Internal Revenue Service

Number: **201430009**
Release Date: 7/25/2014

Index Number: 45.00-00

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:

Telephone Number:

Refer Reply To:
CC:PSI:B6
PLR-147498-13

Date:
March 26, 2014

LEGEND

Taxpayer =

Company A =
Company B =
Company C =
Company D =
Company E =
Company F =
Company G =
Business A =
Individual A =
Individual B =
Individual C =
Individual D =
Utility A =
Utility B =
Licensor =
State A =
State B =
State C =
State D =
State E =
State F =
State G =

Country =
Exchange =
Plant A =
Plant B =
Date 1 =
Date 2 =
Date 3 =
Date 4 =
Date 5 =
Date 6 =
Date 7 =
Date 8 =
Date 9 =
Date 10 =
Date 11 =
Date 12 =
Date 13 =
Date 14 =
Additive 1 =
Additive 2 =
Center =

Test Rep 1 =
Test Rep 2 =

Test Rep 3 =

source region A =
source region B =
source region C =
a% =
b% =
c% =
d% =
e% =

Dear :

This is in response to your request for rulings, submitted by your authorized representative, concerning the federal income tax consequences of the transaction described below.

Taxpayer has represented the facts as follows:

Background

Company B, a State A limited liability company, is a fiscal year taxpayer and employs the accrual method of accounting for both book and tax purposes. The members of Company B are Company A, Taxpayer and Company C, each of which is a State A limited liability company. Taxpayer and Company C are indirect, wholly owned subsidiaries of Company D, which is a company incorporated under the laws of Country that is primarily engaged in Business A and whose shares are listed on the Exchange. The ultimate principal owners of Company A are Individual A, Individual B, Individual C and Individual D. Those individuals have worked and invested together in various projects since at least Date 1. Some of their prior projects included the development, construction and operation of synthetic fuel production facilities and waste coal processing facilities. Commencing in Date 2, the principals agreed to develop a new refined coal business, including the business now conducted by Company B.

Company A was organized on Date 3 to construct a facility for the production of refined coal that was placed in service at a mine site in State B on or about Date 4 and produced and sold refined coal with the expectation that it would be burned to produce steam. However, due to unforeseen difficulties in identifying customers willing to enter into long-term contracts to purchase refined coal, Company A did not continue producing refined coal after Date 5.

Subsequently, on Date 6, Company A entered into contracts with Utility A and Utility B to locate a refined coal production facility on a site adjacent to Plant A in State C, and to sell refined coal produced in that facility to Utility A and Utility B. Because its existing facility did not meet the functional requirements for producing refined coal at this new location, Company A arranged for the construction of a new refined coal production facility.

Subsequently, on Date 7, Company A terminated its agreements at Plant A, and then engaged in discussions with Utility B to relocate its facility to a location near another power plant owned in part and operated by Utility B. On Date 8, Company E entered into contracts with Utility B, as described below, to locate a refined coal production facility on a site adjacent to Plant B in State D, and to sell refined coal produced in that facility to Utility B. Subsequently, on Date 9, Company E merged with and into Company A, such that Company A became the successor in interest under the contracts with Utility B. Company A then commenced to relocate its newly constructed facility to the new location on a site adjacent to Plant B in State D. Such relocations of refined coal facilities are a routine exercise that can be accomplished with only limited duplication of certain common equipment and civil works and foundations, which are relatively minor in the context of these projects. In connection with the relocation of the facility to State D, all essential components of the facility were relocated and retained.

Company A's original facility, that was placed in service on or about Date 4, was subsequently sold to Company F.

In anticipation of the transaction with Taxpayer and Company C described below, Company A transferred its facility to the Taxpayer on Date 10, together with its contracts with Utility B and certain related assets. Immediately following that contribution, Company A owned all of the interests in Company B, such that the Company B was disregarded as a separate entity from Company A for U.S. federal income tax purposes.

