Supporting Information – Time-Resolved Cost Analysis of Natural Gas Power Plant Conversion to Bioenergy with Carbon Capture and Storage to Support Net-Zero Emissions

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Supporting information consists of 21 pages with 12 tables and 10 figures.

Section S1. Natural Gas and Electricity Price Projections

Figure S1 displays the EIA's electricity price projection for a reference case and the $25 carbon allowance fee scenarios. The EIA reference case projection is used in the "no emissions pricing", "social costs of greenhouse gases", and "EIA $25 without feedback" scenarios. The EIA $25 carbon allowance fee is used for the "EIA $25 with feedback" scenario. Figure S2 displays the natural gas price projections for the EIA reference case and $25 carbon allowance fee scenarios. The EIA reference case projection is used for the "no emissions pricing" and "social costs of greenhouse gases" scenarios. The EIA $25 carbon allowance fee projection is used for the "EIA $25 without feedback" and "EIA $25 with feedback scenarios.

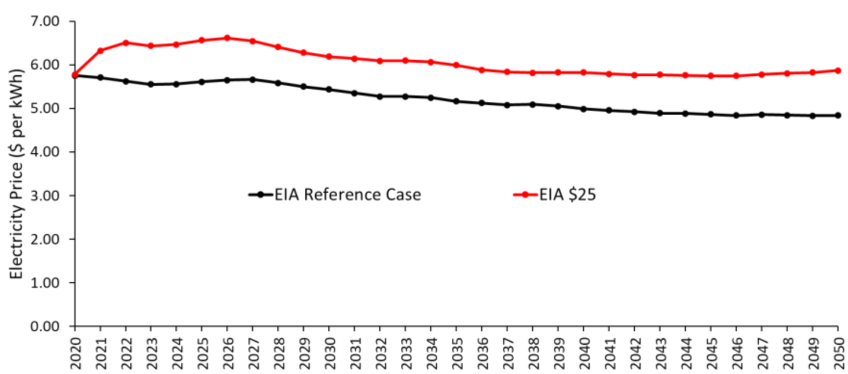

Figure S1. Price of electricity from EIA Reference Case and EIA $25 Carbon Allowance Fee scenarios[1].

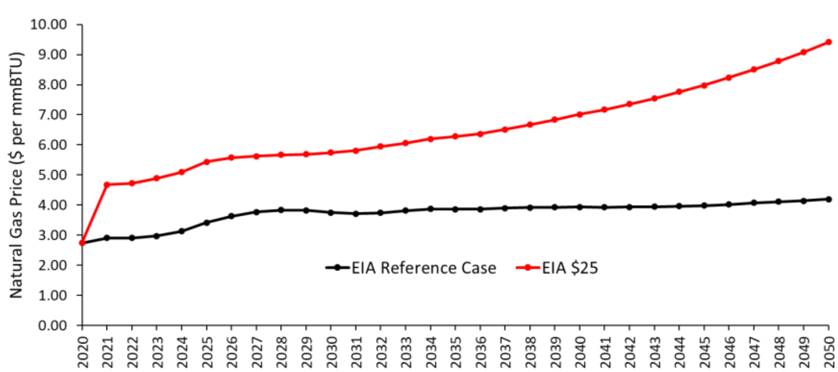

Figure S2. Price of natural gas from EIA Reference Case and EIA $25 Carbon Allowance Fee scenarios[1].

Section S2. Life Cycle Assessment Data

Normal Operation of an NGCC Power Plant

Data for normal operation of the NGCC power plant was sourced from NETL as summarized in Table S1[2]. This report was selected as it has a breakout of individual greenhouse gases (CO_2, CH_4, and N_2O), as well as adequate resolution to estimate time resolved emissions. The first emissions extracted from the report were those associated with upstream natural gas production. For this model, a U.S. domestic onshore natural gas well was selected to represent the front of the system boundary. Emissions attributed from this well started with construction and installation. Since a full scale NGCC power plant is supported by a range of well-sites feeding into a pipeline network, the installation (and deinstallation) emissions were assumed to be evenly distributed over the lifetime of the plant. This distribution conveys that wells are not constructed at the onset of the NGCC power plant lifetime but are instead consistently coming online to continue support of power production across the entire sector. Once constructed and installed, operational emissions at the well were assumed to be consistent across all years of the plant. Of the well site emissions, fugitive methane emissions are the most significant contributor to global warming. As a result, these emissions were set as a variable input parameter in the model, with a recent estimate from Alvarez et al. serving as the baseline[3]. Upon leaving the well-site, natural gas is assumed to travel through a domestic onshore pipeline to the NGCC power plant. Emissions from construction, installation, operation, and deinstallation of the pipeline are modeled consistently with the well-site emissions. Pipeline and well-site fugitive emissions are lumped together as a single number. All emissions data from the well-site and pipeline are sourced from NETL in units of kg of greenhouse gas per kg of natural gas delivered to the power plant. The energy content of natural gas (0.049 mmBTU per kg) and the NGCC power plant heat rate (6.45 mmBTU per MWh) are used to convert emissions so they correspond to a functional unit of kW (for construction) or kWh (for operation). At the natural gas power plant emissions are broken down by construction, commissioning, operation, and decommissioning. For the analysis in this work, construction emissions were distributed evenly across the three years of construction from 2017 through 2019. Within the model, an alternative option exists to distribute the construction emissions according to the capital investment in the first three years of construction. Commissioning emissions were applied in 2019, as they are assumed to occur in the final year of construction. After commissioning, operational emissions are considered constant from 2020 to the end of life or the year in which the NGCC plant is converted to a new technology (biomethane, CCS, or BECCS). At end of life, decommissioning emissions are applied in the final year of operation. All power plant related emissions are sourced in kg of greenhouse gas per MWh of electricity produced.

Table S1. Life cycle emissions data extracted for domestic on shore natural gas production and combustion in an NGCC power plant[2].

