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Revision 0

Case Study: Hybrid Carbon Conversion Using Low-Carbon Energy Sources in Coal-Producing States

Improving plant profits and performance with carbon capture

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Integrated Energy Systems

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EXECUTIVE SUMMARY

The demand for more carbon efficient power sources and a decrease in natural gas prices has decreased the desire for coal power. This decrease in demand has led to massive job losses in coal mining regions over the past decade. The purpose of this project is to develop a hybrid energy system utilizing both a coal power plant and advanced reactor, which is competitive with natural gas by improving on profitability and decreasing carbon emissions.

This report details the problem with a summary of the impact on the coal industry and the availability of renewable energy sources in the Appalachian region. Because of the geography of the region, variable renewable energy sources are not available without significant size and siting restrictions. However, biomass in the form of wood waste is abundant and can be used as a carbon neutral energy source. Combining biomass and coal processing, in addition to thermal power plants, can increase system profits and efficiency by providing peaking power and conversion opportunities for secondary markets.

The electric load is based on publicly available demand data from Appalachian Power, which services the western Virginia and southern West Virginia in the Appalachian region. The demand information is combined by service, normalized, and scaled to an average demand of 1000 kW, which will be the basis for sizing the hybrid energy system.

A traditional screening curve analysis for a coal plant and advanced reactor shows that the least cost design varies significantly based on the assumed discount rate and capital recovery period. An optimization program to size the design in TEAL based on the load curve gives 10 optimal designs, all with a negative resulting net present value (NPV) and a coal plant capacity of less than 15%. Including profits from selling captured carbon at a flat rate results in a positive NPV; however, the coal capacity factor only increases to about 40%. There are limitations with this optimization as well since the price of CO_2 is likely to decrease as more is sold to the conversion market.

The suggested design will combine coal power, an advanced reactor, and coal and biomass coprocessing to produce a variety of products that can be sold to the conversion market while increasing system efficiency. The analysis of conversion pathways for coal and biomass reveals that multiple options will need to be included in the analysis to produce the optimal system design.

Three systems will be optimized and compared to determine the best design based on the figures of merit of total NPV and cost of carbon avoided. The first system will include a coal power plant and an advanced reactor that will sell electricity to the grid to meet demand and sell captured carbon to the conversion market. The second system adds a high-temperature steam electrolysis plant, which will utilize electricity during times of low demand to produce hydrogen and sell it to the conversion market. The third system adds biomass and coal processing with options for hydrocarbon oils, syngas to be produced for the conversion market, and electricity generation to power components within the system or provide peaking power.

This analysis will be based on a new approach that combines traditional screening curve methods with a dispatch algorithm that optimizes the system based on the opportunity cost of different production options. The resulting optimization algorithm should provide results with less processing time than HERON's stochastic optimization approach.

The results from this analysis will determine an optimal design and reinforce the benefits of coal power when used in a hybrid energy system. The initial results show that the addition of a secondary market for carbon sales could result in a positive NPV and increases the capacity factor of the coal plant as compared to a design with only sales to the electricity market. The addition of more markets and additional coal consumption from biomass coprocessing could increase NPV further, replace carbon in other markets through the sale of biomass-derived hydrocarbons, and demonstrate the value of coal power technology.

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ACRONYMS

CRP	capital recovery period
CTS	Concentrated Solar Thermal
DCFC	direct carbon fuel cells
GWh	gigawatt-hours
HERON	Holistic Energy Resource Optimization Network
HTSE	High-Temperature Steam Electrolysis
kW	kilowatt
kWh	kilowatt-hours
LCOE	levelized cost of energy
MW	megawatt
MWh	megawatt-hour
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PJM	Pennsylvania-New Jersey-Maryland Interconnection
SMR	Small Modular Reactor
TEAL	Tool for Economic AnaLysis
VRE	variable renewable energy

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Hybrid Carbon Conversion Using Low-Carbon Energy Sources in Coal-Producing States

1. PROJECT MOTIVATION

The expansion in the renewable energy capacity across the United States has created new jobs and supported global goals of a carbon dioxide reduction in the energy sector. However, the volatile nature of these renewable technologies is forcing traditional baseload power plants, such as coal and nuclear, to operate flexibly at overall lower capacity factors, which reduces revenue, decreases efficiency, and potentially increases maintenance costs. Baseload power continues to be an important part of the electric grid to provide power when electricity from renewable sources is in low supply.

This project focuses specifically on the coal industry in the Appalachian region of the United States, which is concentrated in the areas of western Pennsylvania, West Virginia, and eastern Kentucky, as shown in Figure 1. Although coal production has decreased across the country, it has decreased significantly in these regions, causing severe impacts on local economies.

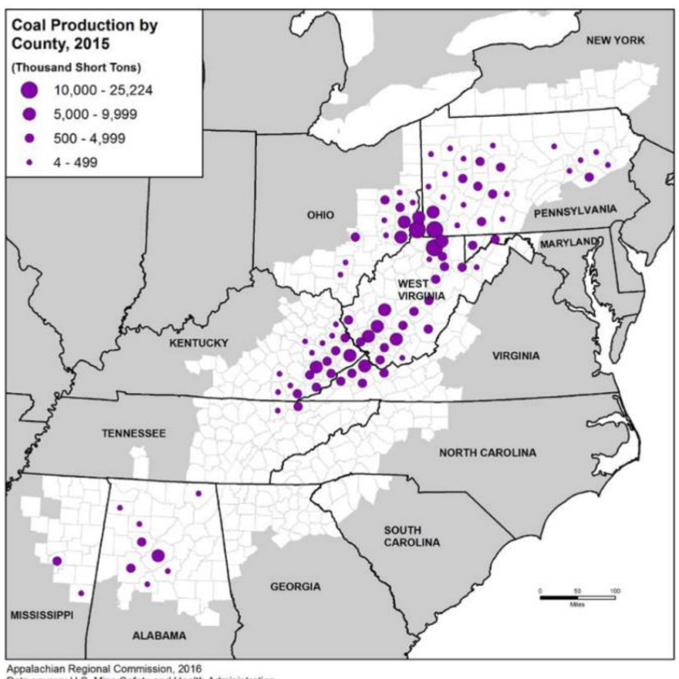
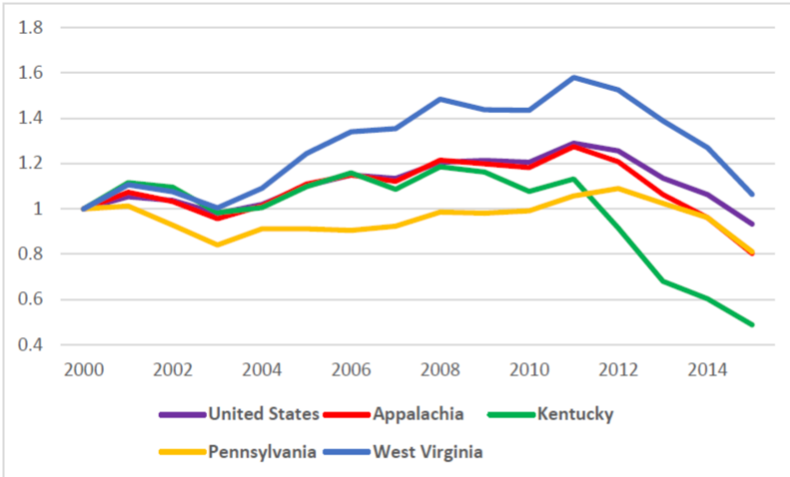


Figure 1. Map of coal production by county in the Appalachian region. [1]

Coal production in Appalachia peaked around 1990 and has declined since, with the decline accelerating after 2010. According to the Appalachian Regional Commission report of the Appalachian coal industry, power generation, and supply chain, from 2004 to 2014, coal production in Appalachia has decreased by 45%, which is more than double the national decrease of 21%. [1]

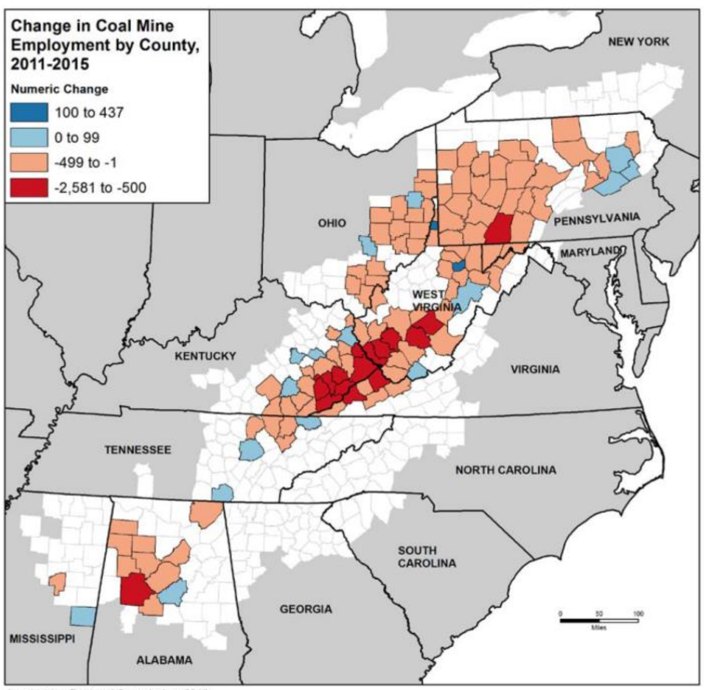
As expected, employment in the Appalachian region has also decreased. Of 26,432 coal mining jobs lost in the United States from 2011 to 2015, 23,058 direct jobs in mining were lost in the Appalachian region. [1] Figure 2 shows the loss of jobs in the largest coal-producing states within the region, with Kentucky losing about half of its mining jobs by 2015, and only West Virginia maintaining a slight increase in 2015. [1]



Source: U.S. Department of Labor, Mine Safety and Health Administration (MSHA)

Figure 2. Job loss in the coal mining industry by state. [1]

Figure 3 shows the change in employment by county. As expected, the greatest loss of employment tends to correspond with the counties with the greatest production.



Appalachian Regional Commission, 2016
Data source: U.S. Mine Safety and Health Administration

Figure 3. Change in coal mine employment by county in the Appalachian region. [1]

The goal of this project is to conserve the coal economy in the Appalachian region and increase the profitability of a baseload power plant while aligning with the goals of decarbonization.

2. CARBON CONVERSION

Globally, 230 million tons of carbon dioxide are used for industrial processes and products every year. The largest consumer is the fertilizer industry producing urea, followed by the oil and gas industry, which consumes CO_2 for enhanced oil recovery. Other commercial applications involve the direct use of CO_2 in food and beverage production, metal fabrication, cooling, fire suppression, and greenhouse plant growth.

Unfortunately, CO_2-based chemicals and fuels are more expensive and energy intensive than their commercial counterparts, mainly due to the production of hydrogen. The cost of methanol and methane from CO_2 are typically 2 to 7 times higher than fossil fuel produced alternatives, with the cost of electricity accounting for between 40–70% of the production costs. Using cost-competitive renewable energy and hydrogen production can lessen the gap and make CO_2-based products more competitive.

It should also be noted that, while CO_2 conversion is a useful companion to storage for emissions reductions, it cannot replace CO_2 storage in delivering the significant emissions reductions needed to meet global climate goals. Currently, the key emerging CO_2 use applications include:

- Converting hydrogen into fuels that are easy to handle and use
- Integrating CO_2 into chemical products
- Producing cement and concrete with higher performance
- Stabilizing waste products as a feedstock for higher value building materials while reducing waste disposal costs
- Enhancing the yield of biological processes for improved crop output.

All of these technologies will only be viable if they produce products with lower carbon emissions than their fossil fuel derived counterparts.

CO_2 use is most economical and effective when the lifecycle of the feedstock, product, and reemission is collocated. The transportation of feedstocks and products increases costs and decreases the lifecycle climate benefits of CO_2 capture. Additionally, different conversion products provide different climate benefits, as shown in Figure 4. Products with the highest climate benefits use minimal amounts of fossil energy or heat for conversion and have long residence times. [2]

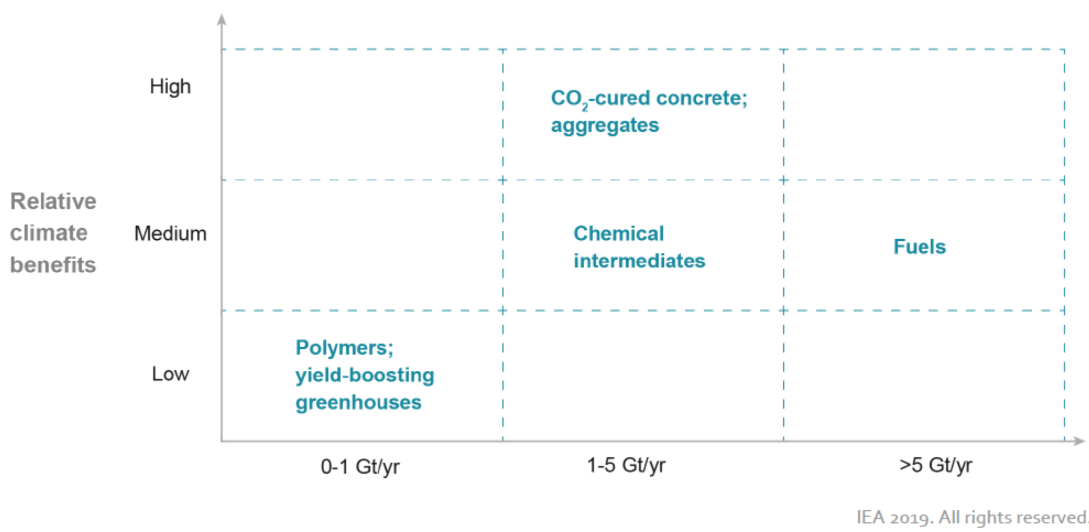


Figure 4. Comparison of climate benefits of different carbon utilization strategies. [2]

CO_2 from capture could potentially be converted and used onsite to increase climate benefits. Cost benefits from onsite conversion depend on the market for hydrogen feedstock compared to the market for converted fuels. Figure 5 shows the pathways for CO_2 and H_2 to be converted to fuels and chemicals.

