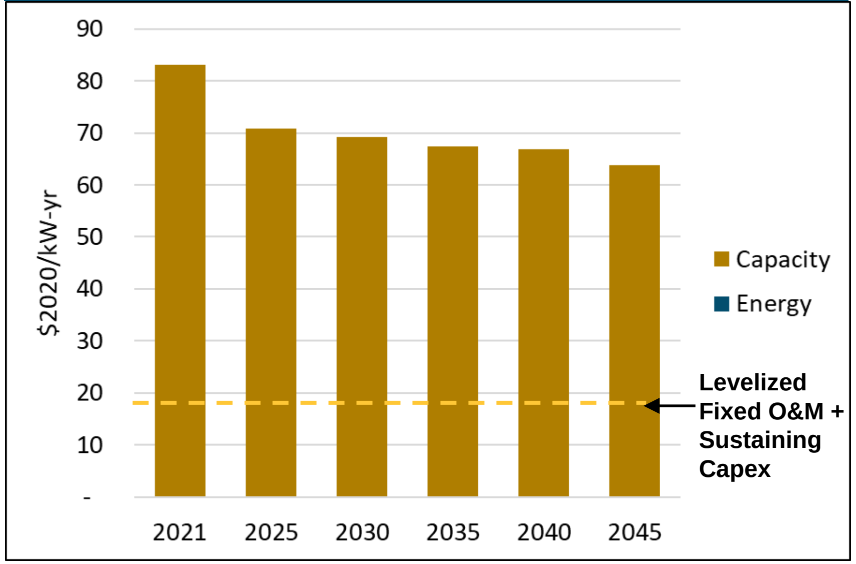
What value do diesel CTs provide?

- Diesel CTs provide capacity value, which reflects the net costs of new capacity. By maintain the existing Diesel CT fleet, investment in new CTs can be avoided while maintain capacity contributions toward peak loads
- In addition, diesel CTs provide non-spinning reserve capacity service, the value of which is not shown in the charts below
- Diesel CTs are not run often because of their relatively higher fuel costs relative to alternative resource options; as such replacement energy does not factor into these calculations

Diesel Peakers Marginal Value - 1.0.A



Diesel Peakers Marginal Value – 2.1.C

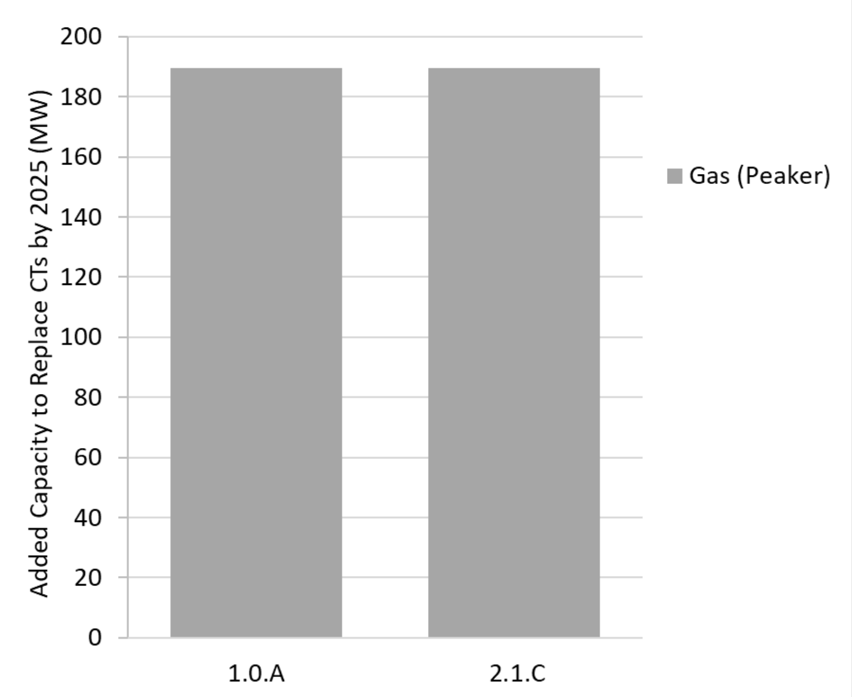


Incremental Capacity Additions when Diesel CTs Removed from the System

- **The 231 MW diesel CTs are largely used to provide capacity and ancillary services when included in the system**
  - They are not run frequently (<1% CF)
- **When diesel CTs are removed, RESOLVE builds new gas peakers to replace lost capacity**
  - Note that higher ELCC* for replacement gas peakers means less than 231 MW is needed for an equivalent reliability contribution
  - The gas peaker replacement resource is selected economically ahead of other potential replacement options (e.g. battery storage or NGCC units)
- **On aggregate, maintaining the existing diesel CTs is worth about ~$186 MM (no end effects) and ~$240 MM (with end effects) to the system on an NPV basis**

**Effective Load Carrying Capacity*

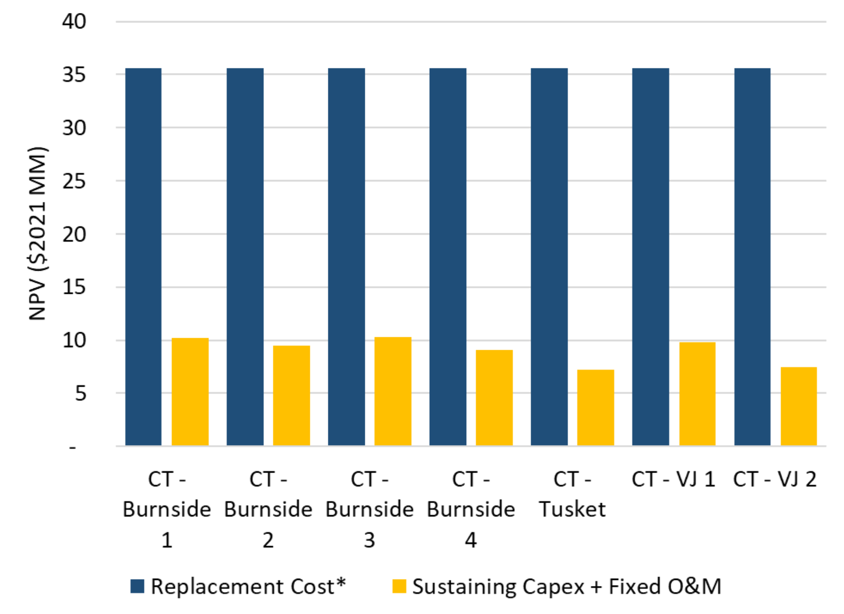
Added Capacity to Replace Diesel CT by 2025



System Value of Diesel CTs - 1.0.A

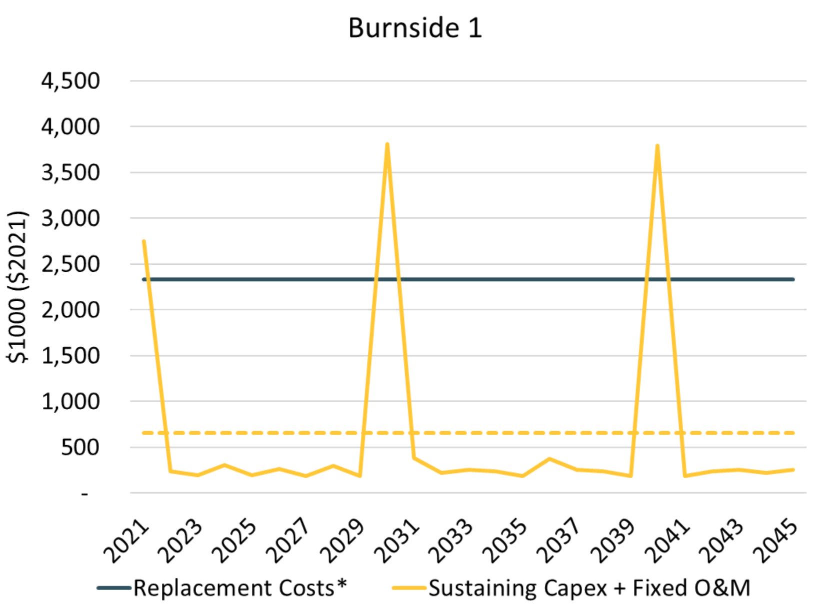
- While the sustaining costs of maintaining diesel CTs are higher in certain years of investment, this analysis shows the costs to replace with alternative resources exceeds the costs to retain the resources over the planning horizon on an NPV basis
- The difference between the blue and yellow bars/lines reflects the net system value

Cost to Replace Diesel CT vs Sustaining Capex (1.0.A)



* Replacement energy and capacity costs reflect net system savings adjusted for avoided sustaining capital and fixed O&M

Sustaining Capex vs Replacement Cost by Years

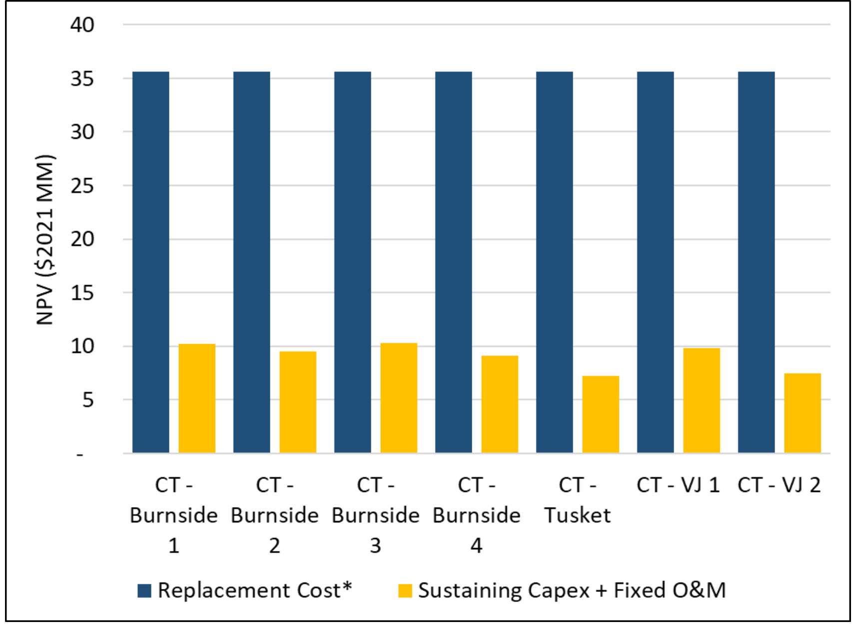


Dotted line reflects the levelized sustaining capital expenditures and fixed O&M

System Value of Diesel CTs – 2.1.C

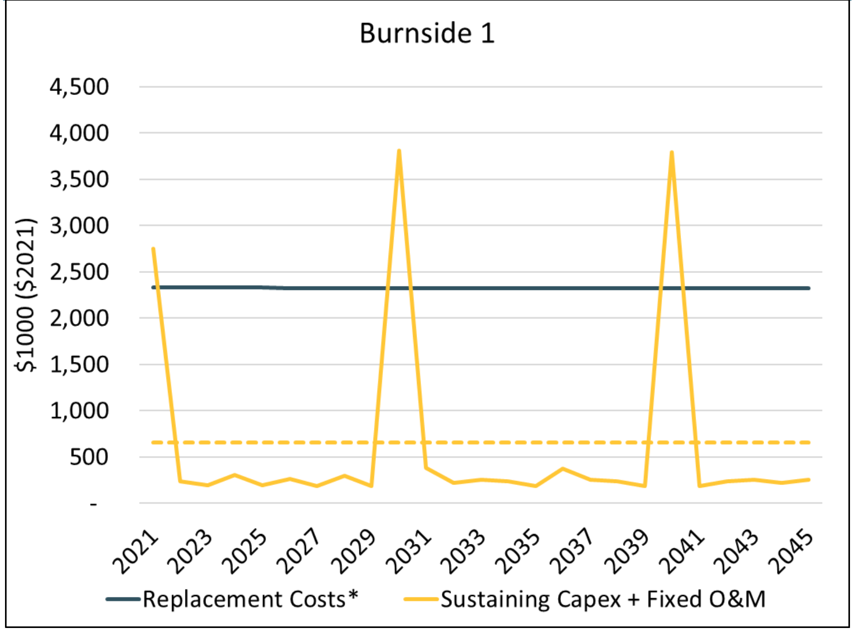
+ **Results remain the same under 2.1.C., given similar replacement builds required to provide required system capacity**

Cost to Replace Diesel CT vs Sustaining Capex



** Replacement energy and capacity costs reflect net system savings adjusted for avoided sustaining capital and fixed O&M*

Sustaining Capex vs Replacement Cost by Years



Dotted line reflects the levelized sustaining capital expenditures and fixed O&M

System Value of Diesel CTs – 2.1.C - Lower PRM Requirement

+ The value of the diesel CT units does not change with a lower PRM
+ When diesel CTs were removed, the model still replaces the peakers with 190 MW of new gas CTs
+ Removing a 33 MW of diesel CT from the model under the lower PRM sensitivity resulted in a total system cost NPV that was higher than when the unit was sustained through the planning horizon

RESOURCE SCREENING RESULTS
HYDRO

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RESOURCE SCREENING – HYDRO

- Screening of the existing hydro systems was conducted by E3 using RESOLVE
- During screening the model was free to re-optimize the resource portfolio and to select any available supply options to replace the hydro capacity and energy (e.g. new gas CTs/CCGTs, batteries, firm and non-firm imports, wind, etc.)
- Analysis was completed on two key scenarios (1.0A and 2.1C)
- Sustaining and Decommissioning costs were taken from NS Power's most recent Hydro Asset Study
- Wreck Cove and Mersey were modeled individually and remaining systems were modeled in two groups with similar operating characteristics
- Screening results showed that sustaining the existing hydro systems is economic vs. replacement alternatives; existing hydro will be assumed "in" in the Initial Portfolio Study runs
- NS Power will conduct a capacity expansion run in PLEXOS with the Mersey hydro system retired

Overview of Hydro Screening Analysis

- **The hydro screening analysis assesses the value of NSP's hydro assets**
- **E3 performed "in" and "out" cases in RESOLVE under core IRP scenarios**
  - "In" Cases: Model the NSP system under the given IRP scenario, with all existing hydro units assumed to continue operating
  - "Out" Cases: Removes a given hydro unit/ group from the model and performs capacity expansion without the asset, replacing the system services provided to meet demand at lowest cost subject to model constraints
- **The hydro asset's value is based on the costs to sustain versus decommission the unit**
- **Comparison done over 40 years given timeframe of input data on sustaining capital and decommissioning costs**

1 **Run the "In" Case:** Run RESOLVE with all existing units in the model to identify optimal future resource portfolio that meets reliability and GHG goals while minimizing customer costs

2 **Run the "Out" Case:** Run RESOLVE with existing units except the hydro asset in the model to identify optimal future resource portfolio that meets reliability and GHG goals while minimizing customer costs, but without those units available

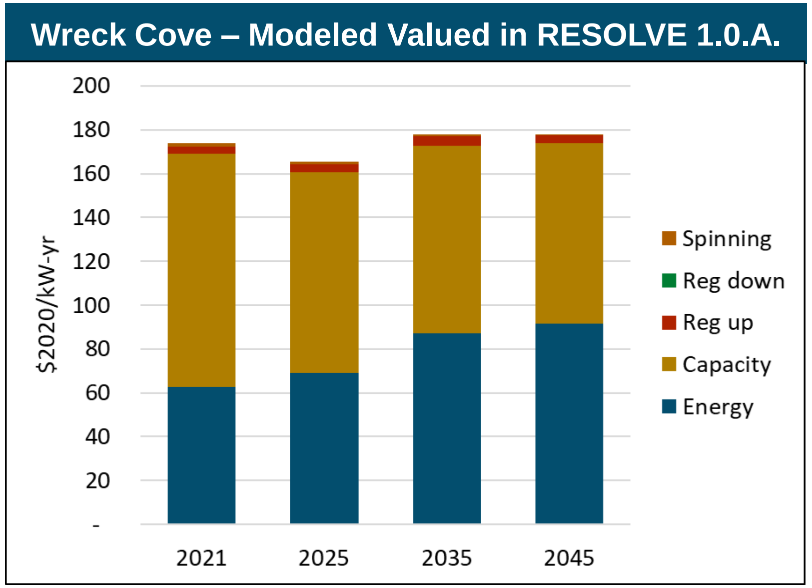
3 **Organize modeled and non-modeled costs:**

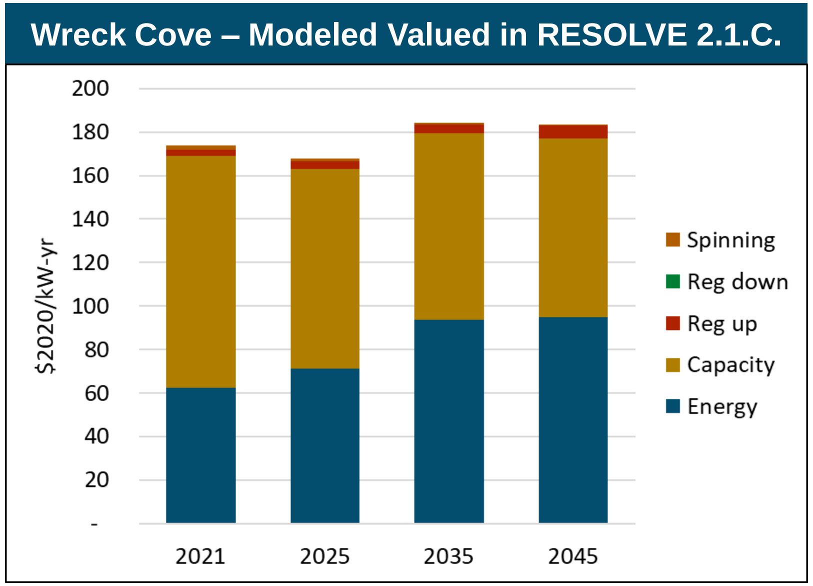
Sustaining/Operating Asset:	Decommissioning Asset:
- Sustaining Capital (in RESOLVE) - Fixed O&M (in RESOLVE)	- Decommissioning Costs (outside RESOLVE) - Replacement System Costs (in RESOLVE)

The difference between decommissioning and sustaining/operating reflects the system benefit (or cost if negative) associated with the hydro asset

Wreck Cove Hydro: System value provided by Wreck Cove in RESOLVE

- Wreck Cove provides incremental energy and capacity value to the system; the energy value are higher in later years as emissions become binding and coal units are retired
- Wreck Cove is slightly more valuable in the 2.1.C. scenario, which has higher loads and lower carbon targets, but access to emissions-free imports

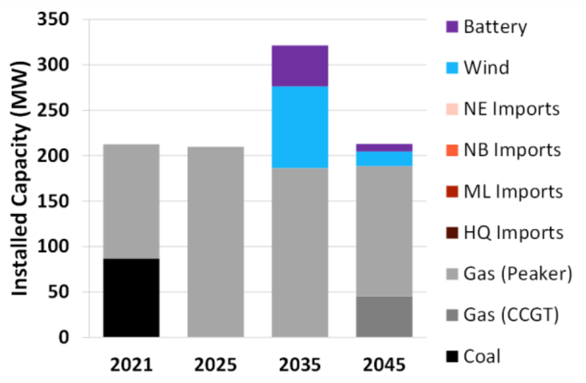


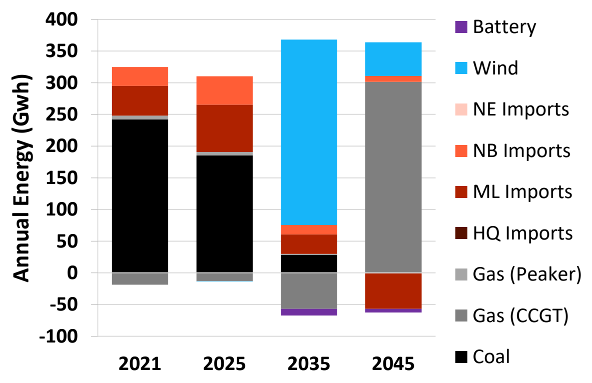


Wreck Cove: Replacement capacity and energy when Wreck Cove removed from the model

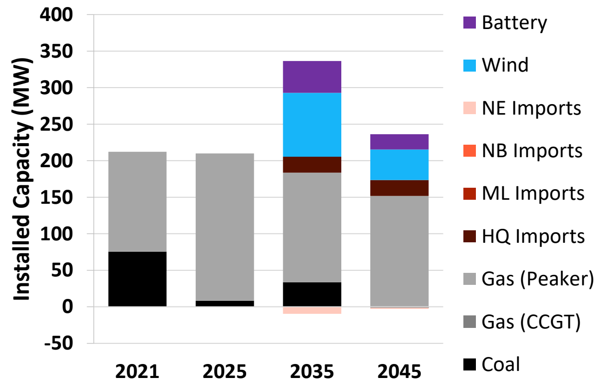
- When Wreck Cove is removed from the system, the model builds gas peakers for replacement capacity
- The model replaces Wreck Cove's energy primarily with coal before 2030 when emissions are not binding, and with wind, imports, and gas CCGT after 2035 when emissions become more constrained

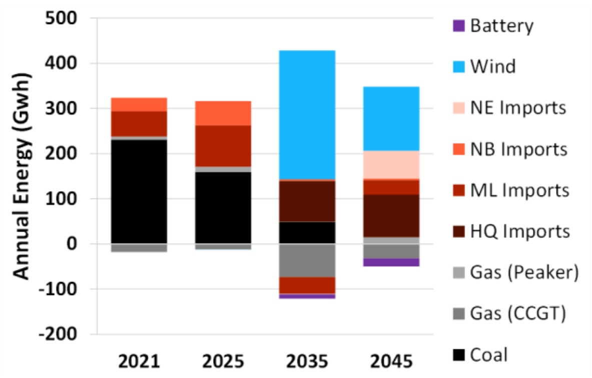
Replacement Capacity and Energy when Wreck Cove Removed – 1.0.A.





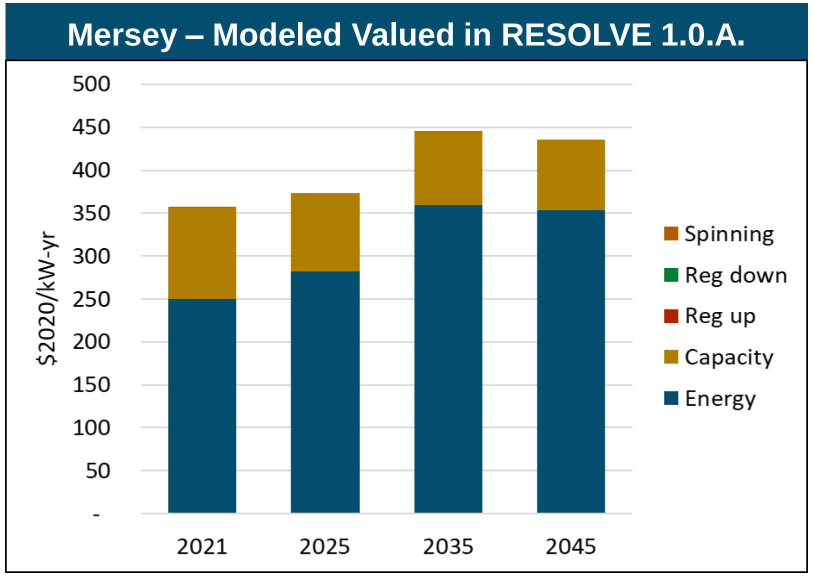
Replacement Capacity and Energy when Wreck Cove Removed – 2.1.C.

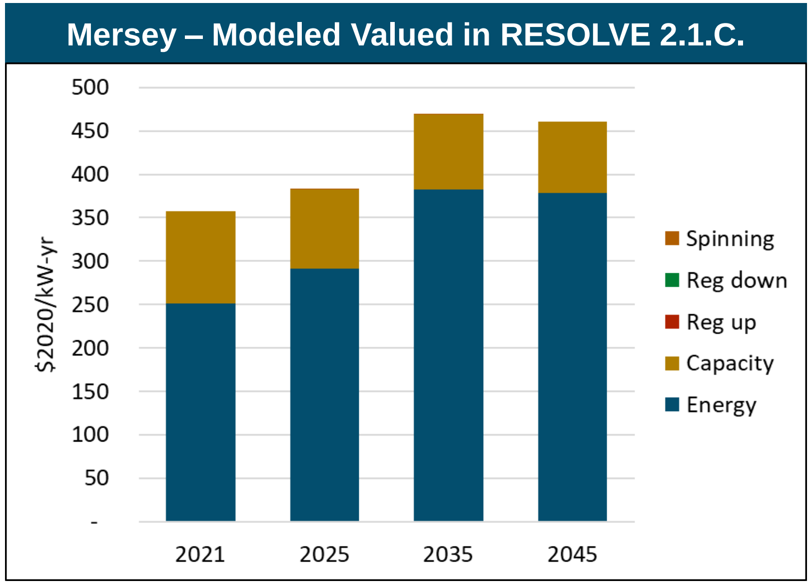




Mersey Hydro: System value provided by Mersey in RESOLVE modeling

+ Mersey provides significant energy value to the system, as well as some incremental capacity value; the energy value are higher in later years as emissions become binding and coal units are retired
+ Mersey is slightly more valuable in the 2.1.C. scenario, which has higher loads and lower carbon targets, but access to emissions-free imports



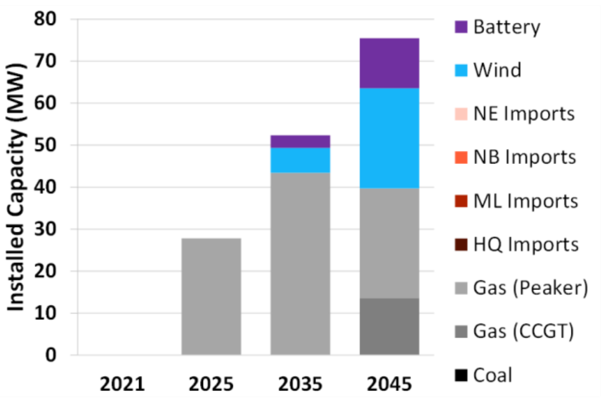


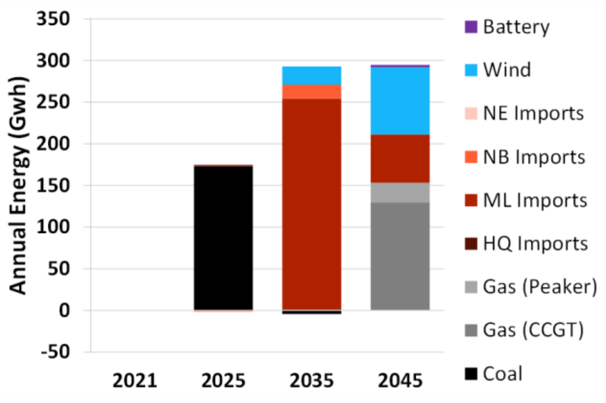
Mersey: Replacement capacity and energy when Mersey removed from the model

+ When Mersey is removed from the system, the model initially builds gas peakers for replacement capacity

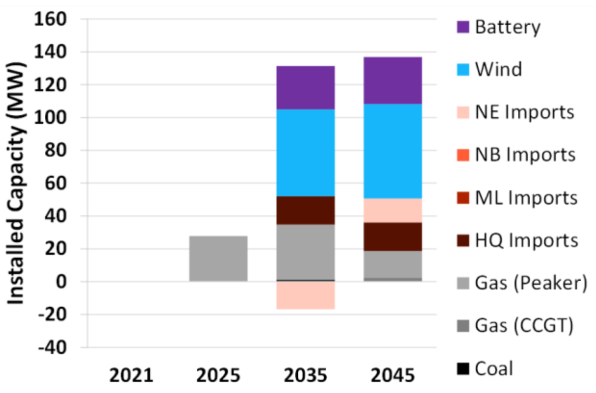
+ The model replaces Mersey's energy primarily with coal before 2030, and with wind, imports, and gas CCGT after 2035 when emissions become more constrained

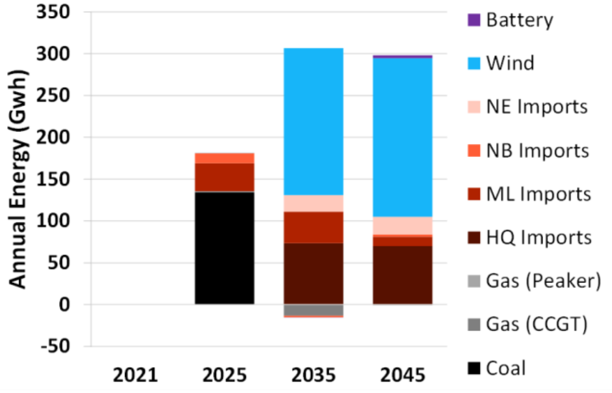
Replacement Capacity and Energy when Mersey Removed – 1.0.A.





Replacement Capacity and Energy when Mersey Removed – 2.1.C.

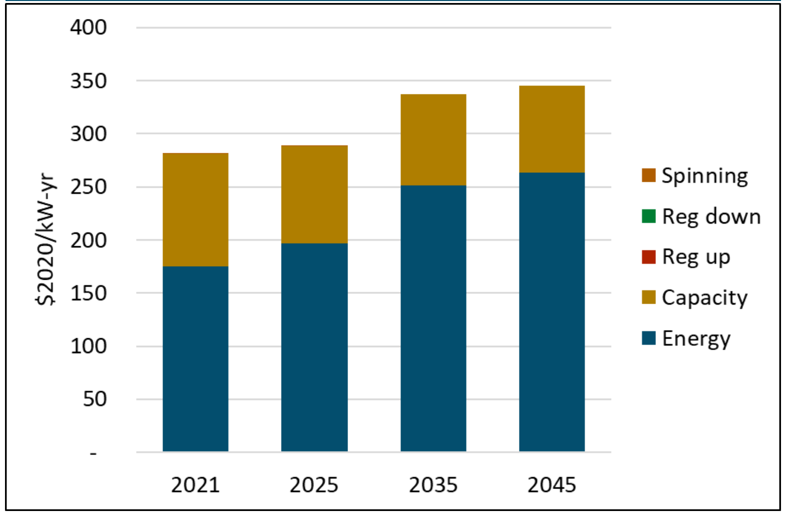




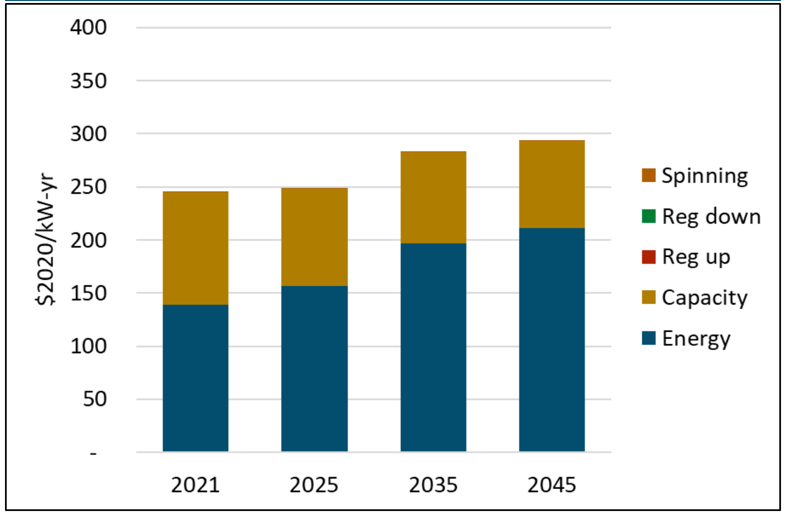
Small Hydro Groups: System value provided by Hydro Assets in RESOLVE modeling

- Several smaller hydro systems in Nova Scotia provide energy value to the system, as well as some incremental capacity value
- In total, hydro assets within Group 1 provided more energy value than Group 2 units due to its higher capacity factor in winter when loads are high
- The energy values are higher in later years as emissions become binding and coal units are retired
- Small hydro systems are slightly more valuable in the 2.1.C. scenario, which has higher loads and lower carbon targets, but access to emissions-free imports

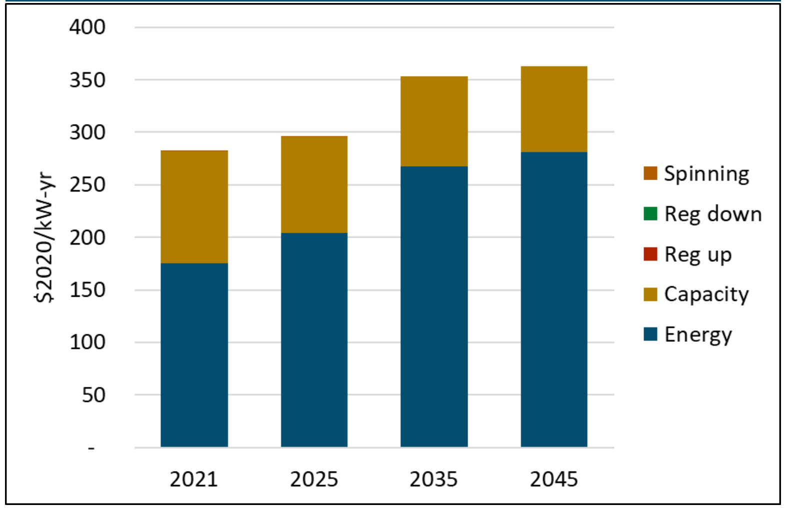
Modeled Valued in RESOLVE 1.0.A – Group 1



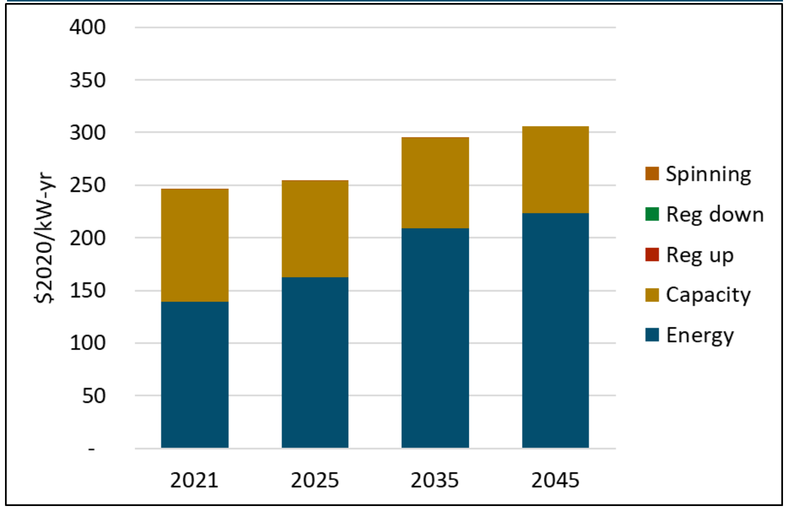
Modeled Valued in RESOLVE 1.0.A - Group 2