	Well Site (kg per kg natural gas)			
	Installation/Deinstallation	Construction	Operation	Total
CO_2	8.54E-07	2.00E-03	1.05E-01	1.07E-01
N_2O	2.09E-11	6.25E-08	2.19E-07	2.82E-07
CH_4	9.10E-10	3.66E-06	1.67E-03	1.67E-03
	Pipeline (kg per kg natural gas)			
	Installation	Construction	Operation	Total
CO_2	3.54E-06	4.52E-04	7.96E-03	8.42E-03
N_2O	7.13E-11	2.41E-08	1.38E-07	1.62E-07
CH_4	3.49E-09	5.31E-07	4.94E-04	4.95E-04
	NGCC Plant without CCS (kg per MWh)			
	Installation/Deinstallation	Construction	Operation	Total
CO_2	3.70E-01	1.50E-02	3.65E+02	3.65E+02
N_2O	1.15E-05	3.75E-07	2.06E-06	1.39E-05
CH_4	3.19E-04	1.60E-05	7.47E-06	3.42E-04
	NGCC Plant with CCS (kg per MWh)			
	Installation/Deinstallation	Construction	Operation	Total
CO_2	5.10E-01	1.94E-02	4.71E+01	4.76E+01
N_2O	1.82E-05	4.83E-07	2.39E-06	2.11E-05
CH_4	4.57E-04	2.06E-05	8.76E-06	4.86E-04

Fuel Switch to Biomethane

Biomethane production emissions vary across literature. An estimate of 25 gCO_2-eq per MJ was selected for this analysis. A breakout of individual greenhouse gases was not available, therefore all 25g of CO_2eq are considered as CO_2 within the model. In the case of a fuel switch, all emissions associated with natural gas are removed from the analysis and replaced with this single emissions value. This corresponds to a 100% replacement of natural gas with biomethane.

Retrofit of NGCC plant with CCS

CCS data was also sourced from the NETL report for consistency. Adding CCS to the NGCC plant results in additional construction, commissioning, and decommissioning emissions, as well as different operational emissions. Construction and commissioning emissions are applied in the year in which CCS was added. Operational emissions occur from the addition of CCS to the plant end of life. Operational emissions include the burden of an increased heat rate (7.53 mmBTU per MWh) from fuel consumption required to recover amine solvents. However, overall combustion emissions are greatly reduced by an assumed 90% post-combustion CO_2 separation and storage rate.

Fuel Switch to Biomethane and Addition of CCS Resulting in BECCS

When fuel switching and addition of CCS occur simultaneously the result is a bioenergy with CCS (BECCS) system. In the BECCS system, 25 g CO_2 is attributed to biomethane production and CCS capital and operational costs are adjusted in line with the retrofit mentioned above. The result is an overall net-negative emissions burden associated with BECCS power production.

Section S3. Example of Conversion with No Emissions Pricing in 2025

Using the baseline defined in Section 2.3.1, this example evaluation considered converting to low-emissions technology options in the year 2025 to illustrate how cost targets are created. In the evaluation, the NGCC power plant was constructed over three years starting in 2017 and operated normally from 2020-2024. In 2025, operation was changed to one of three technology options. The first option was a fuel switch from natural gas to biomethane. This switch required placing a price on biomethane which has estimated production costs ranging from below \$10 per mmBTU to over \$20 per mmBTU[4,5]. This initial evaluation assumed \$10 per mmBTU, which aligns with production cost estimates from a UC Davis report and a previous fixed contract price (\$9.80 per mmBTU) paid by the Los Angeles Department of Water and Power[4,6]. However, this value was also varied in the analysis to demonstrate the effects of uncertainty of biomethane pricing and the potential for future technological development resulting in further cost reduction. The second option was the addition of CCS to the existing NGCC power plant. In this option the plant continued operation, but it was retrofit with CCS over the course of a year. CCS capital costs of the retrofit were set at \$1797 per kW, which aligns with an average estimate used in EIA electricity models[7]. Separation and compression of the CCS CO_2 stream using an amine solvent required increased operational costs, as well as an increased heat rate (7.53 mmBTU per MWh or 45.3%) due to the increased consumption of natural gas associated with solvent recovery[8]. The third option was BECCS based on the combined switch from natural gas to biomethane and the addition of CCS. In this scenario, the two changes occur simultaneously (biomethane switch at the onset of the CCS construction) and the BECCS system operates from 2025 to the plant's end of life in 2050. In addition to these three technology options, a fourth option of plant shutdown was also considered. During shutdown all operations and revenue ceased immediately, and the plant was decommissioned over a one-year period. The four options were each run through the TEA and solved for the resulting NPV. The results were compared across each technology option as well as the baseline case of normal operation.

CCS capital costs and biomethane fuel costs were then varied to determine cost targets that result in the technology options matching the NPV of normal operation.

Figure S3 displays the NPV for normal operation, shutdown, and the three low-emissions technology options without emission pricing policies. Changing from normal operation of the NGCC power plant to any of the three low-emissions technologies will result in a negative NPV. Switching to biomethane at $10 per mmBTU is the cheapest of the technology options, but still yields an NPV significantly worse than shutdown. Addition of CCS represents a large cost as seen in the large negative slope in 2025 and results in an NPV less than -$1000 per kW at the end of life, making both CCS alternatives (natural gas and biomethane) uncompetitive. The modeling work assumes biomethane and CCS costs based on existing literature, as there is ongoing technological development in these areas to reduce costs. Due to the uncertainty of these costs, further work was done to understand the impact of varying these costs and identify cost targets that would make biomethane, CCS, and BECCS options yield an NPV equal to the baseline of normal operation.

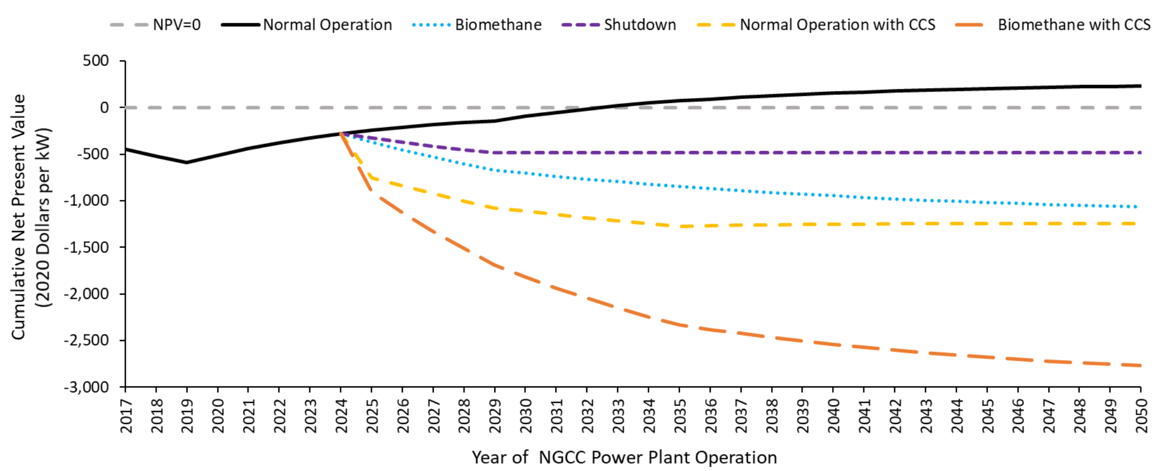

Figure S3. Comparison of continuing normal operation of natural gas power plant (black line) and shutdown (purple line) with changing to one of three different technology alternatives in the year 2025 without emissions pricing. Viable options would either meet or exceed the NPV of normal operation.