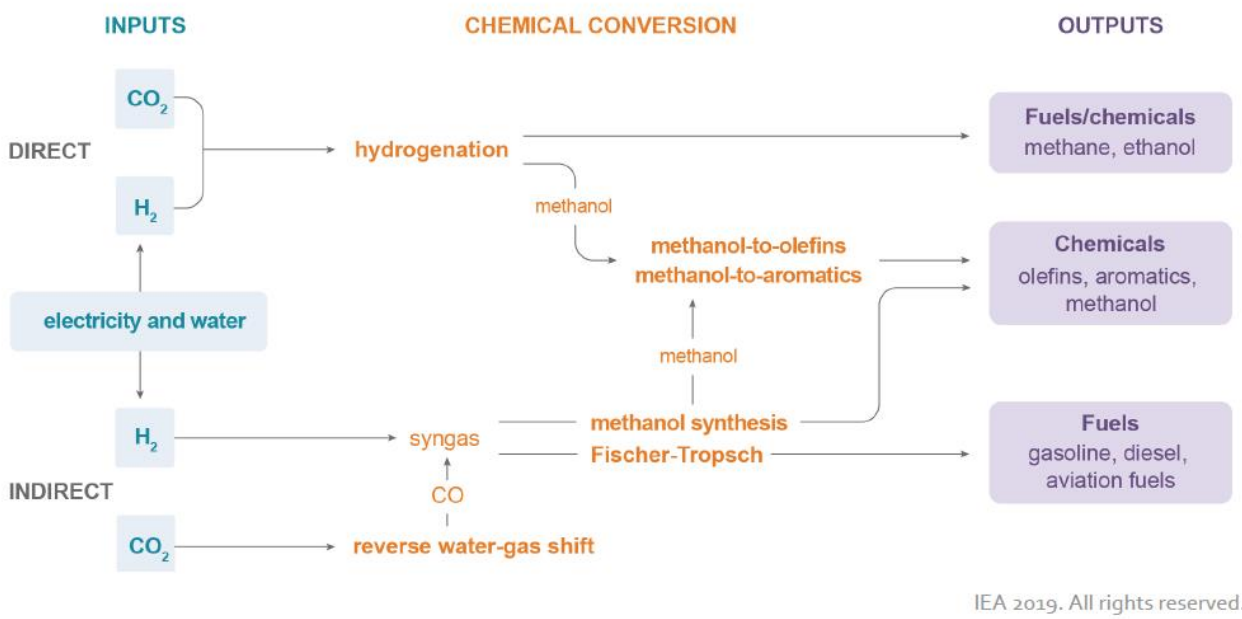


Figure 5. Chemical conversion pathways for captured carbon. [2]

The conversion to methane and methanol is an energy intensive process that decrease the climate benefits of conversion. The benefits are increased by using nuclear-generated electricity for hydrogen electrolysis. Figure 6 shows the typical inputs and losses associated with the steps to methane and methanol conversion.

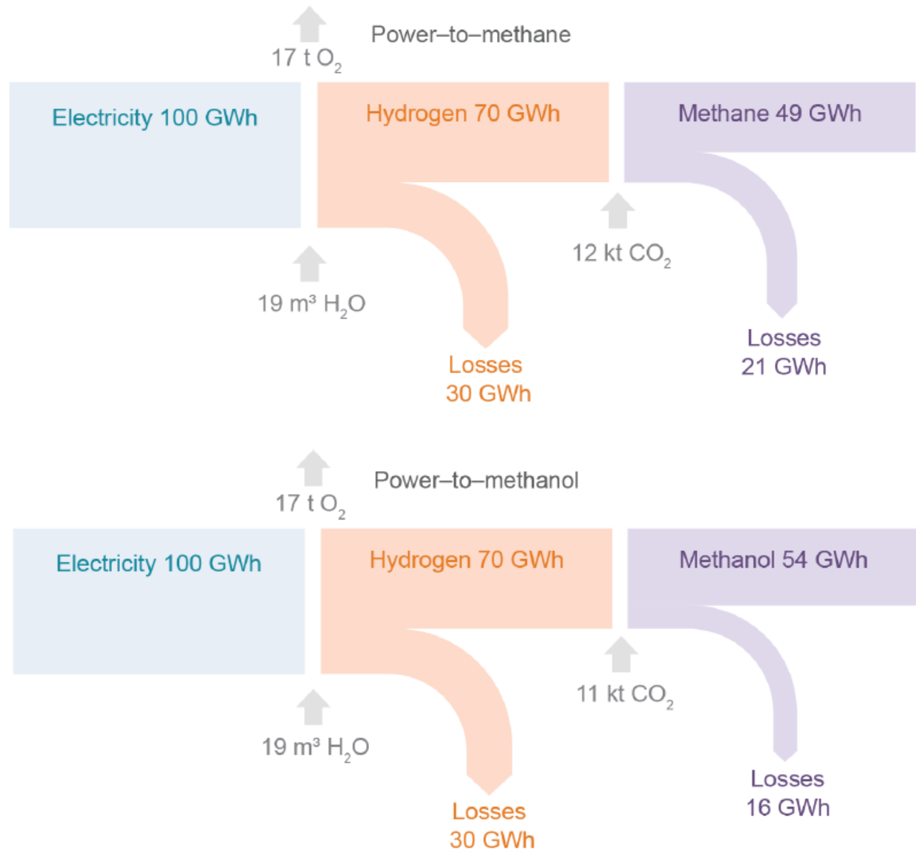


Figure 6. Energy losses from the carbon conversion pathway. [2]

3. INITIAL PROPOSED SYSTEM

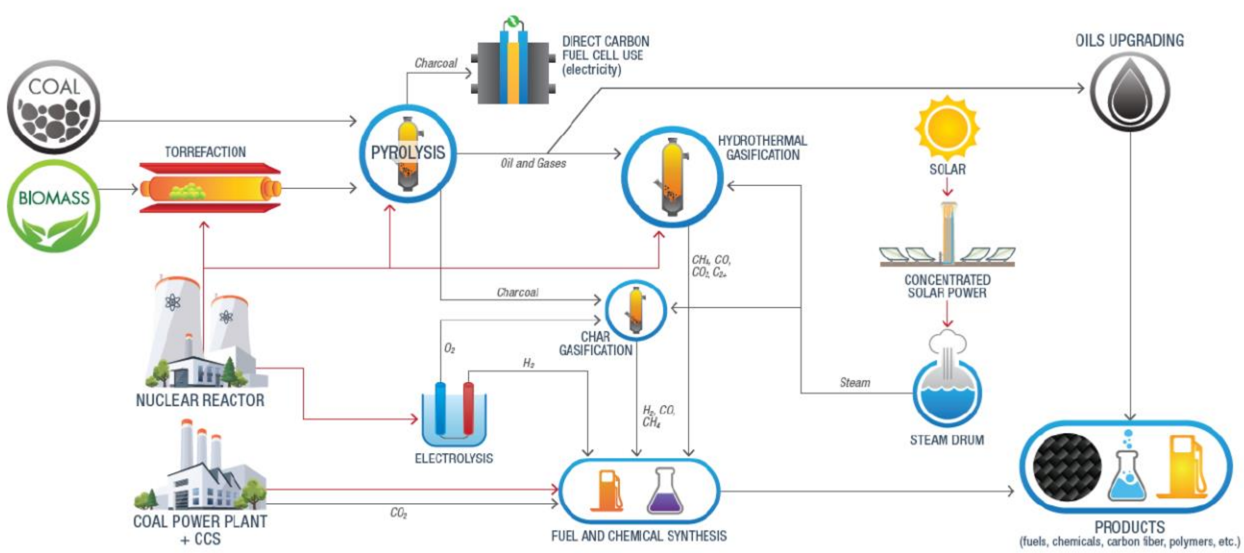


Figure 7. Proposed system configuration incorporating a coal power plant and advanced reactor. [3]

The proposed system in Figure 7 includes a coal power plant with carbon capture and storage and a nuclear power plant (likely an advanced reactor) that meet the electric demands of the area. Both plants can also provide heat to the ancillary systems which generate valuable products in times of low demand. The carbon captured from the coal plant can be converted to fuel, chemicals, or materials with the addition of heat and electricity from elsewhere in the system.

In addition to the coal and nuclear power sources, the system processes coal and biomass separately to generate processed fuels. This includes the need for a tertiary steam source, shown here as a concentrated solar power system. Alternatively, steam could be generated using heat from the power sources.

4. RENEWABLE ENERGY POTENTIAL

4.1 Solar

The outlook for solar power in the Appalachian region is poor, especially compared to the solar potential in other parts of the country. According to data from the National Renewable Energy Laboratory (NREL) in Figure 8, depending on where in the region the solar array is placed, it will receive up to 5.01 kWh/m^2/day of solar insolation. This means it would take 200–239 m^2 to produce 1 MWh of electricity.

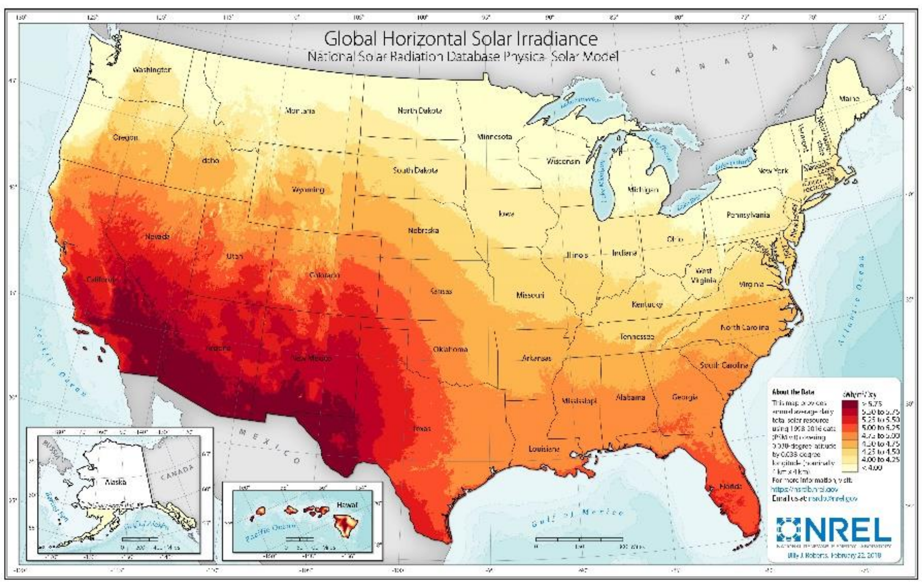


Figure 8. Horizontal solar irradiance in the United States. [4]

Arnette and Zobel performed a siting analysis for potential solar farms in the southern Appalachian region, using slope and aspect, type of land, and land use restrictions to designate the location and size of land for acceptable solar construction. The resulting potential sites are shown in Figure 9. Although there were many potential sites found across the region, many were restricted by size and therefore restricted in generation potential. This led to a higher estimate in levelized cost of energy (LCOE) for those areas over the areas with a higher generation due to fixed costs that could be spread over a larger site. [5]

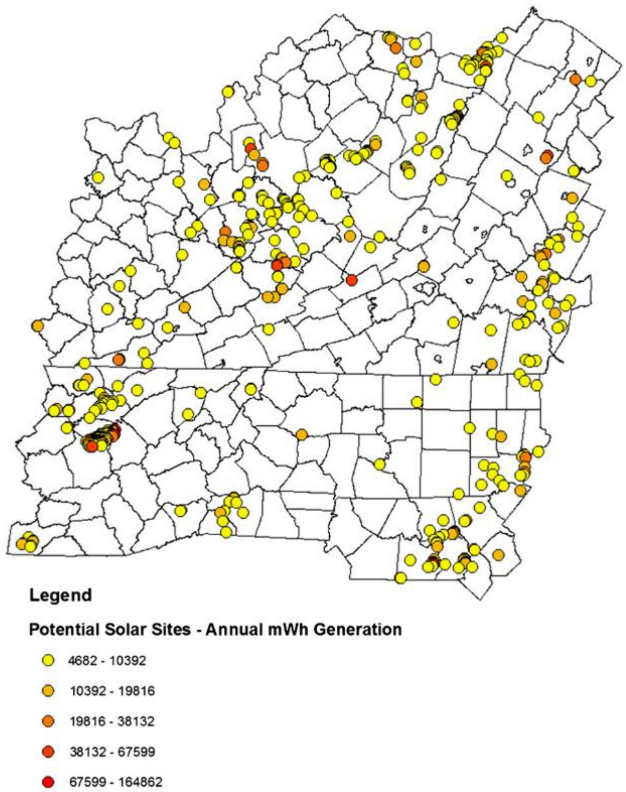


Figure 9. Potential solar sites in the Appalachian region. [5]

4.2 Wind

Wind is a more logical option for renewable power in a mountain region; however, like solar, the availability of wind resources is very limited. At the 80m level, NREL data in Figure 10 shows high wind speeds in some mountainous areas, but the speed reduces quickly in the areas immediately surrounding it.

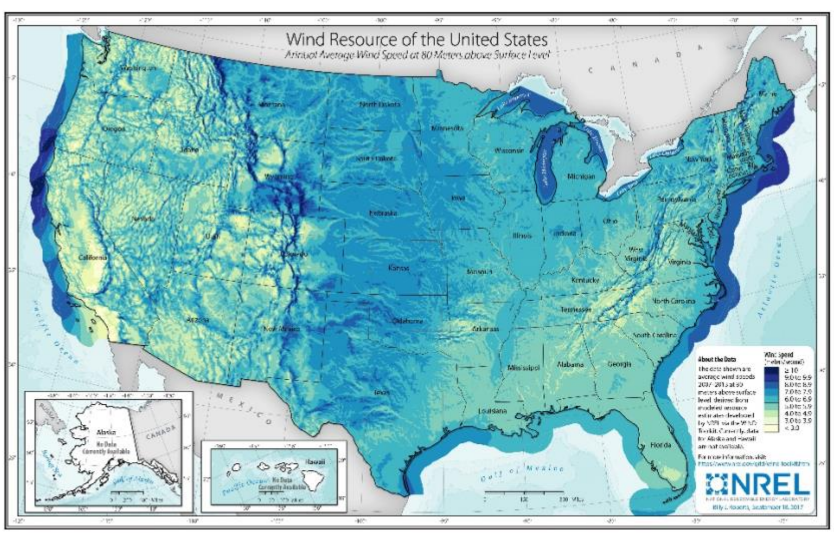


Figure 10. Map of wind resources in the United States. [6]

Arnette and Zobel also did a siting analysis of wind power in the southeast Appalachian region. The analysis found only 2.3% of land in the region suitable for wind farm development based on wind speed alone. When including additional restrictions for buffering distances, over 99.995% of land in the region was eliminated from consideration. [5] This resulted in even more limited potential wind generation in the region, with sites concentrated along the West Virginia and Virginia border. The resulting potential sites are shown in Figure 11.

