NATIONAL ENERGY TECHNOLOGY LABORATORY

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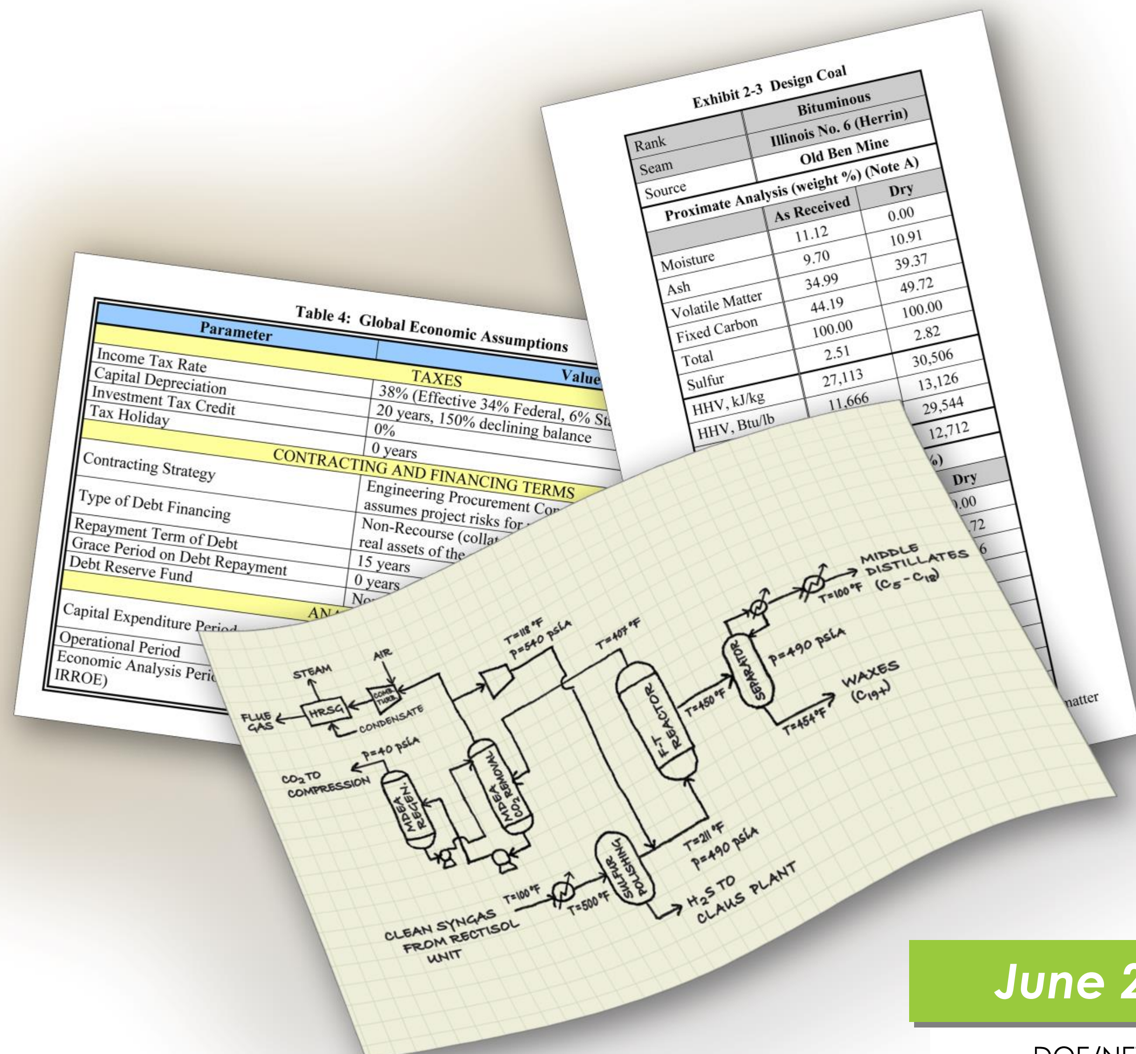
QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Fuel Prices for Selected Feedstocks in NETL Studies



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NATIONAL ENERGY TECHNOLOGY LABORATORY

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Disclaimer

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LIST OF EQUATIONS

Acronyms and Abbreviations

AEO	Annual Energy Outlook
bdt	Bone-dry ton
BT16	2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy
Btu	British thermal unit
CAISO	California Independent System Operator
CPI-U	Consumer Price Index
DOE	U.S. Department of Energy
dt	Dry ton
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FGD	Flue gas desulfurization
FOB	Free on board
FRCC	Florida Reliability Coordinating Council
HHV	Higher heating value
HHV-AF	Higher heating value, as-fired
hr	Hour
ILB	Illinois Basin
ISO	Independent system operator
lb	Pound
LHV	Lower heating value
M	Million
MC	Moisture content
MISO	Midcontinent Independent System Operator
MMBtu	Million British thermal units
MSW	Municipal solid waste
NETL	National Energy Technology Laboratory
NG	Natural gas
PJM	PJM Interconnection
PRB	Powder River Basin
QA	Quality adjusted
QGESS	Quality Guidelines for Energy System Studies
RC	Reliability Coordinator
SERC	Southeastern Electric Reliability Council
SO_2	Sulfur dioxide
SOCO	Southern Company
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
U.S.	United States
VACS	SERC VACAR South region
wt%	Weight percent
yr	Year

1 Overview

The purpose of this document is to develop feedstock price values to be used in the United States (U.S.) Department of Energy's (DOE) National Energy Technology Laboratory (NETL) energy systems studies. An earlier version of this document, "Quality Guidelines for Energy System Studies (QGESS): Coal Specification for Selected Feedstocks, January 2019," focused primarily on the price of coal delivered to the plant gate and a single natural gas price based on the Henry Hub price for a given year [1]. This version of the QGESS incorporates electricity and biomass fuel costs and updates and expands the coal and natural gas costs. Specifically, this document expands the previous document accordingly:

- Coal
    - Calculates the quality-adjusted (QA) delivered coal price and transportation costs in $2023 and $2030 for nine coal regions in the United States
    - Calculates the 30-year levelized QA delivered coal price
- Natural gas
    - Updates natural gas values to a market basis with associated basis differential modifiers to enable analysis for different locations
        - Power sector
        - Industrial sector
    - Calculates the 2060 levelized delivered natural gas price
- Electricity
    - Adds sections on state electricity prices for the following:
        - Delivered
            - Industrial sector
    - Adds sections on region/market-based electricity prices for the following:
        - Delivered
            - Industrial sector
            - Power sector
- Biomass
    - Adds sections on biomass documenting the following:
        - Biomass characteristics
        - Roadside cost
        - Transportation cost

The levelized price values[a] are calculated for coal. For natural gas and electricity, the costs are calculated for the year 2030; however, specific biomass costs are not calculated due to multiple factors, including the following:

[a] The 30-year levelized cost for a plant that begins operations in 2030 and runs through the end of 2060.

- The non-centralized nature of biomass feedstocks
- The fact that biomass is the property of many landowners and is not owned or controlled by major corporations, making it a less predictive commodity
- The lack of reported biomass purchase prices for operating power generation

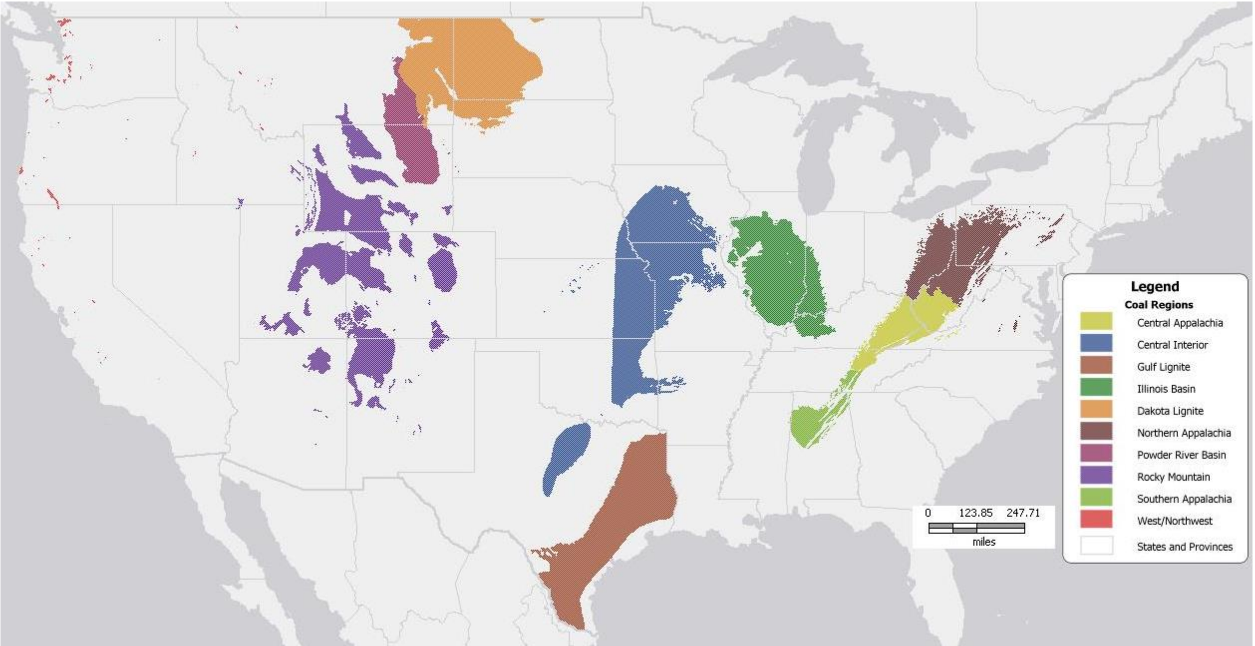
Instead, this document provides a roadmap to calculate biomass costs depending on conversion plant size and location.

2 COAL

2.1 OBJECTIVE

The purpose of this section is to estimate the levelized price of coal delivered to power plants from specific coal regions. In the United States, there are nine major coal regions: Powder River Basin (PRB), Rocky Mountain, Illinois Basin (ILB), Dakota Lignite, West/Northwest, Gulf Lignite, Central Interior, Northern Appalachia, and Central Appalachia. The Central Interior region is located through Iowa, Missouri, Kansas, Oklahoma, and Northern Texas; the Dakota Lignite region is located primarily in North Dakota with parts in Montana and South Dakota; PRB runs through the eastern parts of Montana and Wyoming; and the West/Northwest region is scattered throughout Washington, Oregon, Idaho, Montana, California, and Alaska. The coal regions are shown in Exhibit 2-1 [2].

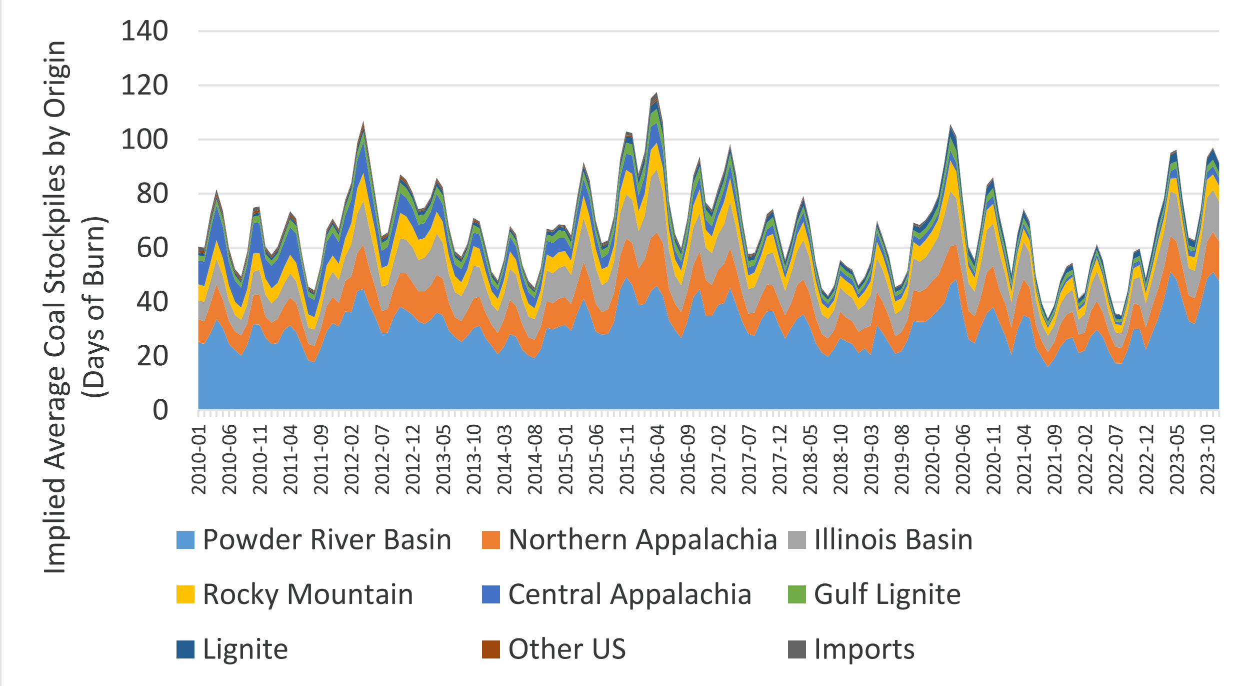
Exhibit 2-1: Coal regions across the United States



Source: Hitachi Energy [2]

The Appalachia basin comprises three sub-basins: North, Central, and Southern. Southern Appalachia coal is metallurgical and coking coal used in industry, such as steel manufacturing, and not for power generation, and is therefore not included in this report [3]. A majority of coal consumed in the United States is produced in the PRB, Rocky Mountain, ILB, and Northern Appalachia regions, as seen in Exhibit 2-2.

Exhibit 2-2. Days of burn in U.S. coal stockpiles, 2010–2023



Source: U.S. Energy Information Administration (EIA) [4]

All coal basin values come from queries in Hitachi Energy's Velocity Suite. Transportation costs were calculated by coal region by finding the weighted average of the miles traveled by the coal to each plant location and the weighted average of the transportation cost of the coal from mine location to plant gate. Each weighted average was calculated by weighting the amount of coal delivered in tons. This allows the cost of transportation to be modified depending on how far the coal must travel from mine to plant and is also transportation-mode agnostic.

2.2 Approach

Coal Data Collection: EIA survey Form EIA-923 collects detailed data (monthly and annually) on a variety of metrics for electric power plants in the United States. Fuel receipts, costs, coal quality, and source are among the metrics collected. This set of data was gathered and filtered using Velocity Suite, a compilation of energy industry and market databases [2]. Specifically, the "Monthly Plant Coal Transactions & Costs" query was used by filtering for coal basin and year of interest. Data used included the following:

- Quantity

- Ash percentage
- Heating value (Btu/lb)
- Sulfur dioxide content (lb SO_2/MMBtu)
- Free on board (FOB) mine price
- Transportation and handling cost
- Delivered price
- Average transportation miles

Using the quantity data, the weighted value of each coal shipment by tons was then calculated and used for a weighted average. Hitachi Energy uses the ABB Transportation model to estimate the transportation cost and the number of transport miles, and to impute missing values such as the mine if the specific mine is not evident from the EIA data [3].[b]

The coal quality used in NETL studies was reported in "QGESS: Coal Specifications for Selected Feedstocks," which used quality specifications for four coal regions of interest to the current guidelines, summarized as follows [1]:

- ILB coal: 11,666 Btu/lb, 4.30 lb SO_2 MMBtu, 9.70 wt% ash
- Dakota Lignite: 6,617 Btu/lb, 1.90 lb SO_2/MMBtu, 9.86 wt% ash
- Gulf Lignite: 6,554 Btu/lb, 2.75 lb SO_2/MMBtu, 15.0 wt% ash
- PRB, all other: 8,564 Btu/lb, 1.70 lb SO_2/MMBtu, 8.19 wt% ash

For coal regions not included in the above list, the PRB coal quality metric was used because it is currently the most prevalent coal used in the United States. To account for differences in coal quality between the observed 2023 Velocity Suite data and the qualities used in "QGESS: Coal Specifications for Selected Feedstocks," this guideline adjusts the delivered price of coal to account for quality differences [1]. The three quality parameters (and their units) used in this guideline for price adjustments are energy content (Btu/lb), sulfur content (lb SO_2/MMBtu), and ash content (wt%).

Coal Btu Adjustment: The per-ton price is QA to keep a consistent per-Btu price. The adjustment is calculated by multiplying the ratio of the coal energy content (with the Btu content of the coal being adjusted in the denominator) by the price of the coal being adjusted, as shown in Equation 1:

$$Quality\ Adjusted\ Price = \left(\frac{Btu\ coal\ QA}{Btu\ coal\ velocity}\right) * FOB\ Price\ velocity$$

Equation 1: Quality-adjusted price

[b] The ABB Transportation model also estimates leg-by-leg shipment routes for each coal transaction where a mode or carrier change occurs. From these estimates and the NETL weighting methodology, it is possible to estimate the cost contribution of each specific leg or mode; however, that is more detail than is necessary for this guideline, which provides for estimation of final delivered coal cost.

Coal Ash Adjustment: The differences in the ash content will affect the cost of ash disposal, which must be taken into consideration. An ash content higher than the QA value will increase the overall price, while an ash content lower than the QA value will decrease the overall price of coal. This guideline uses an adjustment of $0.37/ton of coal (2023$) multiplied by the percentage point difference in the coal ash contents, expressed in wt% as seen in Equation 2:

$$\$Ash\ Adjustment = \$0.37/ton * (Ash\ \%\ QA - Ash\ \%\ Velocity\ )$$

Equation 2: Ash adjustment

A 2017 contract indicated a value of $0.30/ton, and for purposes of this guideline, it was adjusted to 2023$ [5]. The value of ash adjustment is dependent on contractual conditions agreed to by both the coal mine and the power plant; values might differ depending on agreement and can be inserted into Equation 2.