On Date 11, Taxpayer acquired a% of the class B membership interests in Company B from Company A, and Company C acquired b% of the class B membership interests in Company B from Company A, in a transaction treated as a taxable sale or exchange of a proportionate share of all of Company B's assets, followed by a contribution of such assets to a newly formed partnership pursuant to section 721. Company A also granted an option to Taxpayer and Company C, pursuant to which they have the right to acquire the class C membership interests in Company B. The limited liability agreement of Company B sets forth the members' agreement regarding the respective rights and obligations of the class A, class B and class C interests in Company B, the management and related decision-making of Company B, and certain related matters.

Pursuant to its agreements with Utility B, Company B purchases coal feedstock from Utility B. The coal supply agreement does not prohibit Company B from purchasing coal feedstock from third parties, and does not prohibit Company B from purchasing more feedstock coal than Utility B would expect to buy from Company B in the form of refined coal.

The feedstock coal purchased by Company B typically is coal that Utility B itself purchased from third party vendors, consistent with its coal specifications. Company B uses the Process (as described below) to produce refined coal that it sells to Utility B pursuant to a refined coal sales agreement. Company B at any given time produces refined coal from one or more coal source regions or ranks, presently expected to be bituminous coal obtained from various mines in coal source regions A, B and C. However, it is possible that in the future Company B will obtain feedstock coal from other coal source regions or ranks which may be sourced from other mines. The refined coal is then sold to Utility B, which then deposits the refined coal into one of the stockpiles it maintains for each coal source region and rank. Utility B typically blends the refined coal at Power Plant B from each stockpile before combustion, with such blend expected initially to be bituminous coal in the proportions of approximately c% from source region A, approximately d% from source region B, and approximately e% from source region C, but sometimes may feed the boilers at Power Plant B using refined coal produced from only one coal source region or rank, or in different proportions than as reflected above. All of the refined coal produced in the facility is expected to be used as a fuel at Plant B to produce steam for the generation of electricity. However, any refined coal not purchased by Utility B can be sold to one or more third parties.

Company B has no employees. Rather, it entered into an operations and maintenance agreement with Company G, a State A limited liability company and affiliate of Company A. Pursuant to that agreement, Company G will operate, repair and maintain the facility in accordance with an agreed operating plan, will make arrangements to coordinate delivery of spare parts and supplies, will coordinate deliveries of coal feedstock purchases and sales of refined coal, and will perform certain administrative functions in support thereof. In addition, Company G will arrange for testing of refined coal as described below.

Description of the Process

The process at issue for production of refined coal currently employed at the facility involves the mixing of proprietary chemicals (additives) with feedstock coal prior to combustion (the Process). The patent for the Process is licensed by Licensor to Company B. Licensor is entitled to certain per ton royalties based on production for the use of its technology. Test results have shown that when mixed with coal, the proprietary additives result in reduced NO_x, SO_2 and mercury emissions during combustion. Different chemicals are targeted at specific pollutants. Based on the characteristics of the feedstock coal burned at Plant B, Taxpayer has chosen a combination of additives that target the reduction of NO_x and mercury. In the case of NO_x, Taxpayer understands that Additive 1 is believed to cause a portion of the NO_x to adhere to, or react with, the additive so that it can be captured and is not emitted. In the case of mercury, Taxpayer understands that Additive 2 is believed to react with the elemental mercury in the feedstock coal so that it is converted into a chemical species of mercury (mercury oxide) that can be effectively captured by particulate control devices.

Emissions Reduction Testing

For purposes of determining emissions reductions under § 45, Company B will arrange for pilot-scale combustion testing (and laboratory analysis for redetermination purposes), and will not rely on any continuous emissions monitoring system or other field testing. Company B engaged the research center of a prominent university (the Center) to conduct tests on behalf of Company B at its pilot-scale combustion test facility (CTF) to determine the emission reductions associated with burning the refined coal compared to the feedstock coal. Center reports described below state:

> The CTF has been extensively used to research and investigate SO_x and NO_x emissions and the transformation of toxic trace metals (Hg [mercury], As, and Pb) during the combustion of coal and other fuels or waste materials. The CTF is capable of producing gas and particulate samples

that are representative of those produced in industrial- and full-scale pulverized coal (pc)-fired boilers.