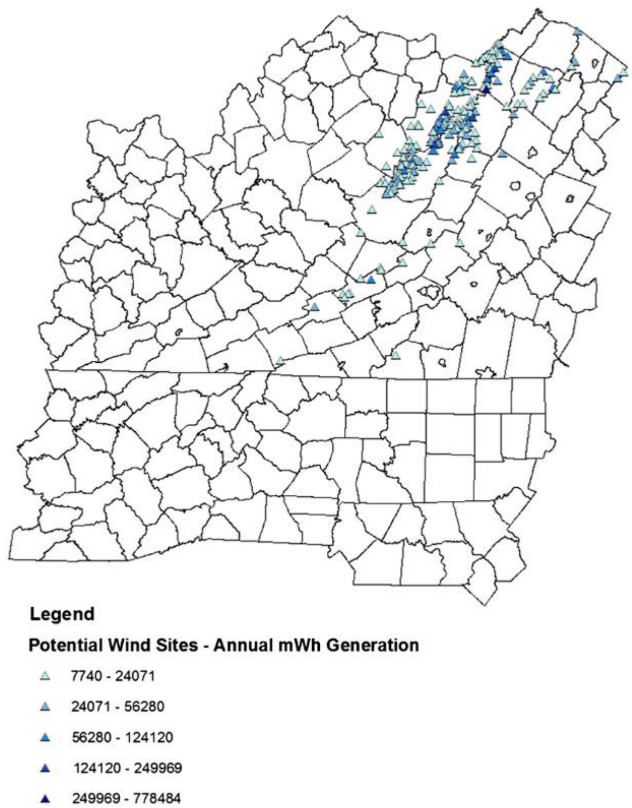


Figure 11. Potential wind sites in the Appalachian region. [5]

4.3 Biomass

Perhaps the most abundant renewable resource in the Appalachian region is biomass. Although the potential amount of biomass is questionable when compared to the rest of the U.S., solid wood waste from urban wood waste, primary and secondary mill residue, and forest residue is available throughout the entire region. [5] Wood waste can be cofired with coal with minimal investment and process interruption, while other biomass sources generally require the construction of new equipment for effective use. [5] The abundance of biomass sources in the region are shown in Figure 12.

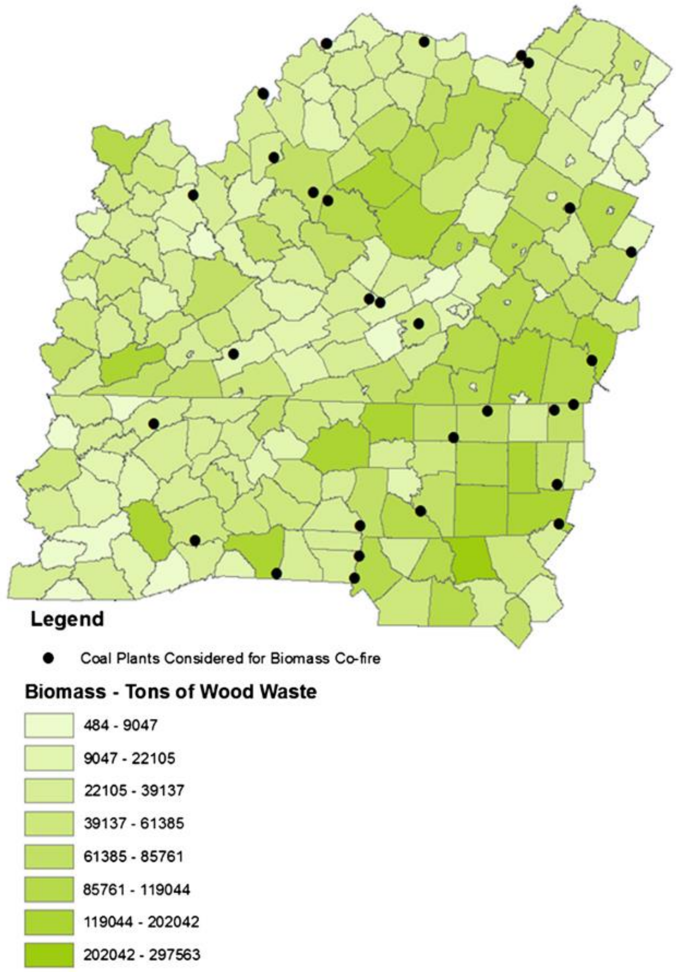


Figure 12. Availability of biomass in the Appalachian region. [5]

4.4 Potential for Use in Proposed System

The initial system diagram proposes solar thermal power to provide steam for tertiary fuel systems. Based on the analysis of solar availability, it would be possible to utilize solar steam generation, although the limited capacity and areas for construction will be limiting factors for both system production and siting considerations.

Wind power can produce electricity. If used for steam generation, an electric steam generator would be needed in addition to the wind power. Wind power is unsuitable for this project for several reasons. First, there is little need for a variable electricity source within this system since the goal is to utilize base load power. Additionally, the limited availability of locations for new wind construction will place restrictions on siting, especially since the areas suitable for wind power development are likely not suitable for nuclear or coal plant development at the same location.

Biomass is the most suitable renewable energy source for the system. The availability of biomass throughout the entire region eliminates the siting constraints of wind and solar. Additionally, wood waste could be cofired with the coal plant, burned separately for steam generation, or processed into synfuel as suggested in the model. Rather than utilizing solar thermal for steam generation, a portion of the gasified biomass could be used to provide steam back to the gasification processes. Biomass is considered a carbon neutral fuel, so it could be fired within the system without increasing the net carbon output of the system or requiring separate carbon capture.

5. ELECTRIC LOAD DATA

Loading data was obtained from Appalachian Power, which provides service to the southwest areas of the Appalachian Region in Virginia, West Virginia, and a small part of Tennessee as shown in Figure 13. The total generation capacity of the grid is 8.6 GW, with over a million customers. Out of 100 customers, approximately 85 are residential, 14 are commercial, and one represents industrial and “other”. [7]

The loading data provides the average hourly demand per customer for residential service, and small, medium, and large general services for 2017–2018. A total estimate of the demand curve can be obtained by determining the relative weight of the curve of each service.

Figure 13. Service region for Appalachian Power. [8]

5.1 Annual Load Duration Curve

Since this analysis is for a single plant, the total demand of the grid is not important. Once a typical shape of the demand curve is established, it can be assigned to any average demand to determine the sizing of electricity generation in the model. The shape of the load curve varies greatly by the type of service, so the demand curve of the plant cannot be accurately represented by just one service. Additionally, it cannot be accurately represented by a simple average due to the variations in demand and number of customers between services. Figure 14 compares the load curve shapes for the first week in January 2017 (Sunday–Saturday). The average load at each hour is normalized by the average load of that service over 2017 to show the shapes of the curves. The residential curve has multiple peaks throughout the day, while the medium and large services have only one. A simple average of these signals would not be sufficient to estimate the actual demand curve for a plant in the area. Instead, the shape of the curve is determined by the average load of each customer and the number of customers using each service.

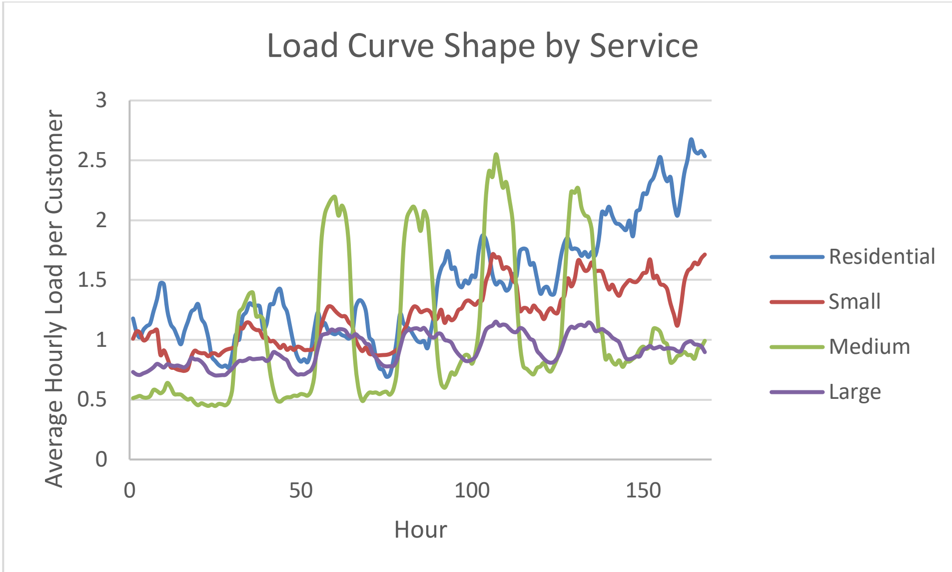


Figure 14. Load curve estimation by service for the first week of 2017. [9]

First, each hourly data point is converted into a signal by normalizing it by the average load for that service over 2017 and 2018. The contribution of each signal is determined from the average load for each service and the percent of customers that use each service. The percentage of each load contribution to the total load gives an estimate of the proportional contribution of each load.

Table 1. Estimated service contribution to average load curve. [9]

	Residential	Small General Service	Medium General Service	Large General Service	Total
Percent of Customers	85.00	5.00	9.00	1.00	100.00
Average Hourly Load (kW)	1.55	1.07	15.33	58.58	76.53
Load Contribution (kW)	131.64	5.33	137.93	58.58	333.49
Proportional Contribution	0.39	0.02	0.41	0.18	1.00

Once the hourly demand data for each service is normalized into a load curve, it can be used to create a load duration curve. In this estimation, the average hourly load of the plant over the course of the year is 1 GW. The resulting load distribution is shown in Figure 15.

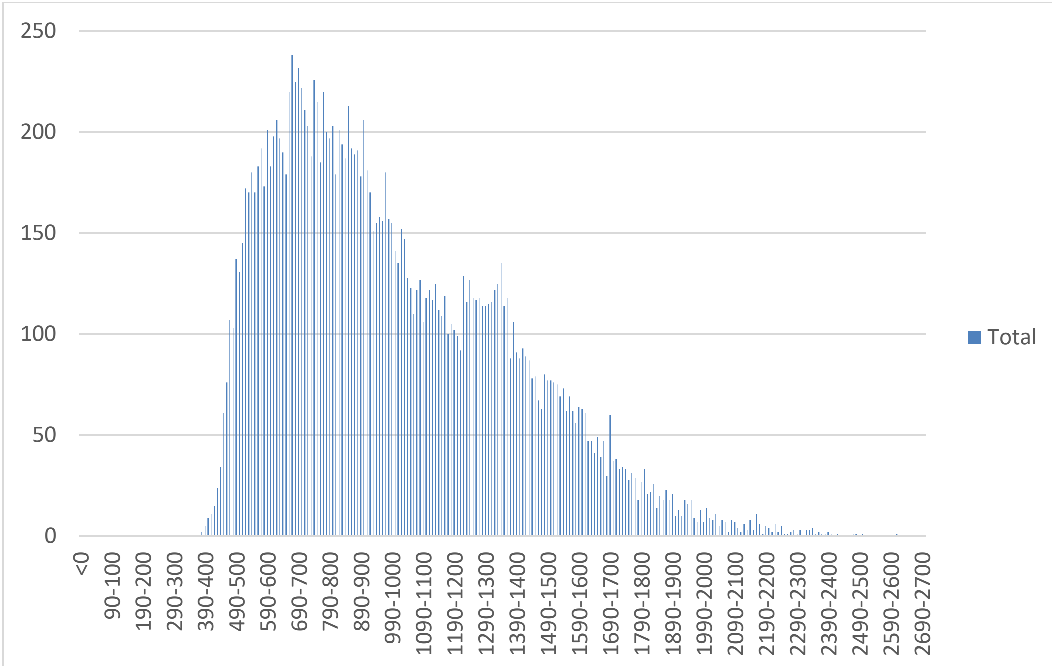


Figure 15. Two year load curve for total hours verus load level.

Analyzing the two years of data by month and season in Table 2 illustrates the fluctuations and spread of demand throughout the year.

Table 2. Descriptive statistics of the 2017–2018 load data by month and season, normalized by a 1000 kW average load.

	Min.	**Max**	**Ave.**	**Median**
All	**389**	**2,610**	**1,000**	**921**
Jan.	581	2,610	1,266	1,222
Feb.	445	2,007	1,039	983
Mar.	460	2,322	1,050	971
Winter	**445**	**2,610**	**1,121**	**1,043**
Apr.	393	1,737	870	774
May	408	1,753	876	779
Jun.	437	2,096	978	904
Spring	**393**	**2,096**	**908**	**813**
July	460	2,362	1,120	1,002
Aug.	405	1,951	966	892
Sep.	389	1,796	864	765
Summer	**389**	**2,362**	**985**	**890**
Oct.	389	1,748	842	729
Nov.	415	1,955	981	916
Dec.	571	2,359	1,142	1,081
Fall	**389**	**2,359**	**988**	**931**

The resulting load duration curve is shown in Figure 16.

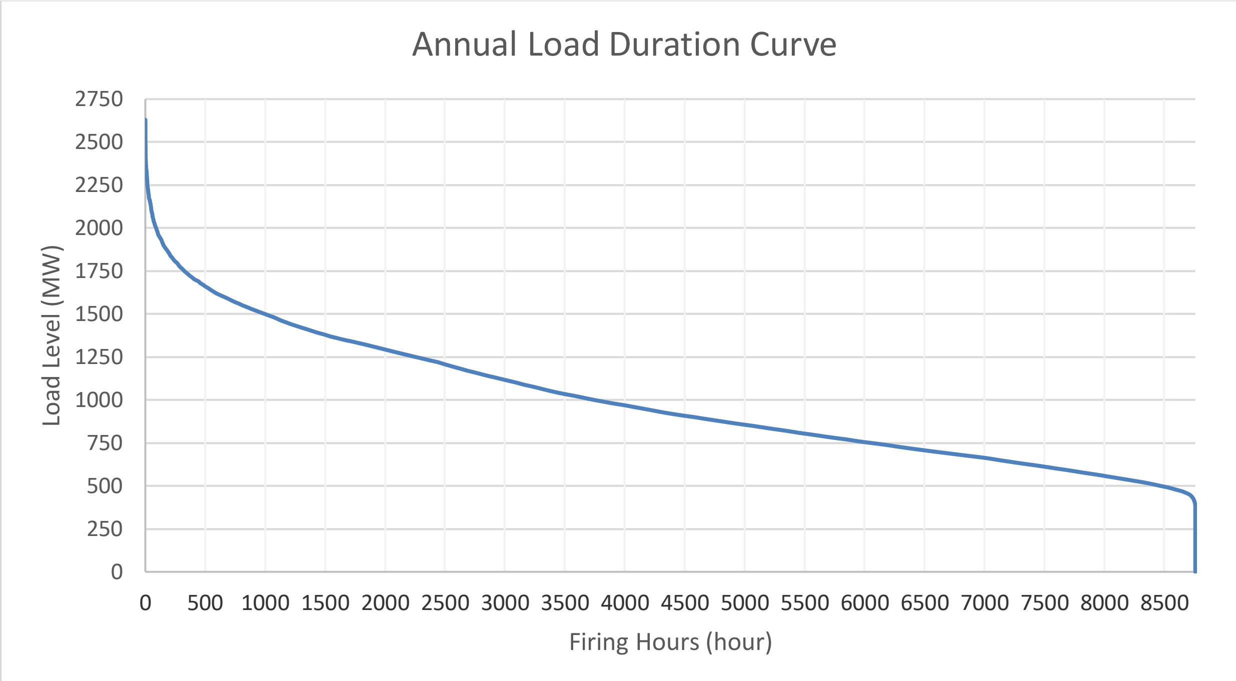


Figure 16. Annual load duration curve for the Appalachian Power Service Region normalized with a 1000 kW average load.