Modeled Valued in RESOLVE 2.1.C - Group 1



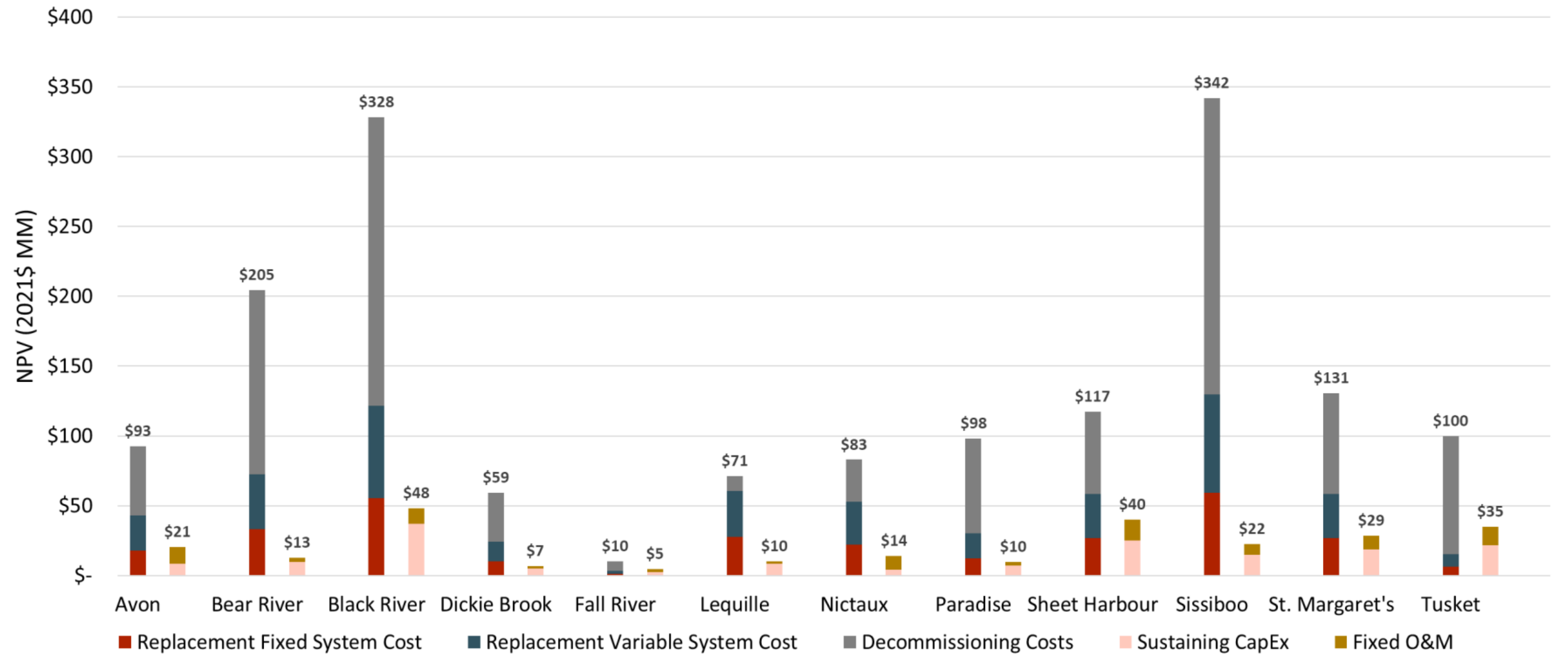
Modeled Valued in RESOLVE 2.1.C. - Group 2

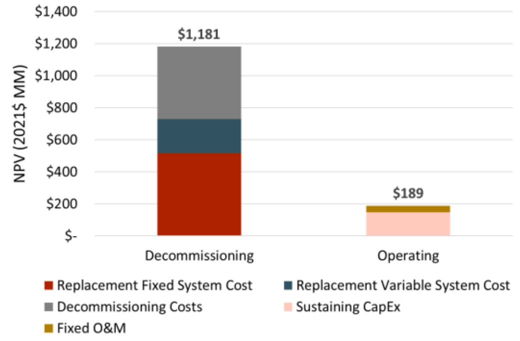


Hydro Assets: Total decommissioning costs relative to sustaining operations – 1.0.A

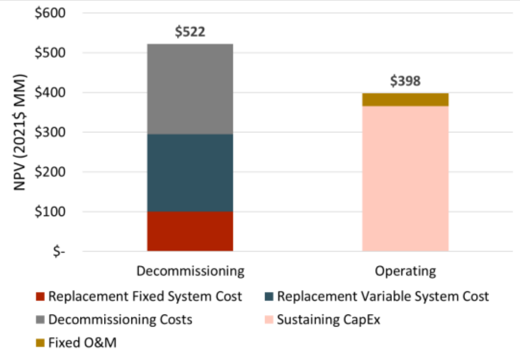
+ This analysis indicates the cost to replace individual hydro assets with alternative resources exceeds the costs to retain the resource over a 40-year planning horizon on an NPV basis

Cost to Replace Small Hydro Assets vs Sustaining Capex (1.0.A)





Wreck Cove

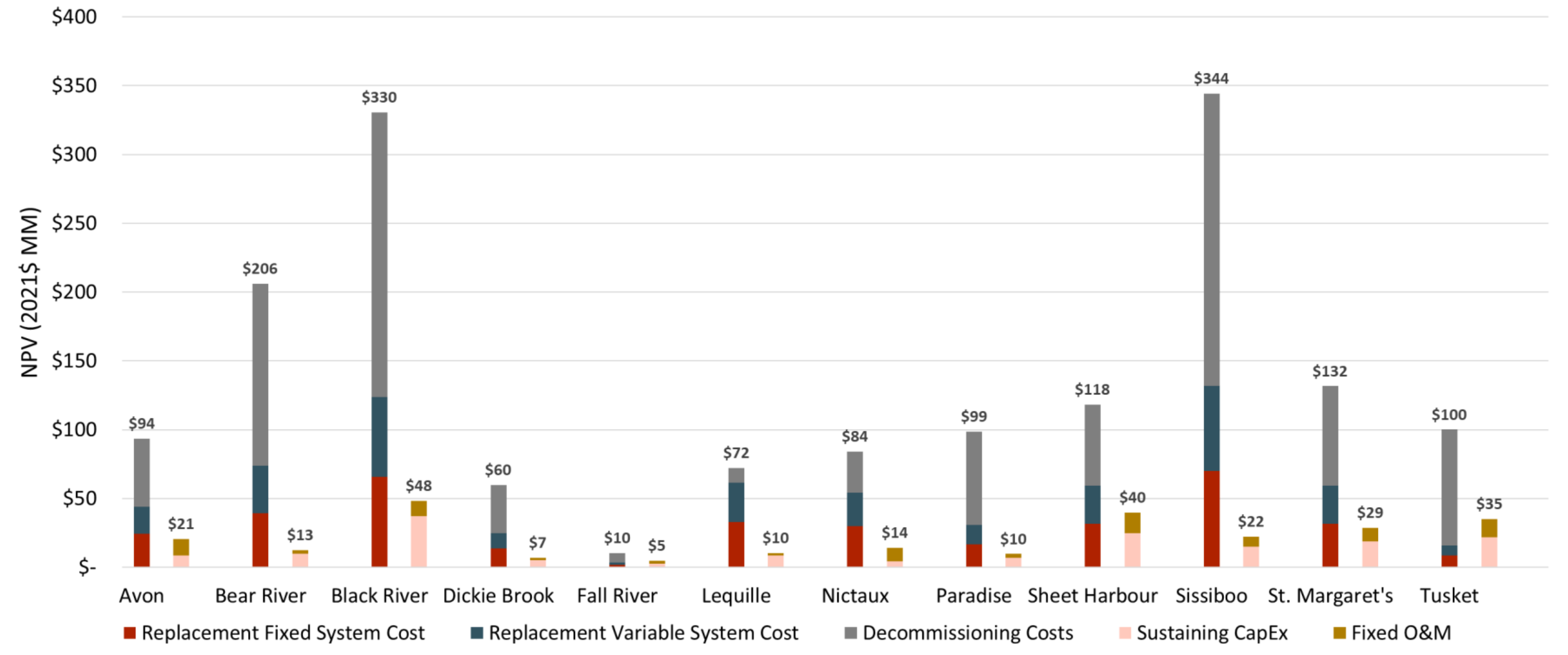


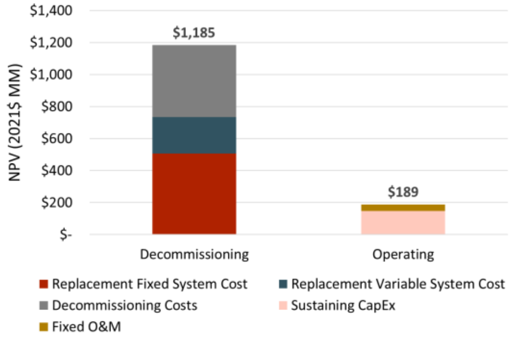
Mersey

Hydro Assets: Total decommissioning costs relative to sustaining operations – 2.1.C

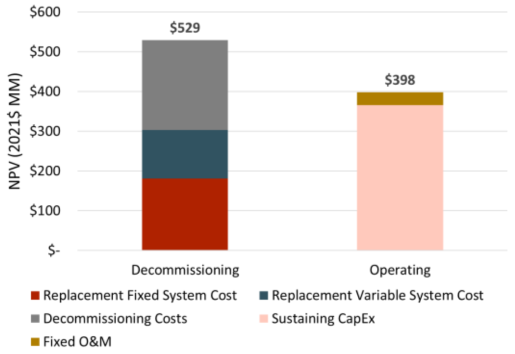
+ Similar results are found for the 2.1C scenario where the more constrained emissions and higher load results in higher replacement costs for renewable hydro capacity

Cost to Replace Small Hydro Assets vs Sustaining Capex (2.1.C)





Wreck Cove



Mersey

RESOURCE SCREENING RESULTS
KEY SCENARIOS

Nova Scotia
POWER
An Emera Company

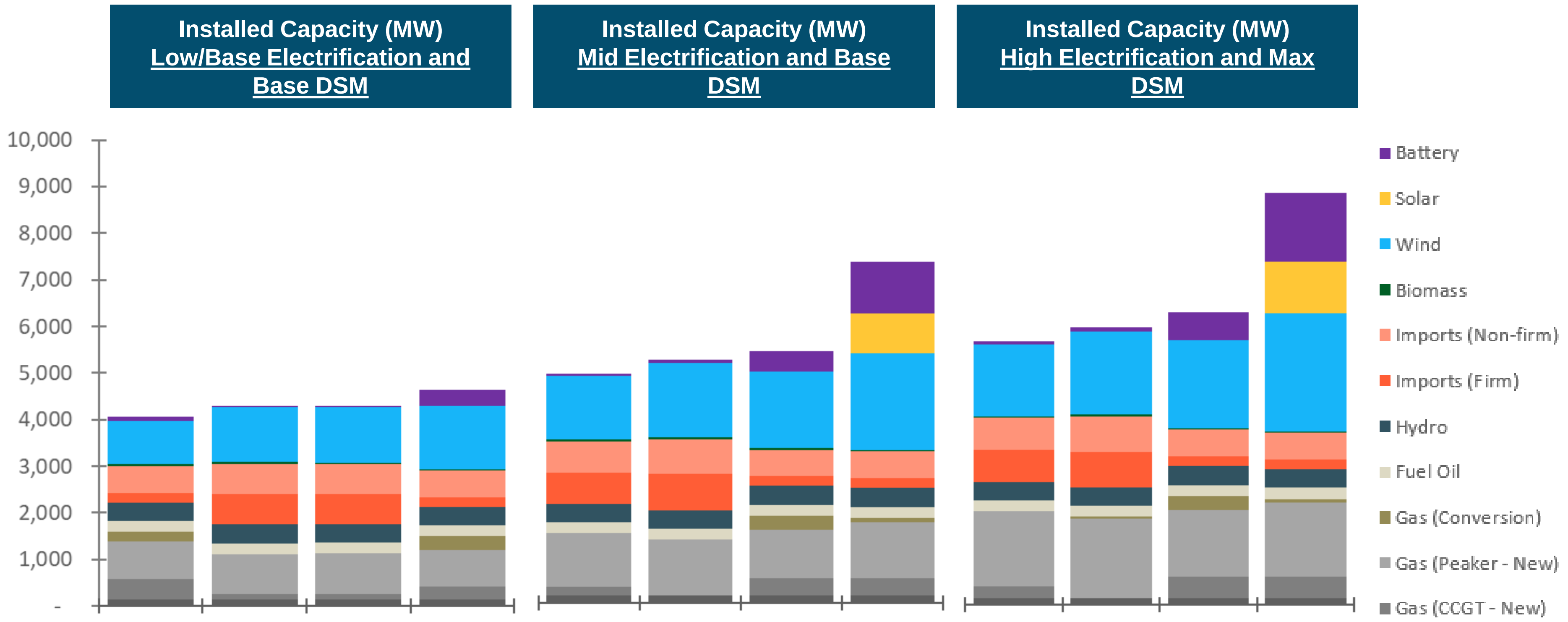
RESOURCE SCREENING – KEY SCENARIOS

- Initial runs of select key scenarios and sensitivities were conducted by E3 using RESOLVE
- Early runs in both PLEXOS and RESOLVE were used to validate the construction of the two models concurrently, providing insights by comparing runs of the same scenario across both tools
- Based on the results of the screening results, the supply options available to the PLEXOS Initial Portfolio Study runs were further refined
- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and costs considered outside of the long-term model optimization (i.e. energy efficiency costs)

Nova Scotia POWER
An Emera Company

2045 Installed Capacity Across Current Landscape and Regional Integration Cases

- Higher loads and more stringent decarbonization targets drive greater renewable builds, though access to greater regional imports (“C” Regional Integration cases) slightly mitigates builds and costs



	1.0.A	1.0.C	2.0.C	2.0.A	2.1.C	3.1.C	2.1.A	3.1.A	2.2.C	3.2.C	2.2.A	3.2.A
NPV* ($MM) (2021-2045)	$12,257	$12,193	$12,215	$12,275	$12,954	$13,468	$13,049	$13,607	$14,948	$15,372	$15,057	$15,854
Avg. Generation Cost (¢/kWh)	7.6	7.6	7.6	7.7	7.7	8.0	7.8	8.1	8.6	8.9	8.7	9.2

1.0.A - Case Summary

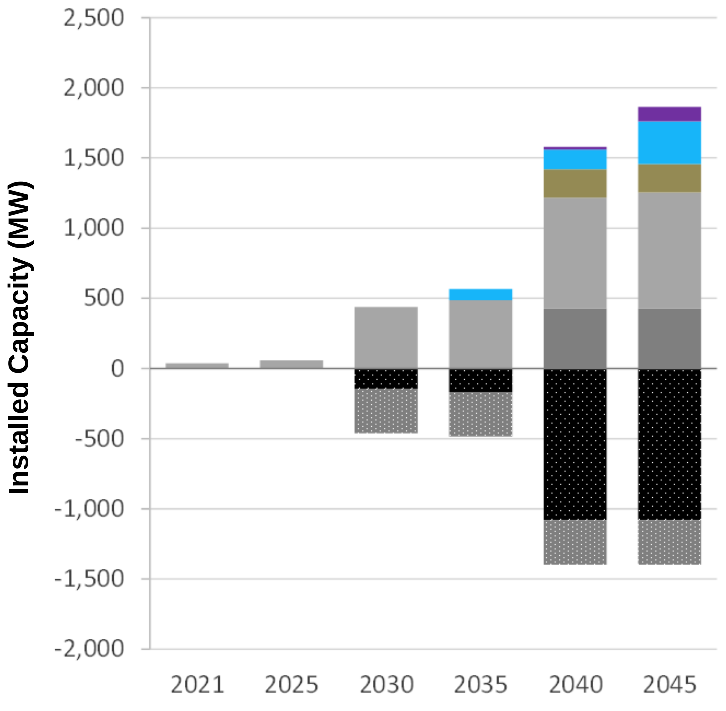
Comparator, Low Elec./Base DSM, Current Landscape

Key Observations

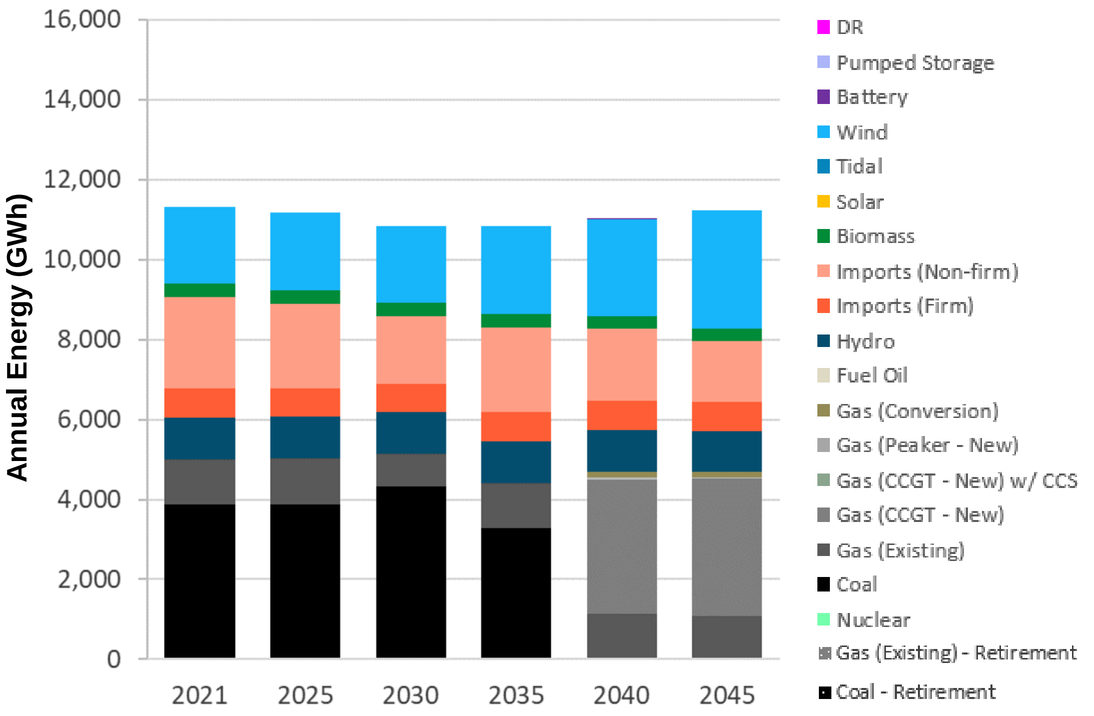
+ A combination of gas peakers, gas CCGT, and wind is built to replace the retired coal capacity
+ ~300 MW of new wind is built by 2045

Metric	2035	2045
GHG Emissions (MMT)	3.7	2.2
GHG Marginal Abatement Cost ($/ton)	$16	$0
NPV ($2021)	$12,257	
NPV ($2021) – with 20-year end effects	$15,989	
Average Generation Cost (c/kWh)	7.6	

Capacity Addition (+) and Retirement (-) (MW)



Energy Balance (GWh)



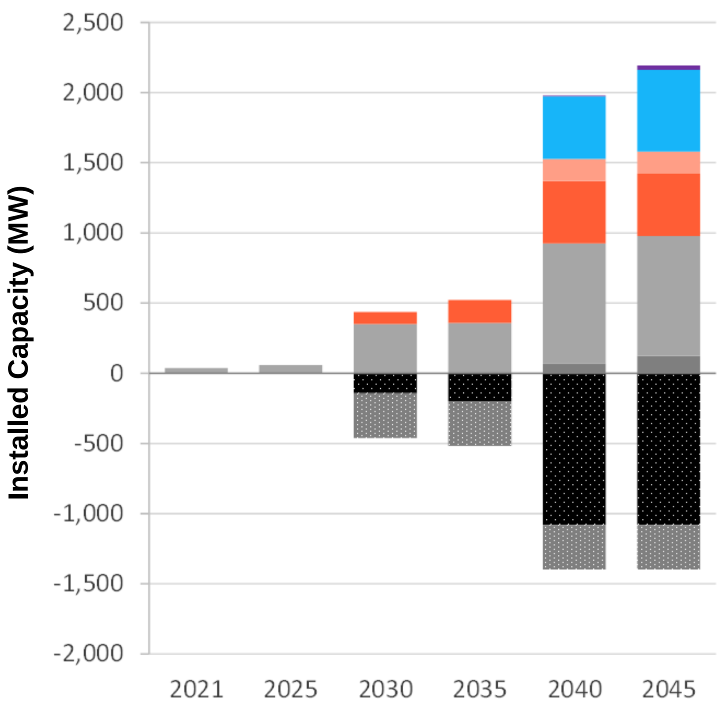
1.0.C - Case Summary

Comparator, Low Elec./Base DSM, Regional Integration

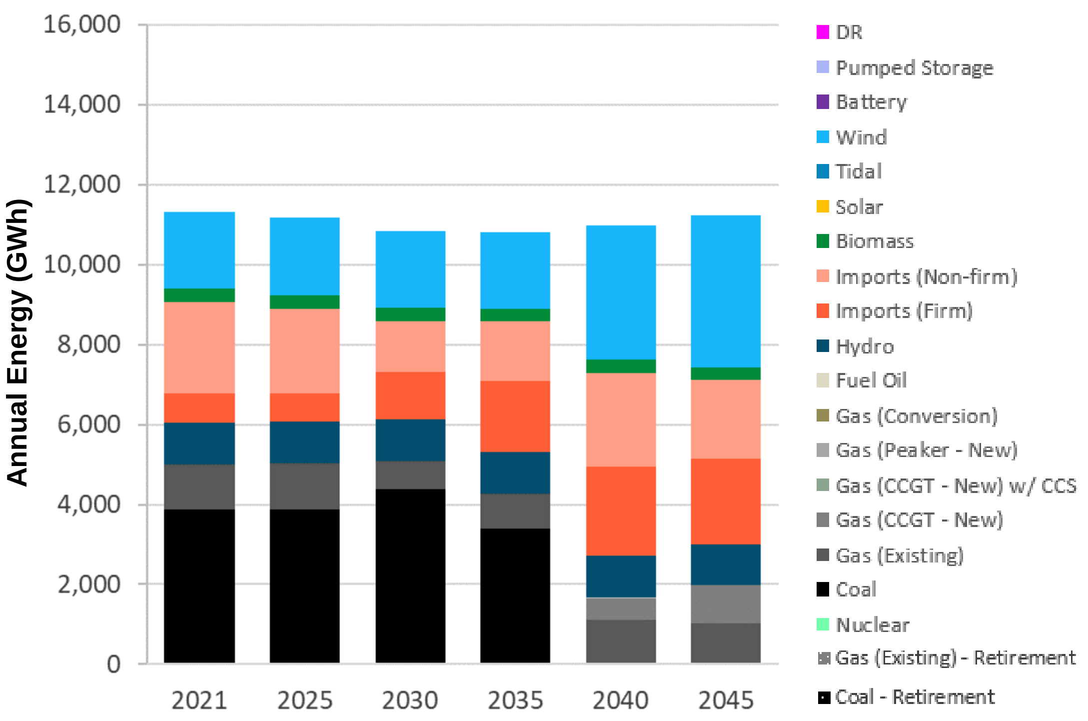
Key Observations
+ Model selects firm imports when available; ~600 MW of transmission line is built to access imports in the later years
+ New wind capacity is higher than 1.0.A. The new transmission lines allow for more wind integration without a large storage build
+ New transmission lines help drop 2045 annual GHG emissions to just 1 MMT

Metric	2035	2045
GHG Emissions (MMT)	3.7	1.0
GHG Marginal Abatement Cost ($/ton)	$12	$0
NPV ($2021)	$12,193	
NPV ($2021) – with 20-year end effects	$15,862	
Average Generation Cost (c/kWh)	7.6	

Capacity Addition (+) and Retirement (-) (MW)



Energy Balance (GWh)



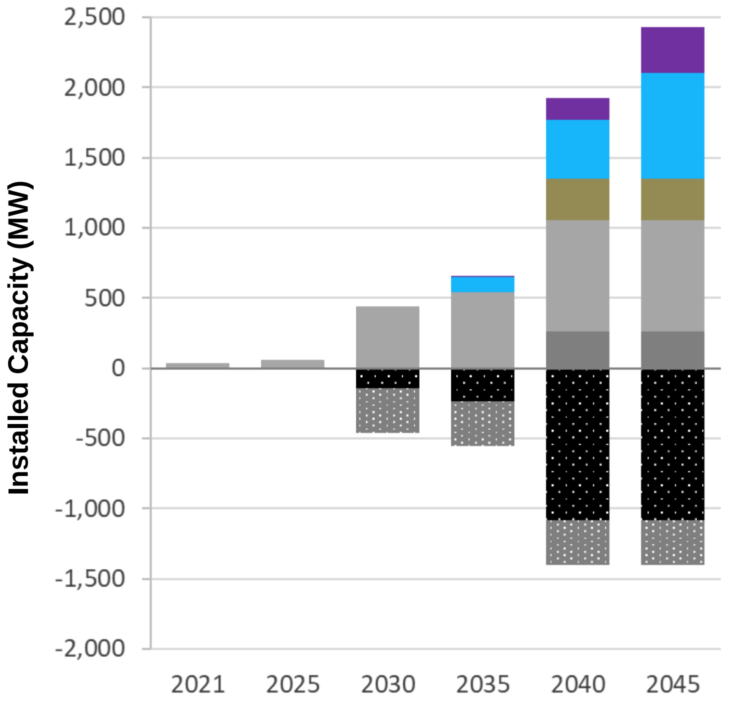
2.0.A - Case Summary
Net Zero, Low Elec./Base DSM, Current Landscape

Key Observations

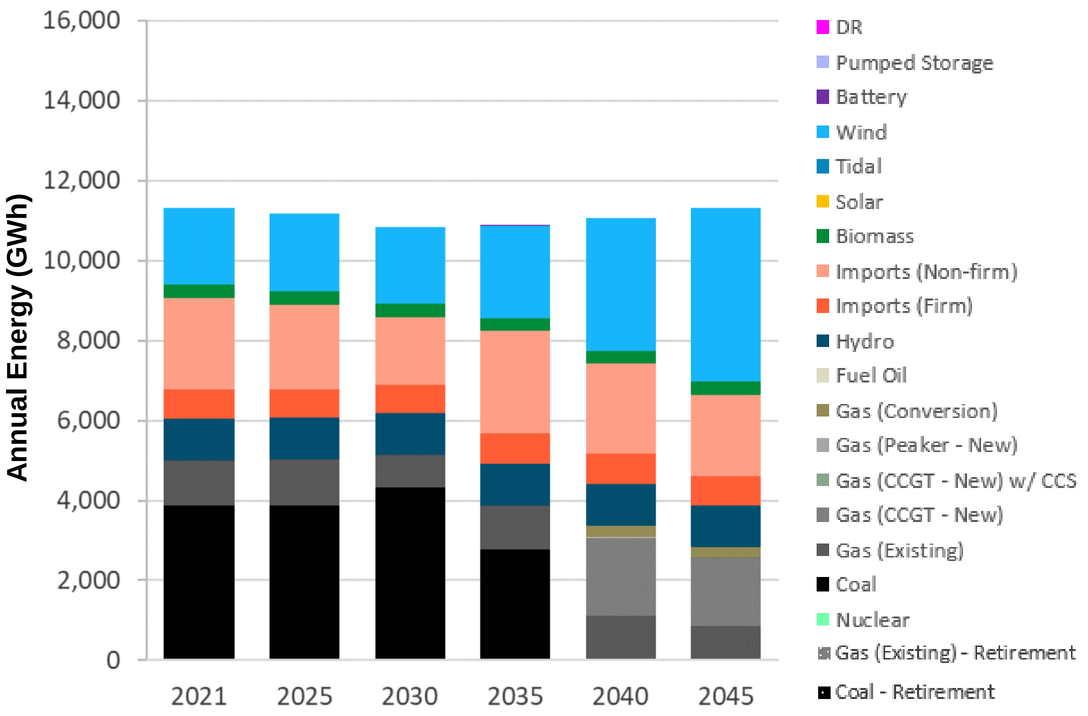
- The net zero case has more stringent GHG constraints compared to the comparator case
- Compared to 1.0A, the system relies less on gas peakers and more on wind and imports

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$21	$33
NPV ($2021)	$12,275	
NPV ($2021) – with 20-year end effects	$16,040	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



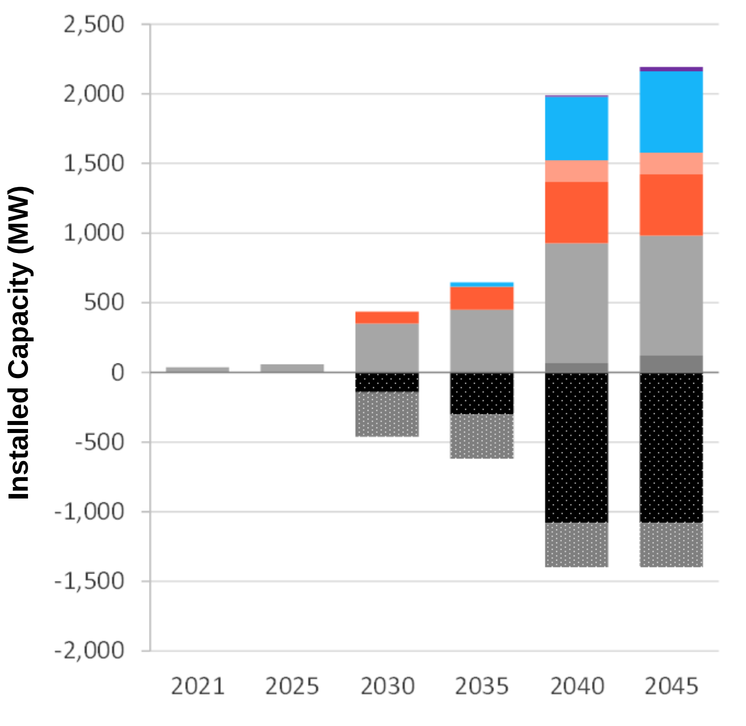
2.0.C - Case Summary
Net Zero, Low Elec./Base DSM, Regional Integration

Key Observations

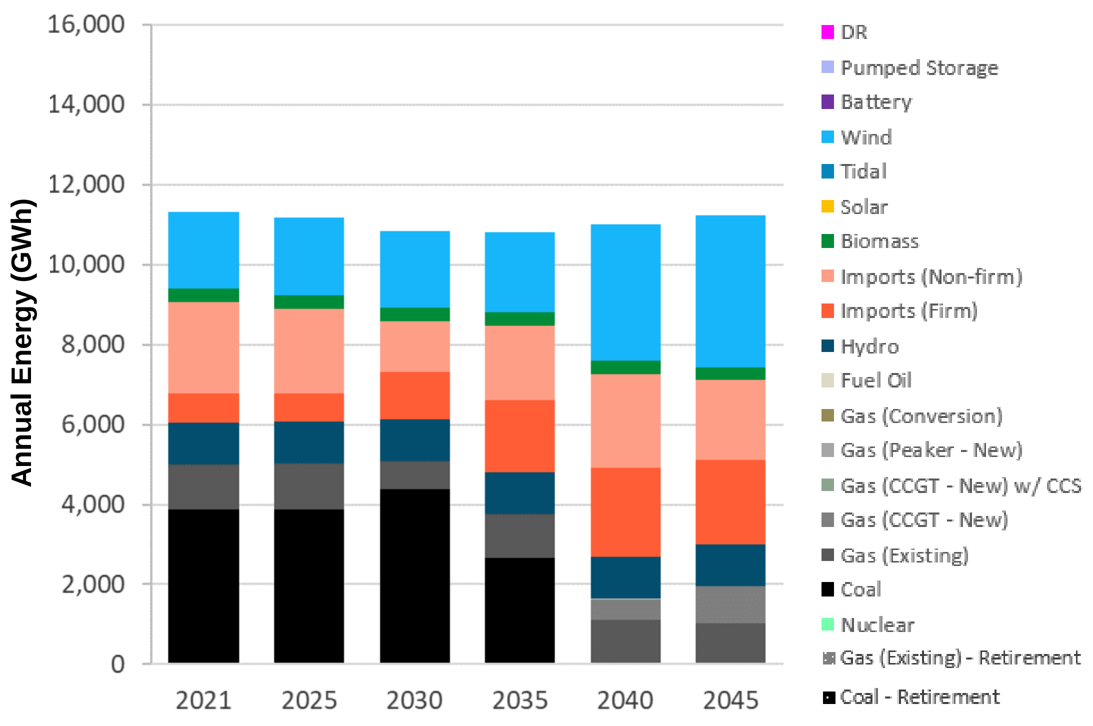
- Compared to 2.0.A we see less wind and more imports, while also requiring fewer batteries for wind balancing. About 30 MW of batteries are built by 2045 which helps balance the system and provide ancillary services
- System cost is similar to 1.0A

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.0
GHG Marginal Abatement Cost ($/ton)	$24	$0
NPV ($2021)	$12,215	
NPV ($2021) – with 20-year end effects	$15,885	
Average Generation Cost (c/kWh)	7.6	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



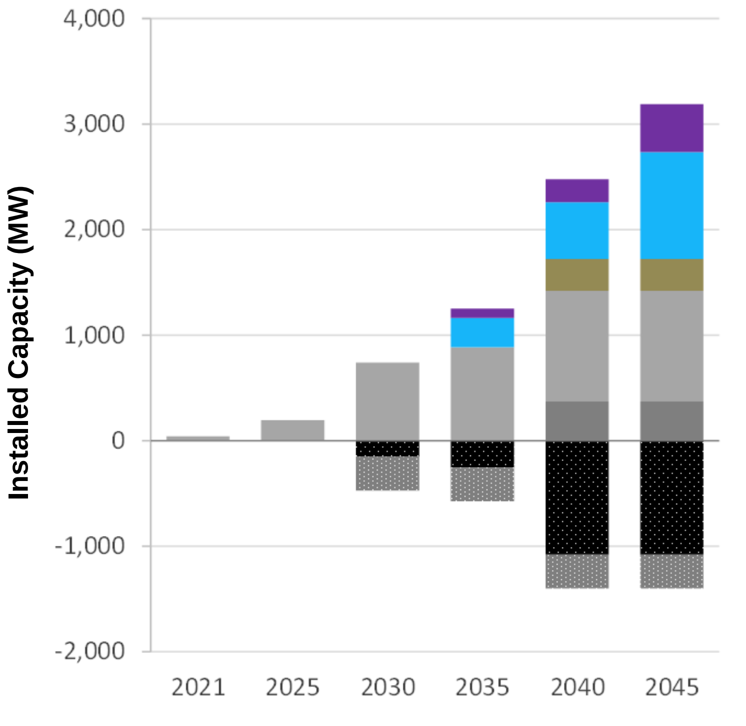
2.1.A - Case Summary
Net Zero, Mid Elec./Base DSM, Current Landscape

Key Observations

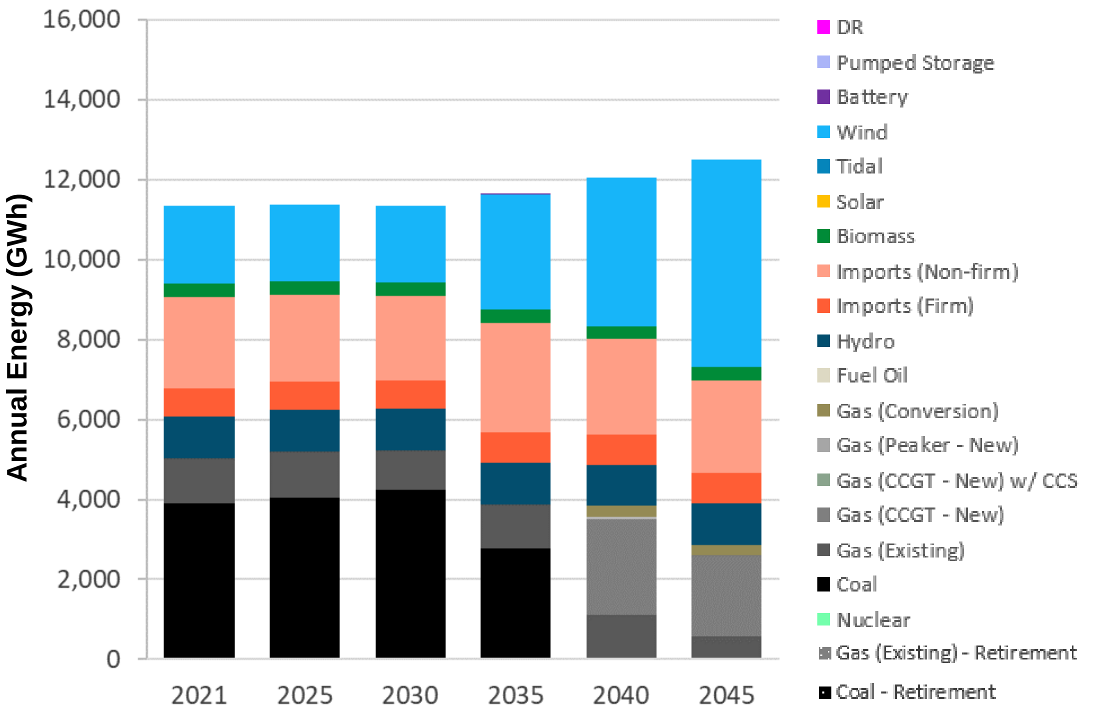
- Higher loads than 2.0.A leads to about ~260 MW more gas peaker build; ~105 MW more CCGT build; ~260 MW more wind build; and~130 MW more battery build
- The average generation cost also increases because the load is peakier and thus more expensive to serve
- Over 40% of total generation comes from wind by 2045, and about 25% of total generation comes from imports

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$23	$44
NPV ($2021)	$13,049	
NPV ($2021) – with 20-year end effects	$17,315	
Average Generation Cost (c/kWh)	7.8	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