Coal Sulfur Dioxide Adjustment: During combustion, sulfur in coal is converted to SO_2, the emissions of which are regulated by federal and state laws. Because of this, the cost of complying with these laws will vary for coals with different sulfur contents, and the price must be adjusted accordingly. When the sulfur content is higher than the QA value, the price of coal increases, while the price of coal decreases when the sulfur content is less than the QA value. The theoretical cost of SO_2 may represent a combination of many factors, such as the cost of flue gas desulfurization (FGD), percent of the coal market that has installed FGD, emissions limits in the coal market area, and market demand.

The SO_2 adjustment was made for several basins—Appalachia, Northern Appalachia, Rocky Mountain, ILB, and PRB—using the Coal Spot Price Forecast query in Velocity. A national average was also calculated and used for basins not listed. The Velocity query includes coal origin location, spot price, heat, and sulfur content in the results. From this, the coal origin locations were separated, and each unique SO_2 and heat content value was identified. The remaining data points were then averaged. For locations with one sulfur value and multiple heat content values, each unique heat content value was treated independently. The summary data were then sorted from smallest to largest sulfur values then from largest to smallest heat content values. The average heat content and price were calculated for each sulfur content value. After finding the average heat content and price, the adjusted price was calculated using Equation 3[c]:

$$Higher\ SO2\ Adjusted\ Price = \ Low\ SO2\ Price * \left(\frac{BTU\ Low\ SO2}{BTU\ Higher\ SO2}\right)$$

Equation 3: Higher SO_2 adjusted price

Once the adjusted price was calculated, the difference between the lower sulfur coal price and the adjusted price was taken. This is shown in Equation 4:

[c] For instance, the ILB Btu adjustment calculation was as follows: $31.53/ton x (11,800 Btu/lb /11,500 Btu/lb) = $32.36/ton.

$$Price\ Difference = Low\ sulfur\ price - high\ sulfur\ adjusted\ price$$

Equation 4: Price difference

With the price difference, the implied difference could then be calculated using Equation 5[d]:

$$Implied\ Difference = Price\ Difference * \left(\frac{1}{(High\ SO2\ value - Low\ SO2\ value)}\right)$$

Equation 5: Implied difference

In basins that had three or more sulfur and heat content pairings, the average of all the implied differences was taken to determine the overall implied difference for the basin. When the sulfur contents are the same, the denominator in Equation 5 is 1. An example of these calculations is shown in Exhibit 2-3.

Exhibit 2-3. Sulfur price adjustment

Coal Price Point Name	SO_2 Content (lb/MMBtu)	Heat Content (Btu/lb)	Average Price	Adjusted Price	Price Difference	Implied Difference vs. Mid
Mid sulfur	5	11,800	$66.82	$56.37		
High sulfur	5.2	11,500	$63.30	$54.23	$2.15	$10.73
Low Btu high sulfur	6	11,000	$56.63	$49.53	$6.84	$6.84

The average implied difference for ILB was $8.78/ton coal per 1 lb SO_2/MMBtu. Exhibit 2-4 shows the average implied difference across all basins.

Exhibit 2-4. Coal region average sulfur implied difference

Basin	Average Sulfur Implied Difference (lb SO_2/MMBTU)
Northern Appalachia	$2.24
Central Appalachia	$21.51
Rocky Mountain	$0.33
Illinois Basin	$8.78
Powder River Basin	$3.15
Total	$7.86

Once the ash and sulfur adjustments were determined, Equation 6 was used to calculate the final adjusted price of coal in each basin:

[d] For instance, the ILB implied SO_2 cost calculation was as follows: ($66.82/ton-$63.30/ton) x (1/0.2lb SO_2/MMBtu) = $10.73 /lb SO_2/MMBtu.

$$P_{adj} = P_{orig} \times \left(\frac{Btu_{adj}}{Btu_{orig}}\right) - \$Ash\ Adjustment \times [A_{adj} - A_{orig}] - \$Sulfur\ Adjustment \times [S_{adj} - S_{orig}]$$

Equation 6: Adjusted price of coal

where:

- P = coal price ($/ton)
- adj = coal to which the price is being adjusted (from Velocity)
- $orig$ = original coal (from QA)
- Btu = higher heating value (HHV) of the coal (Btu/lb as received)
- A = ash content of the coal (wt% as received)
- S = sulfur content of the coal (lb SO_2/MMBtu)

The transportation costs in 2023$ were calculated by multiplying the weighted average by ton of dollars per mile by the weighted average by ton of miles traveled. This is shown in Equation 7:

$$Transportation\ cost = miles\ traveled * (\$/mile)$$

Equation 7: Transportation cost

To find the 2030 values for coal price and transportation cost, the projected growth rate was needed. The FOB coal average annual price growth rate and the transportation average annual growth rate were found using the EIA Annual Energy Outlook (AEO) 2023 Coal Minemouth Prices reference case [6]. The transportation growth rate was 0.074 percent and was used for every region. The average annual growth rate from 2023 to 2050 was assumed to be the same until 2060. The coal average annual growth rate used for each region is shown in Exhibit 2-5.

Exhibit 2-5. Annual coal price growth rate, 2023–2030

Region	Annual Growth Rate (2023–2030)
Powder River Basin	-0.875%
Rocky Mountain	-0.108%
Illinois Basin	0.373%
Northern Appalachia	5.281%
Dakota Lignite	-0.829%
West/Northwest	-0.724%
Gulf Lignite	-0.25%
Central Interior	0.864%
Central Appalachia	2.287%

Source: EIA [6]

The coal average annual growth rate was used in Equation 8 to find the 2030$/ton.

$$\$2030\ price\left(\frac{\$}{ton}\right) = \$2023\left(\frac{\$}{ton}\right) * (coal\ growth\ rate + 1)^{(2030-2023)}$$

Equation 8: 2030$/ton

The r prime values for FOB coal price and transportation were both calculated using Equation 9. The calculation also requires the discount rate, which is currently 5.5 percent and has been since July 2023 [7]. This is a 20-year high and a conservative value for the long-term economics of a coal project. The life span is 30 years.

$$\mathrm{r}' = \frac{(\text{discount rate} - \text{growth rate})}{(1 + \text{growth rate})}$$

Equation 9: r prime values

Using these r prime values, the levelized price ($/ton of coal) was calculated using Equation 10:

$$Levelized\ price\left(\frac{\$}{ton}\right) = 2030\$ * \frac{discount\ rate}{1-((1+discount\ rate)^{-yr})} \Bigg/ \frac{r'}{1-((1+r')^{-yr})}$$

Equation 10: Levelized price

To adjust the price value to $/MMBtu, Equation 11 was used:

$$\$/MMBtu = Price\ (\$/ton) \Bigg/ \frac{QA\ Btu * 2{,}000}{1{,}000{,}000}$$

Equation 11: Price value in MMBtu

2.3 Results

2.3.1 Powder River Basin Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from PRB had the characteristics shown in Exhibit 2-6. All dollar figures for each of the coal basins are reported in 2023$, and all averages are weighted by tonnage.

Exhibit 2-6. PRB coal characteristics

2023 Weighted Averages		
Metric	**Value**	**Standard Deviation**
FOB Coal Price	$17.02/ton	7.91
Transportation Cost	$0.02/ton/mile	0.01
Number of Miles Traveled	1,087 miles	401.89
Delivered Coal Price	$37.47/ton	11.53
Higher Heating Value	8,701.71 Btu/lb	269
Ash Content	5.11%	0.81

2023 Weighted Averages		
Metric	Value	Standard Deviation
Sulfur Content	0.64 lb SO_2/MMBtu	0.19
Prices QA to 8,564.00 Btu/lb, 1.70 lb SO_2/MMBtu, 8.19% Ash		
Metric	2023$/ton	2023$/MMBtu
QA FOB Coal Price	$12.31	$0.72
QA Delivered Coal Price	$33.42	$1.95
2030 Forecasted QA Delivered Coal Price	$33.24	$1.94
30-Year Levelized QA Delivered Coal Price	**$32.22**	**$1.89**

2.3.2 Rocky Mountain Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from the Rocky Mountain region had the characteristics shown in Exhibit 2-7.

Exhibit 2-7. Rocky Mountain coal characteristics

2023 Weighted Averages		
Metric	Value	Standard Deviation
FOB Coal Price	$55.19/ton	40.64
Transportation Cost	$0.11/ton/mile	0.10
Number of Miles Traveled	102.92 miles	468.06
Delivered Coal Price	$61.83/ton	48.26
Higher Heating Value	9,836.68 Btu/lb	1,304.57
Ash Content	13.31%	6.84
Sulfur Content	1.34 lb SO_2/MMBtu	0.57
Prices QA to 8,564.00 Btu/lb, 1.70 lb SO_2/MMBtu, 8.19% Ash		
Metric	2023$/ton	2023$/MMBtu
QA FOB Coal Price	$49.83	$2.91
QA Delivered Coal Price	$61.41	$3.59
2030 Forecasted QA Delivered Coal Price	$61.34	$3.58
30-Year Levelized QA Delivered Coal Price	**$60.82**	**$3.55**

2.3.3 Illinois Basin Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from ILB had the characteristics shown in Exhibit 2-8.

Exhibit 2-8. ILB coal characteristics

2023 Weighted Averages		
Metric	**Value**	**Standard Deviation**
FOB Coal Price	$70.15/ton	38.43
Transportation Cost	$0.05/ton/mile	0.05
Number of Miles Traveled	338.72 miles	341.91
Delivered Coal Price	$80.39/ton	39.55
Higher Heating Value	11,168.83 Btu/lb	632.9
Ash Content	10.82%	2.05
Sulfur Content	5.35 lb SO_2/MMBtu	1.02
Prices QA to 11,666 Btu/lb, 4.30 lb SO_2/MMBtu, 9.70% Ash		
Metric	**2023$/ton**	**2023$/MMBtu**
QA FOB Coal Price	$82.94	$3.55
QA Delivered Coal Price	$101.25	$4.34
2030 Forecasted QA Delivered Coal Price	$103.92	$4.45
30-Year Levelized QA Delivered Coal Price	**$107.90**	**$4.62**

2.3.4 Northern Appalachia Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from the Northern Appalachia region had the characteristics shown in Exhibit 2-9.

Exhibit 2-9. Northern Appalachia coal characteristics

2023 Weighted Averages		
Metric	**Value**	**Standard Deviation**
FOB Coal Price	$78.72/ton	42.57
Transportation Cost	$0.09/ton/mile	0.05
Number of Miles Traveled	261.76 miles	298.35
Delivered Coal Price	$89.20/ton	41.52
Higher Heating Value	12,289.16 Btu/lb	1,747.88
Ash Content	11.32%	8.61
Sulfur Content	4.77 lb SO_2/MMBtu	1.66

Prices QA to 8,564.00 Btu/lb, 1.70 lb SO_2/MMBtu, 8.19% Ash		
Metric	**2023$/ton**	**2023$/MMBtu**
QA FOB Coal Price	$62.89	$3.67
QA Delivered Coal Price	$85.81	$5.01
2030 Forecasted QA Delivered Coal Price	$113.68	$6.64
30-Year Levelized QA Delivered Coal Price	**$203.96**	**$11.91**

2.3.5 Central Appalachia Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from the Central Appalachia region had the characteristics shown in Exhibit 2-10.

Exhibit 2-10. Central Appalachia coal characteristics

2023 Weighted Averages		
Metric	**Value**	**Standard Deviation**
FOB Coal Price	110.81	46.48
Transportation Cost	15.87	9.38
Number of Miles Traveled	354.47	246.04
Delivered Coal Price	126.68	46.30
Higher Heating Value	12,104.47	663.97
Ash Content	12.13	3.30
Sulfur Content	1.76	0.76
Prices QA to 8,564.00 Btu/lb, 1.70 lb SO_2/MMBtu, 8.19% Ash		
Metric	**2023$/ton**	**2023$/MMBtu**
QA FOB Coal Price	$80.58	$4.70
QA Delivered Coal Price	$101.28	$5.91
2030 Forecasted QA Delivered Coal Price	$115.64	$6.75
30-Year Levelized QA Delivered Coal Price	**$139.32**	**$8.13**

2.3.6 Dakota Lignite Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from the Dakota Lignite region had the characteristics shown in Exhibit 2-11.

Exhibit 2-11. Lignite coal characteristics

2023 Weighted Averages		
Metric	**Value**	**Standard Deviation**
FOB Coal Price	$23.93/ton	17.54
Transportation Cost	$0.06/ton/mile	0.07
Number of Miles Traveled	5.42 miles	63.76
Delivered Coal Price	$24.98/ton	20.9
Higher Heating Value	6,591.56 Btu/lb	2,578.76
Ash Content	9.65%	1.35
Sulfur Content	2.17 lb SO_2/MMBtu	0.539
Prices QA to 6,617.00 Btu/lb, 1.90 lb SO_2/MMBtu, 9.86% Ash		
Metric	**2023$/ton**	**2023$/MMBtu**
QA FOB Coal Price	$26.04	$1.97
QA Delivered Coal Price	$26.34	$1.99
2030 Forecasted QA Delivered Coal Price	$24.87	$1.88
30-Year Levelized QA Delivered Coal Price	**$22.66**	**$1.71**

2.3.7 West/Northwest Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from the West/Northwest region had the characteristics shown in Exhibit 2-12.

Exhibit 2-12. West/Northwest coal characteristics

2023 Weighted Averages		
Metric	**Value**	**Standard Deviation**
FOB Coal Price	$67.30 ton	25.2
Transportation Cost	$0.08/ton/mile	0.02
Number of Miles Traveled	4 miles	0
Delivered Coal Price	$67.61/ton	25.20
Higher Heating Value	7,375.75 Btu/lb	872.08
Ash Content	6.74 %	1.25
Sulfur Content	0.34 lb SO_2/MMBtu	0.06

Prices QA to 8,564.00 Btu/lb, 1.70 lb SO_2/MMBtu, 8.19% Ash		
Metric	**2023$/ton**	**2023$/MMBtu**
QA FOB Coal Price	$66.90	$3.91
QA Delivered Coal Price	$67.21	$3.92
2030 Forecasted QA Delivered Coal Price	$63.90	$3.73
30-Year Levelized QA Delivered Coal Price	**$58.84**	**3.44**

2.3.8 Gulf Lignite Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from the Gulf Lignite region had the characteristics shown in Exhibit 2-13.

Exhibit 2-13. Gulf Lignite coal characteristics

2023 Weighted Averages		
Metric	**Value**	**Standard Deviation**
FOB Coal Price	$35.38/ton	8.40
Transportation Cost	$0.18/ton/mile	0.07
Number of Miles Traveled	7.64 miles	4.38
Delivered Coal Price	$37.09/ton	8.84
Higher Heating Value	6,337.45 Btu/lb	810.9
Ash Content	16.76%	5.48
Sulfur Content	3.25 lb SO_2/MMBtu	2.84
Prices QA to 8,564.00 Btu/lb, 1.70 lb SO_2/MMBtu, 8.19% Ash		
Metric	**2023$/ton**	**2023$/MMBtu**
QA FOB Coal Price	$41.18	$3.14
QA Delivered Coal Price	$42.52	$3.24
2030 Forecasted QA Delivered Coal Price	$41.84	$3.19
30-Year Levelized QA Delivered Coal Price	**$40.69**	**$3.10**

2.3.9 Central Interior Coal Region

A Velocity Suite query shows that during 2023, coal delivered to coal power plants in the United States from Central Interior region had the characteristics shown in Exhibit 2-14.

Exhibit 2-14. Central interior coal characteristics

2023 Weighted Averages		
Metric	**Value**	**Standard Deviation**
FOB Coal Price	\$14.97/ton	53.19
Transportation Cost	\$0.02/ton/mile	0
Number of Miles Traveled	850.23 miles	314.57
Delivered Coal Price	\$30.07/ton	60.90
Higher Heating Value	8,691.43 Btu/lb	1,240.37
Ash Content	5.42%	2.55
Sulfur Content	0.7 lb SO_2/MMBtu	0.27
Prices QA to 8,564.00 Btu/lb, 1.70 lb SO_2/MMBtu, 8.19% Ash		
Metric	**2023\$/ton**	**2023\$/MMBtu**
QA FOB Coal Price	\$5.85	\$0.34
QA Delivered Coal Price	\$20.85	\$1.22
2030 Forecasted QA Delivered Coal Price	\$21.66	\$1.26
30-Year Levelized QA Delivered Coal Price	**\$21.61**	**\$1.26**

2.4 Summary

Exhibit 2-15 shows a summary of each region in \$/ton for the QA delivered coal price in 2023 and the levelized price in 2060. The least expensive coal in 2023 in terms of \$/ton comes from the Central Interior region followed by the Dakota Lignite and PBR regions. The lowest levelized price of coal in terms of \$/ton comes from Central Interior region followed by Dakota Lignite and PBR regions. The most expensive regions are Northern Appalachia, Central Appalachia, and ILB.

Exhibit 2-15. Coal regions 2023\$/ton summary

Coal Region	QA FOB Delivered Price (2023\$/ton)	2060 Levelized Delivered Price (2023\$/ton)
Powder River Basin	\$33.42	\$32.33
Rocky Mountain	\$61.41	\$60.82
Illinois Basin	\$101.25	\$107.90
Northern Appalachia	\$85.81	\$203.96
Dakota Lignite	\$26.34	\$22.66
West/Northwest	\$67.21	\$58.84
Gulf Lignite	\$42.52	\$40.69

Coal Region	QA FOB Delivered Price (2023$/ton)	2060 Levelized Delivered Price (2023$/ton)
Central Interior	$20.85	$21.61
Central Appalachia	$101.28	$139.32

Exhibit 2-16 shows a summary of each region in $/MMBtu for the QA delivered coal price in 2023 and the levelized price in 2060. The least expensive coal in 2023 in terms of $/MMBtu comes from the Central Interior region followed by the Dakota Lignite and PBR regions. The least expensive levelized price of coal in terms of $/MMBtu comes from the Central Interior region followed by Dakota Lignite and PBR regions. The most expensive regions are Northern Appalachia, Central Appalachia, and ILB.