6. SCREENING CURVE ANALYSIS

6.1 Generating Prices

The EIRP 2017 report "Standardized Cost Analysis of Advanced Nuclear Technologies in Commercial Development" lists eight participating companies with advanced reactors currently in development, of which only two are not based in the United States. Unfortunately, the report only gives the average, minimum, and maximum cost for each category, rather than the specifics for each project. The variable costs in this report include operation and maintenance (O&M), financing, and fuel costs. It should be noted that every project in this study was projected to be less expensive than conventional nuclear.

The cost of nuclear power generation depends heavily on the technology chosen and whether it is a first-of-a-kind or nth-of-a-kind technology. The current metric for estimating costs for advanced reactor technology is an overnight cost of \$3500/kW and a fixed cost of \$25/MWh at 95% capacity. [10]

Coal plants with carbon capture also have various costs depending on the technology. The two main technologies considered for this study are supercritical and ultra-supercritical pulverized coal. Both technologies increase the efficiency of coal firing by operating at temperatures and pressures above the critical point of water. Although more expensive to build, ultra-supercritical plants are likely preferable in this case since they operate at higher temperatures and higher efficiencies, resulting in lower emissions. An ultra-supercritical coal plant is also preferable because the heat extracted from the plant will be at higher temperatures and, therefore, more effective for use in secondary processes.

The U.S. Energy Information Administration report "Capital Cost Estimates for Utility Scale Electric Power Generating Technologies" provides estimates for capital, fixed, and variable costs for a new ultra-supercritical pulverized coal plant with 90% carbon capture. Cost estimates are \$5876/kW capital costs,

$59.40/kW-year fixed O&M, and $10.98/MWh variable O&M. [11] The competitiveness of each technology also depends on financing estimates as well as future costs, such as a carbon tax. The sensitivity of these factors will be considered to determine feasible ranges for the size of each generating technology. From the NREL 2020 Annual Technology Baseline data, the fuel cost for coal is $25/MWh. [12]

6.2 Sizing Estimates

An initial screening curve can be created from the basic cost parameters mentioned in the previous section. Although nuclear generation has variable costs, the plant runs at 95% capacity for most of the time, and any outages, maintenance, and fuel costs are planned far in advanced. Therefore, the variable costs become fixed on a MW/year basis.

Figure 17-20 illustrate screening curves for a coal and nuclear plant with changing capital recovery periods (CRP) and discount rates. The first screening curve (Figure 17) is defined by a 0% discount rate and capital costs annualized over 30 years. This is a typical period for calculating levelized costs.

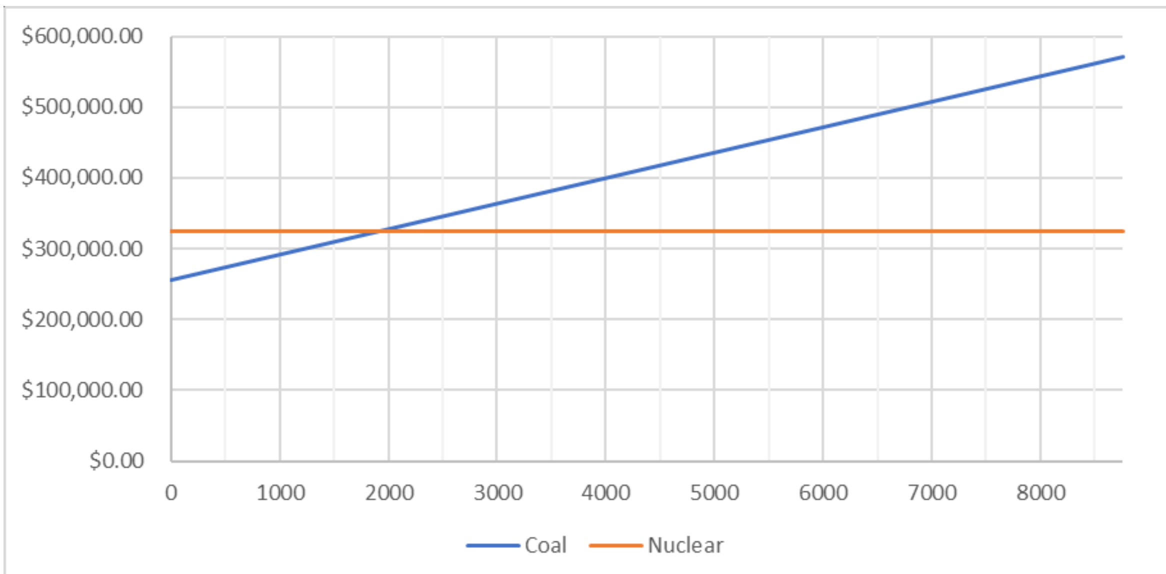


Figure 17. Coal and advanced nuclear screening curve with 0% discount rate, 30-year CRP.

These parameters calculate that running the coal plant is cheapest until approximately 3,000 running hours. Nuclear continues to be the most cost-efficient option up to 8,760 hours. This is because of the high variable costs associated with fossil fuels.

For the next screening curve (Figure 18), the discount rate remains at 0%, while the costs are annualized over 20 years. Shortening the capital recovery period might allow the generators to be more profitable sooner but penalizes technologies with high capital costs. In this scenario, coal is the least cost generator until approximately 2,000 hours.

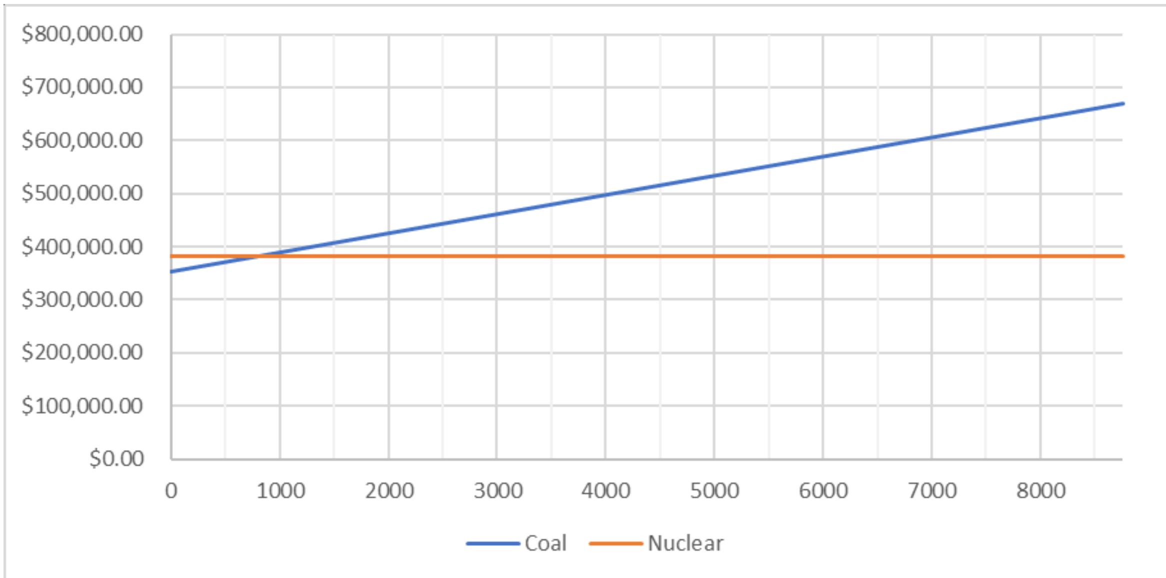


Figure 18. Coal and advanced nuclear screening curve with 0% discount rate, 20-year CRP.

The discount rate also heavily effects the profitability of each technology because it is a factor that determines the NPV of the cash flows, as shown by the third and fourth screening curves (Figure 19 and Figure 20).

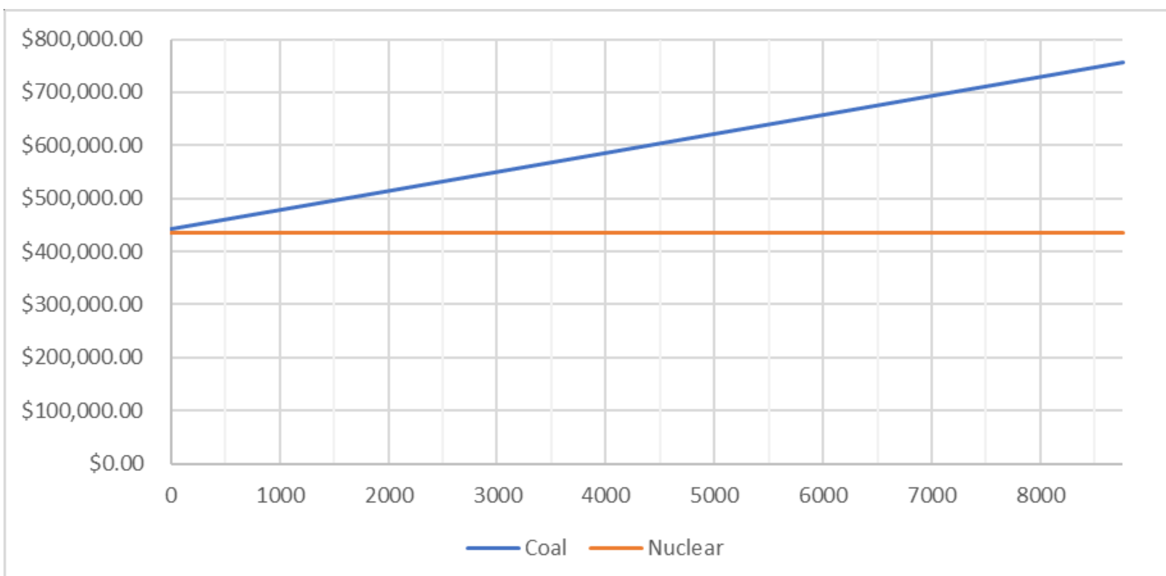


Figure 19. Coal and advanced nuclear screening curve with 5% discount rate, 30-year CRP.

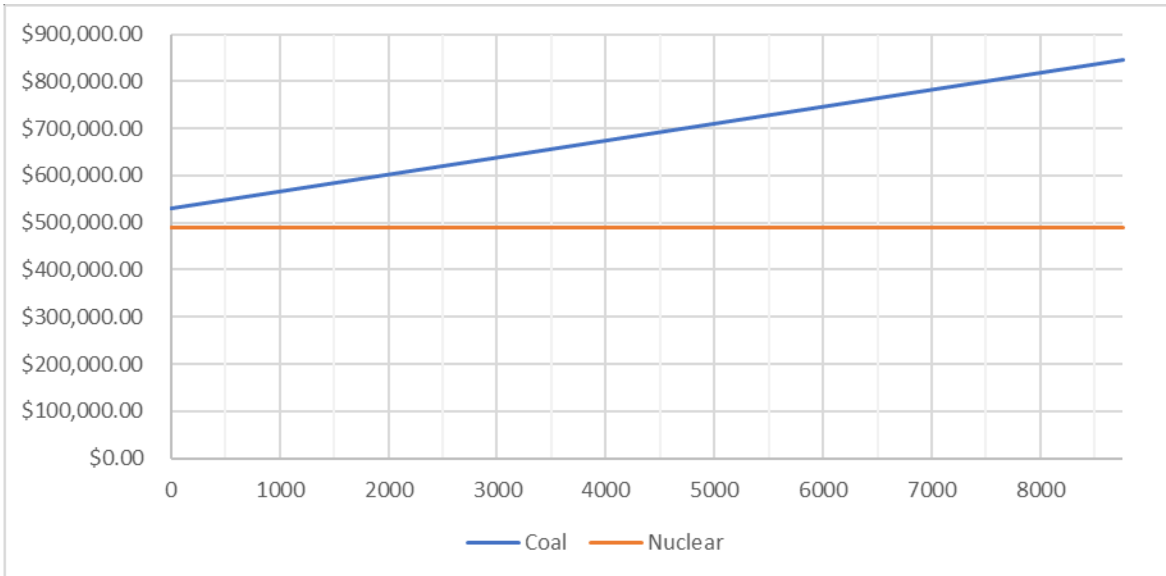


Figure 20. Coal and advanced nuclear screening curve with 5% discount rate, 20-year CRP.

Decreasing the CRP or increasing the discount rate makes nuclear an increasingly more economical option. Based on the analysis, it is unlikely that a coal plant will be economical if run for more than 3,000 hours, although it may be more profitable at an even lower capacity factor.

Comparing these screening curves to the load curves give an estimate of the sizes needed for the most profitable generation mix. A linear interpolation of the load and load hours gives an estimated size of the coal generation. The maximum demand, minus the size of the coal plant, gives the estimated size of the nuclear plant. Table 3 shows the estimated sizes of the coal and nuclear plant based on the load hour intersections of the screening curves.

Table 3. Proposed system sizes at load hour screening curve intersections.

Intersection of Load Hours (hr)	Coal Size (MW)	Nuclear Size (MW)
3,000	1,494	1,116
2,000	1,317	1,293
1,000	1,111	1,499
0	0	2,610

Another way to determine the optimal or least cost generation mix is to sweep all the possible combinations of capacity and determine the highest possible NPV. An algorithm built in TEAL can determine the best generation mix. Being the simulation extremely fast a heuristic optimization approach using a Monte Carlo sampling of the input space was deemed the most effective approach.