The significant effect of varying biomethane fuel costs for the NGCC power plant is presented in Figure S4. Reducing fuel costs from \$10 per mmBTU to \$3 per mmBTU increases NPV by \$1437 per kW and represents an economically viable solution. A fuel cost of \$3.80 per mmBTU will match the baseline NPV of normal operation. The actual production costs of biomethane are dependent upon the specific method of production and the overall market demand for that biomethane. The \$3.80 per mmBTU cost target falls well below current estimates for biomethane production[4,5]. It is important to note that while biomethane was the focus of this analysis, any readily-substitutable fuel produced at or below \$3.80 per mmBTU would provide a viable substitute when emissions pricing is not included. However, the emissions associated with a fuel other than biomethane would have impacts on the emissions pricing evaluations presented in later sections.

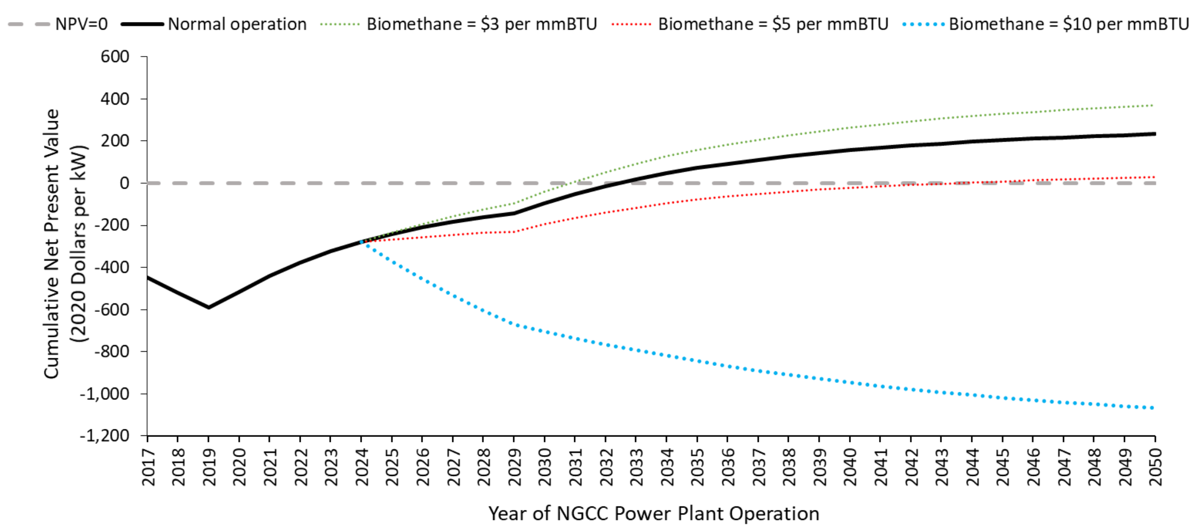

Figure S4. Net present value of normal plant operation with natural gas compared to operating with biomethane at three different biomethane fuel costs without emissions pricing.

A cost target was also identified for adding CCS to the existing NGCC power plant. Defining this target required varying the CCS capital cost and plant operational costs (fuel cost and the heat rate of the NGCC plant after CCS was added), since each of these represents a critical uncertainty of future technological development. Figure S5 shows the cost target result for the addition of CCS. Costs inside the purple shaded region of the figure will result in an NPV equal to or higher than normal operation. It is important to note that in this specific evaluation the fuel cost can be the cost of natural gas, biomethane, or another equivalent drop-in fuel. In later evaluations, the use of emissions pricing will not allow for this simplification. Figure S5 highlights that the cost target for CCS capital is below current cost estimates which the EIA places between $1313 and $2533 per kW[7]. Even at a fuel price of $0 per mmBTU, the CCS capital costs required to compete with normal operation must be at or below $967 which is 26% less than the low end of the current EIA range. Conversely, a more realistic estimate of current CCS operational costs such as $75.3 per MWh ($10 per mmBTU, 7.53 mmBTU per MWh) falls well outside the target, regardless of capital costs. These results further illustrate the findings of Figure S3 and demonstrates that new technologies such as CCS face a significant economic challenge without economic incentives such as emissions pricing.

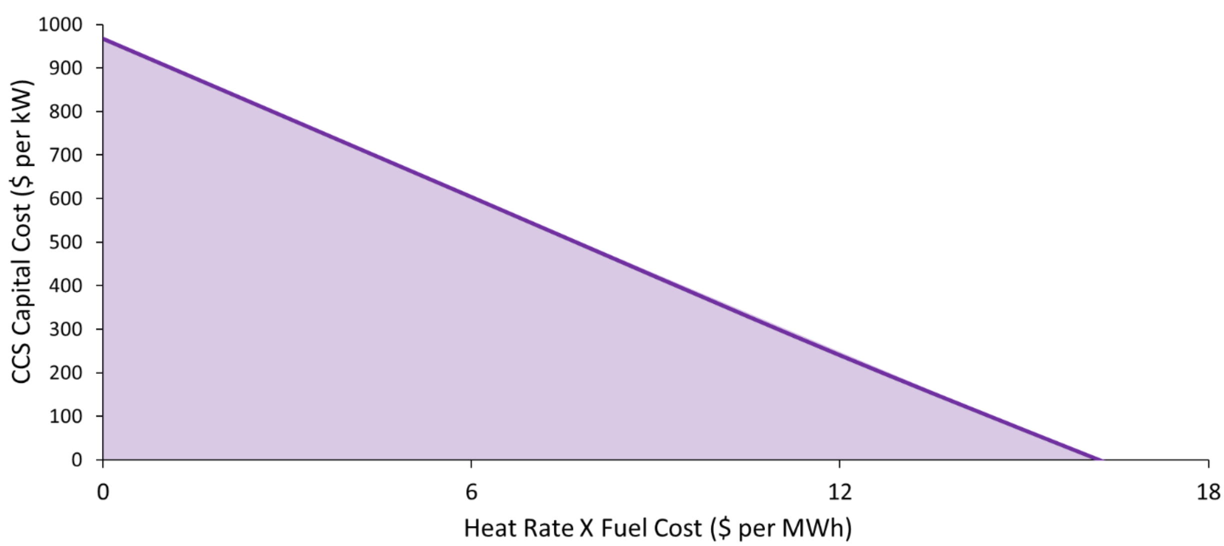

Figure S5. Cost targets for addition of CCS to existing NGCC power plant in the year 2025. Points inside the targets (purple shaded region) will yield an NPV higher than that of normal operation defined in the baseline scenario.