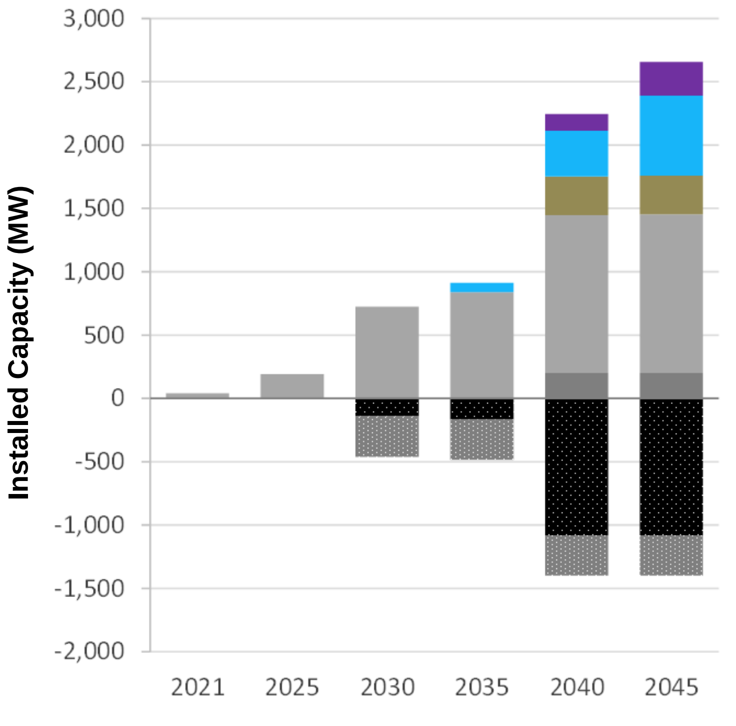
2.1.B - Case Summary
Net Zero, Mid Elec./Base DSM, Distributed Resources

Key Observations

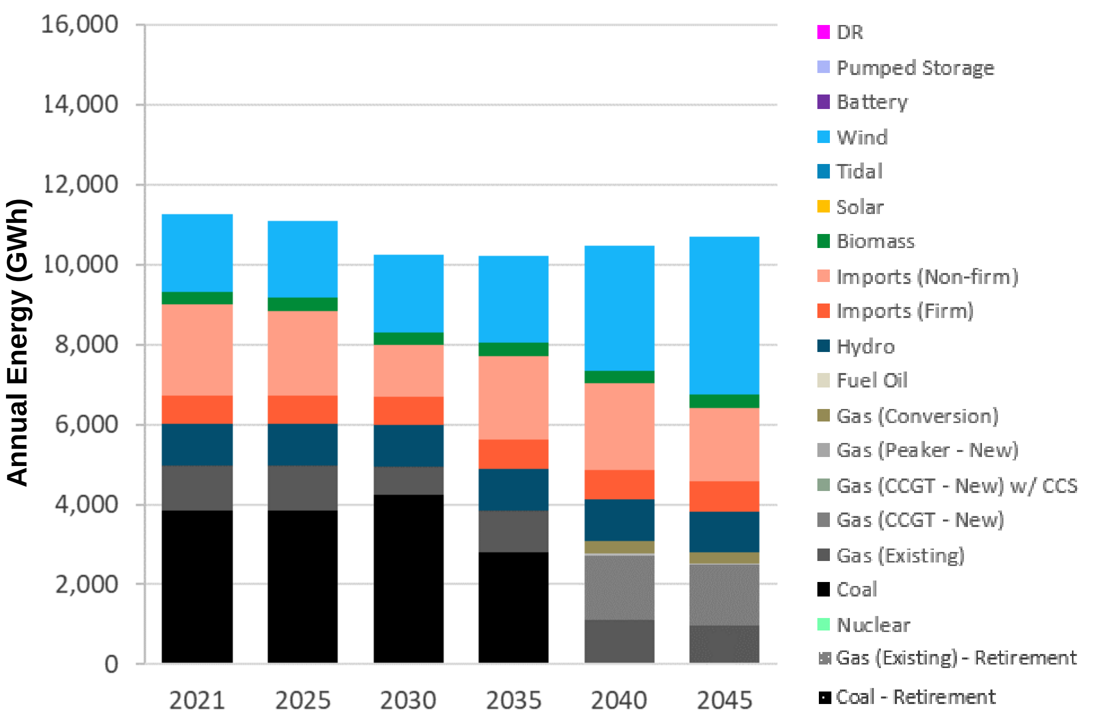
- Although total NPV is lower (reflecting less load served), the average generation cost is higher relative to 2.1A, reflecting system costs spread over less kWh
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$14	$24
NPV ($2021)	$12,264	
NPV ($2021) – with 20-year end effects	$16,017	
Average Generation Cost (c/kWh)	7.9	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



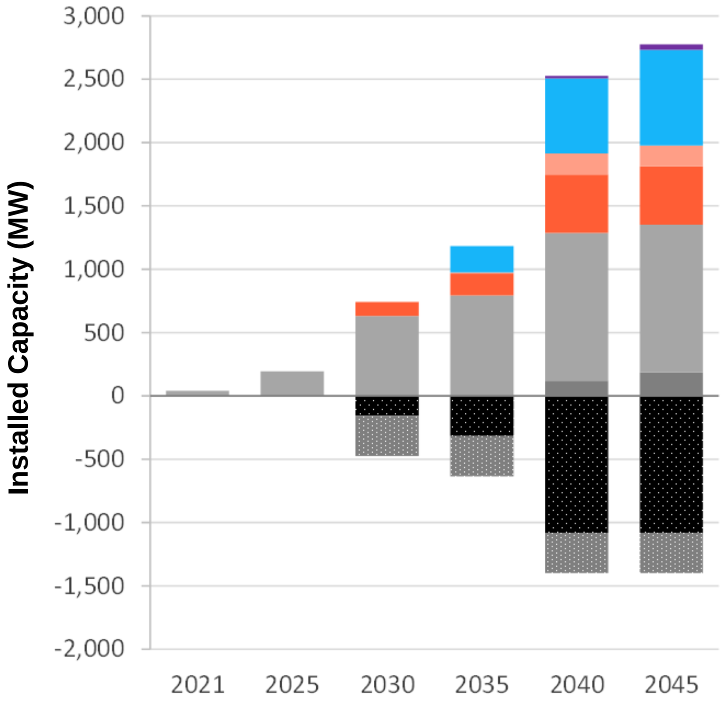
2.1.C - Case Summary
Net Zero, Mid. Elec./Base DSM, Current Landscape

Key Observations

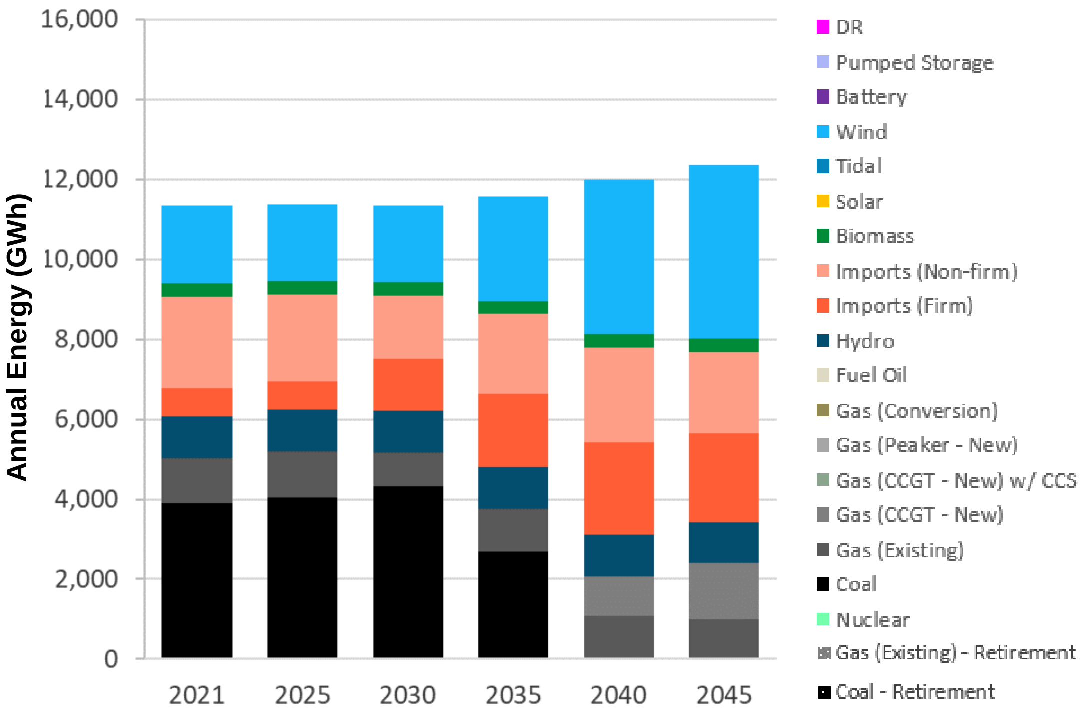
- With access to firm import options, the model chooses incremental firm imports which reduce total system cost
- Greater import access results in ~370 MW less gas build, ~260 MW less wind build and ~400 MW less battery build
- Regional integration lowers NPV of system costs relative to 2.1A

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.2
GHG Marginal Abatement Cost ($/ton)	$26	$0
NPV ($2021)	$12,954	
NPV ($2021) – with 20-year end effects	$17,072	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)

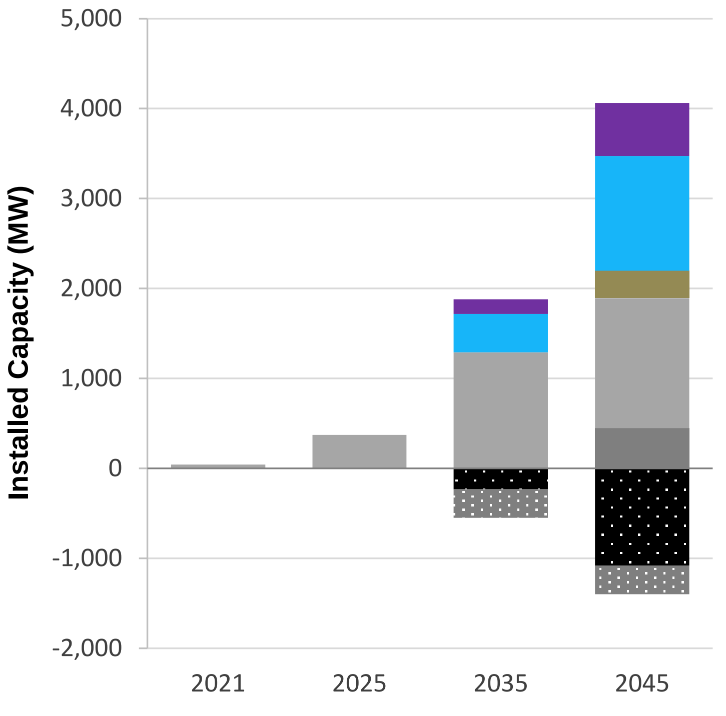


2.2.A - Case Summary
Net Zero, High Elec./Max DSM, Current Landscape

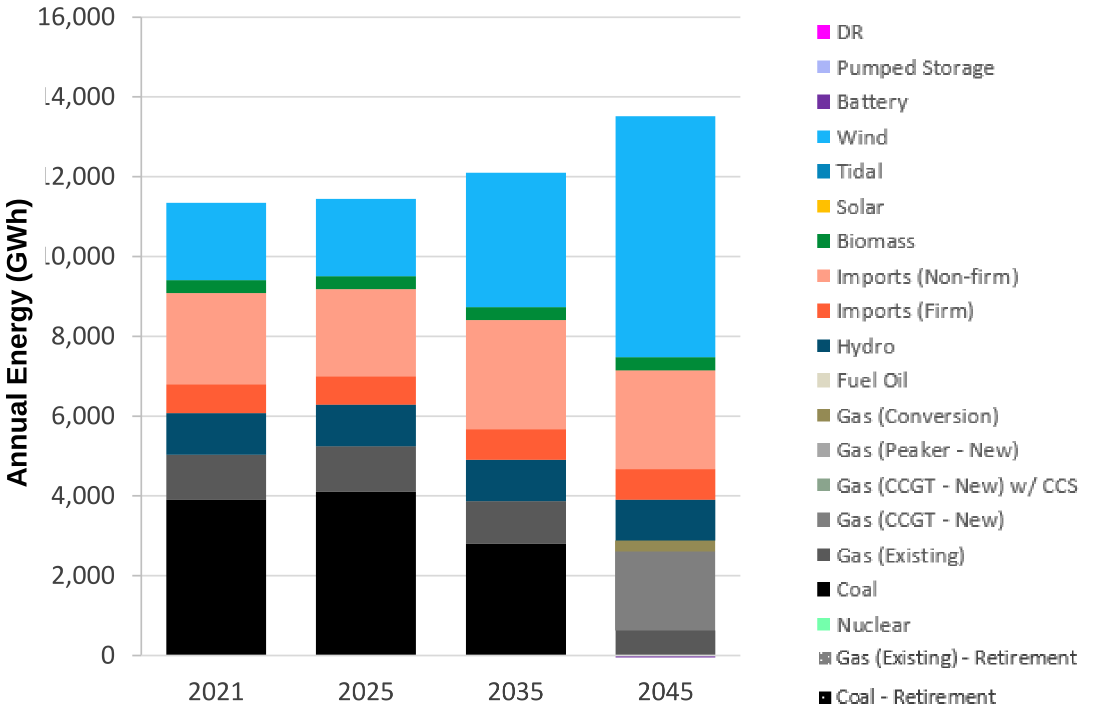
Key Observations
+ The high electrification forecast creates the need for nearly 1 GW of additional nameplate capacity (~600 MW firm) in 2045, relative to 2.1.A
+ This additional capacity is sourced in roughly equal parts from new gas CCGTs, CTs, wind, and batteries
+ The average generation cost increases significantly (~12%) relative to 2.1.A

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$24	$51
NPV ($2021)	$15,057	
NPV ($2021) – with 20-year end effects	$20,068	
Average Generation Cost (c/kWh)	8.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



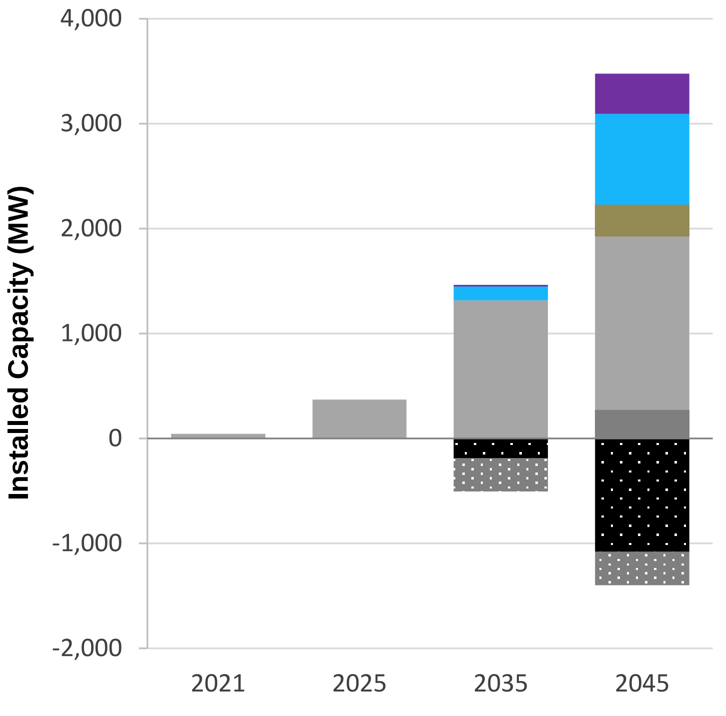
2.2.B - Case Summary
Net Zero, High Elec./Max DSM, Distributed Resources

Key Observations

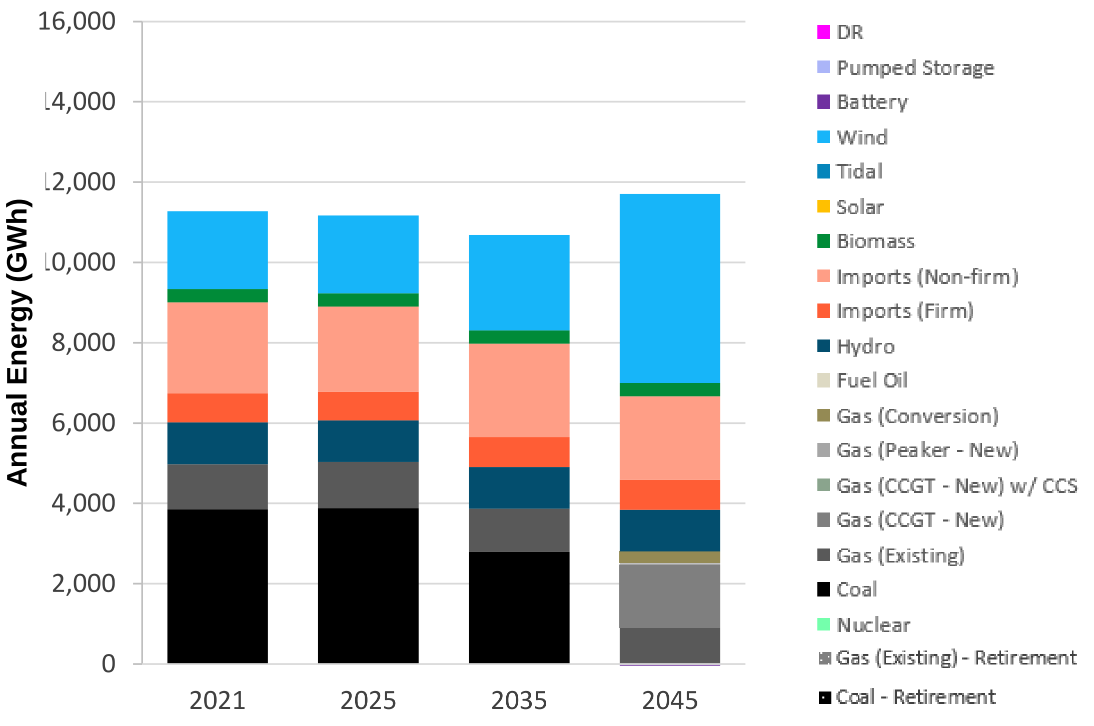
- The addition of DER's mitigates the capacity and energy needs of the high electrification forecast
- Average generation cost increases relative to 2.2A and 2.2C
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$18	$29
NPV ($2021)	$14,291	
NPV ($2021) – with 20-year end effects	$18,766	
Average Generation Cost (c/kWh)	8.9	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.2.C - Case Summary

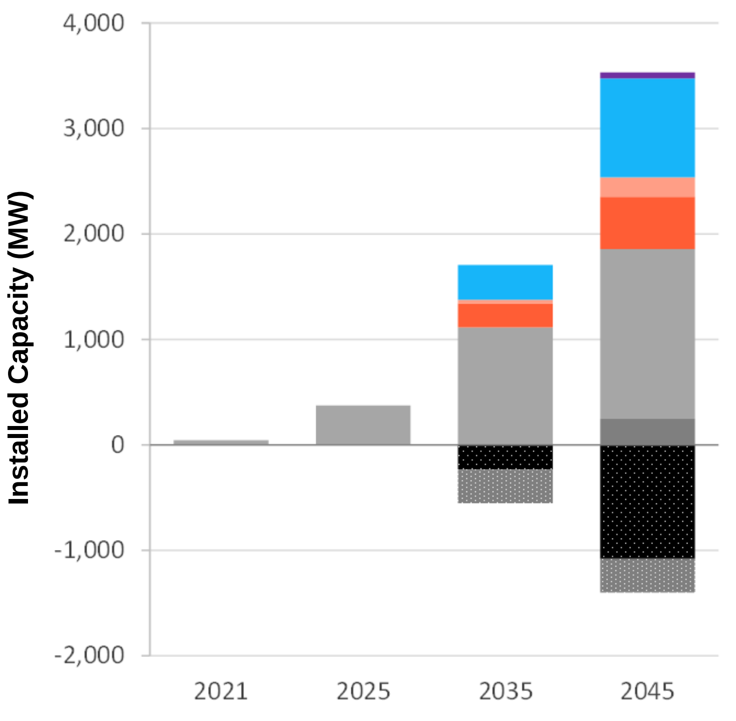
Net Zero, High Elec./Max DSM, Regional Integration

Key Observations

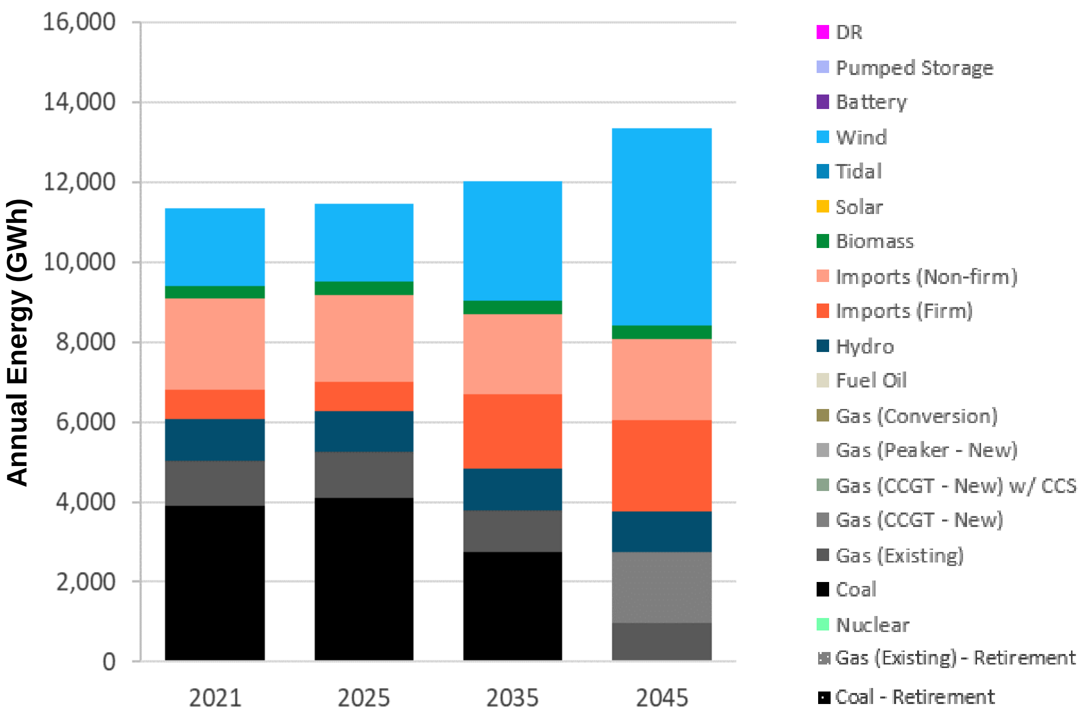
+ Additional import access helps meet the higher capacity and energy needs under high electrification. Costs decline relative to 2.2.A as the model selects cheaper import capacity, and integrates more wind
+ The average generation cost also increases relative to 2.1.C, reflecting the increased cost of serving high electrification load under the same GHG cap

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$22	$3
NPV ($2021)	$14,948	
NPV ($2021) – with 20-year end effects	$19,770	
Average Generation Cost (c/kWh)	8.6	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.1.A - Case Summary

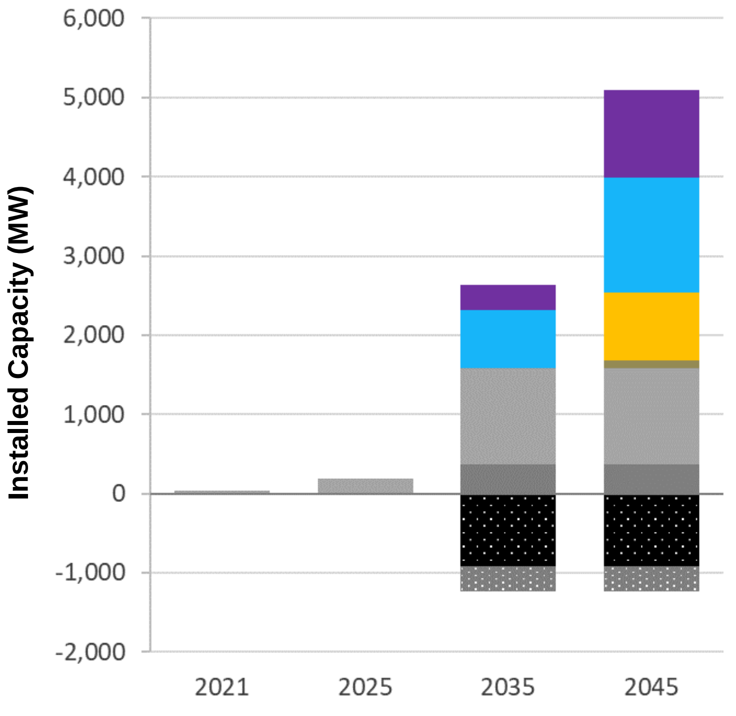
Accel. Net Zero, Mid Elec./Base DSM, Current Landscape

Key Observations

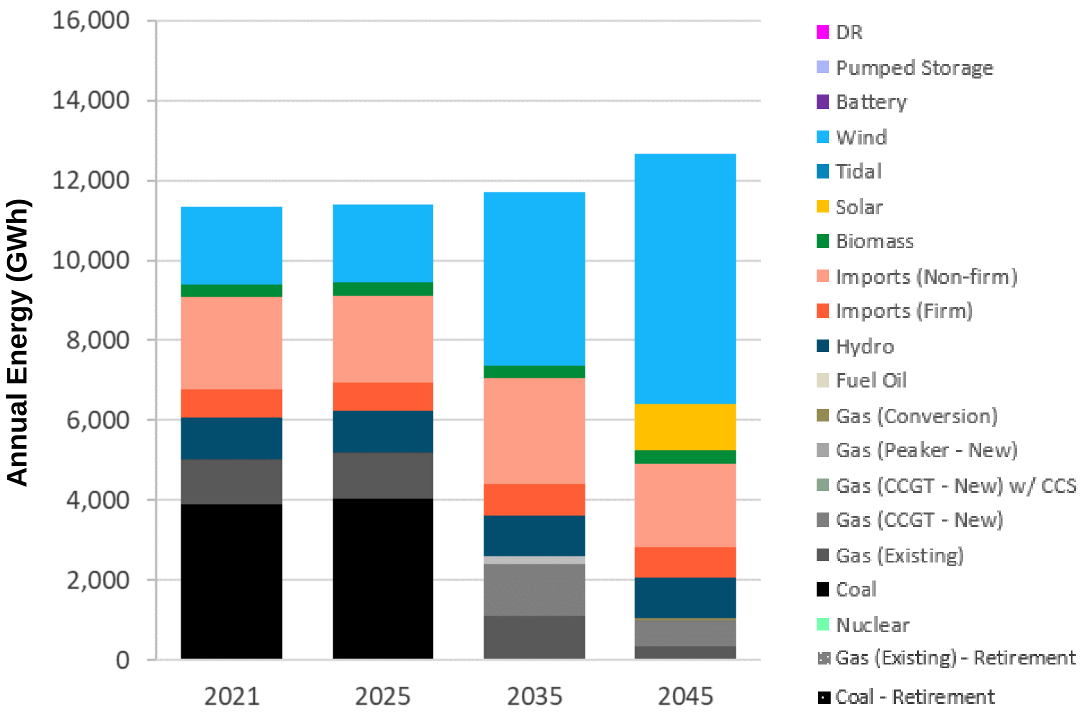
- The system builds more wind, solar, and batteries instead of gas to meet the lower GHG emissions target
- Alternative cases run with emerging technologies (CCS and SMR) resulted in similar costs; the results shown here are without SMR and CCS

Metric	2035	2045
GHG Emissions (MMT)	1.3	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$275
NPV ($2021)	$13,607	
NPV ($2021) – with 20-year end effects	$18,189	
Average Generation Cost (c/kWh)	8.1	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.1.B - Case Summary

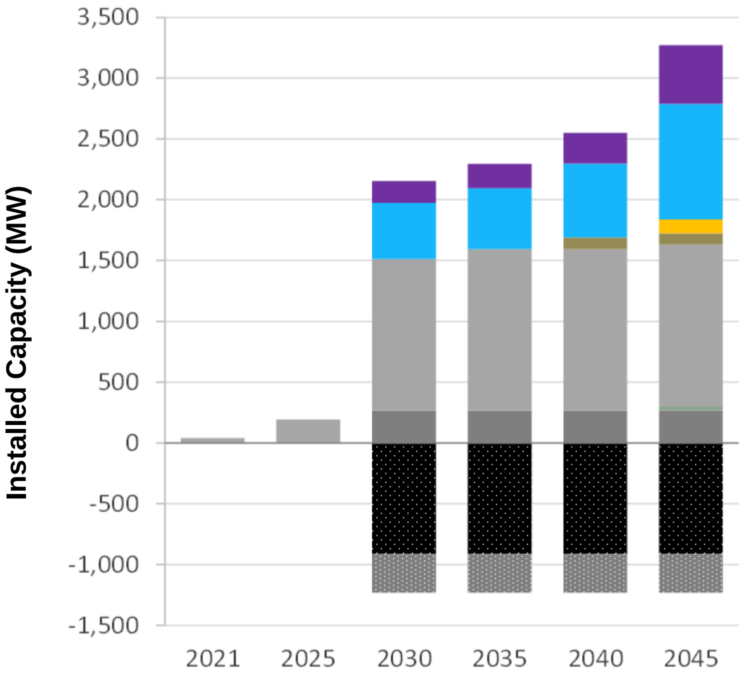
Accel. Net Zero, Mid Elec./Base DSM, Distributed Resources

Key Observations

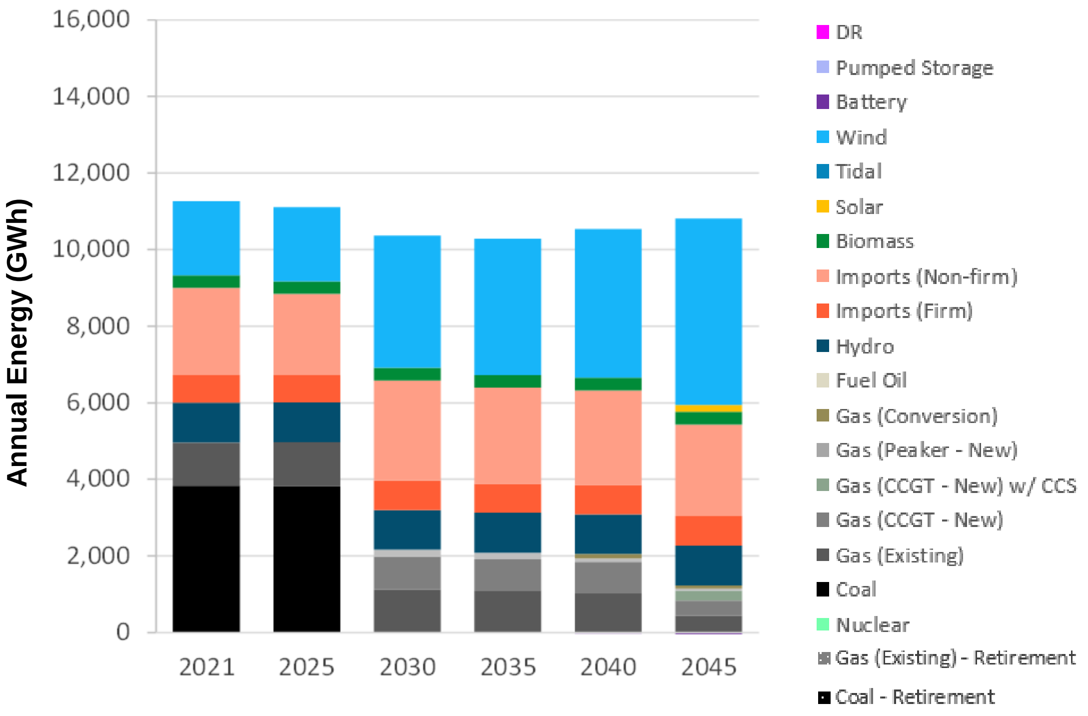
+ The addition of DER's mitigates the capacity and energy needs of the high electrification forecast
+ Total capacity needs in this case resemble the 3.1.A amounts, with an even lower energy forecast reminiscent the low electrification cases
+ DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

Metric	2035	2045
GHG Emissions (MMT)	1.1	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$82
NPV ($2021)	$12,888	
NPV ($2021) – with 20-year end effects	$16,831	
Average Generation Cost (c/kWh)	8.3	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.1.C - Case Summary

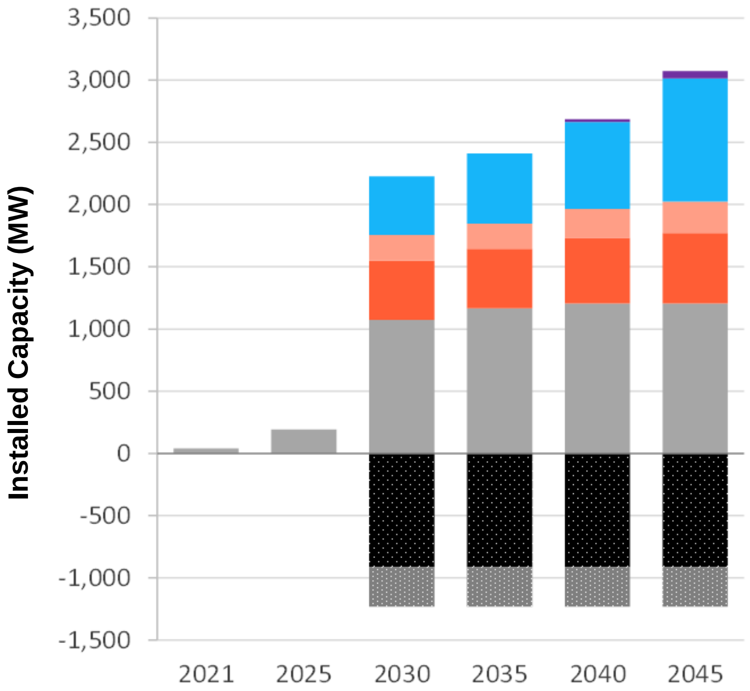
Accel. Net Zero, Mid Elec./Base DSM, Regional Integration

Key Observations

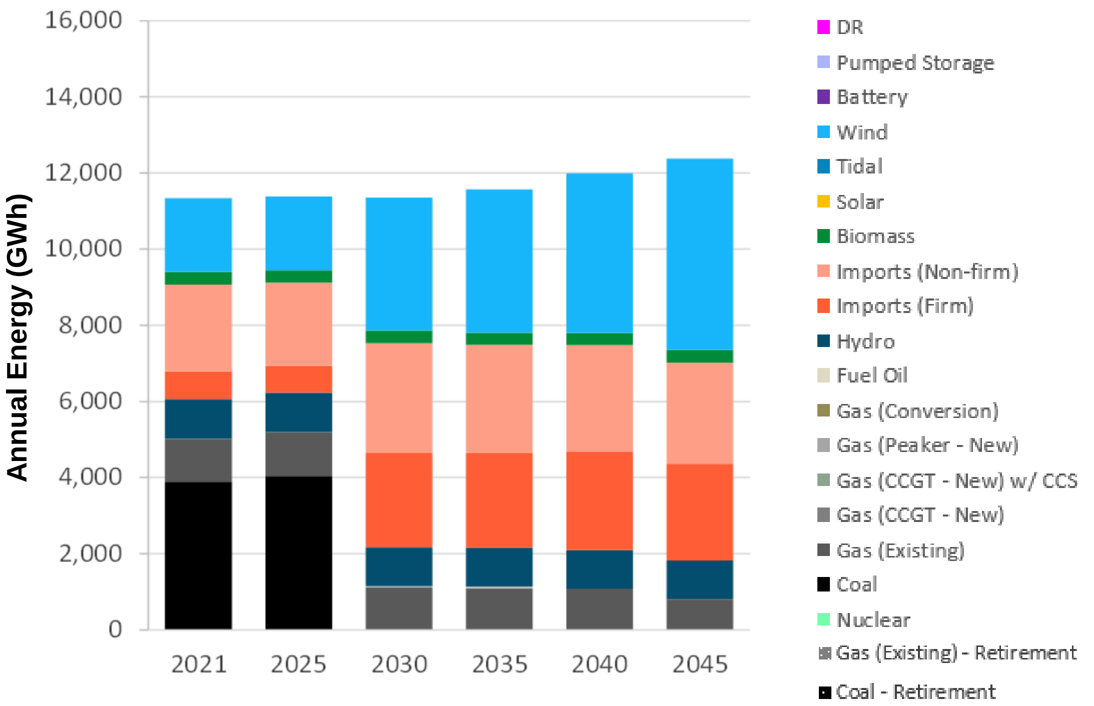
+ System costs decrease relative to 3.1.A when imports from neighboring regions are available
+ ~570 MW of firm and ~250 MW of non-firm import capacity is built to provide cleaner energy and capacity
+ When regional imports are available, the system builds ~ 850 MW less solar, ~500 MW less wind, ~1 GW less batteries, and ~400 MW less CCGT by 2045