The CTF is capable of producing gas and particulate samples that are representative of those produced in industrial and full-scale pulverized coal boilers, and has several pollution control devices that may be used to reduce emissions, including an electrostatic precipitator or fabric filter baghouse for particulate control, a selective catalytic reduction column for NO_x control, and a wet scrubber for control of sulfur emissions. For purposes of qualifying the refined coal produced at the facility, Center conducted separate pilot-scale combustion tests at its CTF on Date 12, Date 13 and Date 14 on feedstock coal of the type typically burned at Plant B.

Test Rep 1, Test Rep 2 and Test Rep 3 (the Test Reports) explain that combustion gas analysis is provided by continuous emissions monitors (CEMs) at two locations: the furnace exit, which is used to monitor and maintain a specified excess air level for all test periods, and the outlet of the particulate control device, which is used to assess any air inleakage that may have occurred so that emissions of interest sampled at the back end of the system can be corrected for the dilution caused by the inleakage. For all three tests, flue gas analyses were obtained from the duct at the outlet of the electrostatic precipitator; for Test Rep 2 and Test Rep 3, flue gas analyses also were obtained from the duct at the outlet of the wet scrubber. Flue gas mercury measurements for all three tests were obtained separately by a continuous mercury monitor located at the flue gas ducting at the exit of the particulate control device; for Test Rep 2 and Test Rep 3, flue gas mercury measurements also were taken at the flue gas ducting at the exit of the wet scrubber. Center conducted a series of tests on the feedstock and refined coal blend, measuring the emissions with these devices. As Utility B has confirmed that it will be operating the wet scrubber at any time the boilers at Power Plant B are in operation, in future tests the Center will obtain the flue gas analyses and mercury measurements at the wet scrubber so that its measurements are taken in a manner consistent with the way that Power Plant B is operated.

The Test Reports state that the test results indicate that the blend of coal and additives achieved the required reductions in both NO_x and total mercury emissions (both determined on a lb/Btu basis) to satisfy the requirements of at least 20% NO_x reduction and at least 40% mercury reduction. Further, Test Rep 3 also states that any one of, or blend of coal from, the three coal source regions tested (i.e., coal source regions A, B and C) would be expected to achieve the required emissions reduction when used to produce refined coal at full scale using the additive levels tested.

<u>Tested Coal</u>

Plant B currently burns coal obtained from various mines located in State C, State E, State F and State G. Company B produces refined coal using this coal and sells that refined coal to Plant B which burns it to generate electricity from steam. The rank of the coal burned at Plant B is classified by the American Society of Testing

Materials (ASTM) as bituminous coal, which is expected to have a gross calorific value of 11,000 to 13,000 btu/lb.

On Date 14 Company B requested that Center test a blend of coal bituminous coal that consisted of approximately c% from source region A, approximately d% from source region B, and approximately e% from source region C, which is an indicative blend consistent with the coal blend expected to be used at Plant B. The reports issued by Center with respect to each of its tests state that the emission reduction requirements outlined in § 45 for NO_x and mercury were satisfied when comparing the results of burning the endpoint fuel to the results of burning the feedstock coal. Further, Test Rep 3 concludes that any one of, or blend of coal from, the three coal source regions tested (i.e., coal source regions A, B and C) would be expected to satisfy the requirements of at least a 20 percent nitrogen oxide reduction and at least a 40 percent mercury reduction using the additive levels describe in the report.