Section S4. Detailed Analysis of Biomethane Fuel Switch without CCS

A biomethane fuel switch was analyzed without CCS, to define biomethane production cost targets for operation at the constant average capacity factor of 58%. A result of 16 separate biomethane cost targets were found by varying emissions pricing and the year in which fuel switch takes place. The relationship between conversion timing, emissions pricing, and biomethane cost targets are presented in Figure S6. Each point in the figure represents the maximum biomethane cost that would allow for a switch to biomethane while yielding a higher NPV than normal operation or shutdown, whichever was most economically favorable. Consideration of shutdown must be included as it sometimes yields a higher NPV than normal operation when there is a price on emissions with the end results dependent on the emissions pricing scenario. For example, if 3% social costs are considered, a switch to biomethane in the year 2035 would be viable if biomethane costs were below $4.95 per mmBTU. Anything above this cost would result in a lower NPV than shutdown and would not be economically viable. Further clarification regarding comparisons to both shutdown and normal operation can be found within Figures S7-S10 of the supporting information.

In Figure S6, two major trends are apparent. The first is that adding a price to emissions raises the biomethane cost targets required to hit the NPV of normal operation with natural gas. This means that biomethane can be purchased at a higher price, making the fuel switch to biomethane more likely. The second major trend in Figure S6 is illustrated by the slopes of the cost target lines across the different scenarios as a function of conversion year. In the scenario with no emissions pricing (blue line), the upward slope of the line indicates that a fuel switch to biomethane should be delayed to decrease the impact of biomethane prices within the analysis. This would result in higher life-cycle greenhouse gas emissions. Conversely, in the social cost scenario (red line), the downward trend of the line indicates that the switch to biomethane should occur as early as possible to mitigate the large costs of near-term greenhouse gas emissions. This demonstrates, in idealized form, the desired effect of an emissions price to incentivize emissions reductions. The EIA $25 carbon fee with and without feedback show two different results. First, the scenario without electricity price feedback shows that the cost target peaks in 2035 and then starts to decline in later years. The scenario with electricity price feedbacks does not decline after 2030, meaning the target increases over time, similar to the no price on emissions scenario, but at a higher price point due to the applied price on emissions. The difference between the scenarios with and without feedbacks after 2025 is the result of large differences in NPV due to expected electricity prices. The scenario with feedbacks will make more revenue from electricity, which compensates for the emissions price, and thus encourages a delay in the switch to biomethane. The situation without feedbacks will not benefit from this increased revenue, leading to the lower cost targets in later years, incentivizing an earlier switch to biomethane.

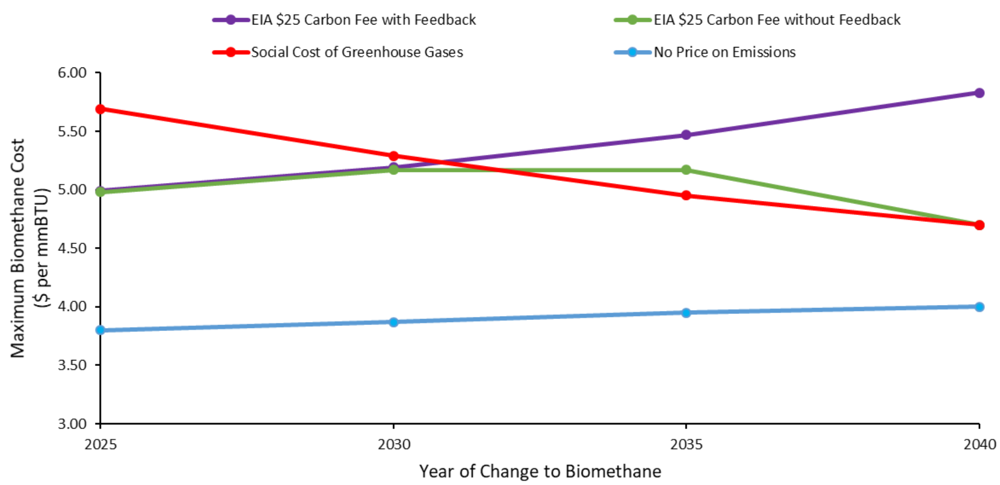

Figure S6. Maximum cost targets for biomethane based on varying fuel switch year and emissions pricing scenarios. A negative slope indicates that an earlier switch to biomethane is favorable.

Figures S7 – S10 display the cumulative NPV results of solving for biomethane fuel switch cost targets. The figures highlight a fuel switch to biomethane in 2025, 2030, 2035, and 2040, with varying emissions pricing scenarios. Across the figures biomethane cost targets are implemented to compete with normal operation or shutdown, whichever has a higher NPV by the year 2050. For example, in Figure S7 the social cost of greenhouse gases gives shutdown a high NPV. As a result, the biomethane cost target is set to match this NPV. In contrast the EIA $25 carbon allowance fee scenarios give normal operation a high NPV, and the biomethane cost target is set to match the NPV of normal operation. In another example, Figure S9 the EIA $25 carbon allowance fee without feedback drives shutdown to have a higher NPV, causing the biomethane cost target to be set to match this NPV. However, in the EIA $25 carbon allowance fee without feedback, normal operation has the highest NPV, causing the biomethane cost target to match this value. Each scenario evaluated is dependent upon the magnitude of the emissions price and year of fuel switch. These factors determine how quickly capital costs are recovered and whether normal operation or shutdown has a higher NPV. Table S2 displays the biomethane fuel switch targets that correspond with matching the highest NPV in Figures S7 – S10.

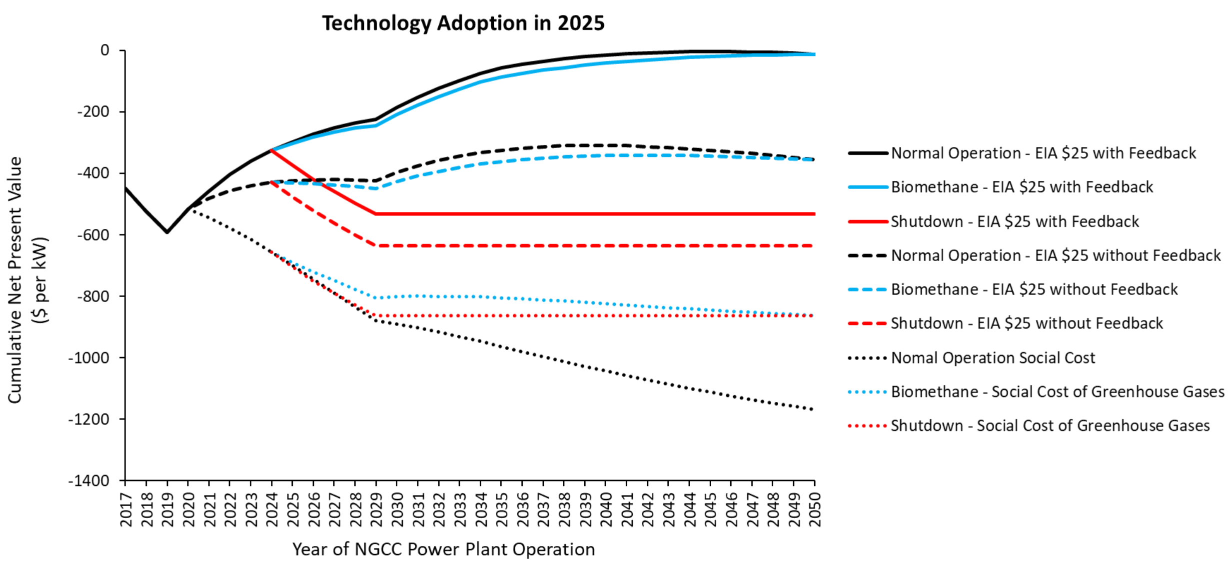

Figure S7. NPV of biomethane fuel switch, shutdown, and normal operation used to identify biomethane cost targets for a fuel switch in the year 2025.