Metric	2035	2045
GHG Emissions (MMT)	0.7	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$29
NPV ($2021)	$13,468	
NPV ($2021) – with 20-year end effects	$17,684	
Average Generation Cost (c/kWh)	8.0	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.2.A - Case Summary

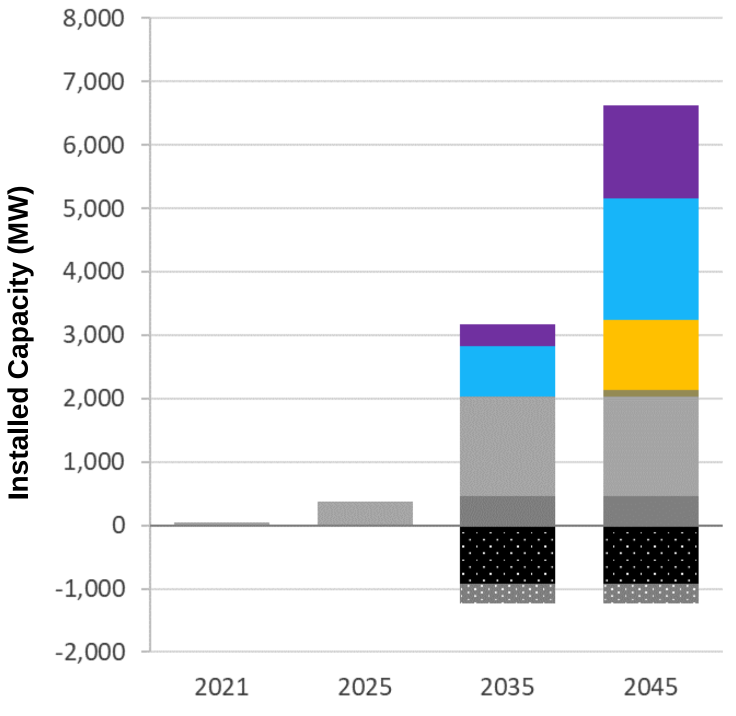
Accel. Net Zero, High Elec./Max DSM, Current Landscape

Key Observations

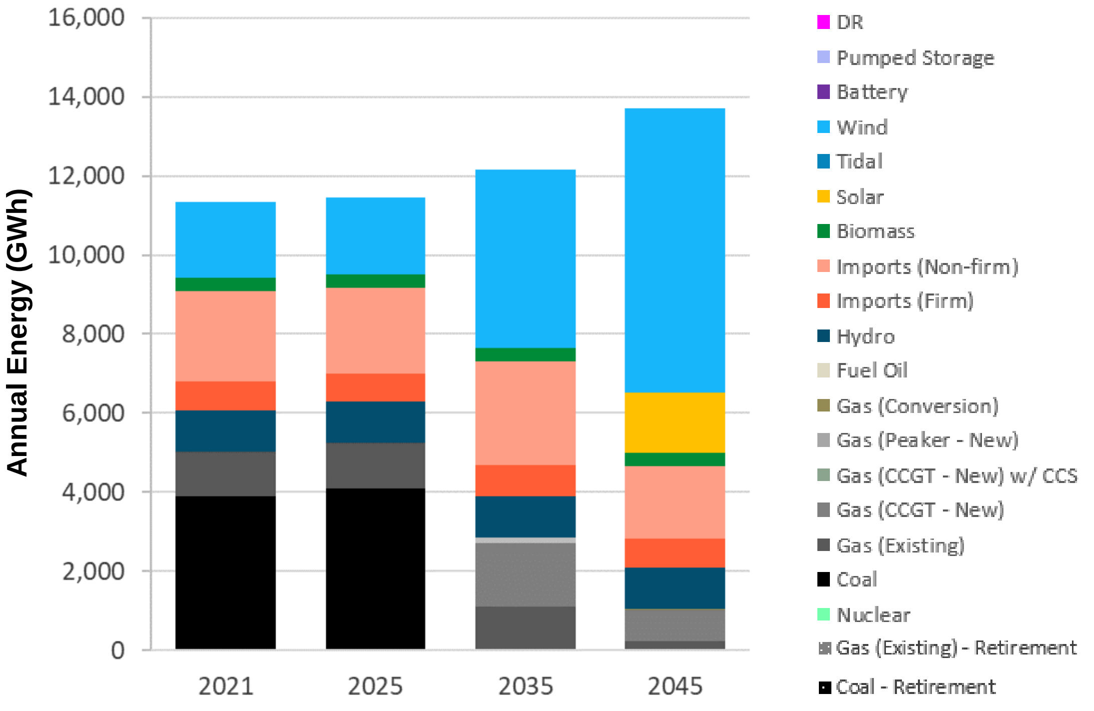
- The system relies on wind, solar, and batteries to meet the additional capacity and energy requirements.
- The system is overbuilt - renewable curtailment in 2045 is 16.4%
- Average generation cost increases significantly relative to 3.1.A
- Cases with/without emerging technologies (CCS and SMR) resulted in similar costs, but results shown here show results without SMR and CCS

Metric	2035	2045
GHG Emissions (MMT)	1.4	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$498
NPV ($2021)	$15,584	
NPV ($2021) – with 20-year end effects	$21,383	
Average Generation Cost (c/kWh)	9.2	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.2.B - Case Summary

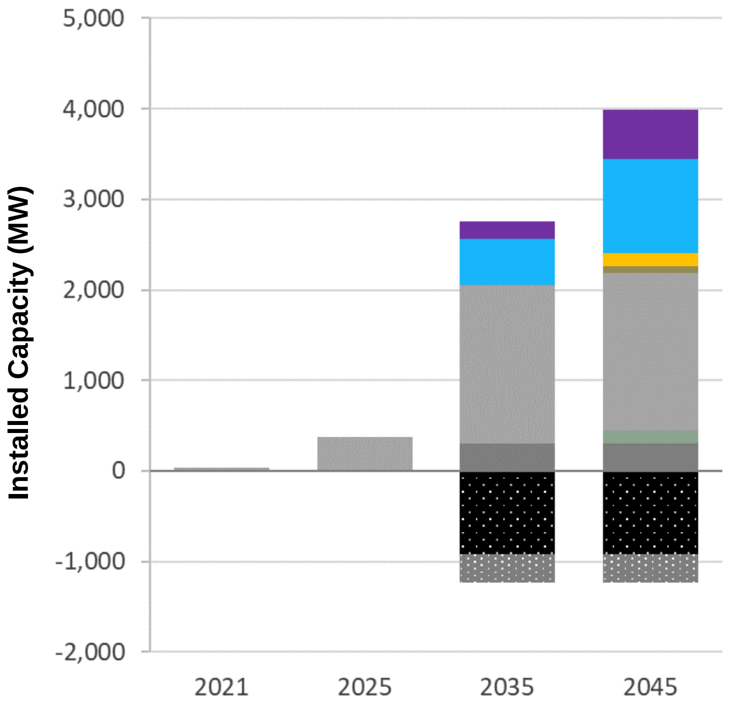
Accel. Net Zero, High Elec., Max DSM, Distributed Resources

Key Observations

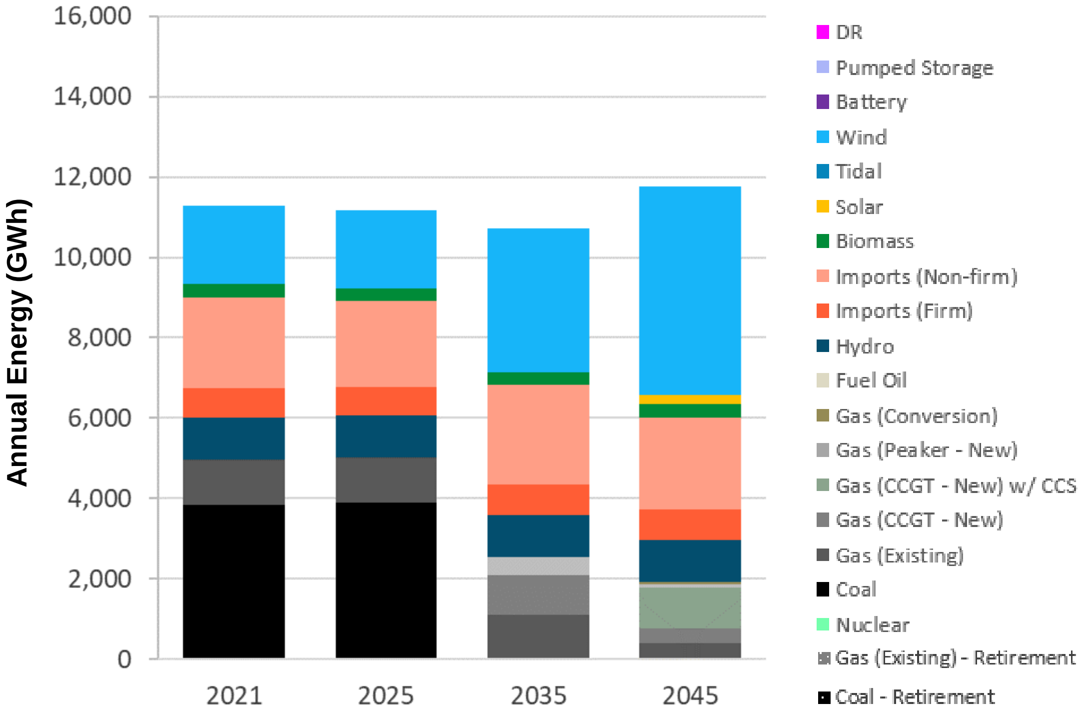
- Due to the load reduction provided by DER, less new capacity is needed to meet the electrification load
- The average generation cost, however, increases because the lower load factor
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

Metric	2035	2045
GHG Emissions (MMT)	1.3	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$101
NPV ($2021)	$14,877	
NPV ($2021) – with 20-year end effects	$19,601	
Average Generation Cost (c/kWh)	9.3	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.2.C - Case Summary

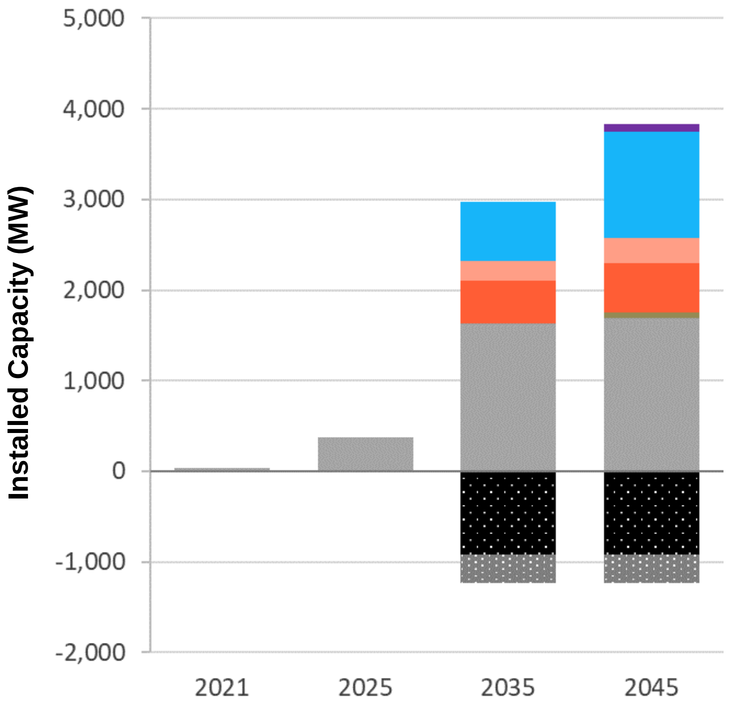
Accel. Net Zero, High Elec./Max DSM, Regional Integration

Key Observations

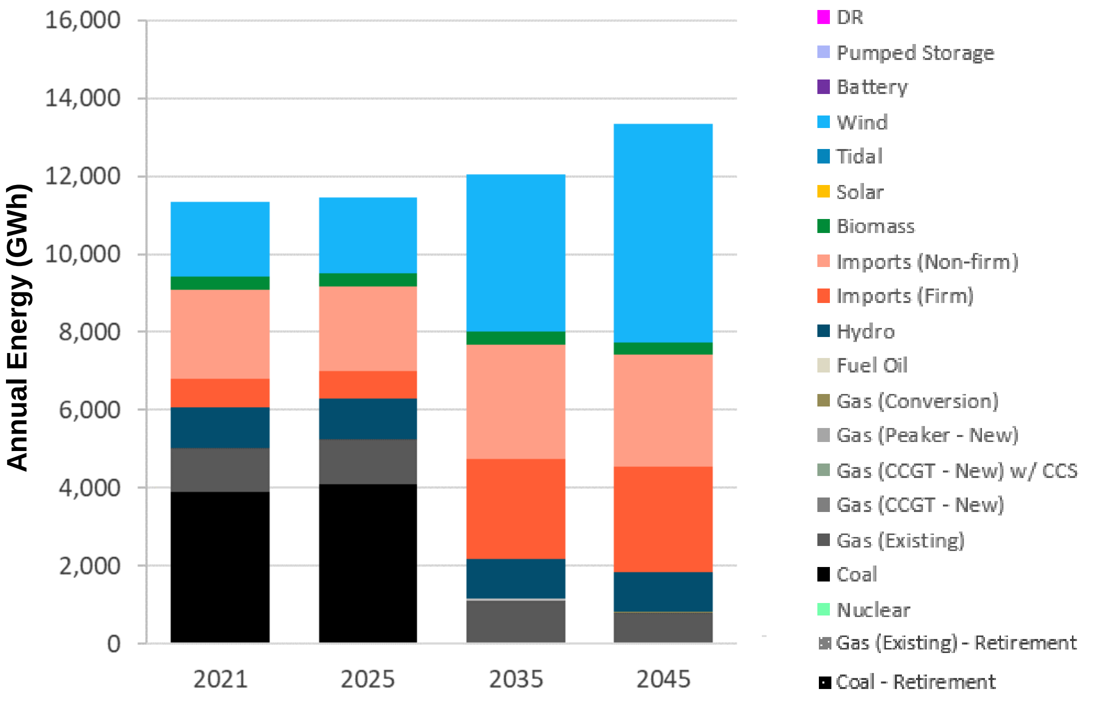
- System costs decrease when imports from neighboring regions are available
- ~550 MW of firm and ~270 MW of non-firm import capacity is built to provide cleaner energy and capacity
- When regional imports are available, the system builds significantly less solar, batteries, wind, and gas by 2045 (relative to 3.2A)

Metric	2035	2045
GHG Emissions (MMT)	0.7	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$30
NPV ($2021)	$15,372	
NPV ($2021) – with 20-year end effects	$20,296	
Average Generation Cost (c/kWh)	8.9	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



1.0.A with Low COVID Forecast

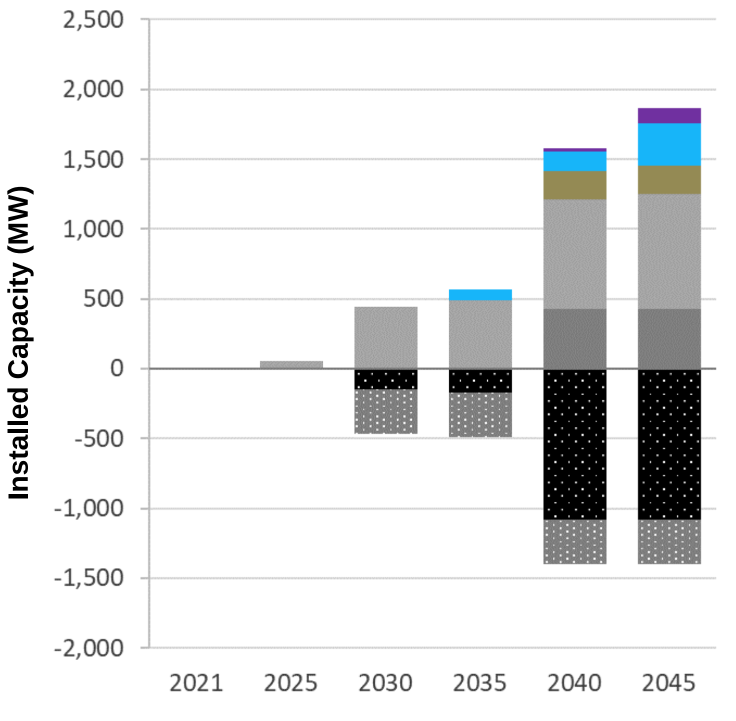
Comparator, Low COVID Load, Current Landscape

Key Observations

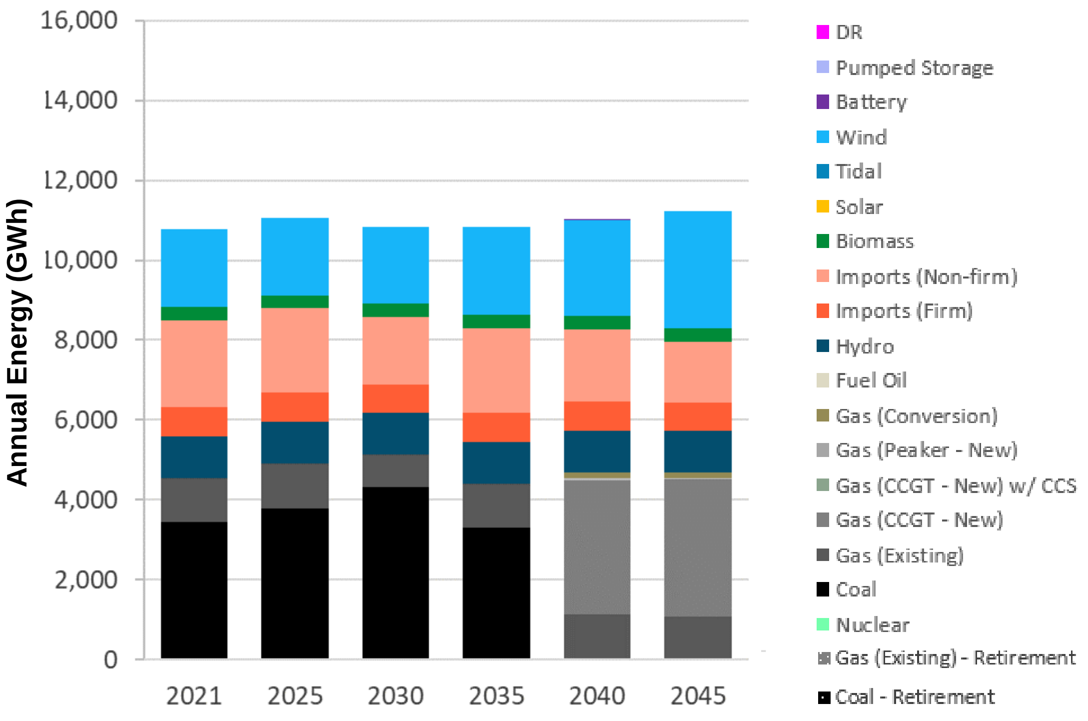
- The slight reduction in load has little impact on the capacity addition decision
- The overall system costs changes only slightly

Metric	2035	2045
GHG Emissions (MMT)	3.7	2.2
GHG Marginal Abatement Cost ($/ton)	$16	$0
NPV ($2021)	$12,178	
NPV ($2021) – with 20-year end effects	$15,910	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.0.A with Low COVID Forecast

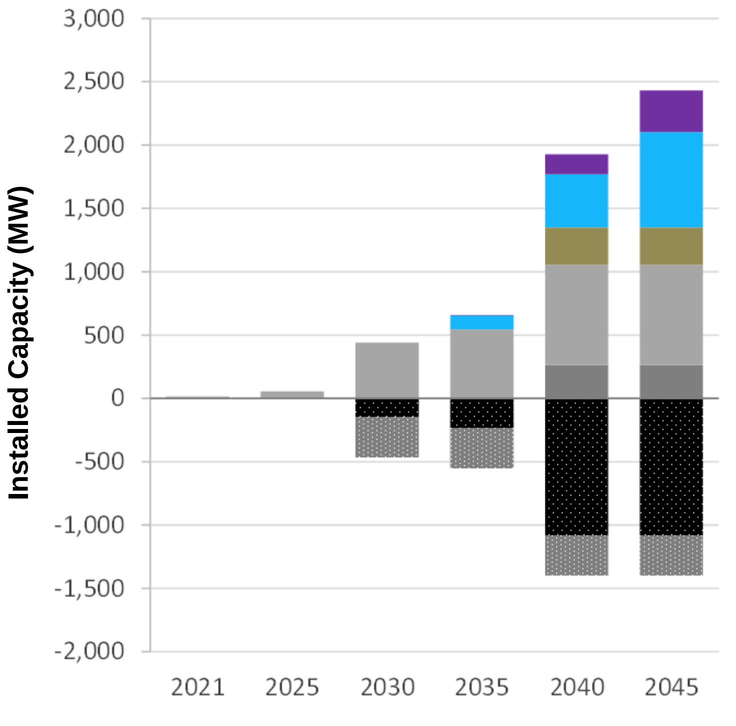
Net Zero, Low COVID Load, Current Landscape

Key Observations

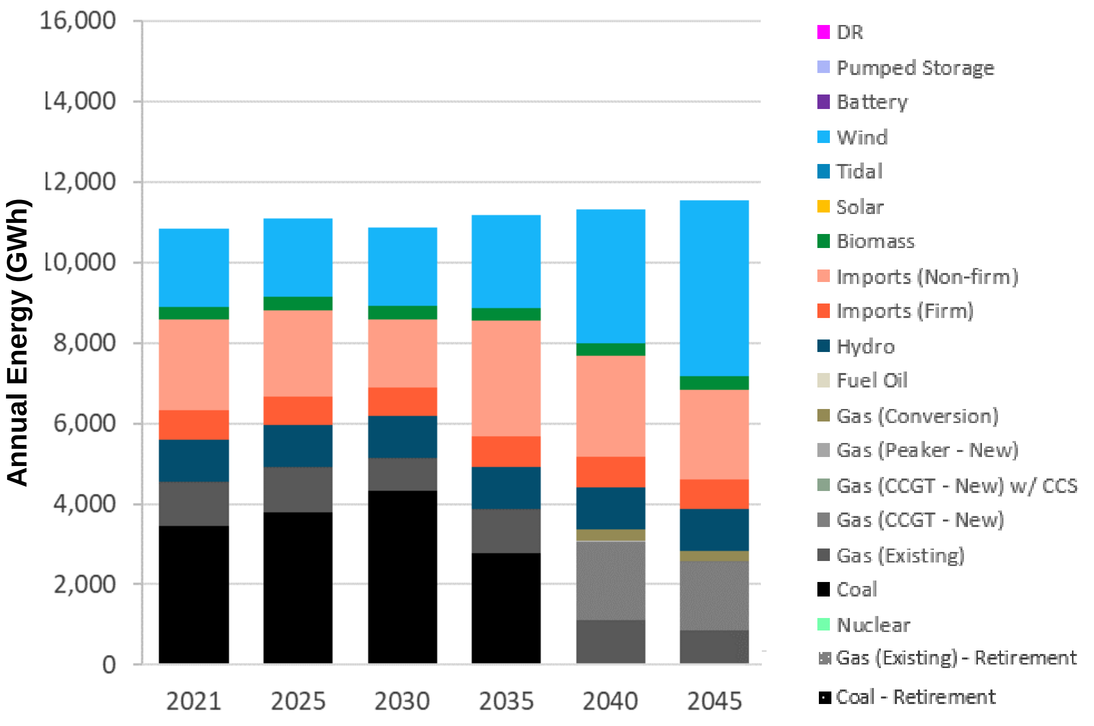
- The slight reduction in load has little impact on the capacity addition decision
- The overall system costs changes only slightly

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$21	$33
NPV ($2021)	$12,196	
NPV ($2021) – with 20-year end effects	$15,961	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.0.C with Low COVID Forecast

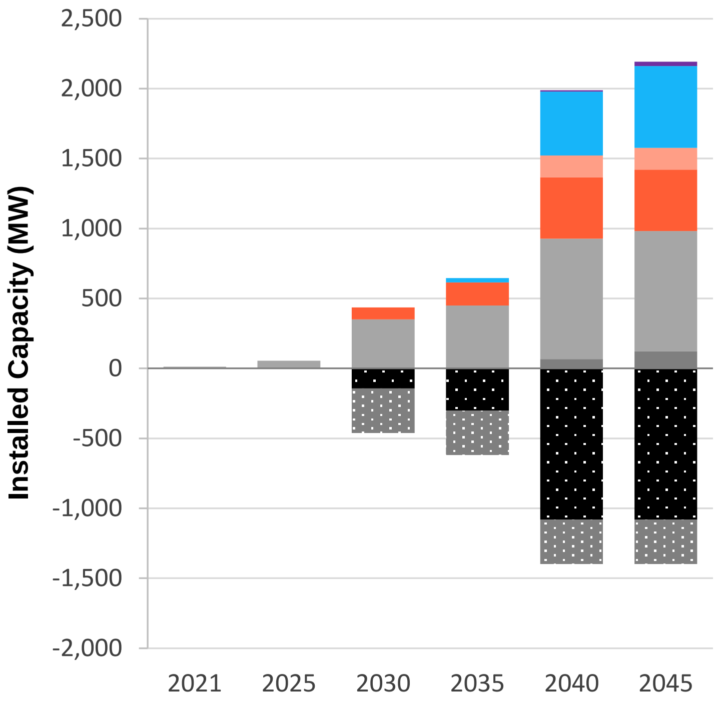
Net Zero, Low COVID Load, Regional Integration

Key Observations

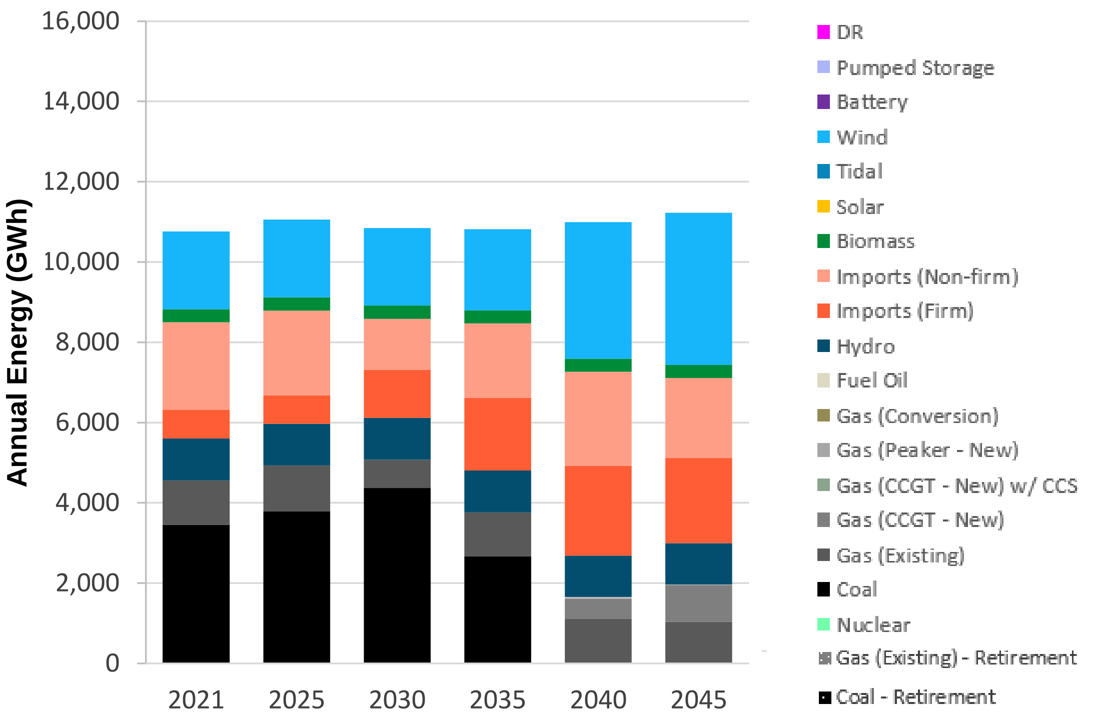
- The slight reduction in load has little impact on the capacity addition decision
- The overall system costs changes only slightly

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.0
GHG Marginal Abatement Cost ($/ton)	$24	$0
NPV ($2021)	$12,138	
NPV ($2021) – with 20-year end effects	$15,808	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



INITIAL PORTFOLIO STUDY RESULTS

Nova Scotia POWER
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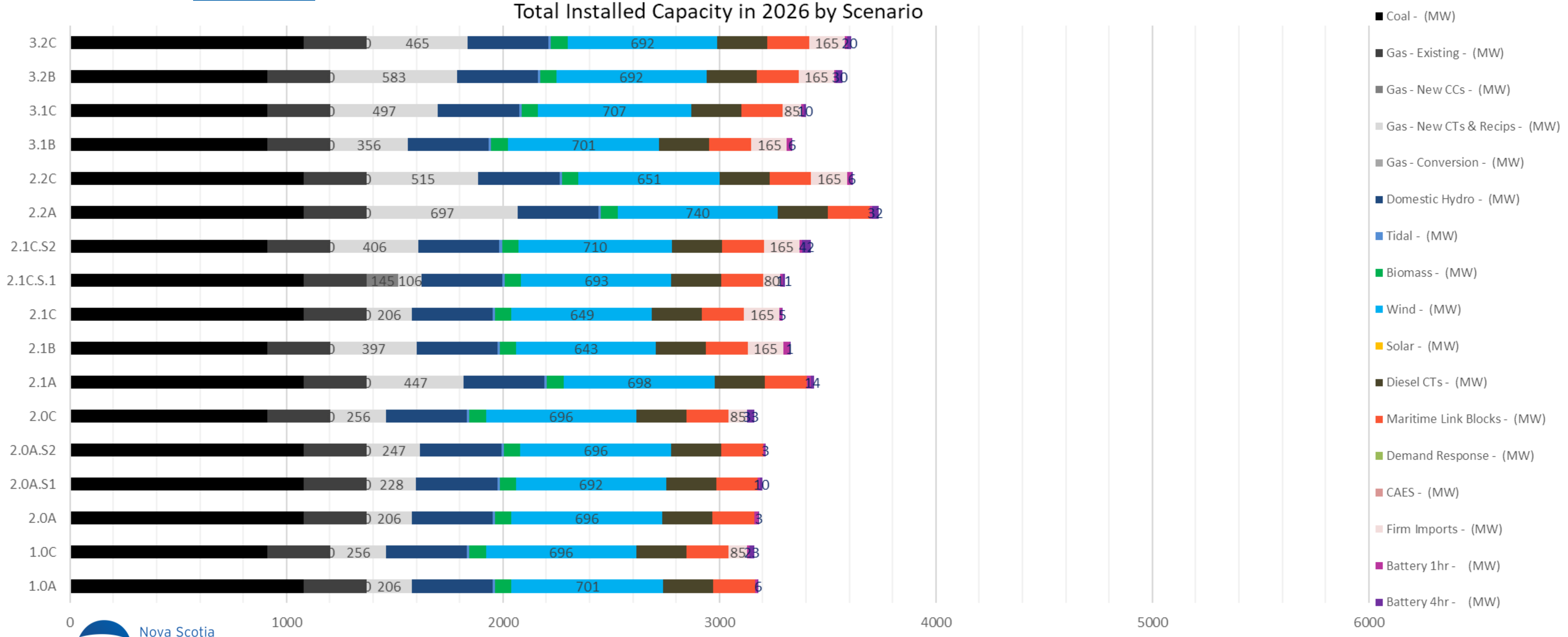
INITIAL PORTFOLIO STUDY

- The following slides provide the Initial Portfolio Study results from PLEXOS LT for the key scenarios as well for select sensitivities (full capacity expansion runs)
- The section includes several summary comparison slides as well as detailed outputs of each scenario including energy mix, nameplate capacity installation, emissions compliance, several metrics of NPV of partial revenue requirement, and scenario notes
- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and costs considered outside of the long-term model optimization (i.e. energy efficiency costs)
- NS Power will continue to refine these scenarios as we move through the Operability / Reliability Assessment and Final Portfolio Study phases of the Modeling Plan

NEAR TERM RESOURCE PORTFOLIOS (2026)



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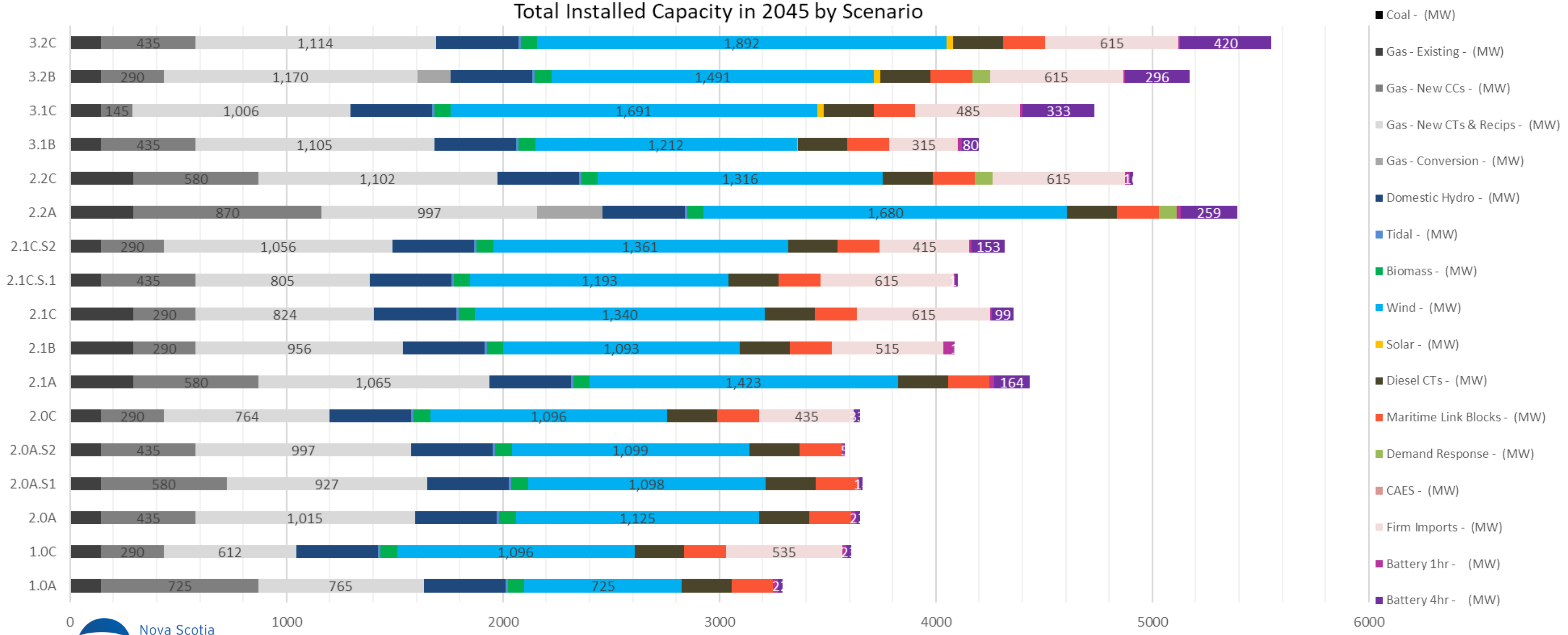
LONG TERM RESOURCE PORTFOLIOS (2045)