First, the capital and variable costs specified in the screening curve analysis define the total cost of the system at a specified number of load hours. Each component (advanced reactor, coal plant) is defined with a lifetime, capital cost, fixed cost, and variable cost. The capital, fixed, and variable costs are defined by a cost driver and cost multiplier. Table 4 gives the specific variables used in the TEAL script.

Table 4. Variables used in TEAL sizing script.

Component Name	Cash Flow	Cost Driver	Description	Alpha	Description
Advanced Reactor (AR)	CapAR (Capex)	AR_capacity	Capacity in MW of the AR power plant	-3500000	$/MW capacity capital cost
	FixAR (Fixed Costs)			-233016	Fixed cost of -$28/MW for 8760 hr/year at 95% capacity
Coal Power Plant (Coal)	CapC (Capex)	Coal_capacity	Capacity in MW of the coal power plant	-5931000	$/MW capacity capital cost
	FixC (Fixed Costs)			-58000	$/MW-yr
	VarC (Variable Costs)	loadHours	Hours of operation	-36	$/MWh of operation
E-Grid	E_sales	Demand	Yearly demand in MWh	36	$/MWh

The load curve is scaled by an average market demand of 1,000 MW; therefore, the total amount of electricity that must be provided over the course of a year is 8,760,000 MWh. The maximum capacity of the system is the maximum demand for the whole year (this assumes that the system can meet all the demand and there is no peaking power installed). The maximum capacity and the total market demand in MWh are set manually by the user in Raven. In this case, the maximum capacity is set at 2,610 MW.

The RAVEN code uses 100 Monte Carlo samples to test a variety of capacity combinations. The first sampled variable is Coal_capacity. It is sampled from a uniform distribution of bounds 0 MW and the max defined capacity.

The next sampled variable is the AR_capacity. AR_capacity is set by a function that subtracts the sampled Coal_capacity variable from the manually set Max_Capacity.

Because the coal plant includes a variable cost, the load hours of the plant must be determined to determine the total cost. We assumed that the advanced reactor always operates at 95% of its designed capacity, even when the demand is lower. The coal plant can be cycled to meet any additional demand. The advanced reactor can cover all the load hours up to its capacity on the load curve. The coal power plant will cover any remaining hours on the load curve.

The load curve is imported as a csv file with the level (in MW) from 0 to 2,610 in the left column and the hours for which that level must be provided for on the right (from 8,760-0). The function reads the file and finds the load level of the advanced reactor (rounded down to the nearest 10). Using a differential integration, the function calculates the area under the load curve that the AR cannot cover, giving the MWh of operation for the coal plant over the course of the year.

The last component included in the TEAL file is the electric grid, which assumes that 860,000 MWh of electricity is sold each year at the average purchase price of $36/MWh in the Pennsylvania, Jersey, Maryland Power Pool (PJM) market. These variables are sent back to TEAL to calculate the cash flows and results in the NPV of the system over the project lifetime. A positive NPV would indicate that the new system is capable to cover the electricity demand with a lower cost. One caveat is that the $36/MWh does not include capacity payment, which are in first approximation not deemed relevant. This is also due to the fact that the optimal point would be independent from the presence of capacity payments which would be just a bias and would not modify the configuration of minimal cost.

The systems that result in the highest 10 NPVs are listed in Table 5. Even for the optimal designs, the NPV is still negative over 30 years with a 5% discount rate.

Table 5. Highest 10 NPV designs found through TEAL optimization.

AR_capacity (MW)	Coal_capacity (MW)	Yearly Demand (MWh)	MaxCapacity (MW)	loadHours (MWh)	Coal Capacity Factor	NPV
1,698	912	8,760,000	2,610	79,630	1.0%	-1.34E+10
1,709	901	8,760,000	2,610	74,809	0.95%	-1.34E+10
1,721	889	8,760,000	2,610	70,307	0.90%	-1.34E+10
1,739	871	8,760,000	2,610	63,945	0.84%	-1.35E+10
1,798	812	8,760,000	2,610	46,256	0.65%	-1.35E+10
1,800	810	8,760,000	2,610	45,536	0.64%	-1.35E+10
1,823	787	8,760,000	2,610	39,972	0.58%	-1.35E+10
1,546	1,064	8,760,000	2,610	171,088	1.8%	-1.35E+10
1,528	1,082	8,760,000	2,610	186,379	2.0%	-1.35E+10
1,518	1,092	8,760,000	2,610	196,013	2.0%	-1.35E+10

It is not surprising that the combination of these two results in a negative NPV, because the advanced reactor has a high capital cost, and the coal plant has a low-capacity factor.

This analysis does not account for the difference in optimal design for NPV when considering the sale of captured CO_2, assumed at a conservative \$100/kWh. Table 6 shows the designs with the highest 10 NPVs, in which most of the system capacity consists of coal. This design does not consider a market saturation for CO_2 sales, but, even making up most of the system, the maximum capacity factor is 37.9%.

Table 6. Highest 10 NPV designs found through TEAL optimization, including sale of captured CO_2.

AR_capacity	Coal_capacity	loadHours	Coal Capacity Factor	NPV
16	2,594	8,617,993	37.9%	1.32E+13
51	2,559	8,312,762	37.1%	1.28E+13
59	2,551	8,241,323	36.9%	1.27E+13
60	2,550	8,234,508	36.9%	1.26E+13
70	2,540	8,147,638	36.6%	1.25E+13
71	2,539	8,135,289	36.6%	1.25E+13
112	2,498	7,782,132	35.6%	1.19E+13
117	2,493	7,734,712	35.4%	1.19E+13
147	2,463	7,475,523	34.6%	1.15E+13
172	2,438	7,251,158	34.0%	1.11E+13

One way to decrease the cost of the systems and increase the coal plant capacity is by decreasing the plant capacity by adding in a peaking power source. The peaking power source can handle a low-capacity factor, and likely the cost of the system can go down. However, if the peaking source is natural gas, there will either need to be carbon capture implemented or account for the cost and impact of carbon emissions. Table 7 shows the estimated cost of carbon avoided for the lowest NPV designs. The cost of a plant without carbon capture was estimated using the NREL Annual Technology Baseline and 894 kg CO_2 emitted per MWh. As expected, decreasing the coal plant increases the cost of carbon avoided because of the high capital costs of a plant with capture.

Table 7. Cost of carbon avoided for lowest NPV designs.

Coal Capacity (MW)	NPV With Capture ($)	NPV Without Capture ($)	Load Hours	Carbon Output (kg)	Carbon Avoided (kg)	Cost of Carbon Avoided ($/kg)
912	-1.3444E+10	-1.1048E+10	79,630	7.12E+7	6.41E+7	37.38
901	-1.3444E+10	-1.1081E+10	74,809	6.69E+7	6.02E+7	39.26
889	-1.3445E+10	-1.1113E+10	70,307	6.29E+7	5.66E+7	41.22

For this, it is important to note that, according to the screening curve method, building a natural gas combined cycle plant with carbon capture is generally cheaper than any combination of coal and nuclear, as shown in Figure 21. However, the goal of this project is to utilize coal and nuclear power in a profitable manner. Costs for the natural gas plant were taken from the NREL Annual Technology Baseline.

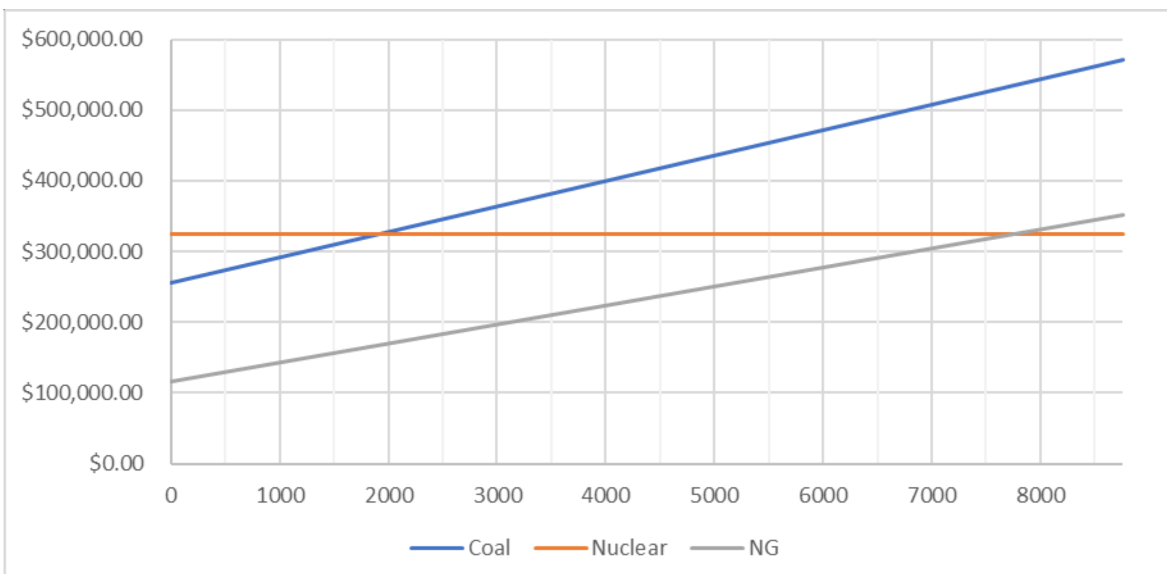


Figure 21. Traditional screening curve for coal, advanced nuclear, and natural gas with 0% discount rate, 30-year CRP.

Another way to increase the capacity of the coal plant is to add a secondary market that demands electricity while producing a profit.

7. CASE 2: COGENERATION WITH HYDROGEN

The purpose of this project is to increase the profitability of the coal and nuclear hybrid system. One way to do this is by adding a secondary market to utilize electricity that is generated but not needed by the grid.

The addition of hydrogen production as a secondary priority stands to benefit the system in many ways. The first is by increasing the capacity factors of the power plants. A higher capacity factor indicates a good utilization of the plant. If the plants are built with a high capacity but low-capacity factor, either the capacity should be increased, or the size should be reduced to make better use of the cash flow.

The sale of hydrogen and oxygen from the high-temperature steam electrolysis (HTSE) plant can also increase the cash flow of the whole system by providing a secondary market for selling electricity. Figure 22 shows the proposed design of the system when hydrogen generation is included.

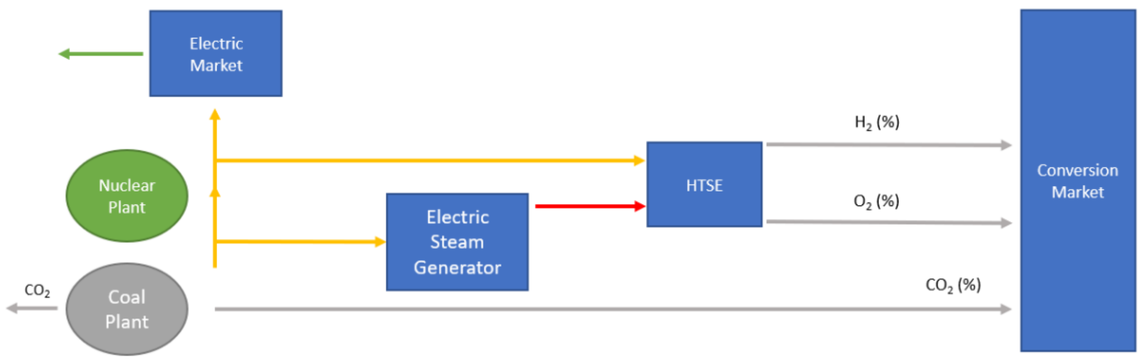


Figure 22. Flowchart of cogeneration with hydrogen case.

8. CASE 3: INTEGRATION OF COAL AND BIOMASS GASIFICATION

According to the proposed model, biomass and coal are co-gasified to generate charcoal and syngas that is passed to other processes. The biomass undergoes torrefaction before pyrolysis with the coal, which gives the biomass more coal-like characteristics. After pyrolysis, the char is split between a direct carbon fuel cell and a char gasification process. Oils and gases from pyrolysis are sent to hydrothermal gasification. When each component is broken down, there may be several feasible options for a gasification and oil upgrading process. Figure 23 shows how biomass can be processed numerous ways to achieve the desired products.

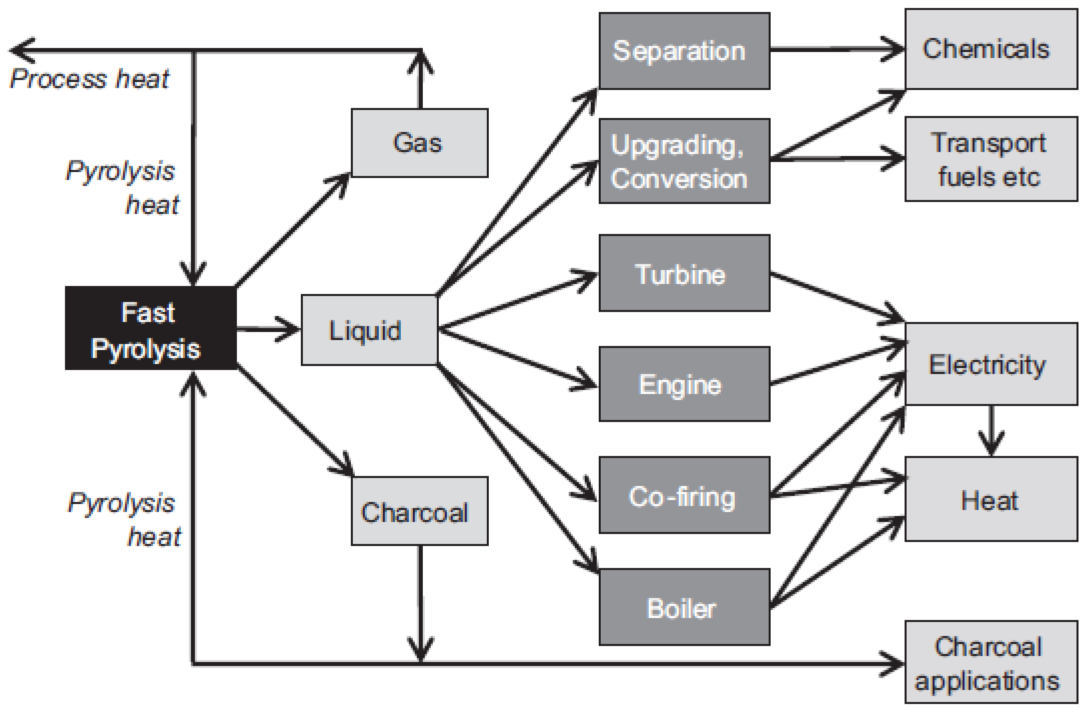


Figure 23. Process pathways for biomass conversion. [16]

8.1 Torrefaction

Torrefaction is a thermal process used to produce high-grade solid biofuels. The torrefaction process increases the quality of the biomass as a fuel, but it especially important when co-burning with coal because it converts the biomass to a more coal-like material with a simplified storage and easier, less-energy intensive grinding. [13] If biomass is used in this system, there is little reason to eliminate it from the process.