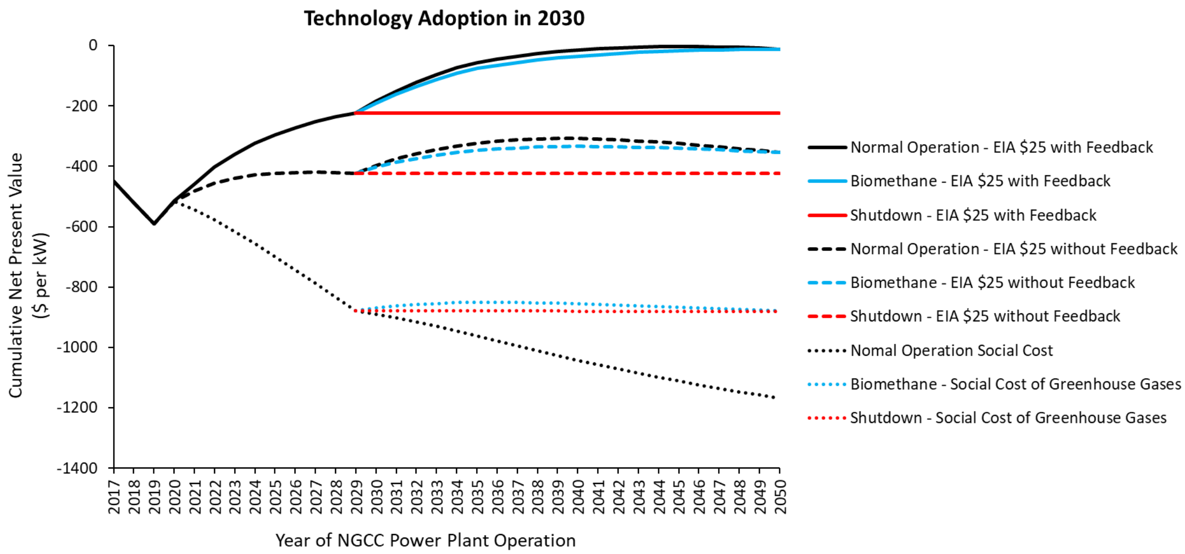

Figure S8. NPV of biomethane fuel switch, shutdown, and normal operation used to identify biomethane cost targets for a fuel switch in the year 2030.

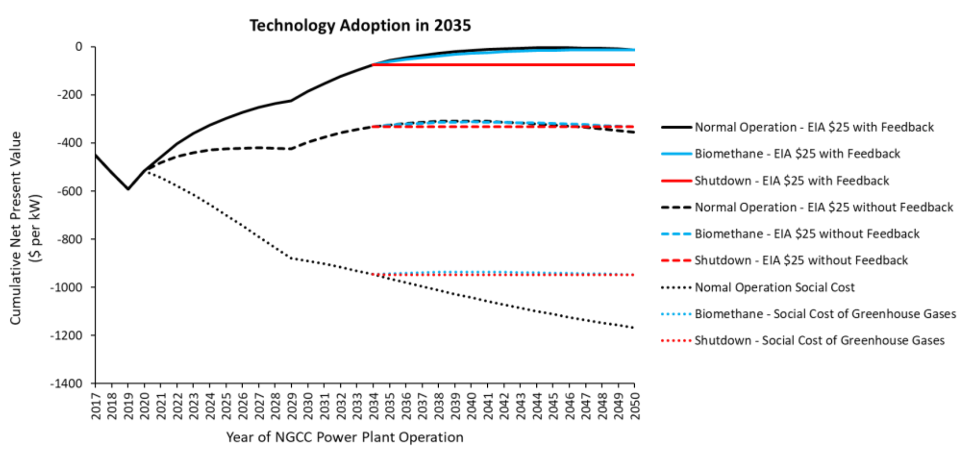

Figure S9. NPV of biomethane fuel switch, shutdown, and normal operation used to identify biomethane cost targets for a fuel switch in the year 2035.

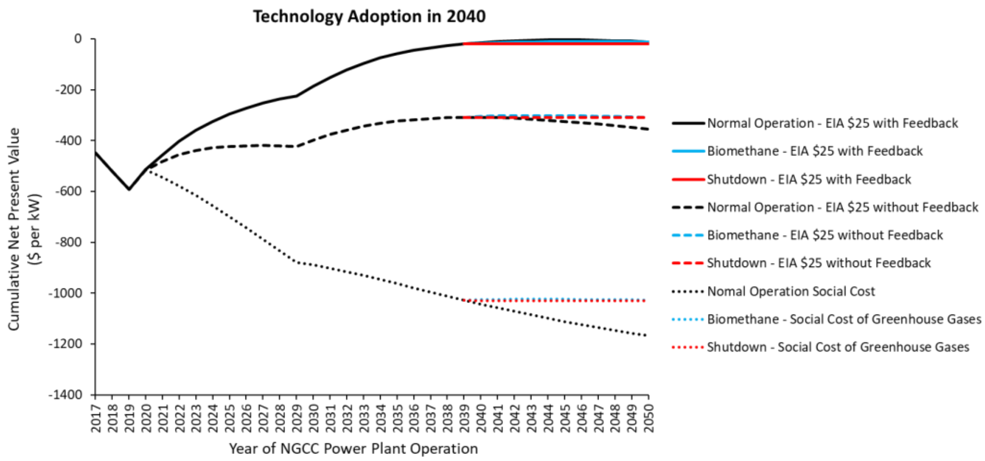

Figure S10. NPV of biomethane fuel switch, shutdown, and normal operation used to identify biomethane cost targets for a fuel switch in the year 2040.

Table S2. Fuel cost targets ($ per mmBTU) for fuel switch to biomethane with varying emissions pricing and years of fuel switch.