Company B currently expects to continue to operate with feedstock coal from the same source regions and of the same rank as those discussed in Test Rep 3. Samples will be taken for redetermination testing within six months after the last emissions test satisfying the qualified emission reduction requirement to redetermine the Approved Application Rates (defined below). Thereafter, within six months after such date, another set of samples will be taken for redetermination testing. In each case, samples will be collected and prepared in accordance with sampling and testing procedures set forth in Company B's operating protocols. Although testing and preliminary reporting is done timely, occasionally the Center is not able to issue the final report until after the six-month period.

For purposes of this letter, the term "Tested Coal" refers to the most recently tested sample tested by Center with respect to which Center has advised Company B of the application rates for the liquid and powder additives that achieved at least a 40 percent reduction in mercury emissions and at least a 20 percent reduction in nitrogen oxide emissions (the "Approved Application Rates"). Although Company B does not currently anticipate making changes to its coal feedstock or additive levels, or using other coal sources or ranks, additional testing will be conducted prior to acquiring coal feedstock from a different coal source region or of a different rank than reflected in the Tested Coal used in the then applicable test report. If the Tested Coal is a blend of coal, the Approved Application Rates will be such that the Center considers any one of, or blend of coal from, the coal source regions in the Tested Coal would be expected to satisfy the qualified emissions reduction test requirements. In the case of a change in the additive levels, tests will also be run at the new minimum levels of additive as the qualified expert advises is necessary to conclude that a qualified emissions reduction will be expected for the new levels of additive.

RULINGS REQUESTED

Based on the foregoing, you have requested that we rule as follows:

1. The refined coal produced by using the Process constitutes “refined coal” within the meaning of §45(c)(7) of the Code, provided that such refined coal is produced from feedstock coal that is the same source or rank as the Tested Coal and provided further that the refined coal satisfies the qualified emission reduction test stated in §45(c)(7)(B) of the Code.

2. Provided that the feedstock coals used to produce refined coal during any determination or redetermination period are from one of the coal source regions represented in the Tested Coal or any blend thereof, and of the same rank as such Tested Coal, all such feedstock coal shall be treated as feedstock coal of the same source and rank for purposes of section 6.04 of Notice 2010-54, regardless of the mines from which such feedstock coal is purchased.

3. Testing by Center for qualified emissions reduction as set forth in its test reports satisfies the requirements of Notice 2010-54. Pilot scale testing conducted at Center (and subsequent permitted laboratory testing as required for a redetermination described in section 6.04(2)(a) or (b) of Notice 2010-54) may be relied upon to satisfy the qualified emission reduction test of §45(c)(7)(B) of the Code.

4. Pursuant to section 6.04(2)(b) of Notice 2010-54, the redetermination requirement of section 6.04 of Notice 2010-54 may be satisfied by laboratory analysis establishing that the sulfur and mercury content of both the feedstock coal and the refined coal, on average, do not vary by more than ten percent below the bottom of (nor more than ten percent above the top of) the range of sulfur content and the range of mercury content of the feedstock coal and the refined coal used in the most recent determination that meets the requirements of section 6.03 of Notice 2010-54.

5. The results set forth by the Center in a redetermination test report for production after the date of the testing may be relied upon even if the report is not received until after the six month period specified in section 6.04(1)(i) of Notice 2010-54.

6. The transfer of the facility by Company A to Company B subsequent to its placed-in-service date will not affect the placed-in-service date of the facility for purposes of §45.

7. Provided the facility was “placed in service” prior to January 1, 2012, within the meaning of §45(d)(8), relocation of the facility to a different location after December 31, 2011, or replacement of part of a facility after that date, will not result in a new placed-in-service date for the facility for purposes of §45 provided the fair market value of the used property (as used equipment not associated with any particular activity) is more than twenty percent of the facility’s total value (the cost of the new property plus the value of the used property) at the time of relocation or replacement.