The torrefaction process will require heat from an external source.

8.2 Pyrolysis

Torrefied biomass and coal can be pyrolyzed together in a reactor. Unlike gasification, pyrolysis is the decomposition of fuels in the absence of oxygen. Pyrolysis results in a combination of solid, liquid, and gaseous products. The co-pyrolysis of biomass and coal has the benefit of producing higher quality products, in part due to the hydrogen-rich nature of the biomass compared to coal. Although non-torrefied biomass contains more H-donors, torrefied biomass can reduce heat and mass transfer limitations in the reactor. [15] One study suggests that the addition of CO_2 to the co-pyrolysis process can increase the quality of the products. [15]

From the pyrolysis reaction, there are several options for processing the solid and liquid and gaseous byproducts. The pyrolysis process will require heat from an external source. An example design for a pyrolysis reactor is shown in Figure 24.

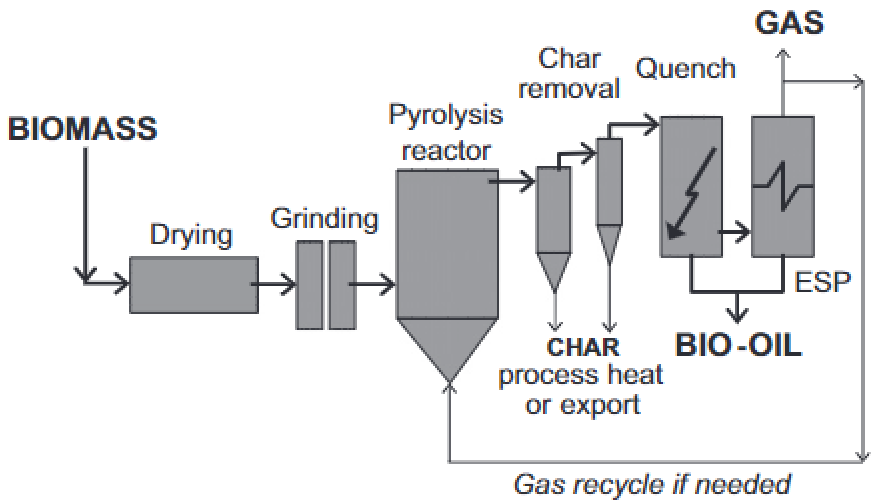


Figure 24. Example design for a pyrolysis reactor for the production of bio-oil. [16]

8.2.1 Solid Byproducts: Direct Carbon Fuel Cell

Direct carbon fuel cells use solid carbon in the anode and oxidize it to CO_2 with air, as illustrated in Figure 25. [19] DCFC requires cleaned carbon feedstock, releasing lower emissions than coal firing plants while CO_2 released is not mixed with other gases. [19] This CO_2 can be sequestered and added to the other captured CO_2 for processing.

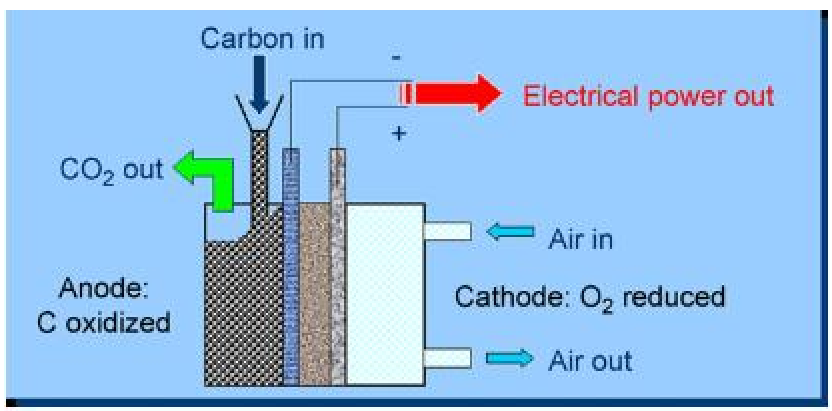


Figure 25. Design of a direct carbon fuel cell. [20]

The DCFC would be useful for peaking power if the power plants are designed below the maximum predicted grid demand or to supply power to the carbon conversion processes. Alternatively, it could be eliminated from the system, and all char could be sent to the gasification process. The conversion of char to syngas may simplify the number of components and processes within the system and produce a more versatile fuel to use elsewhere in the system.

Although DCFC is still considered an emerging technology, it has been shown to reach efficiencies of 65–70%, or higher if waste heat is captured, and has been successfully scaled up to plant sizes as large as 59 MW. [19]

8.2.2 Solid Byproducts: Char Gasification

The solid byproducts of torrefaction can be converted to syngas through gasification. Char gasification requires a gasifying agent, such as air, oxygen, steam, or carbon dioxide. The proposed system uses steam and oxygen as the gasifying agents, with oxygen supplied as a product of HTSE, and steam supplied from concentrated solar thermal (CST) power. As explored in section 4, concentrated solar thermal is not a feasible option for the Appalachian region. While there are other options for steam generation, such as direct steam generation from electricity, or steam generation via heat exchangers from the SMR. Without CST steam generation, there is some incentive lost for generating steam to use in the gasification process.

Without the char gasification process, all solid byproducts would have to be utilized by the DCFC. Electricity from the DCFC would be cleaner than the combustion of the products from char gasification, but syngas is a more versatile fuel source. Also, eliminating char gasification would decrease the production of other useful gases and chemicals to aid in the carbon conversion process to useful products. The need for these gases will of course depend on the products chosen for the conversion process.

Another option is to perform char gasification without steam.

Changing the oxidizer changes the composition of the resulting syngas as illustrated in Table 8. Using oxygen as the oxidizer, rather than air, increases the quality of the syngas but decreases the volume of syngas overall. However, steam generation is still necessary for producing the water-gas shift in the gasification reaction. Without steam, gasification can still occur, but it would be much less effective than using the char in a DCFC. Using oxygen with steam is especially beneficial because it will provide better quality syngas and decrease the required input of heat, coal, and biomass fuel.

Table 8. Syngas and hydrogen conversion rate from char gasification based on oxidizer. [22]

Oxidizer	Syngas	H_2	LHV	Plant Power
Air	2.09	20.2	5.35	29.1
Air/Steam	2.79	52.4	4.42	32
Air/Seam	2.62	51.6	4.8	32.9
O_2/Steam	1.42	46.7	10.5	50.6
O_2/Steam	1.40	51.3	10.7	54.1

8.2.3 Liquid Byproducts: Liquid Gasification

The original model proposes using hydrothermal gasification on the liquid and gaseous byproducts of pyrolysis; however, hydrothermal gasification is most effective on biomass with a high-water content. [23] A high dry mass content results in lower quality syngas with lower proportions of hydrogen and higher proportions of methane. [24] Therefore, there is no reason to use hydrothermal gasification over conventional gasification.

The pyrolysis oil can be gasified and upgraded with steam reforming, or the oil can be upgraded directly through a variety of processes. [25] While gasification is an option, it is not necessary on its own to turn the liquid byproducts into a usable product.

8.2.4 Liquid Byproducts: Oil Upgrading

The process for oil upgrading is dependent on the desired gaseous products to send to the carbon conversion processes. An easy and useful upgrading process to incorporate is hydrotreating, as illustrated in Figure 26. Hydrogen is already produced by the HTSE, and oil upgrading will produce a valuable and versatile fuel that can be sold or burned to generate heat, steam, or electricity within the system. Product quality may increase if the pyrolysis oil is split between the water soluble and non-soluble products. [26]

Steam reforming can be incorporated to increase hydrogen production. [27] The steam reforming process can also be used separately from hydrotreating on the whole or fractioned oil. The downside is that, ideally, steam reforming will gasify a majority of the pyrolysis oil and not produce a usable oil product, which may be important for carbon conversion.

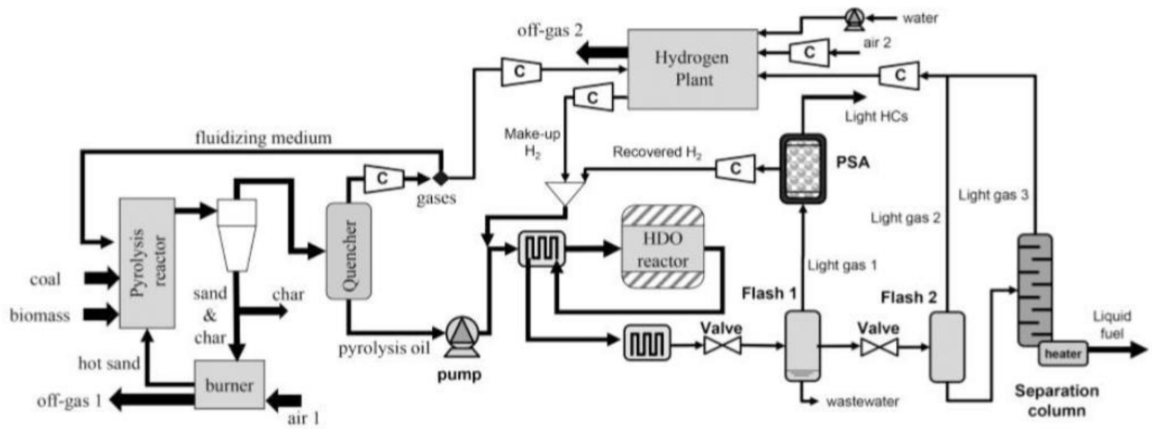


Figure 26. Example co-pyrolysis plant whith hydrotreating of pyrolysis oil. [17]

8.2.5 Gaseous Byproducts

The gaseous byproducts of pyrolysis and other gasification processes must go through a cooling and cleaning process to be usable in most conventional fuel burning applications. The thermal efficiency of the plant can be increased by using heat recovery. [28]

After cooling, the raw syngas must be cleaned of contaminants, including fine particles, sulfur, ammonia, chlorides, mercury, and other trace heavy metals. CO_2 can also be removed in these processes. Conditioning also adjusts the H_2 to CO ratio of the syngas. [28]

The typical process includes cyclone filters for bulk particle removal and then quenching and scrubbing with water for fine char and ash particulate removal. Water from the scrubbing process can be filtered and recycled. [28]

Acid gases and CO_2 produced in the gasification process can be removed with physical or chemical solvents. The solvent choice depends on the sulfur concentration tolerance of the final syngas application. It is also dependent on the amount of CO_2 desired in the final gas. Sulfur removed in the acid gas removal can be recovered if desired. Additional scrubbing may be required to remove mercury and other heavy metals to meet emissions requirements. [28]

The water-gas shift is used if the H_2/CO ratio must be increased or adjusted to meet a downstream reactor. Syngas is passed through a reactor containing shift catalysts that convert CO and water into additional H_2 and CO_2. This final, post-gasification operation can be used for hydrogen production to convert all present CO to CO_2, yielding the maximum amount of hydrogen. [28]

9. WORKFLOW

In the following it will be introduced the figure of merits that are relevant to define the performance of the problem for a more substantive analysis. Second, a discussion on the definition of the relevant system boundaries and then the tools available and their use.

9.1 Figures of Merit (FOM)

9.1.1 Total Net Present Value

The main figure of merit used to compare this system will be cost. One way this can be measured is through a 30-year NPV of the system. A differential NPV between cases takes into account the cost of all system components as well as the profit generated over time.

$$\Delta NPV = NPV(Reference\ Case) - NPV(New\ Case)$$

9.1.2 Cost of Avoided CO_2

Only comparing the total NPV does not give the full picture of the compared systems. Another FOM that can be used is the cost of avoided CO_2. Avoided CO_2 includes changes in the size of CO_2-producing components as well as products that offset traditional fossil fuels in the conversion market.

$$\Delta \$CO_2 = \frac{Cost\ to\ Serve\ Demand\ (New\ Case) - Cost\ to\ Serve\ Demand\ (Reference\ Case)}{CO_2\ Avoided}$$

9.2 System Boundaries

9.2.1 Market Saturation

If left unconstrained, the optimal system size will be one in which the maximum amount of product can be sold to the market for a profit. This results in extreme cases, such as an extremely large coal plant to sell CO_2, or an extremely large nuclear plant to sell more hydrogen. In reality, the market would quickly become saturated with these products, and they would become less valuable the more that is produced. To counter this effect, the price of each product is set to decrease as production increases.

9.2.2 Grid Demand

Demand from the electric grid is based on the Appalachian region demand data. This region includes a large proportion of residential customers as well as industrial customers. The type of customers in the region influence the hourly trends and the total capacity needed for the system.

9.2.3 Geography

As discussed previously in section 4 the location imposes several constraints on the system. The first is the availability of other energy technologies. Unfortunately, solar and wind power are not feasible for this system unless strict location constraints are set. Second, the geography affects the availability of fuel feedstocks. In the Appalachian region, abundant feedstocks are bituminous coal and hardwood biomass.

9.2.4 Conversion Market Prices

There is little concrete information on the prices of feedstock sold to the carbon conversion market. These feedstocks include carbon dioxide, hydrogen, oxygen, syngas, and processed pyrolysis oils. These market prices can be estimated based on available data, and sensitivity studies based on price can help determine if price accuracy is critical to sizing the optimal system. Additionally, simulated market trends will test how changes in price over time will impact the optimal system.

9.2.5 Construction Prices

Construction prices for the power plants are well documented, although capital, fixed, and variable costs for every technology can vary significantly between sources. Prices are estimated based on the most current, applicable sources. Sensitivity studies will be performed to determine how changes in construction prices affect the optimal design. Accurately predicting construction costs of the advanced reactor is a limitation for this study because there is limited data on completed construction costs.

9.2.6 Pareto Efficiency

Pareto efficiency is an economic state where resources cannot be reallocated to make one indivudial better off without making at least one individual worse off. In pareto optimization, there can be a number of outcomes that are pareto efficent, and any of these outcomes can be chosen without disrupting the market efficiency. The pareto frontier is the series of all points that are "pareto efficent," as demonstrated in Figure 27. All the red points are points which are pareto efficient. The gray points all exist in the space in which one or more variables can be improved without sacrificing the effiency. For example, in a system that demands 100 MW, a system with a 50 MW nuclear and 50 MW coal would be pareto efficient. A system with 100 MW nuclear and 0 MW coal would also be pareto efficient. A system with 50 MW nuclear and 49 MW coal would not be pareto efficient because the capacity of coal can be increased to meet demand without reducing the nuclear capacity.