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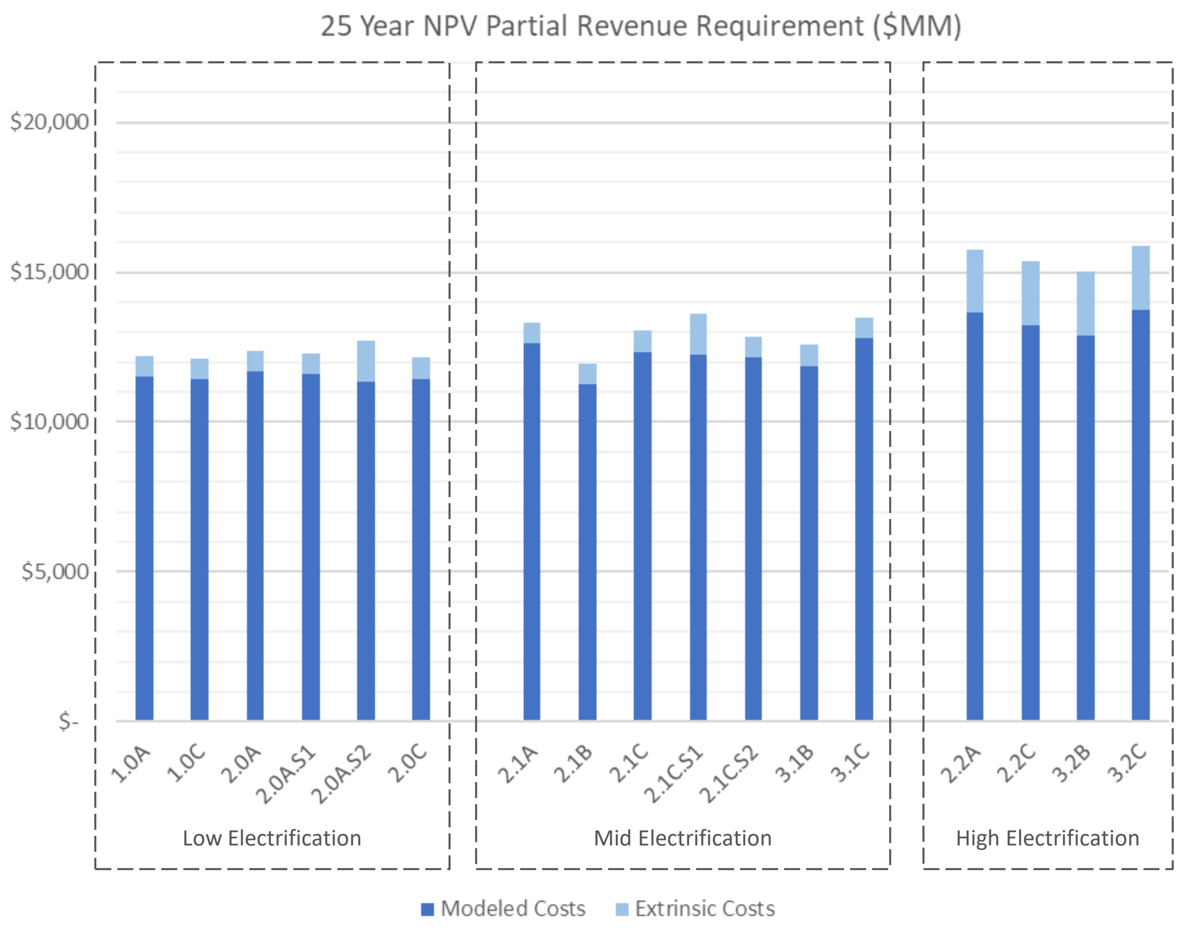
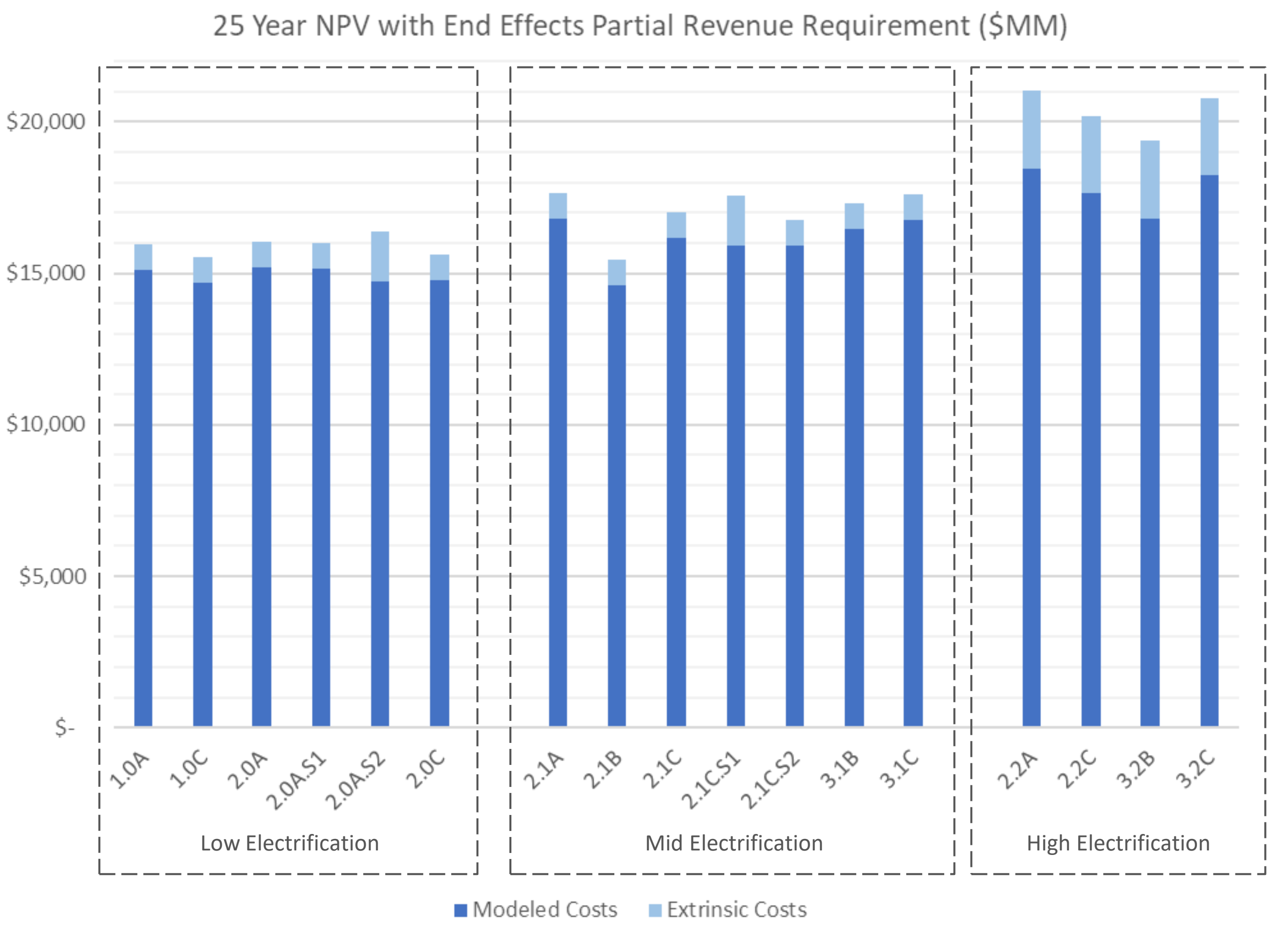
NPV PARTIAL REVENUE REQUIREMENT COMPARISON



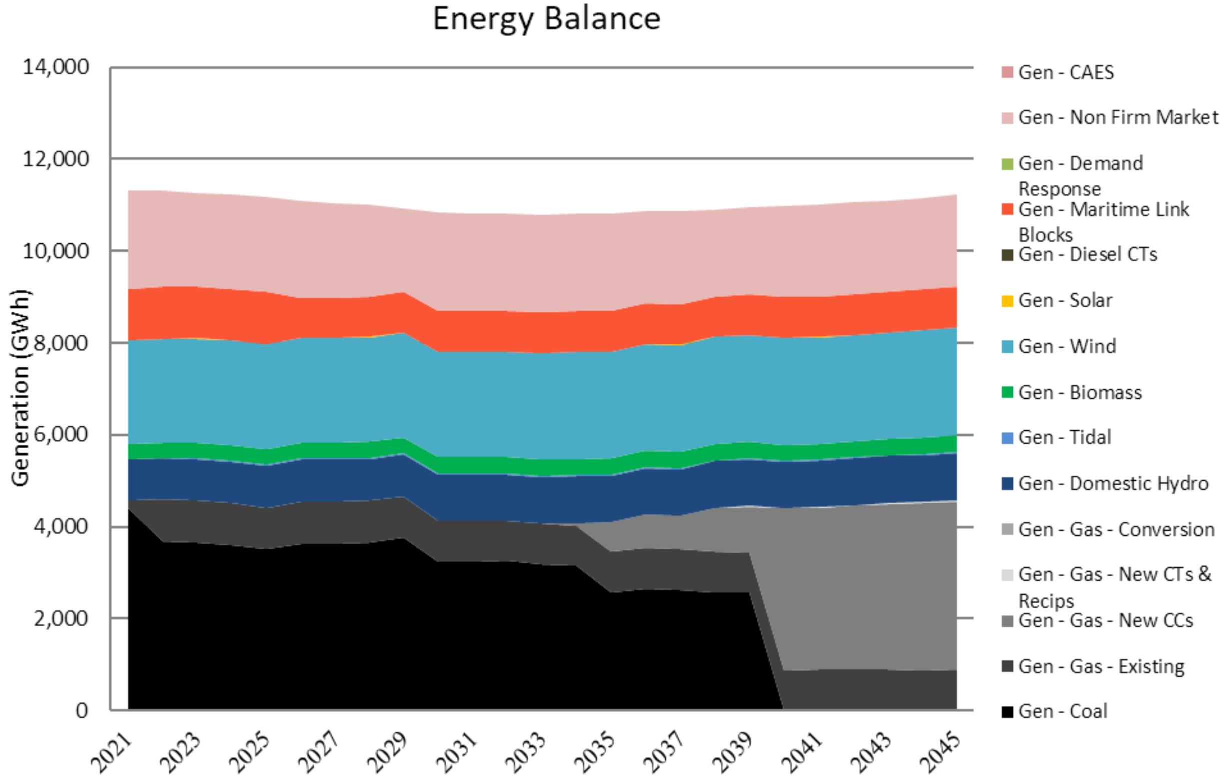


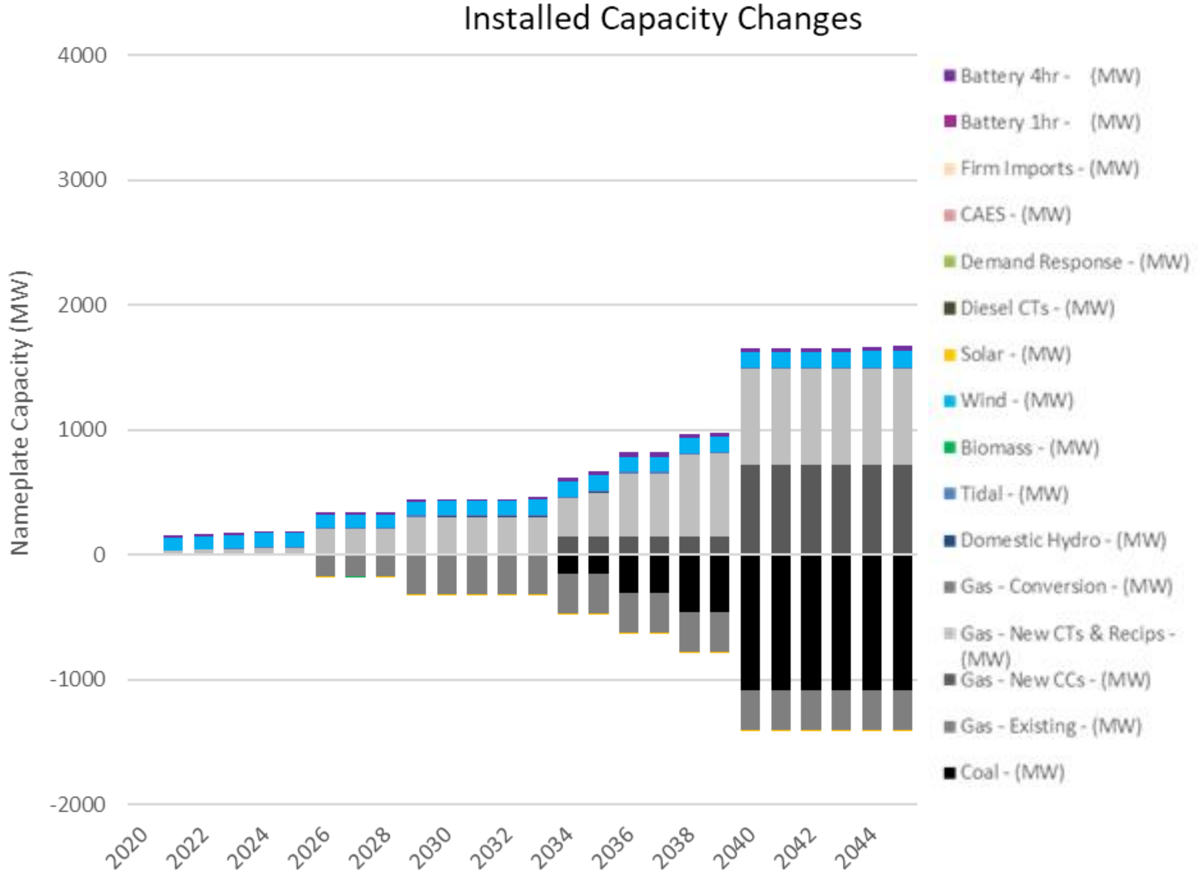
Nova Scotia POWER An Emera Company

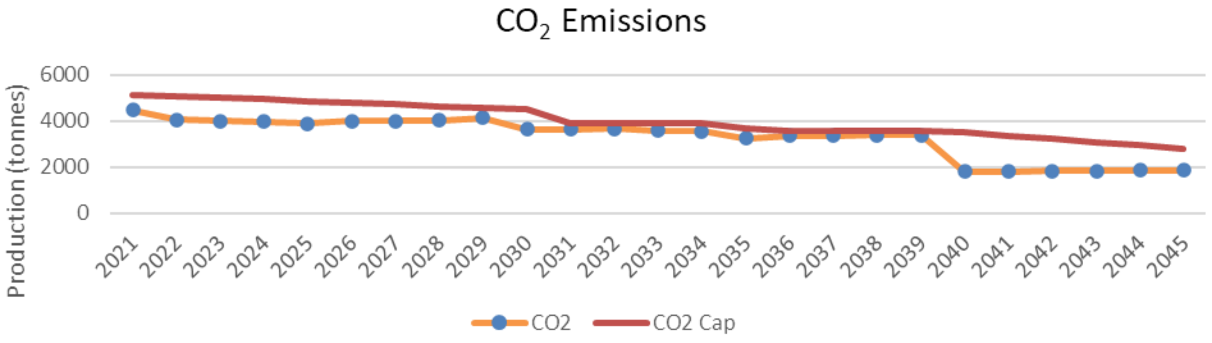
Due to differences in forecast system load affecting production costs, resource plan partial revenue requirement results should not be compared across electrification scenarios

1.0A

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / CURRENT LANDSCAPE



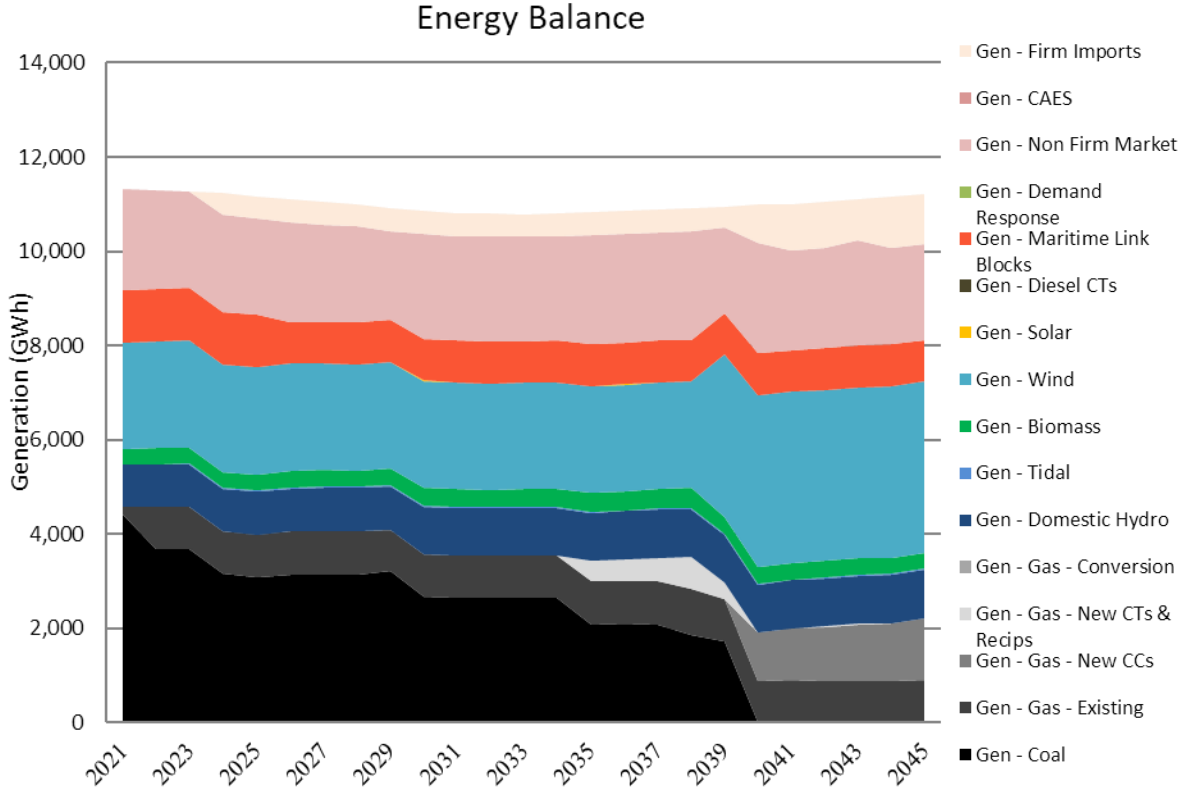


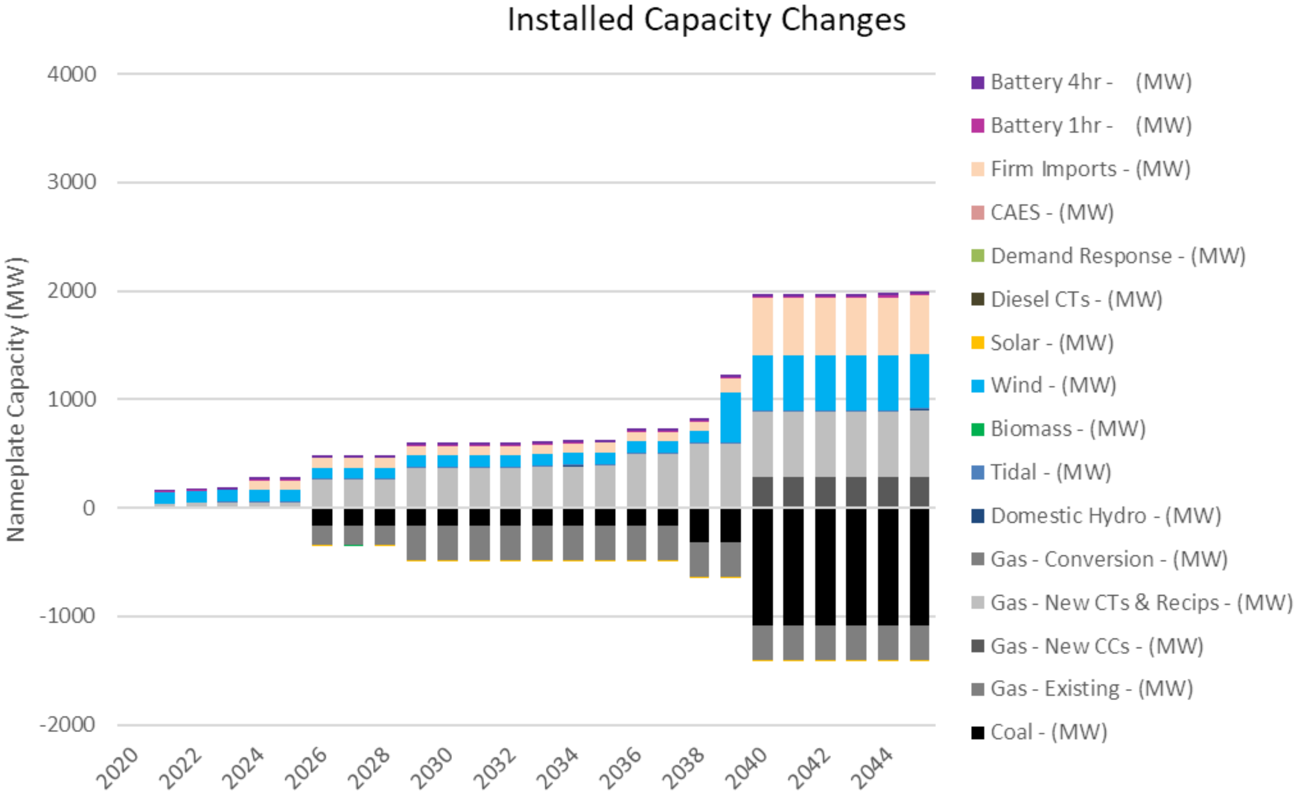


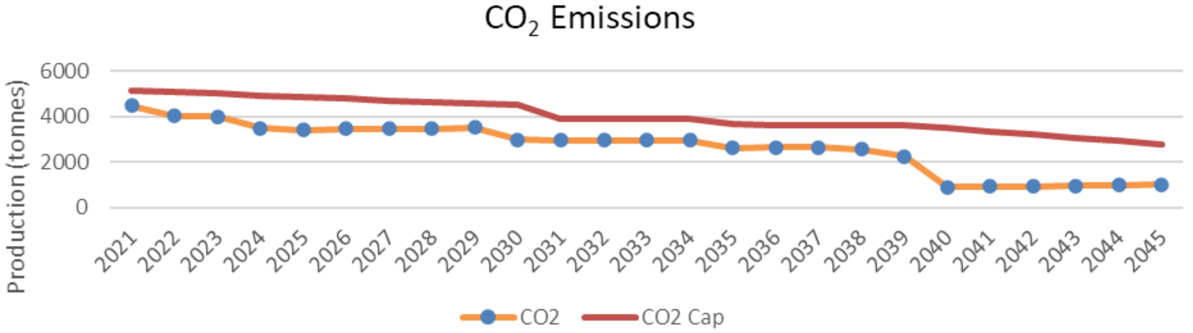
	$MM	Scenario Notes
25-yr NPVRR	$12,204	• Coal capacity replaced with new gas CCGT and CT units
25-yr NPVRR w/ EE	$15,976	
10-yr NPVRR	$6,884	

1.0C

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / REGIONAL INTEGRATION



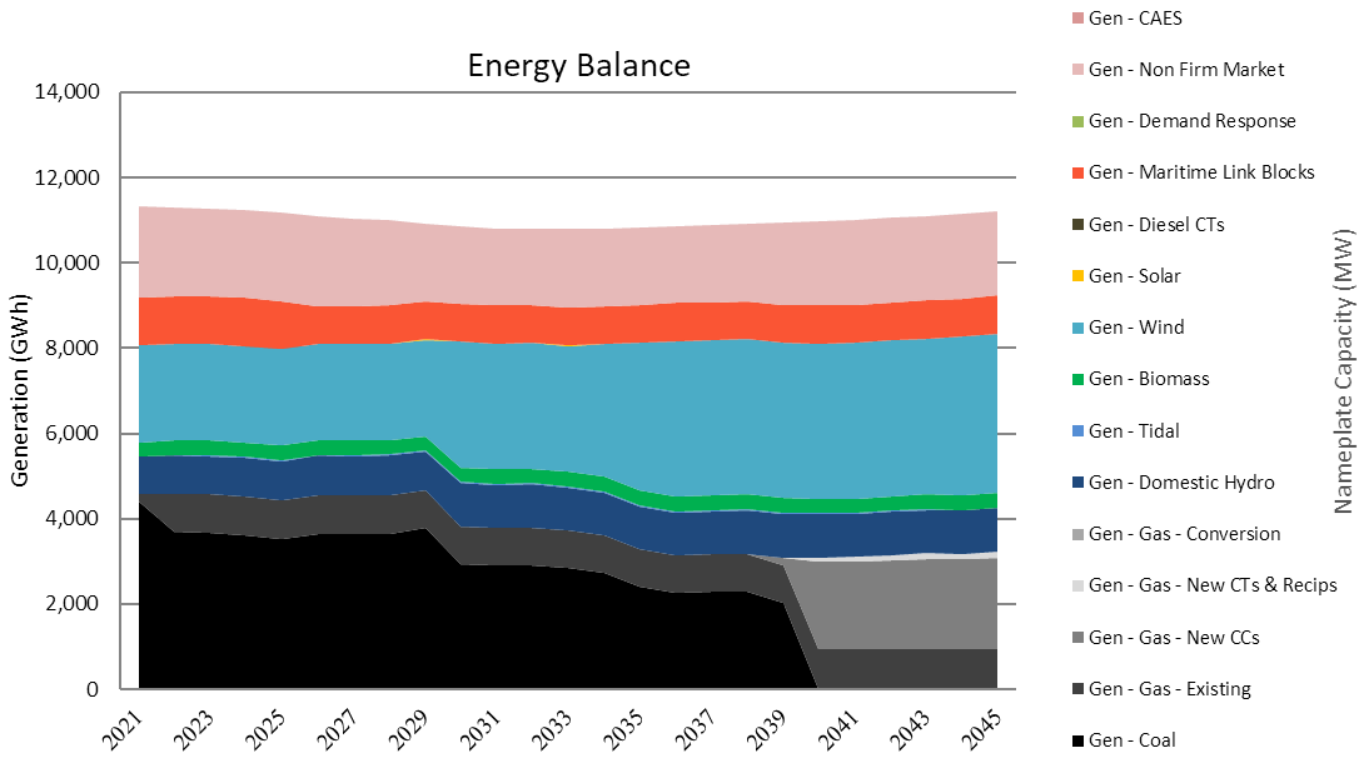


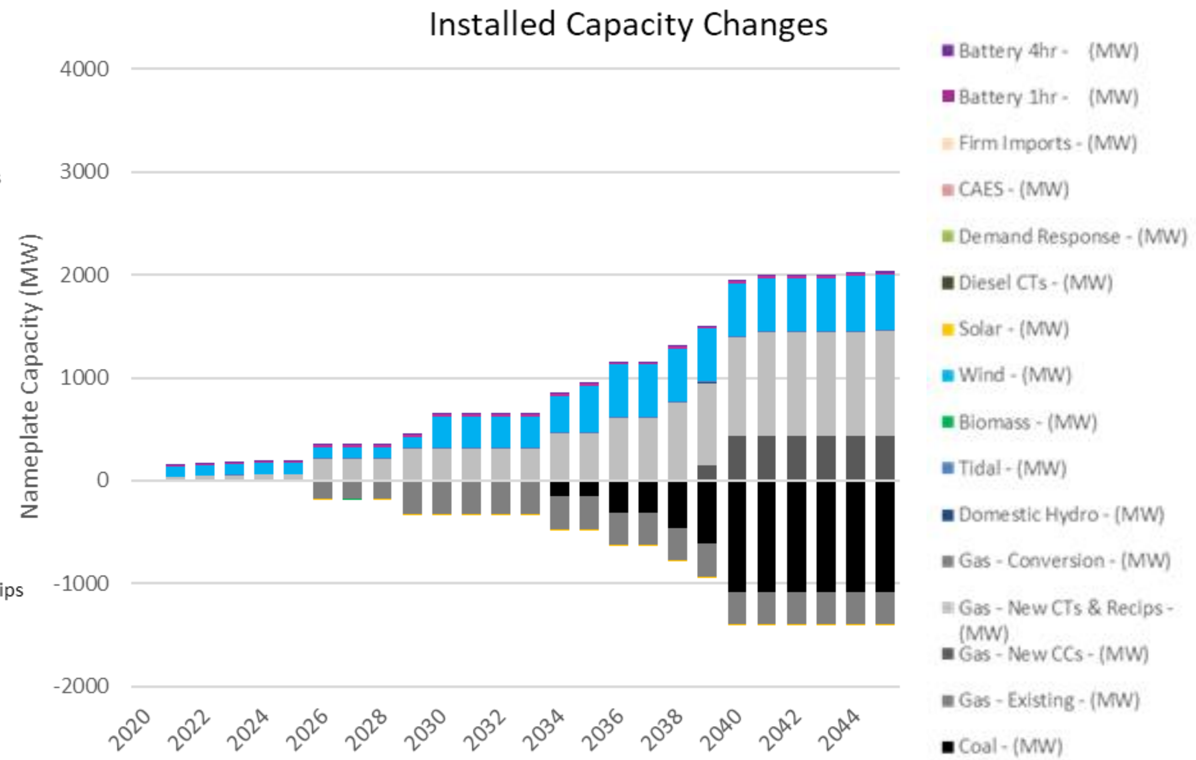


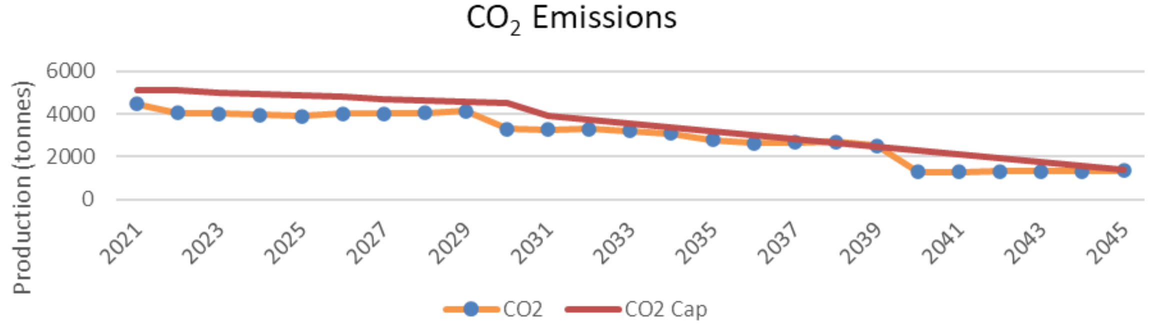
	$MM	Scenario Notes
25-yr NPVRR	$12,107	• Incremental firm imports enable an early coal unit retirement • Regional Interconnection constructed in 2039 allows remaining coal retirements and wind integration
25-yr NPVRR w/ EE	$15,541	
10-yr NPVRR	$6,785	

2.0A

LOW ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE



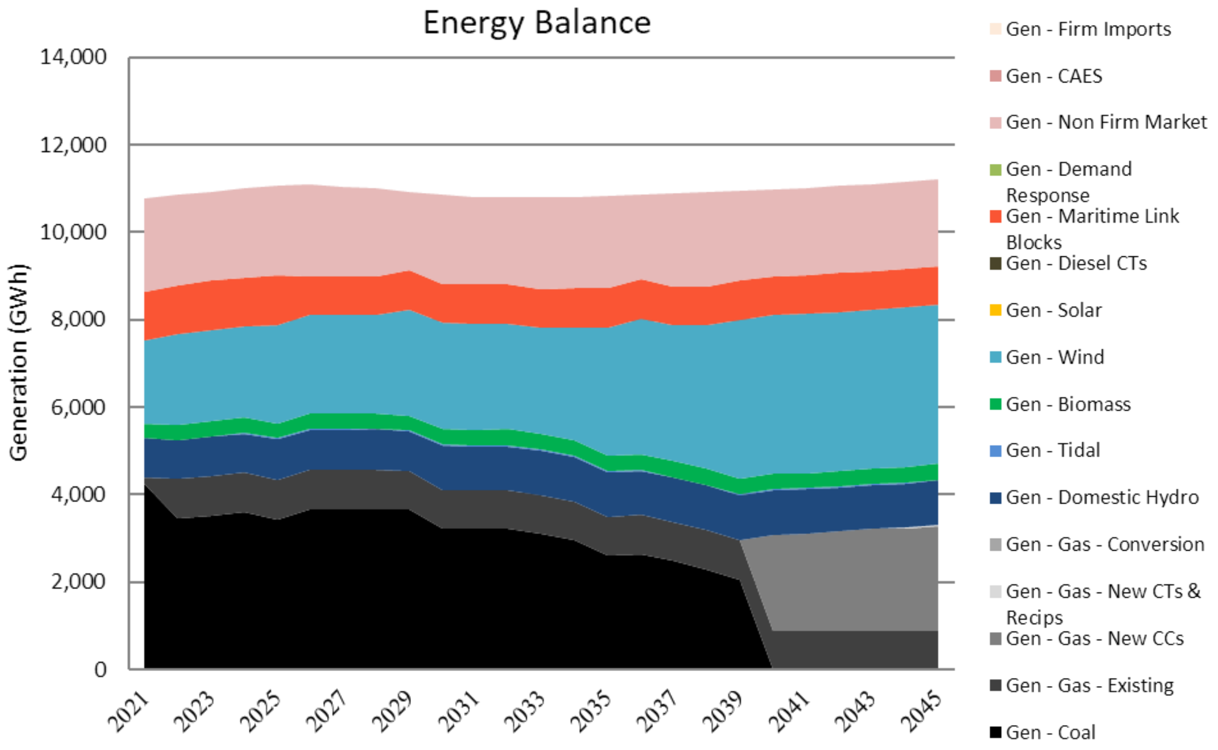


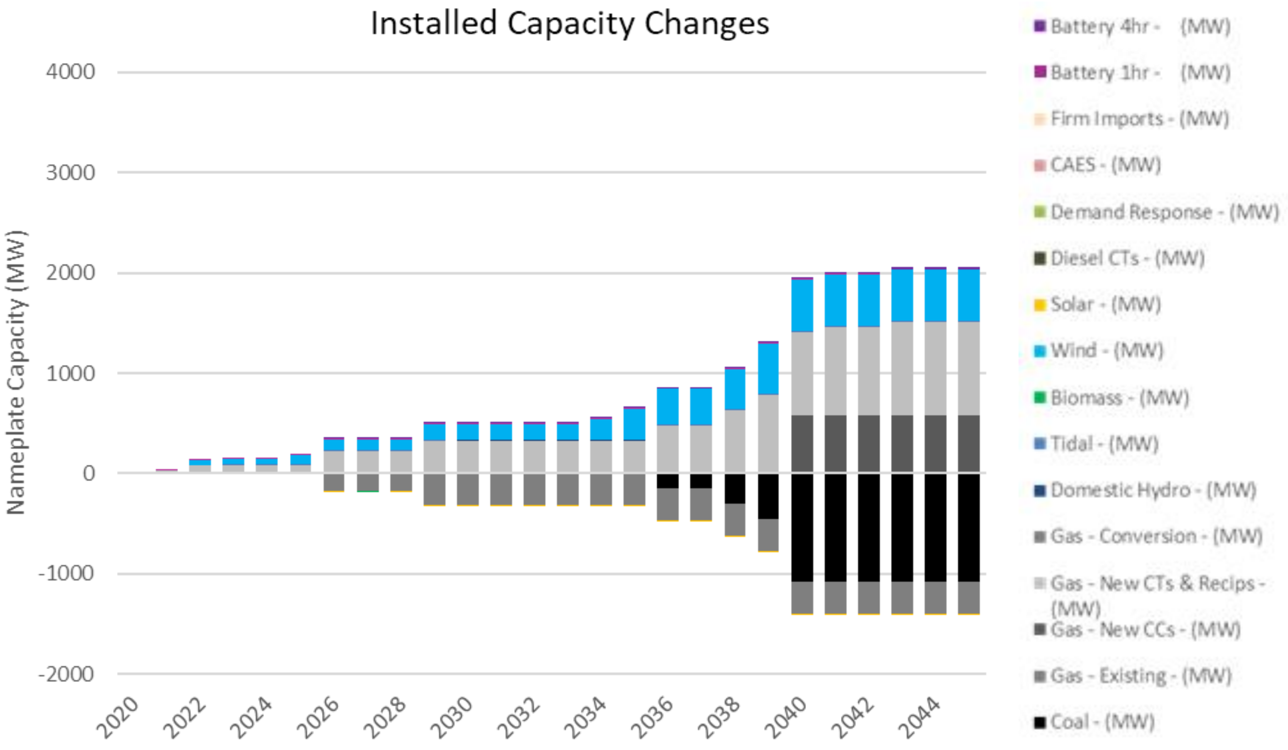


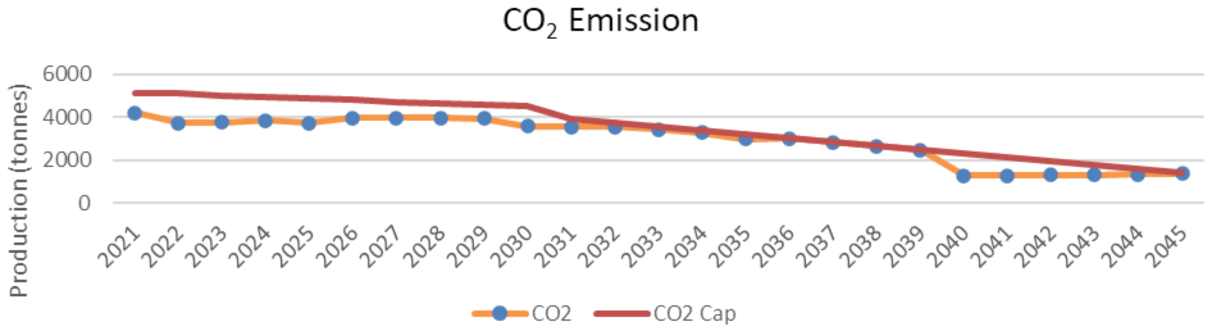
	$MM	Scenario Notes
25-yr NPVRR	$12,392	• Reliability Tie built in 2030 enables wind integration but does not provide firm capacity or energy access • Wind and CT capacity increase and CCGT capacity decreases relative to 1.0A (due to lower GHG cap)
25-yr NPVRR w/ EE	$16,039	
10-yr NPVRR	$7,151	

2.0A.S1 (COVID LOW LOAD)

LOW ELEC. + COVID LOW / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE



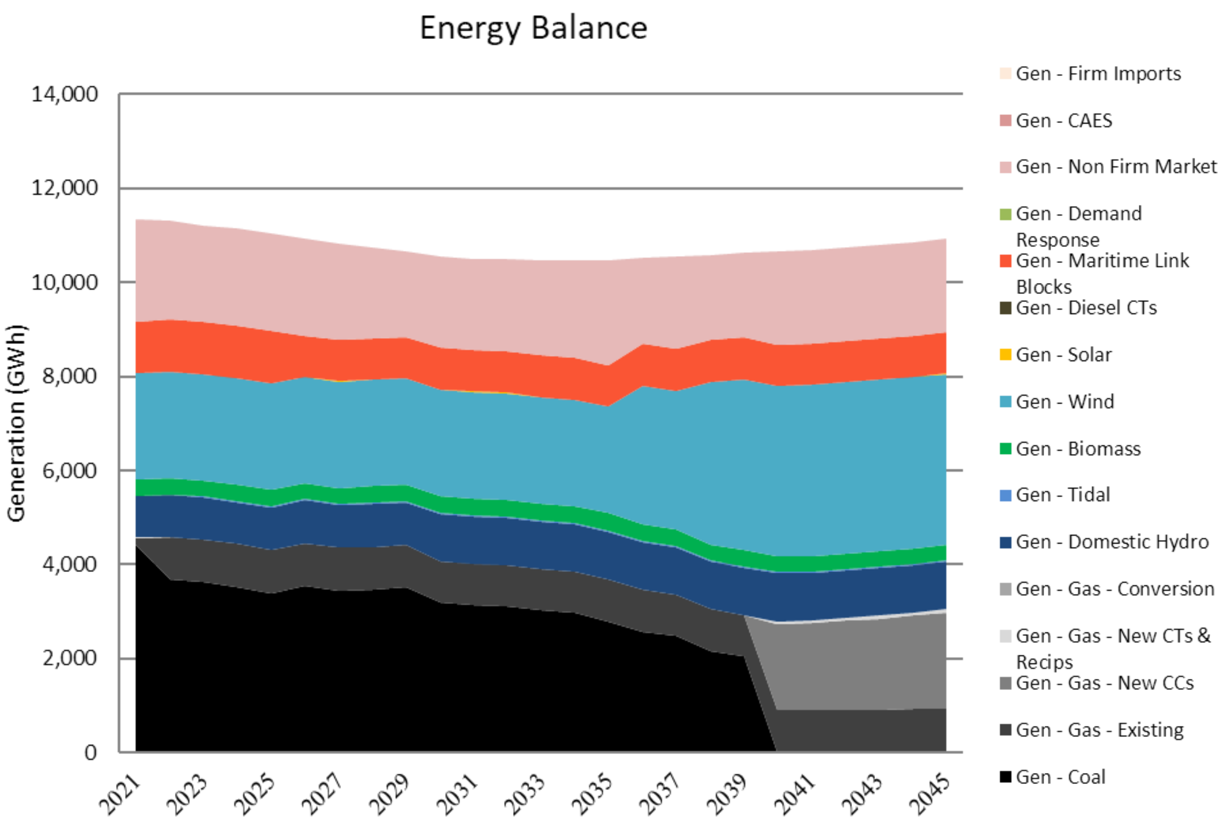


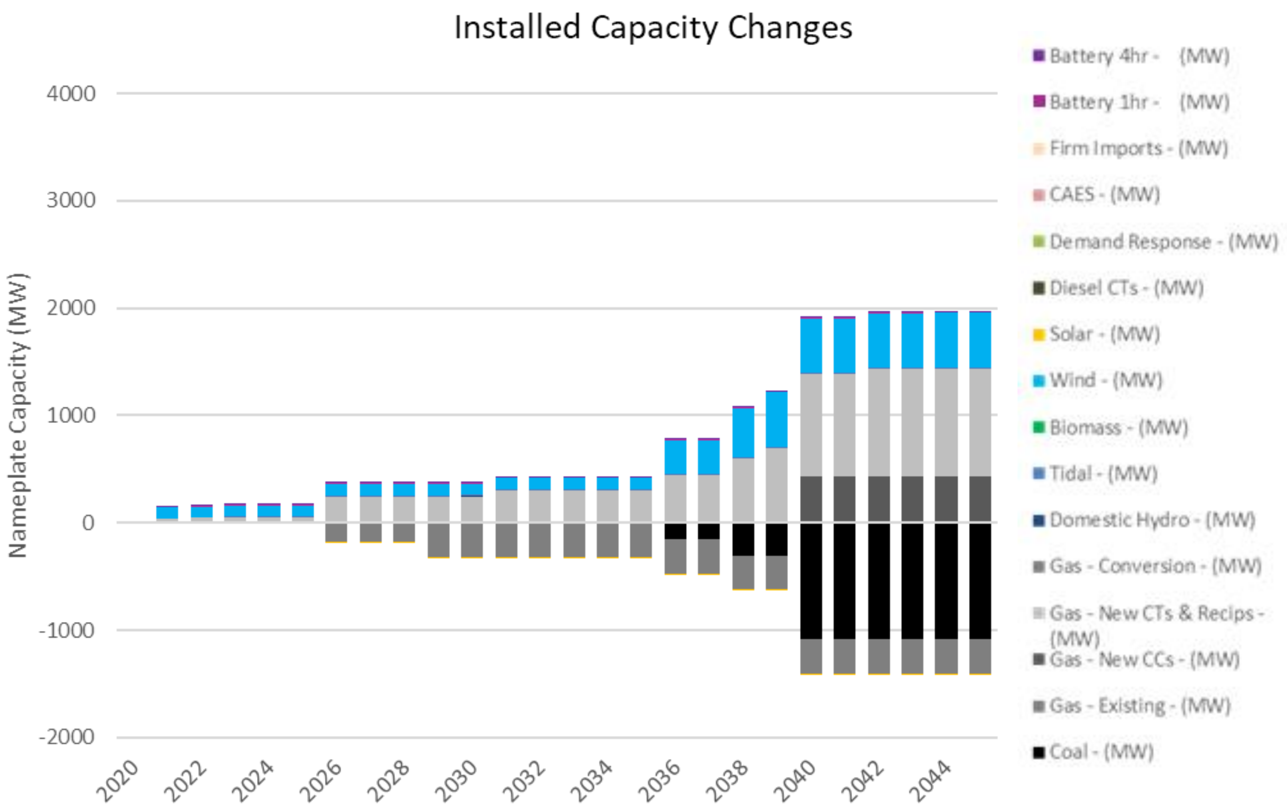


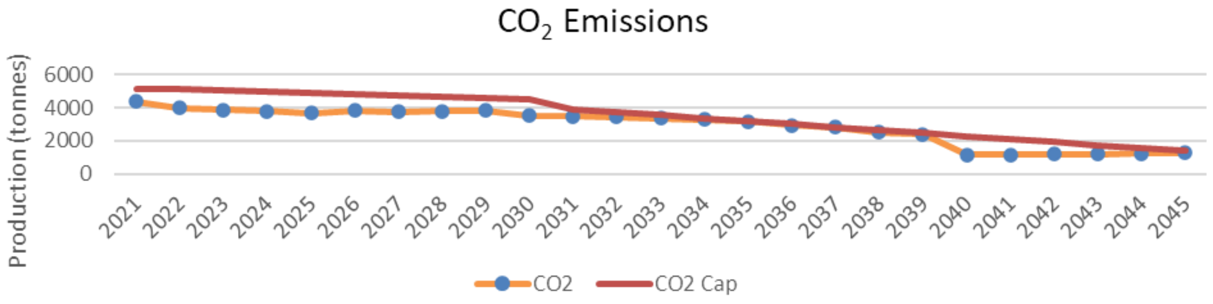
	$MM	Scenario Notes
25-yr NPVRR	$12,288	• Resource plan is essentially unchanged from 2.0A base case; lower production costs in first 5 years due to load reduction lead to a slightly lower NPV
25-yr NPVRR w/ EE	$15,984	
10-yr NPVRR	$7,019	

2.0A.S2 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / CURRENT LANDSCAPE



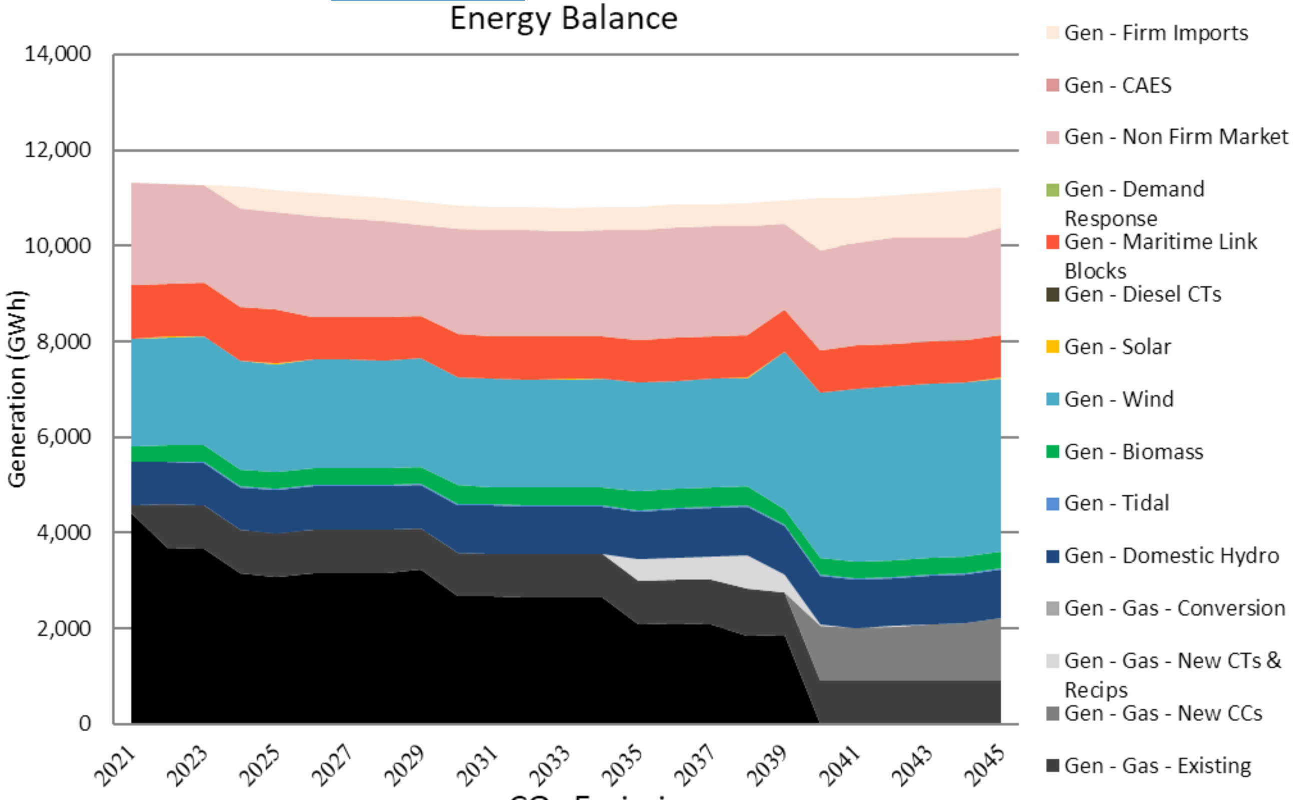


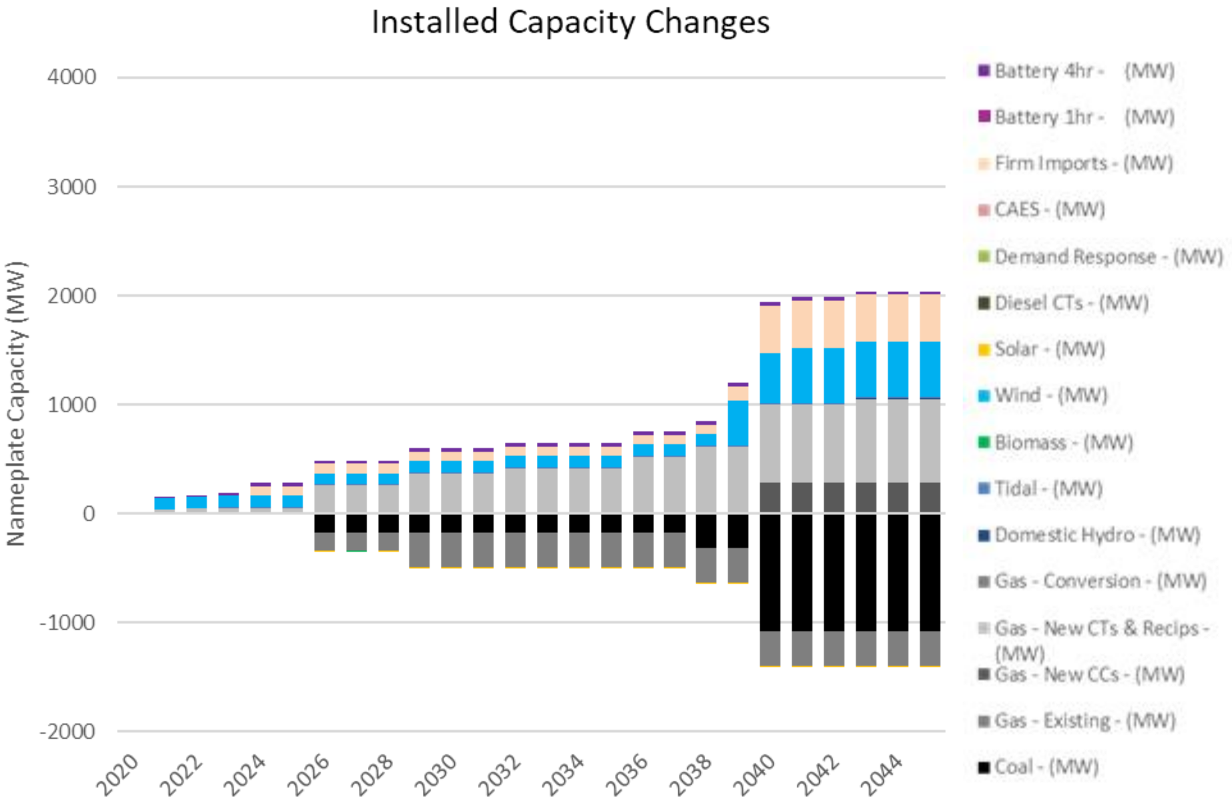


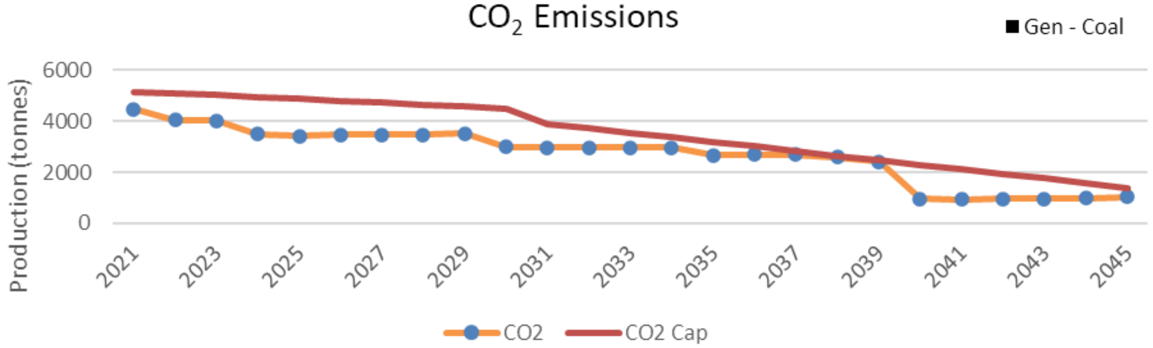
	$MM	Scenario Notes
25-yr NPVRR	$12,732	• Reliability Tie built in 2036 enables wind integration but does not provide firm capacity or energy access • Reduction in gas and wind builds relative to 2.0A
25-yr NPVRR w/ EE	$16,376	
10-yr NPVRR	$7,257	

2.0C

LOW ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION



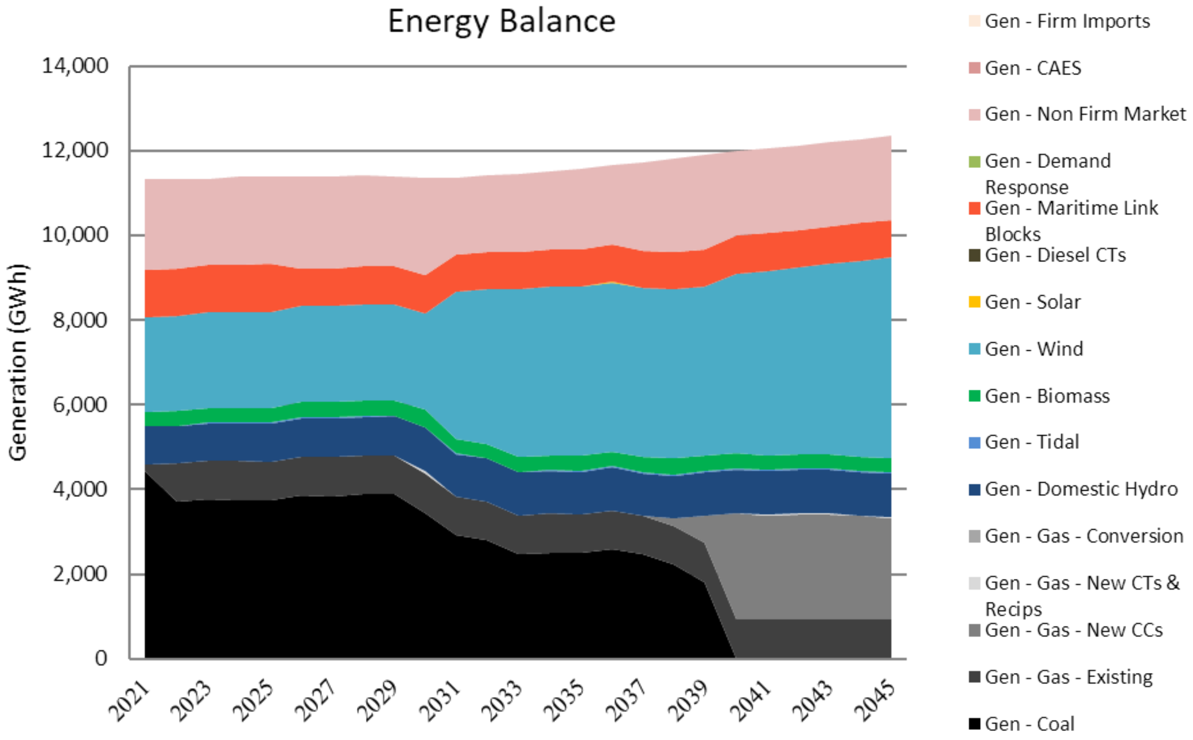


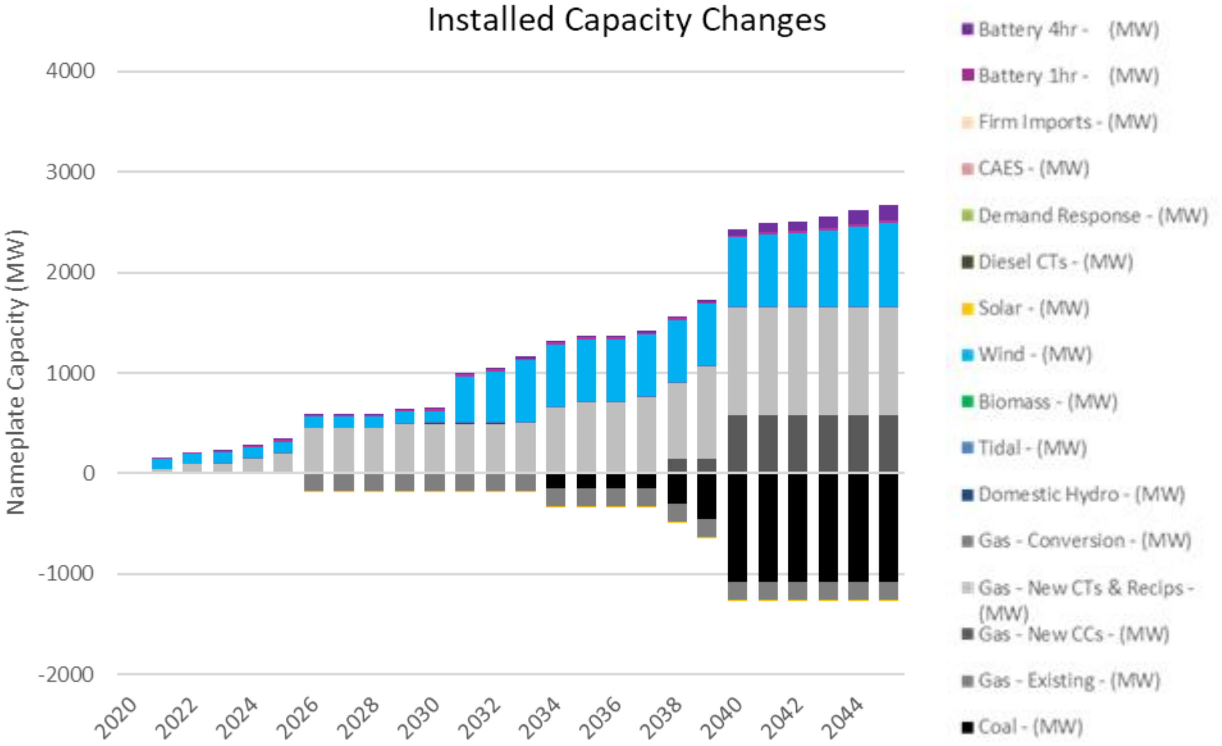


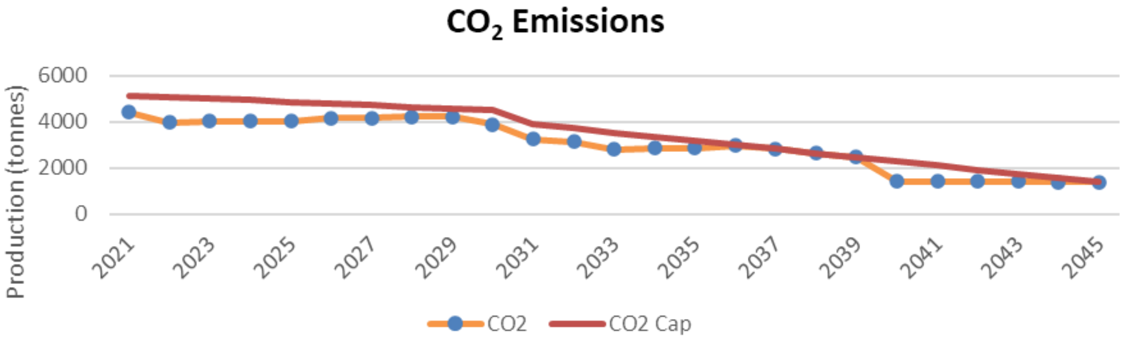
	$MM	Scenario Notes
25-yr NPVRR	$12,146	• Capacity expansion and generation are very similar to 1.0C case but with SDGA compliant GHG curve
25-yr NPVRR w/ EE	$15,624	
10-yr NPVRR	$6,780	

2.1A

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE



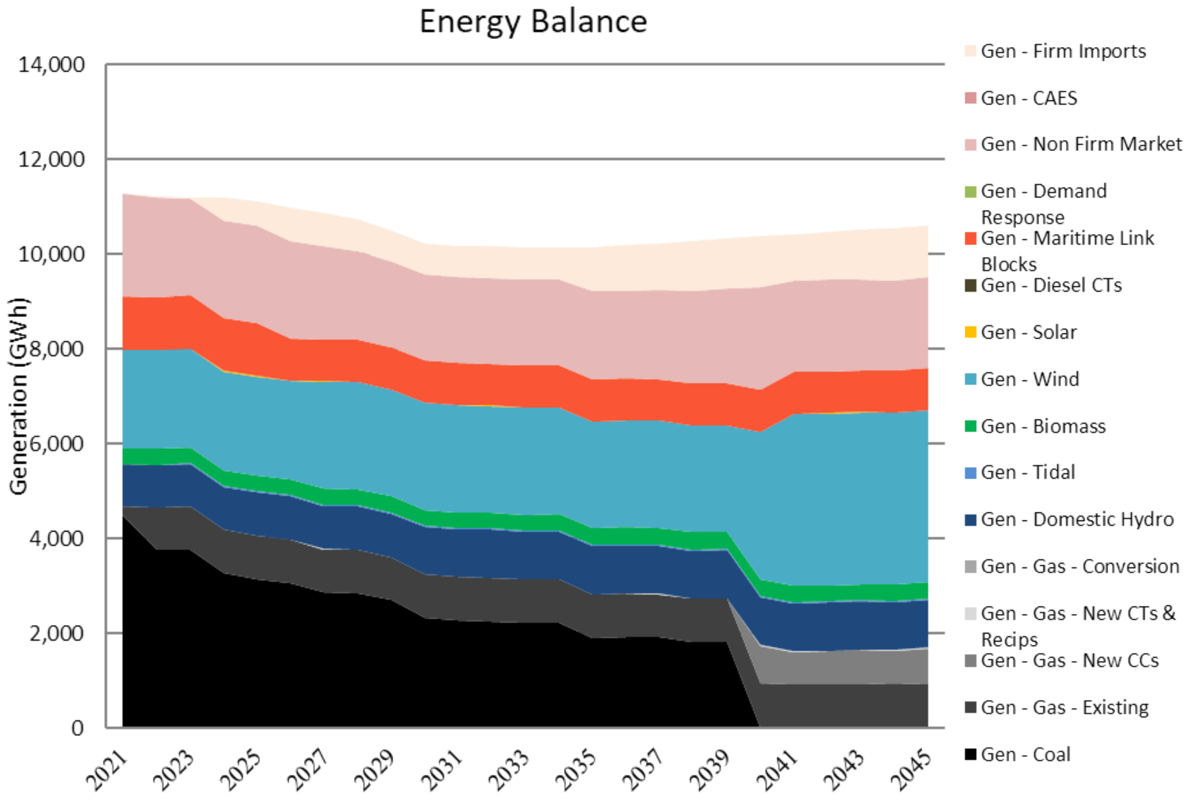


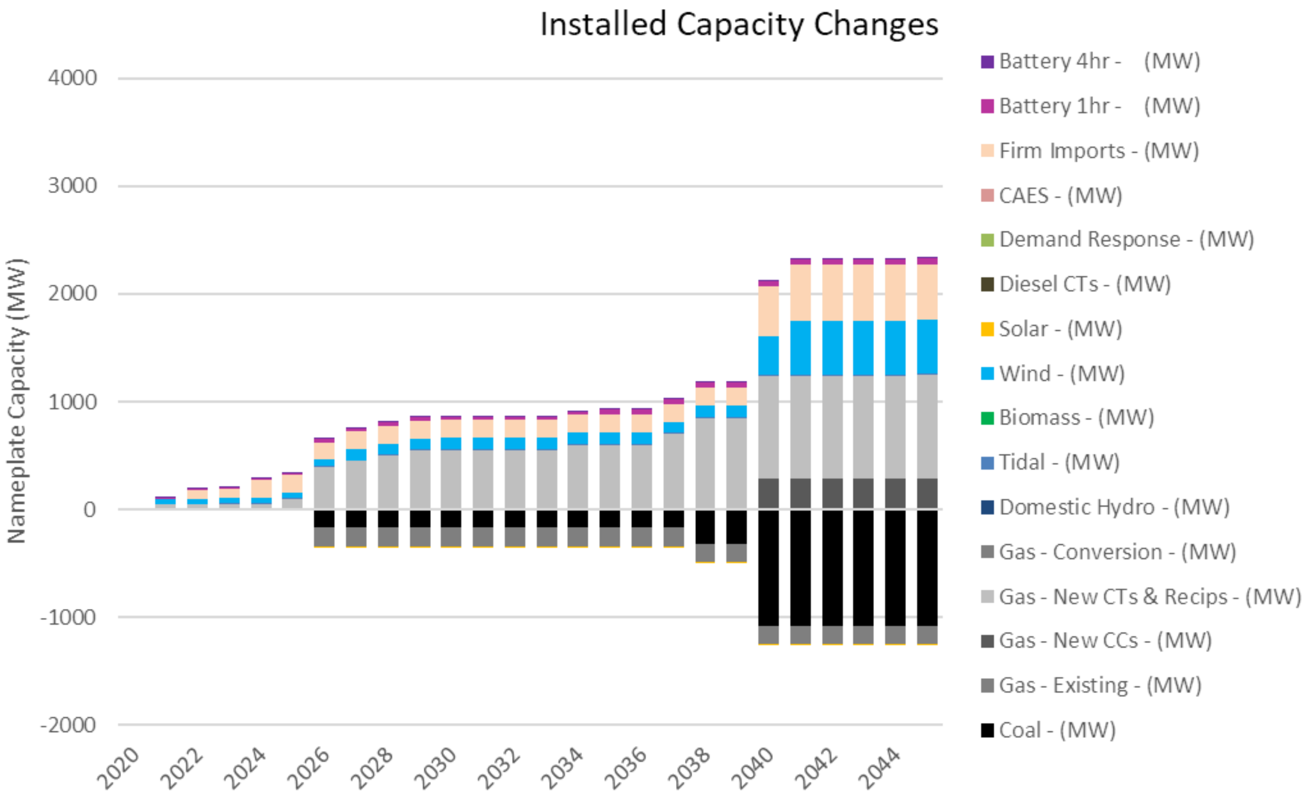


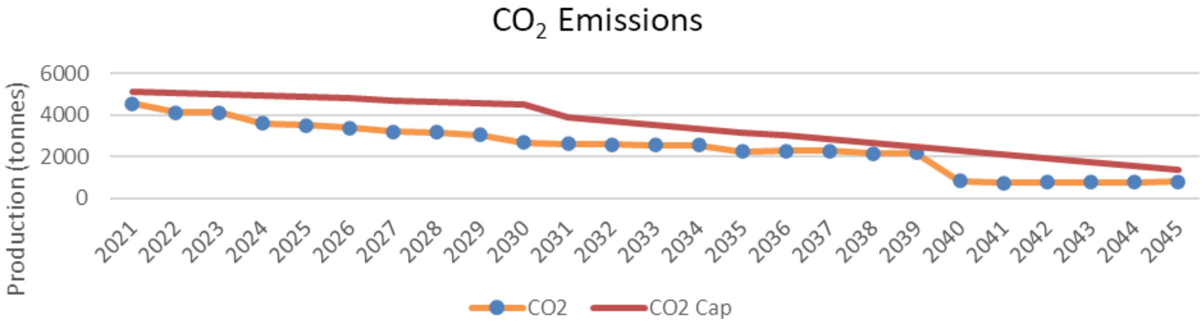
	$MM	Scenario Notes
25-yr NPVRR	$13,306	• Reliability Tie built in 2031 enables wind integration but does not provide firm capacity or energy access • Gas CT builds provide capacity to support early electrification load growth; energy is supplied by wind and non-firm imports, and CCGT when coal units retire
25-yr NPVRR w/ EE	$17,631	
10-yr NPVRR	$7,140	