LAW AND RATIONALE

Section 45(a) of the Code generally provides a credit against federal income tax for the use of renewable or alternative resources to produce electricity or fuel for the generation of steam. Section 45(e)(8) of the Code provides that, in the case of a producer of "refined coal", the credit available under §45(a) of the Code for any taxable year shall be increased by an amount equal to $4.375 per ton of qualified "refined coal" (i) produced by the taxpayer at a "refined coal production facility" during the 10-year period beginning on the date that the facility was originally placed in service, and which is (ii) sold by the taxpayer to an unrelated person during such 10-year period and such taxable year.

For purposes of §45 of the Code, section 3.01 of Notice 2010-54 provides that the term "refined coal" means a fuel which – (i) is a liquid, gaseous, or solid fuel (including feedstock coal mixed with an additive or additives) produced from coal (including lignite) or high carbon fly ash, including such fuel used as a feedstock, (ii) is sold by the taxpayer with the reasonable expectation that it will be used for the purpose of producing steam, and (iii) is certified by the taxpayer as resulting (when used in the production of steam) in a qualified emission reduction. Section 3.04 of the Notice provides that the term "qualified emission reduction" means, in the case of refined coal produced at a facility placed in service after December 31, 2008, a reduction of at least twenty percent (20%) of the emissions of nitrogen oxide and at least forty percent (40%) of the emissions of either sulfur dioxide or mercury released when burning the refined coal (excluding any dilution caused by materials combined or added during the production process), as compared to the emissions released when burning the feedstock coal or comparable coal predominantly available in the marketplace as of January 1, 2003.

Section 45(d)(8) of the Code generally provides that the term "refined coal production facility" means a facility which is placed in service after October 22, 2004 and before January 1, 2012.

Section 6.01 of Notice 2010-54 generally provides that a qualified emissions reduction does not include any reduction attributable to mining processes or processes that would be treated as mining (as defined in §613(c)(2), (3), (4)(A), (4)(C), or (4)(I)) if performed by the mine owner or operator. Accordingly, in determining whether a qualified emission reduction has been achieved, the emissions released when burning the refined coal must be compared to the emissions that would be released when burning the feedstock coal. Feedstock coal is the product resulting from processes that are treated as mining and are actually applied by a taxpayer in any part of the taxpayer's process of producing refined coal from coal.

Section 613(c)(5) of the Code describes treatment processes that are not considered as mining unless they are provided for in §613(c)(4) or are necessary or incidental to a process provided for in §613(c)(4). Any cleaning process, such as a process that uses ash separation, dewatering, scrubbing through a centrifugal pump, spiral concentration, gravity concentration, flotation, application of liquid hydrocarbons or alcohol to the surface of the fuel particles or to the feed slurry provided such cleaning does not change the physical or chemical structure of the coal, and drying to remove free water, provided such drying does not change the physical or chemical identity of the coal, will be considered as mining.

Section 6.03(1) of the Notice provides, in part, that emissions reduction may be determined using continuous emission monitoring system (CEMS) field testing. Section 6.03(a)(1) provides, in part, that CEMS field testing is testing that meets all the following requirements: (i) the boiler used to conduct the test is coal-fired and steam-producing and is of a size and type commonly used in commercial operations; (ii) emissions are measured using a CEMS; (iii) if EPA has promulgated a performance standard that applies at the time of the test to the pollutant emission being measured, the CEMS must conform to that standard; (iv) emissions for both the feedstock coal and the refined coal are measured at the same operating conditions and over a period of at least 3 hours during which the boiler is operating at a steady state at least 90 percent of full load; and (v) a qualified individual verifies the test results in a manner that satisfies the requirement of section 6.03(1)(b).

Section 6.03(2) of the Notice provides that methods other than CEMS field testing may be used to determine the emission reduction. The permissible methods include (a) testing using a demonstration pilot-scale combustion furnace if it establishes that the method accurately measures the emission reduction that would be achieved in a boiler described in section 6.03(1)(a)(i) and a qualified individual verifies the test results in a manner that satisfies the requirements of section 6.03(1)(c)(i), (ii), (v) and (vi) of the Notice; and (b) a laboratory analysis of the feedstock coal and the refined coal that complies with a currently applicable EPA or ASTM standard and is permitted under section 6.03(2)(b)(i) or (ii).