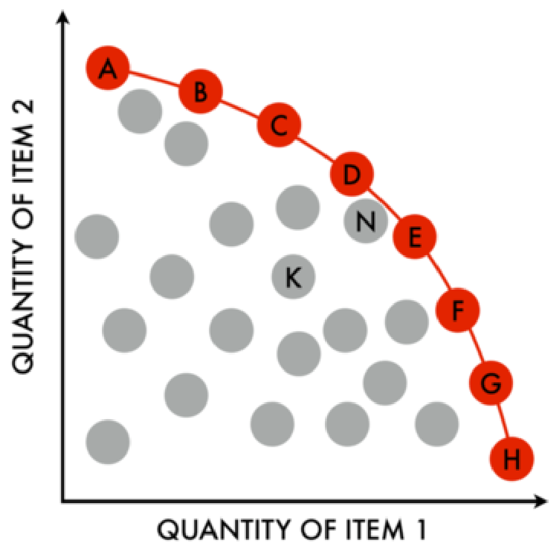


Figure 27. A function with a number of pareto efficient possibilities (red) and inefficient possibilities (gray) [29].

9.3 Methods

So far it has been presented the preliminary impact of adding a CO2 market to the initial systems, which has led to a great improvement in the NPV of the systems. The methodology tested has shortcomings in term of representation of coproduct markets (e.g., CO_2 market) and therefore it will need to augment. The extension of the screening curve method is described in the section below by the introduction of the opportunity cost. This extension will not still be capable to capture the presence of variable renewable that are not dispatchable resources, and therefore violate the assumption of the screening curve method. To overcome this issue an external loop would set the size of not dispatchable resources and, for example, subtract the production of electricity by the variable renewable form the demand, determining what is call net demand.

Once an initial screening of the different option, named phases in the following sections, will be done with the here proposed new screening curve method and optimization, the best performing system could be eventually tested by using HERON which allow an higher degree of fidelity but it is computational expensive.

9.3.1 Modified Screening Curve Method

The screening curve method can help determine the lowest cost generation mix of a system; however, the standard screening curve does not support the addition of components and markets beyond standard variable load power plants. Introducing these components into the system can help to determine the lowest cost system mix when all options are considered.

The optimal system configuration is dependent on capital, fixed, and variable costs; profits; and opportunity costs. The "opportunity cost" represents the cost of not producing a product or selling to a market. Standardizing all the technology options in this way helps to normalize all options to fit into a traditional screening curve.

The opportunity cost allows for the optimization algorithm to consider multiproduct options. Some of these options may have ripple effects within the system or will replace a purchased resource rather than provide an opportunity for profit.

9.3.2 TEAL

TEAL is used to run a simplified version of the economic analysis that uses yearly trends over hourly, stochastic data. The advantage of TEAL is the ability for a greater control of the cash flows and variables with the implementation of custom functions. Although it does not have built-in optimization functions, distributions and a detailed output gives a larger picture of the variables and can be used for a more detailed analysis of the system. TEAL can be used also as a part of an optimization scheme managed by RAVEN, but the screening curve in this case would provide that optimization result and therefore the capability to perform a parametric sweep on the cost parameters of the different technology is a better use of TEAL capacity.

9.3.3 HERON

HERON is a dispatch optimizer that works in conjunction with a stochastic time series. An estimate of the hourly demand series is available from the demand profile data. HERON is specifically intended to analyze flexible systems that include electricity generation and the generation of a secondary product. Typically, HERON is used with stochastic price prediction and dispatches production based on the most profitable product at each hour. Figure 28 shows an example of a HERON simulation that sells electricity to the grid or produces hydrogen. This simulation will have the first priority of meeting grid demand and a second priority of producing secondary products to maximize the system NPV. HERON can be used to optimize system performance under two different assumption, price taker and price maker. The price maker would be preferred in this analysis since it will allow to capture the cost minimization at the system level deriving from the reconfiguration of the system and from the introduction of additional cash streams.

HERON also includes a built-in optimizer, but, because there are so many components to be optimized, the decision tree process of the optimizer would take significant computation time. This is the reason why, while still deciding among so different possible system configuration of the system, the modified screen curve method here proposed is preferred for the initial screen of the possible system configuration.

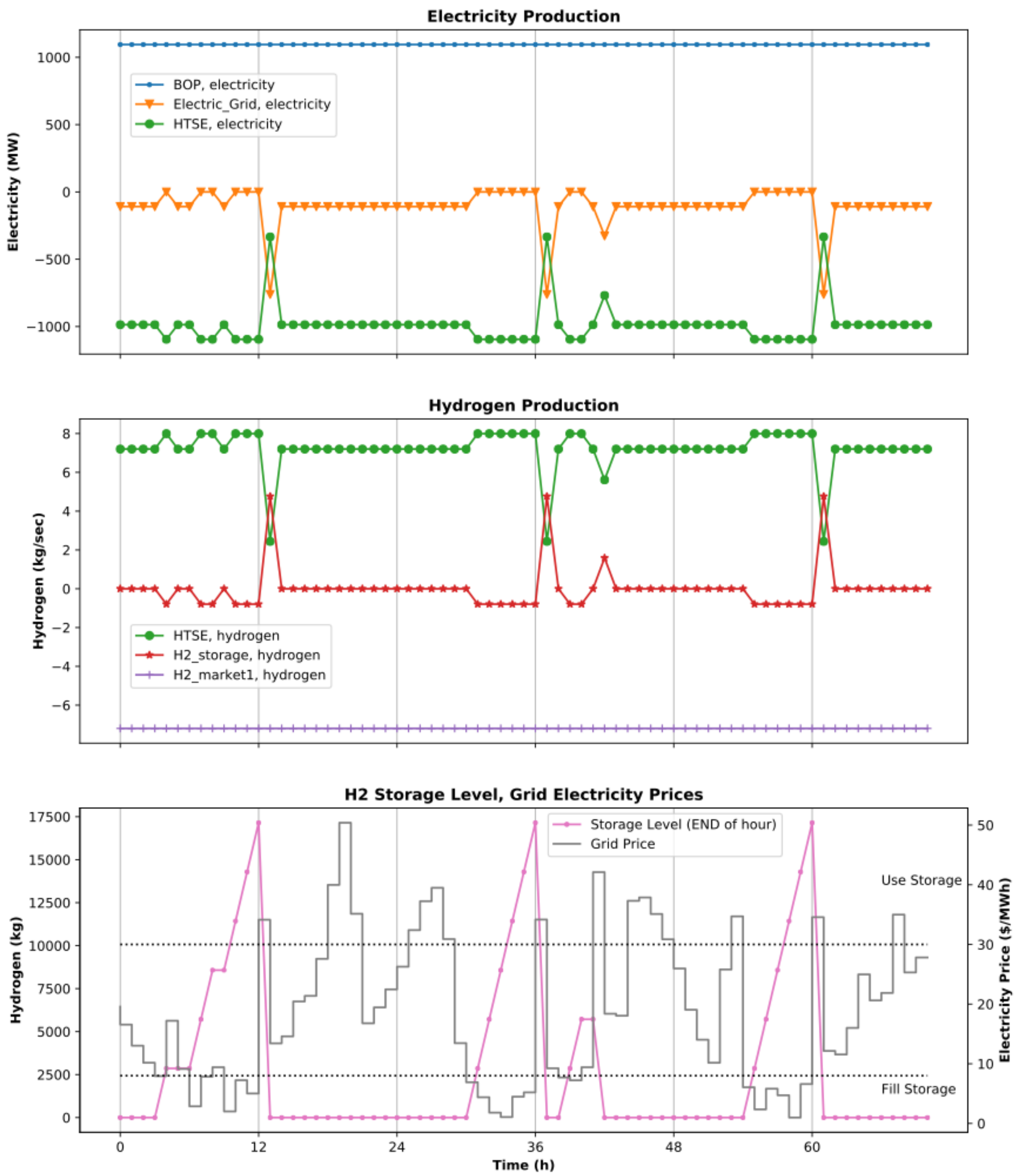


Figure 28. Results from a HERON optimization with the cogeneration of hydrogen and electricity [30].

9.3.4 Optimization Algorithm

An optimization algorithm will be built that utilizes the modified screening curve method, including the theory of a dispatch method. The algorithm will include an inner and outer optimization, which prioritizes meeting demand before sizing secondary components. Figure 29 gives an example of this algorithm, including variable renewable energy (VRE), a gasifier, and a hydrogen market. The inner optimization sizes any non-VRE generators based on the demand curve and finds the cost. The outer optimization loop sizes any remaining components VRE, secondary products, etc. and finds resulting operating hours, costs, and profits to determine the total cost of the system. The algorithm can return to the inner loop to resize the thermal power plants and find the highest possible NPV.

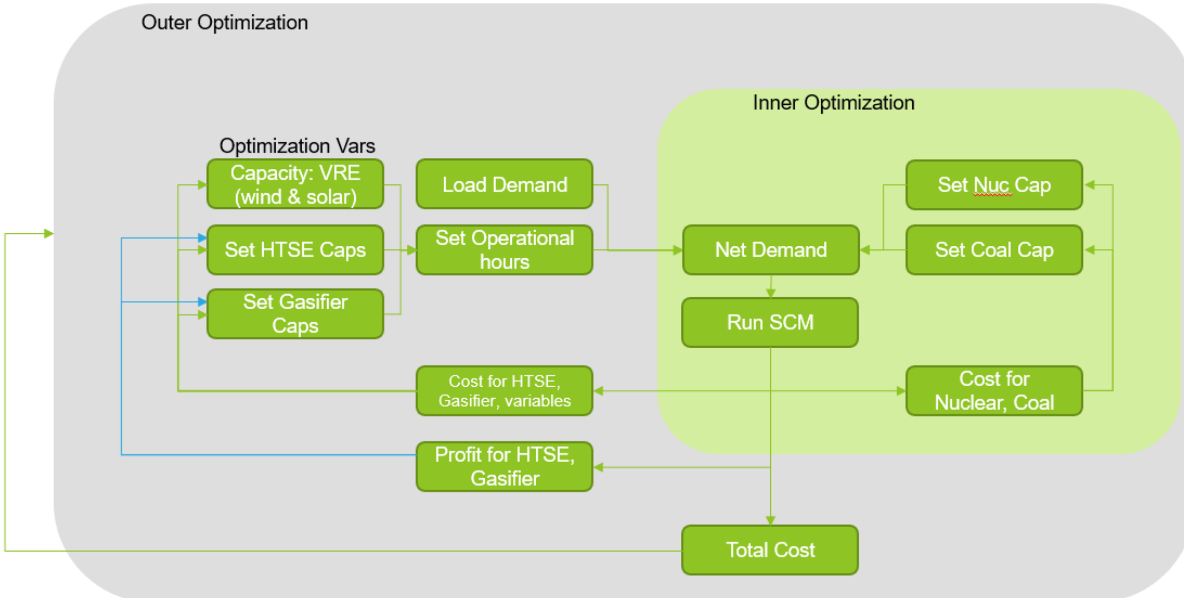


Figure 29. Example of the proposed optimization algorithm, including thermal power plants, VREs, and secondary markets.

9.3.5 Phase 1 (Reference Case):

The reference case consists of a coal power plant and an advanced reactor that generate electricity to meet market demand. The coal plant is equipped with 90% carbon capture and sells captured carbon to the conversion market. The other 10% of produced CO_2 is released into the atmosphere. The proposed process design is illustrated in Figure 30.

Component 1: Advanced Reactor

- Costs: Capital and fixed costs. Variable costs are annualized based on a 95% capacity and combined with fixed costs.
- Profits: Electricity sold to the grid
- Produces: Electricity
- Demands: None

Component 2: Coal Plant

- Costs: Capital, fixed, and variable costs. CO_2 penalities if applicable.
- Profits: Electricity sold to the grid, CO_2 sold to conversion market
- Produces: Electricity, CO_2
- Demands: None

Component 3: Electric Market

- Costs: Payments for electricity sold to the grid.
- Profits: None

- Produces: None
- Demands: Electricity

Component 4: Conversion Market

- Costs: Payments for purchased CO_2.
- Profits: None
- Produces: None
- Demands: CO_2

The reference case will provide the baseline cost to which all other systems will be compared.

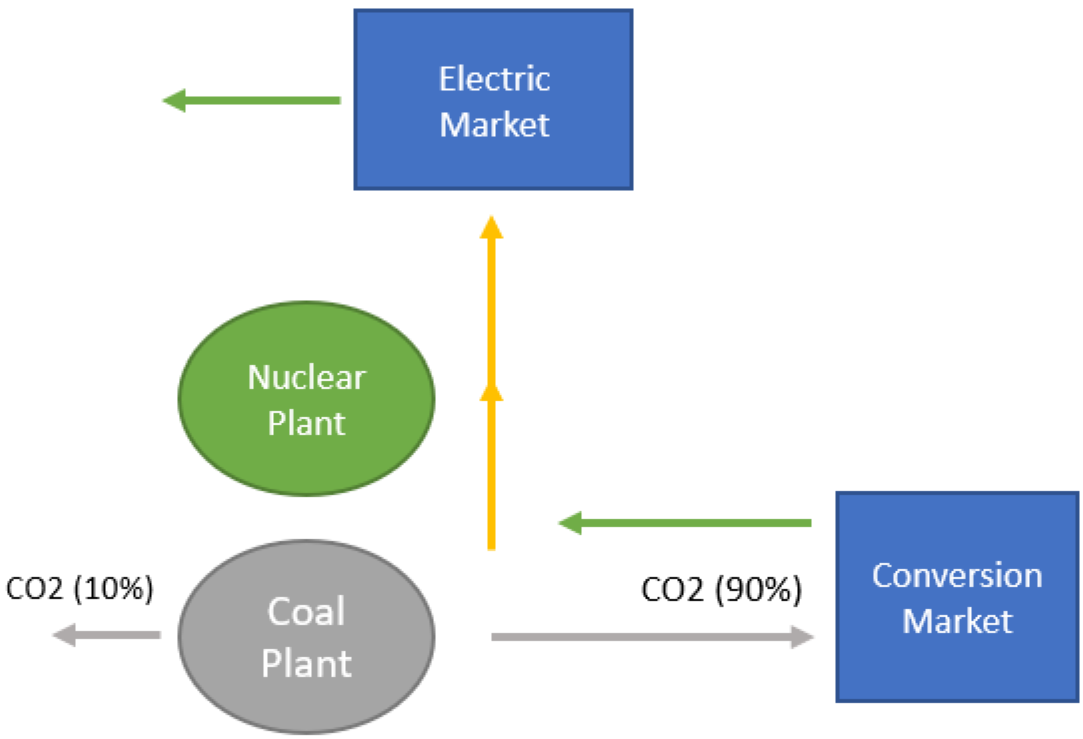


Figure 30. Phase 1 flowchart including electric and conversion markets.