Exhibit 2-16. Coal regions 2023$/MMBtu

Coal Basin	QA FOB Delivered Price (2023$/MMBtu)	2060 Levelized Delivered Price for System (2023$/MMBtu)
Powder River Basin	$1.95	$1.89
Rocky Mountain	$3.59	$3.55
Illinois Basin	$4.34	$4.62
Northern Appalachia	$5.01	$11.91
Dakota Lignite	$1.99	$1.71
West/Northwest	$3.92	$3.44
Gulf Lignite	$3.24	$3.10
Central Interior	$1.22	$1.26
Central Appalachia	$5.91	$8.13

3 Natural Gas

3.1 Natural Gas Hub Breakdown

3.1.1 Objective

This section aims to create a guideline to estimate the spot price a power plant or other consumer may pay for natural gas. This guideline outlines how to achieve this for any natural gas hub across the United States. In order to account for fluctuations in the oil and gas markets, three different possibilities have been analyzed. The first is a reference case that follows a trend of current market conditions. The other two are high and low oil and gas supply conditions.

3.1.2 Delivered (Purchased) Natural Gas Price

The delivered price of natural gas reflects the price paid by an entity to procure natural gas and is comprised of transportation fees, pipeline tariffs, fuel costs, and other logistical expenses. While an entity may enter into a supply agreement at a different rate or directly connect to the major pipelines, the default price utilized should be the local natural gas hub prices following the subsequent methodology depending on the level of project siting uncertainty, unless the use of an alternative can be clearly justified. The difference between the local hub price and the Henry Hub price (Equation 13) accounts for the localization difference in the delivered prices while using the same AEO delivered price for all hubs across the US. Adding AEO's delivered natural gas price to the local hub and Henry hub's spot price differential results in the local hub's delivered price.

3.1.3 Approach

All data collected for this section are from 2023, as these are the most recent data available for an entire year. The natural gas hub prices ($/MMBtu) can be collected at any trusted source of market information, as all should report the same values. For this analysis, values were gathered from S&P Global [8]. The next two pieces of gathered data came from EIA's AEO 2023 natural gas delivered prices at both the electric power and industrial levels [9]. The first-year data are adjusted with a growth rate also calculated from EIA's AEO, specifically the Wholesale Price Index for Fuel and Power (Exhibit 3-1) using a standard growth rate equation (Equation 12).

$$Growth\ Rate\ = \frac{(Price\ Index_{2030} - Price\ Index_{2023})}{Price\ Index_{2023}}$$

Equation 12: Growth rate

Exhibit 3-1. Wholesale Price Index: Fuel and Power, derived from EIA's 2023 AEO

Index Year	2023	2030
Wholesale Price Index: Fuel and Power	2.79	2.59

It is important to note the relationship between Henry Hub and other hubs across the United States; Henry Hub is the basis for forecasting the prices at any other hub. Henry Hub's pricing [10] is based on the actual supply and demand of natural gas as a stand-alone resource, which differs from others because other natural gas markets establish a benchmark price based on secondary commodities, like crude oil. Also, the Henry Hub is connected to substantial storage facilities and is at the intersection of many intrastate and interstate pipelines that deliver natural gas throughout the United States, impacting the market in every region. In summary, Henry Hub is the natural gas market's benchmark due to its strategic location and logistical infrastructure.

The Henry Hub price adjustment can be made through a differential. This differential accounts for regional market conditions, transportation costs, and available transmission capacity. This differential price adjustment (Equation 13) is recommended when forecasting a local market's spot price.

$$Differential = Local\ Hub\ Price *_{original} - Henry\ Hub\ Price *_{benchmark}$$

Equation 13: Differential price adjustment

*Local Hub Price and Henry Hub Price must be collected in the same data set for consistency

Once the differentials are calculated, the natural gas delivered prices from AEO must be acquired. These natural gas prices should be at both an electric power and industrial level and for the specific year for which the price is being forecasted. There will be three of each of the delivered electric power and industrial prices per year: one reference case, one high oil and gas supply case, and one low oil and gas supply case. The last step is to take the local hub differential, calculated previously, and add that to AEO's delivered price for the case or cases of interest. This calculation, in turn, will give a forecasted annual price of the local hub in the year of choice (Equation 14):

$$Local\ Hub\ Price_{Forecast} = Differential + AEO\ Natural\ Gas\ Delivered\ Price_{Industrial}$$

Equation 14: Local hub price

3.1.4 Results

An S&P Global dataset including annual prices for 28 local hubs across the United States based on the Henry Hub prices seen in Exhibit 3-2, was tested with this method. This demonstration aimed to employ the method described to forecast local hub prices for the year 2030. Exhibit 3-3 and

Exhibit 3-4 show results with a price for each of the three possible cases, and Exhibit 3-5 to Exhibit 3-8 show maps of U.S. natural gas (NG) hubs.

Exhibit 3-2. 2023 natural gas price at Henry Hub derived from S&P Global

Trading Hub	Unadjusted Local Hub Price 2023$/MMBtu	Adjusted Local Hub Price 2023$/MMBtu
Henry Hub	$2.536	$2.359

Exhibit 3-3. Electric power natural gas prices at different U.S. hubs based on AEO 2023 projections of the 2030 Henry Hub price

	AEO 2030 NG Electric Power			$3.11	$2.90	$4.82
Trading Hub	Unadjusted 2023 Local Hub Price (S&P) 2023$/MMBtu	Adjusted 2023 Local Hub Price (S&P) 2023$/MMBtu	Henry Hub Basis Differential 2023$/MMBtu	Electric Power: Reference Case 2023$/MMBtu	Electric Power: High Oil and Gas 2023$/MMBtu	Electric Power: Low Oil and Gas 2023$/MMBtu
Northeast						
Algon Gates	$2.887	$2.685	$0.326	$3.44	$3.22	$5.15
Iroquois Z 2	$3.422	$3.182	$0.823	$3.93	$3.72	$5.65
Niagara	$1.877	$1.746	$(0.613)	$2.50	$2.28	$4.21
Mid-Atlantic						
Transco Z 5	$2.801	$2.604	$0.246	$3.36	$3.14	$5.07
Transco Z 6 non-NY	$1.904	$1.771	$(0.588)	$2.52	$2.31	$4.23
Dominion N	$1.681	$1.563	$(0.796)	$2.32	$2.10	$4.03
Dominion S	$1.676	$1.559	$(0.800)	$2.31	$2.10	$4.02
TCO pool	$1.813	$1.686	$(0.672)	$2.44	$2.23	$4.15
TETCO M2	$1.669	$1.552	$(0.807)	$2.30	$2.09	$4.02
TETCO M3	$1.937	$1.801	$(0.558)	$2.55	$2.34	$4.26
Southeast						
FGT Z 3	$2.699	$2.510	$0.151	$3.26	$3.05	$4.97
TETCO M1 30 in	$2.279	$2.119	$(0.239)	$2.87	$2.66	$4.58
Midwest						
ANR-SW	$2.247	$2.089	$(0.269)	$2.84	$2.63	$4.55
Chicago	$2.322	$2.160	$(0.199)	$2.91	$2.70	$4.62

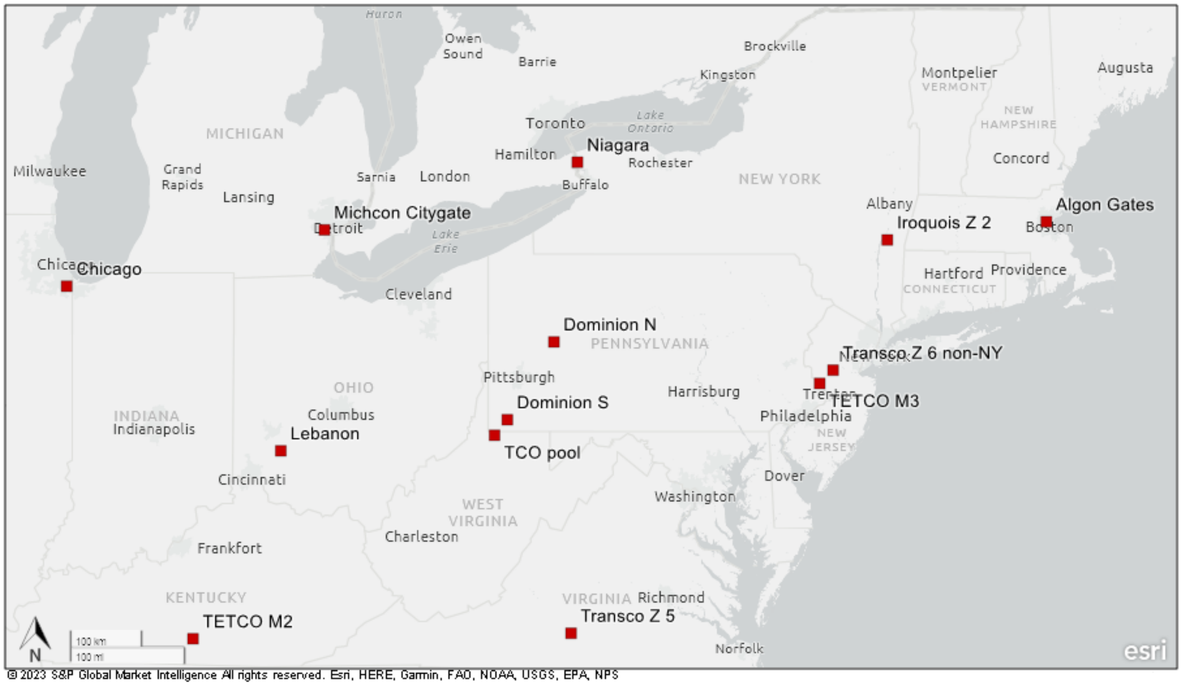
	AEO 2030 NG Electric Power			$3.11	$2.90	$4.82
Trading Hub	Unadjusted 2023 Local Hub Price (S&P) 2023$/MMBtu	Adjusted 2023 Local Hub Price (S&P) 2023$/MMBtu	Henry Hub Basis Differential 2023$/MMBtu	Electric Power: Reference Case 2023$/MMBtu	Electric Power: High Oil and Gas 2023$/MMBtu	Electric Power: Low Oil and Gas 2023$/MMBtu
Lebanon	$2.231	$2.074	$(0.284)	$2.83	$2.61	$4.54
Michcon Citygate	$2.321	$2.158	$(0.200)	$2.91	$2.70	$4.62
NNG Demarc	$2.315	$2.153	$(0.206)	$2.91	$2.69	$4.62
NNG Ventura	$2.321	$2.159	$(0.200)	$2.91	$2.70	$4.62
Texas						
Carthage	$2.187	$2.033	$(0.325)	$2.79	$2.57	$4.50
Houston Ship Channel	$2.261	$2.103	$(0.256)	$2.86	$2.64	$4.57
TETCO S TX	$2.316	$2.154	$(0.205)	$2.91	$2.69	$4.62
Waha Hub	$1.831	$1.703	$(0.656)	$2.46	$2.24	$4.17
West						
AECO Storage Hub	$1.963	$1.825	$(0.533)	$2.58	$2.36	$4.29
El Paso San Juan	$3.457	$3.215	$0.856	$3.97	$3.75	$5.68
NW Opal WY	$4.757	$4.423	$2.065	$5.18	$4.96	$6.89
NW Sumas	$4.266	$3.967	$1.608	$4.72	$4.51	$6.43
PG&E Gate	$6.239	$5.802	$3.443	$6.55	$6.34	$8.27
SoCal Citygate	$6.778	$6.302	$3.944	$7.06	$6.84	$8.77

Exhibit 3-4. Industrial natural gas prices at different U.S. hubs based on AEO 2023 projections of the 2030 Henry Hub price

	AEO 2030 NG Industrial Prices			$4.08	$3.77	$6.20
Trading Hub	Unadjusted 2023 Local Hub Price (S&P) 2023$/MMBtu	Adjusted 2023 Local Hub Price (S&P) 2023$/MMBtu	Henry Hub Basis Differential 2023$/MMBtu	Industrial: Reference Case 2023$/MMBtu	Industrial: High Oil and Gas 2023$/MMBtu	Industrial: Low Oil and Gas 2023$/MMBtu
Northeast						
Algon Gates	$2.887	$2.685	$0.326	$4.40	$4.09	$6.53
Iroquois Z 2	$3.422	$3.182	$0.823	$4.90	$4.59	$7.03
Niagara	$1.877	$1.746	$(0.613)	$3.46	$3.16	$5.59
Mid-Atlantic						
Transco Z 5	$2.801	$2.604	$0.246	$4.32	$4.01	$6.45
Transco Z 6 non-NY	$1.904	$1.771	$(0.588)	$3.49	$3.18	$5.62
Dominion N	$1.681	$1.563	$(0.796)	$3.28	$2.97	$5.41
Dominion S	$1.676	$1.559	$(0.800)	$3.28	$2.97	$5.40
TCO pool	$1.813	$1.686	$(0.672)	$3.40	$3.10	$5.53
TETCO M2	$1.669	$1.552	$(0.807)	$3.27	$2.96	$5.40
TETCO M3	$1.937	$1.801	$(0.558)	$3.52	$3.21	$5.65
Southeast						
FGT Z 3	$2.699	$2.510	$0.151	$4.23	$3.92	$6.36
TETCO M1 30 in	$2.279	$2.119	$(0.239)	$3.84	$3.53	$5.96
Midwest						
ANR-SW	$2.247	$2.089	$(0.269)	$3.81	$3.50	$5.93
Chicago	$2.322	$2.160	$(0.199)	$3.88	$3.57	$6.01
Lebanon	$2.231	$2.074	$(0.284)	$3.79	$3.48	$5.92

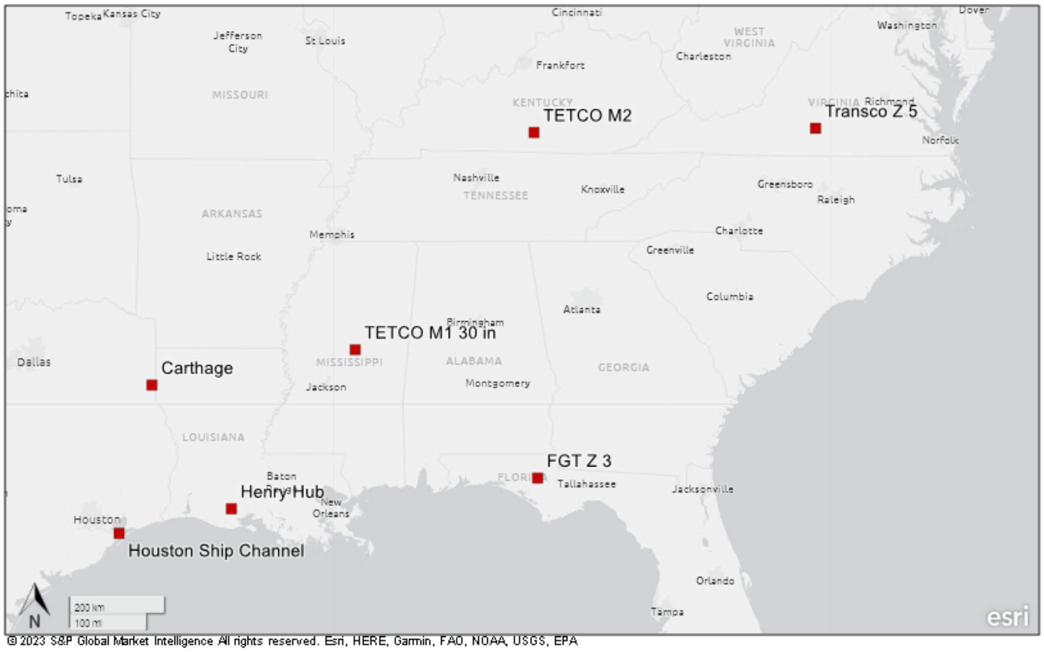
	AEO 2030 NG Industrial Prices			$4.08	$3.77	$6.20
Trading Hub	Unadjusted 2023 Local Hub Price (S&P) 2023$/MMBtu	Adjusted 2023 Local Hub Price (S&P) 2023$/MMBtu	Henry Hub Basis Differential 2023$/MMBtu	Industrial: Reference Case 2023$/MMBtu	Industrial: High Oil and Gas 2023$/MMBtu	Industrial: Low Oil and Gas 2023$/MMBtu
Michcon Citygate	$2.321	$2.158	$(0.200)	$3.88	$3.57	$6.00
NNG Demarc	$2.315	$2.153	$(0.206)	$3.87	$3.56	$6.00
NNG Ventura	$2.321	$2.159	$(0.200)	$3.88	$3.57	$6.00
Texas						
Carthage	$2.187	$2.033	$(0.325)	$3.75	$3.44	$5.88
Houston Ship Channel	$2.261	$2.103	$(0.256)	$3.82	$3.51	$5.95
TETCO S TX	$2.316	$2.154	$(0.205)	$3.87	$3.56	$6.00
Waha Hub	$1.831	$1.703	$(0.656)	$3.42	$3.11	$5.55
West						
AECO Storage Hub	$1.963	$1.825	$(0.533)	$3.54	$3.24	$5.67
El Paso San Juan	$3.457	$3.215	$0.856	$4.93	$4.62	$7.06
NW Opal WY	$4.757	$4.423	$2.065	$6.14	$5.83	$8.27
NW Sumas	$4.266	$3.967	$1.608	$5.68	$5.38	$7.81
PG&E Gate	$6.239	$5.802	$3.443	$7.52	$7.21	$9.65
SoCal Citygate	$6.778	$6.302	$3.944	$8.02	$7.71	$10.15

Exhibit 3-5: Northeast and mid-Atlantic gas hubs



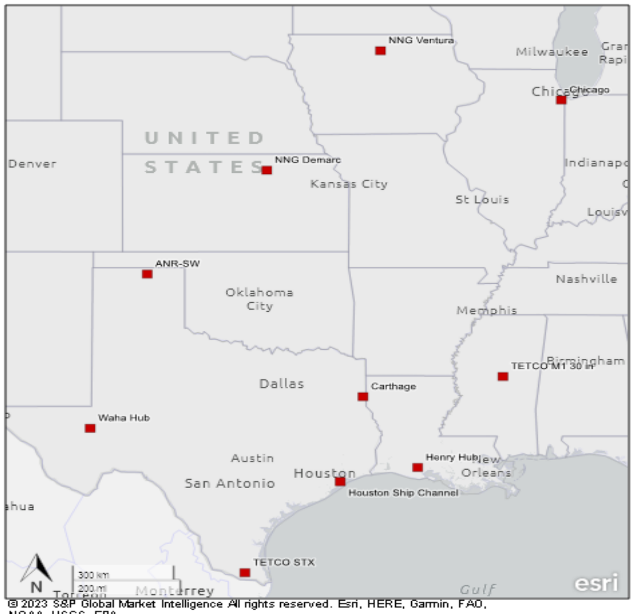
Source: S&P Global [8]

Exhibit 3-6: Southeast gas hubs



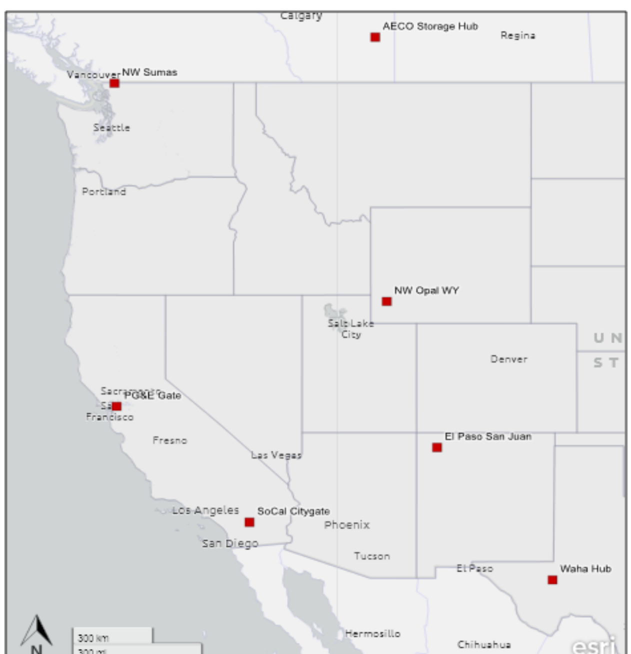
Source: S&P Global [8]

Exhibit 3-7: Midwest and Texas gas hubs



Source: S&P Global [8]

Exhibit 3-8: Western gas hubs



Source: S&P Global [8]

3.2 Regional Levelized Forecast Summary

3.2.1 Objective

This section aims to create a guideline to estimate the levelized natural gas prices for each region across the United States derived from the natural gas hub spot prices that a power plant or other consumer may pay for natural gas. This will provide the most recent annual delivered prices and levelized prices for 2060. This guideline outlines how to achieve this for all natural gas regions across the United States.

3.2.2 Approach

All data collected for this section are from 2023, as these are the most recent data available for an entire calendar year. The natural gas hub prices ($/MMBtu) can be collected at any trusted source of market information, as all should report the same values. For this analysis, values were gathered from S&P Global [8]. The next two pieces of data gathered came from EIA's AEO 2023 natural gas delivered prices at both the electric power and industrial levels [9] and the Wholesale Price Index for Fuel and Power. The data from the "2023 Delivered Price" columns in Exhibit 3-11 and Exhibit 3-12 are derived using the same methodology used in Section 3.1 (Equation 13: ***Differential price adjustment***and Equation 14). The only noteworthy differences are that this was performed for 2023 instead of 2030 and used only the reference case AEO price. After the 2023 first-year hub price data from S&P Global were adjusted to 2023 delivered prices using the method described in Section 3.1, an arithmetic average of the hub results was taken for each region, resulting in the second columns for Exhibit 3-11 and Exhibit 3-12. The hubs in each region are broken down in the same way as in Exhibit 3-3 and Exhibit 3-4.

The results of the 2023 delivered prices for each hub now need to be levelized to 2060. The price levelization requires EIA's AEO natural gas electric power and industrial delivered prices and the Wholesale Price Index for Fuel and Power from 2022–2060. While the 2022–2050 data were pulled directly from EIA's AEO, 2051–2060 data had to be estimated. EIA's AEO only forecasts the natural gas delivered prices and Wholesale Price Index for Fuel and Power out to 2050. To calculate the prices and indexes for 2051–2060, an annual growth rate was determined for the Fuel and Power Index, Natural Gas Electric Power Price, and Natural Gas Industrial Price for each year from 2022 to 2050 (Equation 12). An average growth rate, seen in Exhibit 3-9, was then taken from those sets of annual growth rates and applied to the years 2051–2060 as a constant growth rate giving the estimated indexes and prices shown in Exhibit 3-10.

Exhibit 3-9. Average growth rate percentage from 2022–2050 from EIA's AEO natural gas electric power and industrial delivered price and Wholesale Price Index: Fuel and Power

AEO Category	Fuel and Power Index	Natural Gas: Electric Power	Natural Gas: Industrial
2022–2050 Average Growth Rate	1.61%	-2.08%	-1.51%

Exhibit 3-10. 2051–2060 estimated Wholesale Price Index: Fuel and Power derived from EIA's 2023 AEO and the calculated average growth rate from 2022–2050

Data Year	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
Wholesale Price Index: Fuel and Power	4.52	4.59	4.66	4.74	4.81	4.89	4.97	5.05	5.13	5.21
Natural Gas Delivered Price: Electric Power	$3.70	$3.62	$3.55	$3.47	$3.40	$3.33	$3.26	$3.19	$3.13	$3.06
Natural Gas Delivered Price: Industrial	$4.71	$4.64	$4.57	$4.50	$4.44	$4.37	$4.30	$4.24	$4.18	$4.11

Once the 2051–2060 natural gas delivered prices and fuel and power indexes were determined, the 2060 levelized delivered prices for each natural gas hub could be calculated using the same methodology for levelization used in Section 2 (Equation 8, Equation 9, and Equation 10). Once those were calculated, an arithmetic average of the levelized hub results was taken for each region resulting in the "2060 Levelized Delivered Price" given in Exhibit 3-11 and Exhibit 3-12.

3.2.3 Results

An S&P Global dataset, including annual prices for 28 local hubs across the United States, was tested with this method. This is the same dataset that was used in Section 3.1. This demonstration aimed to utilize the method described above to forecast 2060 levelized prices. Exhibit 3-11 and Exhibit 3-12 show results with a price for each natural gas region, and Exhibit 3-5 to Exhibit 3-8 from Section 3.1 show maps of the U.S. natural gas hubs that comprise the regions listed.

Exhibit 3-11. Electric power natural gas region 2023$/MMBtu summary

NG Region	2023 Delivered Price (2023$/MMBtu)	2060 Levelized Delivered Price (2023$/MMBtu)
Northeast	$6.02	$3.86
Mid-Atlantic	$5.22	$3.04
Southeast	$5.78	$3.61
Midwest	$5.59	$3.41
Texas	$5.44	$3.27

NG Region	2023 Delivered Price (2023$/MMBtu)	2060 Levelized Delivered Price (2023$/MMBtu)
West	$7.87	$5.73

Exhibit 3-12. Industrial natural gas region 2023$/MMBtu summary

NG Region	2023 Delivered Price (2023$/MMBtu)	2060 Levelized Delivered Price (2023$/MMBtu)
Northeast	$6.73	$4.87
Mid-Atlantic	$5.92	$4.06
Southeast	$6.49	$4.63
Midwest	$6.29	$4.43
Texas	$6.15	$4.29
West	$8.57	$6.75

4 Electricity

4.1 Objective

The purpose of this section is to create a guideline to estimate the average delivered (purchased) and sales (marketed) price for electricity. This guideline lays out how to achieve this for U.S. states and market regions. Three different possibilities have been analyzed when accounting for fluctuations in the oil and gas market. The first is a reference case that follows a trend of current market conditions. The other two are high and low oil and gas supply conditions.

For instances where alternative prices are utilized that do not follow the methodology outlined in this document, the reasoning and justification should be clearly explained and documented in as much detail as possible without violating any legally binding agreements or Funding Opportunity Announcement terms related to business-sensitive information. For studies utilizing a "generic plant site in the midwestern United States," as in the *Cost and Performance Baseline for Fossil Energy Plants* [11], the price for MISO North/Central should be used. It is also important to note that the sections covering delivered electricity price at a regional level (Section 4.2.2) and marketed electricity (Section 4.3) use 2022 data because 2023 data are not available, while the state-level section (Section 4.2.1) uses 2023 data.

4.2 Delivered (Purchased) Electricity Price

The delivered price of electricity reflects the price paid by an entity to procure utility electricity services and is comprised of generation, transmission, and distribution components. While an entity may enter into a power purchase agreement at a different rate or directly connect to the bulk electric system, the default price utilized should be the more granular of state or regional electricity price following the subsequent methodology depending on the level of project siting uncertainty, unless the use of an alternative can be clearly justified. State level pricing is preferred whenever possible because the regulatory compact governing rates beyond wholesale is administered by state utility commissions with limited federal involvement. The first-year data are adjusted with a growth rate calculated from EIA's AEO Wholesale Price Index for Fuel and Power (Exhibit 3-1) using a standard growth rate equation (Equation 12).

4.2.1 State Level

4.2.1.1 Approach

The state average delivered electricity price (¢/kWh or $/MWh) can be collected from EIA on their Electricity Data Browser [12]. Another piece of data also from EIA can be found in Table 8 of AEO 2023 [13]. AEO is used to gather the electricity end-use prices at the industrial level.

Electricity prices are more straightforward than the other categories investigated in this QGESS. This is mainly due to basis differential adjustments to cost. Any change or adjustment is built into the original data used.

The method employed to forecast electricity end-use prices starts with finding the percent of the U.S. average for each state (Equation 15). That is to say, if Alaska's state average price is $90/MWh and the U.S. average is $100/MWh, Alaska's percent of the U.S. average would be 90.

$$\%\ of\ Average \quad = \frac{State\ Average\ Price}{U.S.Average\ Price} * 100$$

Equation 15: Percent of U.S. average

After each state's average percentage is calculated, the electricity end-use prices from AEO must be acquired. Most instances referencing this document should use the price for the industrial sector and for the specific forecasted year. In instances where the price for a different sector is used, the reasoning should be explicitly described in the relevant study. In each year, a range of three delivered sectoral price sensitivities is recommended, drawn from the AEO reference case, high oil and gas supply case, and low oil and gas supply case. The last step is to take the percent of the U.S. average calculated previously and multiply that by AEO's end-use price for the case or cases of interest. This will give a forecasted annual price for the state in the year of choice (Equation 16).

$$State\ Average\ Price_{Forecast} = \%\ of\ Average * \ AEO\ Electricity\ End\ Use\ Price_{Industrial}$$

Equation 16: State average price

4.2.1.2 State-Level Results

This section aims to create a guideline to estimate the spot price a power plant or other consumer may pay for electricity. In order to account for fluctuations in the oil and gas markets, three different possibilities have been analyzed. The first is a reference case that follows a trend of current market conditions. The other two are high and low oil and gas supply conditions.

EIA's state electricity profiles (which included annual state average pricing for electricity) were tested using this method. This example exercises the method described to forecast state average electricity prices for 2030. Exhibit 4-1 shows the results with a price for each of the three possible cases.

Exhibit 4-1. 2030 delivered industrial electricity price by state based on adjusted AEO

AEO Electricity End-Use Price: Industrial			$67.68	$66.63	$74.96
State	**Unadjusted 2023 State Price (EIA) 2023$/MWh**	**Adjusted 2023 State Price (EIA) 2023$/MWh**	**Reference Case 2023$/MWh**	**High Oil and Gas Supply 2023$/MWh**	**Low Oil and Gas Supply 2023$/MWh**
Alabama	$115.00	$106.76	$61.18	$60.24	$67.77
Alaska	$213.90	$198.57	$113.80	$112.05	$126.06
Arizona	$121.40	$112.70	$64.59	$63.60	$71.55
Arkansas	$97.40	$90.42	$51.82	$51.02	$57.40
California	$247.30	$229.57	$131.57	$129.55	$145.74
Colorado	$117.70	$109.26	$62.62	$61.66	$69.37
Connecticut	$242.10	$224.75	$128.81	$126.83	$142.68
Delaware	$129.60	$120.31	$68.95	$67.89	$76.38
District of Columbia	$165.30	$153.45	$87.95	$86.59	$97.42
Florida	$135.10	$125.42	$71.88	$70.77	$79.62
Georgia	$113.60	$105.46	$60.44	$59.51	$66.95
Hawaii	$387.00	$359.26	$205.90	$202.73	$228.07
Idaho	$91.20	$84.66	$48.52	$47.78	$53.75
Illinois	$119.10	$110.56	$63.37	$62.39	$70.19
Indiana	$115.00	$106.76	$61.18	$60.24	$67.77
Iowa	$94.30	$87.54	$50.17	$49.40	$55.57
Kansas	$111.20	$103.23	$59.16	$58.25	$65.53
Kentucky	$100.50	$93.30	$53.47	$52.65	$59.23
Louisiana	$88.80	$82.43	$47.25	$46.52	$52.33
Maine	$209.50	$194.48	$111.46	$109.75	$123.47
Maryland	$143.70	$133.40	$76.45	$75.28	$84.69
Massachusetts	$229.70	$213.23	$122.21	$120.33	$135.37

AEO Electricity End-Use Price: Industrial			$67.68	$66.63	$74.96
State	Unadjusted 2023 State Price (EIA) 2023$/MWh	Adjusted 2023 State Price (EIA) 2023$/MWh	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh
Michigan	$136.60	$126.81	$72.68	$71.56	$80.50
Minnesota	$121.70	$112.98	$64.75	$63.75	$71.72
Mississippi	$111.00	$103.04	$59.06	$58.15	$65.42
Missouri	$110.10	$102.21	$58.58	$57.68	$64.89
Montana	$109.10	$101.28	$58.05	$57.15	$64.30
Nebraska	$91.90	$85.31	$48.89	$48.14	$54.16
Nevada	$130.10	$120.77	$69.22	$68.15	$76.67
New Hampshire	$229.80	$213.33	$122.26	$120.38	$135.43
New Jersey	$154.10	$143.05	$81.99	$80.73	$90.82
New Mexico	$96.70	$89.77	$51.45	$50.66	$56.99
New York	$183.20	$170.07	$97.47	$95.97	$107.97
North Carolina	$108.60	$100.82	$57.78	$56.89	$64.00
North Dakota	$79.20	$73.52	$42.14	$41.49	$46.68
Ohio	$111.20	$103.23	$59.16	$58.25	$65.53
Oklahoma	$94.00	$87.26	$50.01	$49.24	$55.40
Oregon	$102.30	$94.97	$54.43	$53.59	$60.29
Pennsylvania	$125.40	$116.41	$66.72	$65.69	$73.90
Rhode Island	$219.70	$203.95	$116.89	$115.09	$129.48
South Carolina	$107.60	$99.89	$57.25	$56.37	$63.41
South Dakota	$104.20	$96.73	$55.44	$54.59	$61.41
Tennessee	$107.90	$100.17	$57.41	$56.52	$63.59
Texas	$99.90	$92.74	$53.15	$52.33	$58.87
Utah	$90.30	$83.83	$48.04	$47.30	$53.22
Vermont	$175.20	$162.64	$93.21	$91.78	$103.25
Virginia	$109.20	$101.37	$58.10	$57.21	$64.36
Washington	$96.10	$89.21	$51.13	$50.34	$56.64
West Virginia	$102.70	$95.34	$54.64	$53.80	$60.53
Wisconsin	$126.30	$117.25	$67.20	$66.16	$74.43
Wyoming	$83.40	$77.42	$44.37	$43.69	$49.15

AEO Electricity End-Use Price: Industrial			$67.68	$66.63	$74.96
State	Unadjusted 2023 State Price (EIA) 2023$/MWh	Adjusted 2023 State Price (EIA) 2023$/MWh	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh
U.S. Total	$127.20	$118.08	$67.68	$66.63	$74.96

4.2.2 Regionalization

In the event that a more generalized, but less than national level, cost is desired because of siting uncertainty, this section provides regionalized market price estimates at the North American Reliability Corporation Reliability Coordinator (RC) level, which also often aligns with power market regions.

4.2.2.1 Approach

The market-based approach closely follows the same methodology used for the states, but with modifications to reflect a build-up from utility-reported industrial-sector sales data collected from EIA Form 861 Schedule 4[e] [15]. The method employed to forecast electricity end-use prices for the RC level follows Equation 17 and Equation 18.

$$RC\ Delivered\ Price = \frac{\sum Utility\ Reported\ Industrial\ Revenues_{Parts\ A\ thru\ D}}{\sum Utility\ Reported\ Sales\ _{Parts\ A,B\ \&\ D}}$$

Equation 17: Regional delivered price

$$\%\ of\ Average = \frac{Regional\ Delivered\ Price}{U.S.Average\ Price} * 100$$

Equation 18: Percent of U.S. average

After each RC average percentage is calculated, the electricity end-use prices from AEO must be acquired. Most instances referencing this document should use the price for the industrial sector and for the specific forecasted year.[e] In each year, a range of three delivered sectoral price sensitivities is recommended, drawn from the AEO reference case, high oil and gas supply case, and low oil and gas supply case. The last step is to take the percent of average calculated previously and multiply that by AEO's end-use price for the case or cases of interest. This will give a forecasted annual price for the region in the year of choice (Equation 19).

$$Regional\ Average\ Price_{Forecast} = \%\ of\ Average *\ AEO\ Electricity\ End\ Use\ Price_{Industrial}$$

Equation 19: Regional average price

[e] In some applications, it may be appropriate to utilize data for a different sector. For those instances, the reasoning behind the exception should be clearly explained in the relevant study.

4.2.2.2 Regional-Level Results

This section aims to create a guideline to estimate the spot price a power plant or other consumer may pay for electricity. In order to account for fluctuations in the oil and gas markets, three different possibilities have been analyzed. The first is a reference case that follows a trend of current market conditions. The other two are high and low oil and gas supply conditions.

This example exercises the method described to forecast regionalized average electricity prices for 2030. Exhibit 4-2 shows the results with a price for each of the three possible cases.

Exhibit 4-2. 2030 delivered industrial electricity price by region based on adjusted AEO

Region	2022 Unadjusted Delivered Prices (EIA Form 861) 2023$/MWh	2022 Adjusted Delivered Prices (EIA Form 861) 2023$/MWh	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh
ISO-New England	$158.35	$147.00	$123.72	$121.82	$137.05
New York ISO	$78.64	$73.01	$61.45	$60.50	$68.06
PJM	$84.51	$78.45	$66.03	$65.01	$73.14
MISO[f]	$83.44	$77.46	$65.19	$64.19	$72.21
North/Central	$85.30	$79.19	$66.65	$65.62	$73.83
South	$77.66	$72.09	$60.68	$59.74	$67.21
SERC	$77.81	$72.24	$60.80	$59.86	$67.35
VACS	$71.53	$66.40	$55.89	$55.03	$61.91
SOCO	$87.76	$81.47	$68.57	$67.52	$75.96
TVA	$67.30	$62.48	$52.58	$51.77	$58.25
FRCC	$95.51	$88.67	$74.63	$73.48	$82.66
SPP	$76.29	$70.82	$59.61	$58.69	$66.03
ERCOT	$74.15	$68.84	$57.94	$57.05	$64.18
SPP West	$83.49	$77.50	$65.23	$64.23	$72.26
RC-West	$110.82	$102.88	$86.59	$85.26	$95.91
CAISO	$189.39	$175.81	$147.97	$145.70	$163.91
non-CAISO	$75.85	$70.41	$59.26	$58.35	$65.65
Alaska	$191.91	$178.15	$149.94	$147.63	$166.09
Hawaii	$382.23	$354.83	$298.65	$294.05	$330.81

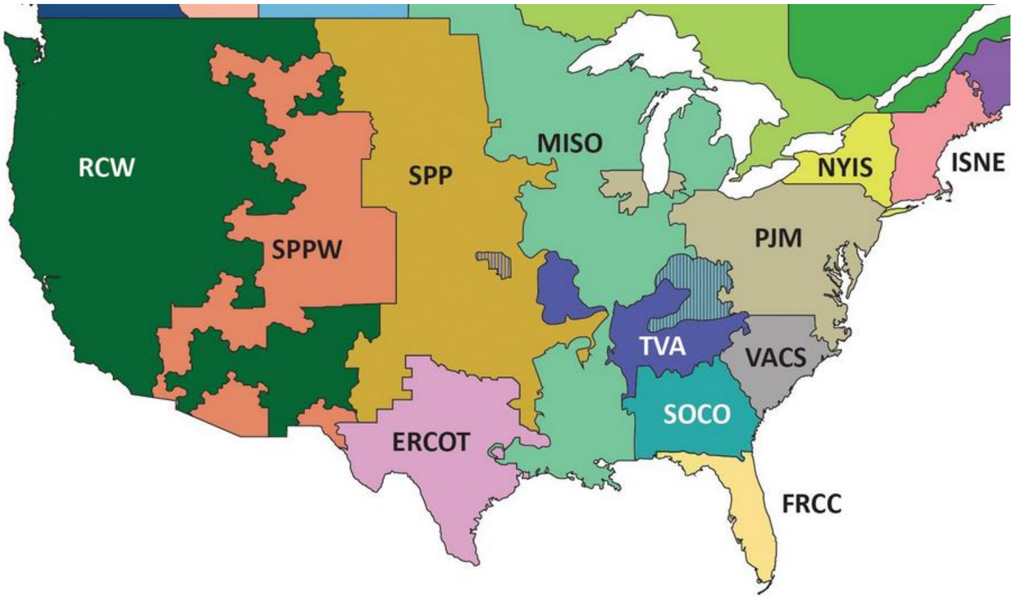
[f] Sub-regional pricing is provided for MISO as it effectively operates as two separate systems due to system interchange limitations between the North/Central and South sub-regions. The South sub-region includes MISO entities in Arkansas, Louisiana, Mississippi, and Texas (Load Resource Zones 8, 9, and 10); all others are in the North/Central sub-region.

Region	2022 Unadjusted Delivered Prices (EIA Form 861) 2023$/MWh	2022 Adjusted Delivered Prices (EIA Form 861) 2023$/MWh	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh
U.S.	$86.62	$80.41	$67.68	$66.63	$74.96

4.3 Marketed Electricity

Whereas delivered electricity prices include generation, transmission, and distribution components, the sales price received by an entity for the marketing of electricity would typically only consist of the generation component, with modifications to reflect local deliverability costs from transmission congestion and loss. In practicality, a fully specified project may be able to estimate these modifiers and should include them, if possible; however, most utilizing this document will not have the level of siting certainty to do so. Additionally, whereas delivered prices in the preceding section were defined at the state and market level, marketed electricity will be sold either directly to a purchasing counterparty via contract or into one of the wholesale regional marketplaces shown in Exhibit 4-3, meaning that the calculation of state-level prices received would not be advisable. If a project is utilizing a sales price set by the former, this should be explained along with the level of contract certainty and term provided within the bounds allowed by legally binding agreements and Funding Opportunity Announcement terms related to business-sensitive information; otherwise, the methodology in the following section or one of the alternatives set forth in Section 4.3.5 should be utilized. The first-year data are adjusted with a growth rate calculated from EIA's AEO Wholesale Price Index for Fuel and Power (Exhibit 3-1) using a standard growth rate equation (Equation 12). This section takes the results from Section 4.2.2 and adjusts them using a ratio from AEO.

Exhibit 4-3. Continental U.S. RCs



Source: Hitachi Energy Velocity Suite [2]

4.3.1 Regional-Level Approach

While a multiplicity of factors (particularly volatility in commodity prices) impacts prices from year to year, it is expected that many of these same factors would impact other analysis inputs relying upon the same base year; i.e., increases in natural gas price would lead to increased unit operating costs while also likely triggering an increase in regional energy price, meaning that the net effect would be one of pseudo-cancellation. In order to calculate the energy price to be used, the prices by service category for generation, transmission, and distribution for a given year from Table 8 of AEO and the calculated delivered industrial price (see Section 4.2.2) are needed. Once identified, these can be applied to determine the nominal generation price received by region using Equation 20. As with purchased electricity, a range of three sensitivities is recommended, drawn from the AEO reference case, high oil and gas supply case, and low oil and gas supply case.

$$\begin{aligned} &20xx\ Regional\ Generation\ Electricity\ Price\ Received \\ &\quad = Calculated\ Regional\ Delivered\ Industrial\ Price_{20xx} \\ &\quad * \frac{AEO\ Price\ by\ Service\ Category{:}\ Generation_{20xx}}{\sum AEO\ Prices\ by\ Service\ Category_{20xx}} \end{aligned}$$

Equation 20: Regional generation price received

4.3.2 Regional-Level Results

This section aims to create a guideline to estimate the average annual price a power plant or other producer would receive. In order to account for fluctuations in the oil and gas markets, three different possibilities have been analyzed. The first is a reference case that follows a trend of current market conditions. The other two are high and low oil and gas supply conditions.

This example exercises the method described to forecast wholesale regional market prices for 2030 for each of the three identified cases. The AEO prices by service for generation only and the total price (generation, transportation, and distribution) are shown in Exhibit 4-4. Exhibit 4-5 shows the results with a price for each of the three possible cases.

Exhibit 4-4. 2030 AEO prices by service

	Generation			Total (Generation, Transport, Distribution)		
AEO 2023 (Year)	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh
2030	$52.058	$51.017	$59.346	$108.281	$107.240	$118.693

Exhibit 4-5. 2030 generator-received electricity price by region

Region	Reference Case $/MWh	High Oil and Gas Supply $/MWh	Low Oil and Gas Supply $/MWh
ISO-New England	$59.48	$57.95	$68.52
New York ISO	$29.54	$28.78	$34.03
PJM	$31.75	$30.93	$36.57
MISO[g]	$31.34	$30.54	$36.11
North/Central	$32.04	$31.22	$36.91
South	$29.17	$28.42	$33.60
SERC	$29.23	$28.48	$33.67
VACS	$26.87	$26.18	$30.95
SOCO	$32.97	$32.12	$37.98
TVA	$25.28	$24.63	$29.12
FRCC	$35.88	$34.96	$41.33
SPP	$28.66	$27.92	$33.01
ERCOT	$27.86	$27.14	$32.09
SPP West	$31.36	$30.56	$36.13
RC-West	$41.63	$40.56	$47.96
CAISO	$71.14	$69.31	$81.95
non-CAISO	$28.49	$27.76	$32.82
Alaska	$72.09	$70.23	$83.04

[g] Sub-regional pricing is provided for MISO as it effectively operates as two separate systems due to system interchange limitations between the North/Central and South sub-regions. The South sub-region includes MISO entities in Arkansas, Louisiana, Mississippi, and Texas (Load Resource Zones 8, 9, and 10); all others are in North/Central sub-region.

Region	Reference Case $/MWh	High Oil and Gas Supply $/MWh	Low Oil and Gas Supply $/MWh
Hawaii	$143.58	$139.89	$165.40
U.S.	$32.54	$31.70	$37.48

4.3.3 State-Level Approach

Market electricity will be sold either directly to a purchasing counterparty via contract or into one of the wholesale regional marketplaces shown in Exhibit 4-3, meaning that the calculation of state-level prices received would not be advisable. Although the previous statement is true, it may be helpful in other aspects to have the average generator received electricity price by state. The same process for the regional level will be used here with a slight adjustment in Equation 21.

$$20xx\ State\ Generation\ Electricity\ Price\ Received = Calculated\ State\ Delivered\ Industrial\ Price_{20xx} * \frac{AEO\ Price\ by\ Service\ Category: Generation_{20xx}}{\sum AEO\ Prices\ by\ Service\ Category_{20xx}}$$

Equation 21: State generation price received

4.3.4 State–Level Results

This section aims to create a guideline to estimate the average annual price a power plant or other producer would receive. In order to account for fluctuations in the oil and gas markets, three different possibilities have been analyzed. The first is a reference case that follows a trend of current market conditions. The other two are high and low oil and gas supply conditions.

This example exercises the method described to forecast wholesale state market prices for 2030 for each of the three identified cases. Exhibit 4-6 shows the results with a price for each of the three possible cases.

Exhibit 4-6. 2030 generator received electricity price by state

State	Unadjusted 2023 State Price (EIA) 2023$/MWh	Adjusted 2023 State Price (EIA) 2023$/MWh	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh
Alabama	$115.00	$106.76	$29.42	$28.66	$33.89
Alaska	$213.90	$198.57	$54.71	$53.31	$63.03
Arizona	$121.40	$112.70	$31.05	$30.25	$35.77
Arkansas	$97.40	$90.42	$24.91	$24.27	$28.70
California	$247.30	$229.57	$63.26	$61.63	$72.87

State	Unadjusted 2023 State Price (EIA) 2023$/MWh	Adjusted 2023 State Price (EIA) 2023$/MWh	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh
Colorado	$117.70	$109.26	$30.11	$29.33	$34.68
Connecticut	$242.10	$224.75	$61.93	$60.33	$71.34
Delaware	$129.60	$120.31	$33.15	$32.30	$38.19
District of Columbia	$165.30	$153.45	$42.28	$41.19	$48.71
Florida	$135.10	$125.42	$34.56	$33.67	$39.81
Georgia	$113.60	$105.46	$29.06	$28.31	$33.47
Hawaii	$387.00	$359.26	$98.99	$96.45	$114.04
Idaho	$91.20	$84.66	$23.33	$22.73	$26.87
Illinois	$119.10	$110.56	$30.46	$29.68	$35.09
Indiana	$115.00	$106.76	$29.42	$28.66	$33.89
Iowa	$94.30	$87.54	$24.12	$23.50	$27.79
Kansas	$111.20	$103.23	$28.44	$27.71	$32.77
Kentucky	$100.50	$93.30	$25.71	$25.05	$29.61
Louisiana	$88.80	$82.43	$22.71	$22.13	$26.17
Maine	$209.50	$194.48	$53.59	$52.21	$61.73
Maryland	$143.70	$133.40	$36.76	$35.81	$42.34
Massachusetts	$229.70	$213.23	$58.75	$57.24	$67.68
Michigan	$136.60	$126.81	$34.94	$34.04	$40.25
Minnesota	$121.70	$112.98	$31.13	$30.33	$35.86
Mississippi	$111.00	$103.04	$28.39	$27.66	$32.71
Missouri	$110.10	$102.21	$28.16	$27.44	$32.44
Montana	$109.10	$101.28	$27.91	$27.19	$32.15
Nebraska	$91.90	$85.31	$23.51	$22.90	$27.08
Nevada	$130.10	$120.77	$33.28	$32.42	$38.34
New Hampshire	$229.80	$213.33	$58.78	$57.27	$67.71
New Jersey	$154.10	$143.05	$39.42	$38.40	$45.41
New Mexico	$96.70	$89.77	$24.73	$24.10	$28.49
New York	$183.20	$170.07	$46.86	$45.66	$53.98
North Carolina	$108.60	$100.82	$27.78	$27.06	$32.00
North Dakota	$79.20	$73.52	$20.26	$19.74	$23.34

State	Unadjusted 2023 State Price (EIA) 2023$/MWh	Adjusted 2023 State Price (EIA) 2023$/MWh	Reference Case 2023$/MWh	High Oil and Gas Supply 2023$/MWh	Low Oil and Gas Supply 2023$/MWh
Ohio	$111.20	$103.23	$28.44	$27.71	$32.77
Oklahoma	$94.00	$87.26	$24.04	$23.43	$27.70
Oregon	$102.30	$94.97	$26.17	$25.49	$30.14
Pennsylvania	$125.40	$116.41	$32.08	$31.25	$36.95
Rhode Island	$219.70	$203.95	$56.20	$54.75	$64.74
South Carolina	$107.60	$99.89	$27.52	$26.82	$31.71
South Dakota	$104.20	$96.73	$26.65	$25.97	$30.70
Tennessee	$107.90	$100.17	$27.60	$26.89	$31.79
Texas	$99.90	$92.74	$25.55	$24.90	$29.44
Utah	$90.30	$83.83	$23.10	$22.50	$26.61
Vermont	$175.20	$162.64	$44.81	$43.66	$51.63
Virginia	$109.20	$101.37	$27.93	$27.21	$32.18
Washington	$96.10	$89.21	$24.58	$23.95	$28.32
West Virginia	$102.70	$95.34	$26.27	$25.59	$30.26
Wisconsin	$126.30	$117.25	$32.31	$31.48	$37.22
Wyoming	$83.40	$77.42	$21.33	$20.78	$24.58
U.S. Total	$127.20	$118.08	$32.54	$31.70	$37.48

4.3.5 Alternatives

In lieu of the methodology in Section 4.3.1, annualized electricity prices derived using methods approved by regional market operators, state utility regulators, and the Federal Energy Regulatory Commission may be substituted with supporting documentation and any models that were used in the derivation. Additionally, prices derived using energy market modeling following the most recent public version of NETL's *Quality Guideline for Energy Systems Studies: Economic Unit Commitment and Dispatch Modeling Guidelines for NETL Studies* [16] may also be utilized as long as model cases are provided. It is acknowledged that each of these alternatives may trigger the need for execution of non-disclosure and/or Critical Energy Infrastructure Information agreements; as such, the use of these alternatives should be discussed with the proper NETL authority prior to use. As an advisory to potential project respondents, the use of these alternatives will most likely only be considered for projects at the preliminary front end engineering design stage or later.

5 Biomass

5.1 Objective

This section aims to create a guideline to estimate the delivered cost of biomass to the plant gate for conversion to make electricity, hydrogen, or other intermediates or products. This guideline outlines how to estimate the cost of herbaceous or woody biomass types in the United States that are currently being considered for mass production in the bioeconomy. As there are many different types of biomass, and their density and location are not uniform across the United States, the choice of biomass will be highly dependent on the location and size of the biomass conversion plant, as well as the type of conversion system chosen.

5.2 Approach

For more than a decade, DOE has been quantifying the potential of U.S. biomass resources, under biophysical and economic constraints, for production of renewable energy and bioproducts. The *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy* (BT16) evaluates the most recent estimates of potential biomass that could be available for new industrial uses in the future [17]. BT16 is the third generation of a large-scale cooperative analysis between DOE, the Department of Agriculture and Forestry, academia, and industrial experts. BT16 has been widely peer-reviewed and is considered the benchmark for biomass resource analysis.

5.2.1 Biomass Characteristics

Like coal, biomass types have different properties that can make them attractive or unattractive to combustion or conversion to bioproducts. Therefore, there must be an understanding of the different properties of woody and herbaceous biomass types as different biomass resources behave differently and have different heating values and compositions. Exhibit 5-1 provides HHV[h] and lower heating value[i] (LHV) ranges for common herbaceous and woody biomass types, as well as common urban residues [18].