Section 6.04(1) of the Notice provides that a taxpayer may establish that a qualified emission reduction determined under section 6.03 applies to production from a facility by a determination or redetermination that is valid at the time the production occurs. A determination or redetermination is valid for the period beginning on the date of the determination or redetermination and ending with the occurrence of the earliest of the following events: (i) the lapse of six months from the date of such determination or redetermination; (ii) a change in the source or rank of the feedstock coal that occurs after the date of such determination or redetermination; or (iii) a change in the process of producing refined coal from the feedstock coal that occurs after the date of such determination or redetermination.

Section 6.04(2) of the Notice provides that in the case of a redetermination required because of a change in the process of producing refined coal from the feedstock coal, the redetermination required under section 6.04 must use a method that meets the requirements of section 6.03. In any other case, the redetermination requirement may be satisfied by laboratory analysis establishing that – (a) the sulfur (S) or mercury content of the amount of refined coal necessary to produce an amount of useful energy has been reduced by at least 20 percent (40 percent, in the case of facilities placed in service after December 31, 2008) in comparison to the S or mercury content of the amount of feedstock coal necessary to produce the same amount of useful energy, excluding any dilution caused by materials combined or added during the production process; (b) the S or mercury content of both the feedstock coal and the refined coal do not vary by more than 10 percent from the S and mercury content of the feedstock coal and refined coal used in the most recent determination that meets the requirements of the Notice.

Section 6.05 of the Notice provides that the certification requirement of section 3.01(1)(c) of the Notice is satisfied with respect to fuel for which the refined coal credit is claimed only if the taxpayer attaches to its tax return on which the credit is claimed a certification that contains the following: (1) a statement that the fuel will result in a qualified emissions reduction when used in the production of steam; (2) a statement indicating whether CEMS field testing was used to determine the emissions reduction; (3) if CEMS field testing was not used to determine the emissions reduction, a description of the method used; (4) a statement that the emissions reduction was determined or redetermined within the six months preceding the production of the fuel and that there have been no changes in the source or rank of the feedstock coal used in the process of producing refined coal from feedstock coal since the emissions reduction was most recently determined or redetermined; and (5) a declaration signed by the taxpayer in the following form: "Under penalties of perjury, I declare that I have examined this certification and to the best of my knowledge and belief, it is true, correct, and complete."

Finally, section 45(d)(8) of the Code provides that a refined coal production facility must be placed in service within certain timeframes. For purposes of the refined coal credit allowable with respect to refined coal other than steel industry fuel, the facility must be placed in service after October 22, 2004 and before January 1, 2012. Section 3.07 of Notice 2010-54 provides that the year in which property is placed in service is determined under the principles of § 1.46-3(d) of the regulations; i.e., when the property is placed in a condition or state of readiness and availability for a specifically assigned function. Section 5.02 of Notice 2010-54 provides that a refined coal production facility will not be treated a placed in service after October 22, 2004 if more than 20 percent of the facility's total value (the cost of the new property plus the value of the used property) is attributable to property placed in service on or before October 22, 2004. Notice 2010-54 also states that the IRS will not issue private letter rulings relating to when a refined coal production facility has been placed in service.