2.1B

MID ELEC. / BASE DSM / NET ZERO 2050 / DISTRIBUTED RESOURCES



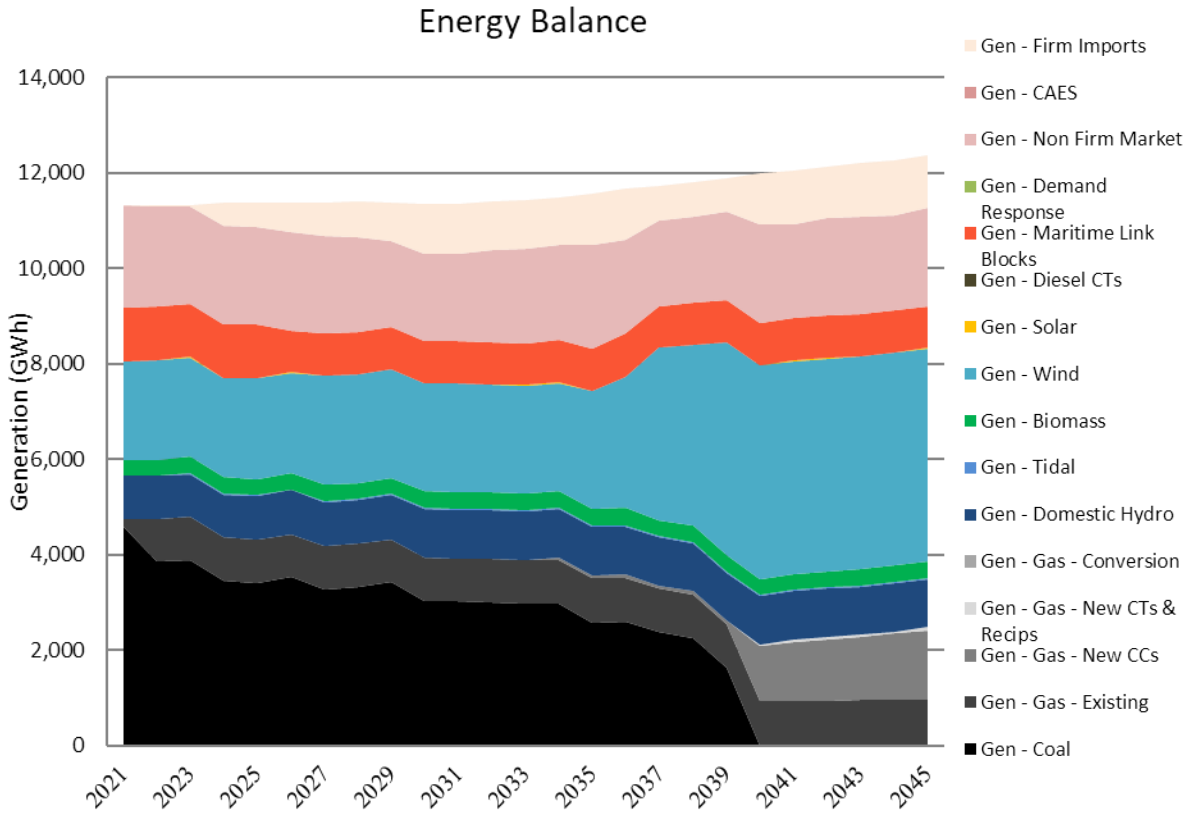


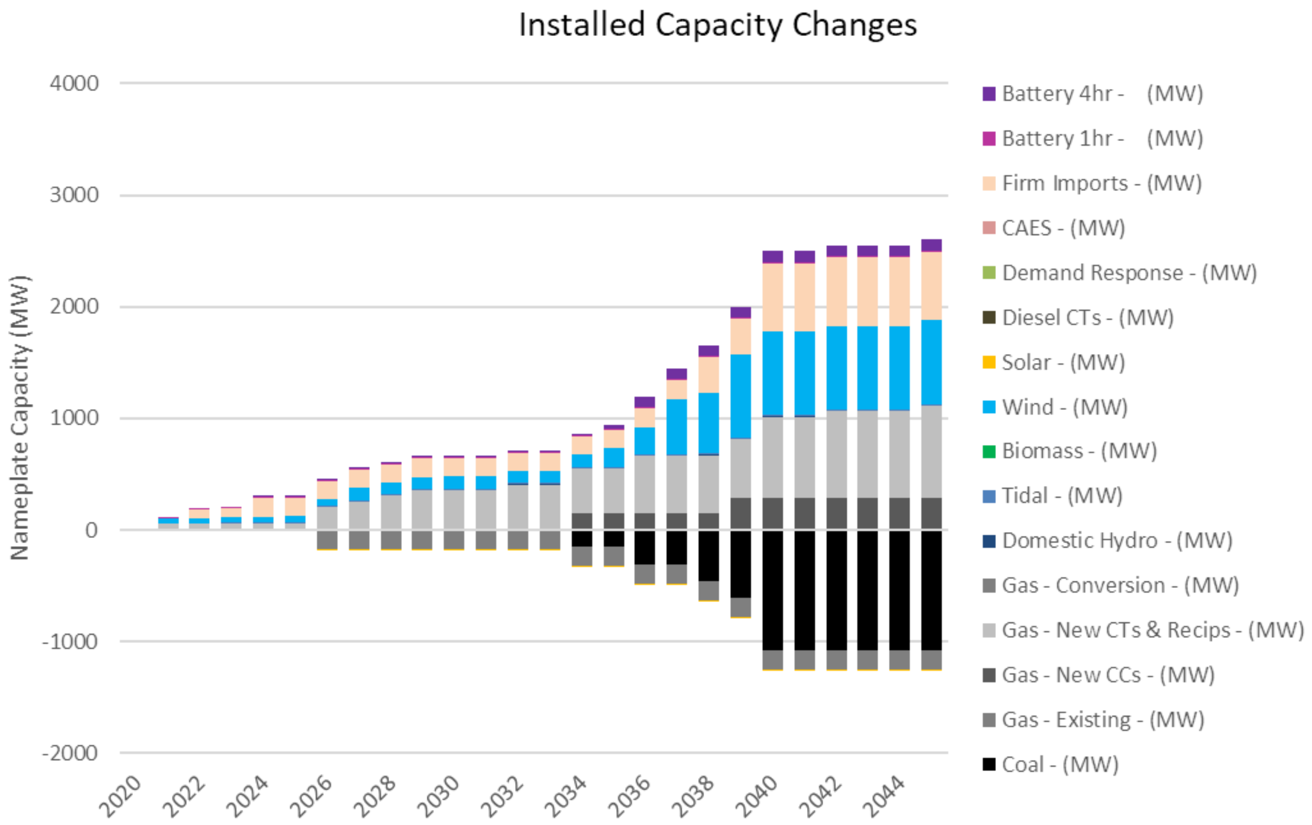


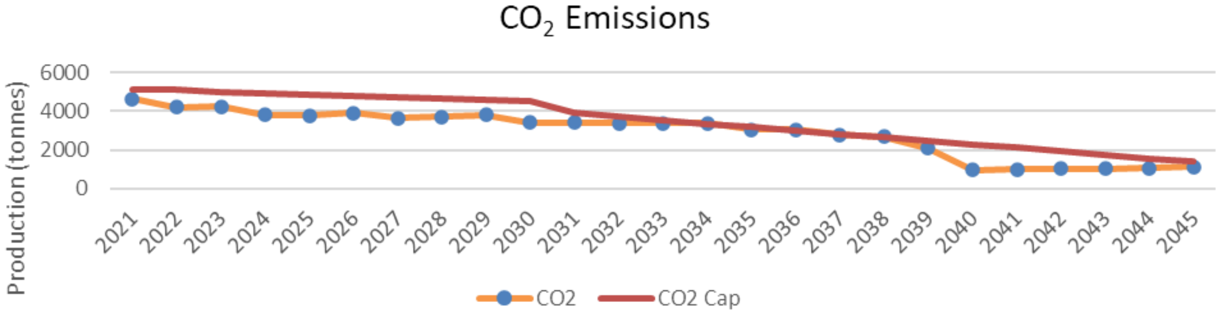
	$MM	Scenario Notes
25-yr NPVRR	$11,958	• Regional Interconnection built in 2040 with coal unit retirements • DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)
25-yr NPVRR w/ EE	$15,477	
10-yr NPVRR	$6,724	

2.1C

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION



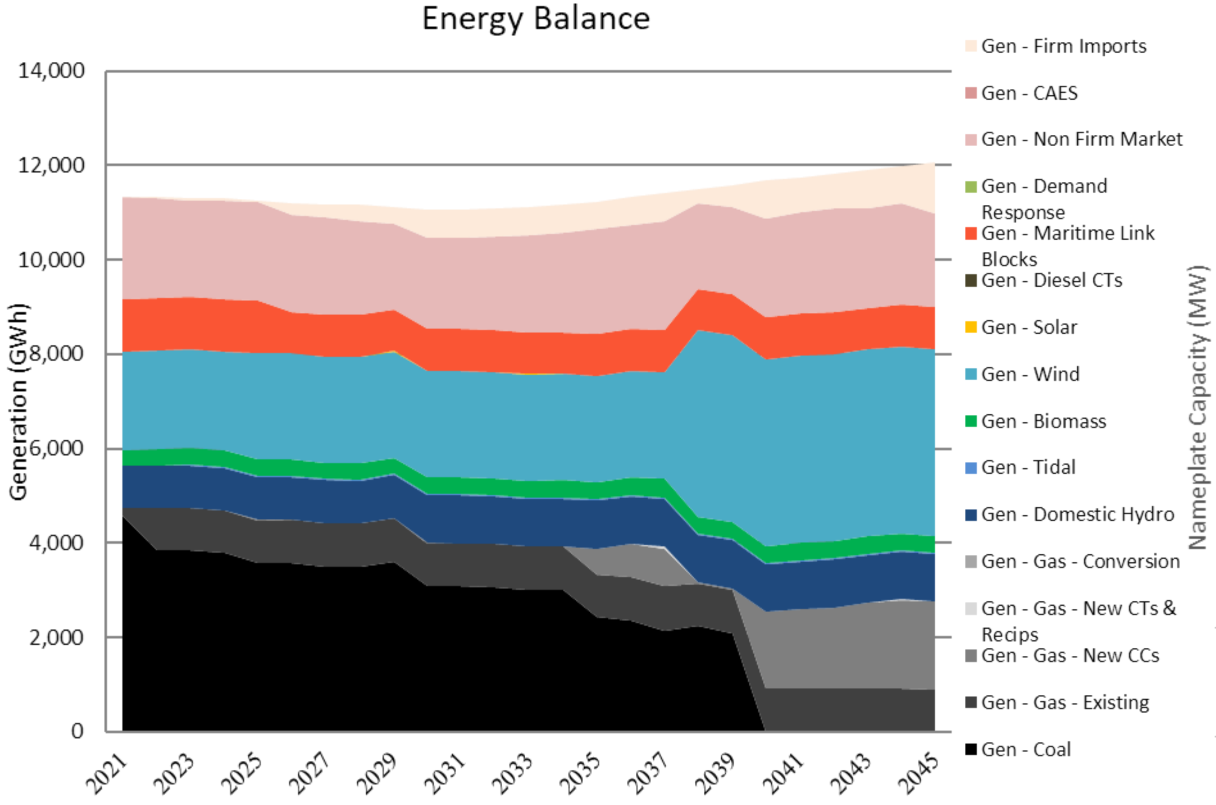


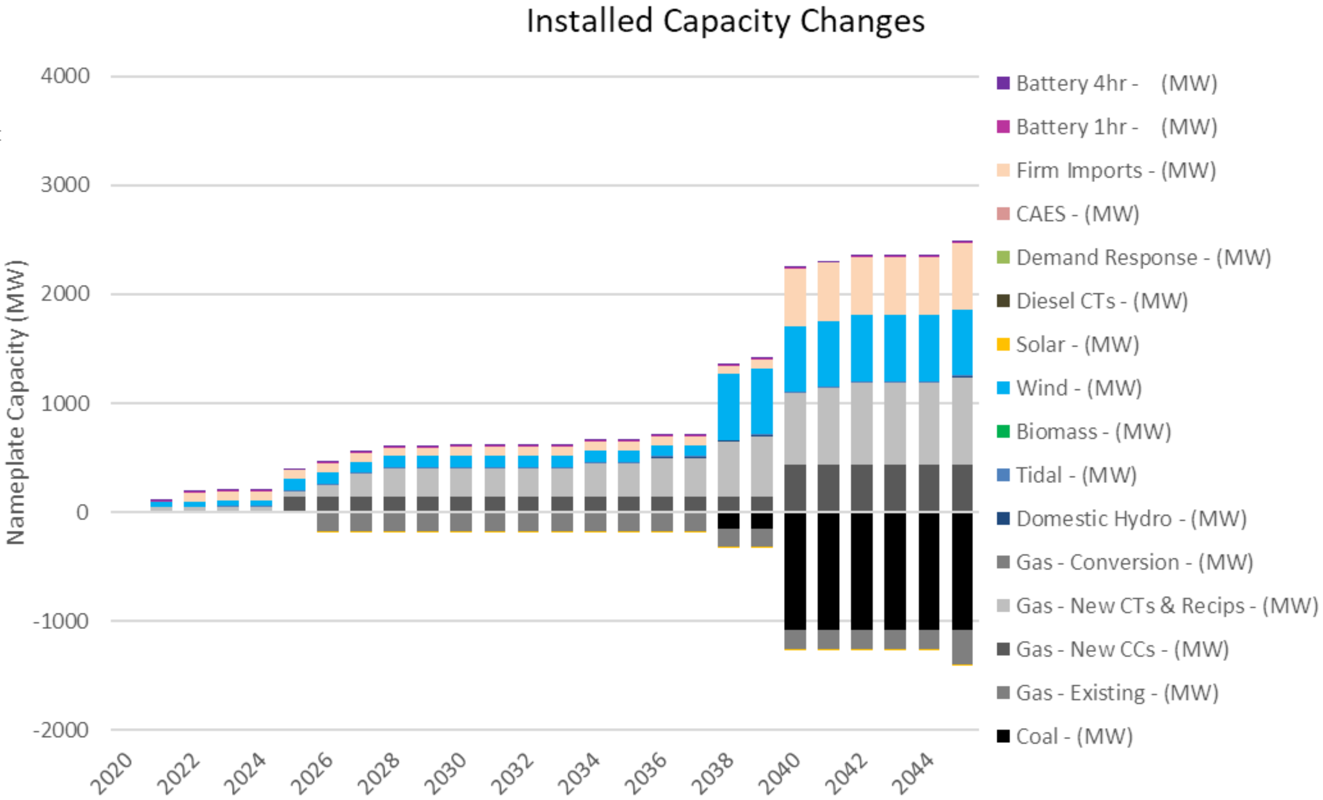


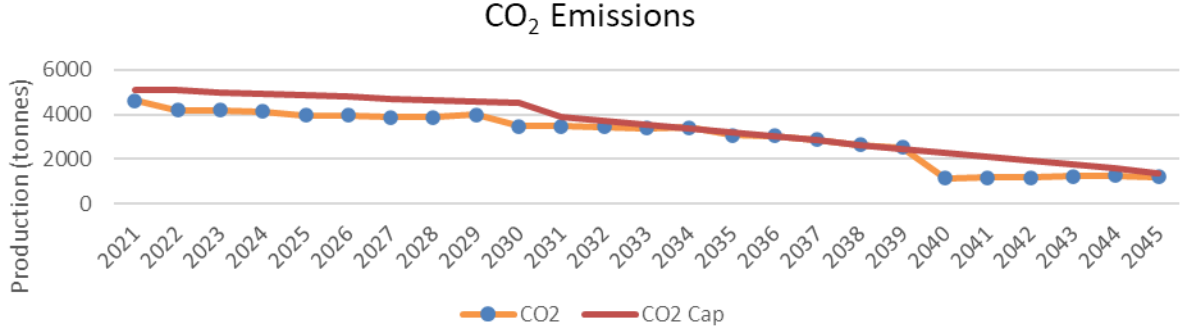
	$MM	Scenario Notes
25-yr NPVRR	$13,037	• Reliability Tie built in 2037 enables wind integration • Regional Interconnection built in 2038 to access firm imports (staged from reliability tie)
25-yr NPVRR w/ EE	$17,029	
10-yr NPVRR	$7,019	

2.1C.S1 (MID DSM)

MID ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION



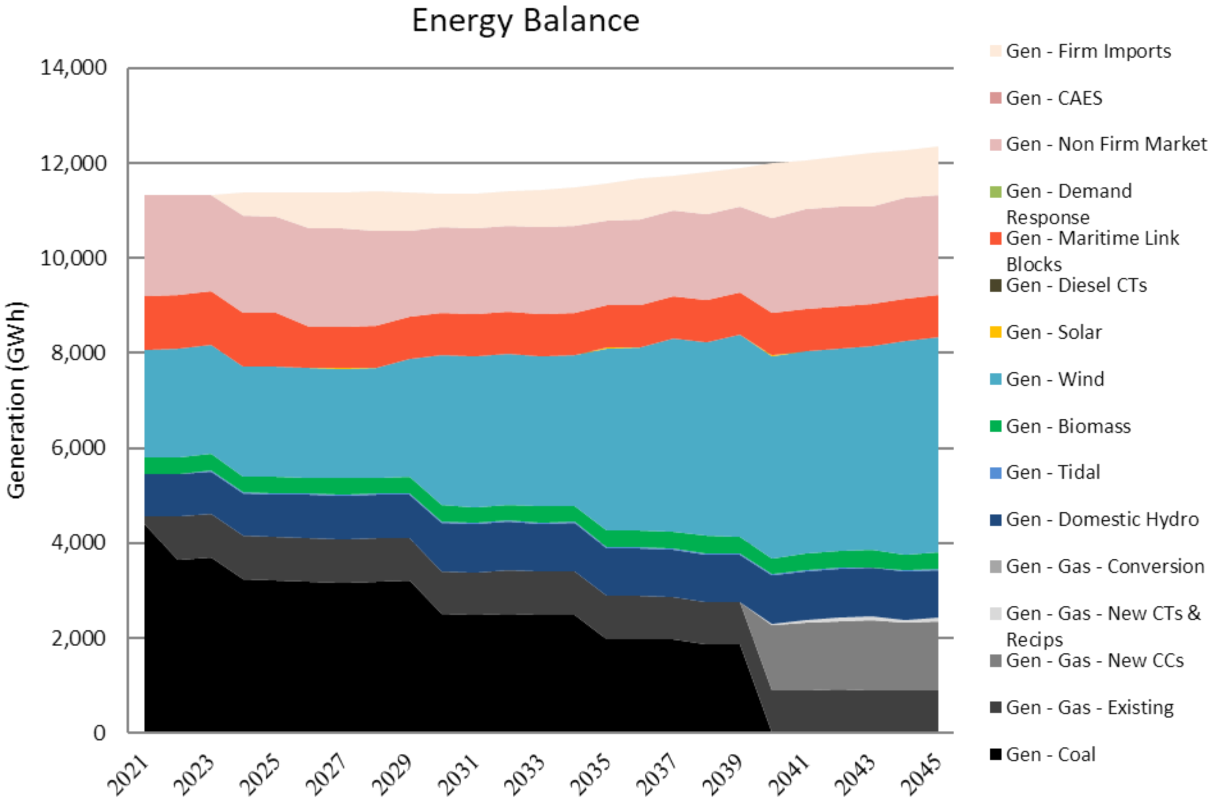


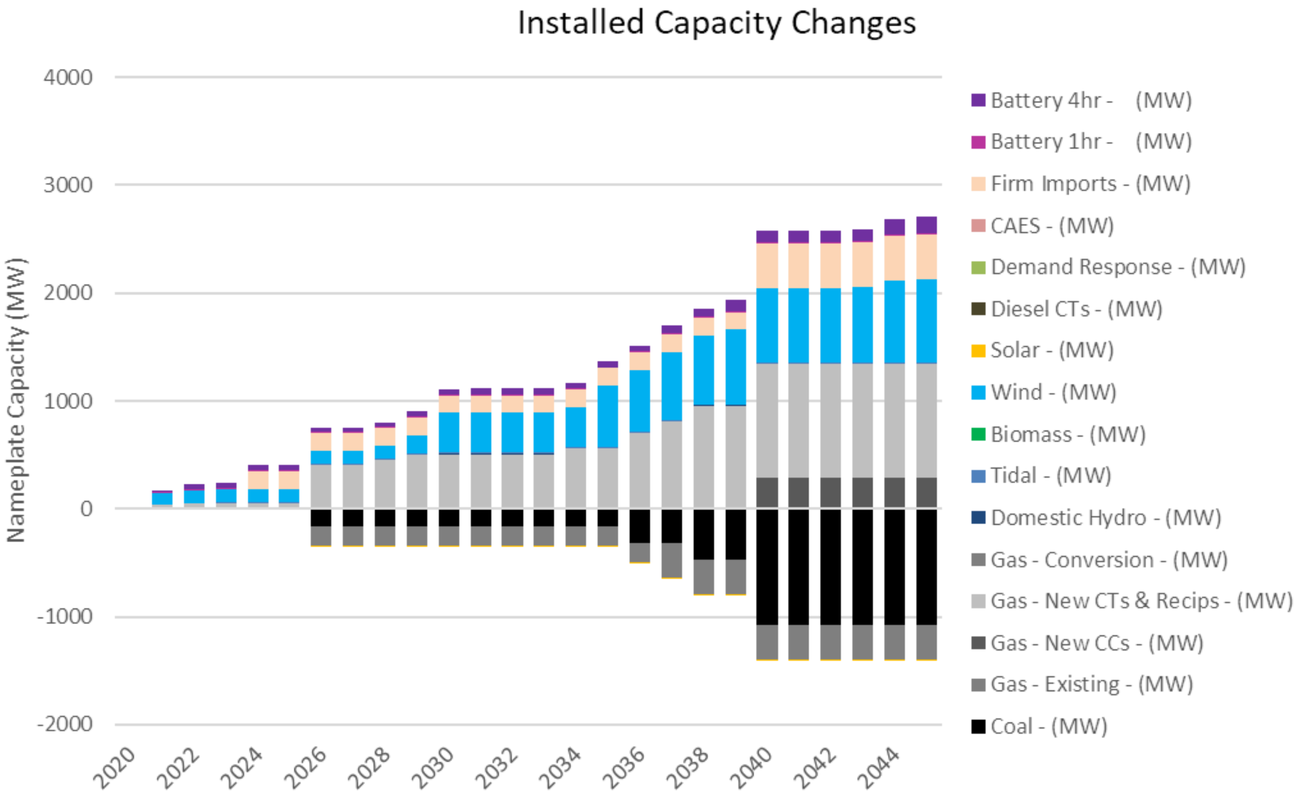


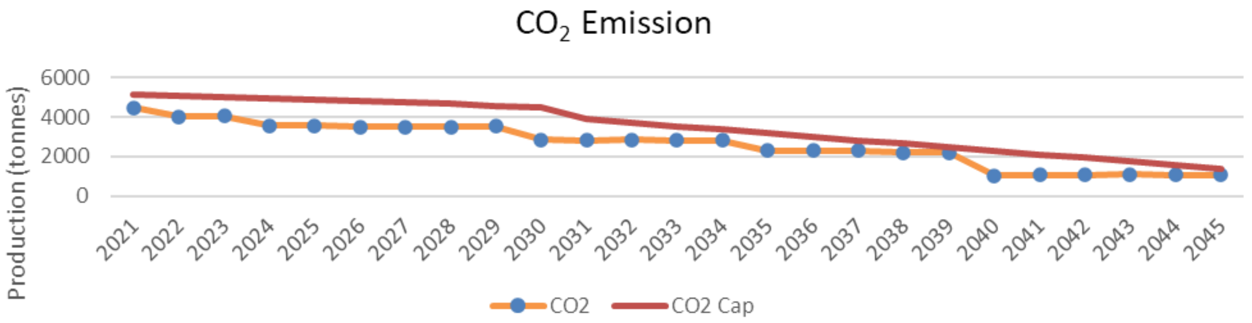
	$MM	Scenario Notes
25-yr NPVRR	$13,608	• Reliability Tie built in 2038 enables wind integration • Regional Interconnection built in 2040 to access firm imports (staged from reliability tie)
25-yr NPVRR w/ EE	$17,563	
10-yr NPVRR	$7,487	

2.1C.S2 (LOW WIND COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION





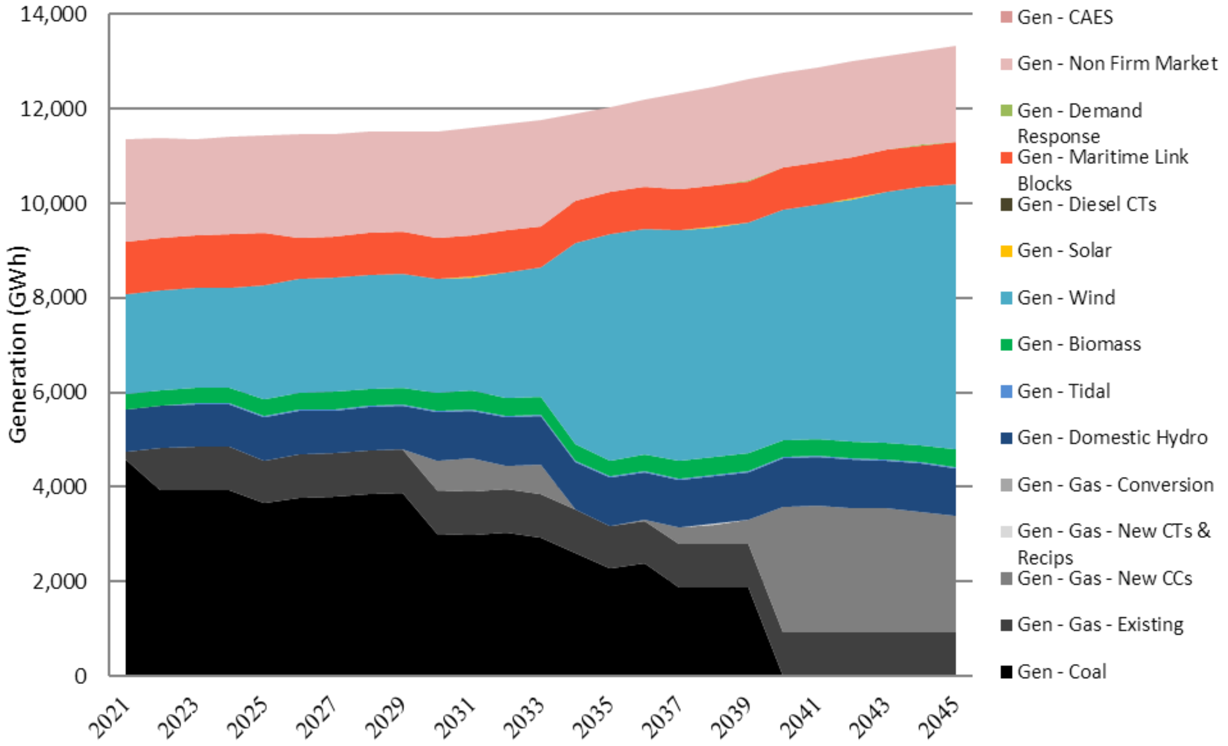


	$MM	Scenario Notes
25-yr NPVRR	$12,852	• Total wind build very similar to 2.1C but larger wind additions start earlier (2030 vs. 2037) • Reliability Tie built in 2029 enables wind integration • Regional Interconnection built in 2040 to access firm imports (staged from Reliability Tie)
25-yr NPVRR w/ EE	$16,760	
10-yr NPVRR	7,249	

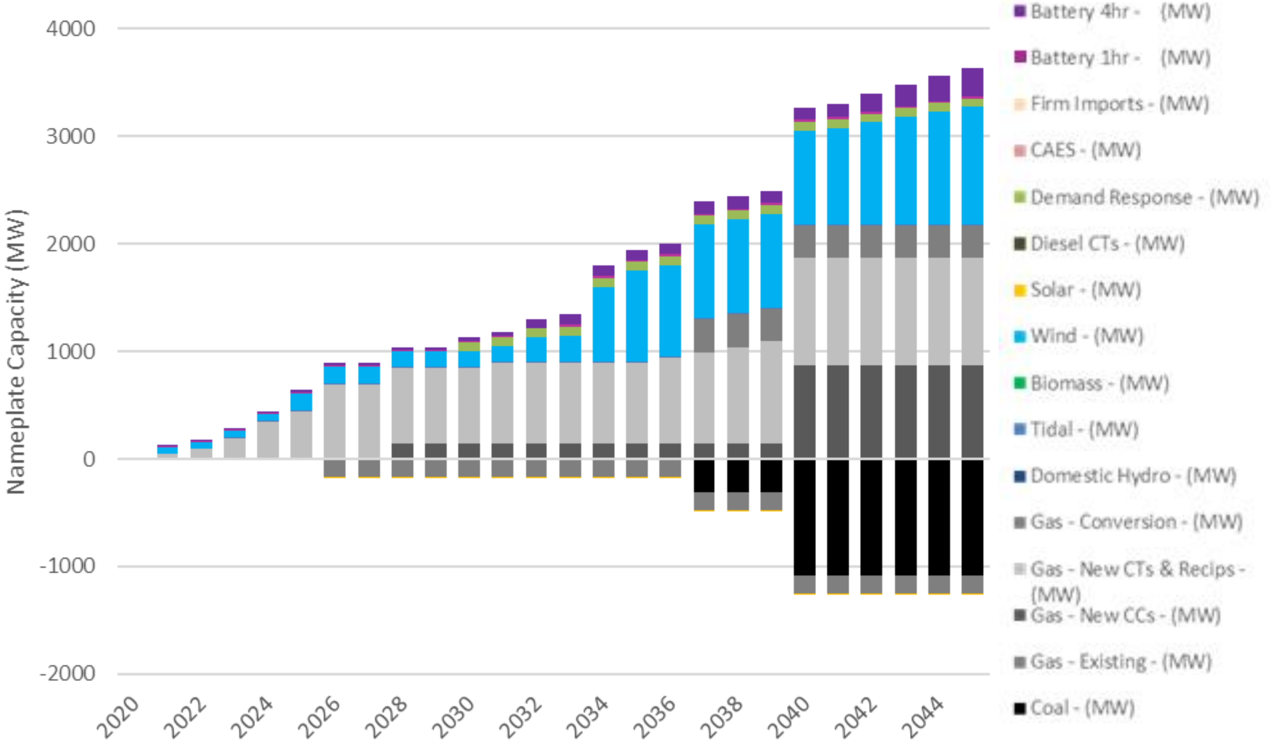
2.2A

HIGH ELEC. / MAX DSM / NET ZERO 2050 / CURRENT LANDSCAPE

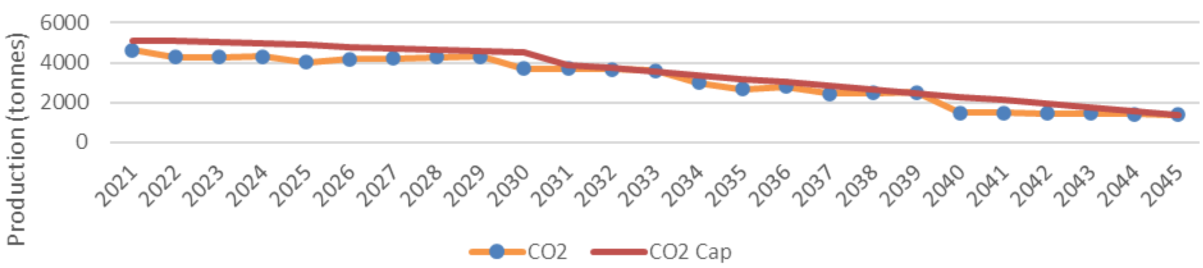
Energy Balance



Installed Capacity Changes



CO_2 Emissions



	$MM
25-yr NPVRR	$15,763
25-yr NPVRR w/ EE	$21,020
10-yr NPVRR	$8,364

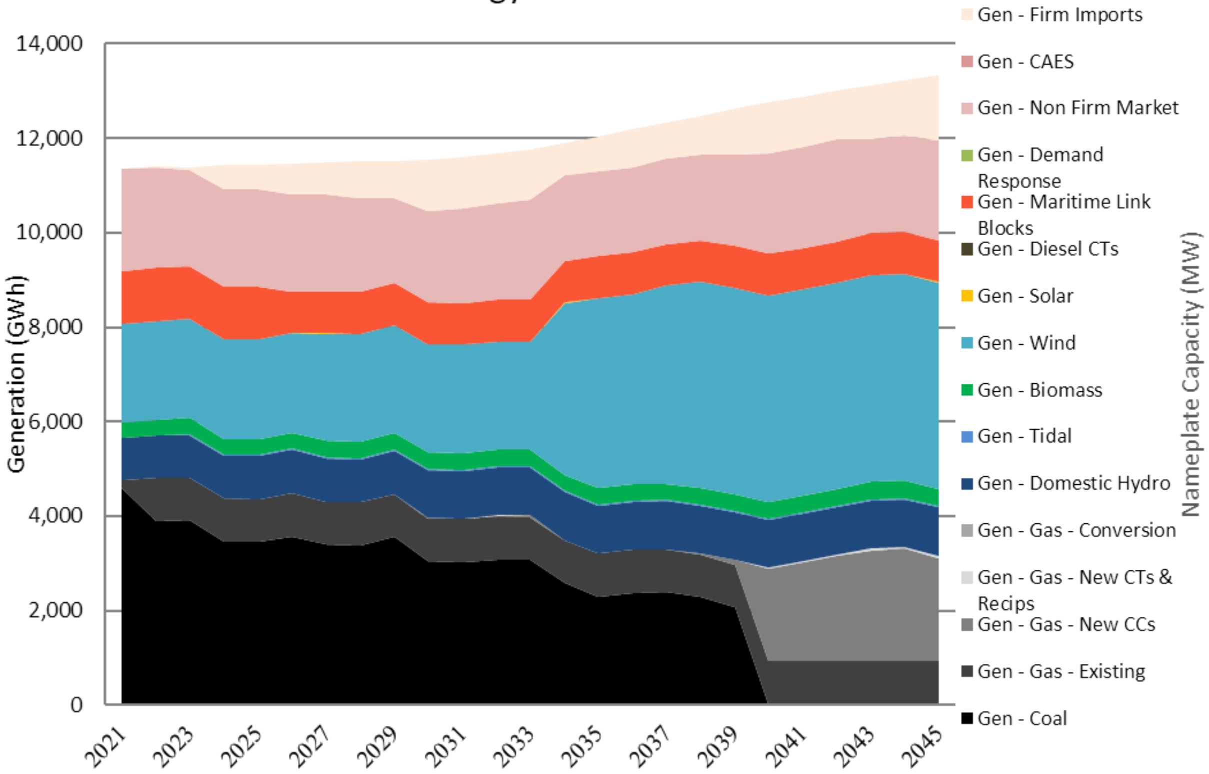
Scenario Notes

- Early load growth served by incremental gas CTs and non-firm import energy
- Reliability Tie built in 2034 enables wind integration
- Additional wind is integrated with local mitigation
- DR resources selected starting in 2030

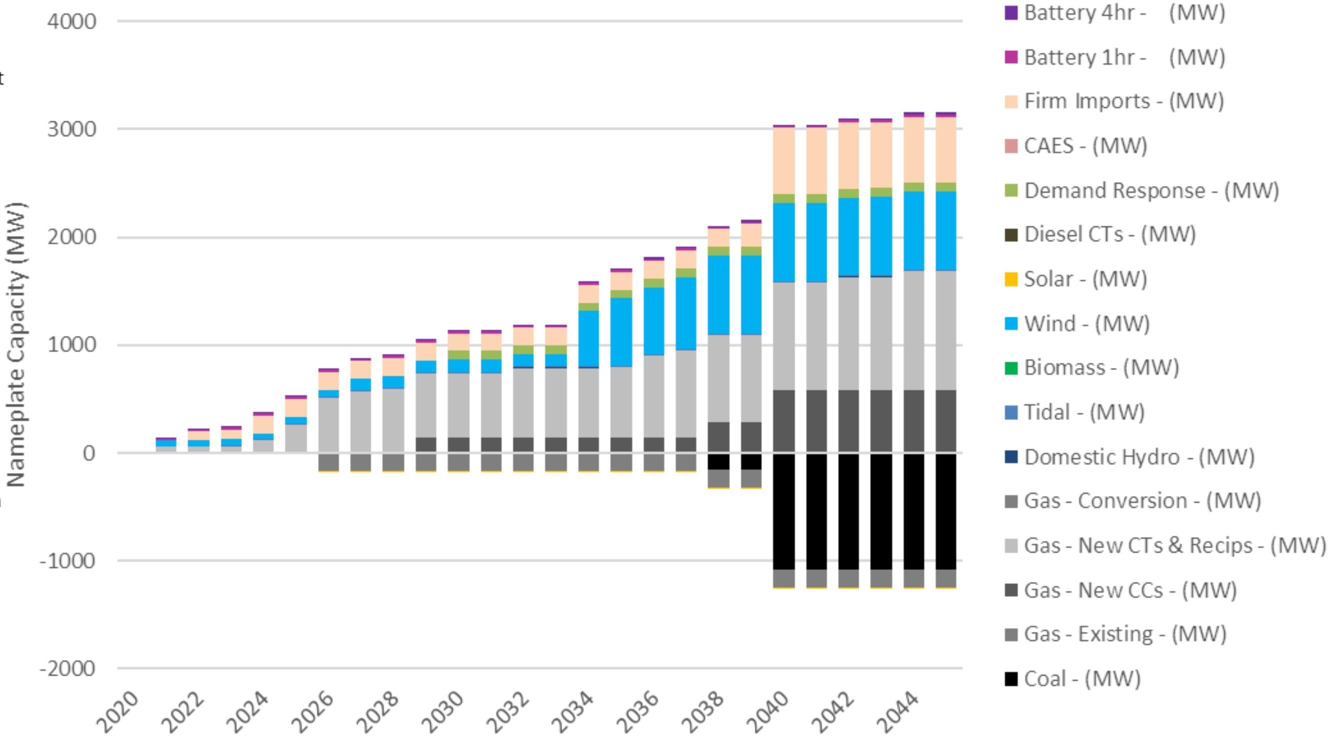
2.2C

HIGH ELEC. / MAX DSM / NET ZERO 2050 / REGIONAL INTEGRATION

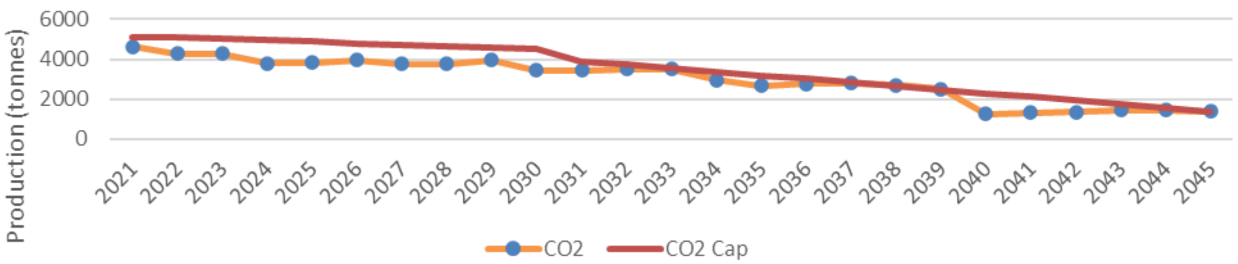
Energy Balance



Installed Capacity Changes



CO_2 Emissions

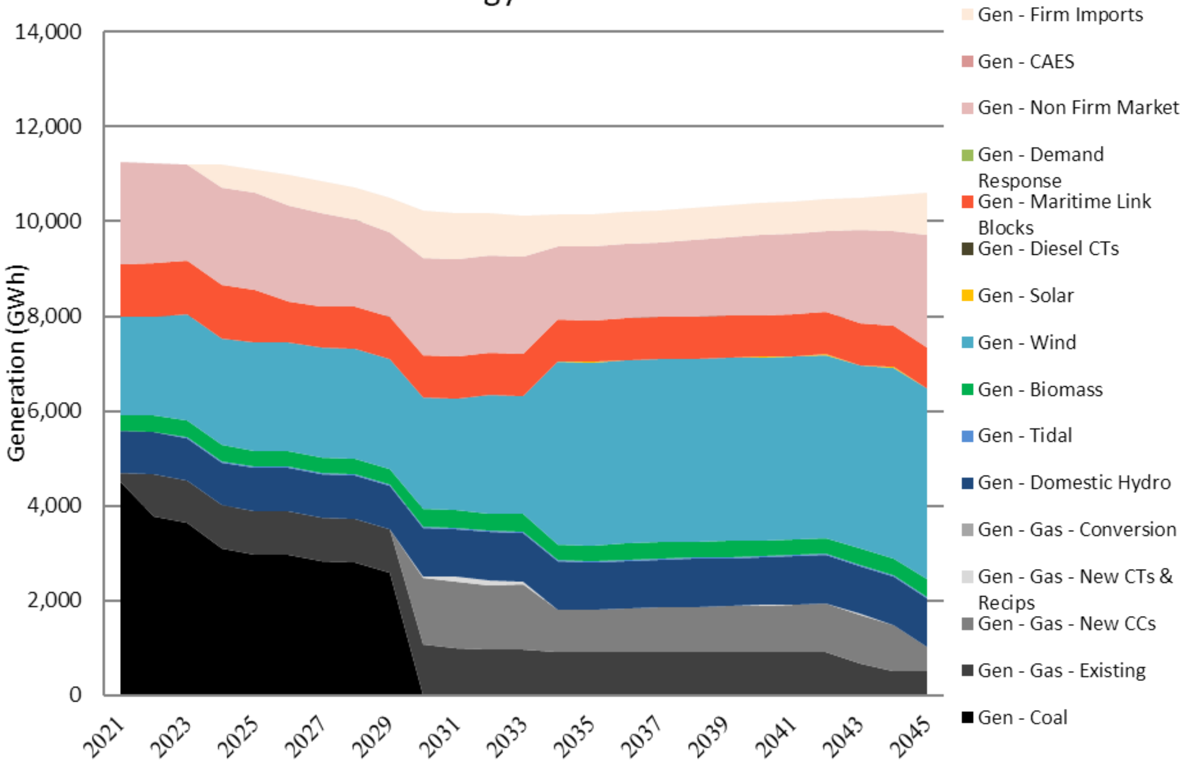


	$MM	Scenario Notes
25-yr NPVRR	$15,353	• Reliability Tie built in 2034 enables wind integration • Regional Interconnection built in 2039 to access firm imports (staged from reliability tie) • DR selected beginning in 2030
25-yr NPVRR w/ EE	$20,205	
10-yr NPVRR	$8,212	