Exhibit 5-1. Heating value ranges for different biomass types

Biomass Type	HHV Range				LHV Range			
	Btu/lb		MMBtu/ton		Btu/lb		MMBtu/ton	
Agricultural Residues								
Corn stalks/stover [19, 20, 21]	7,582	7,962	15.2	15.9	7,244	7,605	14.5	15.2

[h] The HHV (also known as gross calorific value or gross energy) of a fuel is defined as the amount of heat released by a specified quantity (initially at 25 °C) once it is combusted and the products have returned to a temperature of 25 °C, which takes into account the latent heat of vaporization of water in the combustion products. The HHVs are derived only under laboratory conditions and are frequently used in the United States for solid fuels.

[i] The LHV (also known as net calorific value) of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25 °C) and returning the temperature of the combustion products to 150 °C, which assumes the latent heat of vaporization of water in the reaction products is not recovered.

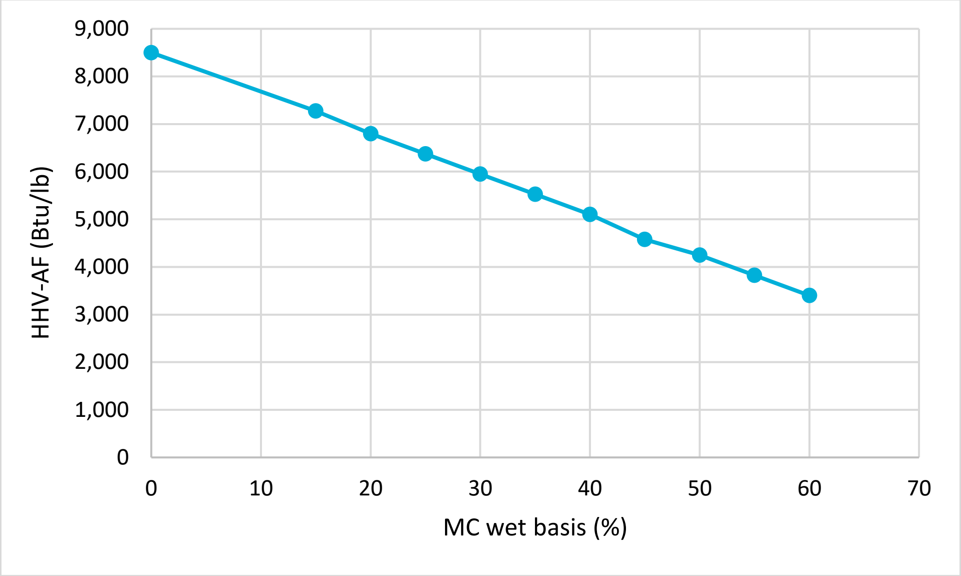
Biomass Type	HHV Range				LHV Range			
	Btu/lb		MMBtu/ton		Btu/lb		MMBtu/ton	
Sugarcane bagasse [19, 20, 21]	7,445	8,344	14.9	16.7	7,615	7,678	15.2	15.4
Wheat straw [19, 20, 21]	6,960	8,143	13.9	16.3	6,484	7,592	13.0	15.2
Hulls, shells, prunings [20, 22]	6,806	8,832	13.6	17.7				
Herbaceous Crops								
Miscanthus [21]	7,782	8,418	15.6	16.8	7,660	7,780	15.3	15.6
Switchgrass [19, 22, 21]	7,749	8,227	15.5	16.5	7,209	7,435	14.4	14.9
Other grasses [21]	7,818	7,984	15.6	16.0	7,270	7,458	14.5	14.9
Woody Crops								
Black locust [19, 21]	8,403	8,576	16.8	17.2	7,582		14.5	
Eucalyptus [19, 20, 21]	8,169	8,426	16.3	16.9	7,582		14.5	
Hybrid poplar [19, 22, 21]	8,178	8,485	16.4	17.0	7,582		14.5	
Willow [20, 22, 21]	7,978	8,491	16.0	17.0	7,194	7,919	14.4	15.8
Forest Residues								
Hardwood [20, 21]	7,896	8,914	15.8	17.8				
Softwood [19, 20, 22, 23, 24, 21]	7,994	9,080	16.0	18.2	7,530	8,929	15.1	17.9
Urban Residues								
Municipal solid waste (MSW) [20, 21]	5,640	8,536	11.3	17.1	5,155	7,980	10.3	16.0
Refuse-derived fuel [20, 21]	6,679	8,557	13.4	17.1	6,137	8,000	12.3	16.0
Newspaper [20, 21]	8,471	9,544	16.9	19.1	7,906	8,900	15.8	17.8
Corrugated paper [20, 21]	7,423	7,933	14.8	15.9	7,582		15.1	
Waxed cartons [20]	11,719	11,728	23.4	23.5	7,582		15.1	

The HHV and LHV provided in Table 1 and Table 2 of the Biomass Energy Data Book, Edition 2, Appendix A, assume that the fuels contain 0 percent water [18]. Since recently harvested wood fuels usually contain 30–55 percent water, it is useful to understand the effect of moisture content (MC) on the heating value of wood fuels. Exhibit 5-2 shows the effect of MC percent on HHV as-fired (HHV-AF) of a wood sample starting at 8,500 Btu/lb (oven-dry) [18].

The MC wet and dry weight bases are calculated as follows:

- MC (dry basis) = 100 (wet weight-dry weight)/dry weight
- MC (wet basis) = 100 (wet weight-dry weight)/wet weight
- To convert MC wet basis to MC dry basis: MC(dry) = 100xMC(wet)/100-MC(wet)
- To convert MC dry basis to MC wet basis: MC(wet) = 100xMC(dry)/100+MC(dry)

Exhibit 5-2. Effect of fuel moisture on wood heat content



Biomass composition is also a critical component to consider when choosing the fuel for a power plant or any bioconversion facility. Herbaceous feedstocks tend to contain higher ash content and lower volatile content than woody biomass types. The higher ash content can be an issue in combustion chambers as the ash, especially when containing chlorine and silica, can lead to corrosion and pitting in the combustion chamber, leading to lower efficiency and more equipment damage. Exhibit 5-3, Exhibit 5-4, and Exhibit 5-5 provide average compositions for multiple woody, herbaceous, and waste feedstocks, respectively[j] [25].

Exhibit 5-3. Feedstock compositions for specific woody feedstocks (average)

Feedstock Composition	Shrub Willow	Hybrid Poplar	Pine	Other Softwoods	Other Hardwoods
Proximate (%)					
Volatiles	84.7	84	83.5	81.3	85.1
Ash	1.5	1.3	0.7	2.1	1.8
Fixed carbon	13.8	14.6	15.7	16.5	13.1
Ultimate (%)					
Hydrogen	6	6	6.1	6.1	6.1
Carbon	50.3	50	51.5	51.8	50.2
Nitrogen	0.36	0.35	0.17	0.27	0.55

[j] The source data in Exhibit 5-4 through Exhibit 5-6 contain the number of samples tested for each biomass type and the standard deviation for each biomass component for each type. These were left out of this document but can be found in the reference.

Feedstock Composition	Shrub Willow	Hybrid Poplar	Pine	Other Softwoods	Other Hardwoods
Oxygen	42.6	42.8	41.4	39.7	41.1
Sulfur	0.04	0.03	0.02	0.03	0.05
Structural (%)					
Cellulose	–	43.8	47.4	42.1	50.8
Hemicellulose	–	14.7	21.9	25.1	29.7
Lignin	–	25.7	28.6	29.1	19.5

Exhibit 5-4. Feedstock compositions for specific herbaceous feedstocks (average)

Feedstock Composition	Corn Stover	Switchgrass	Sorghum	Energy Cane (Bagasse)	Mixed Grasses	Miscanthus
Proximate (%)						
Volatiles	78.1	82.4	77	82.2	78.6	82.5
Ash	6.3	4	7.2	3.4	6.6	2.6
Fixed carbon	15.6	13.6	15.7	14.4	14.8	14.8
Ultimate (%)						
Hydrogen	5.7	5.9	5.7	6.1	5.8	5.8
Carbon	47.1	47.1	46.4	48.8	47.6	48.9
Nitrogen	0.63	0.6	1.04	0.43	1.38	0.35
Oxygen	40.3	42.4	40.3	-	39.5	42.3
Sulfur	0.14	0.06	0.11	-	0.12	0.04
Structural (%)						
Cellulose	34.3	34.2	28.6	32.1	28.9	38.9
Hemicellulose	20.7	21.9	15.4	19.5	16.7	20.1
Lignin	15.2	19.2	12.2	16.3	15.7	21.1

Exhibit 5-5. Feedstock compositions for specific waste feedstocks (average)

Feedstock Composition	MSW	Construction & Demolition Waste	Woody Residues
Proximate (%)			
Volatiles	76.5	76.5	81.1
Ash	11.8	0.8	1.2
Fixed carbon	11.2	18.9	17.8
Ultimate (%)			

Feedstock Composition	MSW	Construction & Demolition Waste	Woody Residues
Hydrogen	5.6	6.2	6
Carbon	43.3	48.3	52.5
Nitrogen	1.52	1.09	0.22
Oxygen	36.3	42.4	40.1
Sulfur	0.25	0.02	0.01
Structural (%)			
Cellulose	28.4	–	–
Hemicellulose	16.4	–	–
Lignin	12.5	–	–

5.2.2 Siting a Biomass Power Plant

To find the cost of delivered biomass, the size and location of a biomass power plant must be chosen. Having the information contained in Section 5.2.1 and understanding where different types of biomass are located in the United States will help make the decision of where to locate a biomass power plant, and the potential size, based on feedstock availability.

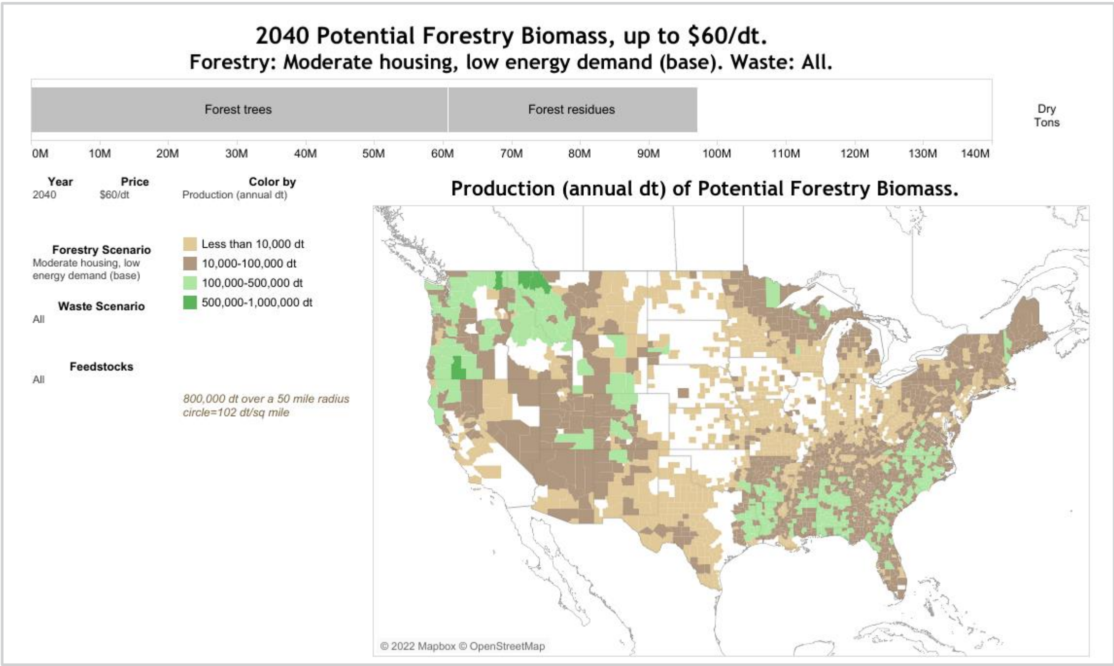
BT16 contains interactive maps where the user can choose a location in the United States and then examine the biomass resources in the region to see if they are suitable to site a power plant. BT16 provides biomass quantities in bone-dry tons (bdt). To determine how much biomass is required, the conversion between wet and dry weight must be calculated using the equations listed in Section 5.2.1. A sample of biomass MC is shown in Exhibit 5-6.

Exhibit 5-6. Biomass MC at harvest

Biomass	MC at Harvest (%)
Corn Stover [17]	20
Switchgrass [17]	15
Miscanthus [17]	15
Sorghum [17]	40
Yard Trimmings [17]	20
Wheat Straw [26]	16
Barley Straw [26]	30
Willow [26]	60
Poplar [26]	45

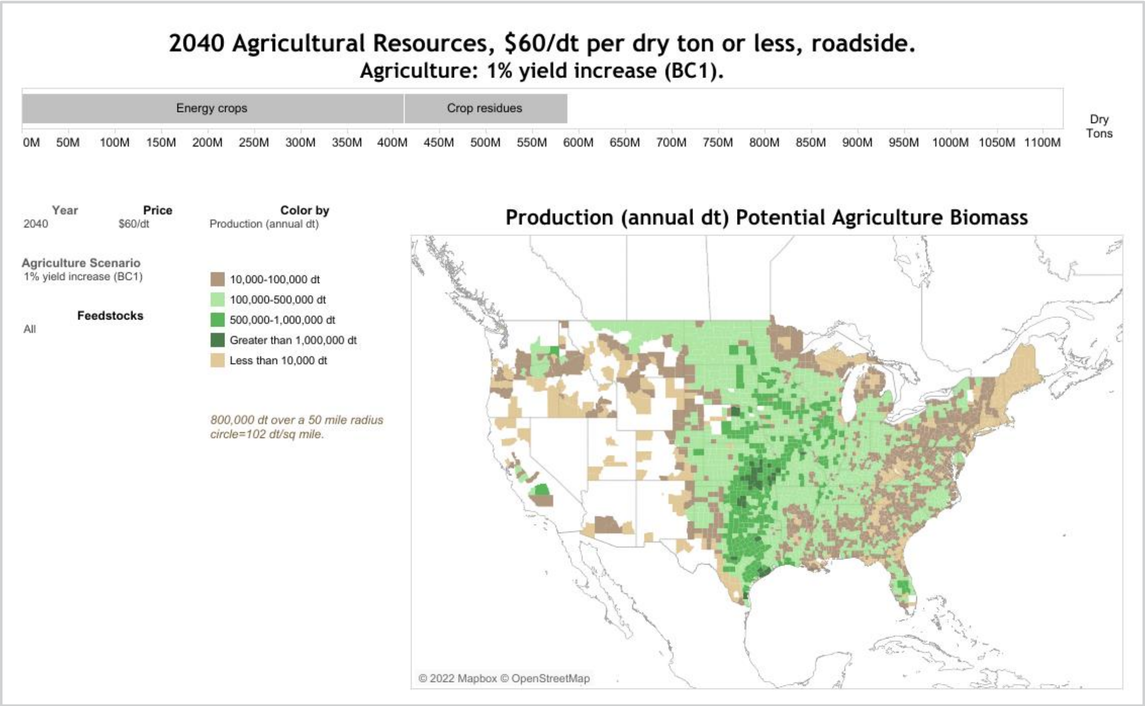
Exhibit 5-7, Exhibit 5-8, and Exhibit 5-9 show maps of the United States for woody biomass, herbaceous biomass, and wastes, respectively [17]. These maps are a starting point for narrowing down biomass types and regions.