With respect to the first issue, the Process starts with several chemical additives being added to the feedstock coal from each coal source region separately prior to its combustion in a furnace. The additives provide the chemical structure that results in the reduction of emissions of nitrogen oxide and mercury during combustion. Section 6.01 of the Notice provides generally that a qualified emissions reduction does not include any reduction attributable to mining processes or processes that would be treated as mining if performed by the mine owner or operator. In the instant case, the Process is not a mining process. Further, section 3.01 of the Notice clarifies §45(c)(7) of the Code and specifically provides that refined coal includes feedstock coal mixed with additives. Thus, additive processes that mix certain chemicals or other additives with the coal in order to achieve emissions reductions may qualify for the refined coal production tax credit. Additionally, section 3.03 defines comparable coal as coal that is of the same rank as the feedstock coal and that has an emissions profile comparable to the emissions profile of the feedstock coal. Accordingly, we conclude that the coal produced by using the Process constitutes a "refined coal" within the meaning of §45(c)(7) of the Code, provided that the refined coal (i) is produced by the Taxpayer from feedstock coal that is the same source or rank as the "Tested Coal" and (ii) satisfies the qualified emission reduction test stated in §45(c)(7)(B) of the Code.

With respect to the second issue, the emissions profile of the refined coal product is compared to the emissions profile of either the feedstock coal or a comparable coal predominantly available in the marketplace as of January 1, 2003. Section 3.03 of the Notice provides that a "comparable coal" is defined as coal that is of the same rank as the feedstock coal and that has an emissions profile comparable to the emissions profile of the feedstock coal. Section 6.04 of provides that a determination or redetermination of a qualified emissions reduction is valid until the occurrence of the earliest of the following events: (i) the lapse of six months from the date of such determination or redetermination; (ii) a change in the source or rank of the feedstock coal that occurs after the date of such determination or redetermination; or (iii) a change in the process of producing refined coal from the feedstock coal that occurs after the date of such determination or redetermination. Accordingly, we conclude that provided that the feedstock coals used to produce refined coal during any determination or redetermination period are from the same coal source regions and of the same rank as the Tested Coal, all feedstock coal used to produce refined coal which is from any of the coal source regions and ranks reflected in such Tested Coal, and any blend of coal from such regions and ranks, shall be treated as feedstock coal of the same source and rank for purposes of section 6.04 of Notice 2010-54, regardless of the mines from which such feedstock coal is purchased.

With respect to the third issue, section 6.03(3) of the Notice provides that any permissible testing method provided for in the Notice can be used in emission testing for any pollutant. That is, a taxpayer can use different testing methods for each of nitrogen oxide, sulfur dioxide or mercury, provided the method used for any pollutant is a permissible method. Section 6.04(1) provides that an emission test establishing a "qualified emission reduction" qualifies the refined coal for a six-month period provided there is no change in the process for producing the refined coal or in the source or rank of the feedstock coal. Therefore, a taxpayer must "redetermine" the emission reductions to qualify for the succeeding six-month period using one or more approved methods. In the instant case, the Taxpayer will arrange for pilot-scale combustion testing, and will not rely on any continuous emissions monitoring system or other field testing, which is permitted under section 6.03 of the Notice. Specifically, Company B will arrange with the Center to conduct testing (including redetermination testing) at its CTF to determine the emissions reductions associated with burning the refined coal product compared to the feedstock. For purposes of qualifying the refined coal produced at the facilities, the Center has conducted pilot-scale combustion tests at its CTF as documented in the Test Reports. In conducting such tests, the Center conducted tests on the feedstock, and then mixed a separate sample of the feedstock with the additives so that it could conduct tests on the refined coal product. In each of its reports, the Center reported that the test results indicated that the blend of coal and additives achieved the required emissions reductions. In addition, Test Rep 3 concluded that that any blend of coal from the three coal source regions included in the Tested Coal for purposes of that test would be expected to achieve the required emissions reduction when used to produce refined coal at full scale using the additive levels tested. Based on the foregoing, we conclude that testing by the Center for qualified emissions reductions as set forth in its test reports (including interim reports) satisfies the requirements of Notice 2010-54. Qualified emissions reduction through testing by the Center at its combustion research facility or similar pilot-scale combustion testing facilities under Notice 2010-54 may be relied upon.