Year of Switch to Biomethane	**2025**	**2030**	**2035**	**2040**
No Price on Emissions	3.80	3.87	3.95	4.00
Social Cost of Greenhouse Gases	5.69	5.29	4.95	4.70
EIA $25 Carbon Fee without Feedback	4.98	5.17	5.17	4.7
EIA $25 Carbon Fee with Feedback	4.99	5.19	5.47	5.83

Section S5. Full list of BECCS technology cost targets

Tables S3 – S12 display the full list of cost targets required for BECCS to compete with the NPV of normal operation or shutdown, whichever is higher for a given scenario. For a BECCS conversion to be viable, capital and operation (fuel cost X heat rate) costs must be equal to or less than the cost targets. Negative values imply that the technology would not be feasible. Tables S3 – S6 are the cost targets if the BECCS conversion continued to operate at a constant average capacity factor (58%) for its remaining lifetime. Tables S7 – S10 are the cost targets if the BECCS conversion operated at a higher capacity factor (87%) after the conversion was complete. Tables S11 – S12 show the impact of altering biomethane production and distribution emissions under two different capacity factor scenarios.

Table S3. Full list of cost targets for fuel switch to biomethane and addition of carbon capture and storage in 2025 at constant average capacity factor (58%).

2025		Fuel Cost ($ per mmBTU)										
		0	1	2	3	4	5	6	7	8	9	10
Emissions Pricing	**Heat Rate (mmBTU per MWh)**	**Capital Cost ($ per kW)**										
No Emissions Pricing	**6**	967	603	240	-100	-396	-694	-1040	-1420	-1800	-2180	-2561
	8	967	482	-2	-396	-801	-1293	-1800	-2307	-2814	-3321	-3828
	10	967	361	-199	-694	-1293	-1927	-2561	-3194	-3828	-4462	-5096
	12	967	240	-396	-1040	-1800	-2561	-3321	-4082	-4842	-5603	-6363
3% Social Cost	**6**	3124	2761	2398	2033	1667	1297	916	536	156	-224	-605
	8	2911	2426	1940	1450	944	437	-70	-577	-1084	-1591	-2098
	10	2697	2090	1478	845	212	-422	-1056	-1690	-2323	-2957	-3591
	12	2483	1752	1000	239	-521	-1282	-2042	-2802	-3563	-4323	-5084
EIA $25 without Feedback	**6**	1915	1554	1193	833	472	110	-263	-644	-1024	-1404	-1784
	8	1915	1434	953	472	-11	-517	-1024	-1531	-2038	-2545	-3052
	10	1915	1314	712	110	-517	-1151	-1784	-2418	-3052	-3686	-4319
	12	1915	1193	472	-263	-1024	-1784	-2545	-3305	-4066	-4826	-5587
EIA $25 with Feedback	**6**	1925	1565	1204	843	479	116	-202	-531	-911	-1291	-1672
	8	1925	1444	963	479	-4	-415	-911	-1418	-1925	-2432	-2939
	10	1925	1324	722	116	-415	-1038	-1672	-2305	-2939	-3573	-4206
	12	1925	1204	479	-202	-911	-1672	-2432	-3193	-3953	-4713	-5474

Table S4. Full list of cost targets for fuel switch to biomethane and addition of carbon capture and storage in 2030 at constant average capacity factor (58%).

2030		Fuel Cost ($ per mmBTU)										
		0	1	2	3	4	5	6	7	8	9	10
Emissions Pricing	**Heat Rate (mmBTU per MWh)**	**Capital Cost ($ per kW)**										
No Emissions Pricing	**6**	933	593	253	-71	-348	-625	-916	-1271	-1627	-1982	-2338
	8	933	480	26	-348	-719	-1152	-1627	-2101	-2576	-3050	-3525
	10	933	366	-163	-625	-1152	-1745	-2338	-2931	-3525	-4118	-4711
	12	933	253	-348	-916	-1627	-2338	-3050	-3762	-4473	-5185	-5897
3% Social Cost	**6**	2893	2550	2207	1858	1502	1146	790	435	79	-277	-633
	8	2678	2219	1751	1277	802	328	-147	-621	-1096	-1570	-2045
	10	2461	1882	1289	696	102	-491	-1084	-1677	-2270	-2863	-3456
	12	2245	1538	826	114	-597	-1309	-2021	-2733	-3444	-4156	-4868
EIA $25 without Feedback	**6**	1976	1637	1297	956	616	273	-81	-437	-793	-1149	-1505
	8	1976	1523	1070	616	156	-319	-793	-1267	-1742	-2216	-2691
	10	1976	1410	843	273	-319	-912	-1505	-2098	-2691	-3284	-3877
	12	1976	1297	616	-81	-793	-1505	-2216	-2928	-3640	-4352	-5063
EIA $25 with Feedback	**6**	1961	1623	1285	946	608	269	-58	-348	-696	-1052	-1408
	8	1961	1510	1059	608	156	-249	-696	-1170	-1645	-2119	-2594
	10	1961	1397	834	269	-249	-815	-1408	-2001	-2594	-3187	-3780
	12	1961	1285	608	-58	-696	-1408	-2119	-2831	-3543	-4254	-4966

Table S5. Full list of cost targets for fuel switch to biomethane and addition of carbon capture and storage in 2035 at constant average capacity factor (58%).

2035		Fuel Cost ($ per mmBTU)										
		0	1	2	3	4	5	6	7	8	9	10
Emissions Pricing	**Heat Rate (mmBTU per MWh)**	**Capital Cost ($ per kW)**										
No Emissions Pricing	**6**	859	555	250	-44	-292	-539	-790	-1073	-1391	-1709	-2028
	8	859	453	48	-292	-622	-969	-1391	-1815	-2240	-2664	-3089
	10	859	352	-126	-539	-969	-1497	-2028	-2558	-3089	-3619	-4150
	12	859	250	-292	-790	-1391	-2028	-2664	-3301	-3938	-4574	-5211
3% Social Cost	**6**	2582	2264	1945	1627	1309	990	672	354	35	-283	-601
	8	2368	1943	1519	1095	670	246	-179	-603	-1028	-1452	-1877
	10	2154	1623	1093	562	31	-499	-1030	-1560	-2091	-2621	-3152
	12	1939	1303	666	29	-607	-1244	-1881	-2517	-3154	-3791	-4427
EIA $25 without Feedback	**6**	1882	1577	1271	965	657	342	23	-295	-613	-932	-1250
	8	1882	1475	1067	657	236	-189	-613	-1038	-1462	-1887	-2311
	10	1882	1373	862	342	-189	-719	-1250	-1780	-2311	-2842	-3372
	12	1882	1271	657	23	-613	-1250	-1887	-2523	-3160	-3797	-4433
EIA $25 with Feedback	**6**	1945	1641	1337	1032	728	424	120	-150	-432	-751	-1069
	8	1945	1539	1134	728	323	-67	-432	-857	-1281	-1706	-2130
	10	1945	1438	931	424	-67	-538	-1069	-1600	-2130	-2661	-3191
	12	1945	1337	728	120	-432	-1069	-1706	-2342	-2979	-3616	-4252

Table S6. Full list of cost targets for fuel switch to biomethane and addition of carbon capture and storage in 2040 at constant average capacity factor (58%).