Exhibit 5-7. BT16 interactive woody biomass map



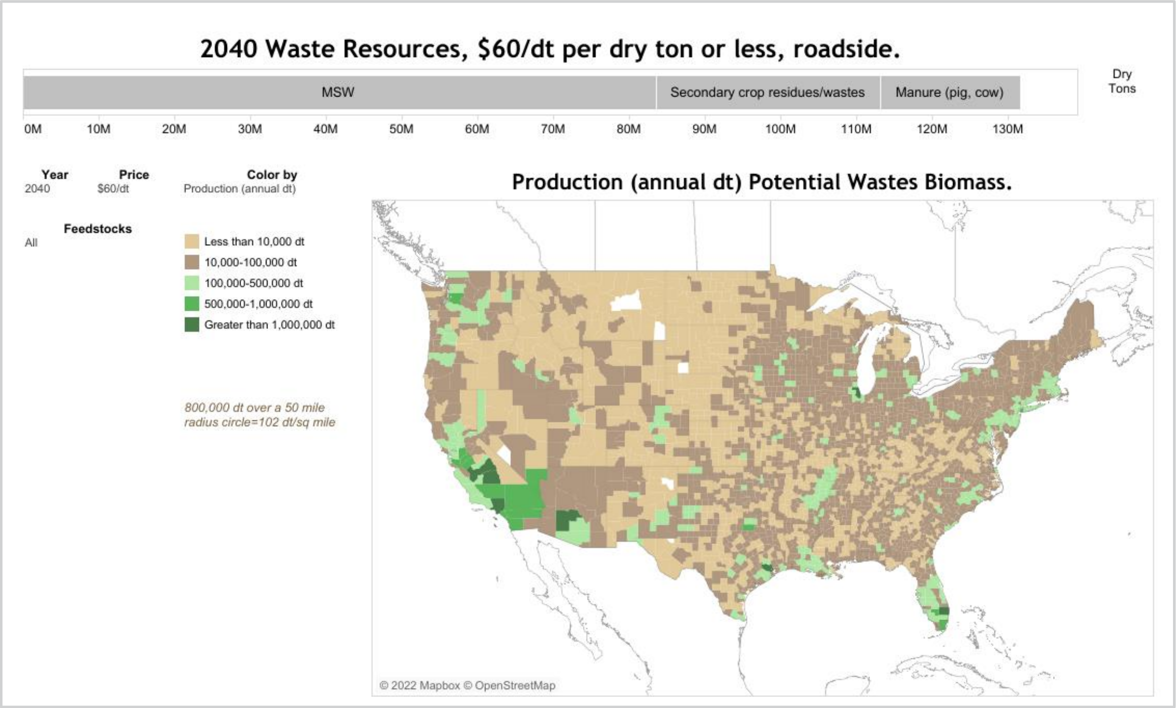
Source: BST16 [17]

Exhibit 5-8. BT16 interactive herbaceous biomass map



Source: BST16 [17]

Exhibit 5-9. BT16 interactive waste resources map



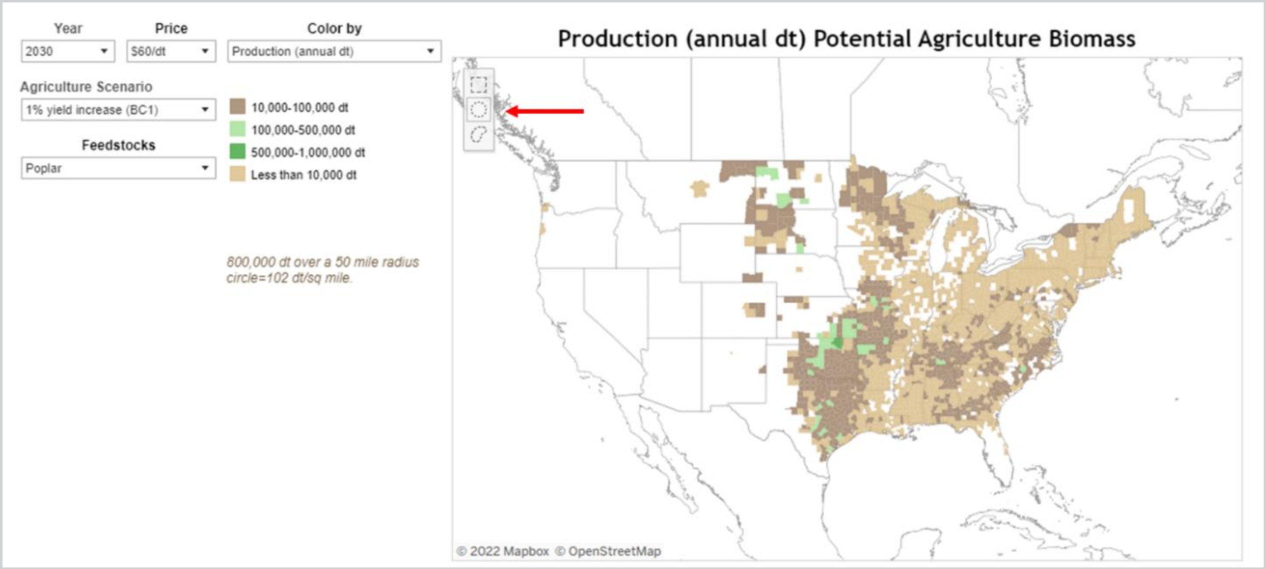
Source: BST16 [17]

5.2.2.1 Example of Calculating Biomass in a Specified Region Using the BT16 Interactive Map

Following is a step-by-step process to calculate the volume of biomass needed for a chosen biomass power plant. The interactive tool allows the user to choose a year, feedstock(s), feedstock price ($/bdt), different economic scenarios, and either production (bdt) or density (annual bdt/square mile).

For this example, the volume of hybrid poplar (bdt) will be chosen in 2030 under an increase in yield of poplar by 1 percent, using a $60/bdt roadside cost. Exhibit 5-10 shows where hybrid poplar is available and how much is available at a county level.

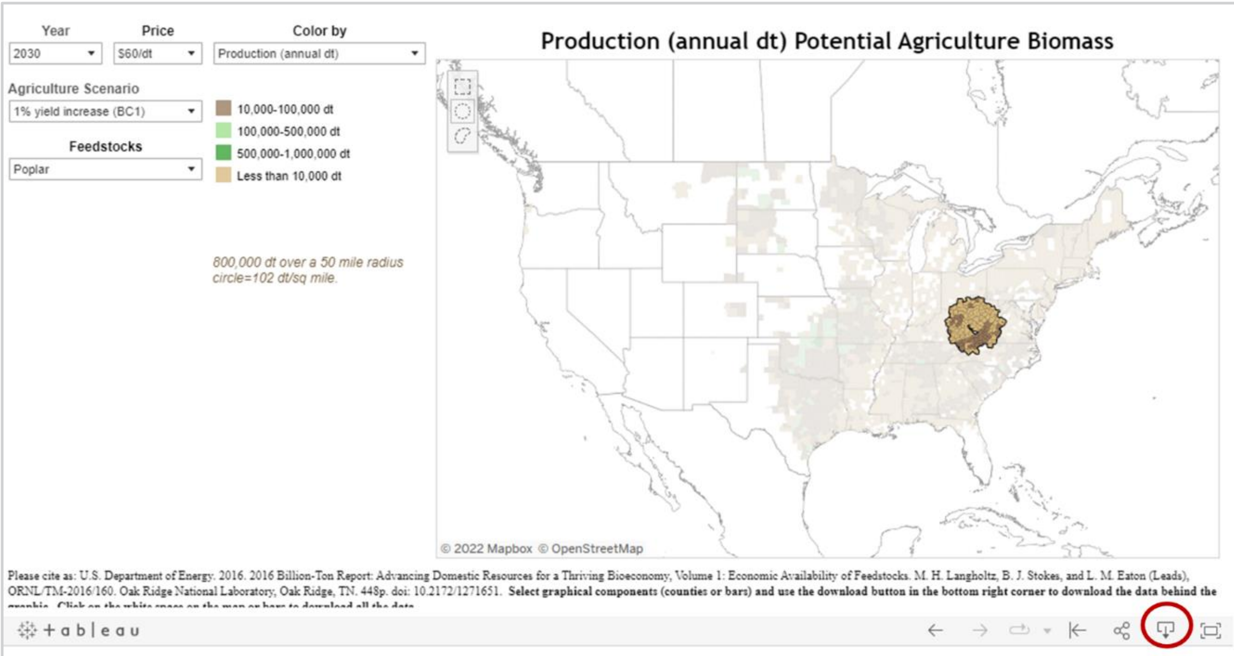
Exhibit 5-10. 2030 hybrid poplar, $60/dt or less, roadside



Source: BST16 [17]

The next step in examining the biomass availability is to select a region using the circle in the shape tool in the top left of the map (see red arrow in Exhibit 5-10). In Exhibit 5-11, the circular shape tool was chosen, and a region in Appalachia was selected.

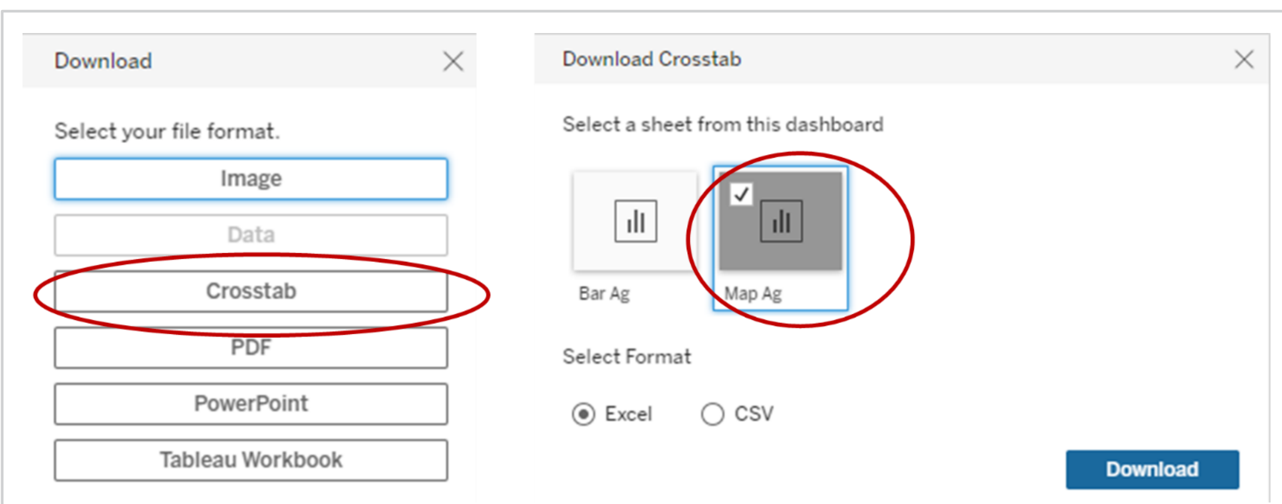
Exhibit 5-11. Selecting a region to analyze



Source: BST16 [17]

The next step is to choose the download button on the lower right side of Exhibit 5-11 (see red circle). Once the download button is chosen, the following image (Exhibit 5-12, left) appears on top of the picture. Choose the Crosstab, then check the Map Ag selection (Exhibit 5-12, right).

Exhibit 5-12. Down-selecting a region to download the volume of biomass



After the Map Ag option has been chosen, a spreadsheet will download with biomass volume totals for the selected counties.

This is an iterative process to obtain the amount of biomass needed for the plant in the region selected. Once that has been accomplished, use the legend on the map to estimate the diameter of the circle. That diameter will be used to calculate the transportation distance to the plant, assuming the plant is in the center of the circle, and then the transportation costs.

5.2.3 Developing Delivered Biomass Costs

Biomass costs are a combination of the cost of harvesting and transporting biomass from the field/forest to the plant gate, on top of the cost of growing and cultivation, which are captured in the biomass selling price. However, in many cases, raw, harvested biomass must be processed between the field and the plant gate along the supply chain in order to minimize the transportation costs by maximizing the physical and/or energy density of biomass. Exhibit 5-13 and Exhibit 5-14 portray high-level block diagrams of the major process steps in the supply chain for woody and herbaceous biomass.

Exhibit 5-13. Supply chain for woody biomass from the forest to the power plant

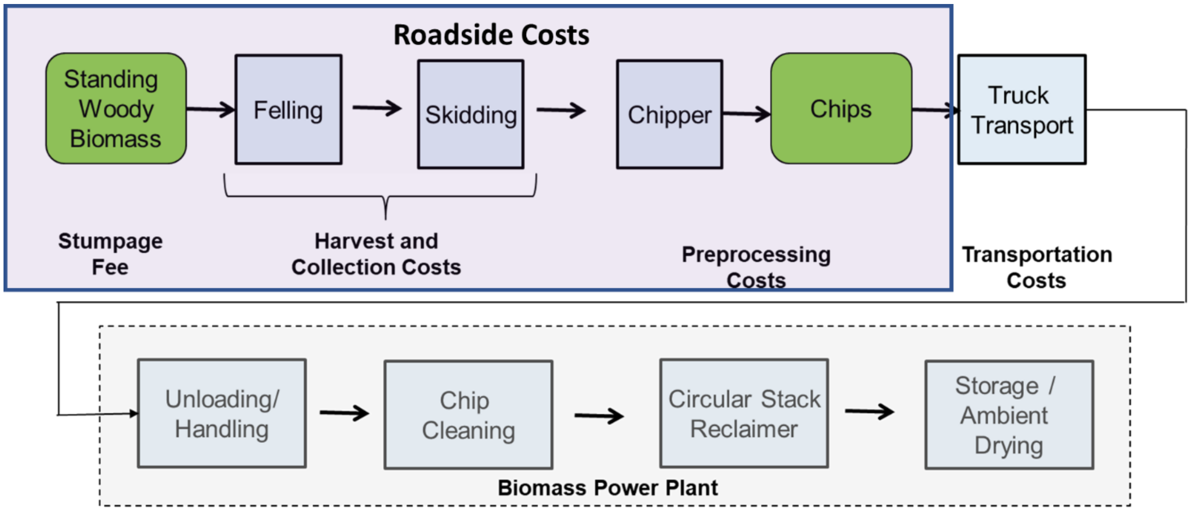
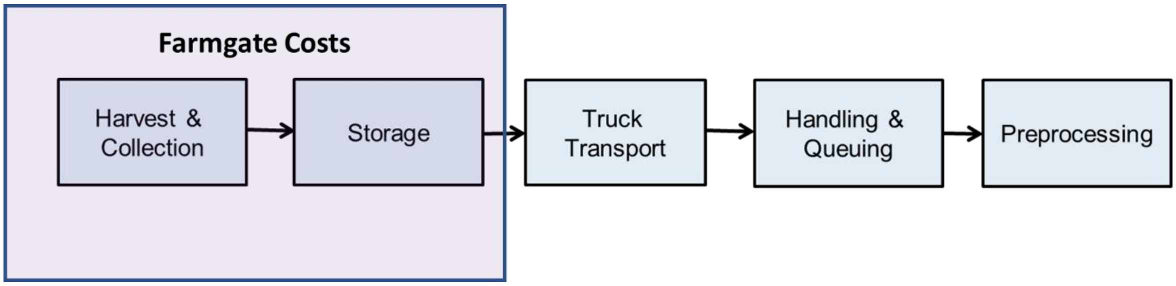


Exhibit 5-14. Supply chain for herbaceous biomass from the field to the power plant



BT16 provides the roadside cost for woody biomass and the farmgate cost for herbaceous biomass. The roadside/farmgate costs include the preprocessing of the biomass in the field, so that woody biomass is in chip form and herbaceous biomass is in bale form. Therefore, all costs upstream from transportation are rolled up in the estimated costs in BT16. For this document, truck transportation cost will be defined, although the process is similar for rail and barge transportation as well.

Truck transportation costs are determined by the amount of biomass needed at the plant gate per year and the mean distance traveled. Chipped biomass and baled biomass require different truck types resulting in slightly different maximum loads per truck. Exhibit 5-15 provides the weight limit for truck, rail, and barge.

Exhibit 5-15. Biomass payloads for truck, rail, and barge

Transportation Constants		
Chipped Truck Payload	29.7	tons/container
Baled Truck Payload	23	tons/container
Truck Capacity Factor	95	%
Rail Payload	100	tons/container
Barge Payload	1,500	tons/container

The mass of biomass to be transported is calculated by using the MC of the chosen resource and the bdt of biomass in the selected resource region, as chosen and defined in Section 5.2.2.1. The distance traveled is a weighted average of the distance traveled from harvest site to plant gate. By using a weighted average, the distance from harvest site to plant location and the percentage of total biomass supply from each harvest site is considered. When most of the biomass production occurs close to the plant location, the weighted average of distance traveled is minimal. As more production occurs farther from the plant location, the weighted average of distance traveled increases. Exhibit 5-16 shows the transportation requirements including the weighted travel distance where h is a specific harvest site and n is the total number of harvest sites.

Exhibit 5-16. Biomass transportation requirement calculations

Parameter	Calculation
Weighted transportation distance, one way (miles)	$= \frac{\sum_{h=1}^{n}(distance\ traveled\ one\ way)_h * \ (site\ production)_h}{\sum_{h=1}^{n}(site\ production)_h}$
Loads needed per year	Total weight of wet biomass in a year/max weight per truck
Loads needed per day	Loads needed per year/365

The next calculation is the number of trucks required to haul the biomass. Exhibit 5-17 shows how to calculate the number of trucks. It is assumed that the life of a truck is 5 years [27].

Exhibit 5-17. Calculating the number of trucks needed to deliver biomass

Parameter	Calculation
Average speed (mi/hr)	35
Loading/unloading time (min)	45
Trip time (hr)	$\left(\frac{2 * \ Distance\ traveled_{weighted}(mi)}{Speed(mph)}\right) + load\ time(hr) + unload\ time(hr)$
Trips per day	Assuming an 8-hour work day per truck, =IF(Trip_time<2.5,3,IF(AND(Trip_time >2.5, Trip_time <5),2,1))
Trucks needed per day	=# Loads needed per day/trips per day
Spare trucks	10% of trucks needed per day, rounded up
Total trucks needed in inventory	= # of trucks needed per day + spare trucks

Finally, the transportation costs can be calculated from the information in the last two exhibits and information provided in Exhibit 5-18, which shows the equations to calculate the transportation costs on a per-ton basis.

Exhibit 5-18. Calculating the cost of biomass transportation

Cost	Value	Unit
Truck labor	24.20 [28]	$/hr (2021)
Loaded semi	5.72	miles/gallon
Unloaded semi	7.73	miles/gallon
Average semi	6.725 (average of loaded and unloaded)	miles/gallon
Diesel costs	EIA [29]	$/gallon
Average annual cost to own and operate a new truck and trailer [27]	$60,686	$/yr (2017)
Truck payments [27]	$29,368	$/yr (2017)
Tires [27]	$7,469	$/yr (2017)
Maintenance and repair [27]	$6,500	$/yr (2017)
Insurance (full coverage) [27]	$6,458	$/yr (2017)
Shop [27]	$3,000	$/yr (2017)
Support personnel [27]	$2,872	$/yr (2017)
Licenses, tags, etc. [27]	$1,569	$/yr (2017)
Employment screening (physicals, drug tests, etc.) [27]	$202	$/yr (2017)
Other [27]	$3,248	$/yr (2017)
Truck depreciation period	5	Years

Cost	Value	Unit
Annual capital payment	= average annual cost to own and operate a new truck and trailer/tons of bdt biomass transported per year	$/bdt
Fuel costs	= loads needed per year *(transportation distance round-trip (miles)/bdt of biomass transported per year) * (diesel costs/average semi miles per gallon)	$/bdt
Labor costs	= (loads needed per year * transportation distance round-trip (miles)/average speed + 2* loading/unloading time (hr))* truck labor/bdt of biomass transported per year	$/bdt
Total transportation costs	= annual capital payment + fuel costs + labor costs	$/ton

The cost of biomass delivered to the plant comprises the total transportation costs from Exhibit 5-18 plus the roadside/farmgate costs calculated using the interactive tool from BT16. However, the costs as derived are not in the same cost year, and, therefore, they need to be adjusted to the cost year in which the study to be performed will be based. The biomass farmgate/roadside costs are in 2014$, the labor rate for trucking is in 2021$, and the trucking capital and operating costs are in 2017$. Using the Consumer Price Index (CPI-U) seen in Exhibit 5-19, the values can be put into a common year of 2023 [30].

