CO_2 Reduction Alternatives Focusing on Natural Gas Utilization

PPL companies

February 9, 2022

Objective

- What is the most cost-effective means of reducing CO_2 emissions?
- Other considerations:
  - What can be done in near-term, without spending capital?
  - What are longer-term solutions, or solutions that require capital to implement?
- Categories of alternatives evaluated:
  - Displace coal with SCCT energy
  - Natural gas co-firing
  - Natural gas conversion
  - Incremental solar
  - Replace 2028 SCCTs w/ NGCC

Background Information

- All alternatives are compared to IRP reference case through 2036
  - Coal Retirements:
    - MC1 at end of 2024
    - MC2 and BR3 in 2028
    - GH1-2 in 2034
  - Additions:
    - 100 MW solar in 2023 (Rhudes Creek)
    - 125* MW solar in 2025 (Ragland)
    - 2 SCCTs (440 MW) and 500 MW solar in 2028
    - 4 SCCTs (880 MW) and 1,600 MW solar in 2034
    - 100 MW battery storage in 2035
    - 100 MW battery storage in 2036
- CO_2 emissions
  - 2010 baseline emissions for PPL are 62.6 million metric tons CO_2+CO_2e
  - 2022 forecasted emissions for LKE are 26.5 million metric tons CO_2+CO_2e
  - 1 million metric tons reduction is 1.6% reduction compared to 2010 PPL baseline

*IRP analysis assumed 160 MW PPA for Green Tariff Option 3 in 2025. This analysis was updated to reflect final contract value of 125 MW.

Summary of Results

- Most cost-effective near-term alternative is displacing coal with SCCT energy
- Most expensive alternative is gas conversion
- Most cost-effective actionable alternative overall is adding incremental solar
  - Replacing SCCT w/ NGCC not considered actionable

Cost Considerations

- No changes to assumed retirement dates were contemplated in this analysis
- System production costs (fuel & variable O&M)
- Lost CCR revenue
- Gas conversion costs/savings
  - Conversion capital
  - Gas pipeline capital
  - Incremental firm gas transportation costs
  - O&M savings from reduced labor & coal handling needs; reduced reagent costs
  - Fixed coal transportation savings (rail, barging costs)
- Other items
  - Cost differences between SCCT and NGCC
  - Solar PPA costs; REC prices
  - Not quantified/considered in this analysis:
    - IMEA/IMPA reimbursement
    - OSS implications
    - Alternative gas price forecasts
    - Implementation risk (e.g., pipeline permitting for conversion alternatives)

Alternatives Evaluated

Category	Alternative	Description	Affected Units	Notes
Disp	Displace coal with SCCT energy (6 cases)	Commit select coal units after SCCTs (out of merit order)	Various configurations of BR3, GH4, MC1-2	Capacity factors of these coal units typically < 10%. Units remain available to ensure reliability.
CoF	NG co-firing (3 cases)	Use existing infrastructure to co-fire NG	Various configurations of MC3-4, TC1-2	BR/GH use oil as start fuel and can't co-fire without modifications. MC gas supply and unit constraints limit capability to 7.5% for MC3-4 only. TC1-2 can accommodate 10% without modification.
Conv	NG conversion (5 cases)	Fully convert coal-fired units to burn NG	Various configurations of BR3, GH1-4, MC2-4, TC1-2	Capital intensive. Engineering studies imply lost efficiencies, resulting in increased heat rates and reduced max capacities.
Sol	Incremental solar (2 cases)	Add new solar PPAs		Analysis assumes new PPAs online in 2025 at a cost of $28.05/MWh.
CC	Build NGCCs instead of SCCTs (2 cases)	Replace 2x SCCTs (440 MW) in 2028 with 1x NGCC (513 MW)		Analysis considered two scenarios: normal depreciation, and accelerated depreciation of incremental capital.

CO_2 Reduction Cost and Potential

- Least-Cost CO_2 reductions (no capital)

Time Frame	Alternative	Annual Fuel Cost ($M)	Annual CO_2 Reduction (000 metric tons/year)	Levelized CO_2 Reduction Cost ($/metric ton)
2022-2024	Commit BR3 After SCCTs	6	348 (0.6%)	18
2025-2036	Incremental 200 MW solar	1	344 (0.5%)	4

- Highest-impact CO_2 reductions (no capital)

Time Frame	Alternative	Annual Fuel Cost ($M)	Annual CO_2 Reduction (000 metric tons/year)	Levelized CO_2 Reduction Cost ($/metric ton)
2022-2036	Commit MC1-2, BR3, & GH4 After SCCTs	31	920 (1.5%)	34

- Least-Cost CO_2 reductions (with capital spend)

Time Frame	Alternative	Annual Fuel Cost ($M)	Annual CO_2 Reduction (000 metric tons/year)	Levelized CO_2 Reduction Cost ($/metric ton)
2028-2036	Replace 2028 SCCTs with 513 MW NGCC	(22)	1,586 (2.5%)	4

- Gas conversion alternatives were highest cost

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Results Summary

Category	Alternative	Levelized CO_2 Reduction Cost ($/metric tons)	Average CO_2 Removed (000s metric tons/year)	Average Annual Change in Fuel/O&M Costs ($M/year)	Incremental Capital ($M)
--	2021 IRP Reference Case*	--	--	--	--
CC	**Replace 2028 SCCTs with 513 MW NGCC (40-Yr Depreciable Life)**	**4**	**1,586 (2028-2036)**	**(22)**	**242**
Sol	**Incremental 200 MW Solar**	**4**	**344 (2025-2036)**	**1**	**0**
Sol	Incremental 100 MW Solar	4	170 (2025-2036)	1	0
CC	Replace 2028 SCCTs with 513 MW NGCC (Full Recovery of $242M by 2036)	13	1,586 (2028-2036)	(22)	242
Disp	**Commit BR3 After SCCTs**	**18**	**348 (2022-2027)**	**6**	**0**
Disp	Commit MC1 & BR3 After SCCTs	26	517 (2022-2027)	13	0
CoF	NG Co-Fire: TC1-2	27	233 (2022-2036)	6	0
Disp	Commit MC1-2 & BR3 After SCCTs	31	760 (2022-2027)	23	0
Disp	Commit BR3 & GH4 After SCCTs	31	769 (2022-2036)	24	0
CoF	NG Co-Fire: MC3-4 & TC1-2	33	485 (2022-2036)	16	0
Disp	**Commit MC1-2, BR3, & GH4 After SCCTs**	**34**	**920 (2022-2036)**	**31**	**0**
Disp	Commit MC1 After SCCTs	37	294 (2022-2024)	11	0
CoF	NG Co-Fire: MC3-4	40	235 (2022-2036)	10	0
Conv	NG Conversion: MC3-4	56	1,416 (2024-2036)	66	108 (12 pipe)
Conv	NG Conversion: Fleet	64	5,952 (2024-2036)	333	682 (179 pipe)
Conv	NG Conversion: BR3, GH1-4, & MC3-4	73	4,193 (2024-2036)	265	580 (179 pipe)
Conv	NG Conversion: BR3	97	259 (2024-2027)	2	92 (46 pipe)
Conv	NG Conversion: MC2	119	271 (2024-2027)	13	50 (12 pipe)

Conclusions

- No alternatives have lower PVRR than Reference Case
- Adding more solar is lowest-cost actionable alternative for reducing CO_2, but annual reductions are small and would not begin until 2025
- CO_2 reduction cost for gas conversion is two to three times higher than displacement and co-firing, but annual CO_2 reduction potential is greater
- Cost of displacement and co-firing is $6 to $31 million per year
- Absent long-term technology risk, NGCC is most cost-effective alternative for reducing significant quantities of CO_2 through 2036

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Appendix

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Gas Conversion Assumption Summary

$M	BR3	GH1	GH2	GH3	GH4	MC2	MC3	MC4	TC1	TC2
Conversion Capital (2023$)	46	53	54	54	53	45	44	53	41	61
O&M Savings (2024$)	(11)	(12)	(12)	(12)	(12)	(9)	(10)	(12)	(9)	(14)
Firm Gas Transportation (2024$)	15	16	16	16	16	10	13	16	12	16

- Conversion capital and annual O&M savings for Brown 3 and Mill Creek 2 based on engineering studies. Cost for other units scaled from Brown 3 based on max summer capacity.
- Annual firm gas transportation costs derived using Cane Run 7 costs scaled to daily gas burn at full load for converted units.
- Pipeline capital (2023$)
  - Brown: $46 M
  - Ghent: $120 M
  - Mill Creek: $12 M
- Station fixed coal transport costs (2024$)
  - Brown: $7 M
  - Ghent: $3 M
  - Mill Creek: $2 M
  - Trimble County: $1 M
- Loss of efficiency expected to increase net heat rates by 13.6% based on engineering studies and feedback from peer utilities.
- Gross maximum capacity expected to decrease by ~5% per unit, partially offset by a decrease in aux load due to reduced environmental controls (e.g., FGD, baghouses), resulting in ~2% loss in net maximum capacity by unit.
- Minimum capacity expected to decrease by 25%, allowing for more unit turndown capability.
- Analysis assumes 50% reduction in ammonia costs due to reduced NO_x emissions from gas combustion. Analysis assumes elimination of costs from all other reagents for environmental controls of converted units.

Gas Co-Firing Assumption Summary

- Brown and Ghent units are unable to co-fire NG without modifications to switch startup/stabilization fuel from oil to gas.
- Mill Creek is currently served by the LG&E LDC. Existing gas supply lines and unit constraints limit co-firing capability. Without modifications, co-firing would be limited to ~7.5% on units 3 and 4 only.
- Trimble County is capable of 10% co-firing on units 1 and 2 without modifications.
- Analysis assumes units can revert to 100% coal as needed, obviating need for incremental firm gas transport to co-fire.