2040		Fuel Cost ($ per mmBTU)										
		0	1	2	3	4	5	6	7	8	9	10
Emissions Pricing	Heat Rate (mmBTU per MWh)	Capital Cost ($ per kW)										
No Emissions Pricing	6	693	453	212	-24	-227	-430	-633	-871	-1132	-1392	-1653
	8	693	372	51	-227	-498	-784	-1132	-1479	-1827	-2174	-2521
	10	693	292	-92	-430	-784	-1218	-1653	-2087	-2521	-2956	-3390
	12	693	212	-227	-633	-1132	-1653	-2174	-2695	-3216	-3738	-4259
3% Social Cost	6	2098	1838	1577	1316	1056	795	535	274	13	-247	-508
	8	1914	1566	1219	871	524	176	-171	-518	-866	-1213	-1561
	10	1730	1295	861	426	-8	-442	-877	-1311	-1745	-2180	-2614
	12	1545	1024	503	-18	-540	-1061	-1582	-2103	-2625	-3146	-3667
EIA $25 without Feedback	6	1434	1194	953	712	471	229	-24	-284	-545	-805	-1066
	8	1434	1113	792	471	148	-197	-545	-892	-1240	-1587	-1935
	10	1434	1033	632	229	-197	-632	-1066	-1500	-1935	-2369	-2803
	12	1434	953	471	-24	-545	-1066	-1587	-2108	-2630	-3151	-3672
EIA $25 with Feedback	6	1713	1472	1231	990	750	509	268	27	-212	-473	-734
	8	1713	1392	1071	750	429	107	-212	-560	-907	-1255	-1602
	10	1713	1311	910	509	107	-299	-734	-1168	-1602	-2037	-2471
	12	1713	1231	750	268	-212	-734	-1255	-1776	-2297	-2818	-3340

Table S7. Full list of cost targets for fuel switch to biomethane and addition of carbon capture and storage in 2025 with increase to high capacity factor (87%).

2025		Fuel Cost ($ per mmBTU)										
		0	1	2	3	4	5	6	7	8	9	10
Emissions Pricing	Heat Rate (mmBTU per MWh)	Capital Cost ($ per kW)										
No Emissions Pricing	6	1437	940	442	-46	-453	-859	-1271	-1771	-2293	-2814	-3336
	8	1437	774	109	-453	-995	-1597	-2293	-2988	-3684	-4380	-5076
	10	1437	608	-182	-859	-1597	-2467	-3336	-4206	-5076	-5946	-6816
	12	1437	442	-453	-1271	-2293	-3336	-4380	-5424	-6468	-7511	-8555
3% Social Cost	6	4358	3865	3372	2879	2384	1888	1388	874	352	-170	-692
	8	4065	3408	2750	2089	1424	734	39	-657	-1353	-2049	-2745
	10	3772	2950	2124	1291	421	-449	-1318	-2188	-3058	-3928	-4798
	12	3479	2490	1495	456	-588	-1631	-2675	-3719	-4763	-5807	-6850
EIA $25 without Feedback	6	2751	2261	1771	1280	790	300	-177	-699	-1221	-1743	-2265
	8	2751	2097	1444	790	136	-525	-1221	-1917	-2613	-3309	-4004
	10	2751	1934	1117	300	-525	-1395	-2265	-3135	-4004	-4874	-5744
	12	2751	1771	790	-177	-1221	-2265	-3309	-4352	-5396	-6440	-7484
EIA $25 with Feedback	6	2767	2275	1782	1288	793	297	-165	-575	-1055	-1577	-2099
	8	2767	2111	1453	793	130	-437	-1055	-1751	-2446	-3142	-3838
	10	2767	1946	1123	297	-437	-1229	-2099	-2968	-3838	-4708	-5578
	12	2767	1782	793	-165	-1055	-2099	-3142	-4186	-5230	-6274	-7317

Table S8. Full list of cost targets for fuel switch to biomethane and addition of carbon capture and storage in 2030 with increase to high capacity factor (87%).

2030		Fuel Cost ($ per mmBTU)										
		0	1	2	3	4	5	6	7	8	9	10
Emissions Pricing	**Heat Rate (mmBTU per MWh)**	**Capital Cost ($ per kW)**										
No Emissions Pricing	**6**	1371	909	445	-15	-393	-771	-1152	-1594	-2079	-2565	-3050
	8	1371	754	136	-393	-897	-1432	-2079	-2726	-3374	-4021	-4668
	10	1371	600	-141	-771	-1432	-2241	-3050	-3859	-4668	-5477	-6285
	12	1371	445	-393	-1152	-2079	-3050	-4021	-4991	-5962	-6932	-7903
3% Social Cost	**6**	4013	3551	3088	2625	2160	1694	1209	724	239	-247	-732
	8	3719	3102	2484	1863	1222	575	-72	-719	-1366	-2013	-2660
	10	3425	2653	1878	1074	265	-544	-1353	-2162	-2971	-3779	-4588
	12	3131	2203	1248	278	-693	-1663	-2634	-3605	-4575	-5546	-6517
EIA $25 without Feedback	**6**	2807	2348	1889	1430	971	511	47	-438	-924	-1409	-1894
	8	2807	2195	1583	971	358	-277	-924	-1571	-2218	-2865	-3512
	10	2807	2042	1277	511	-277	-1085	-1894	-2703	-3512	-4321	-5130
	12	2807	1889	971	47	-924	-1894	-2865	-3836	-4806	-5777	-6747
EIA $25 with Feedback	**6**	2798	2338	1879	1420	960	500	38	-352	-782	-1267	-1753
	8	2798	2185	1573	960	346	-223	-782	-1429	-2076	-2723	-3370
	10	2798	2032	1266	500	-223	-944	-1753	-2561	-3370	-4179	-4988
	12	2798	1879	960	38	-782	-1753	-2723	-3694	-4664	-5635	-6606

Table S9. Full list of cost targets for fuel switch to biomethane and addition of carbon capture and storage in 2035 with increase to high capacity factor (87%).