9.3.6 Phase 2 (Secondary Market):

The second phase includes a secondary market for electricity sales. Electricity can be sold to the grid, or to a HTSE plant that produces hydrogen and oxygen to be sold to the conversion market. The proposed process design is illustrated in Figure 31.

This is the first case in which the opportunity cost is considered. The option between selling electricity to the grid and using it to produce hydrogen makes an impact on the optimal system size. The opportunity cost is the profit from producing hydrogen minus the cost to generate it. This value should be positive, otherwise it would not be economical to include the component in the market. The prices will be set to change in response to market saturation so that one market does not dominate the optimal system size.

Component 1: Advanced Reactor

- Costs: Capital and fixed costs. Variable costs are annualized based on a 95% capacity and combined with fixed costs.
- Profits: Electricity sold to the grid, electricty sold to the HTSE
- Produces: Electricity
- Demands: None

Component 2: Coal Plant

- Costs: Capital, fixed, and variable costs. CO_2 penalities if applicable.
- Profits: Electricity sold to the grid, CO_2 sold to conversion market, electricity sold to the HTSE
- Produces: Electricity, CO_2
- Demands: None

Component 3: Electric Market

- Costs: Payments for electricity sold to the grid.
- Profits: None
- Produces: None
- Demands: Electricity
- Opportunity cost: Price of electricity

Component 4: HTSE

- Costs: Capital, fixed, and variable costs.
- Profits: Sales of H_2 and O_2
- Produces: Hydrogen, Oxygen
- Demands: Electricity
- Opportunity cost: Price of hydrogen/oxygen minus production costs

Component 5: Conversion Market

- Costs: Payments for feedstocks purchased.
- Profits: None
- Produces: None
- Demands: CO_2, H_2, O_2

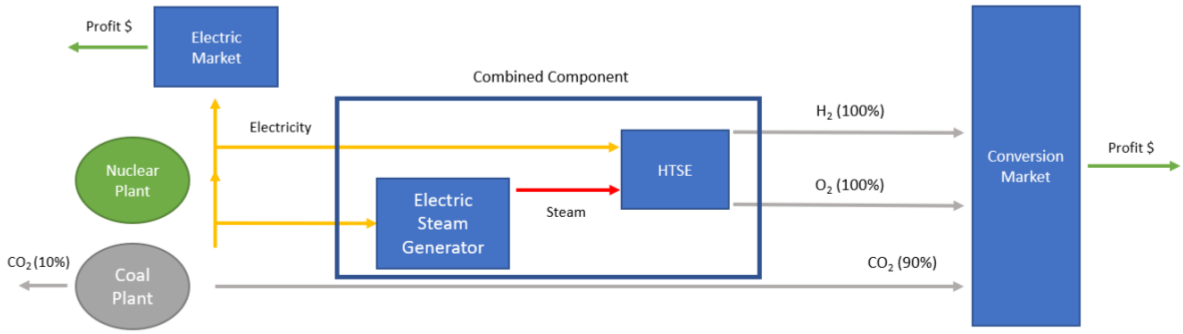


Figure 31. Phase 2 flowchart with electric, hydrogen, and conversion markets.

9.3.7 Phase 3: Independent Pyrolysis Plant

The third phase will test system operation for the pyrolysis plant independent of the electricity generating power plants. This system would share steam and electricity resources with the power plant and hydrogen and oxygen from the HTSE component. The optimization of this system in isolation will give an idea of the optimal system sizing by considering only the opportunity costs in hydrocarbon production. The proposed process design is illustrated in Figure 32.

Component 1: Torrefaction

- Costs: Capital, fixed costs, biomass feedstock variable costs.
- Profits: None
- Produces: Torrefied wood
- Demands: Woody biomass, steam/heat

Component 2: Pyrolysis

- Costs: Capital, fixed costs, coal feedstock variable costs.
- Profits: None
- Produces: Pyrolysis oils, gases, char
- Demands: torrefied wood, coal, heat/steam

Component 3: Oil Upgrading

- Costs: Capital, fixed costs, variable costs, electricity and hydrogen variable costs.
- Profits:Sale of hydrocarbon
- Produces: Hydrocarbons, carbon offset
- Demands: Pyrolysis oil and gases, hydrogen, electricity

Component 4: Char Combustion

- Costs: Capital, fixed costs, CO_2 penalties.
- Profits: None
- Produces: Heat, CO_2
- Demands: Char
- Opportunity Cost: production of heat

Component 5: Steam Gasification

- Costs: Capital, fixed costs, electricity, steam.
- Profits: Methanol sold to market
- Produces: Methanol
- Demands: Char, steam, electricity
- Opportunity Cost: Profits from methanol minus cost of operation

Component 6: Direct Carbon Fuel Cell

- Costs: Capital costs.
- Profits: Electricity sold to market
- Produces: Electricity
- Demands: Char
- Opportunity Cost: Profits from electricity minus cost of operation OR cost of electricity purchased for other components

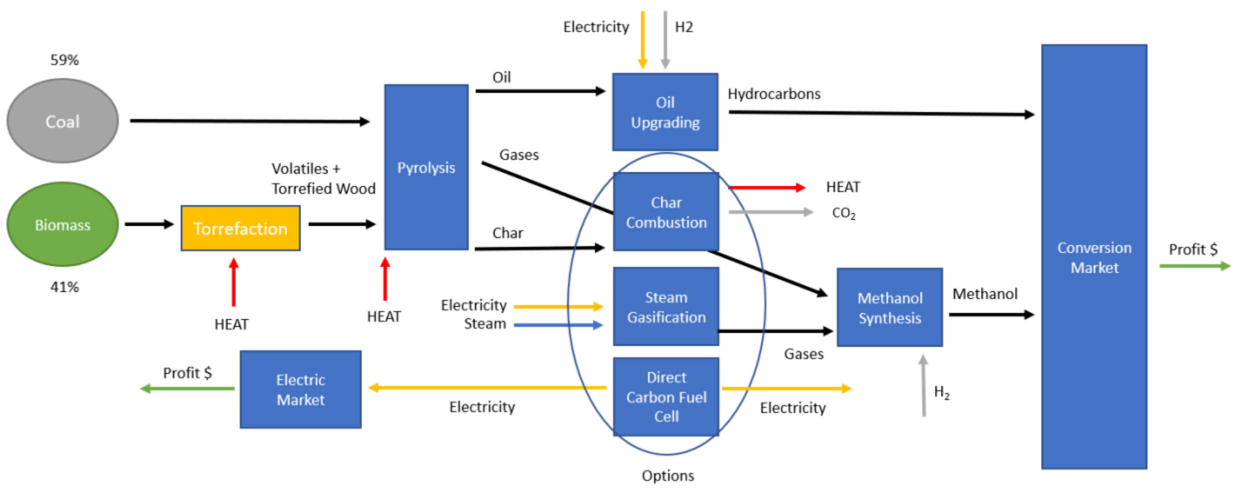


Figure 32. Phase 3 flowchart with options for coal and biomass conversion and processing.

9.3.8 Phase 4: Pyrolysis Plant Integration

The final phase integrates phases 2 and 3 to determine an optimal process design which includes hydrogen generation and a pyrolysis plant. The suggested process design is illustrated in Figure 33.

Component 1: Advanced Reactor

- Costs: Capital and fixed costs. Variable costs are annualized based on a 95% capacity and combined with fixed costs.
- Profits: Electricity sold to the grid, electricty sold to the HTSE, electricity sold to steam generator
- Produces: Electricity
- Demands: None

Component 2: Coal Plant

- Costs: Capital, fixed, and variable costs. CO_2 penalities if applicable.

- Profits: Electricity sold to the grid, CO_2 sold to conversion market, electricity sold to the HTSE, electricity sold to steam generator
- Produces: Electricity, CO_2
- Demands: None

Component 3: Electric Market

- Costs: Payments for electricity sold to the grid.
- Profits: None
- Produces: None
- Demands: Electricity
- Opportunity cost: Price of electricity

Component 4: HTSE

- Costs: Capital, fixed, and variable costs.
- Profits: Sales of H_2 and O_2
- Produces: Hydrogen, Oxygen
- Demands: Electricity
- Opportunity cost: Price of hydrogen/oxygen minus production costs

Component 5: Conversion Market

- Costs: Payments for feedstocks purchased.
- Profits: None
- Produces: None
- Demands: CO_2, H_2, O_2

Component 6: Torrefaction

- Costs: Capital, fixed costs, biomass feedstock variable costs.
- Profits: None
- Produces: Torrefied wood
- Demands: Woody biomass, steam/heat

Component 7: Pyrolysis

- Costs: Capital, fixed costs, coal feedstock variable costs.
- Profits: None
- Produces: Pyrolysis oils, gases, char
- Demands: torrefied wood, coal, heat/steam

Component 8: Oil Upgrading

- Costs: Capital, fixed costs, variable costs, electricity and hydrogen variable costs.
- Profits: Sale of hydrocarbon
- Produces: Hydrocarbons, carbon offset

- Demands: Pyrolysis oil and gases, hydrogen, electricity

Component 9: Char Combustion

- Costs: Capital, fixed costs, CO_2 penalties.
- Profits: None
- Produces: Heat, CO_2
- Demands: Char
- Opportunity Cost: Production of heat

Component 10: Steam Gasification

- Costs: Capital, fixed costs, electricity, steam.
- Profits: Methanol sold to market
- Produces: Methanol
- Demands: Char, steam, electricity
- Opportunity Cost: Profits from methanol minus cost of operation

Component 11: Direct Carbon Fuel Cell

- Costs: Capital costs.
- Profits: Electricity sold to market
- Produces: Electricity
- Demands: Char
- Opportunity Cost: Profits from electricity minus cost of operation OR cost of electricity purchased for other components

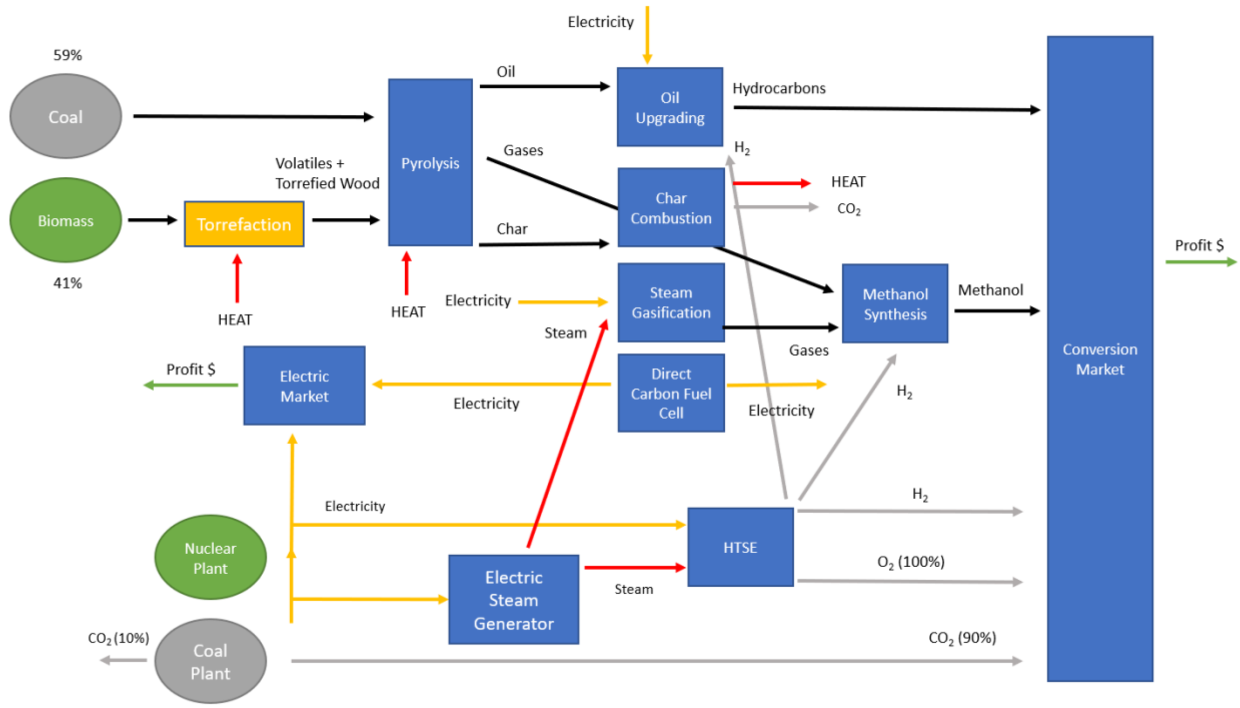


Figure 33. Phase 4 flowchart to combine all conversion and processing options.

10. CONCLUSION

In order to assess a complex hybrid system configuration, the screening curve method has been tested, in conjunction with the cash flow tracing capability of TEAL.

The initial results reinforce that the construction of a hybrid energy system that only includes a coal plant and advanced reactor will not be profitable throughout its lifetime. However, the inclusion of an additional carbon market is promising to increase profitability while offsetting carbon production in the markets in which the captured CO_2 is used. The addition of more markets in the second and third cases may increase NPV further by providing additional revenue streams and providing opportunities to generate heat and electricity that can be utilized by other components in the design.

The initial analysis has also highlight shortcoming of the screening curve methodology in capturing non dispatchable resources and complex secondary markets. A modified screening curve method has been proposed to overcome such challenges. The software to implement this new methodology has been identified possible workflow explored and the most promising one identified.

All the data in terms of cost and transfer functions (i.e., efficiencies) of the possible chemical process have been collected and they are ready for further investigation of the economic viability of the system.

The modified screening curve optimization algorithm will combine the ease of a traditional screening curve method with the secondary market options of a dispatch algorithm. The new algorithm should decrease processing times to optimize a system with many options and potential products. Calculating the opportunity cost of production will normalize the options to be used similarly to a traditional screening curve. These analyses could reinforce the value of coal power as part of a hybrid energy system.

This work represents the initial step to define an approach for the quick screening of large set of possible configurations of integrated energy systems. The preparation of journal paper where the new methodology and its application will be presented is the next step of this work.

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