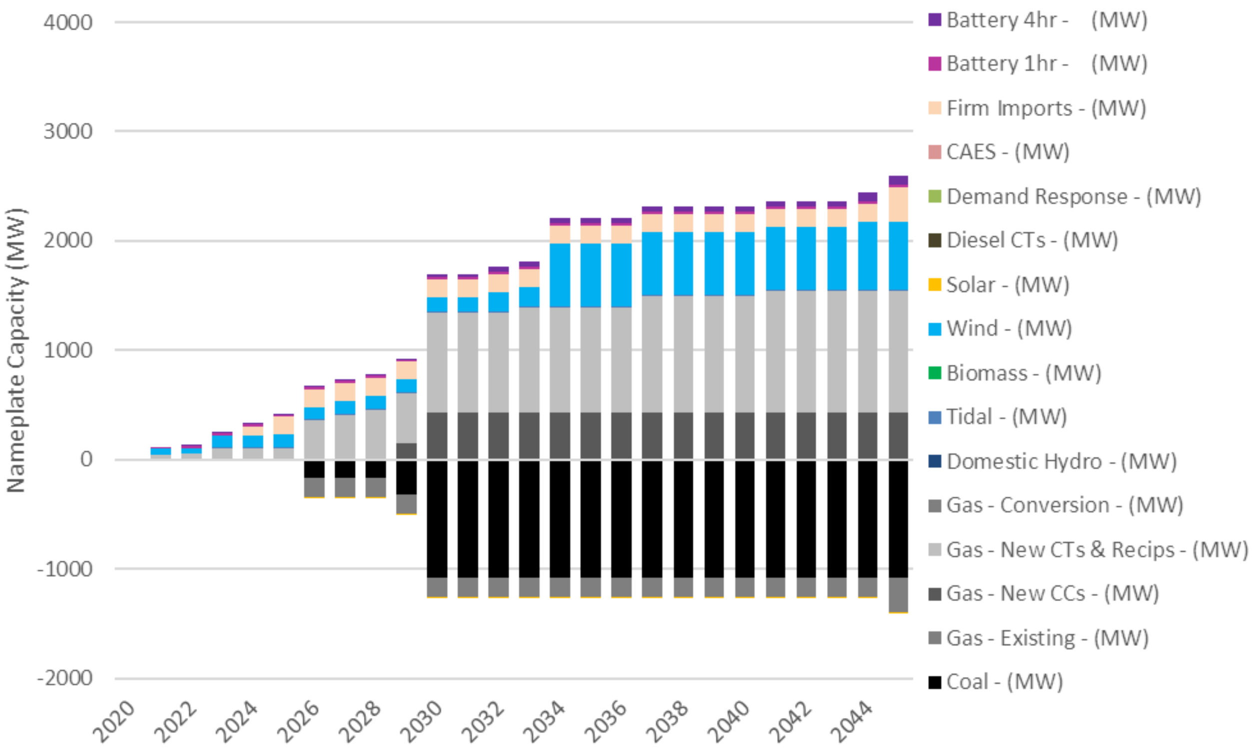
3.1B

MID ELEC. / BASE DSM / ACCEL. ZERO 2045 / DISTRIBUTED RESOURCES

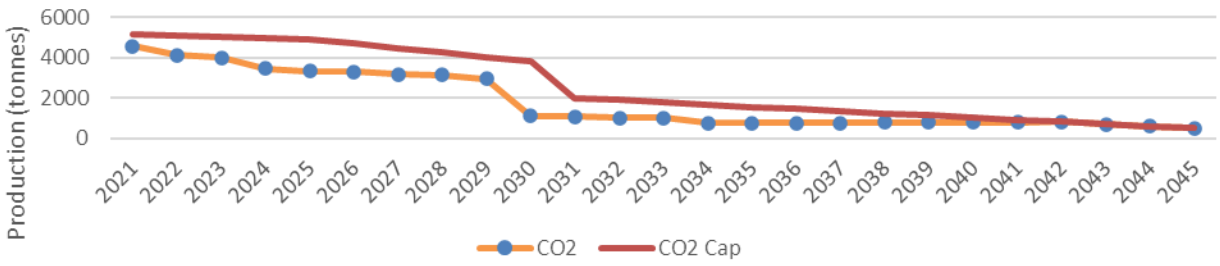
Energy Balance



Installed Capacity Changes



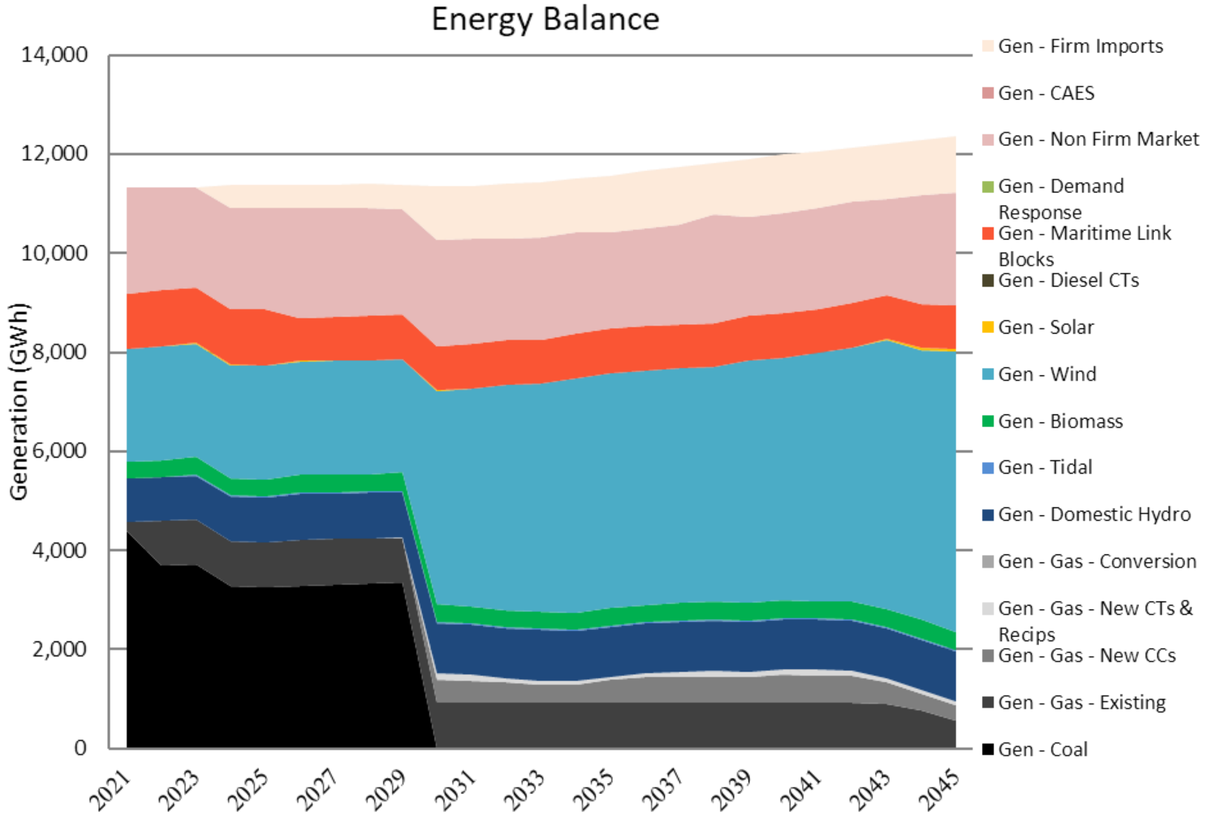
CO_2 Emissions

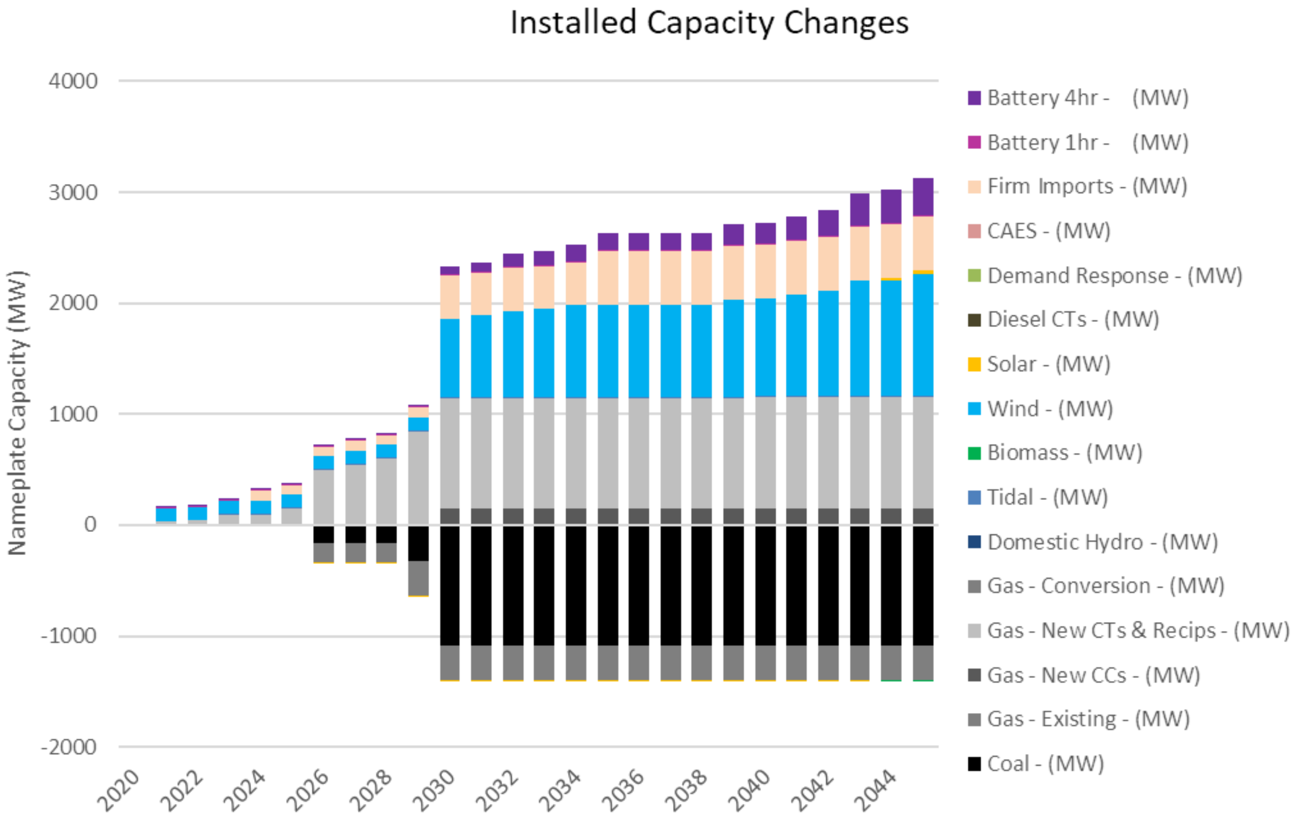


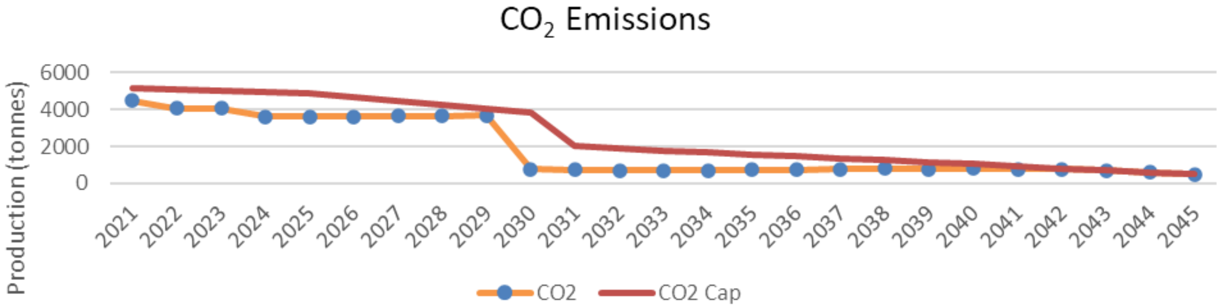
	$MM	Scenario Notes
25-yr NPVRR	$12,575	• Reliability Tie build in 2034 enabled wind integration • Regional Interconnection built in 2045 to access firm imports (staged from reliability tie) • DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)
25-yr NPVRR w/ EE	$17,311	
10-yr NPVRR	$6,827	

3.1C

MID ELEC. / BASE DSM / ACCEL. ZERO 2045 / REGIONAL INTEGRATION



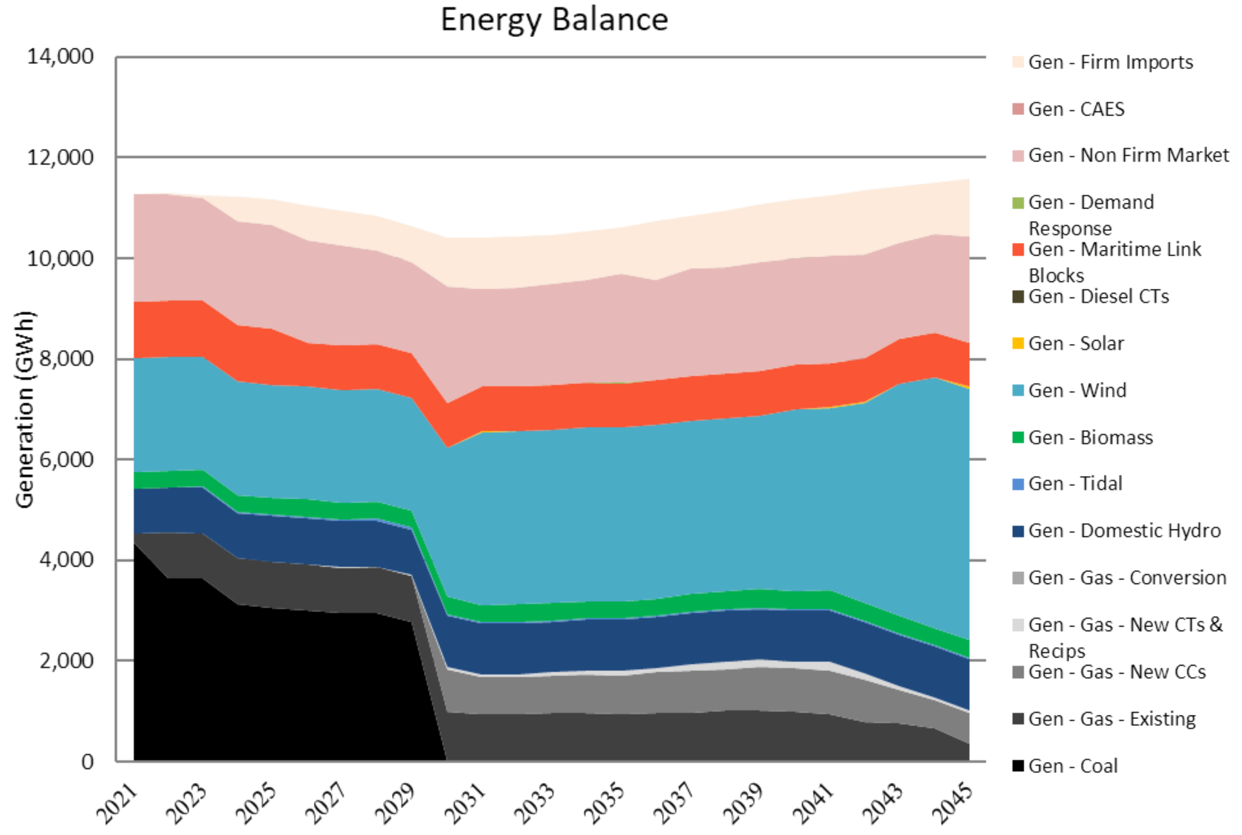


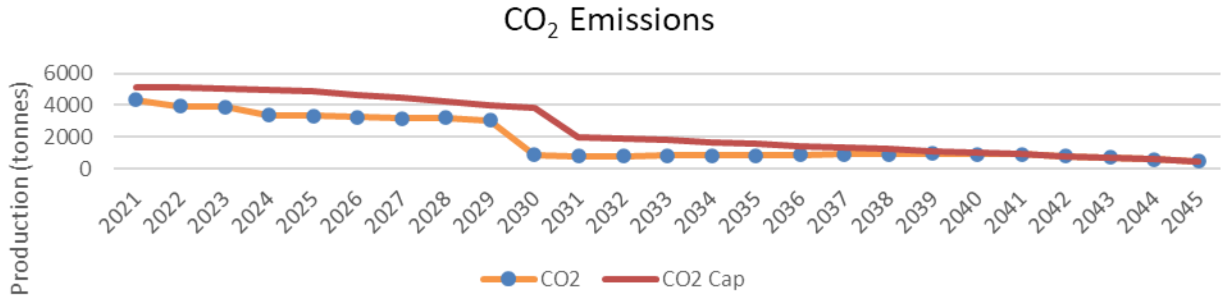


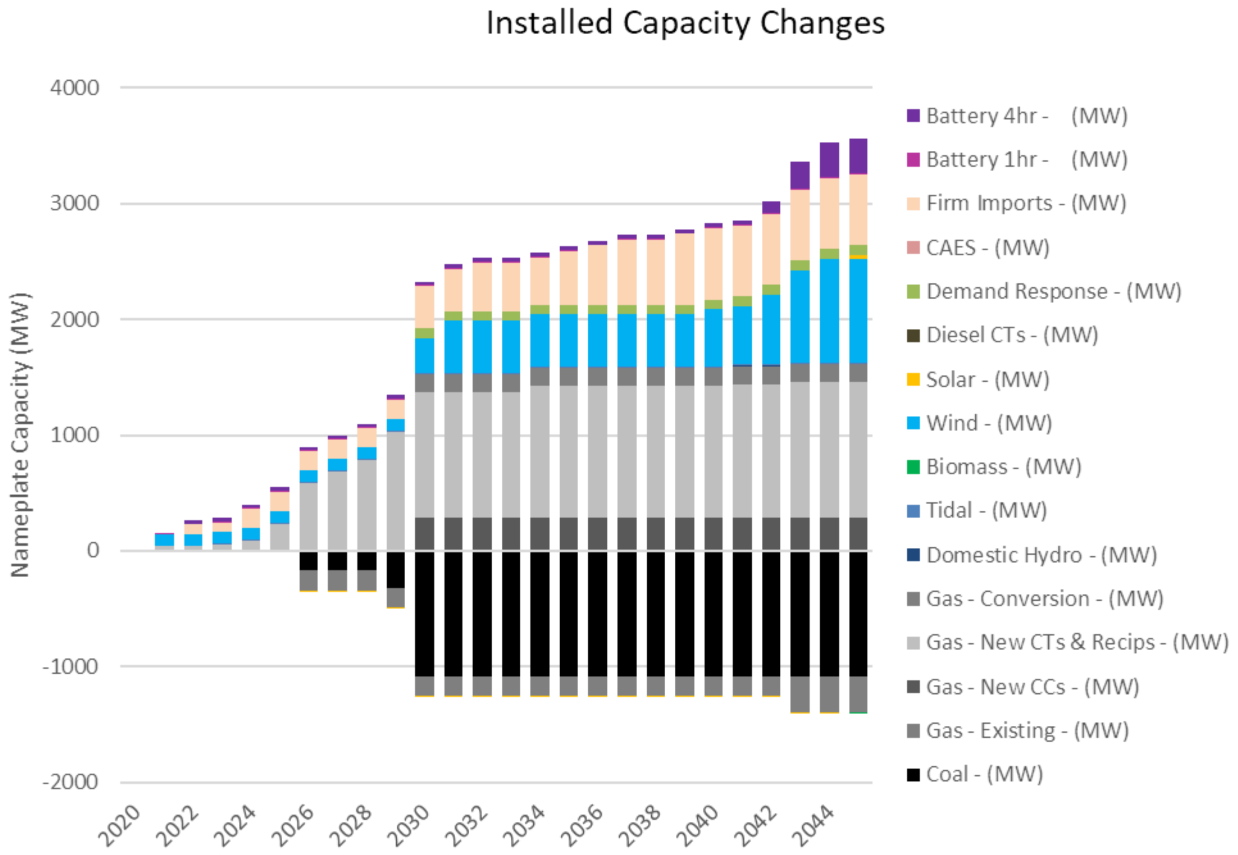
	$MM	Scenario Notes
25-yr NPVRR	$13,477	• Full Regional Interconnection built in 2030 enables firm imports and wind integration • Local mitigations (4hr batteries and synchronous condensers) enable additional wind builds to 2045
25-yr NPVRR w/ EE	$17,619	
10-yr NPVRR	$7,505	

3.2B

HIGH ELEC. / MAX DSM / ACCEL. ZERO 2045 / DISTRIBUTED RESOURCES



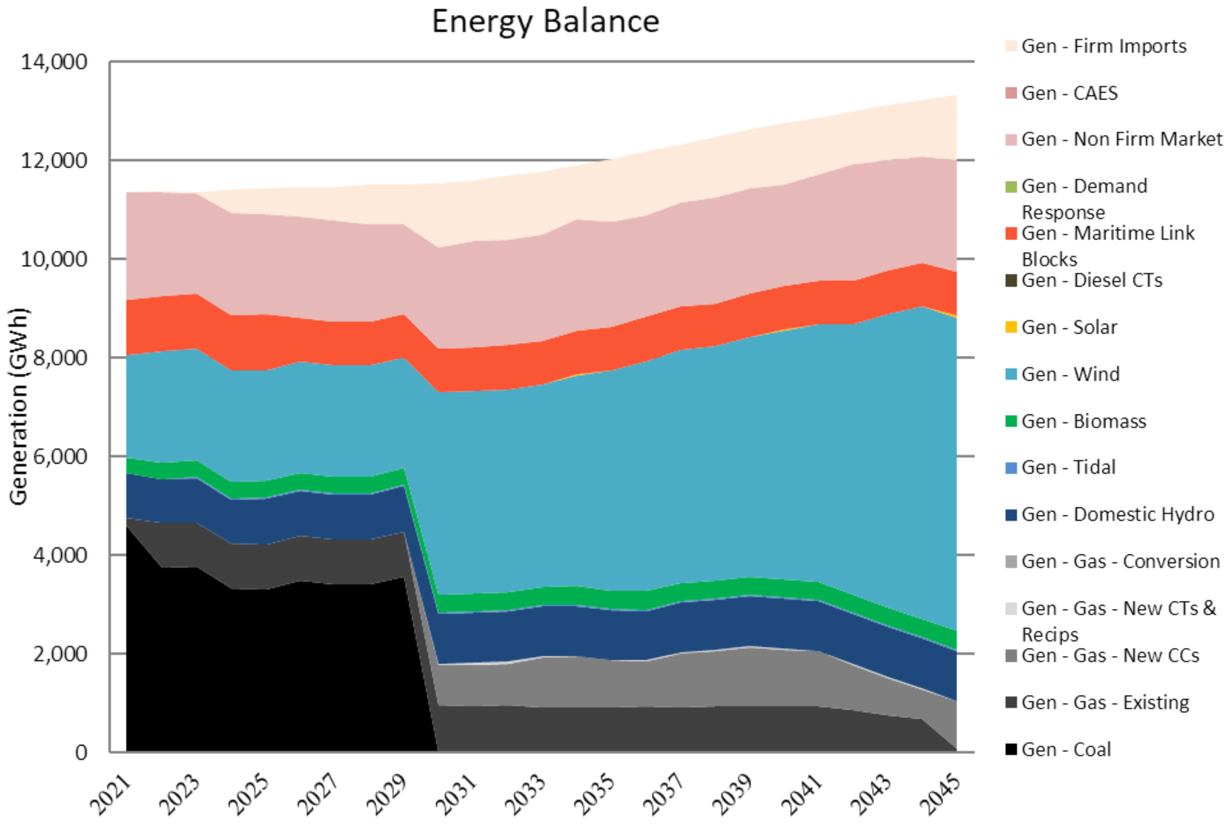


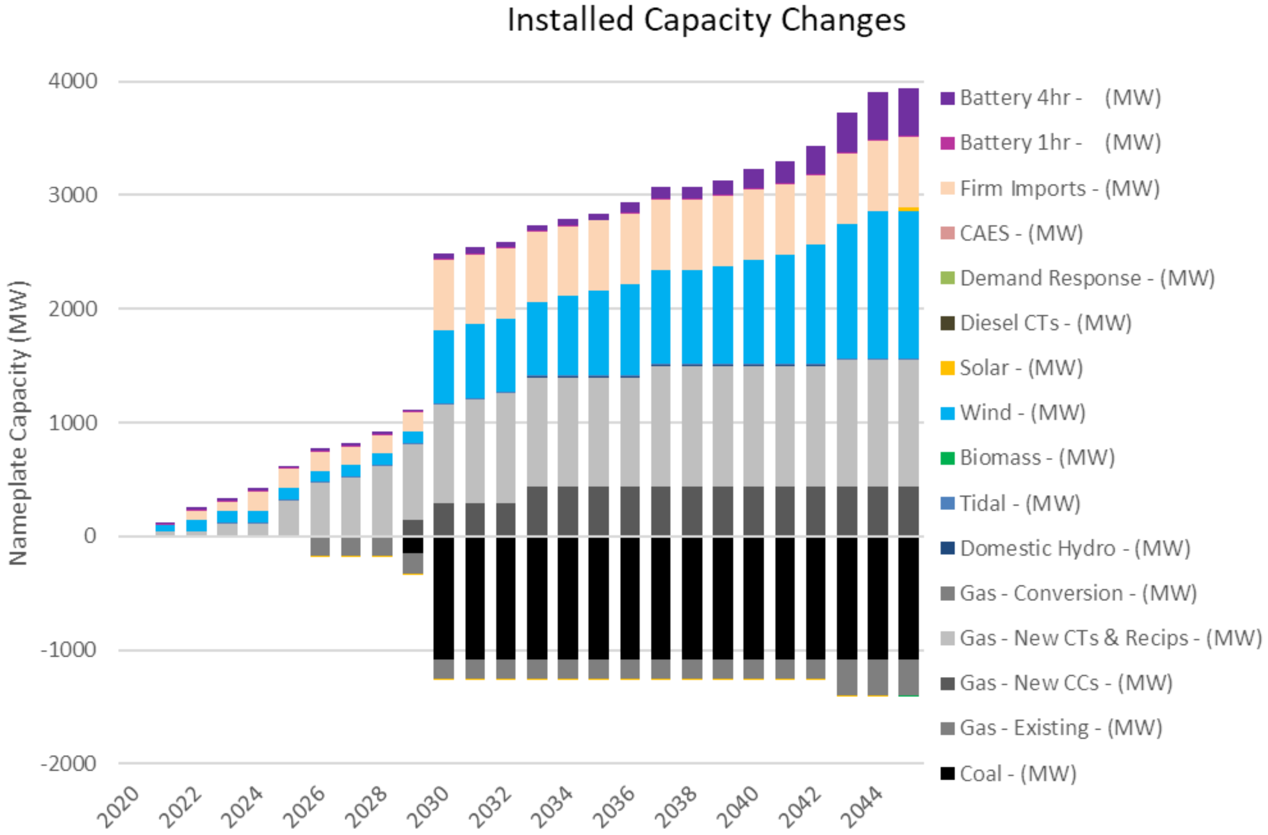


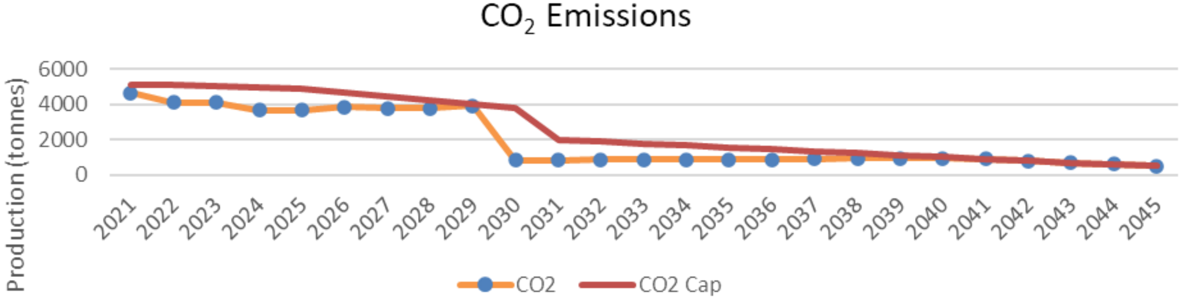
	$MM	Scenario Notes
25-yr NPVRR	$15,015	• Full Regional Interconnection built in 2030 enables firm imports and wind integration • DR selected starting in 2030 • DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)
25-yr NPVRR w/ EE	$19,365	
10-yr NPVRR	$8,436	

3.2C

HIGH ELEC. / MAX DSM / ACCEL. ZERO 2045 / REGIONAL INTEGRATION



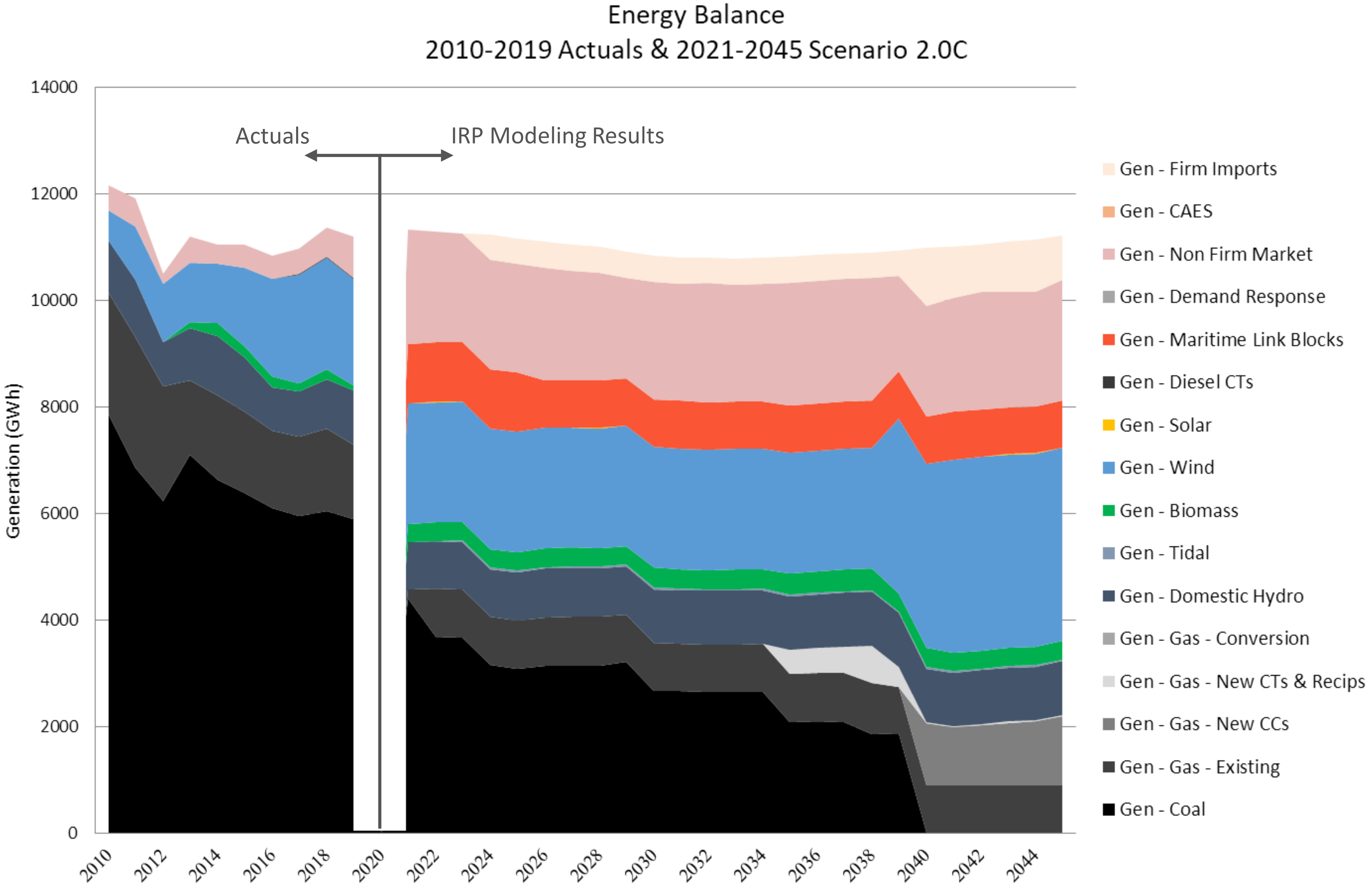




	$MM	Scenario Notes
25-yr NPVRR	$15,857	• Gas CT builds and incremental firm imports support early load growth • Full Regional Interconnection built in 2030 enables firm imports and wind integration; local mitigation allows additional wind builds to 2045
25-yr NPVRR w/ EE	$20,790	
10-yr NPVRR	$8,704	

IRP IN THE CONTEXT OF ONGOING GENERATION TRANSFORMATION

- The graph to the right includes actual annual generation for 2010-2019 and forecast generation from PLEXOS LT for 2021-2045 (2020 is left blank)
- This chart highlights the increasing penetration of renewables on the Nova Scotia system since 2010 as well as the anticipated changes due to the availability of energy over the Maritime Link beginning in 2021



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