2035		Fuel Cost ($ per mmBTU)										
		0	1	2	3	4	5	6	7	8	9	10
Emissions Pricing	**Heat Rate (mmBTU per MWh)**	**Capital Cost ($ per kW)**										
No Emissions Pricing	**6**	1241	831	421	11	-325	-659	-993	-1351	-1778	-2207	-2636
	8	1241	694	148	-325	-770	-1227	-1778	-2350	-2922	-3494	-4067
	10	1241	558	-102	-659	-1227	-1921	-2636	-3351	-4067	-4782	-5497
	12	1241	421	-325	-993	-1778	-2636	-3494	-4353	-5211	-6069	-6927
3% Social Cost	**6**	3589	3167	2738	2309	1880	1451	1022	593	164	-265	-694
	8	3305	2733	2161	1589	1017	445	-127	-699	-1271	-1843	-2415
	10	3014	2299	1584	869	154	-561	-1276	-1991	-2706	-3421	-4136
	12	2723	1865	1007	149	-709	-1567	-2425	-3283	-4141	-5000	-5858
EIA $25 without Feedback	**6**	2609	2201	1792	1384	975	564	141	-288	-717	-1146	-1575
	8	2609	2065	1520	975	426	-145	-717	-1289	-1861	-2433	-3005
	10	2609	1928	1248	564	-145	-860	-1575	-2290	-3005	-3720	-4436
	12	2609	1792	975	141	-717	-1575	-2433	-3291	-4150	-5008	-5866
EIA $25 with Feedback	**6**	2734	2326	1918	1510	1101	693	283	-104	-456	-885	-1314
	8	2734	2190	1646	1101	556	10	-456	-1028	-1600	-2172	-2744
	10	2734	2054	1374	693	10	-599	-1314	-2029	-2744	-3459	-4175
	12	2734	1918	1101	283	-456	-1314	-2172	-3030	-3888	-4747	-5605

Table S10. Full list of cost targets for fuel switch to biomethane and addition of carbon capture and storage in 2040 with increase to high capacity factor (87%).

2040		**Fuel Cost ($ per mmBTU)**										
		0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Emissions Pricing	**Heat Rate (mmBTU per MWh)**	**Capital Cost ($ per kW)**										
No Emissions Pricing	**6**	971	655	339	22	-248	-515	-781	-1074	-1417	-1759	-2102
	8	971	549	128	-248	-603	-962	-1417	-1874	-2330	-2787	-3243
	10	971	444	-70	-515	-962	-1531	-2102	-2673	-3243	-3814	-4385
	12	971	339	-248	-781	-1417	-2102	-2787	-3472	-4156	-4841	-5526
3% Social Cost	**6**	2845	2503	2160	1818	1475	1133	791	448	106	-237	-579
	8	2602	2145	1688	1232	775	319	-138	-595	-1051	-1508	-1964
	10	2358	1787	1216	646	75	-496	-1067	-1637	-2208	-2779	-3350
	12	2114	1429	744	59	-626	-1310	-1995	-2680	-3365	-4050	-4735
EIA $25 without Feedback	**6**	1955	1639	1323	1007	690	373	53	-290	-632	-975	-1317
	8	1955	1534	1112	690	267	-176	-632	-1089	-1545	-2002	-2459
	10	1955	1429	901	373	-176	-746	-1317	-1888	-2459	-3029	-3600
	12	1955	1323	690	53	-632	-1317	-2002	-2687	-3372	-4057	-4742
EIA $25 with Feedback	**6**	2337	2021	1705	1389	1073	757	441	125	-184	-527	-869
	8	2337	1916	1494	1073	652	230	-184	-641	-1098	-1554	-2011
	10	2337	1810	1284	757	230	-298	-869	-1440	-2011	-2581	-3152
	12	2337	1705	1073	441	-184	-869	-1554	-2239	-2924	-3609	-4294

Table S11. Full list of cost targets for fuel switch to biomethane and addition of carbon capture in 2025 with varying biomethane emissions at constant average capacity factor (58%).

2025 - Constant Avg Capacity Factor		**Fuel Cost ($ per mmBTU)**										
		0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Biomethane Emissions Scenario	**Heat Rate (mmBTU per MWh)**	**Capital Cost ($ per kW)**										
High (50 g CO_2 per MJ)	**6**	2481	2117	1751	1380	1000	620	239	-141	-521	-901	-1282
	8	2052	1562	1056	549	42	-465	-972	-1479	-1986	-2493	-3000
	10	1618	984	351	-283	-917	-1551	-2184	-2818	-3452	-4085	-4719
	12	1167	406	-354	-1115	-1875	-2636	-3396	-4157	-4917	-5678	-6438
Baseline (25 g CO_2 per MJ)	**6**	3123	2760	2396	2032	1666	1297	916	536	156	-224	-605
	8	2909	2425	1938	1449	944	437	-70	-577	-1084	-1591	-2098
	10	2695	2089	1478	845	212	-422	-1056	-1690	-2323	-2957	-3591
	12	2481	1751	1000	239	-521	-1282	-2042	-2802	-3563	-4323	-5084
Low (12.5 g CO_2 per MJ)	**6**	3443	3080	2717	2354	1989	1624	1255	875	494	114	-266
	8	3336	2852	2368	1882	1393	889	382	-125	-632	-1139	-1646
	10	3229	2625	2018	1407	776	142	-492	-1125	-1759	-2393	-3027
	12	3123	2396	1666	916	156	-605	-1365	-2125	-2886	-3646	-4407

Table S12. Full list of cost targets for fuel switch to biomethane and addition of carbon capture in 2025 with varying biomethane emissions and increase to high capacity factor (87%).

2025 - High Capacity Factor		**Fuel Cost ($ per mmBTU)**										
		0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Biomethane Emissions Scenario	**Heat Rate (mmBTU per MWh)**	**Capital Cost ($ per kW)**										
High (50 g CO_2 per MJ)	**6**	3479	2985	2490	1994	1495	978	456	-66	-588	-1110	-1631
	8	2891	2231	1565	874	178	-518	-1214	-1910	-2606	-3302	-3997
	10	2302	1465	595	-275	-1144	-2014	-2884	-3754	-4624	-5493	-6363
	12	1707	665	-379	-1423	-2466	-3510	-4554	-5598	-6642	-7685	-8729
Baseline (25 g CO_2 per MJ)	**6**	4358	3865	3372	2879	2384	1888	1388	874	352	-170	-692
	8	4065	3408	2750	2089	1424	734	39	-657	-1353	-2049	-2745
	10	3772	2950	2124	1291	421	-449	-1318	-2188	-3058	-3928	-4798
	12	3479	2490	1495	456	-588	-1631	-2675	-3719	-4763	-5807	-6850
Low (12.5 g CO_2 per MJ)	**6**	4797	4305	3812	3319	2826	2331	1834	1335	821	300	-222
	8	4651	3994	3337	2679	2018	1353	665	-31	-727	-1423	-2119
	10	4505	3683	2861	2036	1203	334	-535	-1405	-2275	-3145	-4015
	12	4358	3372	2384	1388	352	-692	-1736	-2780	-3823	-4867	-5911

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