Exhibit 5-19. Historic U.S. inflation index (2014–2023)

Date	CPI-U
December 31, 2014	236.736
December 31, 2015	237.017
December 31, 2016	240.007
December 31, 2017	245.12
December 31, 2018	251.107
December 31, 2019	255.657
December 31, 2020	258.811
December 31, 2021	270.97
December 31, 2022	292.66
December 31, 2023	304.702

Source: U.S. Department of Labor, Bureau of Labor Statistics [30]

To calculate the costs to 2023$, make the following calculations:

- For biomass roadside/farmgate costs: {2014 cost*[304.70/236.736]}
- For transportation costs: {2017 cost*[304.70/245.12]}
- For labor costs: {2021 labor cost*[304.70/270.97]}

The resulting values can then be used to calculate a same-year cost for biomass from the field/forest to the plant gate.

5.2.4 Biomass Transportation Cost Examples

Exhibit 5-20 shows the transportation cost of woody biomass by transportation distance and MC. It is assumed that 2,000 bdt per day is needed for the plant to be operational. All of the following examples use 2,000 bdt per day as the amount of biomass being transported. The number of trucks needed in the fleet is shown for 10 percent and 50 percent MC. The number of trucks required in the fleet increases at 5–10 miles, 20–25 miles, and 40–45 miles and increases as the MC increases. The increase in the number of trucks is due to each truck being able to complete one fewer trip per day and more trucks being required to move the same amount of biomass. The higher the MC of the biomass, the more trucks are required because higher MC-content biomass weighs more than the same volume of dry biomass.

Exhibit 5-20. Cost of woody biomass transported from harvest site to plant gate

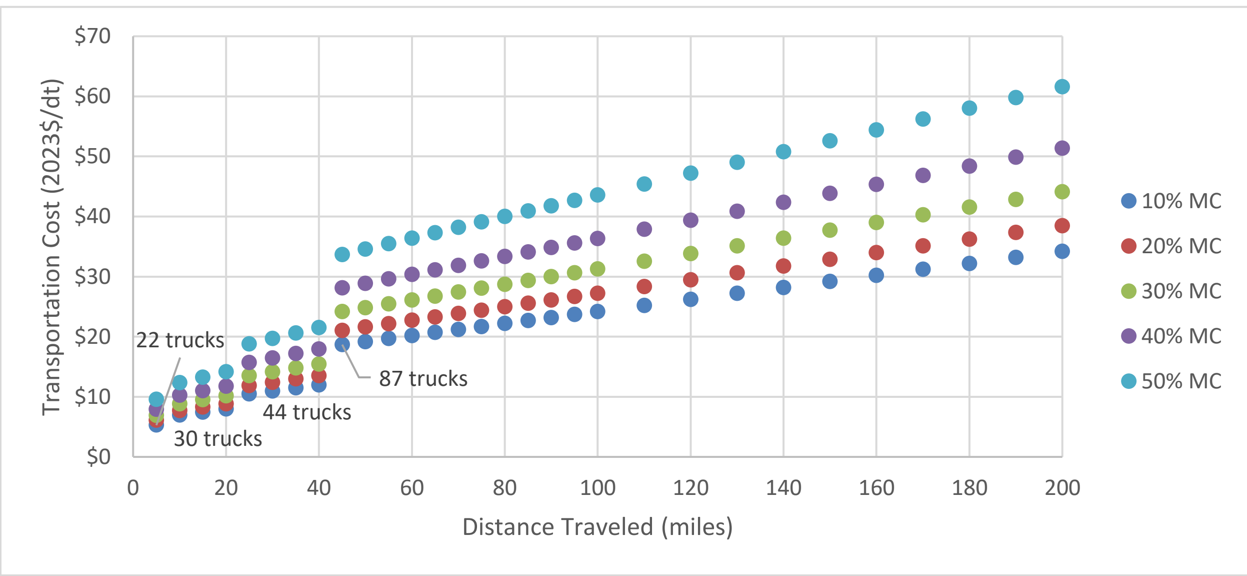


Exhibit 5-21 shows the transportation cost for herbaceous biomass versus one-way distance traveled by MC. Less herbaceous biomass can be transported per truck resulting in a higher transportation cost and more trucks being required compared to woody biomass. An increase in the number of trucks still occurs at 5–10 miles, 20–25 miles, and 40–45 miles.

Exhibit 5-21. Cost of herbaceous biomass transported from harvest site to plant gate

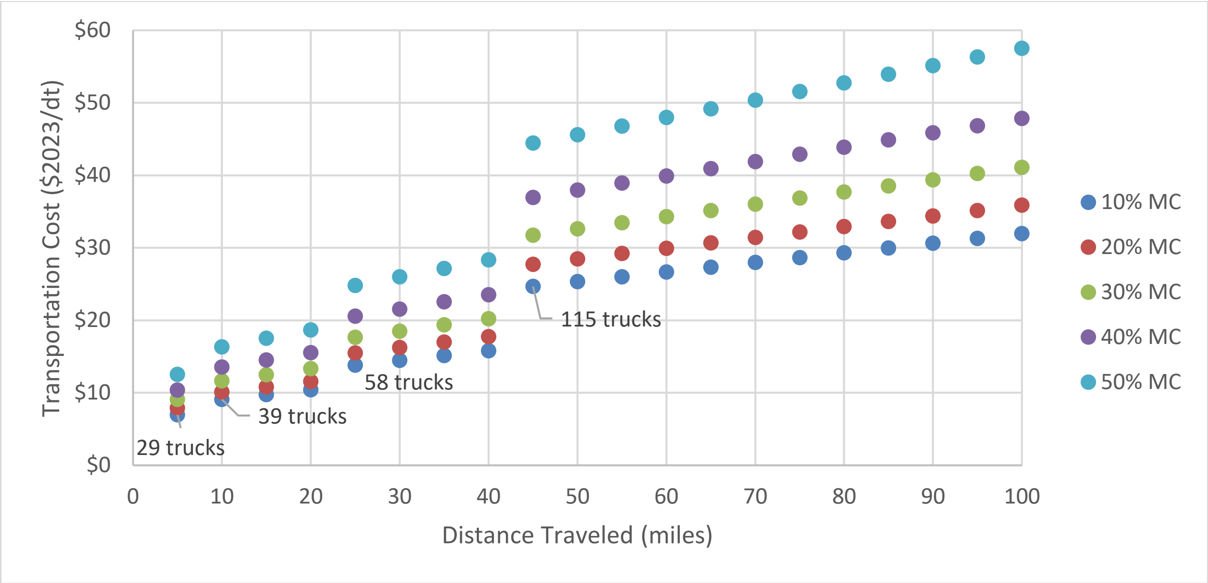


Exhibit 5-22 shows the total cost of transporting woody biomass from harvest site to plant gate. This cost includes the cost of transportation and the cost of buying the woody biomass at the harvest site. Biomass with lower MC has a lower total cost. As the distance traveled increases, the price difference in MC traveling the same distance increases.

Exhibit 5-22. Cost of woody biomass purchased and transported from harvest site to plant gate

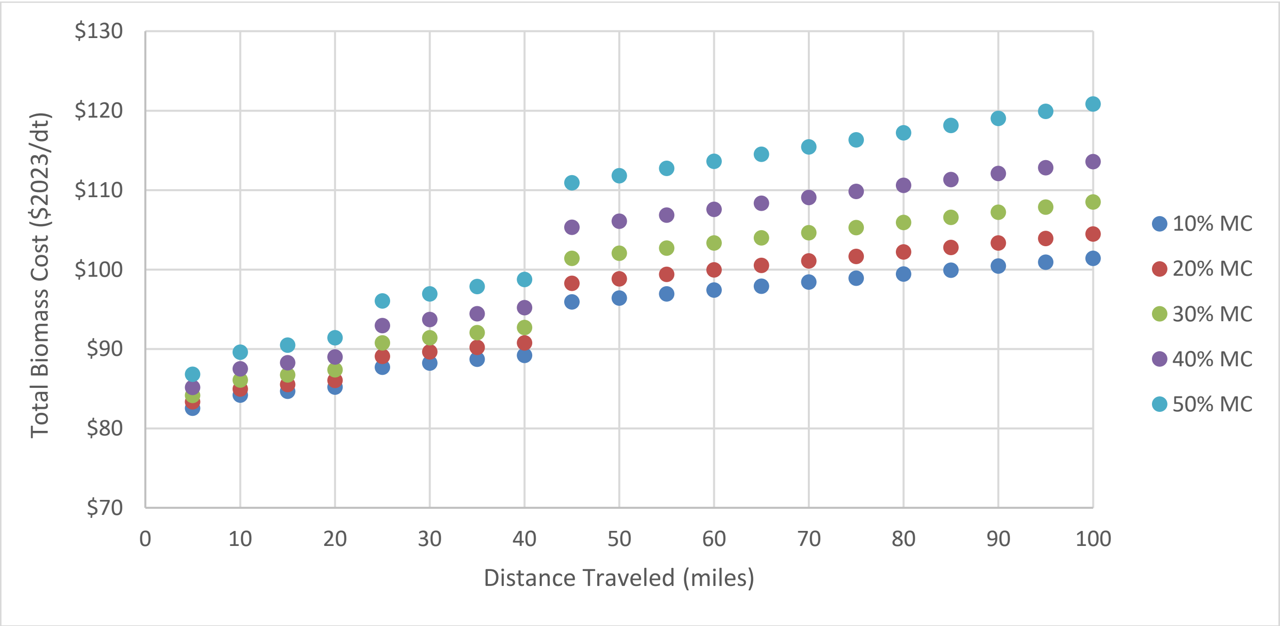


Exhibit 5-23 shows the total cost of transporting herbaceous biomass from harvest site to plant gate. The total cost of herbaceous biomass is higher than the total cost of woody biomass.

Exhibit 5-23. Cost of herbaceous biomass purchased and transported from harvest site to plant gate

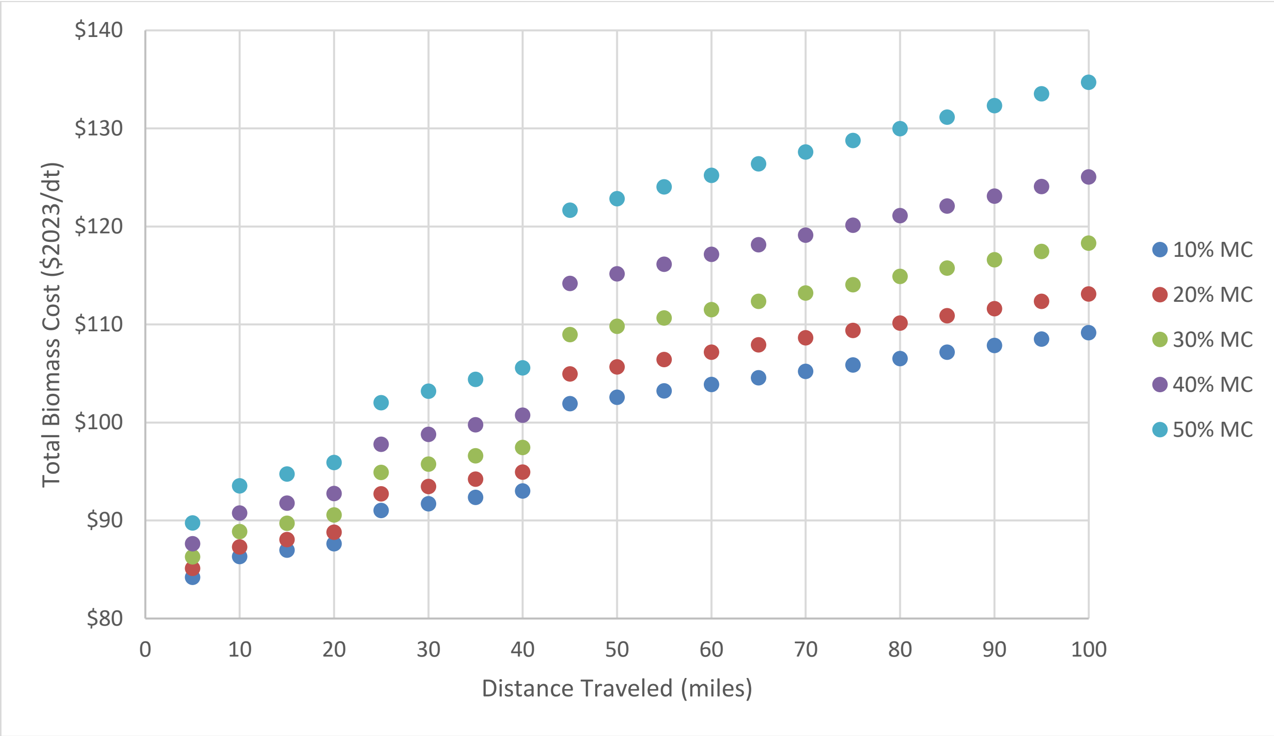
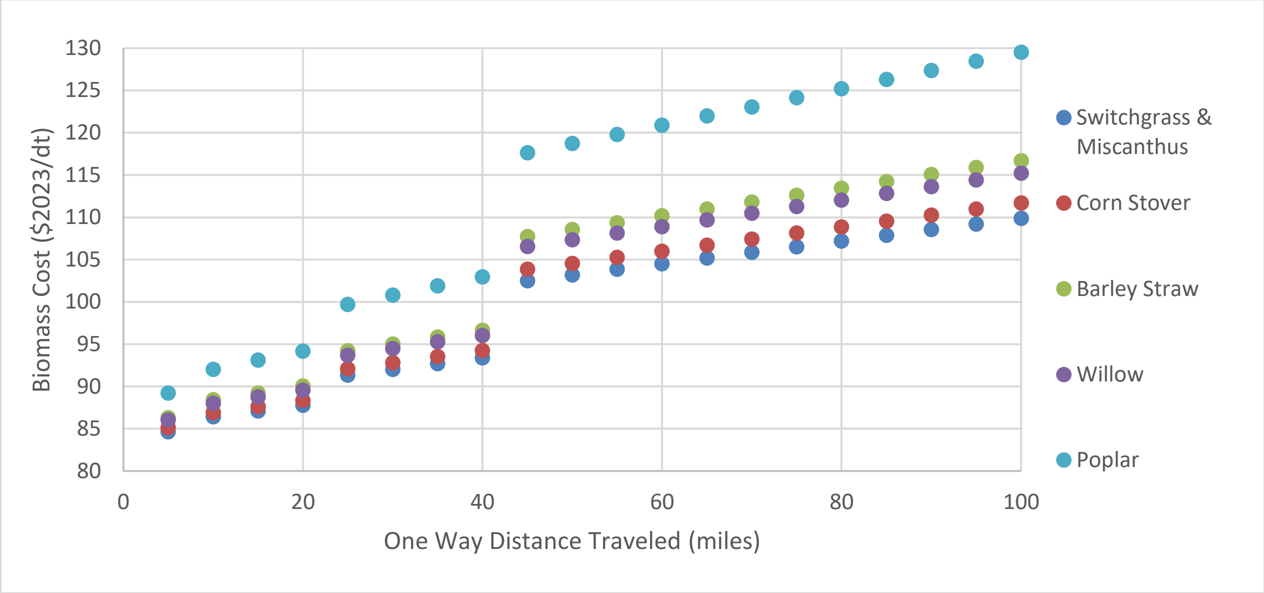


Exhibit 5-24 shows the total cost of common biomass resources based on the one-way distance traveled from harvest site to plant gate. Willow and poplar are both woody biomasses with an MC of 60 percent and 45 percent, respectively. While woody biomasses tend to have lower total costs compared to herbaceous biomasses, they both have a higher cost than switchgrass, miscanthus, and corn stover due to the MC of the biomasses. Switchgrass and miscanthus have a MC of 15 percent while corn stover has a MC of 20 percent. The cost of transporting low-MC herbaceous biomass is less than the cost of transporting high-MC woody biomass. The total cost of a biomass cannot be assumed to be lower because it is woody; the MC of the biomass also impacts the cost.

Exhibit 5-24. Cost of common U.S. biomass purchased and transported from harvest site to plant gate



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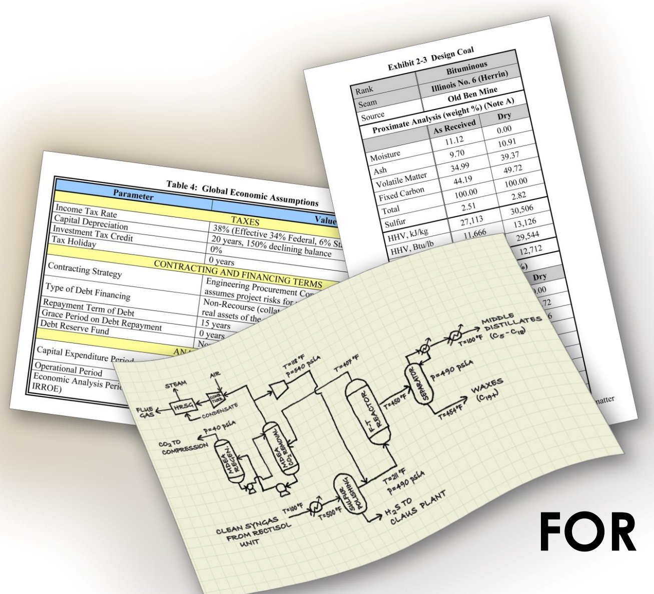

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