With respect to the fourth issue, section 6.04(2) of Notice 2010-54 provides, in part, that in the case of a redetermination required because of a change in the process of producing refined coal from the feedstock coal, the redetermination required under section 6.04 must use a method that meets the requirements of section 6.03. In any other case, the redetermination requirement may be satisfied by laboratory analysis establishing that the sulfur and mercury content of both the feedstock coal and the refined coal do not vary by more than 10 percent from the sulfur and mercury content of the feedstock coal and refined coal used in the most recent redetermination that meets the requirements of the Notice. Accordingly, we conclude that Taxpayer may satisfy the redetermination requirement of section 6.04 of Notice 2010-54, by laboratory analysis establishing that the sulfur and mercury content of both the feedstock coal and the refined coal, on average, do not vary by more than ten percent below the bottom of (nor more than ten percent above the top of) the range of sulfur content and the range of mercury content of the feedstock coal and the refined coal used in the most recent determination that meets the requirements of section 6.03 of Notice 2010-54.

With respect to the fifth issue, it is intended that the Taxpayer will engage in redetermination testing every six months, or more frequently if required pursuant to Notice 2010-54. However, the Center is not always able to issue the written report required by section 6.03(2)(a) of Notice 2010-54 within the six month period. Thus, although redetermination testing is completed within the six month period, the report may be received after the six month period. Nevertheless, the delay by the Center in issuing its report cannot be indefinite. Accordingly, we conclude that the results set forth by the Center in a redetermination test report for production may be relied upon after the date of testing even if the report is not received until after the six-month period specified in section 6.04(1)(i) of Notice 2010-54, so long as the Taxpayer receives the written report within 90 days from the date of testing. However, the redetermination of qualified emissions reduction must occur during the earliest of the events described in section 6.04 of Notice 2010-54 regardless of the time of the actual receipt of Center's test report.

With respect to the sixth issue, the placed-in-service language in §45(d)(8) focuses on the facility, and does not, by its terms, require the facility to have been placed in service by the taxpayer claiming the credit. Accordingly, we conclude that the transfer of the facility by Company A to Company B subsequent to its placed-in-service date will not affect the placed-in-service date of the facility for purposes of §45.

With respect to the seventh issue, the facility was relocated from State C to State D, and in connection with that relocation all essential components of the facility were relocated and retained. In addition, during the life of the facility, it may be necessary to replace certain major components. In the event of relocation or replacement of a component, there should be no change in the placed-in-service date of the facility as long as the test described in section 5.02 of Notice 2010-54 has been met. Based on the foregoing, we conclude that provided the facility was "placed in service" prior to January 1, 2012, within the meaning of §45(d)(8), relocation of the facility to a different location after December 31, 2011, or replacement of part of the facility after that date, will not result in a new placed in service date for the facility for purposes of §45 provided the fair market value of the used property (as used equipment not associated with any particular activity) is more than twenty percent of the facility's total value (the cost of the new property plus the value of the used property) at the time of relocation or replacement.

This ruling expresses no opinion about any issue not specifically addressed in this ruling letter, including (1) whether any person has sold refined coal to an unrelated person, or (2) when the facility was "placed in service." In particular, we express or imply no opinion that the Taxpayer has sufficient risks and rewards of the production activity to qualify as the producer of the refined coal. The Service may challenge an attempt to transfer the credit to a taxpayer who does not qualify as a producer, including transfers structured as partnerships, sales or leases that do not also transfer sufficient risks and rewards of the production activity.

In accordance with the Power of Attorney on file with this office, we are sending a copy of this letter to your authorized representatives. A copy of this ruling must be attached to any income tax return to which it is relevant. Alternatively, taxpayers filing their returns electronically may satisfy this requirement by attaching a statement to their return that provides the date and control number of the letter ruling.

This ruling is directed only to the Taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. We are sending a copy of this letter ruling to the Industry Director.

Sincerely,

Peter C. Friedman
Senior Technician Reviewer, Branch 6
Office of Associate Chief Counsel (Passthroughs
(& Special Industries)

cc: